Energy 265 (2023) 126351

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

The photovoltaic revolution is on: How it will change the electricity system in a lasting way

Reinhard Haas [a,*], Neven Duic [b], Hans Auer [a], Amela Ajanovic [a], Jasmine Ramsebner [a], Jaroslav Knapek [c], Sebastian Zwickl-Bernhard [a]

[a] TU Wien, Energy Economics Group, Vienna, Austria
[b] University of Zagreb, Department of Energy, Power Engineering and Environment (FSB), Croatia
[c] Czech Technical University in Prague, Faculty of Electrical Engineering, Czech Republic

ARTICLE INFO

Keywords:
Photovoltaic market development
Grid parity
Photovoltaic potential
Tariff schemes
Environmental performance

ABSTRACT

Electricity generation from photovoltaic (PV) plants plays a major role in the decarbonization of the energy sector. The core objective of this paper is to identify the most important conditions for the future development of PV in order to achieve its greatest possible benefits of PV systems for society. This analysis is based on the documentation of the historical deployment of quantities of PV and on the lessons learned regarding cost developments. In addition, the improvements of PVs technical and environmental performance parameters are investigated. A major result is that the impact of PV feed-in on network capacities may be substantial. Hence, classical energy-based network charges are inadequate. Changes in tariff and pricing structures are needed especially on retail level. The major conclusions is that customers should also receive time-variable price signals that tells them the real-time value of electricity in the system and provides incentives for taking electricity from the grid or feed-in. In addition, the tariffs should have components for maximum power from and to the grid. Another conclusion is that on retail level grid parity already today provides sufficient incentives to purchase a PV system in many countries without additional financial support.

1. Introduction

In the course of climate change mitigation, there is an urgent need to reduce global greenhouse gas (GHG) emissions [1] to which the electricity sector contributes approximately 38% and is one of the most important sectors to be addressed in this respect. Renewable electricity plays a major role in the decarbonization of all end-consumption sectors either through direct electrification by an adaption of their processes or indirectly via a transformation of electricity into renewable gases, liquid fuels or heat. A promising and already established technology for renewable electricity generation is photovoltaics (PV). Despite its invention already in the 19th century, only in the late 1980s, the first solar PV systems have been implemented and paved the way for autark, decentral electricity production. In the early 1990s, the first grid-connected PV power plants were installed in Japan, Italy, Australia and Germany [2].

The potential benefits of solar PV systems range from widely emission-free electricity generation during the operational phase, allowing electricity pro-sumers to cover at least part of their demand. There is great value in PV for society, and it could become a major source of electricity generation [10]. Developing countries can provide electricity to rural areas without grid connection which may help to replace fossil fuels for housholds. Additionally, the integration of PV systems with agricultural activities, so-called agrovoltaics, makes it possible to diversify farmers' incomes and increase local energy independence. Eventually, large-scale renewable electricity generation may decarbonize the electricity system and be transformed into gases such as hydrogen, methane, or kerosene, especially in industry and transport.

However, several challenges remain to be addressed. Historically, the electricity system has mainly constisted of fossile fuel based generation plants and therefore quite flexible in their operation. Renewable technologies, by contrast, are dependent on the availability of hydro, wind and solar power and imply variable electricity production. With the increasing use of variable renewable energy sources (VRES) the matching of supply and demand, as a result, is characterized by increasing storage and other supply and demand-side flexibility options

* Corresponding author.
E-mail address: haas@eeg.tuwien.ac.at (R. Haas).

https://doi.org/10.1016/j.energy.2022.126351
Received 10 August 2021; Received in revised form 21 November 2022; Accepted 4 December 2022
Available online 5 December 2022

From the supply side, battery storage can buffer the discrepancy with demand. Nevertheless, it is obvious from economic and environmental point-of-view that not every peak in solar PV electricitiy production should be stored., From the demand side the change of the role of households from pure consumers to ‘prosumagers’ – consumers who also produce and store electricity – also requires different approaches to ensure their most beneficial integration into existing systems. Properly designed new pricing and tariff sytems could provide an incentive to shift consumption to match electricity supply. Hirschhausen et al. [11] argue that beside the potential of prosumage for decarbonization, this type of change to the energy system is also often regarded as a threat, especially by utilities. Optimal solutions regarding storage and grid interaction still need to be found. In 1994, when PV was not even a niche technology, Haas [12] analyzed the value of PV electricity for utilities and already more than 20 years ago documented the challenges utilities face with PV today. Schill et al. [13] highlight the economic system inefficiency as a potential disadvantage of growing solar prosumage and self-consumption using decentral storage. Obviously, this trend adds hardly controllable consumption and production units to an energy system. System cost can be reduced if decentralized storage is operated following requirements in the distribution grid and made available to further electricity market activities instead of mainly focusing on self-comsumption. All these challenges therefore ask for a solution and an optimal strategy – from societys point of view – for integrating PV in the electricity system. In this context an effective regulatory framework and appropriate tariff systems are required for all electricity users to guide future consumer choices [14].

The core objective of this paper is to identify the most important conditions for the future development of PV in order to achieve the greatest possible benefits of its continuously growing market penetration for society. In this context especially the need for further promotion strategies and for a redesign of network tariff and pricing systems is investigated. The later is especially important for grid-parity conditions to bring about a fair network cost allocation among all customers – active pro-sumers (owning a PV system) and passive consumers (just consuming energy from the network). This analysis is based on the documentation of the historical deployment of quantities of PV and on the lessons learned regarding cost developments. In addition, the improvements of PVs technical and environmental performance parameters are investigated and documented over about the last 25 years.

The major new contribution of this paper is to close a research gap regarding a holistic assessment of PV’s role in electricity systems. It includes the simultaneous consideration of the economic and environmental issues (embedded energy) as well as promotion policies for PV systems – in the past, present and future.

This paper is structured as follows: Section 2 outlines the current PV market situation in leading countries. Section 3 documents the historical development of PV systems concerning costs and economics including the issue of grid parity. The future prospects of PV including costs, embedded energy and associated emissions in the PV system production process are analyzed in Section 4. In Section 5, the requirement for new pricing and tariff schemes to efficiently integrate PV electricity in electricity systems is discussed. A summary of major findings, conclusions and an outlook complete the paper.

2. Global PV installation

During the last decades, global PV system installation increased substantially. Small-scale PV units e.g. on rooftops were the driver to make PV the fastest growing technology for electricity generation [3] revolutionizing the traditionally known ways of energy production and consumption. Decentralized, small-scale PV sytems have a substantial impact on the role of the end user in the energy system, which is a main focus of this work. PV applications such as rooftop PV systems, enable electricity consumers to produce their own electricity onsite and turn into ‘pro-sumers’ [4]. Through storage, they can optimize their self-generation for profit maximization and become so-called ‘prosumagers’.

In 2019, global annual solar PV system installations accounted for 111 GW, compared to 29.5 GW in 2012 [2]. Worldwide cumulative PV capacity grew to 623 GW by the end of 2019 [2], and another 127 GW were added globally in 2020 [5]. Figs. 1 and 2 show yearly and cumulative PV system installation for a selection of countries. Yet, in the period before 2012, European countries such as Germany, Spain and Italy were the drivers of PV deployment. After 2012, other regions such as China, the US, India and Japan have taken over the lead. Moreover, PV has been the technology with the most dramatic cost reduction per MWh of about 80% between 2005 and 2015 [[6,7]]. Between 2010 and 2020, the cost decreased by 82%, with a 13% decrease only between 2018 and 2019 [8].

The growing share of PV electricity generation during the last decades implies both (long-term) economic and environmental benefits but can also lead to challenges concerning the further integration of large amounts of PV into existing electricity systems.

While in the early years of PV, grid-connected, distributed installations have dominated, from 2012 onwards, centralized, utility-scale systems picked up mainly due to the new introduction of auctions (see Fig. 3).

This section analyses the major recent developments and trends regarding PV system capacities. Growth rates have increased between 2007 and 2010 in Italy, France, Australia and Germany, followed by an acceleration in the Chinese and Indian markets between 2010 and 2013. Fig. 4 shows the growth rates based on the development of the annual and cumulative installed capacity shown in Figs. 1 and 2. A slight dip followed globally, and growth evened out towards 2018. Nevertheless, during the last few years, it seemed to pick up again in all countries but Italy, Germany and France, where yearly capacity installations stagnated since 2013 around 4–20%.

The countries leading the path towards a growing share of solar PV capacity have changed throughout the last decade. From the 1990s to 2003, Japan was an early adopter of PV technology and ranked number one in installed PV capacity and annual energy production in TWh [9]. Starting in 2003, Germany implemented very ambitious and highly subsidized promotion schemes and guided increased PV installation until 2014. As can be seen from Fig. 5, in 2009, Germany was leading with 46% of global cumulative installed PV capacities, followed by Spain and Japan, with only 17% and 12% respectively ([2,9]). 2012 marked the starting point for these countries to be overtaken by China, representing the market leader in 2019 with a 34% share of the cumulative installed capacity, followed by the USA accounting for 13%, Japan remaining steady at 11%, and Germany ranking fourth with 8% (see Fig. 6). Furthermore, ranking 3rd in the annual installations as described in Fig. 1 in the last years, India is on the rise with highly competitive prices on solar PV installation already achieving a share of 6% in 2019

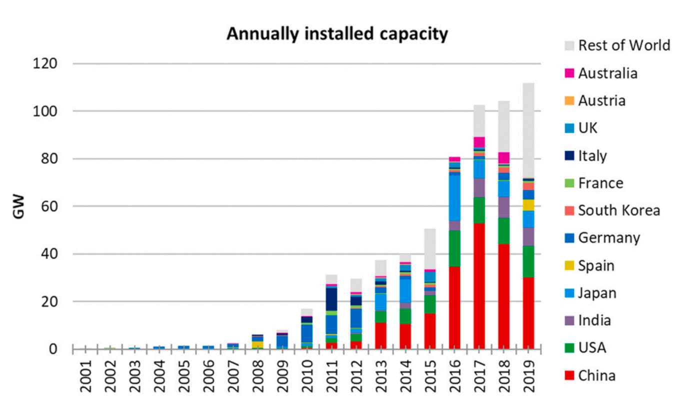

Fig. 1. Development of new installed PV capacities per year in different countries 1992–2019 [[2,9]].

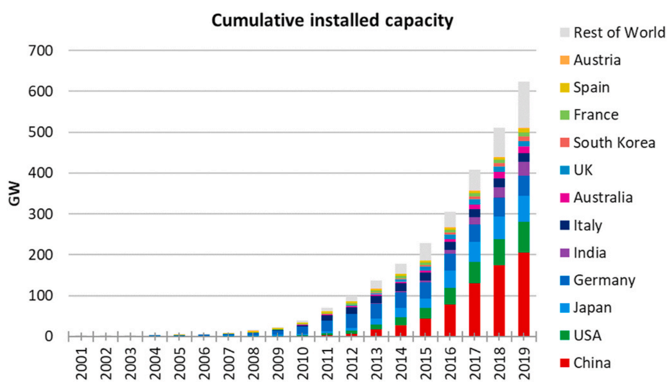

Fig. 2. Development of cumulated stock of PV-capacities in major countries worldwide 2000–2019 [[2,9]].

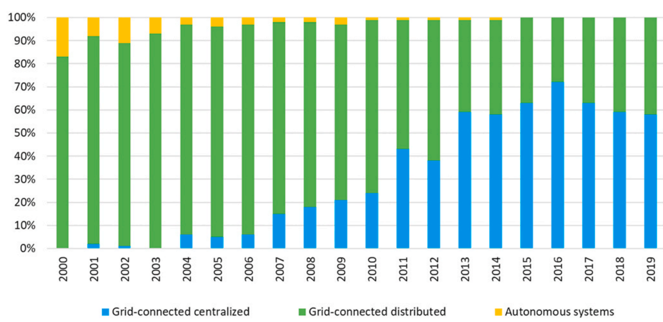

Fig. 3. Annual share of centralized and distributed grid-connected and autonomous installations 2007–2019 [2,16].

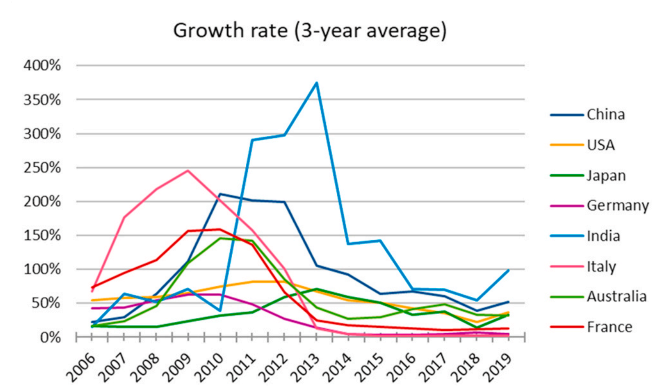

Fig. 4. Growth rates of PV capacity by country [2,9].

while not even having started seriously until 2012. This development can mainly be explained by attractive promotion schemes, which have brought down the costs of investment, as well as technological learning, which has decreased production costs.

3. Historical development of costs, economics and efficiency

Investment cost development is of major importance for PV market competitiveness. In this section, the historical development of module and system investment costs and the electricity generation costs are reviewed. The economics and profitability of PV systems differ by country depending on the amount of solar irradiance and the market structure concerning the market share of large centralized systems delivering electricity to the wholesale electricity markets compared to

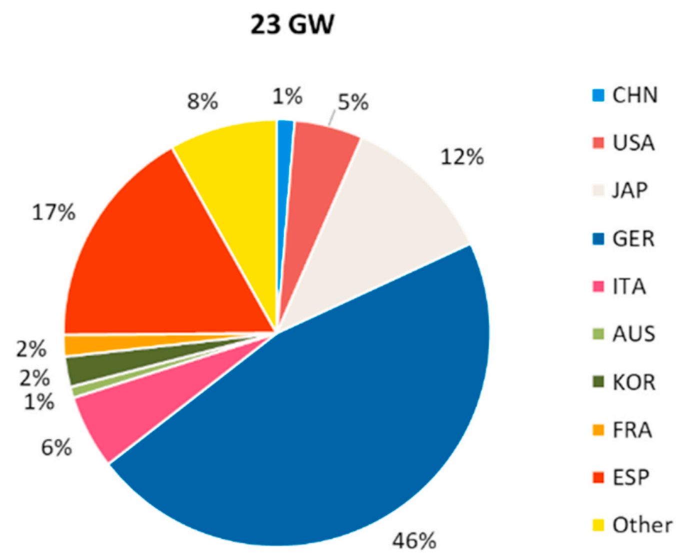

Fig. 5. 23 GW Cumulative installed PV capacities worldwide by the end of 2009 [[2,9]].

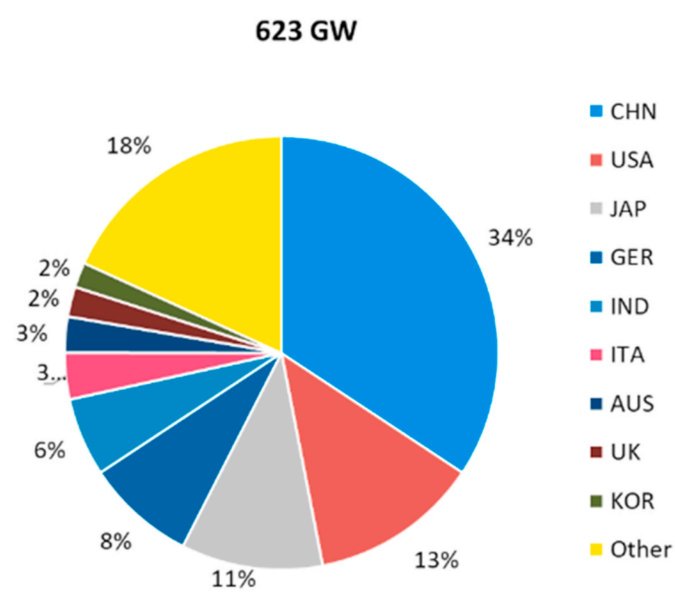

Fig. 6. 623 GW cumulative installed PV capacities worldwide in 2019 [[2,9]].

small, distributed systems mainly for own-consumption. The core mechanisms that lead to a decrease in PV system prices are technological learning and economies of scale. It is well known that the technology cost is expected to drop as it is deployed more widely. Some major references in this context are [[17–20]].

3.1. Global PV system prices

Fig. 7 illustrates the historical development of module prices globally and for Japan, Germany and the US in USD/Wp. Since the early 1990s, prices have virtually crashed. The steepest price decrease is visible between 2010 and 2012 when global incentives on PV system investments and large utility-scale systems were implemented. Between 2012 and 2019, prices decreased slower and seemed to stagnate during the last two years.

PV module cost is only one part of the total PV system cost. The total cost of PV installations (PV system cost) has decreased for utility-scale PV systems between 2007 and 2019 from about USD 5,3/Wp to about

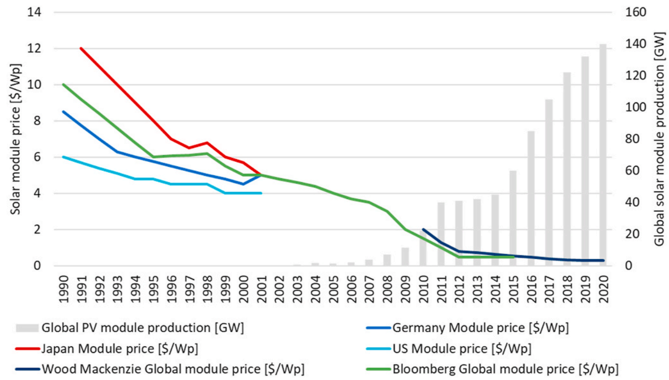

Fig. 7. Historical development of module prices worldwide (USD/Wp) [2,21–23].

USD 0.83/Wp, mainly due to the sharp decrease in PV module prices [24]. Additionally, electronic components (BOS) and other costs (design, fees, etc.) contributed to the price decrease [24]. However, with the price of PV modules falling much faster than the other two components, the share of PV module cost is declining. In 2007, the average share of PV modules in the total cost of utility-scale PV systems accounted for 66%, BOS costs for 19%, and other costs for 15%. In 2019, PV module costs only made up 28.5%, while BOS costs represented 28.5% and other costs 43% [24]. The price of monocrystalline PV modules dropped to an average value of about 0.21 USD/Wp at the end of Q1 2020 (the price range was 0.20–0.38 USD/Wp) as achieved in large tenders in Chinav [24]. The price of PV modules in a tender for a total installed capacity of 1.31 GW using mono-facial PV modules of 540 Wp with delivery in Q1/2022 is about 0.24 USD/Wp [25].

Based on data by Ref. [26], Fig. 8 shows the development in the cost of total installed residential solar PV in USD/kW. France, Japan, Australia and Italy experienced a remarkable cost decrease from 2010 evening out after 2016. Germany shows the most consistent reduction in PV system cost, being placed quite centrally among all regions in 2019. The USA has the by far highest cost per kW since 2015.

The cost reduction between 1980 and 2012 was brought about by several low-level mechanisms of which efficiency gains made up 23%, non-silicon materials cost 21%, the silicon price 16%, silicon usage 14%, the wafer area and plant size each 11%, and 7% by the yield [7]. In the more recent period between 2001 and 2012, plant size represented the major contributor with 37%. Concerning high-level mechanisms, the main drivers to the cost decline were R&D and economies of scale with 59% and 22% respectively between 1980 and 2012. Between 2001 and 2012, the distribution was more balanced, with both contributing around 40% [7].

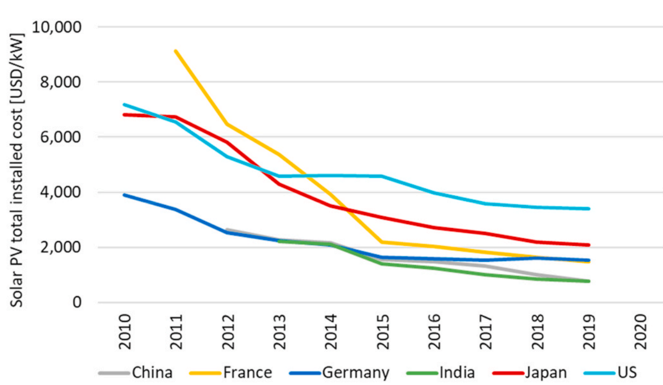

Fig. 8. The development of residential PV system investment cost in selected countries from 2010 to 2019 (adapted from Refs. [22,26]).

The specific investment cost also influences the cost of electricity (COE).[1] The COE is derived from the annual system cost, including yearly capital expenditure derived from the capital recovery factor (α) and operational expenditures, financing and taxes divided by the electricity output achieved by the installed capacity also depending on PV module efficiency (η) [27]. The costs of one kWh PV electricity (C_{PV}) are calculated according to equations (1) and (2) [28].

$$C_{PV} = \frac{I_0\ \alpha}{T} + C_{O\&M} = \frac{I_0\ \alpha}{A_{PV}\ Q_{Sol}\ \eta} + C_{O\&M} \quad (\text{USD / kWh}) \tag{1}$$

$$\alpha = \frac{r\ (1+r)^n}{(1+r)^n - 1} \tag{2}$$

T Full load hours (h/year), A_{PV} Area of the PV plant (m^2), Q_{sol} Solar irradiance (kWh/m^2), η PV system efficiency, α Capital recovery factor, I_0 Initial investment (USD/kW), $C_{O\&M}$ Operating and maintenance cost (USD/kWh), n Depreciation time (years), r Interest rate.

The COE represents the total lifetime cost relative to the produced energy and largely depends on the cell efficiency and output generated from a specific installed capacity. It, therefore, decreases with the amount of full-load hours of operation related to the installed system capacity. IRENA [29] states that between 2010 and 2017, the COE of residential systems has declined globally at a robust pace. "PV is on the way to become the cheapest electricity generation source in many countries worldwide" [15]. The historical development of electricity generation costs in different countries is described in Fig. 9. However, Australia and even more so the US achieve a rather low cost of electricity from PV compared to its cost per kW. This difference can mainly be explained by solar insulation in the respective country and the resulting output that can be achieved with a particular capacity investment.

As explained, the cost decrease was mainly achieved by R&D and economies of scale, which drove technological learning for the innovative module parts. Furthermore, support schemes had to be implemented for solar PV systems to enter a highly competitive energy market with many mature and cheap traditional technologies.

3.2. Major promotion strategies

Because of the very high costs for the new PV technology when first entering the market in the 1990s, several strategies to promote PV have been implemented. There are comprehensive surveys on these strategies

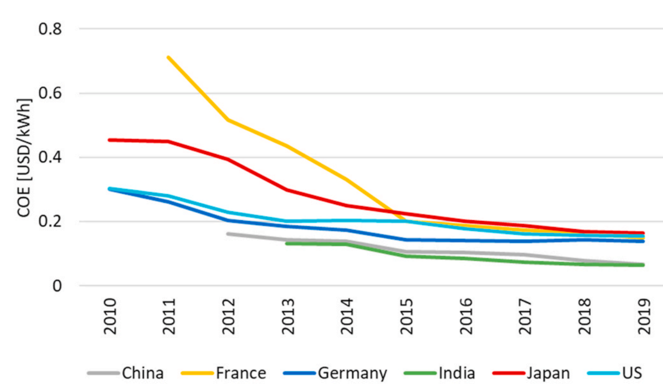

Fig. 9. The development of the cost of electricity (COE) in the residential sector in selected countries from 2010 to 2019 adapted from Ref. [26] and own calculations.

[1] Note that we do not use the so-called LCOE method to avoid discounting energy at the same rate as capital.

in the early years of PV deployment [30,31]. Four different categories of promotion schemes can be differentiated: (i) early schemes; (ii) feed-in-tariff (FIT): In 1998, Germany was the first country to implement a FIT scheme for PV electricity that is fed into the distribution grid, first known as "kostengerechte Vergütung" and in 2004 named "feed-in-tariff"—a groundbreaking step; (iii) in parallel other countries implemented so-called net-metering; (iv) finally since about 2012 bidding/tendering programs have become popular. Other schemes such as green certificates with quota systems or investment subsidies were used but never had a significant impact. A crucial international analysis of the impact and effectiveness of FITs for the development of solar PV is provided by Dijkgraaf et al. [32]. They state that the literature so far has underestimated its impact and that well-designed FITs in terms of magnitude, consistency and duration could reach much further than the formerly applied measures.

While in the beginning, FITs where the favorable promotion tool, bidding schemes or auctions have developed more or less successfully—specifically in developing countries to achieve a specific scope of PV system generation—and can be carried out using different approaches [33]. Auctions are particularly popular in developing countries with high solar radiation and low manufacturing cost. They are mainly known for their efficient and effective way to scale up the use of RESs. Nevertheless, also in developed countries, auctions are becoming the standard promotion instrument. By competitively defining the support levels, setting technology standards, and controlling the capacity expansion based on the demand, the expansion's demand, efficiency, and effectiveness shall be guaranteed. In the case of a well-designed auction, the bidders offering the lowest COE are selected. However [33], find that auctions do not always fulfil their expected purpose, and the results depend on many aspects of the auction and the general regulative situation.

All in all, auctions may lead to a decrease in the cost of new technologies and establish a competitive market along with other RE technologies. In 2016, auctions achieved consistently low utility-scale PV prices in developing countries for the first time [34]. Auctions achieved less than USD 0.1/kWh in India, Zambia, Brazil, South Africa, Peru etc. And even less than USD 0.04/kWh in Chile, Mexico and UAE, leading to a paradigm shift in the electricity sector in many more developing countries. The price decrease also opens broad access to cheap electricity in developing countries with high solar radiation. Brazil has long-term experience in the field of promoting renewables through auctions [35]. The first large-scale auction on PV capacity was held in October 2014, and Brazil has supported the introduction of this technology through long-term contracts that reduce the investment risk. The Brazilian auction achieved a significant price reduction of 17% compared to the starting price, a high average capacity factor of 23%, and introduced the technology in utility-scale generation. Recent developments, however, showed extremely competitive auctions around USD 20/MWh (see Fig. 10), which contributed to the increase of the utility-scale market from 2017 onwards.

3.3. The impact of PV on the electricity market prices

The current market structure and rules of price determination first need to be understood to grasp the effect of PV feed-in on electricity market prices [4]. Prices in a functioning market are usually defined where supply and demand match and are balanced—at the intersection of the merit order supply curve and electricity demand at every point in time. As all power plants in a market are involved in determining the electricity price, also RESs have their specific impact, which may differ from experience with traditional and more flexible generation technologies. This phenomenon is already known since volatile hydropower was first used for electricity generation. RESs influence electricity prices in formerly regulated markets at least at the conceived marginal costs of electricity generation. Later, with the first experience of wind booms (about 2007–2009, in Denmark already earlier), temporarily strong winds in the systems even lead to negative electricity prices [37–39]). However, these effects mostly happened at off-peak times, sometimes because of wrong or careless wind forecasts.

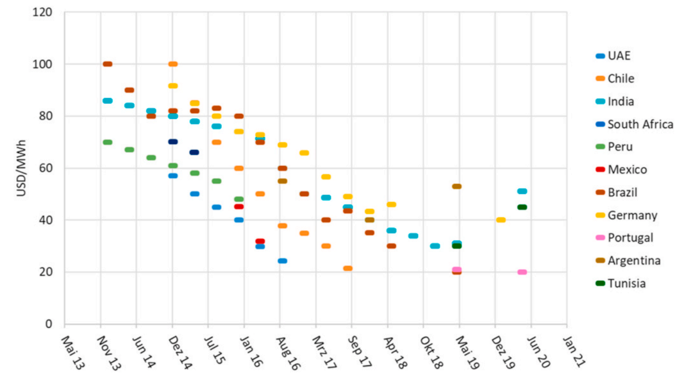

Fig. 10. Bidding prices for PV systems achieved between 2013 and 2020 in different countries world-wide, Source [34,36].

This fundamental approach has led to a quite different price development in several European electricity sub-markets between 2000 and 2017 (see Fig. 11). High volatility and considerable differences between electricity spot market prices have been observed in different sub-markets within this period. Italy tended to experience higher prices and volatility throughout the horizon due to its over-reliance on imported electricity and congested cross-border transmission lines. In the case of the ELSPOT, which includes Sweden, Norway, Finland, and shares of Denmark, the pattern is different with high shares of hydro-electric power and a weak interconnection with continental Europe. Other markets—even the isolated Spanish market—show price convergence. The reason for high prices in 2008 in Continental Europe was the low hydropower availability, while the price decrease after 2008 may, at least to some extent, be associated with the economic crisis.

On the one hand, the merit order effect played a role in increasing renewable electricity sources pushing traditional power plants out of the market. On the other hand, the low CO2 prices do not lead to higher pricing of the remaining fossil-fuel-based plants. The price dip in 2020 is associated with the reduced demand caused by the COVID-19 pandemic.

The massive integration of electricity from RES (especially wind and PV) was most pronounced between 2011 and 2016. The increase in electricity generation from these sources led to the displacement of conventional power plants and this, together with low prices for emission allowances, led to a significant and relatively long-lasting decline in electricity prices. The trend reversed in between 2017 and 2019.2020 and the first half of 2021 are affected by the COVID-19 pandemic and the

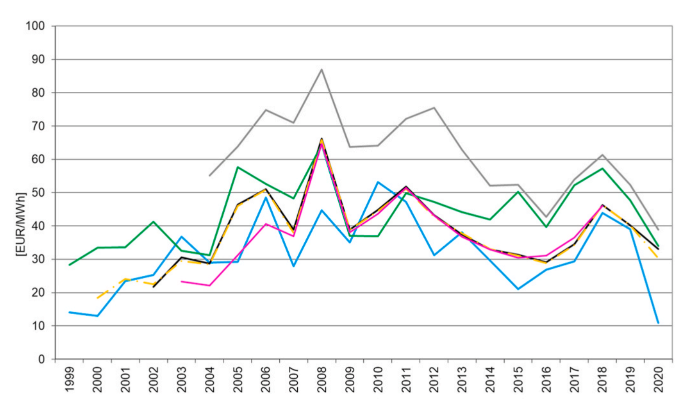

Fig. 11. Day-ahead price Development of day-ahead electricity prices in European electricity markets 1999–2020, Source: Homepages of different energy exchanges.

associated decline in consumption and stagnation in prices.

Similar challenges may arise with the further feed-in of PV electricity, which differs substantially in timing and variability compared to wind availability. Fig. 12 shows the merit order supply curve with and without PV capacities during the peak time of a summer day and the short term marginal costs of conventional electricity capacities. On such a sunny day with strong solar irradiance, PV electricity generation shifts the supply curve to the right, which essentially pushes nuclear and fossil-fuel-generation “out of the market”. Suppose the impact of PV electricity feed-in, e.g. on a sunny day in October, which is not a peak period for solar generation in Germany, can be as dramatic as is shown in Fig. 12. In that case, one can expect much more dramatic impacts on market prices during summer months.

Fig. 13 shows the impact of increasing PV capacity on electricity prices on an exemplary day due to a change in the residual load by PV feed-in, especially during noontime. The result is a shape resembling a duck—the so-called “duck curve”. With more electricity consumed onsite, the grid can be relieved from the noon peaks, and distributed producers can optimize their economic benefit (see Section 3.4).

3.4. Grid parity and the role of battery storage

Fig. 14 compares the cost of electricity from PV systems to household electricity prices for the examples of Germany, Austria and the Czech Republic and the resulting grid parity. According to the commonly used definition, grid parity is achieved when the COE of an alternative source (e.g. a decentral PV generation plant) is lower than the price of electricity from the grid. For small-scale systems (about 3 kWp), the so-called grid parity was reached in Germany already in 2012, when the PV electricity generation cost crossed household electricity prices, in Austria and Czech Republic later. Note, that grid parity depends on solar insolation, the magnitude of the household electricity price and the size of the PV system. In total, for Germany, the situation for PV grid parity in households can be considered rather promising. However, the market remains very sensitive due to its dependence on imports from China and adequate financial support from the government. Hence, full economic competitiveness is not automatically achieved with grid parity but strongly depends on the feed-in price for excess electricity. If storage is added to the PV system, the COE is higher, and grid parity will take a few years longer.

The share of electricity self-consumption is of specific relevance for a cost-effective PV solution. The self-consumption rate is the ratio between the PV energy used directly or to charge the battery, and the overall produced PV energy [41]. Using self-generated electricity provides a means to lower the electricity bill and avoid excessive penetration of PV generated electricity in the grid network. If an onsite PV system covers the whole building demand, the actual self-consumption accounts for about 25–30% in residences and even more in commercial buildings; the rest needs to be fed into the grid. If the total revenue or saving from the use of the installed PV system for self-consumption

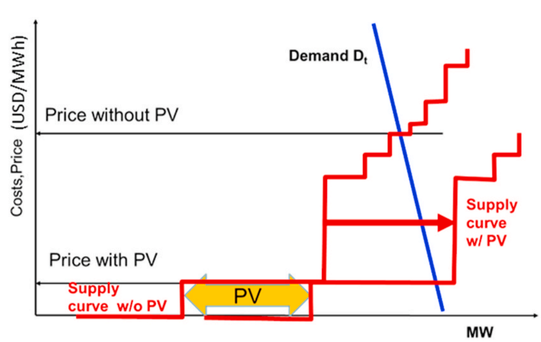

Fig. 12. Example of a merit order electricity supply curve without and with additional PV capacities at noon of a nice summer day.

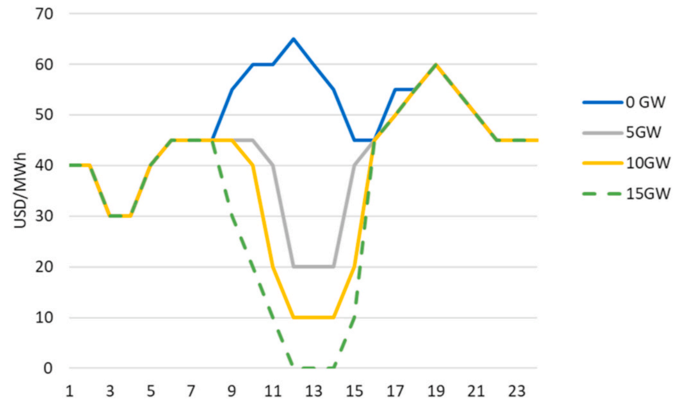

Fig. 13. The duck curve describing the impact of increasing PV penetration on the electricity price in an example from 0 to 15 GW.

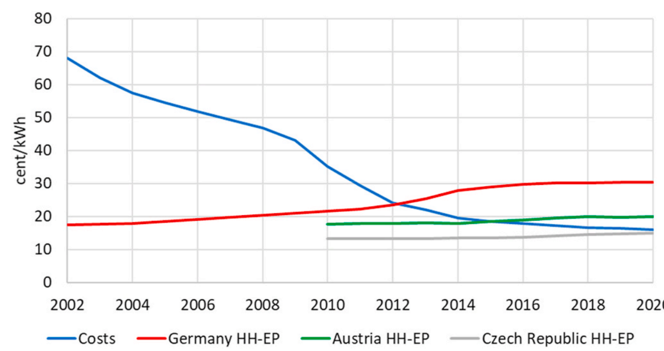

Fig. 14. Historical development of PV cost for small systems up to 2020 in Germany vs. development of household electricity prices for the examples of Germany, Austria and the Czech Republic leading to “grid parity” in different years. Sources [[4,40]].

and remuneration from grid feed-in is greater than the annual cost of setting up and maintaining the PV system, subsidies might no more be necessary. The condition for the economic effectiveness of the PV system from an end-users point of view is defined in Equation (3).

$$E_{self}\, p_{HH} + E_{feed-in}\, p_{feed-in} \; > I_0 \propto + C_{O\&M} \tag{3}$$

E_{self} Own consumption of PV electricity (kWh/year), p_{HH} Variable part of household electricity price (USD/kWh), $E_{feed-in}$ PV electricity fed into the grid (kWh/year), $p_{feed-in}$ Feed-in tariff for PV electricity (USD/kWh).

For the economic evaluation from the point of view of consumer with own PV systems, however, the relatively higher costs for grid feed-in and grid withdrawal due to changed tariff structures must also be taken into account. There are two methods to increase the direct consumption (“Self-Consumption”) of solar electricity. One is to use intelligent control systems, which do load management e.g. switch on major loads (washing/dryer machines, heat pumps, refrigerators, air-conditioners) when the sun is shining.

The second approach requires a means to store the energy, either as electricity in a battery storage or as “product” (storage for heating and coolingpumped water), for use at night or rainy days. Storing electricity may have the additional advantage of making energy offers to the network operator when it is profitable. It is, however, rather doubtful whether there is an economic incentive to implement storage for the owners of small PV systems. Nevertheless, some fraction of the electricity generated usually has to be sold to the grid to use the feed-in remuneration. The fact that the costs of PV-generated electricity can be equal to or lower than residential electricity costs is not yet sufficient to support a self-sustained and unsupported market.

Fig. 15 shows the potential self-consumption of a residential PV system for an exemplary household and the remaining grid consumption and excess generation. In times with low or no PV production, the household will consume electricity from the grid and pay the wholesale price plus taxes and other charges. However, in the case of excess PV production, the household demand will be covered from own production, and excess electricity will be offered to the grid at a FIT or the market price. Therefore, a clear cost advantage arises for the electricity consumer. In times of high supply, the electricity is used directly and to charge a battery to be stored short-term. This way, more PV electricity can be used later during low resource availability by discharging the battery. The amount of produced electricity exceeding the battery capacity and direct consumption is fed into the grid. Since the pattern of solar irradiance is valid in the whole region, all PV systems will feed electricity into the grid at the same time, around noon, imposing substantial pressure on the grid. The question arises if more of these peaks need to be stored to avoid grid congestion and use all solar electricity or if intelligent control systems can achieve demand-side management.

In areas with a well-established grid infrastructure, the main contribution of battery storage to social welfare is a relief of the distribution grid from high grid feed-in at around noon. Fig. 16 shows the difference between uncoordinated and coordinated charging. In the first case, excess PV electricity is stored at maximum capacity until the storage is full, still leading to substantial PV feed-in from that point on. In the coordinated scenario, charging occurs at a constant lower rate throughout the peak phase, resulting in successful peak shaving. In winter, there is no solar PV generation available for storage.

To determine which constellation of storage and PV size leads to the highest amount of PV self-consumption, Fig. 17 describes four cases of storage availability for a household in Germany depending on the size of the PV system: a PV system only, a PV system plus battery storage, PV plus heat storage—to use excess electricity for residential heating or domestic hot water preparation – and finally a combination of the three. The graph illustrates the percentage of self-consumption depending on plant size and availability of battery or thermal storage. In this scenario, Weniger et al. [42] assumed a yearly electricity demand of 4.700 kWh, a battery storage capacity of 5 kWh and heat storage of 800 l.

A pooling effect – different end users join and put together their production – can furthermore increase the self-consumption of distributed PV electricity through combining several demand sources. Energy communities can enable sharing processes of the electricity produced by several households, including battery electric vehicles' (BEV) charging demand. Such strategies can significantly impact the profitability of onsite PV systems and the penetration of distributed renewable generation. As already discussed above, heating systems, especially those based on electricity (e.g. heat pumps), provide an additional local flexibility option. The cost-saving potentials of onsite PV systems significantly depend on the retail price development and the interest rate [43]. In addition, despite increasing onsite PV generation, gas heating remains the cheapest option versus pellet heating, heat pump and district heating. Note that this depends significantly on the CO_2-emission price [43].

Amongst the drivers of the penetration of local renewable generation from PV systems are energy cooperatives or communities. The large-scale potentials of rooftop PV systems in energy communities on the national level was analyzed by Ref. [44]. This work involves determining the cost-optimal onsite PV capacities based on different settlement patterns. The coordination and billing within such energy communities and demand shifting to reach a maximum self-consumption share require new ways of data management and processing and intelligent control systems.

4. Future prospects for PV electricity

4.1. Global PV potential

This section analyses the global PV capacity development until 2050. Such projections depend on and change with global and national policy decisions and the applied scenario estimations. The actual PV system growth depends on the technology's economic performance and associated cost depending on financing options, support schemes and social acceptance. The IEA has published a yearly world energy outlook in which also the trend of solar PV markets is estimated towards 2040 and 2050. Due to more ambitious global climate goals—also demanding changes in support schemes and market frameworks—and respective model adaptions, the forecast has changed yearly and projected cumulative installed capacity has grown.

Cloete et al. [45] critically reviewed the IEA forecasts on PV cumulative installed capacity in an independent global energy forecast based on different policy scenarios: Current Policies Scenario (CPS), New Policies Scenario (NPS) and the Sustainable Development Scenario (SDS) (see Fig. 18). The forecast by IEA [15] is assumed to build the reference case. The author's prediction primarily meets the projections of the IEA SDS scenario, with a slightly higher increase from 2025 onwards. The IEA projections seem to be rather reserved, requiring adjustment with every new edition of the WEO from 2006 up to now.

A six-fold growth of cumulative PV capacity between 2018 and 2030 is expected, with a compound annual growth rate of almost 9% until 2050 [46]. Detailed data for different world regions is provided by IRENA [46] (see Fig. 19). Growth is projected to accelerate from 2030, with Asia leading, followed by North America and Europe. The yearly PV electricity development per region in Fig. 20 shows that China takes over the leading position of the US in 2025. Both countries are expected to be overhauled by India in 2035 whose PV investments are assumed to take-off in 2030. Europe's yearly PV system capacity installation is expected to accelerate from 2030 on.

4.2. Expected future cost development of PV systems and small battery storage

The PV capacity increase and the cost development per kW influence each other in both directions. The PV module prices may decrease due to a production increase and the associated technological learning effect driving the technology towards maturity and competitiveness. The PV system costs and economic performance differ between centralized utility-scale systems—delivering electricity to the wholesale electricity markets—and distributed, residential systems mainly for self-consumption of PV electricity.

The cost development in the PV market mainly depends on four aspects:

1. Cost reduction of modules due to technological learning;
2. System cost reduction due to technological learning;
3. Transaction cost (related cost such as marketing, transportation, distribution channels etc.);
4. Amount of peak shaving and the associated decrease in the full load hours achieved by PV systems.

Fig. 21 describes the different categories in which cost reductions are possible. They focus either on the balance of system (BOS) part, including wires, cables, switches, etc., or the technological learning rate associated with the innovative elements in the inverter or the PV module.

Fig. 22 shows the recent developments, and an outlook on battery investment cost decreasing from USD1300/kWh in 2006 to USD 420/kWh in 2014 by the effects of technological learning and promotion schemes. The different references provide forecasts for batteries, lithium-ion packs and cells and are therefore not all directly comparable.

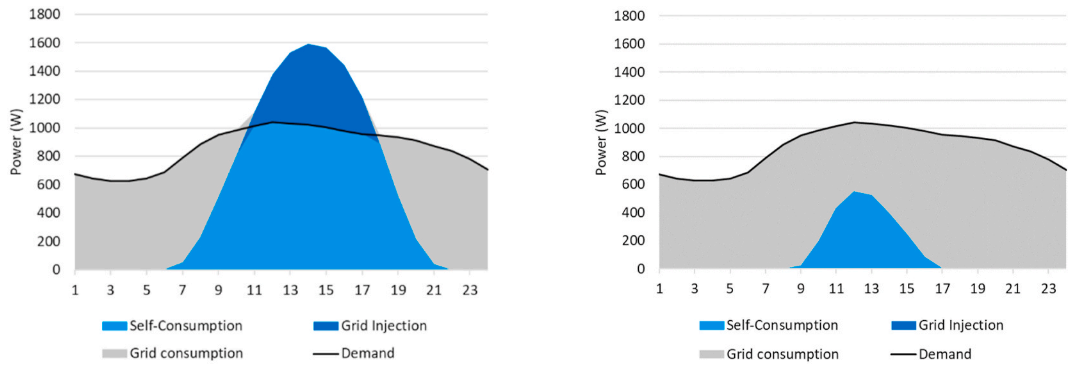

Fig. 15. Comparison of production and consumption profiles summer (left) and winter (right).

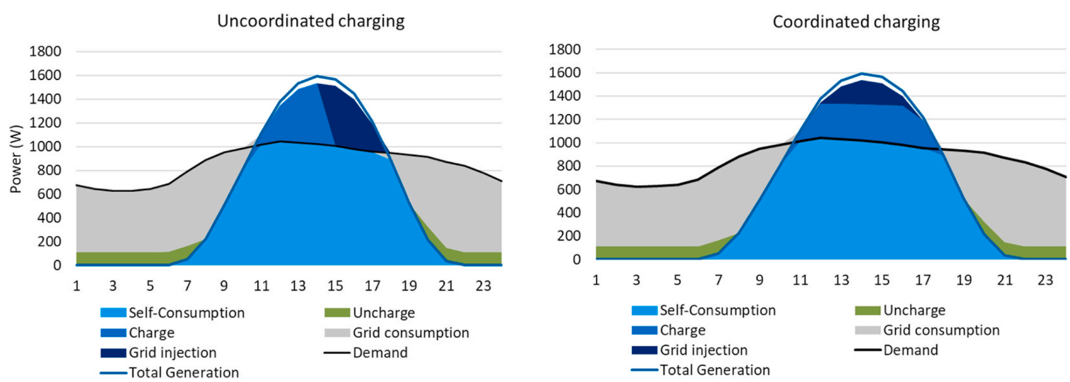

Fig. 16. Coordinated and non-coordinated use of decentral storage in summer.

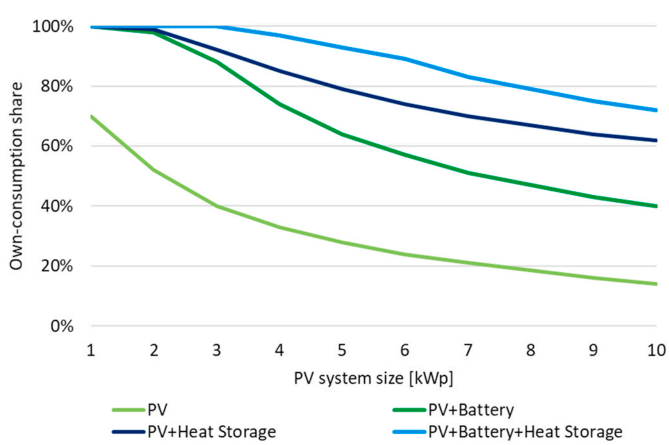

Fig. 17. Shares of self-consumption in single households in Germany for different cases of storage availability depending on the size of the PV system (kWp) (based on [42]).

Usually, a battery system is built up from several cells that form a pack, complemented by power electronics [49]. The forecast by Dorr&Seba [50] for US Lithium-Ion batteries is characterized by a steep decrease after 2020 and arrives at a similar level as the Hoppmann [51] residential PV battery cost estimation and the lithium-ion pack forecast by Bloomberg [52] by 2025 with around 100 USD/kWh.

4.3. Energy payback-time and embedded greenhouse gas emissions of PV-module production and efficiency of PV modules

One of the major remaining barriers to the broader deployment of PV systems is the magnitude of embedded energy and respective CO_2 emissions associated with the production of PV modules. While PV systems do not cause any direct emissions during the electricity generation phase, emissions are still released during the production phase of PV cells and panels, BOS components and battery storage if implemented. The whole life cycle of these components has to be considered. The production of silicon—one of the most important materials of PV systems—still requires a CO_2 source, which is often provided by coal or other fossil fuels, to react with silicon dioxide. There are three PV system generations, which significantly differ in terms of energy intensity, material and manufacturing costs, technology life cycle, and embedded emissions [55].

- **Generation 1** PV cells consist of a crystalline silicon (c-Si) base structure (e.g. single-crystalline silicon (sc-Si) and multi-crystalline silicon (mc-Si) cells). The production is energy-intensive, including high-cost material and production processes and a bad life cycle emission factor.
- **Generation 2** includes thin-film solar cells:
  - o amorphous silicon (a-Si),
  - o cadmium telluride (CdTe) and cadmium sulfide (CdS),
  - o copper indium gallium selenide (CIGS)/copper indium selenide (CIS),
  - o gallium arsenide (GaAs) and
  - o Si based tandem/multi-junction modules).

Their efficiency suffers from minimized material requirements and low-cost manufacturing. The materials used are also geographically concentrated and hard to mine.

- **Generation 3** builds on non-silicon based technologies
  - o organic/semi-organic PV panels (OPV),
  - o perovskite solar cells (PSC),
  - o dye-sensitized solar cell (DSSC), and

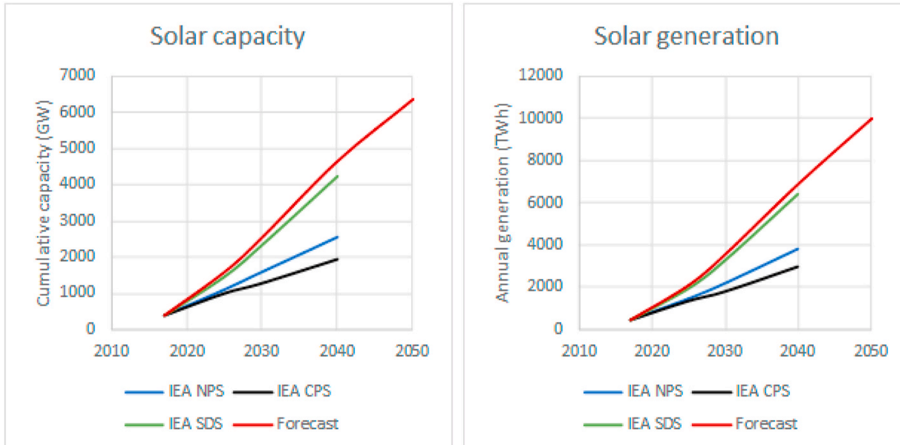

Fig. 18. Independent global solar PV forecast until 2050 by Ref. [45] compared to 2018 IEA scenarios.

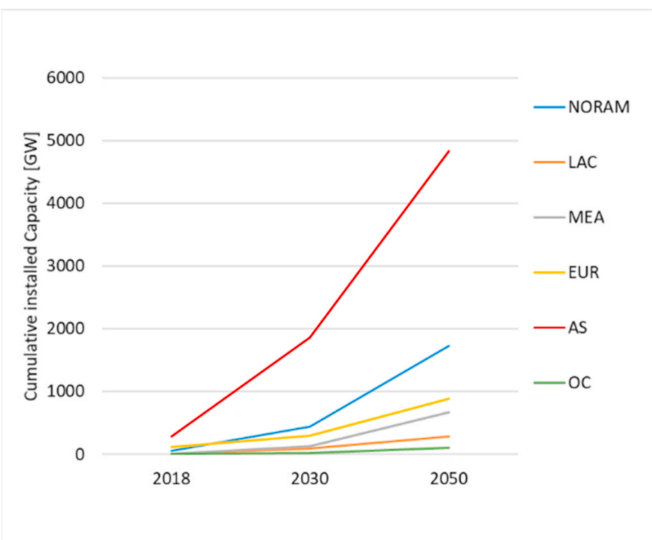

Fig. 19. Cumulative installed PV system capacity per region until 2050, adapted from [46].

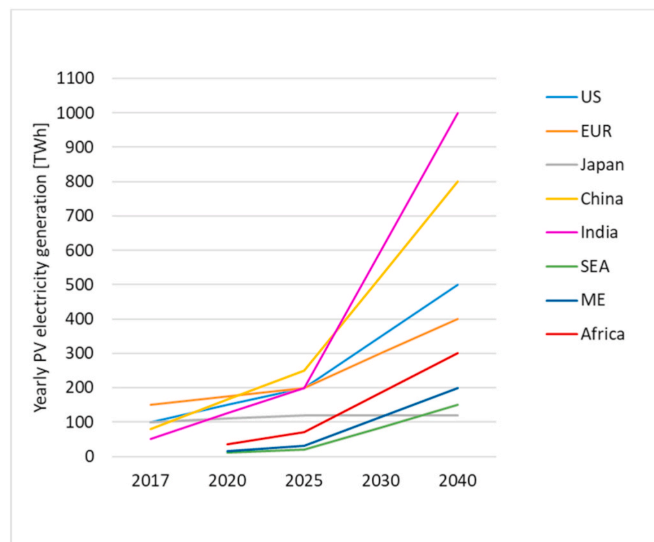

Fig. 20. Yearly PV electricity generation projections until 2040, based on WEO 2018 [15].

o quantum dot (QD) cells).

In this new approach, low production cost meets high efficiency for better life cycle emission factors.

As can be seen from the literature review, the recycling or disposal phase is often neglected, sometimes due to the absence of appropriate data [55]. Most approaches only include cradle-to-use or to-gate.

An indicator that reflects the overall efficiency of PV electricity generation is the Energy Payback Time (EPBT). The EPBT expresses how many years it takes to produce the energy invested in producing the actual PV panels and BOS components (overall embedded energy). A simple formula is applied that expresses EPBT as the ratio between the total energy input and the annual (average) energy production. Yet again, this is a partial, simplified assessment that does not include the energy required for component disposal and material recycling (silicon or other materials).

The energy payback time T_{EPB} (in years) is calculated as:

$$T_{EPB} = \frac{E_{Emb_{PV}}}{E_{Ele_{PV}}} \tag{4}$$

$E_{Emb_{PV}}$ Overall embedded energy use for production, installation and disposal of a PV system (kWh/m^2), $E_{Ele_{PV}}$ Electricity generated per year

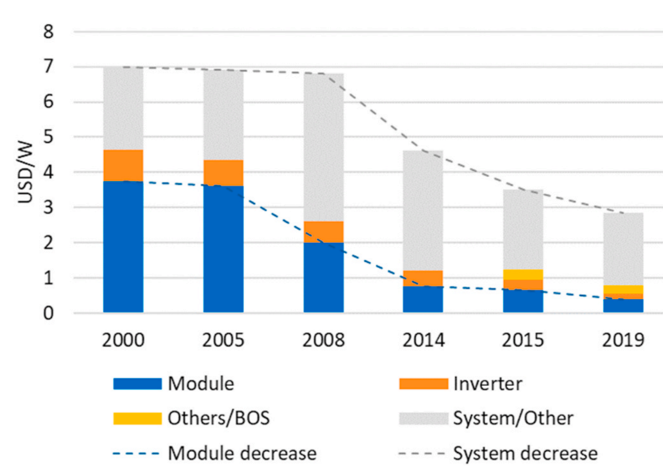

Fig. 21. Cost reduction until 2050 for respective parts of a PV system [2, 47,48].

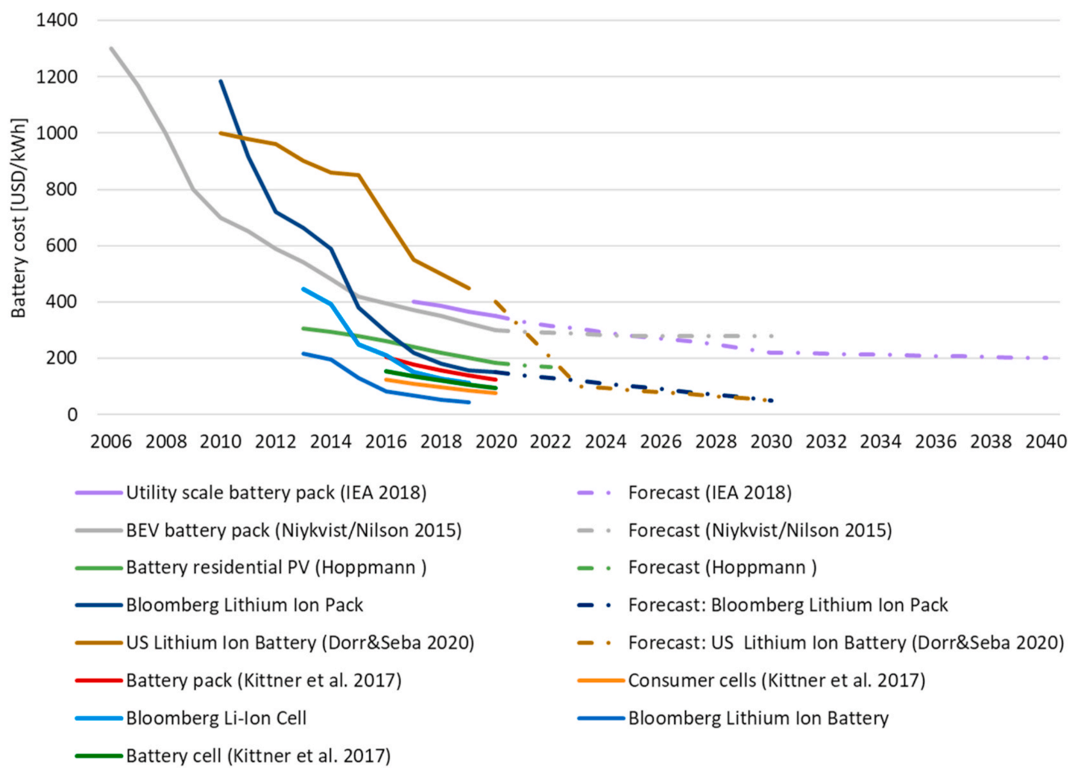

Fig. 22. Scenarios and forecasts for the development of battery costs based on [15,50,51,53,54].

by the PV-System (kWh/m^{2}yr).

The total energy embedded in PV panels and BOS components depends on the type of panels and the technology used for PV module production (resulting in a significant reduction of silicone needed). The EPBT value is also significantly influenced by the PV panel efficiency, the orientation of the PV panels to the sun and the geographical location of the PV plant [56]. EPBT values range between 3.6 and 5.8 years (Barcelona) and 3.7–7.8 years (Exeter and Dublin) for building integrated PV systems [57]. EPBT shows a decreasing trend, both due to more energy-efficient PV panel production and increased panel efficiency. Shorter EPBT times are typical for ground-mounted PV power plants. For example, Wu et al. [58] report an EPBT of 2.3 years for a 1 MW PV plant with multi-Si panels at solar radiation of 2017 kWh/m^2/year. This value includes both the cost of the actual PV panel production and the BOS equipment while also including transport. Significantly lower EPBT values of about 1.1–1.3 years for southern and central European countries are reported [59].

The opposite can be the case for inappropriately designed and operated autonomous applications. For various reasons (e.g. due to high electricity prices), not all PV electricity generation is used efficiently. For example, autonomous applications in Tanzania (with 1900 kWh/m2/year of solar radiation) show an EPBT of 17 years or higher [60]. Another indicator that takes into account the specific CO_2 emissions related to the PV module and BOS component production, installation onsite and final disposal (reprocessing) is the so-called carbon footprint.

The specific CO_2 emissions per kWh PV electricity are described in Equation (5).

$$CO2_{Spec_{PV}} = \frac{CO2_{Emb_{PV}}}{LT_{PV}} \tag{5}$$

$CO2_{Emb_{PV}}$ Overall embedded CO_2 emissions for production, installation and disposal of a PV system (kWh/m^2), LT_{PV} PV system lifetime (years).

A carbon footprint of 27–81 gCO_{2eq}/kWh can be found for PV installations using different module types [61]. Specific CO_2 emissions between 29 and 45 gCO_{2eq}/kWh for monocrystalline PV modules and 23–44 gCO_{2eq}/kWh for multi-SI modules were investigated [56]. A similar range of values for specific CO_2 emissions was found by Louwen et al. [62] at 25–40 gCO_{2eq}/kWh. These values can then be compared with the carbon footprint associated with electricity generation from conventional power plants. The carbon footprint of coal-fired power plants amounts to approximately 980 gCO_{2eq}/kWh [63].

Different parameters need to be considered to improve the PV systems' life cycle emission factor, such as the primary energy consumption and emissions along the life cycle, based on the materials and energy used, and the potential cell efficiency to generate the maximum output [64]. In an analysis for different silicon heterojunction cell designs, a decrease in the lifecycle GHG emissions of complete PV systems from 35 to about 20 gCO_{2eq}/kWh in 2020 was predicted [64]. 45% are made up by BOS components, about 25% by the module and 15% by the silicon feedstock & ingot. The main GHG emissions reduction was achieved in the silicon feedstock with 72%, followed by the cell with 44% and wafering and module with about 33% each (see Fig. 23). The EBPT is expected to decrease below one year in 2020. About 45% of this reduction are associated with the BOS, 22% with the module, and 18% with silicon feedstock and ingot.

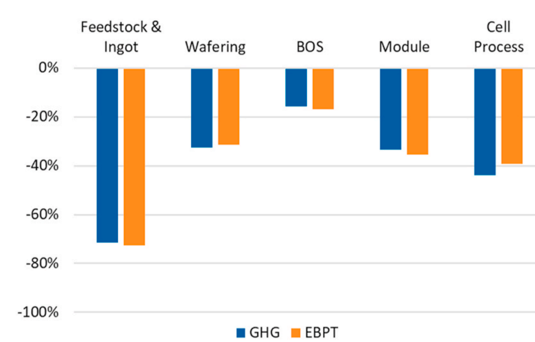

Fig. 23. Reduction of GHG emissions and EPBT for PV system components between 2016 and 2020 (adapted from Ref. [64]).

Several other indicators are also used to assess the environmental impacts of PV power generation, e.g. the Environmental Payback Period (EPBP). EPBP relates, e.g. the embedded CO_2 effects of solar PV systems to those of the usual electricity mix at the location of the PV system installation. This indicator expresses the specific CO_2 emissions and other environmental indicators and describes the value of replacing conventional energy with PV electricity [65].

Fig. 24 describes the development of (a) average PV cell efficiency of new modules on the market, b) energy payback time of new modules, c) primary energy pay-back time and, d) specific greenhouse gas emissions for three different types of new PV modules over time from 1995-2020. Mono and Multi-crystalline modules belong to Generation 1 and CIGS to Generation 2 of PV systems.

When it comes to considering the embedded energy and emissions of PV systems in their whole life cycle and the entire magnitude of their use, however, also processes in which PV electricity may replace fossil fuels with their given capacity need to be considered. In particular, sector coupling technologies, such as power-to-x (PtX) technologies, will play a crucial role here, enabling the massive development of variable energy sources such as PV and wind power plants.

PtX is a general term for transforming excess electricity from these variable sources into specific other useable products such as hydrogen, methane but also chemical products such as ammonia Hydrogen has many possible uses referred to as Hydrogen-to-X (HtX). These include technologies such as HtP (hydrogen to power), HtG (H_2 injection into the natural gas grid), HtG-M (synthetic methane production from hydrogen through methanation), HtS (hydrogen used for liquid solar-fuels), HtCh (hydrogen to chemicals such as methanol) [66]. For the production of synthetic hydrocarbons, CO_2 directly captured from the atmosphere can also be used [67]. However, the PtX concept also includes other storage technologies, such as energy storage in heat supply systems called Power-to-Heat [68]. These technologies differ in their efficiency, material and energy requirements and need to be assessed in terms of the entire life cycle [69]. They will condition the development of PV and wind power plants to integrate their temporarily excess production successfully into the energy system. Therefore, from the system point of view, they indirectly impact the costs of PV applications. The emissions of a PV system should be counted per kWh of PV electricity and per kWh of transformed energy used in other sectors.

4.4. *Agrovoltaics: additional land use of utility-scale PV*

The rise of utility-scale PV systems leads to extensive land use that can maintain its value for economic welfare by using it as agricultural land benefiting from the shade provided by the modules. Agrovoltaics, which connects agriculture with electricity production from PV systems, seeks to eliminate the criticism associated with implementing large-scale PV systems on agricultural land. The concept of agrovoltaics first appeared in 1981 [70] but has only begun to develop significantly in the last decade [71]. Agrovoltaics as a combination of agricultural activities and PV provides several significant advantages: (i) variability of concept, where PV technology can be combined with different agricultural activities, such as growing wine, fruit trees, conventional production, pastures for livestock, etc., (ii) reduction of PV land use and thus a land loss for conventional agriculture - this is especially important in areas with high soil fertility, (iii) combining electricity production appropriately with other farmers' activities such as water pumping, crop drying, cooling (iv) providing so-called non-productive functions such as shade on hot summer days (for both crops and livestock), reduction of soil heating and water vapor. In Europe, the share of projects focusing on agrovoltaics is growing.[2]

[2] Example from the Czech Republic: In the RES + call of the Modernization Fund, financed by the income on emission allowances, by March 2021, about 8.3% (more than 700 projects) of the projects focused on agrovoltaics.

5. New tariff and pricing schemes for efficient PV integration

Grid tariffs are usually imposed with an aim of an equal distribution of the network operation costs among all customers [72]. With more and more consumers installing distributed electricity generation systems, such as solar PV systems and battery storage to maximize their on-site consumption, the historical practice of volumetric, energy-based network tariffs do no more meet the newly arising requirements. The network costs caused by peak-feed-in are not reflected properly in the tariff system. Gambardella et al. [73] argue that price responsive consumers are a major characteristic of renewable electricity markets. The currently static electricity price that consumers are charged do not reflect the variable marginal cost of electricity at different times of the day and are to be rethought [74]. To successfully handle a growing amount of VRES in the distribution grid, time varying electricity prices are essential. Such a system change, however, requires the implementation of advanced metering infrastructure that comes at additional cost. The efficient grid cost recovery for distribution system operators (DSOs) requires a new design of network tariff schemes. The role of DSOs ideally could change to the active management of electricity flows instead of simple grid reinforcements [75].

The challenge today is to develop a tariff scheme that achieves a fair distribution of network charges that meet the network cost in this dynamic setting with an increasing share of reactive customers. As a potential solution, some authors suggest the switch to capacity based grid charges, while others favour a mix of capacity based and time varying energy-based tariff schemes, which could also add value to the operation of decentralized batteries [72].

Energy-based tariffs are related to the volume of energy consumed from the grid in kWh. This implies that a static, mostly sunk, infrastructure cost, that also depends on the power consumed or fed-in, is allocated based on the total energy consumed in a certain period [75]. Capacity based tariffs are based on the maximum power consumed or fed-in to the network, representing the maximum energy consumption in kW [75]. Capacity tariffs can also be designed as time of use tariffs, varying during certain times of a day to even out load peaks through demand side management. In any case, the tariffs have to have components for maximum power from and for maximum power to the grid.

However, these energy based network charges are deemed inadequate given the increasing deployment of PV and battery storage. They cannot achieve a fair recovery of infrastructural cost for all consumers [72]. Consumers with solar PV systems do not pay network charges for the electricity produced on site and own-used, but still rely on the distribution grid, possibly even more than before. Regarding an aggregate case of all the PV fed in, peak generation at noon may impose substantial pressure on the distribution grid, which has an impact on the overall system and also on the costs of simple passive consumers. Currently, the remaining grid cost is distributed among a smaller amount of these passive, grid relient consumers. Additionally, with decentral production and storage in place, PV owners are able to react to more dynamic market prices. However, there is no easy and quick fix for distribution network tariff design, and regulators face many challenges for redesigning the distribution grid tariff and pricing systems.

A more dynamic market design will be crucial to appropriately reflect the more dynamic structure of decentral energy production. Suppose grid costs are mainly sunk, and no efficient, cost-reflective tariffs are implemented, in a way that the actual infrastructure use of passive and also reactive customers is billed accordingly. In that case, the passive customers are always worse off, and tools other than standard tariff options must keep distributional impacts under control while limiting distortions [72]. Investment distortions include the fact that with net metering and the avoidance not only of grid electricity consumption but also network charges, the incentive to invest into PV systems is disproportionately high. With each additional *prosumager* avoiding network cost but still relying on the network, the passive consumers need to bear more of the sunk cost. According to Pollitt et al.

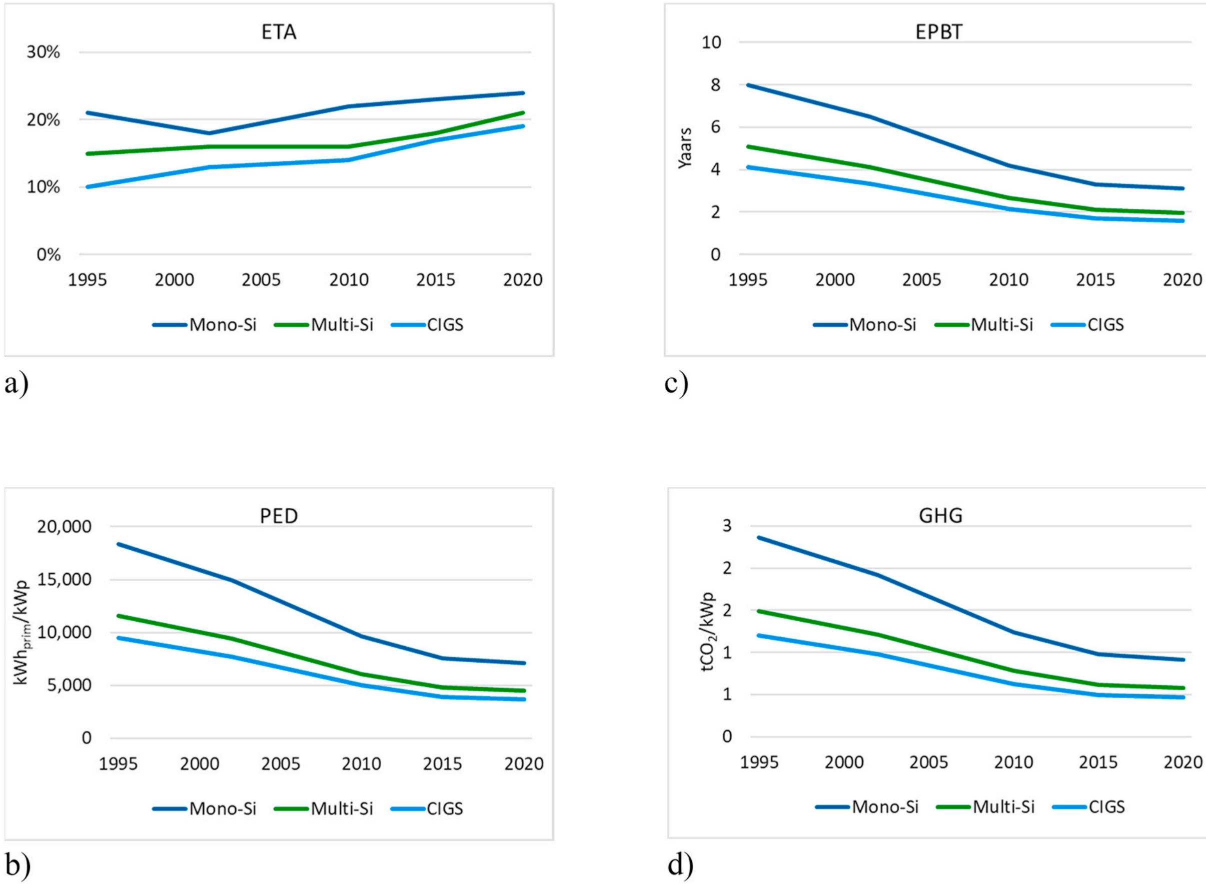

Fig. 24. Development over time 1995–2020 for three different types of new PV modules of: a) average PV cell efficiency of new modules on the market, b) primary energy pay-back time, c) energy payback time of new modules, d) specific greenhouse gas emissions per kWp of PV modules [55,62].

[76] a cost reflective tariff scheme inkludes a fixed price component, a per kW peak tariff and a variable per kWh tariff/price.

Regarding the discussion on rethinking traditional tariff schemes to successfully meet changing network requirements, Fig. 25 provides a suggestion of a dynamic bidirectional tariff system including capacity based and energy based time varying tariffs, taking into account different periods of PV generation and consumption during the day and a maximum feed-in and grid electricity consumption amount. In this example four tariff components are applied:

- T1: volumetric, variable feed-in tariff per kWh

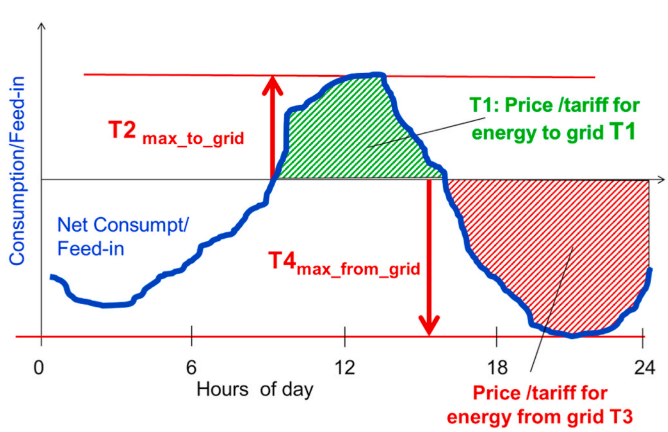

Fig. 25. Exemplary concept of a bidirectional tariff system for power and energy components.

- T2: capacity based tariff per kW for the required maximum power fed into the grid
- T3: volumetric, variable grid-consumption tariff per kWh
- T4: capacity based tariff per kW for the required maximum power taken from the grid

With this set of time varying capacity based prices and tariffs as well as time variable energy-based volumetric tariffs for electricity feed-in and consumption, the price reflects the current situation in the distribution grid and can provide the desired incentive towards the reactive consumers. Peaks in electricity feed-in or consumption are more expensive, and a situation of extensive PV feed in during noon can also be priced accordingly to incentivize decentral storage instead of additional grid feed-in. As a result, the capacity cost is distributed based on the overall system situation and all customers are charged due to their individual load on the power grid. In this way every prosumer and also the normal consumer can react accordingly.

New approaches to the definition of electricity tariffs require the handling of different interests and aspects. On the one hand, active customers – prosumers with own PV production – need incentives and rewards to adapt their electricity consumption and feed-in to the system requirements. On the other hand, there will always be a significant group of customers, especially households, which will not have the means or the will to do so. The regionalization or individualization of tariffs is a promising approach. Energy communitites, for example, generate a (significant) part of electricity from their investments in RES plants and the respective infrastructure and can balance the load diagram through internal measures [75]. Another critical aspect of the new requirements in renewable energy systems are appropriate tariff schemes to integrate the recharging of BEVs in a similar manner as solar

PV systems. A change in the charging tariff schemes for BEVs is required if the share of green electricity used should increase and load management either from the supply side or the demand side needs to be applied to support the grid infrastructure [12,77,78].

Many consumers could even choose not to switch to a variable tariff if they have the choice, to avoid potential cost increases. The key factors are creating a suitable legislative environment and technical conditions (smart grids/smart metering), creating an appropriate incentive scheme, and increasing customer awareness. Customer information and information support will play a key role in increasing demand-side flexibility in the future. A large study among British electricity consumers concludes that a significant amount of customers potentially accept one of the dynamic tariffs (e.g. 1/3 of the respondents accept time-of-use tariffs (TOUs tariffs)) [79]. Nevertheless, the results of this research clearly show a high aversion of electricity consumers to financial losses (due to the choice of TOUs tariffs) - up to 90% of respondents associate a higher weight to potential financial losses than potential economic gains. These complex aspects on the customer side need to be considered to create dynamic tariffs as a steering measure successfully.

6. Major findings, conclusions and outlook

In the next decades it is expected that the investment costs of PV systems are continuing to decrease leading to significant additional deployments virtually world-wide. In this context the following issues are of core relevance: promotion strategies as well as new tariff and pricing systems for grid-connected PV systems.

Regarding promotion schemes for the future two findings are important: on the wholesale market level auctions are clearly most attractive. On retail level grid parity already today provides in many countries sufficient incentives to purchase a PV system without additional financial support and it is expected that this development will continue.

With respect to the tariff and pricing systems for feeding electricity from PV (or any other energy source) into the grid or taking electricity from the grid that severe changes have to be undertaken. The reason is that PV fed into the grid – e. g at noon – may have a severe impact on the network capacities. Classical static energy-based network charges – charging every customer only for the net electricity consumption from the grid over a certain period— are inadequate and cannot achieve the fair recovery of the infrastructure cost for all customers. The problem is that currently "passive" consumers carry the largest share of the burden of network charges while "prosumers" pay far less. In addition, declining electricity prices during peak PV feed-in at noon lead to a self-cannibalization effect of PV installations and reduce their market value. Now, the goal now is to implement a fair cost and tariff system among all customers – those owning a PV system and passive energy consumers. This new system should provide incentives as correct as possible for the PV system owners actively optimize their electricity consumption profile in line with the overall needs in the network and to maximize their self-consumption to avoid excessive PV electricity being fed into the grid at noon.

Hence, the major conclusion is that to bring about the utmost benefits of grid-connected PV systems the main task is the introduction of proper tariff and pricing structures on wholesale as well as on retail level. On wholesale level the PV electricity fed into the grid has to be based on the current market prices at every specific point-of-time. On retail level consumers should also receive a corresponding, time-variable price signal that tells them the current value of the electricity in the system. This will give them a corresponding incentive to save electricity, to switch on devices, to charge/discharge a possible battery storage or an electric vehicle. In addition, the tariffs should have components for maximum power from and to the grid. We are convinced that decentral "prosumagers" are able and willing to react to variable tariff schemes making it a suitable steering tool for investments and demand side management. This has to be seen along with the development of smart metering, digitilization and the introduction of artificial intelligence.

Regarding future research most important is to investigate how incentives to trigger grid-serving respectively electricity system-friendly behaviour should look like in detail depending on the specific. This addresses in detail the proper design of tailor made tariff schemes, time-of-use costs and feed-in prices depending on the specific grid conditions and energy system characteristics of a location.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data have been taken from official publications

References

[1] European Commission (Ec). 'A policy framework for climate and energy in the period from 2020 to 2030'. 2014, Accessed [Online]. Available, https://www.eea.europa.eu/policy-documents/com-2014-15-final; 2020.

[2] Iea Pvps. 'Trends in photovoltaic applications 2020'. Accessed IEA-PVPS 2021; T1–38(2020):2020 [Online]. Available, https://iea-pvps.org/trends_reports/trends-in-pv-applications-2020/.

[3] Eurostat. 'Renewable energy statistics'. https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Renewable_energy_statistics. [Accessed 9 May 2022].

[4] Haas R, Lettner G, Auer H, Duic N. 'The looming revolution: how photovoltaics will change electricity markets in Europe fundamentally'. Energy Aug. 2013;57:38–43. https://doi.org/10.1016/j.energy.2013.04.034.

[5] Irena. 'World Adds record new renewable energy capacity in 2020'. IRENA Newsroom Apr. 2021. https://www.irena.org/newsroom/pressreleases/2021/Apr/World-Adds-Record-New-Renewable-Energy-Capacity-in-2020. [Accessed 2 August 2021].

[6] Luxembourg Jäger-Waldau A. 'PV status report 2019.', publications office of the European union. EUR 29938 EN, 2019. Accessed [Online]. Available, https://op.europa.eu/publication/manifestation_identifier/PUB_KJNA29938ENN; 2021.

[7] Kavlak G, McNerney J, Trancik JE. 'Evaluating the causes of cost reduction in photovoltaic modules'. Energy Pol 2018;123:700–10. https://doi.org/10.1016/j.enpol.2018.08.015.

[8] Rollet C. 'Solar costs have fallen 82% since 2010'. pv magazine International 2020. https://www.pv-magazine.com/2020/06/03/solar-costs-have-fallen-82-since-2010/. [Accessed 2 August 2021].

[9] Bp 'Statistical. Review of World Energy 2020', no 2020;69.

[10] Haas R. 'The value of photovoltaic electricity for society'. Sol Energy 1995;54(1): 25–31. https://doi.org/10.1016/0038-092X(94)00099-Y.

[11] Hirschhausen CV. 'Prosumage and the future regulation of utilities: an introduction'. Volume 6, no. Number Economics of Energy & Environmental Policy 2021;1:2017 [Online]. Available, https://ideas.repec.org/a/aen/eeepjl/eeep6-1-introduction.html.

[12] Haas R. 'The value of photovoltaic electricity for utilities'. Sol Energy Mater Sol Cell 1994;35:421–7. https://doi.org/10.1016/0927-0248(94)90169-4.

[13] Schill W-P, Zerrahn A, Kunz F, Kemfert C. 'Decentralized solar prosumage with battery storage: system orientation required'. DIW Economic Bulletin 2017;7(16): 141–51.

[14] Perez-Arriaga I. 'Improved regulatory approaches for the remuneration of electricity distribution utilities with high penetrations of distributed energy resources'. Energy J 2017;38. https://doi.org/10.5547/01956574.38.3.jjen.

[15] Iea 'World. Energy outlook 2018'. International Energy Agency 2021 [Online]. Available, https://www.iea.org/reports/world-energy-outlook-2018.

[16] 'Trends in Pv applications 2017'. IEA-PVPS. https://iea-pvps.org/trends_reports/2017-edition/. [Accessed 21 April 2021].

[17] Kobos P, Erickson J, Drennen T. 'Technological learning and renewable energy costs: implications for US renewable energy policy'. Energy Pol 2004;34:1645–58. https://doi.org/10.1016/j.enpol.2004.12.008.

[18] McDonald A, Schrattenholzer L. 'Learning rates for energy technologies'. Energy Pol 2001;29:255–61. https://doi.org/10.1016/S0301-4215(00)00122-1.

[19] Wene C-O. Experience Curves for Energy Technology Policy 2000.

[20] Wiesenthal T, et al. Technology Learning Curves for Energy Policy Support 2012. https://doi.org/10.2790/59345.

[21] Sun X. 'Solar technology got cheaper and better in the 2010s. Now What?'. Green Tech Media 2019. https://www.greentechmedia.com/articles/read/solar-pv-has-become-cheaper-and-better-in-the-2010s-now-what. [Accessed 21 April 2021].

[22] Haas R. 'Progress in markets for grid-connected PV systems in the built environment'. Prog Photovoltaics Res Appl 2004;12(6):427–40. https://doi.org/10.1002/pip.560.

[23] solarsouthwest. 'The cost of solar PV - how much do solar panels cost?'. Solar South West 2017. https://solarsouthwest.co.uk/solar-panel-cost/. [Accessed 21 April 2021].
[24] Benda V, Černá L. 'PV cells and modules – state of the art, limits and trends'. Heliyon 2020;6(12). https://doi.org/10.1016/j.heliyon.2020.e05666.
[25] 'Pvinsights'. PV Insights. http://pvinsights.com/. [Accessed 12 May 2022].
[26] IRENA. 'Renewable power generation costs in 2019'. Abu Dhabi: International Renewable Energy Agency; 2019.
[27] ESMAP. 'GLOBAL photovoltaic power potential by country'. 2020. World Bank, Washington, DC.
[28] Haas R, Ajanovic A, Ramsebner J, Perger T, Knápek J, Bleyl JW. 'Financing the future infrastructure of sustainable energy systems'. Green Finance 2021;3(1): 90–118. https://doi.org/10.3934/GF.2021006.
[29] Irena. 'Renewable power generation costs in 2017'. International Renewable Energy Agency 2018. Abu Dhabi.
[30] Haas R. 'Market deployment strategies for photovoltaics: an international review', Renewable and Sustainable Energy Reviews. 7, no 2003;4:271–315. https://doi.org/10.1016/S1364-0321(03)00062-5.
[31] Haas R, Panzer C, Resch G, Ragwitz M, Reece G, Held A. 'A historical review of promotion strategies for electricity from renewable energy sources in EU countries'. Renew Sustain Energy Rev 2011;15(2):1003–34. https://doi.org/10.1016/j.rser.2010.11.015.
[32] Dijkgraaf E, Dorp TP, Maasland E. 'On the effectiveness of feed-in tariffs in the development of solar photovoltaics'. Energy J 2018;39:81–99. https://doi.org/10.5547/01956574.39.1.edij.
[33] Winkler J, Magosch M, Ragwitz M. 'Effectiveness and efficiency of auctions for supporting renewable electricity – what can we learn from recent experiences?'. Renew Energy 2018;119:473–89. https://doi.org/10.1016/j.renene.2017.09.071.
[34] Dobrotkova Z, Surana K, Audinet P. 'The price of solar energy: comparing competitive auctions for utility-scale solar PV in developing countries'. Energy Pol 2018;118:133–48. https://doi.org/10.1016/j.enpol.2018.03.036.
[35] Viana A, Ramos D. 'Outcomes from the first large-scale solar PV auction in Brazil'. Renew Sustain Energy Rev 2018;91:219–28. https://doi.org/10.1016/j.rser.2018.04.003.
[36] Irena. 'Renewable Energy auctions: analysing 2016'. /publications/2017/Jun/Renewable-Energy-Auctions-Analysing-2016 2017. https://www.irena.org/publications/2017/Jun/Renewable-Energy-Auctions-Analysing-2016. [Accessed 12 July 2021].
[37] Liu W, Lund H, Mathiesen B. 'Large-scale integration of wind power into the existing Chinese energy system'. Fuel Energy Abstr 2011;36:4753–60. https://doi.org/10.1016/j.energy.2011.05.007.
[38] Moreno B, López AJ, García-Álvarez MT. The electricity prices in the European Union. The role of renewable energies and regulatory electric market reforms'. Energy 2012;48(1):307–13. https://doi.org/10.1016/j.energy.2012.06.059.
[39] Nicolosi M. 'Wind power integration and power system flexibility–An empirical analysis of extreme events in Germany under the new negative price regime'. Energy Pol 2010;38(11):7257–68. https://doi.org/10.1016/j.enpol.2010.08.002.
[40] Breyer C, Gerlach A. 'Global overview on grid-parity'. Prog Photovoltaics Res Appl 2013;21(1):121–36. https://doi.org/10.1002/pip.1254.
[41] Weniger J, Bergner J, Tjaden T, Quaschning V. Economics of Residential PV Battery Systems in the Self-Consumption Age 2014. https://doi.org/10.4229/EUPVSEC20142014-7DO.14.3.
[42] Weniger J, Tjaden Tjarko, Quaschning V. 'Solare unabhängigkeitserklärung'. pv magazine Deutschland 2012. https://www.pv-magazine.de/2012/10/02/solare-unabhngigkeitserklrung/. [Accessed 3 February 2021].
[43] Fina B, Auer H, Friedl W. 'Profitability of active retrofitting of multi-apartment buildings: building-attached/integrated photovoltaics with special consideration of different heating systems'. Energy Build 2019;190:86–102. https://doi.org/10.1016/j.enbuild.2019.02.034.
[44] Fina B, Auer H, Friedl W. 'Cost-optimal economic potential of shared rooftop PV in energy communities: evidence from Austria'. Renew Energy 2020;152:217–28. https://doi.org/10.1016/j.renene.2020.01.031.
[45] Cloete S. 'An independent Global Energy Forecast to 2050 (part 2 of 5): wind and solar'. Energy Post Sep. 25, 2019. https://energypost.eu/an-independent-global-energy-forecast-to-2050-part-2-of-5-wind-and-solar/. [Accessed 9 February 2021].
[46] Irena. 'Future of solar photovoltaic: deployment, investment, technology, grid integration and socio-economic aspects (A Global Energy Transformation: paper)'. 2019. Accessed. Abu Dhabi: International Renewable Energy Agency; 2021 [Online]. Available:/publications/2019/Nov/Future-of-Solar-Photovoltaic.
[47] Iea Pvps. 'Trends in photovoltaic applications in selected IEA countries between 1992 and 1999'. 2000.
[48] Iea Pvps. 'Trends in PV applications 2006'. IEA-PVPS 2006. https://iea-pvps.org/trends_reports/2006-edition/. [Accessed 22 April 2021].
[49] Nrel A, Pesaran G-H Kim, Keyser M. 'Integration issues of cells into battery packs for plug-in and hybrid electric vehicles'. 2009.
[50] Dorr A, Seba T. 'Rethinking energy 2020-2030 100% solar, wind, and batteries is just the beginning'. 2020.
[51] Hoppmann J, Volland J, Schmidt T, Hoffmann V. 'The economic viability of battery storage for residential solar photovoltaic systems - a review and a simulation model'. Renew Sustain Energy Rev 2014;39:1101–18. https://doi.org/10.1016/j.rser.2014.07.068.
[52] 'A Behind the Scenes Take on Lithium-ion Battery Prices'. BloombergNEF. https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/. [Accessed 29 March 2021].
[53] Nykvist B, Nilsson M. 'Rapidly falling costs of battery packs for electric vehicles'. Nat Clim Change 2015;5:329–32. https://doi.org/10.1038/nclimate2564.
[54] Kittner N, Lill F, Kammen DM. 'Energy storage deployment and innovation for the clean energy transition'. Nat Energy 2017;2(9):17125. https://doi.org/10.1038/nenergy.2017.125.
[55] Muteri V, et al. 'Review on life cycle assessment of solar photovoltaic panels'. Energies 2020;13:252. https://doi.org/10.3390/en13010252.
[56] Peng J, Lu L, Yang H. 'Review on life cycle assessment of energy payback and greenhouse gas emission of solar photovoltaic systems'. Renew Sustain Energy Rev 2013;19:255–74. https://doi.org/10.1016/j.rser.2012.11.035.
[57] Lamnatou Chr, Baig H, Chemisana D, Mallick TK. 'Environmental assessment of a building-integrated linear dielectric-based concentrating photovoltaic according to multiple life-cycle indicators'. J Clean Prod 2016;131:773–84. https://doi.org/10.1016/j.jclepro.2016.04.094.
[58] Wu P, Ma X, Ji J, Ma Y. 'Review on life cycle assessment of energy payback of solar photovoltaic systems and a case study'. Energy Proc 2017;105:68–74. https://doi.org/10.1016/j.egypro.2017.03.281.
[59] Fraunhofer ISE. 'Photovoltaics report'. Freiburg 2020 [Online]. Available, https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/Photovoltaics-Report.pdf.
[60] Tsuchiya Y, Swai TA, Goto F. 'Energy payback time analysis and return on investment of off-grid photovoltaic systems in rural areas of Tanzania'. Sustain Energy Technol Assessments 2020;42:100887. https://doi.org/10.1016/j.seta.2020.100887.
[61] de Wild-Scholten MJ. 'Energy payback time and carbon footprint of commercial photovoltaic systems'. Sol Energy Mater Sol Cell 2013;119:296–305. https://doi.org/10.1016/j.solmat.2013.08.037.
[62] Louwen A, van Sark WGJHM, Faaij APC, Schropp REI. 'Re-assessment of net energy production and greenhouse gas emissions avoidance after 40 years of photovoltaics development'. Nat Commun 2016;7(1). https://doi.org/10.1038/ncomms13728.
[63] Cushman-Roisin B, Cremonini BT, editors. Data, statistics, and useful Numbers for environmental sustainability. Elsevier; 2021. https://doi.org/10.1016/B978-0-12-822958-3.01001-3.
[64] Louwen A. 'Assessment of the energy performance, economics and environmental footprint of silicon heterojunction photovoltaic technology', Dissertation. Utrecht University 2016. Accessed: Jul. 08, 2021, http://localhost/handle/1874/344175.
[65] Grant C, Garcia J, Hicks A. 'Environmental payback periods of multi-crystalline silicon photovoltaics in the United States – how prioritizing based on environmental impact compares to solar intensity'. Sustain Energy Technol Assessments 2020;39:100723. https://doi.org/10.1016/j.seta.2020.100723.
[66] Chehade Z, Mansilla C, Lucchese P, Hilliard S, Proost J. 'Review and analysis of demonstration projects on power-to-X pathways in the world'. Int J Hydrogen Energy 2019;44(51):27637–55. https://doi.org/10.1016/j.ijhydene.2019.08.260.
[67] Vázquez FV, et al. 'Power-to-X technology using renewable electricity and carbon dioxide from ambient air: SOLETAIR proof-of-concept and improved process concept'. J CO2 Util 2018;28:235–46. https://doi.org/10.1016/j.jcou.2018.09.026.
[68] Bloess A, Schill W-P, Zerrahn A. 'Power-to-heat for renewable energy integration: a review of technologies, modeling approaches, and flexibility potentials'. Appl Energy 2018;212:1611–26. https://doi.org/10.1016/j.apenergy.2017.12.073.
[69] Koj JC, Wulf C, Zapp P. 'Environmental impacts of power-to-X systems - a review of technological and methodological choices in Life Cycle Assessments'. Renew Sustain Energy Rev 2019;112:865–79. https://doi.org/10.1016/j.rser.2019.06.029.
[70] Goetzberger A, Zastrow A. 'On the coexistence of solar-energy conversion and plant cultivation'. Int J Sol Energy 1982;1(1):55–69. https://doi.org/10.1080/01425918208909875.
[71] Dinesh H, Pearce J. 'The potential of agrivoltaic systems'. Renew Sustain Energy Rev 2016;54:299–308. https://doi.org/10.1016/j.rser.2015.10.024.
[72] Schittekatte T, Momber I, Meeus L. 'Future-proof tariff design: recovering sunk grid costs in a world where consumers are pushing back'. EUI RSCAS Working Paper (FSR), 2017;70. https://doi.org/10.1016/j.eneco.2018.01.028.
[73] Gambardella C, Pahle M, Schill W-P. 'Do benefits from dynamic tariffing rise? Welfare effects of real-time retail pricing under carbon taxation and variable renewable electricity supply'. Environ Resour Econ 2020;75(1):183–213. https://doi.org/10.1007/s10640-019-00393-0.
[74] Gambardella C, Pahle M. 'Time-varying electricity pricing and consumer heterogeneity: welfare and distributional effects with variable renewable supply'. Energy Econ 2018;76:257–73. https://doi.org/10.1016/j.eneco.2018.08.020.
[75] EDSO. Adapting distribution network tariffs to a decentralised energy future'. European Distribution System Operators for Smart Grids 2015 [Online]. Available, https://www.edsoforsmartgrids.eu/adapting-distribution-network-tariffs-to-a-decentralised-energy-future-position-paper/.
[76] Pollitt MG. 'Electricity network charging for flexibility', Faculty of Economics. Work Pap 2016. https://doi.org/10.17863/CAM.7821.
[77] Fabianek P, Will C, Wolff S, Madlener R. 'Green and regional? A multi-criteria assessment framework for the provision of green electricity for electric vehicles in Germany',. SSRN Electron J 2019. https://doi.org/10.2139/ssrn.3571415.
[78] Schuller A, Flath CM, Gottwalt S. 'Quantifying load flexibility of electric vehicles for renewable energy integration'. Appl Energy 2015;151:335–44. https://doi.org/10.1016/j.apenergy.2015.04.004.
[79] Nicolson M, Huebner G, Shipworth D. 'Are consumers willing to switch to smart time of use electricity tariffs? The importance of loss-aversion and electric vehicle ownership'. Energy Res Social Sci 2017;23:82–96. https://doi.org/10.1016/j.erss.2016.12.001.