International Renewable Energy Agency

IRENA COST AND COMPETITIVENESS INDICATORS

ROOFTOP SOLAR PV

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| About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international cooperation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity. **www.irena.org**

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| Disclaimer

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ABBREVIATIONS

°C	Degrees Celsius
AC	Alternating current
BDEW	*Bundesverband der Energie- und Wasserwirtschaft* (German Association of Energy and Water Industries)
CA	California
CAISO	California Independent System Operator
CHP	Combined heat and power
CPUC	California Public Utilities Commission
CEC	California Energy Commission
CSI	California Solar Initiative
CSS	California Solar Statistics
DC	Direct current
DR-SES	Domestic time-of-use schedule for households with a solar energy system offered by SDG&E
DSO	Distribution system operator
E-6	Residential time-of-use electric schedule offered by PG&E (three different time periods and tiered pricing)
EEG	*Erneurbare-Energien-Gesetz* (German Renewable Energy Act)
E-TOU	Residential time-of-use electric schedule offered by PG&E (two different time periods and baseline credit)
EUR	Euro
FIT	Feed-in tariff
GW	Gigawatt
IITC	IRENA Innovation and Technology Centre
kW	Kilowatt
kWh	Kilowatt-hour
KWK-G	Combined Heat and Power Act (Germany)
LADWP	Los Angeles Department of Water and Power
LCOE	Levelised cost of electricity
NEM	Net energy metering
NREL	National Renewable Energy Laboratory (US)
O&M	Operations and maintenance
PG&E	Pacific Gas and Electric Company
PV	Photovoltaic
IC&CI	IRENA Cost and Competitiveness Indicators
R-1B	Residential time-of-use rate schedule offered by LADWP (three different time periods and associated pricing)
SAM	System Advisor Model (SAM), NREL
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
TOU	Time-of-use
TOU-D	Time-of-use domestic tiered rate schedule offered by SCE (three different time periods and associated pricing)
TOU-D-T	Time-of-use domestic tiered rate schedule offered by SCE (two time periods and four different pricing levels)
TSO	Transmission system operator
US	United States
USD	United States dollars
VAT	Value-added tax

EXECUTIVE SUMMARY

Solar photovoltaics (PV) are one of the most dynamic renewable power generation technologies, with improvements in technology and increases in the scale of manufacturing continuously driving down costs.

Solar PV deployment has grown at an annual average compound rate of 44% between 2000 and 2016, from 0.8 gigawatts (GW) to 291 GW. Solar PV modules have high "learning rates"[1] of between 18% and 22% depending on the period analysed. With the rapid growth in deployment, module prices have declined by around 80–85% between the end of 2009 and 2016. Between 2010 and 2016, the global weighted average total installed cost[2] and the levelised cost of electricity (LCOE) of utility-scale solar PV projects fell by 65% and 67% respectively.

Although utility-scale solar PV projects regularly make headlines for record-low prices, small-scale rooftop solar PV systems represent an important part of the market and are bringing the benefits of modern electricity services to households that previously had no access to electricity, reducing electricity costs on islands and in other remote locations that are dependent on oil-fired generation, as well as enabling residents and small businesses to generate their own electricity.

The International Renewable Energy Agency's (IRENA's) regular PV cost and competitiveness indicators will highlight the growing competitiveness of rooftop solar PV and its potential to economically meet the electricity needs of households in different markets, as well as its potentially disruptive nature for utilities.

The IRENA Solar PV Cost and Competitiveness Indicators series compares solar PV costs to electricity rates. The aim is to help policy makers track the rapid improvements in the competitiveness of renewables.

With rapidly falling PV costs (IRENA, 2016), there is a clear need for up-to-date analysis of the evolving competitiveness of solar PV in different markets. The Solar PV Cost and Competitiveness Indicators (hereafter referred to as "the indicators"), developed by IRENA, complement our cost analysis of utility-scale renewable power generation technologies by informing governments, policy makers, regulators and others about recent trends in the competitiveness of rooftop solar PV. The goal of the indicators is to aid decision makers in designing, adopting or sustaining renewable energy policies to support solar

1 The learning rate concept is borrowed from industry and represents the percentage reduction in costs or observed prices for every doubling of cumulative installed capacity.

2 Total installed costs represent all the major hardware items (e.g., module and inverter) as well as the balance of system components (e.g., cabling, mechanical and electrical installation, permitting, profit margin, etc.). See IRENA, 2016 (page 31) for a detailed characterisation of the balance of system cost components.

PV deployment. The indicators initially will focus on the residential segment but eventually may be extended to the commercial rooftop segment.

The indicators are based on a simple and transparent analysis of reliable cost and performance data. The indicators consist of three key components:

1. PV installed cost trends in different countries (and locations within a country, where data are available).
2. The "effective electricity tariff" when the solar PV system is generating based on local retail electricity tariffs, including time-of-use tariffs where in place, calculated as a weighted average of the tariff in force while solar PV is generating.[3]
3. The location-specific LCOE of solar PV systems based on local irradiation and installed costs.

Notably, the IRENA indicators are not an attempt to identify the direct economic or financial benefits of solar PV in the market segments examined, either for the owner of the solar PV system or for the utility.[4] In particular, the indicators *exclude* the impact of any support measures for solar PV. The exception would be if net metering is in place with a selling price set at the electricity tariff schedule for that customer, and the balancing period was annual.[5] As a result, the actual economics of rooftop solar PV systems for individuals and businesses are in most cases better than the indicators presented here, although this relies on net metering being in place with a selling price based on the electricity tariff, not at lower levels, as is the case in Germany for instance.

To aid readers in understanding the relevance of the indicators, the support policies in place in different markets are highlighted in this report. This gives an understanding of the scope of support policies in the markets examined, but not of their quantitative impact on the financial situation of individual investors.

Rather than show the impact of support policies on the attractiveness of solar PV to individual investors, the indicators are designed instead to show policy makers the evolution of the cost trends of solar PV systems in different markets and to compare these to the effective electricity tariff faced by residential rooftop solar PV homeowners at the time of solar PV generation. They thus provide an indicator that allows policy makers and others to track competitiveness trends.

Future editions of this report may examine how support policies from the individual perspective impact the financial attractiveness in different market segments. However, even analysis of this nature would still require a range of caveats, because it would include assumptions for individual investors that would not necessarily be representative of the range of individual investor circumstances.[6]

The costs of electricity from residential rooftop solar PV are falling rapidly. In just over six years, these costs have fallen 45% for cities in California and 66% in German cities.

This is evident from median levelised LCOE[7] estimates for residential solar PV in cities in these two large, developed electricity markets between Q1 2010 and Q2 2016.

In the US state of California, in the metropolitan areas examined, the LCOE of residential solar PV is estimated to have decreased by an average of 45% between Q1 2010 and Q2 2016 (Figure ES 1). Over the same period, the estimated median LCOE in Germany declined by 66%. This rapid reduction saw the median LCOE of residential solar PV fall below the average effective electricity tariff that applies to these residential customers in six out of the nine cities analysed in this report. In those six cities, the median LCOE fell from between 75% and 104% *higher* than the average electricity tariff (in Munich and Cologne respectively) in Q1 2010, to between 3% and 37% *lower* in Q2 2016 (in San Diego and Munich respectively).

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3 This is therefore different than the average effective electricity tariff faced by a household, as the generation profile of the PV system differs from that of the customer's consumption profile. It also does not take into account any benefit of reducing charges or electricity rates based on maximum power demand or lowering consumption levels into cheaper electricity tariff bands.

4 The detailed data required to accurately assess these values are beyond the scope of this analysis. For instance, this would require the actual cost of finance, exact location, roof slope and orientation, shading effects, system components and design, as well as feed-in tariffs (FITs), fiscal support policies, owners tax status, etc. This level of detailed local analysis is best conducted by national or sub-national institutions or agencies with the resources to accurately model all of these factors.

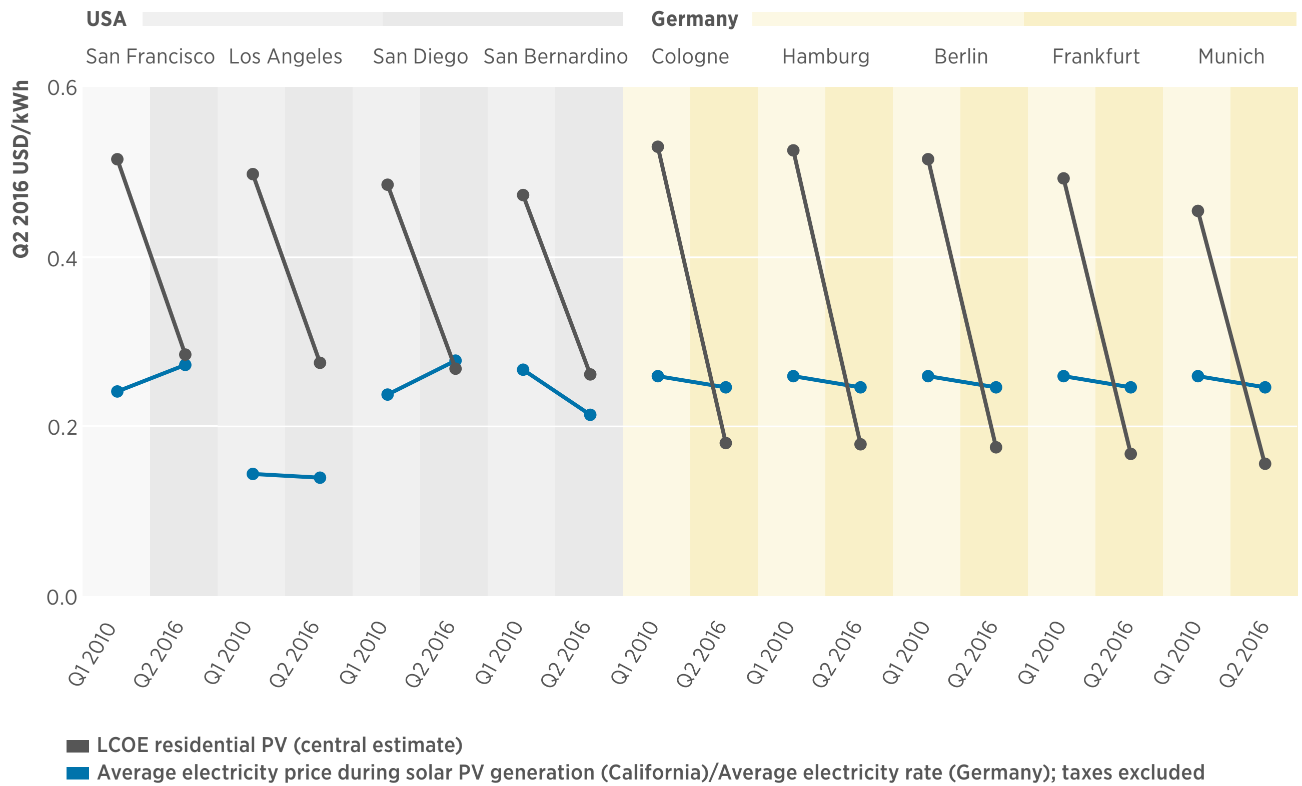
5 In this case, If no other support measures are in place, the indicators would provide a close approximation of competitiveness, assuming that the owners cost of capital matched the assumptions here.

6 Analysing the impact of support policies for individual investors or groups of investors is a very resource-intensive process. IRENA will initially focus its resources on expanding the coverage of the indicators to additional countries in its 151 Member States, but it stands ready to support partners who would like to use the IRENA methodology to examine the implications of support policies for individual market segments and investors.

7 All financial data in this report are expressed in real Q2 2016 USD and assume a 5% real weighted average cost of capital, unless expressly stated otherwise.

In California, different time-of-use electricity schedules are offered by the electric utilities serving different locations. IRENA has calculated the average effective electricity tariff when solar PV is generating in order to compare it to the LCOE. In Germany, the tariff structure is much simpler, and a fixed tariff is in place over all hours of the year. The federal weighted average price (tax components excluded) is used to guide policy makers.[8]

Figure ES 1: Median residential solar PV LCOE and median effective residential electricity rates in different metropolitan locations in California and Germany, Q1 2010 and Q2 2016



Electricity rates: San Francisco: E6; Los Angeles: TOU R-1B; San Diego: DR-SES; San Bernardino: TOU-D-T.

Source: IRENA analysis based on CEC and CPUC, 2016a; LADWP, 2016; PG&E, 2016; SDG&E, 2016; SCE, 2016; BDEW, 2016a.

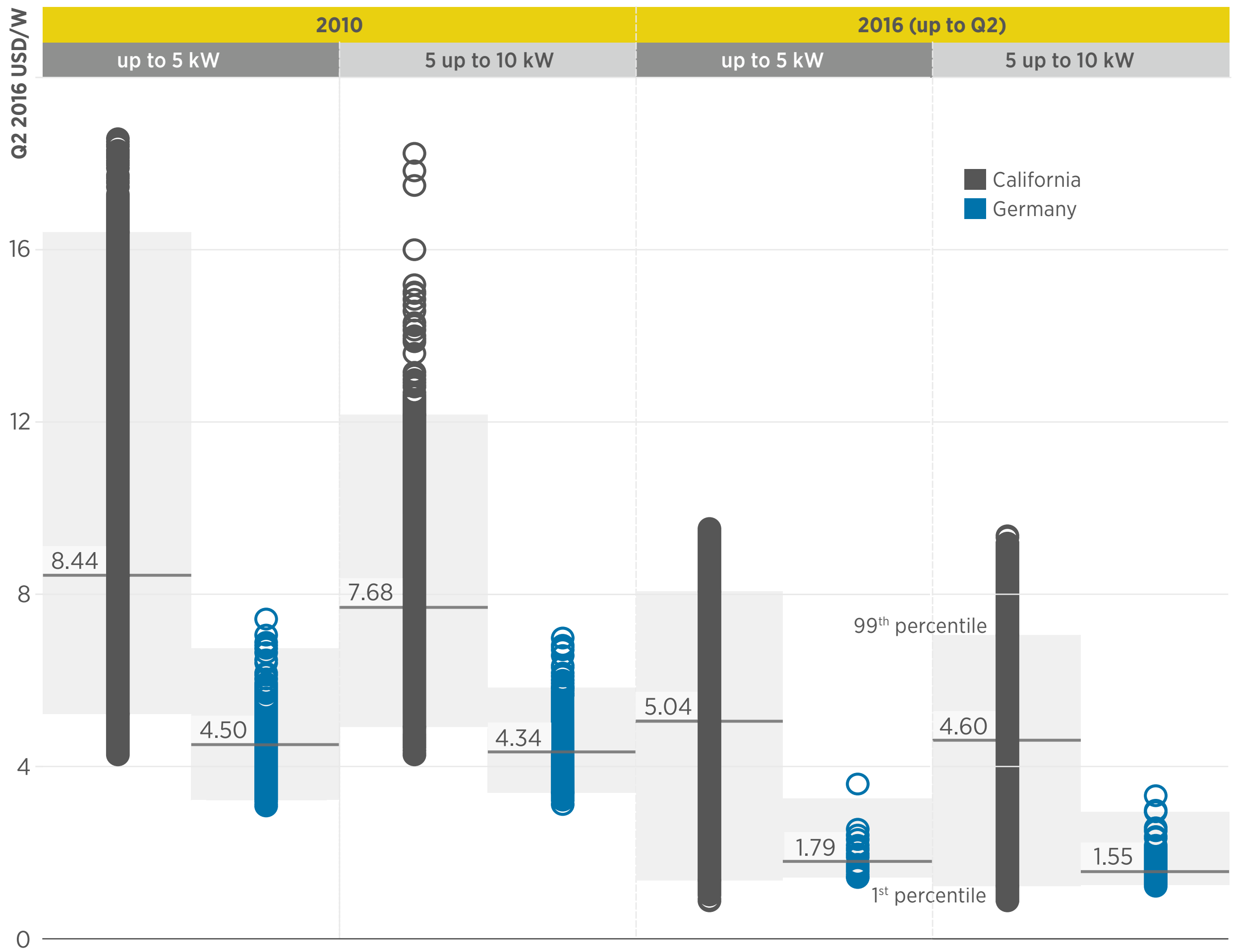
The rapid decreases in electricity costs from rooftop solar PV in California and Germany have been driven by reductions in the total installed costs of these systems. Between 2010 and 2016, the median residential PV system cost declined by around two-thirds in Germany and two-fifths in California.

Technology improvements in solar PV modules, manufacturing advances, economies of scale and reductions in balance of system costs have driven down PV installed costs globally (IRENA, 2016). Figure ES 2 highlights that between 2010 and 2016, the median total installed cost of solar PV systems in California decreased by around 40% in the smaller and larger residential system size classes. In Germany where the market is very competitive and represents best practice cost levels for small-scale solar PV systems, the decline has been 60–64% (60% in the "sub-5 kilowatt (kW)" class and 64% in the "5 to 10 kW" size category).

Total installed costs for systems in California continue to span much wider ranges than in Germany. Some of this difference can be explained by structural factors, but much higher balance of system costs in California cannot be easily explained (IRENA, 2015a). In 2010, residential rooftop systems (<5 kW) in California had total installed costs for the first and ninety-ninth percentiles from USD 5.2 per Watt (W) to USD 16.4/W, with a median of USD 8.4/W. In 2016, this spread for sub-5 kW systems had narrowed, and the first and ninety-ninth percentiles ranged from USD 1.4 to USD 8.1/W with a median value of USD 5/W. This compares to Germany where the first and ninety-ninth percentiles of system costs ranged from USD 3.2 to USD 6.7/W with a median of USD 4.5/W in 2010, falling to USD 1.4 to USD 3.3/W with a median of USD 1.8/W in 2016 for systems of less than 5 kW. A similar, but slightly narrower, pattern can be seen for larger systems in the 5–10 kW range.

8 Analysis of the relative competitiveness of solar PV when taxes are included is also presented in the section examining competitiveness in Germany, given that there is a significant difference in prices with and without tax.

Figure ES 2: Residential PV systems installed cost ranges by size in California and Germany, 2010 and 2016 (up to Q2)



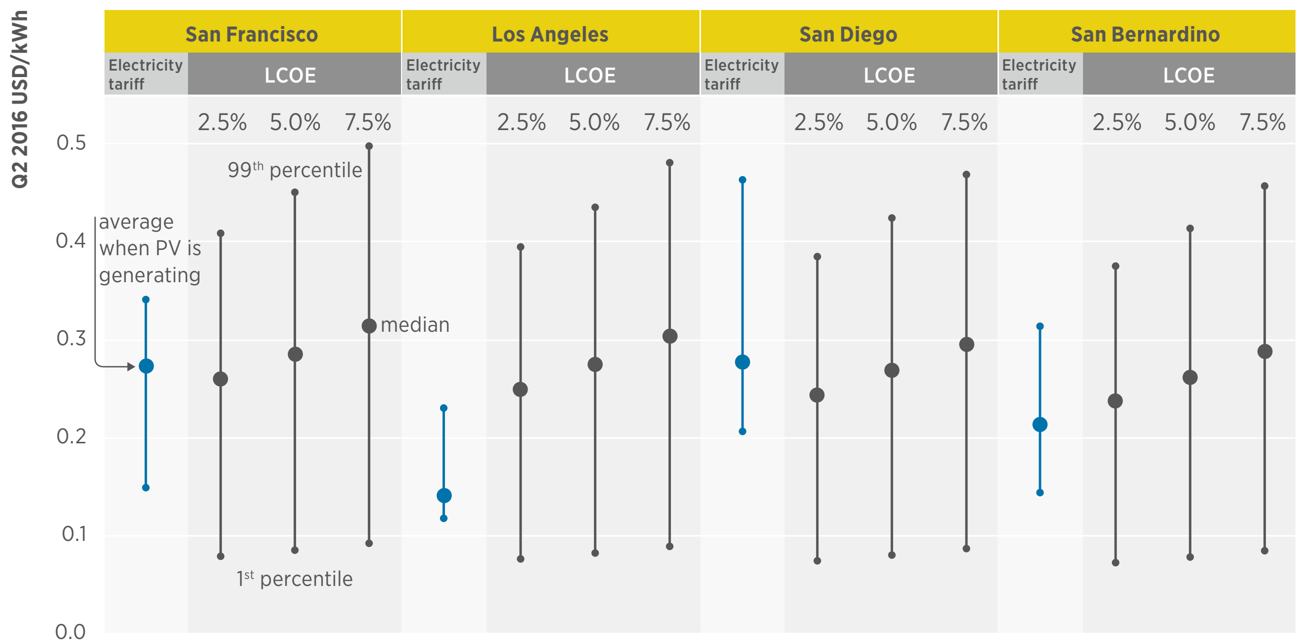
Source: IRENA analysis based on CEC and CPUC, 2016a; EuPD Research, 2017a.

Along with cost decreases, the IRENA Indicators highlight the highly nuanced nature of competitiveness trends for rooftop solar PV. The wide range of installed costs for such systems, notably in California, translates into a wide range of electricity costs from solar PV.

This is readily visible when examining the range of LCOEs for solar PV systems in different Californian cities. Figure ES 3 presents the range of LCOEs compared to the minimum and maximum rates in the TOU schedule for the location, as well as the average rate in effect while solar PV systems are generating in that location. In all cases, there are a range of systems with LCOEs above and below the average effective electricity tariff, yet a simple examination of average values masks this very broad range of individual outcomes.

In San Francisco and San Diego, the central LCOE estimate of residential solar PV systems assuming a weighted average cost of capital (WACC) of 5% is around or lower than the average effective electricity tariff in force when solar PV is generating. In Los Angeles and San Bernardino, lower electricity tariffs mean that the average residential solar PV system is still more costly than the average effective electricity tariff faced by residential solar PV owners when they are generating electricity. Yet, when the range of system costs is examined, a much more nuanced story develops. A large number of systems deliver electricity at a cost lower than the average effective electricity tariff, but lower than the lowest electricity rate in force, before considering the financial support available to these systems. Similarly, a range of systems have costs that exceed the average effective electricity tariff.

Figure ES 3: Residential rooftop solar PV LCOE ranges in California by city and cost of capital compared to electricity rates, Q2 2016



Electricity rates ranges

San Francisco: E6, Tier 1, summer, 'off-peak' to 'peak'. Los Angeles: TOU R-1B, high season, 'base' to 'high peak'.
San Diego: DR-SES, Summer, 'off-peak' to 'on-peak'. San Bernardino: TOU-D-T, summer, level I, 'off-peak' to 'on-peak'

Source: IRENA analysis based on CEC and CPUC, 2016a; EuPD Research, 2017a.

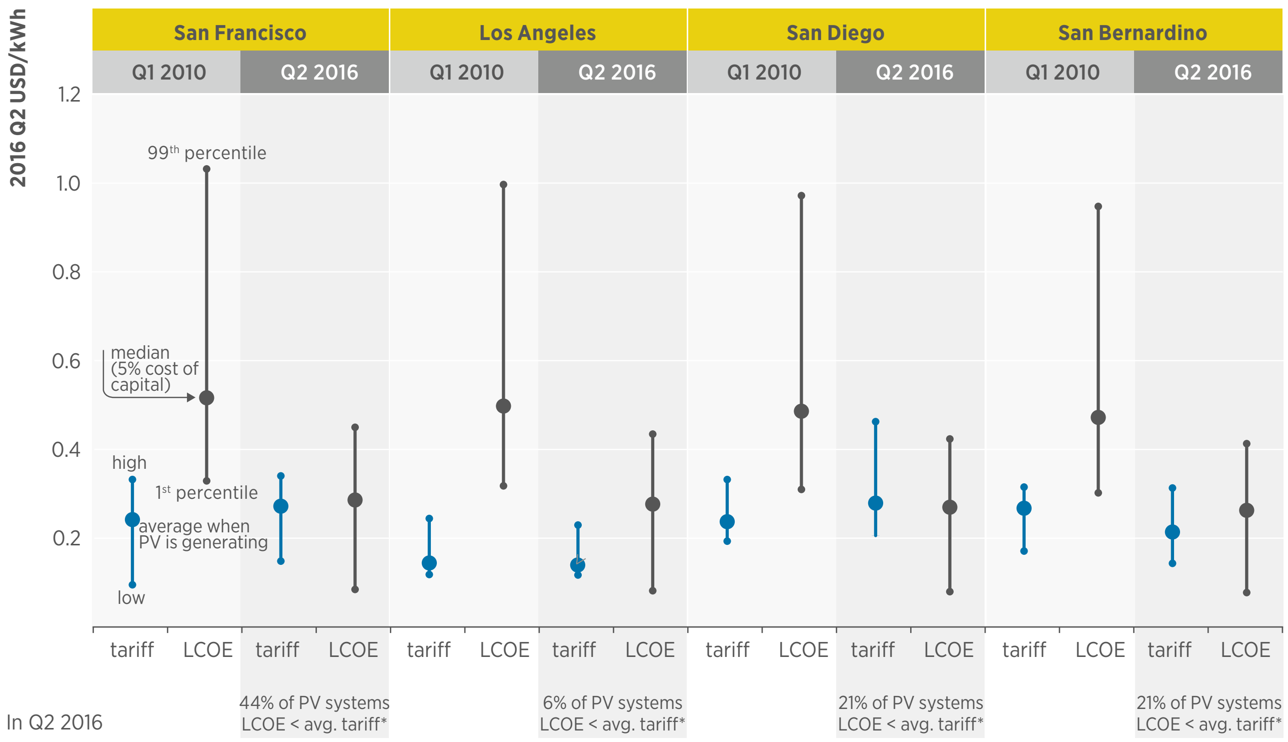
This highlights the importance for solar PV, and for renewables in general, of examining the full range of costs in order to identify the spread of projects or systems which are competitive. It also clearly shows the importance of having data on actual costs in the solar PV segment and market being examined. Without these data there is a real risk of an oversimplified conclusion about the relative competitiveness of solar PV for individual investors and also for policy makers considering how to design solar PV support policies.

In California's large metropolitan areas, rooftop residential solar PV systems are a potentially economic investment, even without financial support. This is due to the state's relatively high and complicated time-of-use tariffs.[9]

Utilities in the analysed locations in California all offer schedules that provide electricity at different prices depending on the time that the electricity is used and also sometimes depending on the level of consumption, day and time of year. These are known as TOU (time-of-use) rates. The simulated effective electricity tariff when solar PV is generating increased between Q1 2010 and Q2 2016 in three out of the four metropolitan areas as electricity tariffs rose (Figure ES 4).[10]

9 Data on the share of consumers on different tariff structures are not readily available, so the results are even more nuanced than is presented here.
10 The average electricity tariff for the month will typically be lower than this measure of the electricity tariff while solar PV is generating, because solar PV generation profiles overlap the peak tariff hours to a larger extent than consumption.

Figure ES 4: Residential rooftop solar PV LCOE trends in California by city compared to average effective electricity rates, Q1 2010 and Q2 2016



Source: IRENA analysis based on CEC and CPUC, 2016a; LADWP, 2016; PG&E, 2016; SDG&E, 2016; SCE, 2016.

* These percentages show the share of residential PV systems at the aggregated state level from data sample for California that yield LCOEs above the average electrical tariff in each of the displayed locations. It may differ from the share at the specific location level.

Taking into account the wide range of installed costs of solar PV in California, in Q2 2016 57% of residential solar PV systems in San Diego had an LCOE below the average effective electricity rate. This share was 44% in San Francisco, 21% in San Bernardino and 6% in Los Angeles. This does not include the financial support policies available to these systems. Factoring in this support (notably the federal investment tax credit) would significantly raise these percentages.

In San Francisco the median LCOE has fallen from USD 0.27 per kilowatt-hour (kWh) higher than the average effective electricity tariff in Q1 2010 to just USD 0.01/kWh in Q2 2016 (a 96% reduction in the gap).

In Los Angeles, from Q1 2010 to Q2 2016 the median LCOE gap over the average effective electricity tariff has fallen from USD 0.35/kWh in Q1 2010 to USD 0.14/kWh in Q2 2016 (a 62% reduction). In San Diego the median LCOE fell below the average effective electricity tariff in Q1 2015 and is USD 0.01/kWh (3%) lower than the average effective electricity tariff. In San Bernardino, the median LCOE of residential PV's differential with the estimated average electricity price has dropped from USD 0.21/kWh in Q1 2010 to USD 0.05/kWh in Q2 2016 (a 77% reduction).

Germany has one of the most competitive small-scale solar PV markets in the world, with very low installed costs offsetting the country's relatively limited sunshine. Rooftop PV power, which cost at least 75% more than average residential electricity prices in early 2010, has fallen in just over six years to at least 27% cheaper than the average residential electricity tariff.

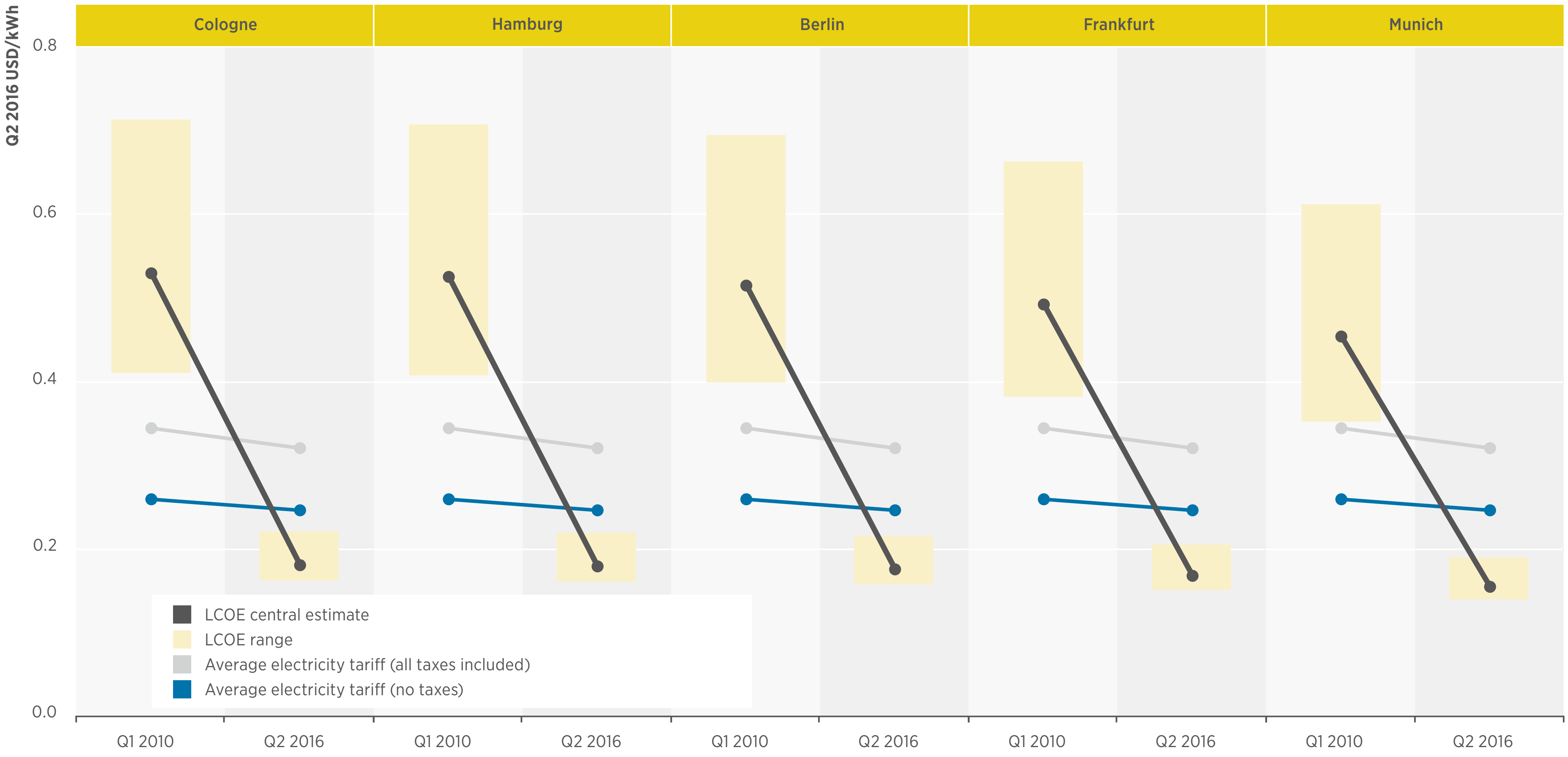
The median LCOE estimates in the German cities evaluated were in the range of USD 0.45 to USD 0.53/kWh in Q1 2010 (Figure ES 5), but had fallen to between USD 0.16 and USD 0.18/kWh during the second quarter of 2016 (an average 66% reduction). In Cologne, the LCOE range of residential PV systems, based on high and low installed cost estimates[11], decreased from USD 0.41 to 0.71/kWh in Q1 2010 to between USD 0.16 and USD 0.22/kWh during Q2 2016, while the central estimate decreased from USD 0.53 to USD 0.18/kWh. Similar results have been obtained for Hamburg,[12] while the residential PV LCOE range in Berlin decreased from between USD 0.40 and 0.69/kWh in Q1 2010 to between USD 0.16 and USD 0.22/kWh during Q2 2016.

11 Ranges are calculated using the first and ninety-ninth percentile of the evaluated installed costs time series.

12 Future editions of these indicators may incorporate region-specific installed cost estimates, rather than using the national range of costs. This will require the development of a model to estimate total installed costs by region in Germany, as the raw installed cost data for each quarter and each region is more or less statistically representative given different volumes of survey response rates in different quarters and regions.

With the highest irradiation of the evaluated German locations, Munich has the lowest PV LCOE levels, and the residential PV LCOE central estimate there has been calculated at USD 0.16/kWh during Q2 2016, with a range of between USD 0.14 and USD 0.19/kWh. In all locations, the LCOE ranges during Q2 2016 are below the electricity tariffs (even when the tax components are excluded).

Figure ES 5: Residential rooftop solar PV LCOE trends in Germany by city compared to average effective electricity rates, Q1 2010 to Q2 2016

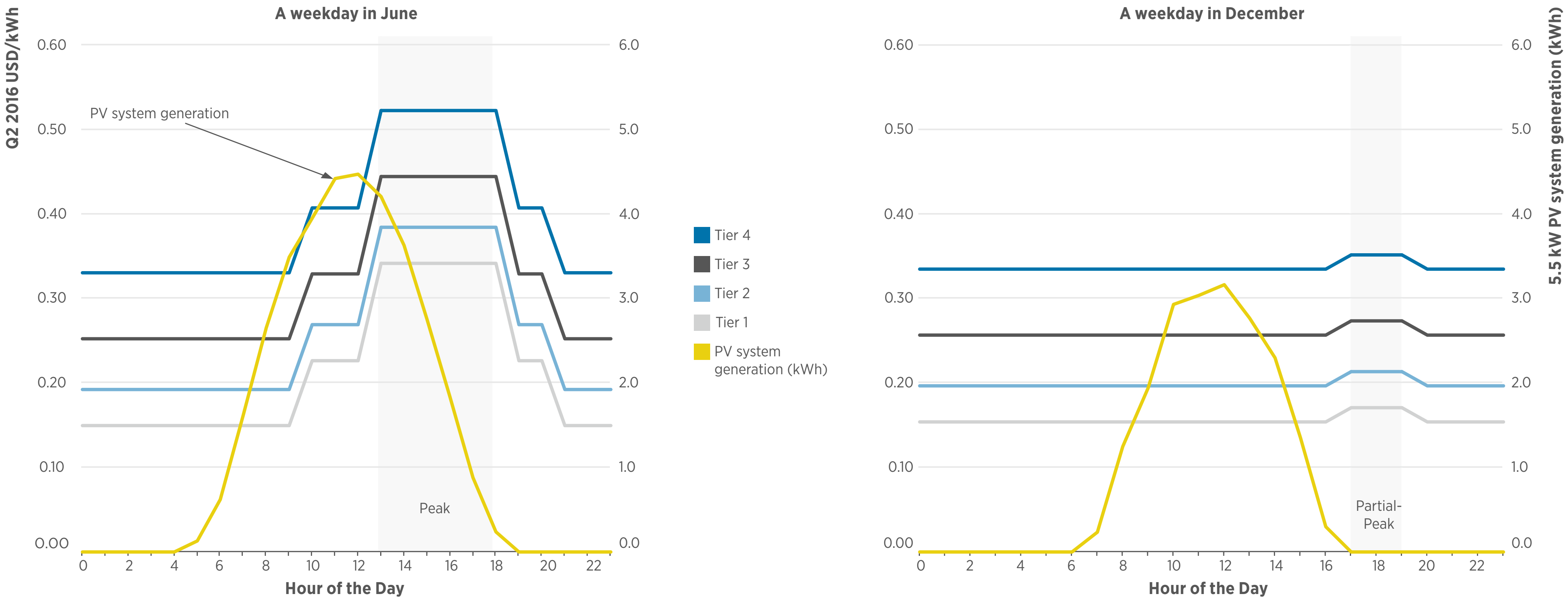


Source: IRENA analysis based on EuPD Research, 2017a ; BDEW, 2016a.

Time-of-use rate schedules can highlight the value of solar PV to the electricity system as a whole. However, if these are too complex, they can reduce overall market transparency about the economics of distributed generation and energy efficiency options.

Figure ES 6 highlights for San Francisco (on PG&E's residential schedule E-6[13]) that the higher summer electricity rates correspond well with high irradiation months and the overlap with the daily PV production profile. It also shows the higher electricity rates in effect as electricity consumption increases and shifts the householder into higher rate "tiers" (also called blocks). Most TOU schedules in California have an increasing charge per unit of energy as the consumption of energy increases above a set tier, but they also change according to season and can differ during weekends and public holidays. These rate structures can quickly become very complex.

Figure ES 6: Electricity rates by tier and PV generation profile in a weekday in June (left) and in December (right) in San Francisco, schedule E-6 (as of Q2 2016)



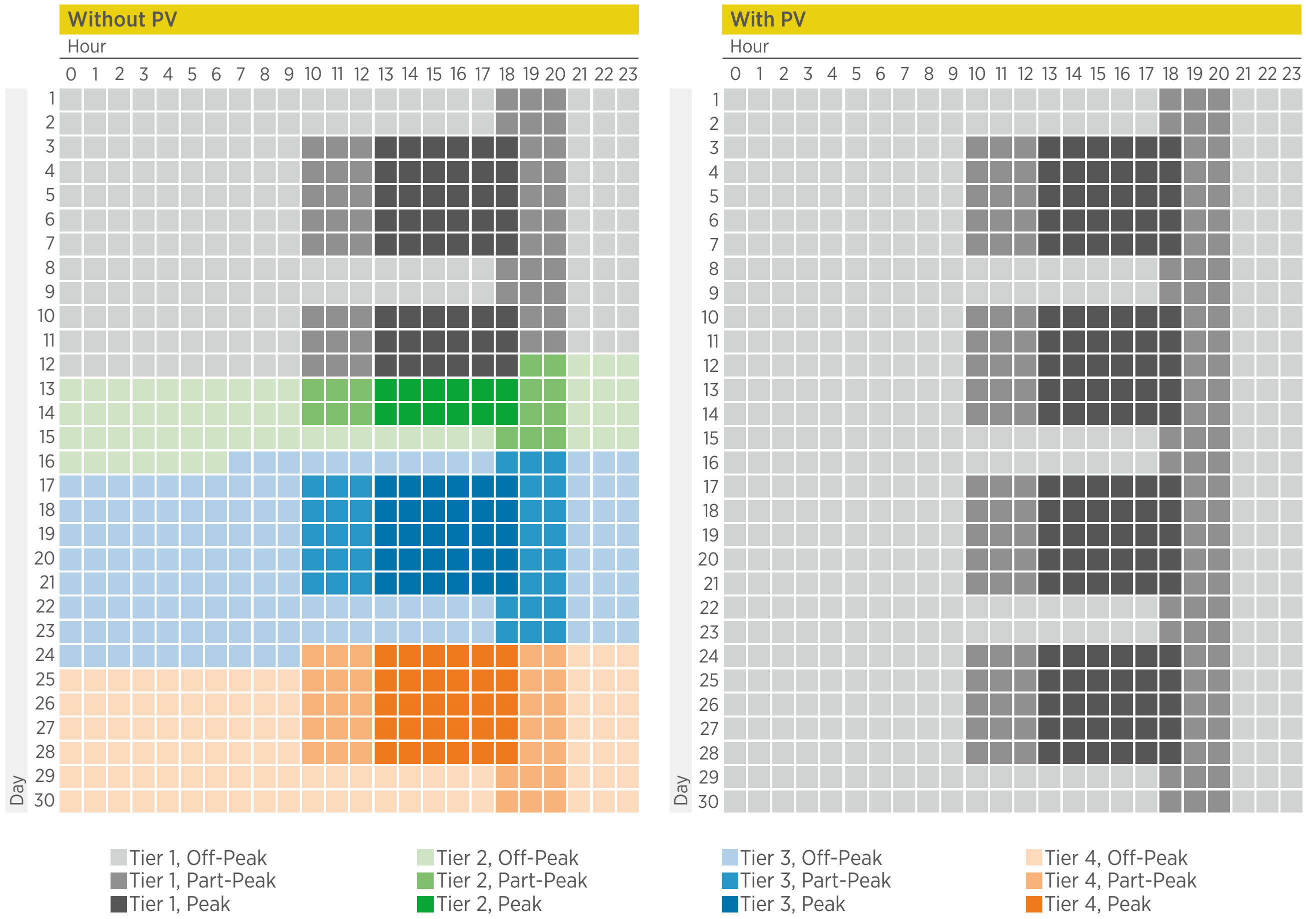
Source: IRENA analysis based on PG&E, 2016.

13 The E-6 schedule is a TOU schedule that varies by location, time of day, monthly consumption, season and day of the week. The E-6 was closed to new customers on 31 May 2016 (although enrolled customers can remain grandfathered if they wish), and a new simpler two-tier rate structure was introduced.

Detailed modelling has been conducted for California in each metropolitan area examined to ensure that the electricity rate that would be in force during the solar PV system operation is accurately captured. The calculation of the effective tariff in force when the solar PV system is generating has been calculated by mapping the hourly output of the PV system to TOU tariff rates over each hour in a year. Such an approach can lead to a better understanding of the value that PV-generated electricity can provide to households under a TOU electric plan (although examining specific economic benefits at the individual household level is beyond the scope of this report).

Under these TOU rate structures in place in California, the benefits of solar PV systems can go beyond the effective electricity tariff, as the solar PV system reduces a household's exposure to the higher-tier rates based on the monthly net consumption tier or block that the household falls under. As an example, Figure ES 7 highlights for San Francisco and PG&E's residential schedule E-6 the impact of solar PV on shifting the monthly electricity consumption from the higher tiers in the tariff rates. Instead of more than half of the month's hourly rates being in tiers 2 to 4, a household with solar PV would remain on the lower, tier 1, rates throughout the month due to the reduction in their net demand.

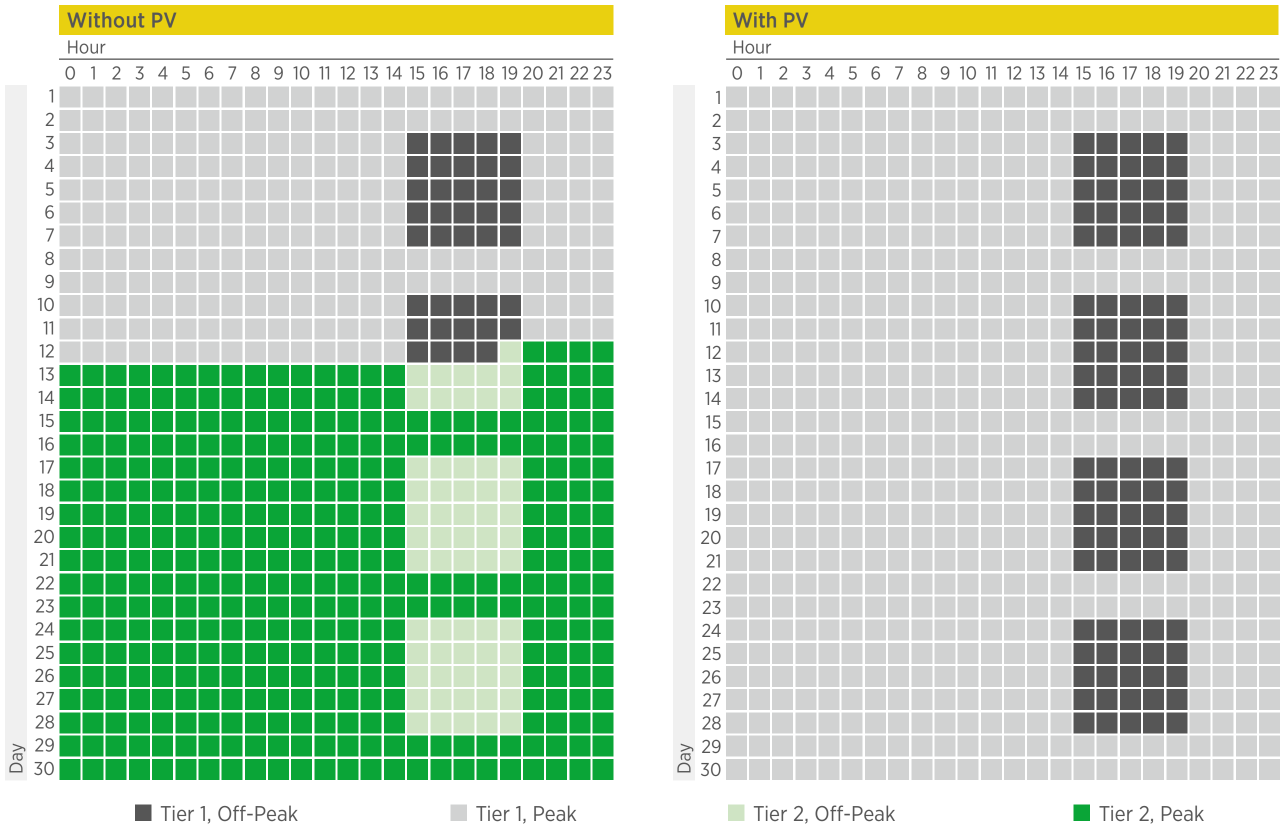
Figure ES 7: Quantity of hours by tier and TOU perid in June in San Francisco (schedule E-6) for a modelled household based on net consumption without (left) and with (right) a solar PV system, Q2 2016



Source: IRENA analysis based on PG&E, 2016.

In line with the "Residential Rate Reform" progress in California, new TOU schedules with simpler structures have been introduced. Starting in Q1 2016 this report also analyses PG&E's schedule E-TOU (option A) for San Francisco. In its option A, this schedule can be interpreted as having two tiers. This is a more simplified structure than the five-tier structure of the standard E-6 schedule. Schedule E-TOU option A also defines only two TOU periods (peak[14] and off-peak) as opposed to the three-period structure of the standard schedule E-6. Figure ES 8 shows that in this case, too, (for the example of June in San Francisco) the tiers and higher charges are avoided when a PV system is assumed.

Figure ES 8: Quantity of hours by tier and TOU period in June without (left) and with (right) a solar PV system on PG&E's residential schedule E-TOU (option A)



Source: IRENA based on PG&E, 2016.

Given that the IRENA indicators are not designed to analyse the financial benefits to individual consumers, the impact of shifting consumption into lower consumption tiers is not analysed in this report.[15] However, it serves to highlight how the complexity of the TOU rate structures can make calculating the benefit of solar PV to individual households extremely challenging.

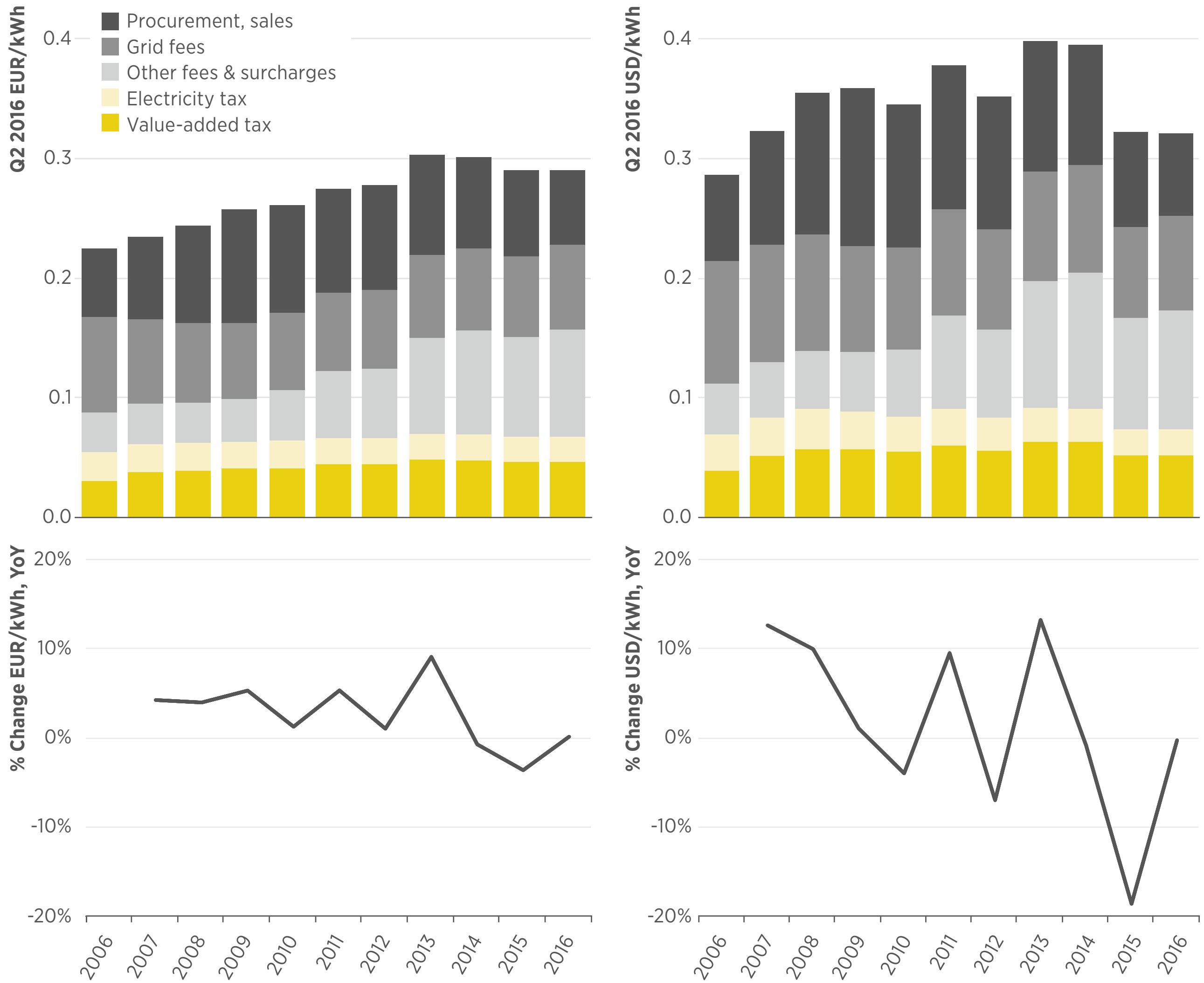
This complexity, which reduces the transparency of the economic benefits of solar PV systems, can act as a barrier to the uptake or solar PV systems without sufficient education and information programmes, as well as simple-to-use analytical tools, that can make these calculations accessible and understandable to the average household. It also can shift the share of benefits from households to others in the value chain that have better information, potentially reducing the support for ongoing programmes. In line with the Residential Rate Reform progress in California, new TOU schedules with simpler structures have been introduced to make costs more transparent to consumers.

14 During the summer season, the Peak Period in schedule E-TOU runs from 3 p.m. to 8 p.m. (for E-6 it runs from 1 p.m. to 7 p.m.). Other TOU definitions also vary.
15 Future editions of the IC&CI may look at the order of magnitude of these impacts for a hypothetical household, but even this type of detailed analysis can serve only as an indicator of the order of magnitude of the potential benefit.

In contrast to California, where TOU schedules are common, Germany has a simple electricity tariff that is essentially fixed over the year. Germany has some of the highest residential electricity prices in Europe, with an average of around EUR 0.29/kWh including all taxes and levies. Much of this is due to the level of taxes and levies borne by residential consumers.

This highlights a significant difference in the support policies for the energy transition in Germany and California. In Germany, the cost of supporting the accelerated deployment of renewable energy technologies is shared by most electricity consumers.[16] In contrast, in California the direct financial support is funded through taxation, at either a federal or state level. The German Association of Energy and Water Industries (*Bundesverband der Energie- und Wasserwirtschaft* – BDEW) data in Figure ES 9 show the federal weighted average rates (excluding "special" tariffs such as "green electricity tariffs", "heating tariffs", etc.). Some of the cost components vary by region according to local tariffs and specific grid areas, but unlike in the US, the variation is not large (typically in the order of 10%).

Figure ES 9: Household electricity prices in Germany by cost groups and year-on-year percentage change, 2006–2016



Source: IRENA analysis based on BDEW, 2016a.

16 The main exemptions are for medium-to-large industrial consumers that compete in international markets and whose competitiveness would be adversely affected by paying the EEG levy.

Although a detailed analysis of electricity price structures in Germany is beyond the scope of this report, Figure ES 9 shows the key cost groups in recent years, expressed in both real Q2 2016 EUR and real Q2 2016 USD per kWh, along with the year-on-year percentage changes for each. In real terms, electricity rates experienced by residential consumers (e.g., in EUR) peaked in 2013. In real Q2 2016 EUR terms, the electricity price (all taxes and levies inclusive) grew from EUR 0.23/kWh in 2006 to EUR 0.30/kWh in 2013, before declining to EU 0.29/kWh in 2016. The volatility of the USD/EUR exchange rate is readily visible when comparing the electricity prices in USD and EUR, notably the weakening of the Euro in 2015.

Although the electricity tariff rates faced by residential households in Germany are simple to understand, a myriad of cost components are in the “other fees and surcharges” grouping. In terms of contribution to the total electricity rate, the largest cost components within the “other fees and surcharges” group in 2016 are the “EEG surcharge” and the “concession levy” (5% of the total electricity tariff in 2006, 22% in 2016) and the “concession levy” (9% of the total electricity rate in 2009, 6% in 2016). The EEG surcharge (*EEG Umlage*) covers the costs of the support schemes for the programmes using a feed-in tariff, while the concession levy (*Konzessionsabgabe*) pays for the use of public rights of way (this money is paid by grid operators to municipalities).

Among all “other fees and surcharges” cost categories, the EEG surcharge changed the most between 2006 and 2016, increasing more than four-fold in that period. In real terms, the absolute EEG surcharge increased by EUR 0.05/kWh (USD 0.06/kWh) from EUR 0.01/kWh to EUR 0.06/kWh between 2006 and 2016. Recent projections estimate that the EEG surcharge will increase by slightly less than EUR 0.01/kWh up until 2022 to reach EUR 0.07/kWh, after which it will start to decrease and fall to EUR 0.05/kWh in 2030 (Agora, 2016).

IRENA Rooftop Solar PV Cost and Competitiveness Indicators:

INTRODUCTION

WHAT ARE THE INDICATORS?

The IRENAs Cost and Competitiveness Indicators for rooftop solar (IC&CI or "indicators" hereafter) are a series of indicators of solar photovoltaic (PV) costs compared to electricity rates.

The solar PV market is one of the fastest moving renewable energy markets, with high learning rates of 18% to 22% (for PV modules) combined with rapid deployment resulting in rapidly falling costs (IRENA, 2016). As a consequence, there is a clear need for up-to-date analysis of the evolving competitiveness of solar PV in different markets.

The IC&CIs are designed to inform governments, policy makers, regulators and others about recent trends in the competitiveness of solar PV. The goal of the indicators is to aid decision makers in designing, adopting or sustaining renewable energy policies to support solar PV deployment.

The results are based on a simple and transparent analysis of reliable cost and performance data, which are updated on a quarterly basis.

The indicators consist of three key components:

1. PV installed cost trends,
2. Effective electricity rate when the solar PV system is generating, and
3. The location-specific levelised cost of electricity (LCOE) of the PV system.

Notably, the IRENA indicators for rooftop solar PV are not an attempt to identify the direct economic or financial benefits of solar PV in the market segments examined, either for the owner of the solar PV system or for the utility. The detailed data required to accurately assess these values are beyond the scope of this analysis.[17] The indicators are designed instead to show the evolution of the costs of solar PV systems in different markets and to compare these to a proxy of the value of solar PV (on the basis of electricity tariffs) to identify competitiveness.

17 For instance, this would require the actual cost of finance, exact location, roof slope and orientation, shading effects, system components and design, as well as FITs, fiscal support policies, owners' tax status, etc.

First and foremost, the analysis is designed to help inform policy makers about the trends in solar PV competitiveness. As a result, although support policies are discussed for each market, their impact on a system owner's financial situation is not analysed. The IC&CI are, however, also designed to be a vehicle for examining special topics around solar PV costs and deployment, so these issues may be discussed in future editions of the indicators.

WHY DEVELOP THESE INDICATORS?

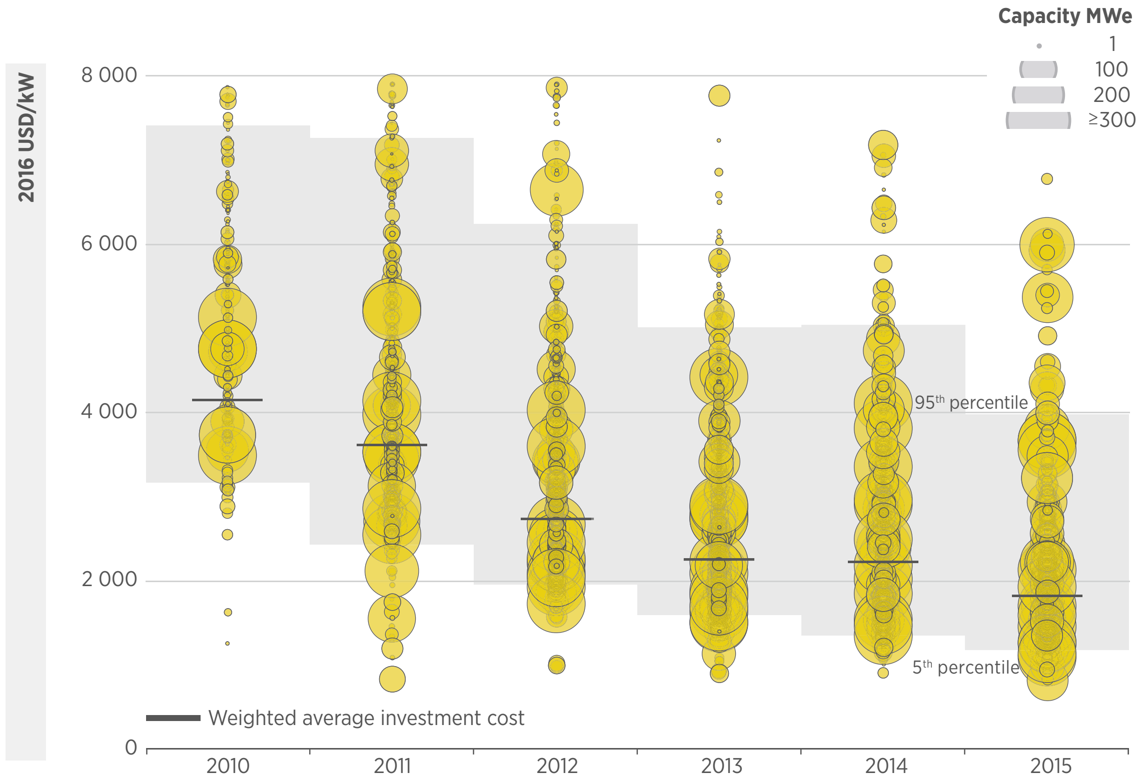
Commercially available solar PV systems have benefited from almost half a century of development and are today a mature and proven technology. Yet PV costs continue to fall rapidly in some markets.

PV is one of the fastest growing renewable power generation technologies and has experienced strong progress in cost reduction. PV modules have fallen in price by around 80% since 2010, with somewhat lower percentage reductions in total installed costs at the rooftop and utility-scale levels (IRENA, 2016). A range of studies has confirmed the competitiveness of solar PV in different markets, such as Germany. Yet, there is also a lack of regularly updated analysis in the public domain for important markets.

BOX 1: IRENA'S RENEWABLE COST DATABASE

The lack of accurate, reliable and up-to-date data on the cost and performance of renewable energy technologies is a significant barrier to their uptake. The cost analysis programme and publications from the International Renewable Energy Agency (IRENA) are filling this gap in knowledge. The IRENA Renewable Cost Database covers 15 000 utility-scale projects around the world, spanning all major renewable power technologies. IRENA can, on this basis, calculate the LCOE for each technology. The Renewable Cost Database (IRENA, 2017a) also incorporates data on around 750 000 small-scale rooftop solar PV systems in Member countries of the Organisation for Economic Co-operation and Development (OECD).

Figure 1: Total installed PV system cost and weighted averages for utility-scale systems, 2010–2015



Source: IRENA Renewable Cost Database, 2017.

An accurate understanding of the evolution of solar PV competitiveness in different markets is critical to ensuring both efficient and effective support policies. The IC&CI are therefore designed to help fill the significant gap in available analysis, by analysing current cost and performance data.

To make the analysis as useful as possible to policy makers, the IC&CI use a series of simple indicators. These still require very detailed modelling, however, combined with transparent methodological assumptions and data. This ensures that policy makers have the best possible analysis to allow them to make informed decisions on the role that distributed solar PV can play in their energy system.

The IC&CI are part of IRENA's cost analysis programme's core products and are designed to leverage the data available in the IRENA Renewable Cost Database and other sources. By focusing on analysis that has direct relevance to policy makers (rather than just reporting installed cost trends) and doing so in a timely manner, the indicators are designed to provide IRENA's Member States and others with timely and useful supporting analysis.

This analysis is particularly topical. Once the LCOE of residential solar PV falls below tariff levels, even in the absence of support measures, installing residential PV systems in order to self-consume PV electricity becomes increasingly attractive. Understanding when this occurs is critical for policy makers and utilities, as small-scale distributed solar PV is a potentially disruptive technology.

At low levels of penetration, solar PV owners and utilities can benefit from solar PV deployment. Customers can reduce their bills and utilities can enjoy lower distribution losses, deferring investments in distribution capacity and in some cases transmission capacity. As solar PV's penetration grows, however, the strong economic incentive for individuals or organisations to install solar PV can affect the balance between costs and income in the system and undermine the existing utility model. As such, utilities start to look more closely at the impacts of solar PV on their profitability, and questions about the appropriate market design can become very important. (IRENA, 2017b)

Understanding these issues well in advance of a market shift will allow policy makers, utilities, regulators and potential solar PV owners to have a balanced debate and analysis of all the direct and indirect costs and benefits of solar PV deployment. They also can understand how the regulatory and support structure needs to adapt to the rise of solar PV, over time. This challenge will only become more pressing as electricity storage costs continue to decline, increasing the potential for self-consumption of solar PV generation.

HOW ARE THE INDICATORS CALCULATED?

To ensure that the analysis is as accessible as possible to policy makers, it is based on a simple set of three indicators:

1. Solar PV installed costs: data for individual systems by country – and in some cases by city – and by market segment (e.g., residential). The analysis is focused on examining trends in installed costs at a relatively granular geographic level (i.e., at the city or state level, where data are available).[18]

2. An indicator of the value of solar PV as measured by mapping the hourly output of the PV system to time-of-use (TOU) tariff rates (if in effect) over the 8 760 hours in a year, assuming an average meteorological year. This is done using freely available modelling software that is specifically adapted to the task.

3. An analysis of the LCOE of the solar PV systems for comparison with the indicator of electricity value, assuming a 5% cost of capital. This is based on a methodological approach that has been used by IRENA over a number of years.[19]

In all cases, the analysis does not include the impact of policy support. This is because the goal is to inform policy makers about any gaps in the level of competitiveness. Where policy support is in place, the relative economics will be better than that implied by the indicators – sometimes significantly so.

18 In some cases, this requires estimation, if data collection in a given quarter is not statistically representative.
19 See, for instance; IRENA, 2012a-e; IRENA, 2013; IRENA, 2015a; IRENA, 2016.

Despite focusing on a set of simple metrics, the analysis and modelling itself can be very complex. This is because of the very granular analysis of costs, performance and competitiveness undertaken at a city/state level. In addition, the sophisticated modelling required to analyse hourly output over the 8 760 hours in a year, while identifying the associated electricity tariff in force in each of those hours, is also a complex procedure. This identification depends on tariff schedules, location, user demand profile for electricity and other factors.

The details of the methodology and definitions used in the IC&CI series can be found in Annex 1 and will be available online in subsequent IC&CI updates.

WHICH MARKETS WILL BE COVERED?

The IC&CI series is being launched with an analysis of residential PV in the markets of California and Germany.

These markets have been chosen because they provide interesting contrasts in terms of costs and electricity tariff structures for residential consumers. Good time-series data are also available for all the relevant parameters. Future editions of the IC&CI will include other markets but may not have the same granularity, given more challenging data collection issues.

This first edition provides indicators for the four largest metropolitan areas in California (Los Angeles, San Francisco, San Diego and San Bernardino) as well as five cities in Germany (Cologne, Berlin, Frankfurt, Hamburg and Munich). The locations in California cover the full range of utilities in the state, which has become one of the most important renewable energy markets worldwide. This first edition also provides indicators for Germany, which remains one of the most competitive residential solar PV markets globally. Additional markets will be added in forthcoming editions of the IC&CI.

Eventually, the analysis could be extended to other market segments, such as commercial rooftop systems, but this is not envisaged in the near future, given the resources required to undertake this extension of the IRENA indicators.

GLOBAL PV MARKET OVERVIEW

PV CAPACITY

The global PV market has grown rapidly in the last decade. The cumulative global installed PV capacity grew from 6.2 gigawatts (GW) at the end of 2006 to 291 GW at the end of 2016. This represents approximately 285 GW of net capacity addition during this 10-year period. Net additions during the more recent period from 2010 to 2016 grew about 28% annually, and 94% of the decade's net capacity was installed during these last years (IRENA, 2017c).

After an all-time high of above 22 GW in 2011, yearly installations in Europe declined for the first time in 2012. In both 2014 and 2015 they did not exceed 8 GW, but with 44% of the global cumulative installed capacity, Europe was still the leading region at the end of 2015. New installations did not exceed 5 GW during 2016, and Europe's share of total cumulative PV capacity declined to 35% (Figure 2).

PV market growth in Asia in recent years (led by China and Japan) more than compensated for the decline in Europe, resulting in continued growth in global new capacity installations, despite a slight overall decline in 2012.

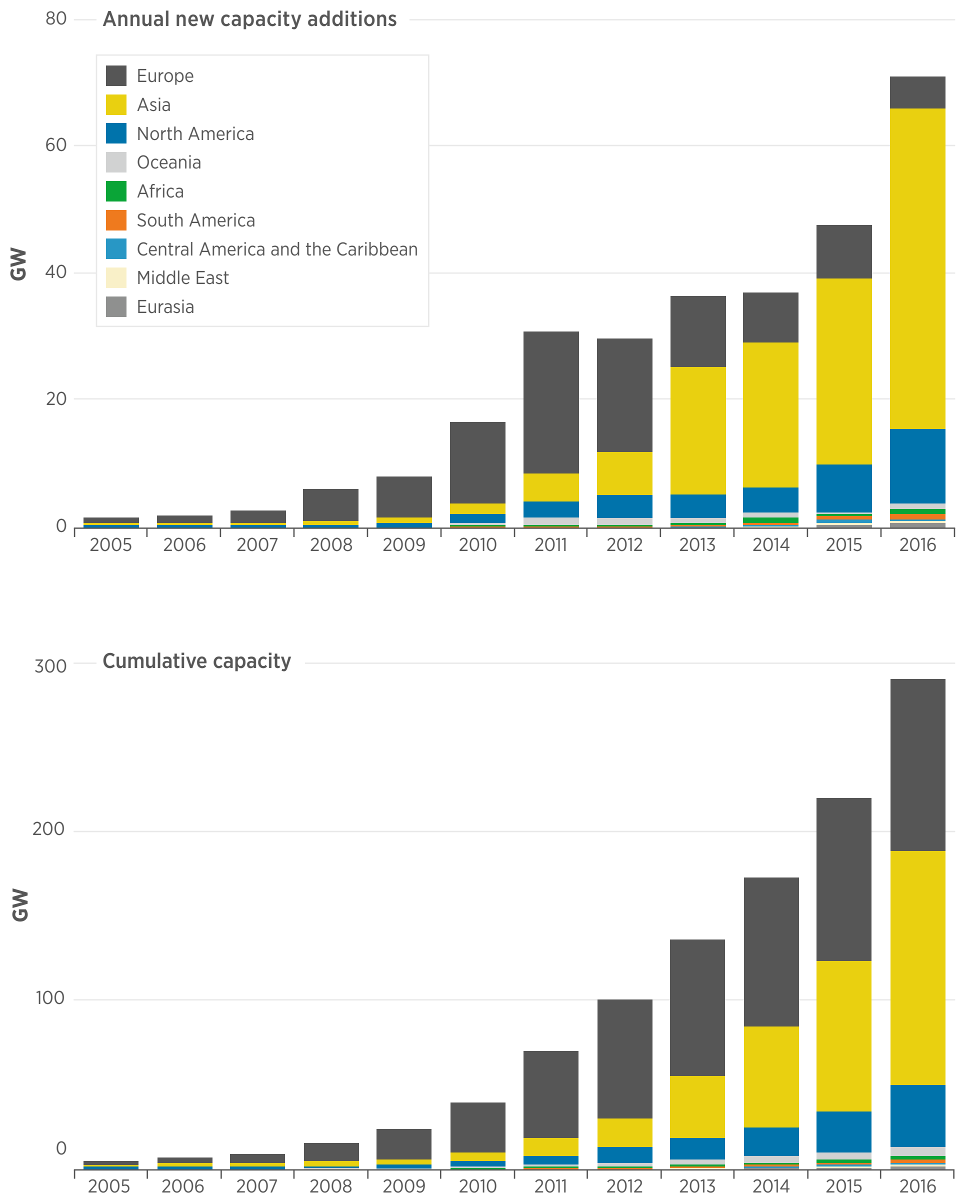
China added more than 10 GW of new PV installations in 2014 and more than 15 GW in 2015, leading the world in both years. By the end of 2015, China had overtaken Germany as the global leader in annual new capacity additions and in cumulative installed capacity, and during 2016 new PV additions in China exceeded 34 GW. Growth in Japan also has continued, and from 2014 to 2016 the country added more than 28 GW of new PV capacity.

The US added more than 11 GW of new PV installations during 2016 and the country remains fourth in the global ranking of cumulative capacity at the end of that year. Through steady growth in recent years, the US has become the most important PV market in North America and one of the world's major PV players.

PV MODULE COSTS

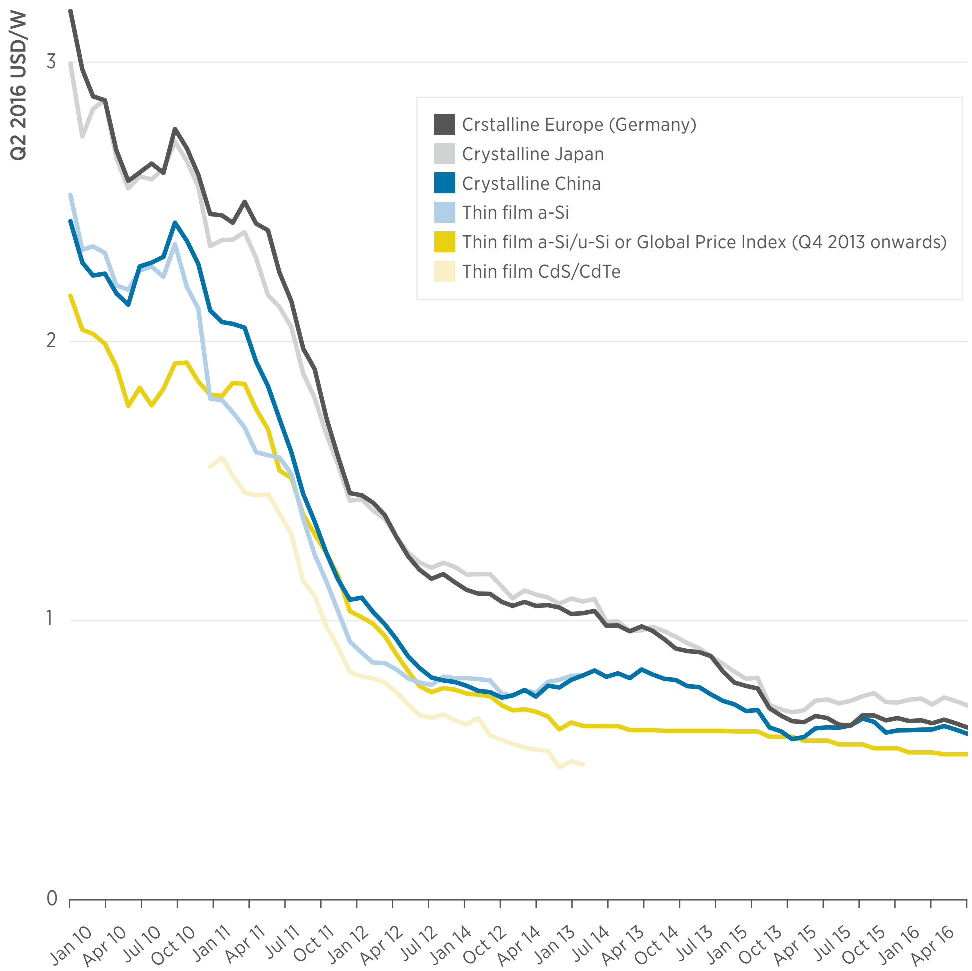
Solar PV modules have high learning rates, ranging from 18% to 22% (IRENA, 2016). As these have combined with rapid deployment – around 42% growth in installed capacity year-on-year between 2005 and 2015 – solar PV module prices have fallen rapidly. Solar PV module prices declined by around 80% between the end of 2009 and the end of 2015 (Figure 3).

Figure 2: Yearly added and cumulative global PV capacity, 2006–2016



Source: IRENA, 2017c.

Figure 3: PV module price trends in Europe



Source: GlobalData, 2015; pvXchange, 2016.

Note: Values displayed in real Q2 2016 USD/W.

In 2011, price declines accelerated as oversupply created a buyer's market. These declines then slowed between 2013 and 2015, as manufacturer margins reached more sustainable levels, while in some markets, trade disputes set price floors.

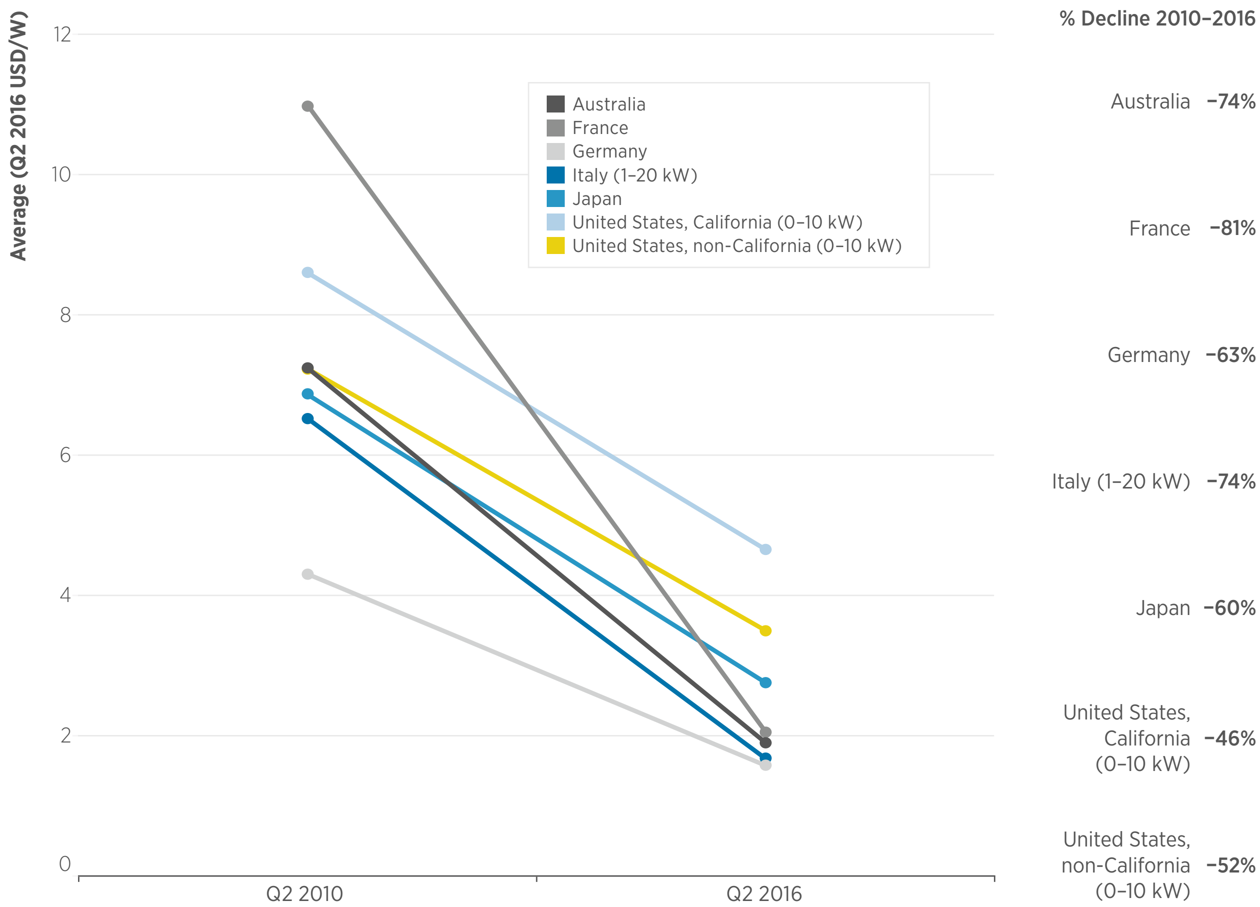
During Q1 2015, solar PV module prices continued their decline, falling by about 15% for crystalline modules and by a slower 3% for thin-film modules. Module prices stabilised during Q3 and Q4 2015, and crystalline prices decreased 2% in the first half of 2016. Thin-film module prices continued their downwards trend and decreased 3% during each quarter of 2015. During early 2016, thin-film prices stayed at around USD 0.5 per Watt (W). The outlook for module price reductions is good, with a projected decline in global weighted average module prices of a further 42% to 2025 (IRENA, 2016).

PV TOTAL INSTALLED COSTS

PV module price reductions have for some years driven down the cost of PV systems globally, with declines in balance of system costs being a smaller contributor to overall cost declines, notably for utility-scale projects (IRENA, 2016).

The global weighted average cost of utility-scale solar PV projects declined by around 56% between 2010 and 2015 (IRENA, 2016). Total installed cost reductions for residential PV systems have followed a similar path, although cost differentials remain within and between countries. In some cases these cost differentials represent structural factors (e.g., higher labour costs). In other cases they are less easily explained, and more analysis is required to identify the underlying drivers. The average total installed cost for residential PV systems in the markets shown in Figure 4, for example, decreased from a range of between USD 4.3/W and USD 8.6/W in Q2 2010, to a range of USD 1.5/W to USD 4.7/W in Q2 2016.

Figure 4: Average total installed cost of residential solar PV systems by country, Q2 2010 and Q2 2016



Source: IRENA Renewable Cost Database, 2017; Solar Choice, 2016; Photon Consulting, 2016; EuPD Research, 2017a.

Between Q2 2010 and Q2 2016, total installed costs in the different markets in Figure 4 decreased by between 46% (California) and as much as 74% (Australia). Australia has achieved very competitive costs for residential applications. Australian residential PV systems now have some of the lowest costs in the world and compare favourably with Germany and China, which also have very competitive pricing.

IC&CI ROOFTOP SOLAR PV:

CALIFORNIA

INTRODUCTION TO CALIFORNIA'S PV MARKET

The US is one of the most important solar PV markets in the world. During 2016, the country installed 14.7 GW_{dc}[20] of PV (GTM Research/SEIA, 2017). Only China installed more PV systems that year, and the installed US volume represented 16% of total global net installations that year. At the end of 2016, the US is home to about 11% of total, global cumulative solar PV installations, with over 40 GW_{dc} of PV capacity. During the period 2010–2016, yearly net installations in the United States grew at a compound annual rate of around 61% (Figure 5).

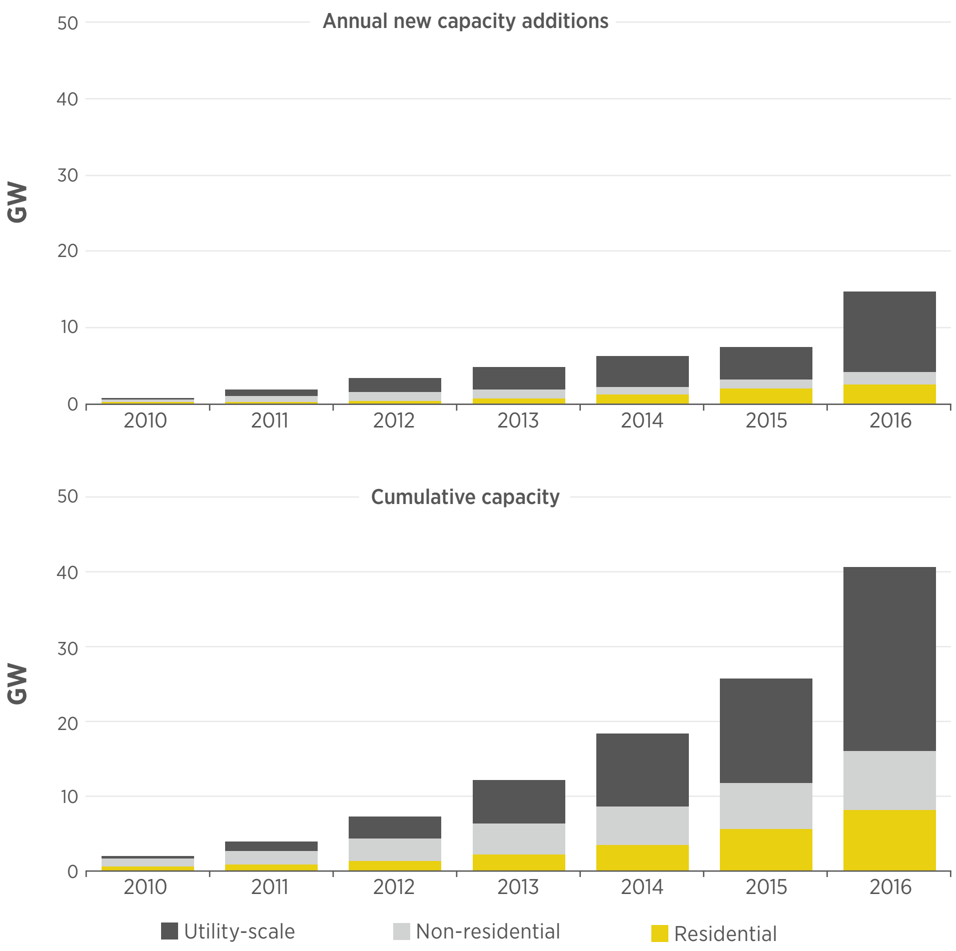
During that same period, about 7.9 GWdc of these installations took place in the residential segment. Residential installations accounted for 20% of the cumulative installed capacity at the end of 2016.

Much of the growth in the US PV market has been led by developments in California. California accounted for 35% of new PV capacity additions in the US in 2016, adding 5.1 GW_{dc} of capacity. This brought total installed solar PV capacity in California to 17.1 GW_{dc} (42% of the US total) at the end of 2016 (Figure 6).

In the residential segment, the state installed about 1.1 GW_{dc} during 2016 (41% of total residential installations in the US) and reached 3.8 GW_{dc} of cumulative installations in this segment. California thus remains the largest residential market in the US, although other states have started to gain momentum, while annual net residential installations in California have stabilised around the 1 GW_{dc} mark.

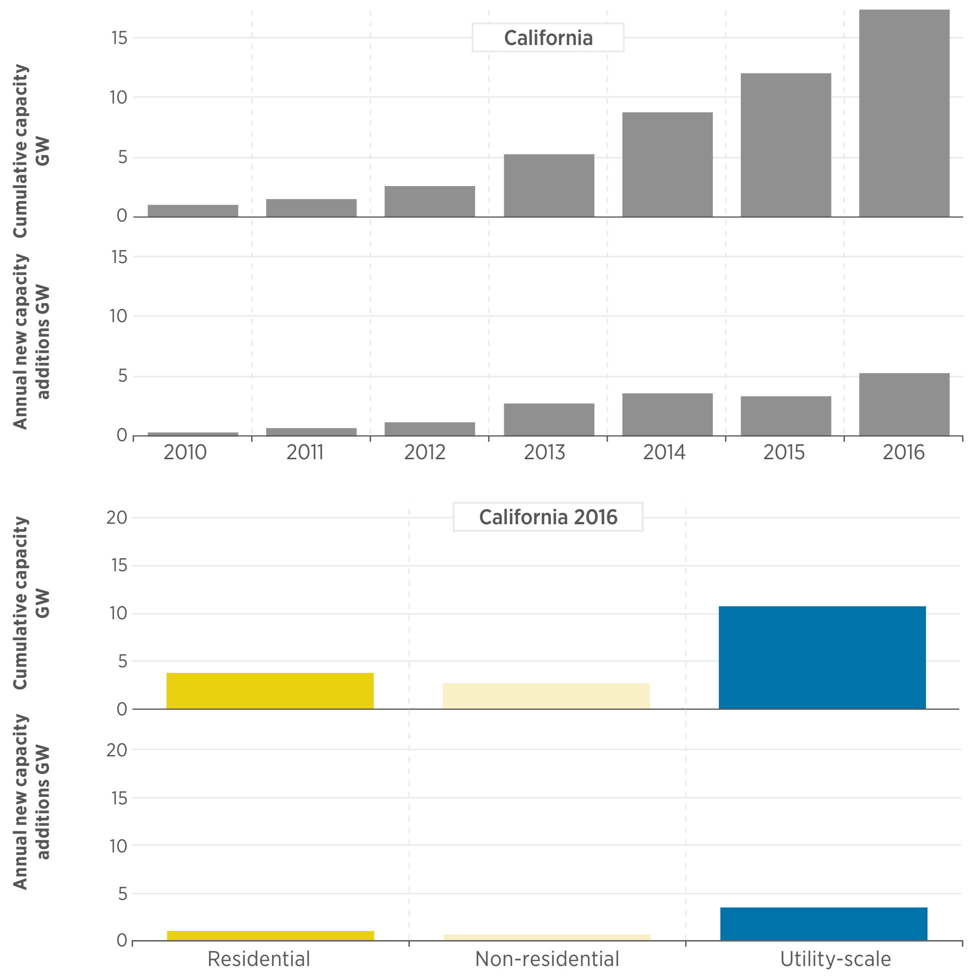
20 GTM Research and SEIA quote numbers in direct current (DC) terms, so these data are somewhat higher than IRENA statistics for North America as a whole, which are in alternating current (AC) terms.

Figure 5: Installed PV capacity in US, 2010–2016



Source: GTM Research/SEIA, 2017.

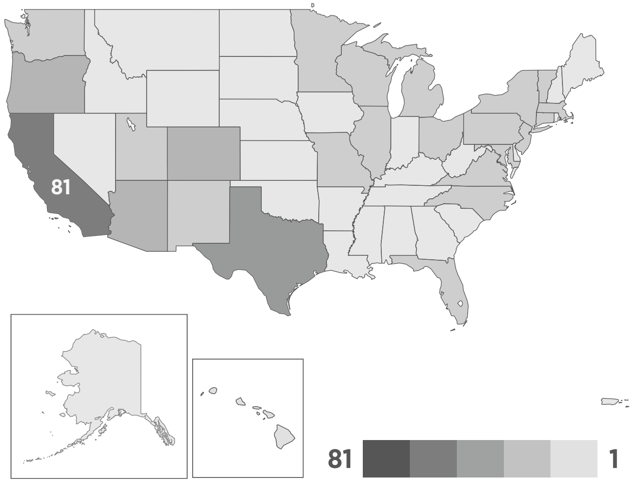
Figure 6: PV Installations in California (2010–2016) and segmental breakdown in California in 2016



Source: GTM Research/SEIA, 2017.

California's role as a leader in solar PV is underpinned by its support policies (Figure 7).

Figure 7: Number of regulatory policies and financial incentive schemes applicable to solar PV in the US by state



Source: IRENA analysis based on DSIRE, 2016.

In California alone, 81 regulatory policies and financial incentive schemes are applicable[21] to solar PV. It is beyond the scope of this report to assess in detail these policies, or their relative effectiveness in underpinning growth. Some of the more important policies influencing the residential PV market in California are summarised in Table 1.

Table 1: Selected regulatory policy and financial incentive schemes in California

Name	Short description	State/ Territory	Category	Policy/ Incentive type	Started	Expires
Residential Renewable Energy Tax Credit	A taxpayer may claim a federal tax credit of between 22% and 30% (depending on the placed-in-service date) of qualified expenditures for a system that is located, owned and used at the residence of the taxpayer. The Consolidated Appropriations Act, signed in December 2015, extended the expiration date for PV and solar thermal technologies, and introduced a gradual step down in the credit value for these technologies.[22]	US	Financial incentive	Personal (Income) tax credit	01/Jan/2006	31/Dec/2021 for solar technologies
Net Energy Metering	Net energy metering (NEM) is a special billing arrangement that provides credit to customers for solar PV electricity exported to the grid at the full retail value of the customer. Over a 12-month period, the customer only pays for the net amount of electricity used from the utility after crediting the exported electricity of their solar system. In January 2016, the California Public Utilities Commission issued a ruling on its net metering successor tariff also known as NEM 2.0 or Net Energy Metering (NEM) Successor Tariff.[23]	CA	Regulatory policy	Net metering	1/Jan/2000	1/Jul/2017 (or once NEM capacity exceeds 5% of a utility's aggregate customer peak demand)
California Solar Initiative – PV Incentives	The California Solar Initiative (CSI) was a rebate programme for California consumers that are customers of the investor-owned utilities. It focused on all consumer-owned solar installations other than on new homes in the territories of three gas and electricity companies (PG&E, SCE, SDG&E) and was overseen by the California Public Utilities Commission. The CSI offered solar customers different incentive levels based on the performance of their solar panels, including such factors as installation angle, tilt and location rather than system capacity alone.	CA	Financial incentive	Rebate programme	01/Jan/2007	Allocated budgets have been reached[24]

Source: IRENA analysis based on DSIRE, 2016.

21 State figures depicted in the map exclude regulatory policies and financial incentive schemes that are applicable across all states.

22 The credit value is 30% for systems placed in service by 31/12/2019, 26% for systems placed in service after 31/12/2019 and before 01/01/2021, and 22% for systems placed in service after 31/12/2020 and before 01/01/2022. No maximum incentive applies for PV systems placed in service after 2008. Systems must be placed in service on or after 01/01/2006 and on or before 31/12/2021.

23 More details on the NEM Successor Tariff can be found at: http://www.cpuc.ca.gov/General.aspx?id=3934.

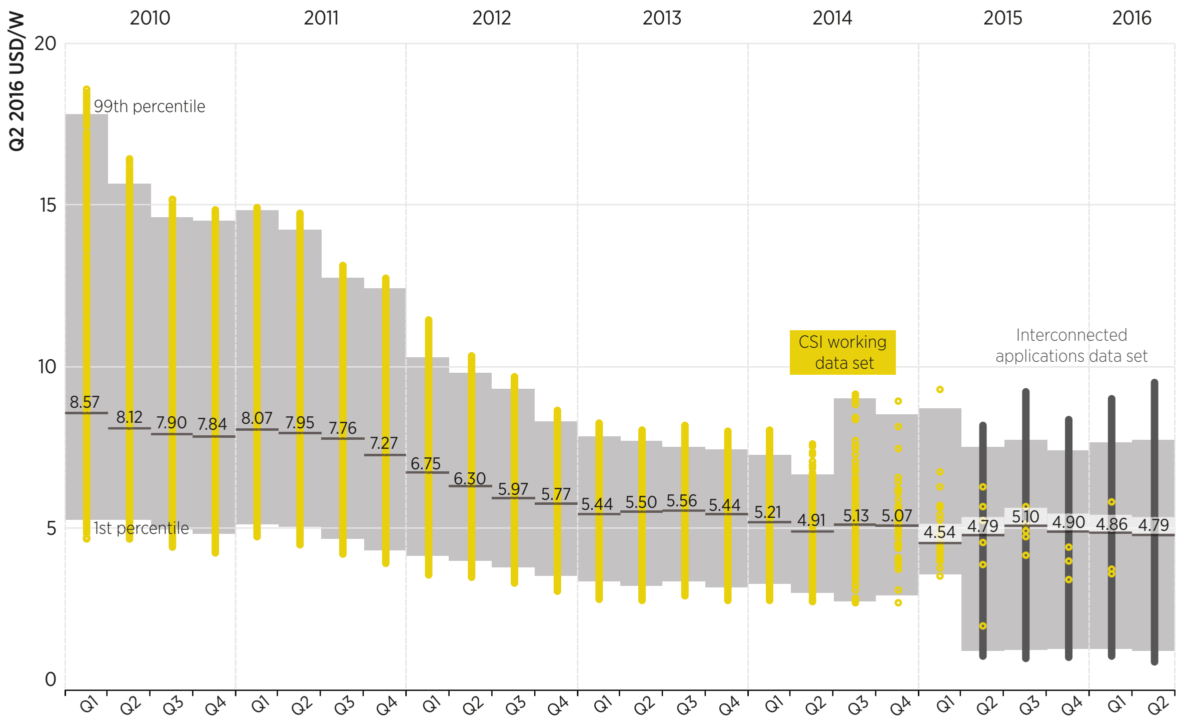
24 All three investor-owned utilities have either reserved or installed enough solar capacity for both their residential and non-residential (commercial, industrial, government, non-profit and agricultural properties) CSI sub-programs to exceed their installation goals. All General Market sub-programmes are now closed. This occurred within the period of 12 December 2013 (PG&E closed its non-residential waitlist) through 9 May 2016 (SDG&E non-residential programme closed). All three investor-owned utilities have exhausted their budget limits for CSI and are no longer accepting applications.

PV SYSTEM COSTS ANALYSIS IN CALIFORNIA

Solar PV installed system costs, based on the comprehensive data collected by the California Public Utilities Commission (CPUC), are used as a basis for the LCOE calculation of the four analysed metropolitan areas.

Early data draw from the California Solar Initiative (CSI) dataset, but with the programme nearing completion, the CPUC issued a decision[25] that has resulted in the availability of net energy metering (NEM) solar PV interconnection data.[26] This has introduced a break in the time-series data, and results should be treated with caution. After excluding outliers, the median cost of residential PV systems in California dropped from USD 8.57/W in Q1 2010 to USD 4.79/W in Q2 2016 (a decrease of about 35%[27]). There has been a narrowing in the range of prices, however, as the ninety-ninth percentile and the first percentile have decreased by 57% and 77%, respectively, during the same period.

Figure 8: Residential solar PV system costs in California, Q1 2010 to Q2 2016

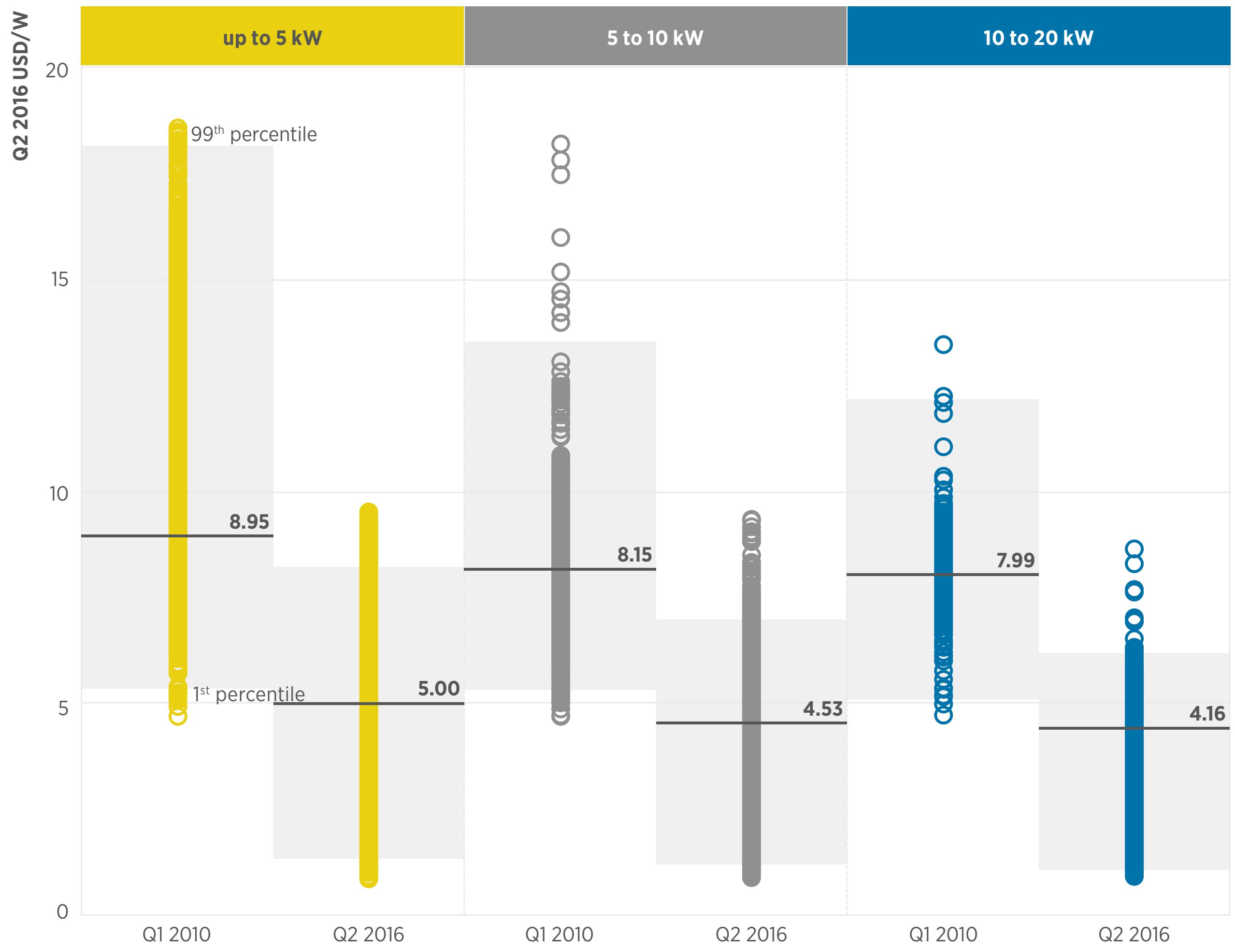


Source: CEC and CPUC, 2016a.

25 Decision 14-11-001 of 6 November 2014.
26 The CSI working dataset and the "interconnection applications dataset" are used. A more detailed discussion of the data used in this edition can be found in Annex II.
27 Unless expressly stated otherwise, all financial data in this report are expressed either in real Q2 2016 USD or in real Q2 2016 EUR (see also Annex I).

Figure 8 also highlights that the two datasets are not of the same quality. The CSI dataset cost data were used for rebate calculations and included verified cost data. The net metering dataset, in contrast, is reporting cost data for information only, and the data show a much wider range. Thus the cost convergence, so clear in the CSI dataset, is reset at a wider range in the NEM dataset. Figure 9 shows the cost trends from the system size class perspective.

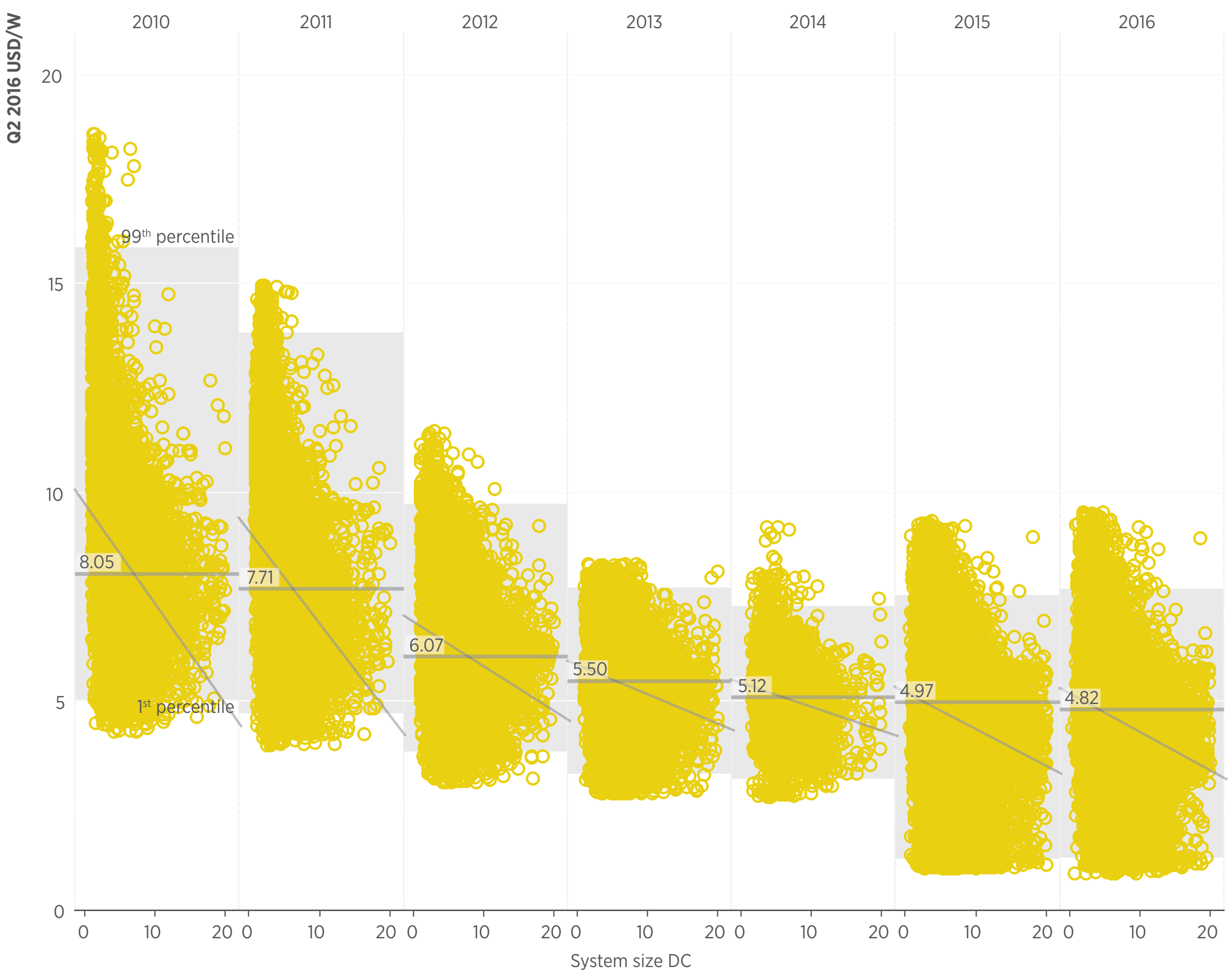
Figure 9: Residential PV system costs in California by size category, Q1 2010 and Q2 2016



Source: CEC and CPUC, 2016a.

The median cost for systems up to 5 kilowatts (kW) in size has fallen 44% (from USD 8.95 to USD 5.00/W) over the period Q1 2010 to Q2 2016. For the larger 5–10 kW systems and 10–20 kW systems, the reduction has been 44% and 48%, respectively, over the same period. There are some economies of scale, even for these small systems, as the median costs fall with increasing size classes. Although the effect of these was more pronounced in the period 2010–2012, it still can be appreciated in the most recent data for 2016. A detailed statistical analysis has not been conducted on this relationship, but a simple linear model indicates a slope change in the trend lines of about 60% between the years 2010 and 2016, with the slopes becoming less negative in the 2013–2016 period (Figure 10).

Figure 10: Residential PV system costs in California in 2010 to 2016 as a function of system size

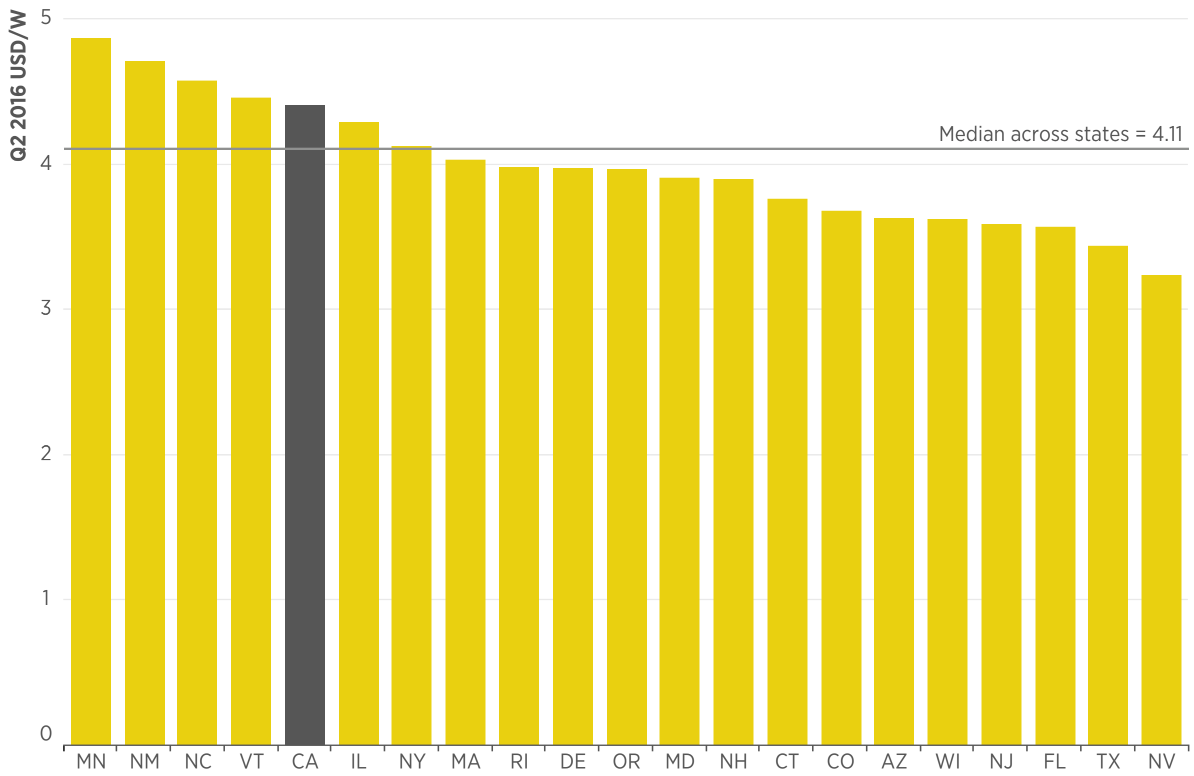


Source: IRENA analysis based on CEC and CPUC, 2016a.

BOX 2: CALIFORNIA RESIDENTIAL COSTS IN THE US CONTEXT

In 2015, 47% of the newly installed residential system capacity in the US was installed in California. During 2014 and 2015, reported median residential prices in California were 7% to 8% above the across-states median for all states. Prices reported in the cheaper, more competitive states (e.g., Texas and Nevada) were 16% to 21% below the California values during 2015. The price differential between the medians of the most expensive and the cheapest (or highest and lowest states displayed) was reported at about USD 1.6/W (compared to USD 1.4/W in 2014). Note that due to reporting differences and slightly different boundary conditions, the median value for California in Galen and Barbose (LBNL, 2016). is lower than was reported in the CPUC CSI database.

Figure 11: Median installed price of 2015 residential PV systems by state



Source: LBNL, 2016.

RESIDENTIAL ELECTRICITY RATES IN CALIFORNIA

Of the four selected metropolitan areas in California that are analysed in this report, three are serviced by investor-owned utilities. The area of Los Angeles, however, is served by the Los Angeles Department of Water and Power (LADWP), a publicly owned municipal utility. An overview of the analysed utilities is provided in Table 2.

These four utilities are the largest in California, with total electricity sales of 216 terawatt-hours in 2015, or 83% of total electricity sales in the state (CEC, 2016). These utilities offer a range of electricity service schedules for residential customers that are differentiated by whether or not a customer has a solar PV system. Specific details on the schedules used in this edition of IC&CI analysis can be found in the Annex.

Time-of-Use (TOU)/Tiered rates

All California utilities analysed in this report offer schedules that provide electricity at different prices, depending on the time that the electricity is used. These are known as TOU rates. For locations where TOU electricity rates are in place, they can vary based on:

- the time of day (e.g., hourly periods or day/night)
- the specific day (e.g., weekday or weekend, holiday)
- the month or season in the year
- the level of electricity consumption in a month relative to a baseline value, depending on customer characteristics and geographical location (this also can be a sliding scale (see the “tiered rates” discussion below).

Not all TOU rates take into account all of these factors, but where they do, these TOU rates are among the most complicated in the world.

An important facet in some California TOU rate schedules is the so-called "tiered rate" (also known as "inclining block rate"). This reflects an increasing charge per unit of energy as the consumption of energy increases above a certain tier (block).

Typically, a base consumption is allocated by the utility (delimiting the first tier), and the upper tiers are structured in reference to this baseline allocation. The areas served by the utility are often divided into different baseline territories (based on climatic zones), which helps determine the baseline allocation for the month. Baseline quantities also differ depending on whether the customer has permanently installed electric heat or not. Electricity rates can be designed to change both according to the TOU as well as depending on the electricity consumption (tier).[28]

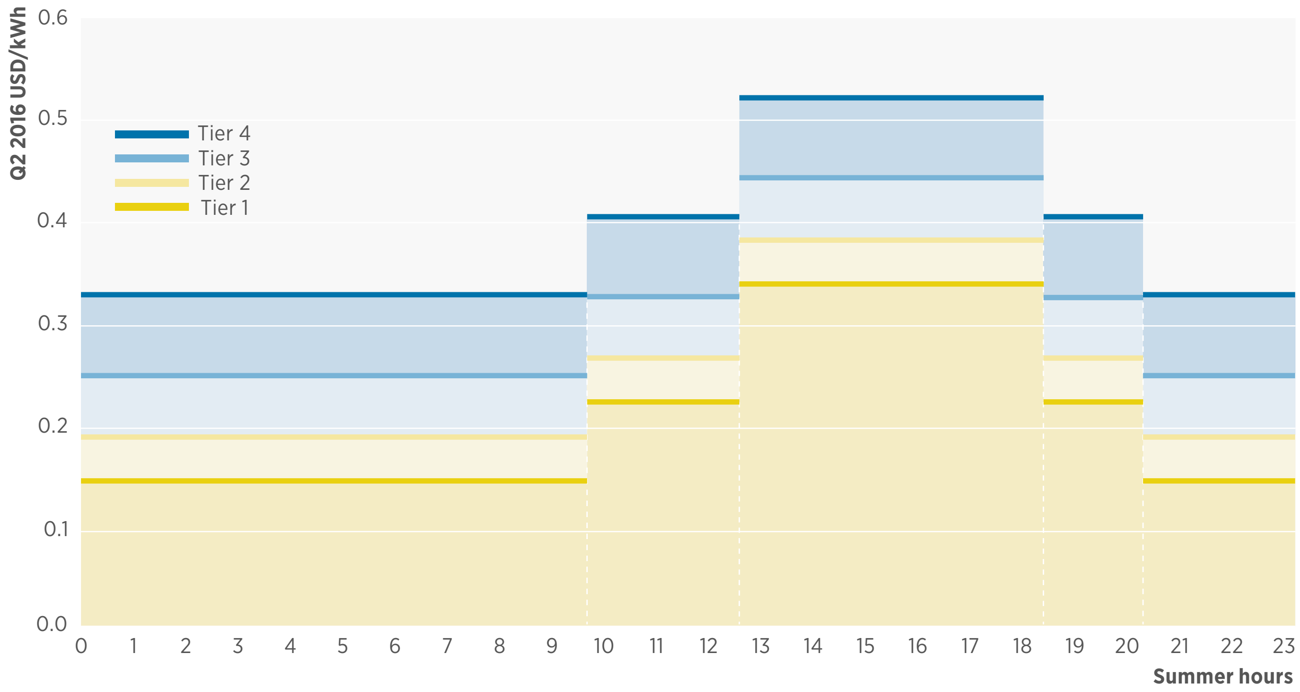
Figure 12 shows an example of such changes in the rate values according to TOU and tier for the weekdays of the summer season in PG&E's E-6 schedule.

Table 2: Utilities servicing the analysed California metropolitan areas

Metropolitan area	Utility	Type of utility
Los Angeles	Los Angeles Department of Water and Power (LADWP)	Publicly owned utility
San Francisco	Pacific Gas and Electric Company (PG&E)	Investor-owned utility
San Diego	San Diego Gas & Electric (SDG&E)	Investor-owned utility
San Bernardino	Southern California Edison (SCE)	Investor-owned utility

Source: CEC, 2015a.

Figure 12: Hourly rate values by TOU period during a summer weekday in PG&E schedule E-6 (Q2 2016)



Source: PG&E, 2016.

Note: Numbers on this axis, indicate the one hour period starting at that time. For example, in this chart the peak time-of-use period covers the 13 to 18 block (that is to say starts at 1.00 pm and ends at once 07:00 pm is reached). Analogous report charts follow the same nomenclature.

28 From a consumer's perspective, this can provide an additional benefit to solar PV, as own-consumption can help reduce monthly consumption into lower tiers.

Such rate structures therefore require detailed modelling to ensure that the electricity rate that would be in force during the solar PV system operation is captured accurately. This very complicated rate structure provides significant incentives to reduce electricity consumption either through energy efficiency or self-generation, but makes the economic benefits for individual households far from transparent.

Residential rate reform

In 2001, California suffered an energy market crisis that resulted in rolling blackouts across the state, caused by market manipulation (CPUC, 2016; FERC, 2003). With the reduced energy supply, wholesale prices rose and California lifted the existing cap on retail rates. Customers faced significant electricity bill impacts. In reaction to this situation, the state passed legislation that restricted electricity rate increases for the low (tier 1) and mid-range (tier 2) consumption levels. This, however, led to prices above cost of service for customers who consumed in the higher consumption levels (tier 3 and tier 4). In the last 15 years, this has led to the majority of utility cost increases being paid for by customers with higher consumption levels (for example, larger family households pushed into the higher tiers in hot climates).

As a result of these issues, in 2013, Assembly Bill 327 (AB 327) was enacted[29], with its main purpose the reform of residential rates. This law was implemented through Residential Rate Reform Order Instituting Rulemaking (R. 12-06-013). As part of these changes, the CPUC passed decision D.15-07-001 on 3 July 2015. This provided direction to the investor-owned utilities in changing their residential rate design structures. It also envisioned a 2019 goal consisting of default TOU and optional two-tier rates (CPUC, 2016; CEC, 2015b). Among other directives, the decision directs utilities to:

- Reduce the number of tiers in their default residential rates for 2015–2018.
- Offer optional (opt-in) TOU rates with no more than two tiers.
- Propose means to increase participation in opt-in TOU rates for 2015–2018.
- Offer a variety of opt-in TOU pilot schedules in 2016 and 2017 and default TOU pilots in 2018.

The residential rate reform is an on-going process, but it already has given birth to residential schedules that follow its directives (for example the opt-in, optional two-tiered TOU schedules from PG&E and SCE). In this transition, some of the previous existing TOU schedules have been closed to new customers. For example, PG&E schedule E-6 was closed to new customers on 31 May 2016 (although enrolled customers can remain grandfathered, if they stay on it).

Other schedules with complex tier structures are also to be phased out as part of the reform process and will be replaced by the newer schedules, which have simpler, or no, tier structures. Research into the load impact of the rates is also on-going, as a critical policy question is whether transparent TOU rates might be able to smooth and flatten the net load curve[30] in California (CEC, 2015b).

The California Independent System Operator (CAISO)[31] and many others (CAISO, 2013; NREL, 2015a; EIA, 2014) have documented and pointed out these on-going and expected changes in the net load shape, as more solar and wind capacity is added in the state. Yet, while important, the increased adoption and proper design of TOU rates is only part of a successful long-term strategy to properly balance the future, greener grids reliably, by providing better temporal and locational granularity to electricity prices (IRENA, 2017b).

29 The bill also deals with other issues, most notably provisions covering net energy metering.
30 The total electric demand in the system minus wind and solar generation.
31 California's main grid operator.

IC&CI Rooftop Solar PV Analysis:

MAJOR METROPOLITAN AREAS IN CALIFORNIA

Table 3 displays a summary of the main assumptions and variables modelled in the analysis of California's rooftop solar PV residential segment, which is presented in the next section. The present IC&CI analysis – including both the LCOE of residential PV systems as well as an indicator of the value of solar PV over the year – requires various assumptions and detailed modelling. More detailed information on the modelling and additional data and assumptions can be found in the Annex of this report.

32 Typical Meteorological Year, version 3 (TMY3) datasets. See also NREL, 2008.

33 Load data are needed for the estimation of the average electricity price during solar PV generation and are assumed from: http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

Table 3: Summary of variables modelled in the analysed metropolitan areas

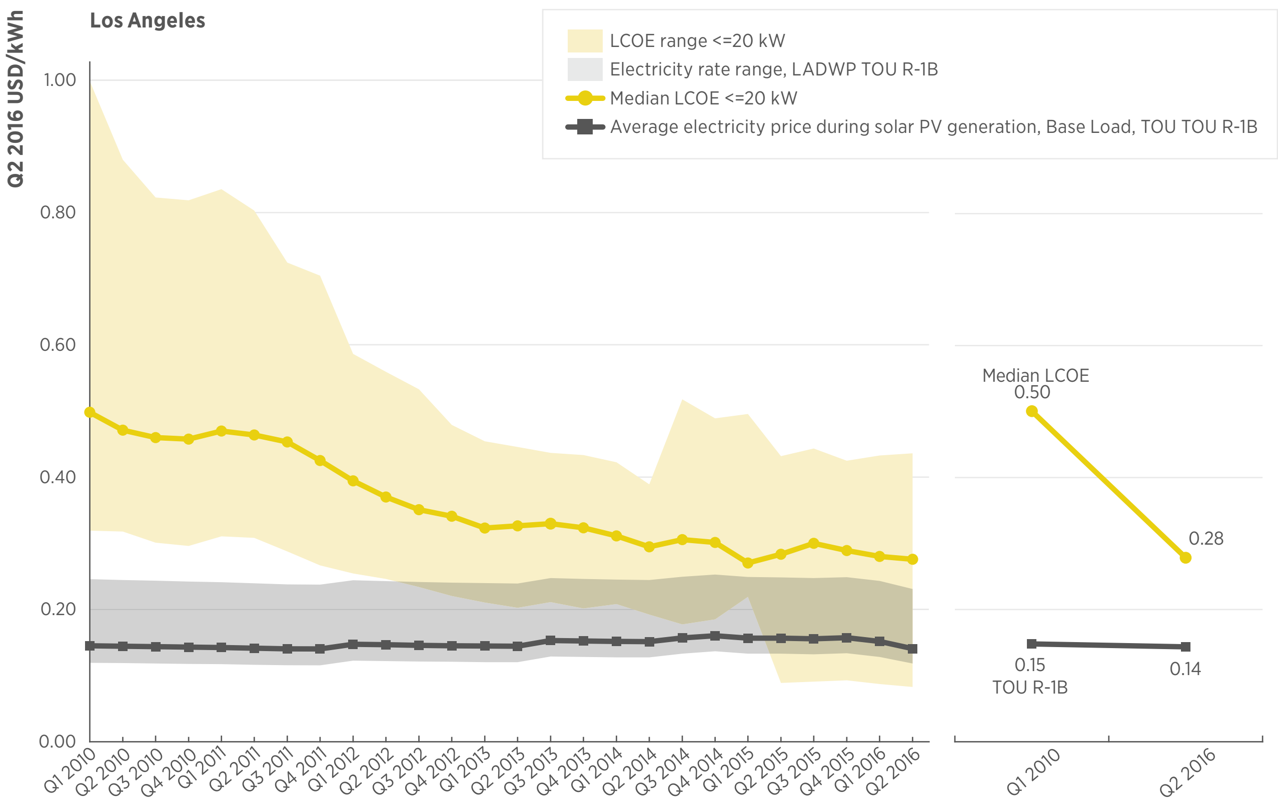
Variable modelled	Los Angeles	San Francisco		San Diego	San Bernardino	
Utility assumed	LADWP	PG&E		SDG&E	SCE	
Rate reference quarter	Q2 2016	Q2 2016		Q2 2016	Q2 2016	
Weather station (TMY3)[32]	Los Angeles International Airport	San Francisco International Airport		San Diego Lindbergh Field	March Air Force Base	
Global horizontal irradiation (GHI) [kWh/m²/day]	5	4.7		5.14	5.44	
Average temperature [°C]	16.8	13.8		17.7	17.3	
Load (base case) [kWh/year][33]	7 930	7 563		8 219	9 327	
PV system size [kW]	5.5	5.5		5.5	5.5	
Electric schedule	Residential Time-of-Use R-1B	E-6	E-TOU (option A)	DR-SES	TOU-D-T (Time-of-Use Domestic Tiered)	TOU-D (option A)
TOU	Yes	Yes	Yes	Yes	Yes	Yes
TOU periods	High Peak, Low Peak, Base	Peak, Part-Peak, Off-Peak	Peak, Off-Peak	On-Peak, Semi-Peak, Off-Peak	On-Peak, Off-Peak	On-Peak, Off-Peak, Super- Off-Peak
Summer/high season peak period hours (weekday)	1:00 p.m. to 5:00 p.m.	1:00 p.m. to 7:00 p.m.	3:00 p.m. to 8:00 p.m.	11:00 a.m. to 6:00 p.m.	12:00 p.m. to 6:00 p.m.	2:00 p.m. to 8:00 p.m.
Summer/high season	June 1 through September 30	May 1 through October 31	June 1 through September 30	May 1 through October 31	June 1 through September 30	June 1 through September 30
Winter/low season	October 1 through May 31	November 1 through April 30	October 1 through May 31	November 1 through April 30	October 1 through May 31	October 1 through May 31
Tiered rate	No	Yes	Yes	No	Yes (levels)	Yes
Number of tiers	No tiers	5	2	No tiers	2 levels[34]	2
Baseline quantity territory or zone	Zone 1	Baseline territory T		None	Zone 10	
Electric code	Basic	Basic quantities		Basic quantities	Basic quantities	
Periods modelled	Q1 2010–Q2 2016	Q1 2010–Q2 2016	Q1 2016–Q2 2016	Q1 2010–Q2 2016	Q1 2010–Q2 2016	Q1 2015–Q2 2016

Source: LADWP, 2016; SDG&E, 2016; PG&E, 2016; SCE, 2016; NREL, 2015b; EERE, 2015.

34 These so-called "levels" can be considered equivalent to a five-tier structure.

US LOS ANGELES

Figure 13: Residential LCOE, average electricity price during solar PV generation and electricity rates in Los Angeles



Source: IRENA analysis based on: CEC and CPUC, 2016a; LADWP, 2016.

Los Angeles, served by LADWP, has some of the lowest TOU rate structures in California and is a more challenging market for solar PV. The median LCOE of residential PV decreased 45% from Q1 2010 to Q2 2016, while the average electricity price during solar PV generation based on the TOU residential R-1B rate decreased slightly (3%). Figure 13 shows that starting in Q3 2012, the low range of the LCOE has consistently stayed below the upper range of LADWP's Residential TOU R-1B rate (the High Peak period rate during the High season[35]).

However, without financial support, the median LCOE indicator remains above the band of tariffs in effect while solar PV generates.

The difference between the median LCOE and the upper boundary of the electricity TOU rate has dropped USD 0.21/kWh from Q1 2010 to Q2 2016 (an 82% reduction) and is now USD 0.04/kWh above. With time, the median LCOE also has moved closer to the average electricity price during solar PV generation for the base load case. Their differential has fallen from USD 0.35/kWh in Q1 2010 to USD 0.14/kWh in Q2 2016 (a 62% reduction). The combination of rate levels and TOU periods has caused the average electricity price during solar PV generation to remain stable and close to the low rate boundary during the considered period, and ended the period at USD 0.14/kWh (Q2 2016).

35 The range shows the "Base" to "High Peak" period rates for the "High" season.

LCOE development

The median LCOE of residential PV in Los Angeles dropped from USD 0.50/kWh in Q1 2010 to USD 0.28/kWh in Q2 2016 for a compound quarterly reduction rate of 2.3% per quarter (Figure 13). Driven by a similar pattern in the California installed costs levels, the first and ninety-ninth percentiles of installed costs also decreased during this time frame from USD 0.32/kWh to USD 0.08/kWh (a 74% decline) and from USD 1.00/kWh to USD 0.44/kWh (a 45% decline), respectively. The LCOE range between the first and ninety-ninth percentiles also fell, from USD 0.68/kWh in Q1 2010 to USD 0.35/kWh in Q2 2016 (a 48% reduction).

Two different LCOE reduction rhythms can be identified. In the first, from Q1 2010 to Q4 2012, the median LCOE decreased 32% from USD 0.50/kWh to USD 0.34/kWh. During the second, from Q4 2012 to Q3 2015, the median LCOE decreased by USD 0.06/kWh for a less-pronounced reduction of about 19%.

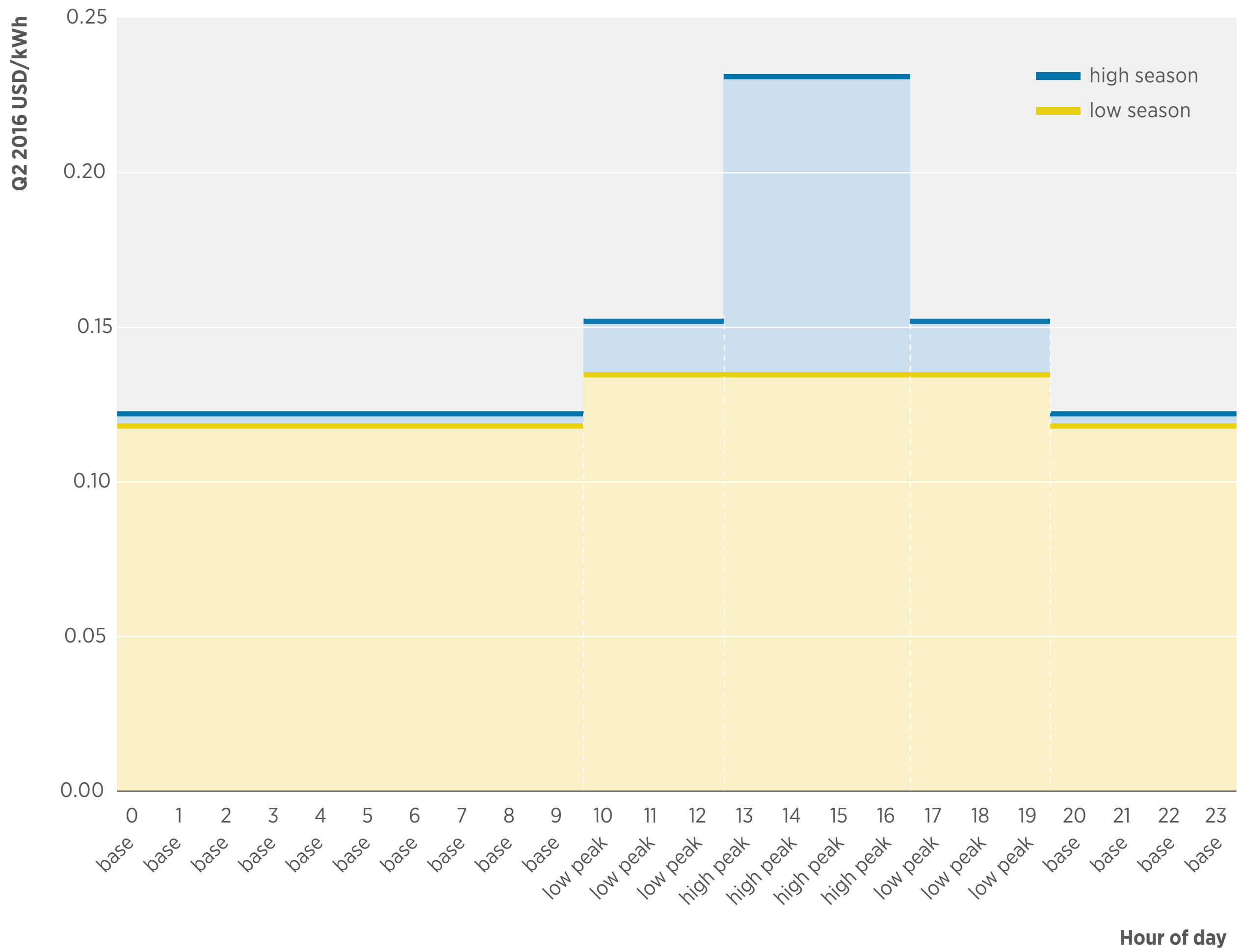
This last period showed a compound quarterly reduction rate of 1.5%.

Electricity rates

The electricity rates of LADWP's Residential TOU R-1B schedule change according to three different TOU periods (High Peak, Low Peak, Base) and for two distinct yearly seasons, a "High" season running from June to September and a "Low" season (LADWP, 2016). The schedule does not change with increasing consumption (no tiers apply).

Figure 14 shows the electricity rates for both seasons and TOU periods during weekdays, when the High Peak period runs from 1 p.m. to 5 p.m.

Figure 14: Hourly rate values by TOU period under LADWP's residential TOU R-1B schedule, Q2 2016.



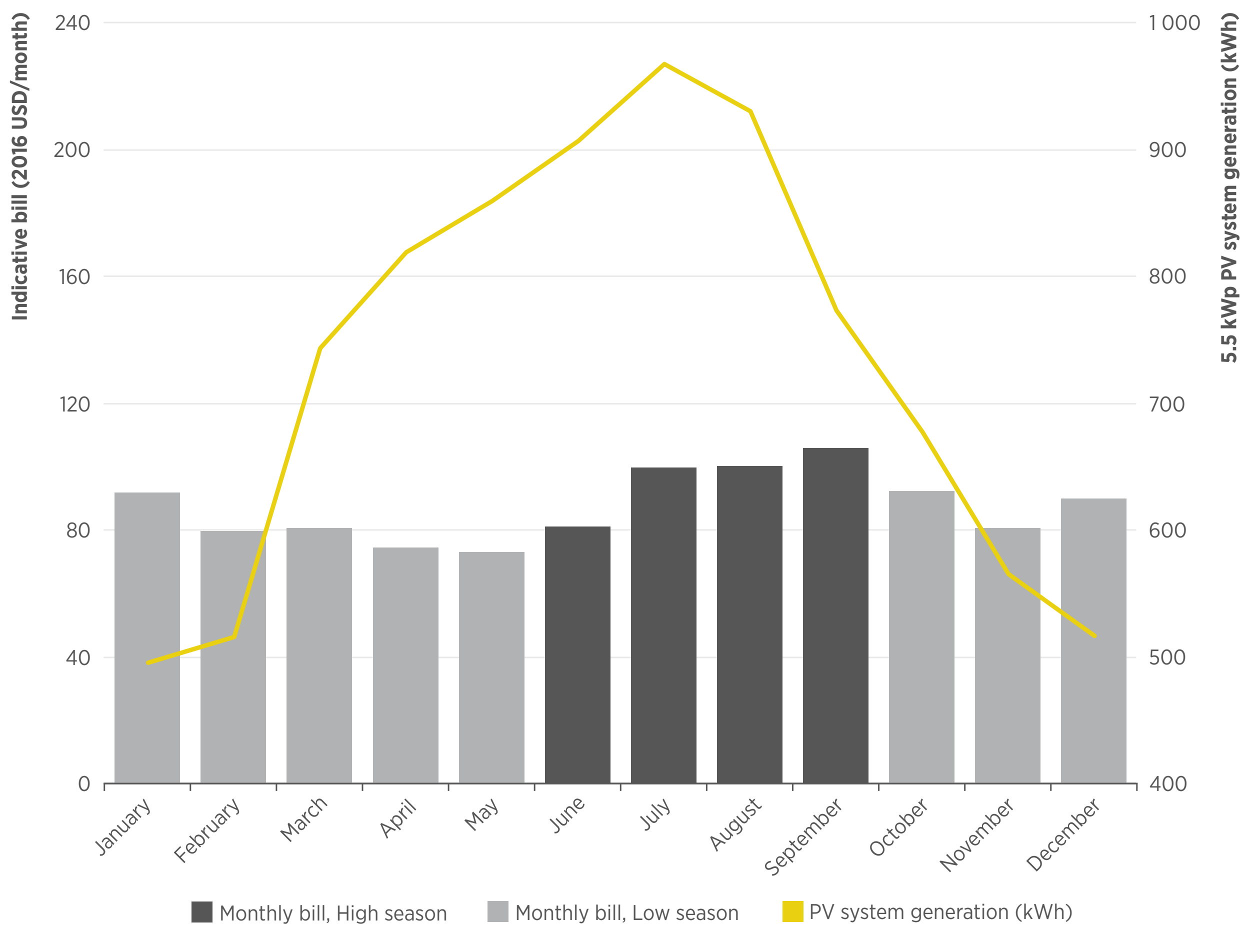
Source: IRENA analysis based on LADWP, 2016.

Electricity expenditure in this schedule tends to be higher than average during the High season, as can be seen in Figure 15.

In terms of the indicative value of solar PV based on the TOU rate, Figure 15 also hints towards the benefits that PV can provide, since higher monthly PV output coincides with higher bill months, which are usually the High season (hotter) months. In these months in particular, homeowners also can benefit from higher PV output during the more expensive High Peak TOU period and partially during the Low Peak period. This situation also can be recognised in Figure 16. This shows a comparison of weekdays in June and December and their respective PV generation profiles and the TOU electricity rates[36] in effect under schedule R-1B.

Figure 16 also clearly shows that the higher energy charges (especially in the summer months) are in effect at the times when PV generation is also high – and, therefore, PV can contribute to offsetting these charges.

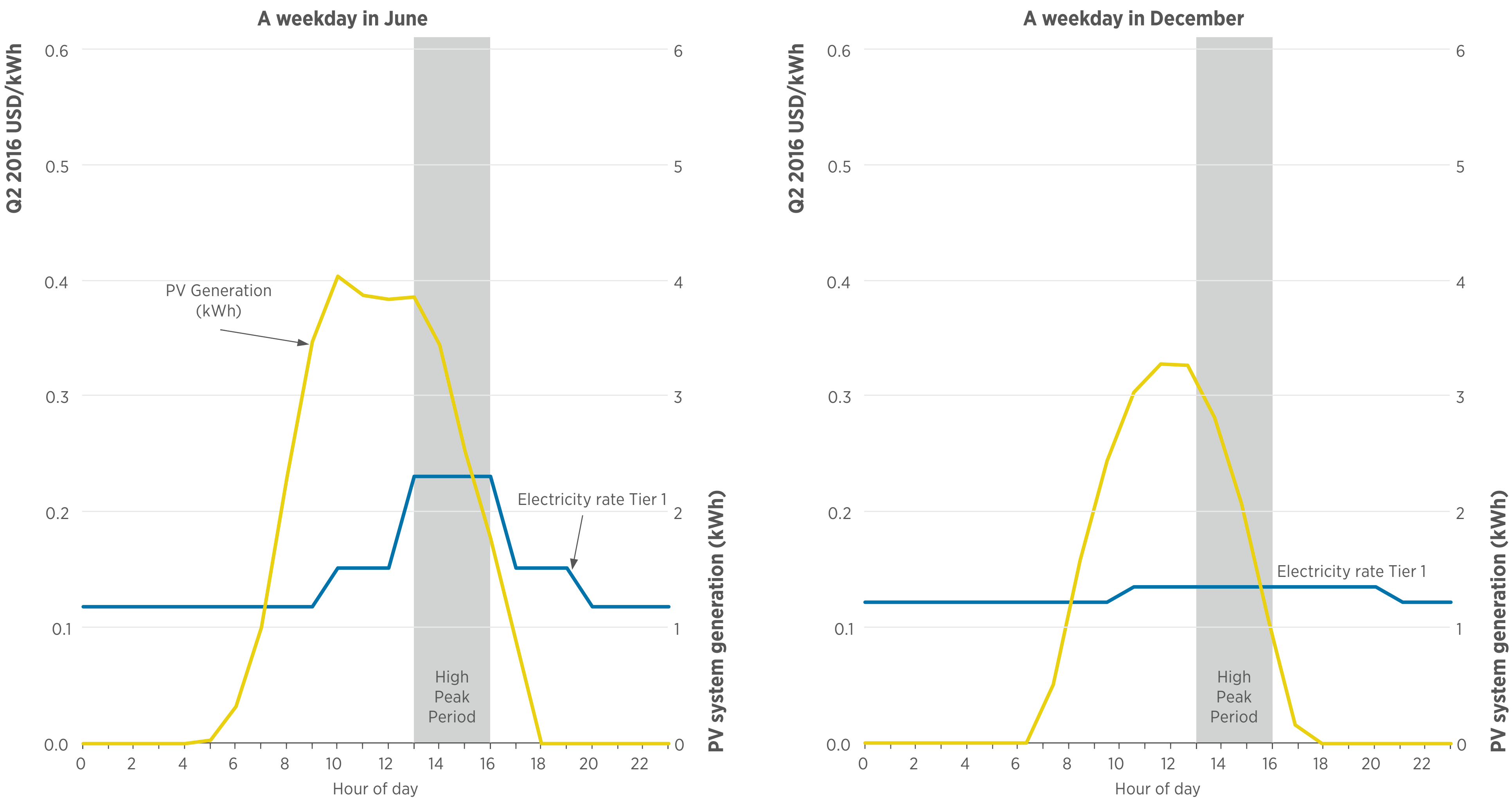
Figure 15: Indicative residential monthly electricity bill for LADWP's TOU schedule R-1B without PV and PV monthly generation



Source: IRENA analysis based on LADWP, 2016.

36 As effective in Q2 2016.

Figure 16: Electricity rates and PV output for June and December in LADWP's residential TOU R-1B schedule

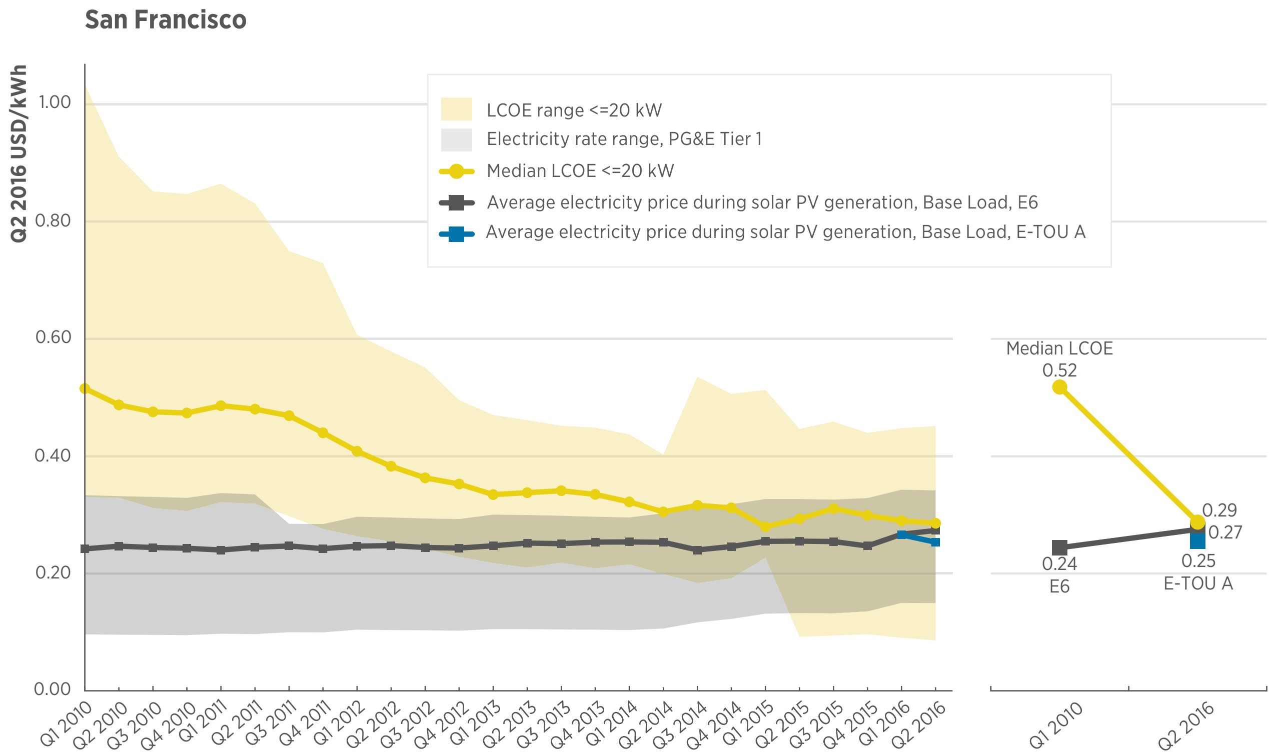


Source: IRENA analysis based on LADWP, 2016.

Note: For the day shown, 25% of PV generation occurs in the "High Peak" period. The "Low Peak" and "Base" periods correspond with 30% and 45% of total PV generation, respectively.

SAN FRANCISCO

Figure 17: Residential LCOE, average electricity price during solar PV generation and electricity rates in San Francisco



Source: IRENA analysis based on CEC and CPUC, 2016a; PG&E, 2016.

Figure 17 highlights that since Q4 2011, residential solar PV systems in San Francisco have become increasingly competitive. During 2010 and 2011, the LCOEs of the cheapest solar PV systems were flirting with the highest TOU rates (PG&E's E-6 Summer Peak tier 1 rate). Since then, the median LCOE in San Francisco has consistently stayed below this high electricity rate boundary.

With time, and with reductions in the installed cost, the median LCOE also has come closer to the estimated average electricity price during solar PV generation. The differential between these two has fallen from USD 0.27/kWh in Q1 2010 to just USD 0.01/kWh in Q2 2016 (a 96% reduction). Since Q4 2012, the low LCOE range and the estimated average electricity price during solar PV generation have consistently overlapped.

Starting in Q1 2016, Figure 17 also shows the modelled average electricity price during solar PV generation for the newly introduced residential schedule, E-TOU. During Q2 2016, the estimated average electricity price during solar PV generation under this schedule was USD 0.25/kWh for option A.[37] This is 7% lower than the estimated average electricity price during solar PV generation under the older, E-6 schedule, which has now been closed to new customers (although customers already enrolled can remain grandfathered, if they stay on this schedule).

37 Option A includes a credit applied to baseline usage only. This schedule also differs from the E-6 in the TOU periods and season definitions. (See also next sections and Annex II: California.)

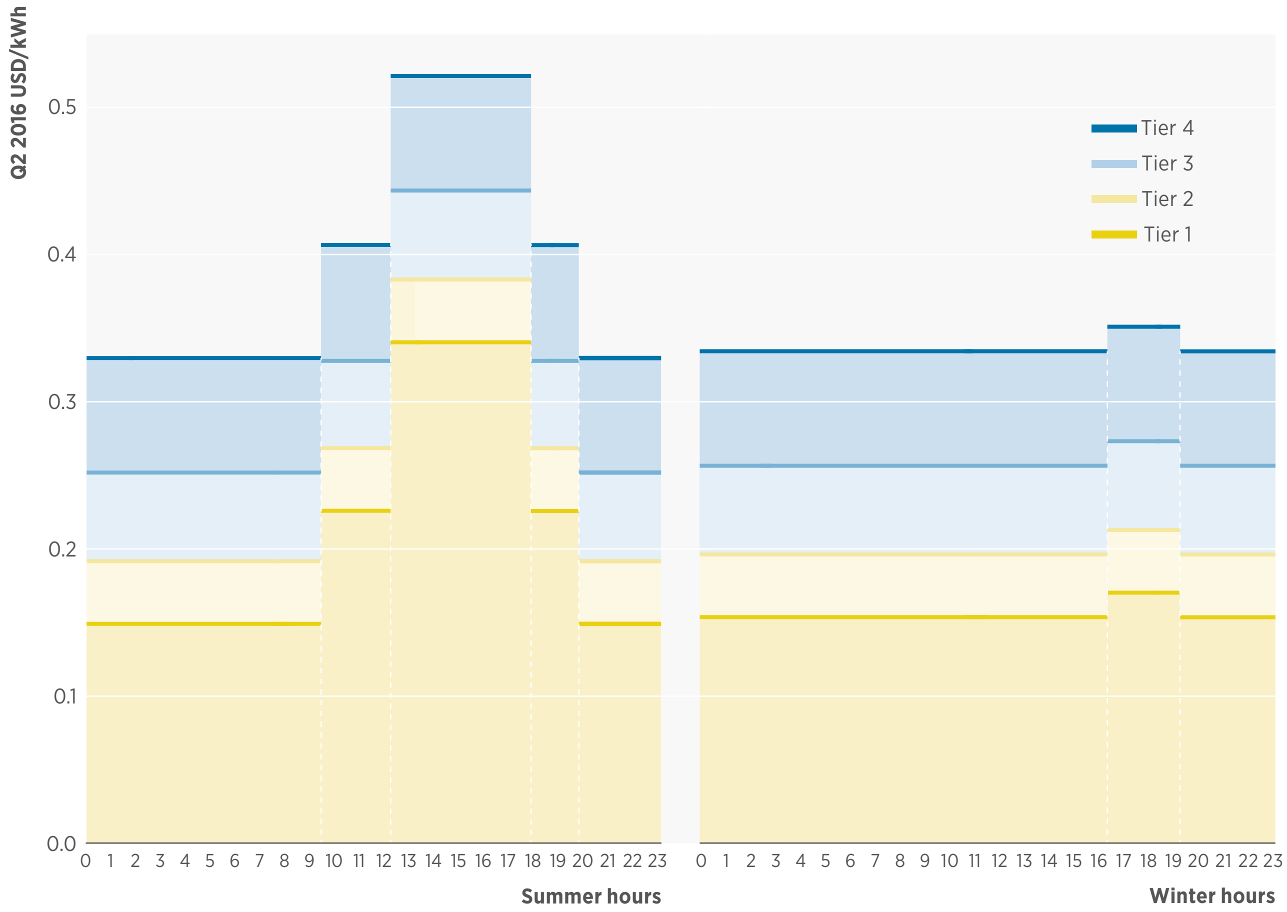
LCOE development

The median LCOE of residential solar PV in San Francisco has declined by 45%, from USD 0.52/kWh in Q1 2010 to USD 0.29/kWh in Q2 2016 (Figure 17). The low and high LCOE boundaries (based on the first and ninety-ninth percentiles of installed costs) also decreased during this time frame from USD 0.33/kWh to USD 0.09/kWh (74%) and from USD 1.03/kWh to USD 0.45/kWh (56%), respectively. The spread in the LCOE between the first and ninety-ninth percentiles fell from USD 0.70/kWh in Q1 2010 to USD 0.37/kWh in Q2 2016 (a 48% reduction).

Electricity rates

PG&E's schedule E-6 is one that changes both from the TOU perspective and with increasing block rates (tiers) depending on consumption levels over the month (Figure 18). PG&E's E-6 Tier 1 summer "peak" and "off-peak" rates are 26% and 48% higher than LADWP's R-1B TOU High Peak and Base rates, respectively.

Figure 18: PG&E E-6 rate values by season and TOU for a weekday in Q2 2016



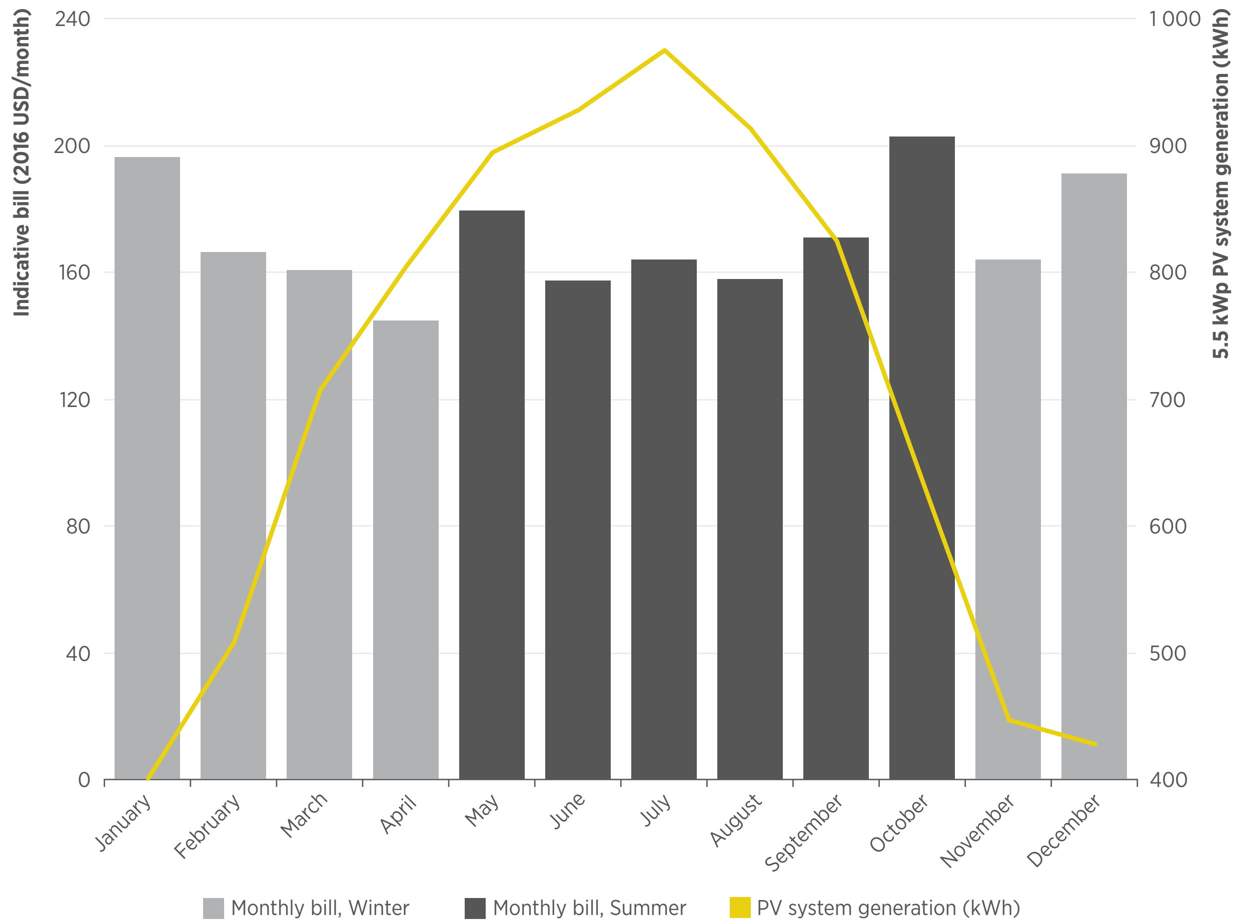
Source: IRENA analysis based on PG&E, 2016.

As electricity consumption increases beyond the allotted baseline quantity for the month, the energy charge moves to the next tier's price level, raising the marginal cost of electricity consumed. Baseline allocations also change with the season (summer or winter), with predefined and weather-based zones in PG&E's service area, called "baseline territories". San Francisco falls under Territory T, which in this report is used for all calculations referring to that metropolitan area.

Baseline quantities also change with the electric code (e.g., households using electricity to heat water fall under Code H instead of the basic Code B).[38] Specific details on baseline quantities for the metropolitan areas considered can be found in Annex II.

In the case of San Francisco, higher summer electricity rates also correspond well with high irradiation months. Not all summer months are above the average bill, however, since the ratio of summer to winter consumption is lower in San Francisco than in other locations in California, due to a milder summer and to less-intensive use of air conditioning in that season (Figure 19).

Figure 19: Indicative residential monthly electricity bill for PG&E's TOU schedule E-6 without PV and PV monthly generation

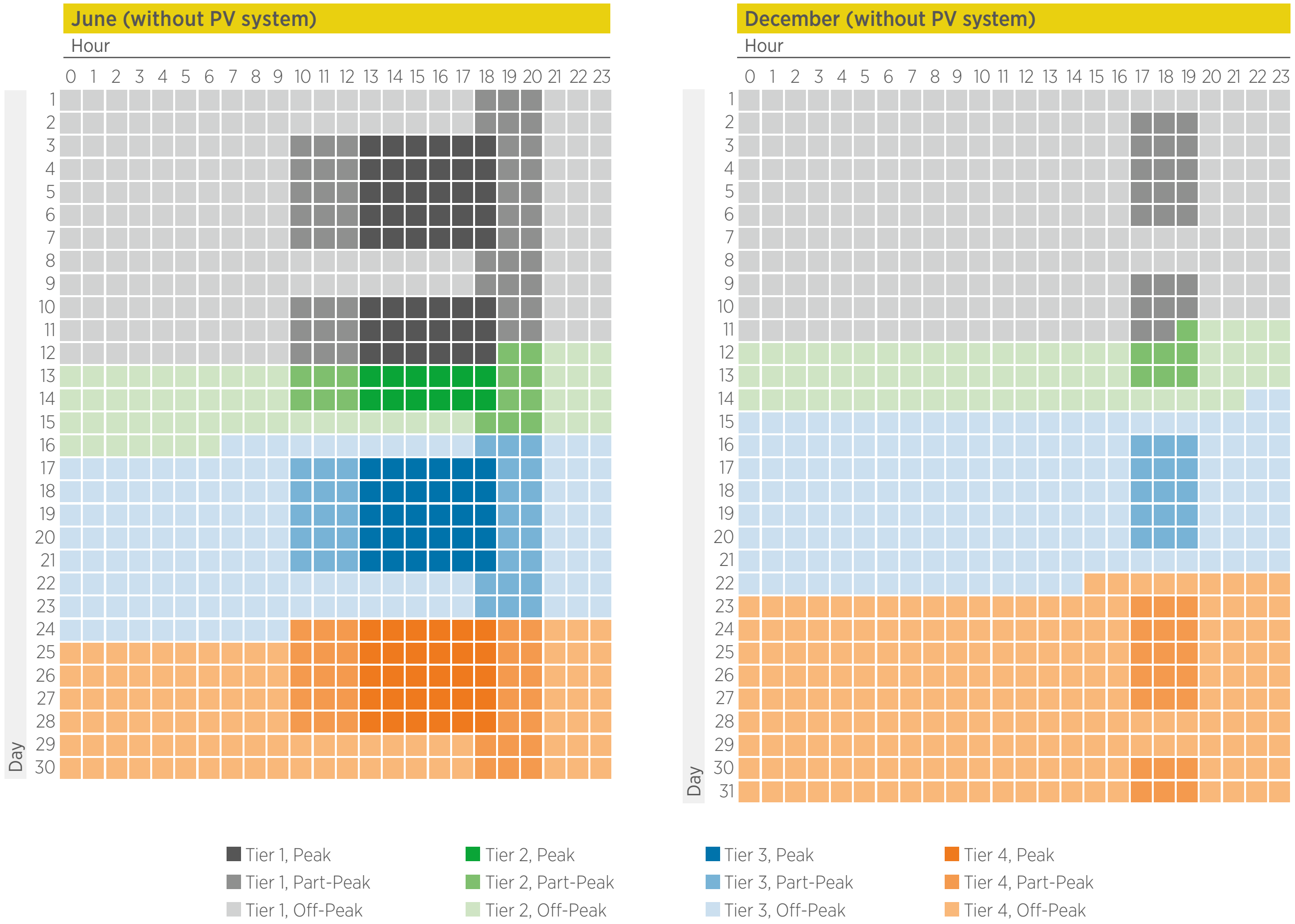


Source: IRENA analysis based on PG&E, 2016.

38 For the IC&CI analysis Code B schedules have been assumed.

For example, a household without a PV system in place and annual consumption of 7 563 kWh has a modelled monthly electricity consumption of 540 kWh in June. Under these model assumptions, the household will exceed its tier 1 allocation at the end of day 12. Solar PV can therefore not only reduce high electricity rate consumption, but also reduce the rate applicable in periods when solar PV is not operating. In December, where modelled consumption is 752 kWh, the higher winter consumption pattern in the territory is offset by the higher winter baseline allocations for tier 1 consumption, meaning that the tier 1 limit is exceeded around the same time as in the June case.

Figure 20: Comparison of quantity of hours in each TOU period and tier in June vs. December without PV on PG&E's residential schedule E-6



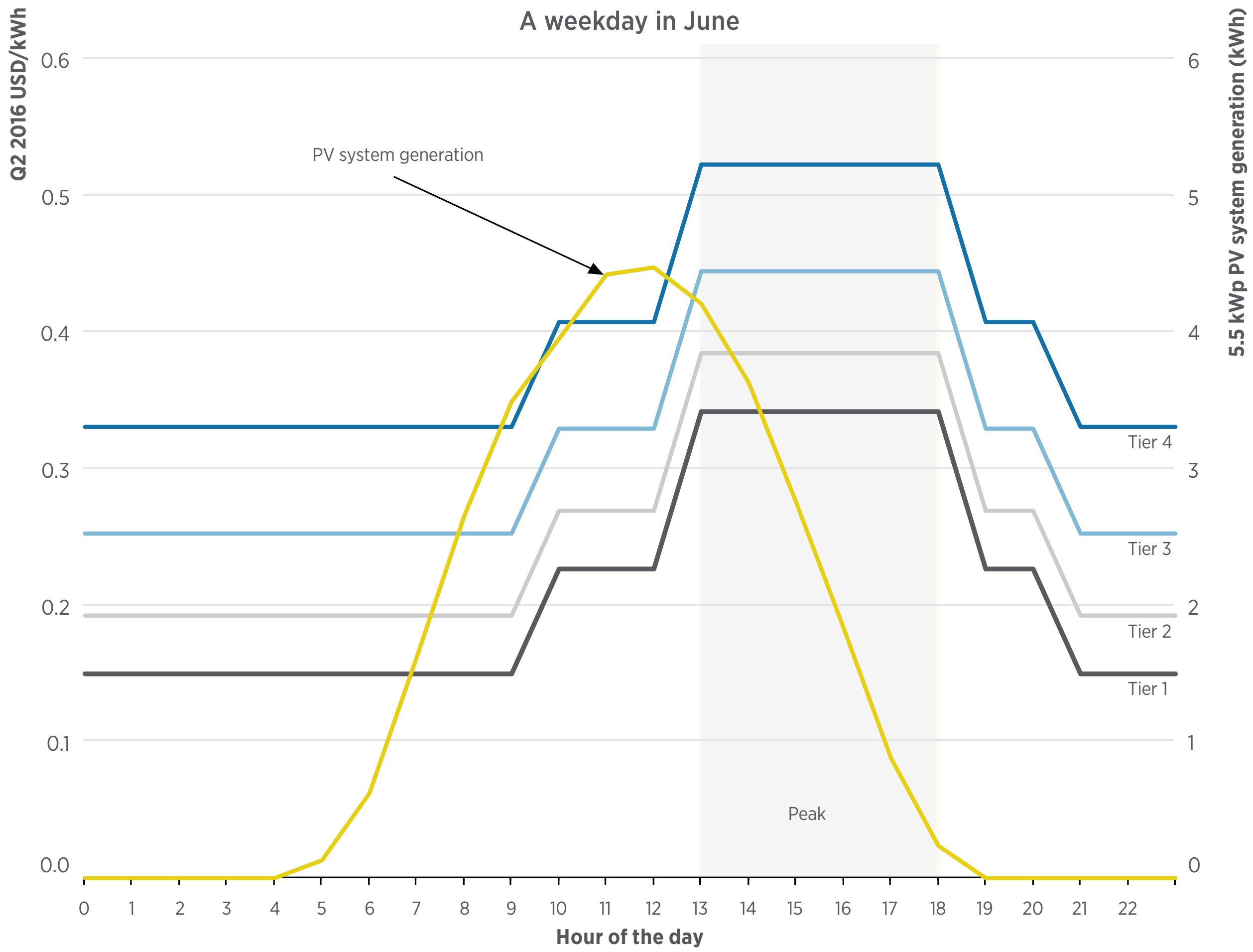
Source: IRENA analysis based on PG&E, 2016.

The practical implication of this is that solar PV has significant value for the average householder, particularly over summer. This can be seen in the following figures, which show the electricity rate structure for each tier alongside the PV generation profile for a weekday in June and December.

From Figure 21, it is easy to appreciate that the times when energy charges are higher over summer correspond with those times when PV generation is also high.

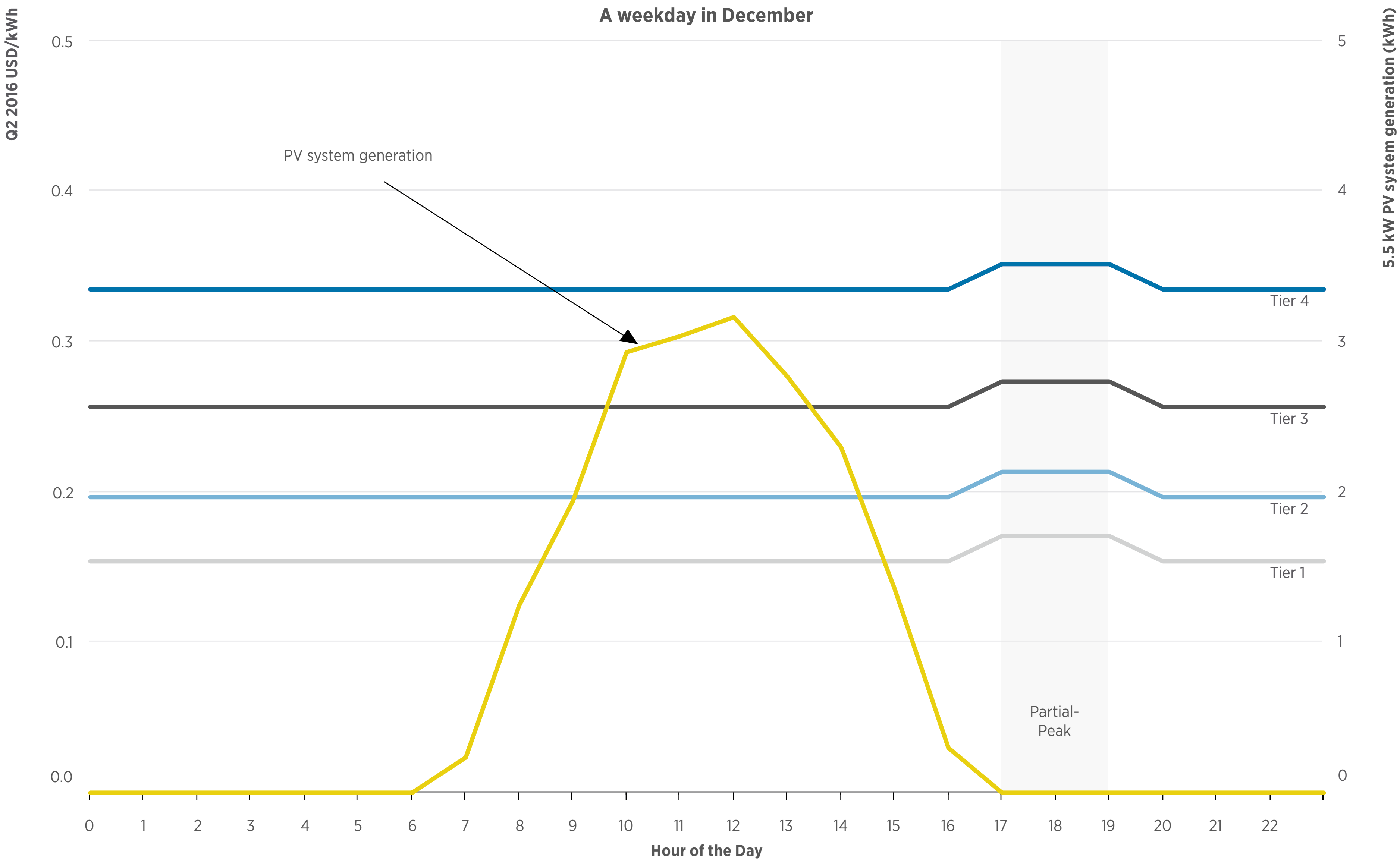
During the winter season this effect is less pronounced (Figure 22).

Figure 21: Electricity rates by tier and PV generation profile in a weekday in June in San Francisco, schedule E-6



Source: IRENA analysis based on PG&E, 2016.

Figure 22: Electricity rates by tier and PV generation profile in a weekday in December in San Francisco, schedule E-6

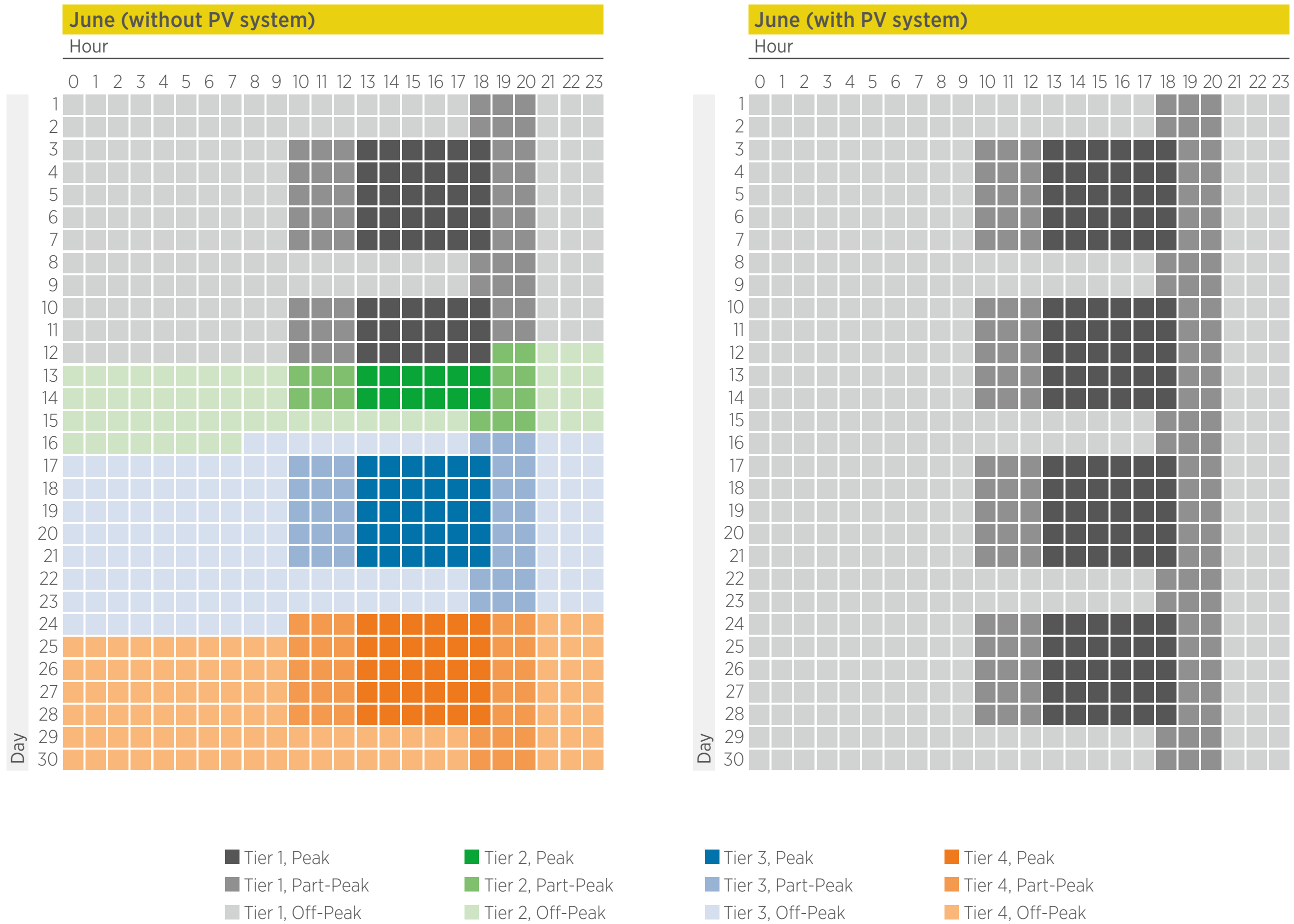


Source: IRENA analysis based on PG&E, 2016.

The role of the IC&CI is not to examine individual household economics, so examining the economic benefits for the householder, including all relevant factors, is beyond the scope of this report. With tiered TOU rates, however, it is worth highlighting the impact that solar PV has on saving electricity – not only at periods of highest pricing, but also in reducing a household's exposure to the higher-tier rates. Figure 23 shows that residential PV installations in this specific example for June in San Francisco reduce monthly consumption below the beginning of the tier 2 threshold. This keeps all hourly prices at the lower, tier 1, rates.

Figure 24 shows this situation under the recently adopted schedule E-TOU (option A).

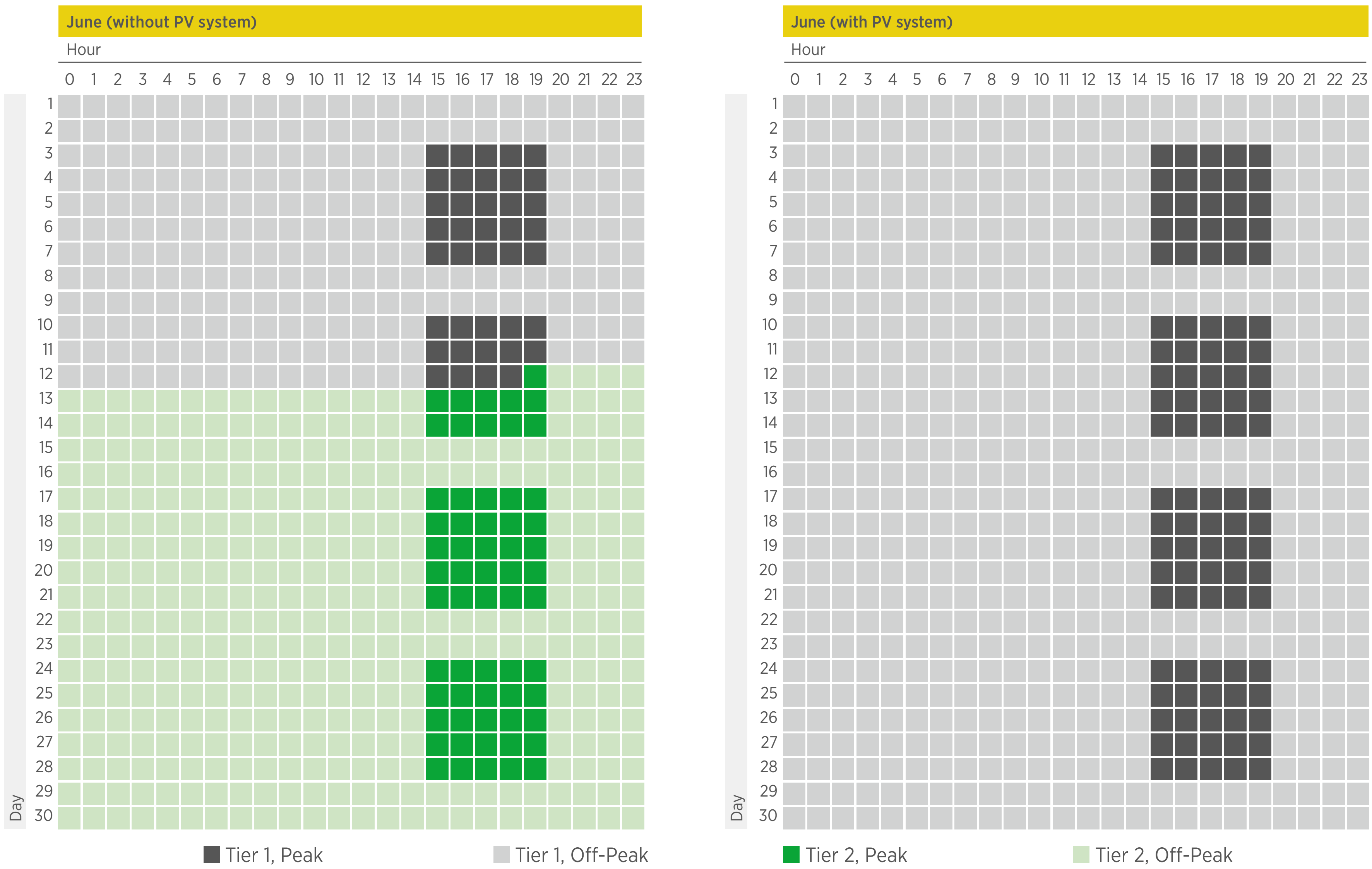
Figure 23: Comparison of quantity of hours in each TOU period and tier in June without PV vs. with PV on PG&E's residential schedule E-6



Source: IRENA analysis based on PG&E, 2016.

Note: The left-hand side shows the situation without solar PV, and the right-hand side shows the case with solar PV.

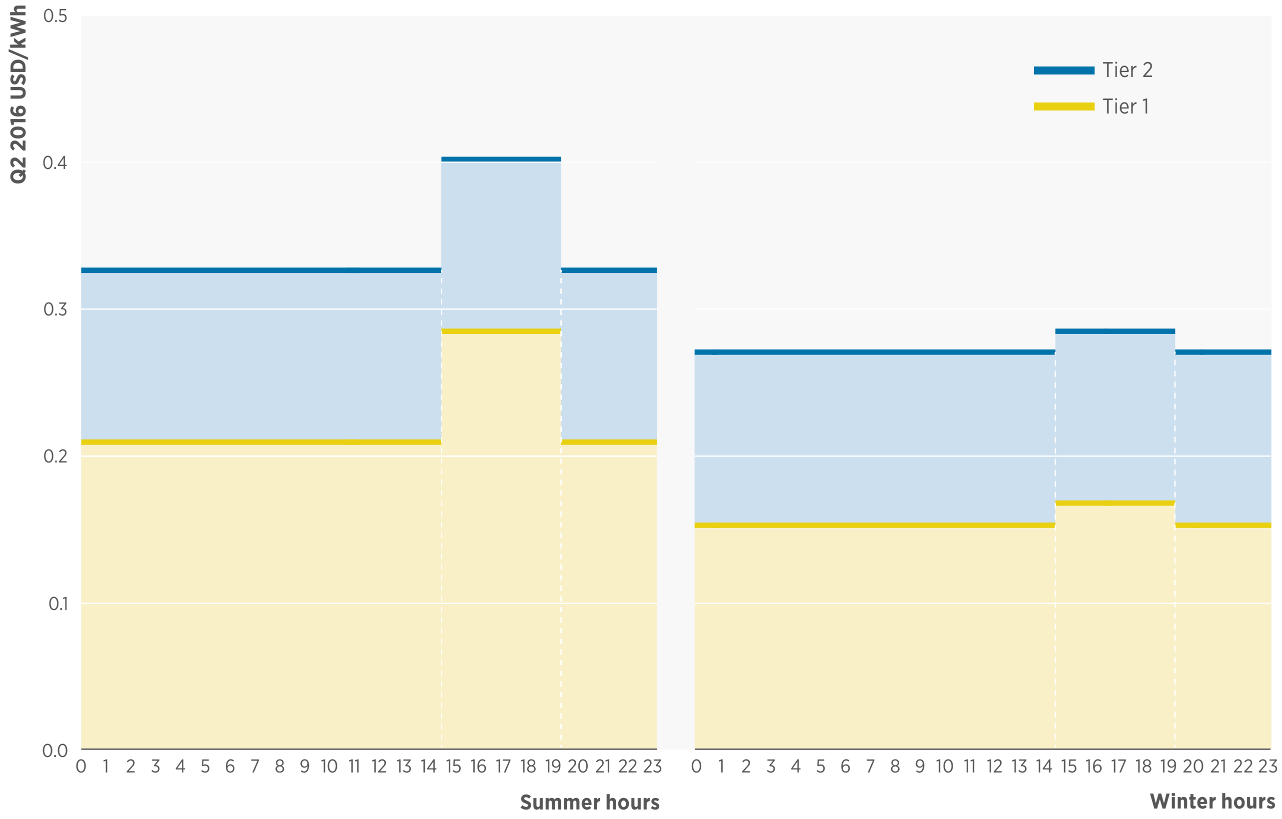
Figure 24: Comparison of quantity of hours in each TOU period and tier in June without PV vs. with PV on PG&E's residential schedule E-TOU (option A)



Source: IRENA analysis based on PG&E, 2016.

In this case also, with solar in place, all hourly prices are kept at the lower-priced rate (tier). Schedule E-TOU (option A) can be modelled as a two-tier schedule. Its four-month "summer season" is shorter than the one, six-month "summer season" under E-6. Schedule E-TOU has only two TOU periods. For option A, the "peak" period runs from 3 p.m. to 8 p.m., Monday through Friday[39], while all other times (including holidays) are considered "off-peak". Figure 25 shows the weekday rates for the E-TOU (option A) schedule.

Figure 25: PG&E E-TOU (option A) rate values by season and TOU for a weekday in Q2 2016

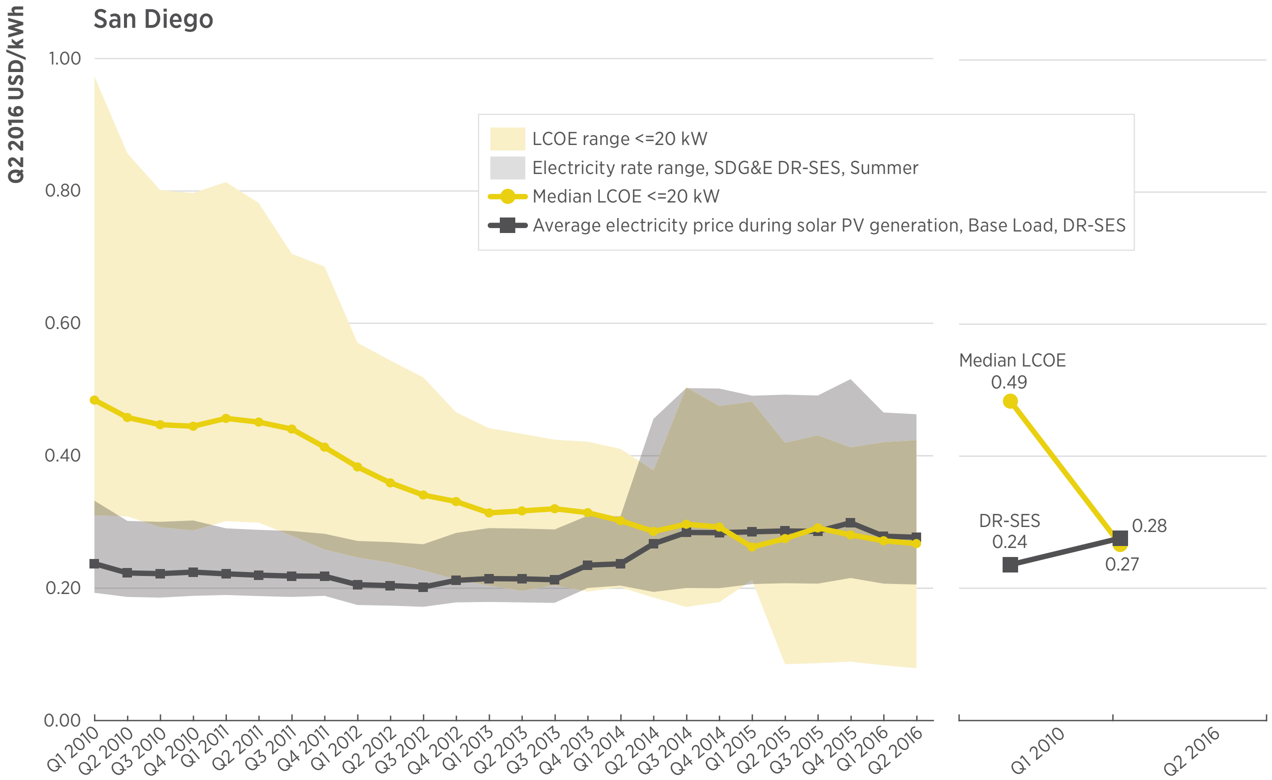


Source: IRENA analysis based on PG&E, 2016.

39 For option A, these "peak" TOU time periods will be in effect through 31 December 2019 after which they will shift to 4 p.m. to 9 p.m. (in conformity with the current option B "peak" time period definition).

SAN DIEGO

Figure 26: Residential LCOE, average electricity price during solar PV generation and electricity rates in San Diego



Source: IRENA analysis based on CEC and CPUC, 2016a; SDG&E, 2016.

In San Diego, the median LCOE for residential solar PV systems and the average effective electricity price have been at around the same level since Q2 2014. The lower end of the range for the solar PV LCOE in San Diego was similar to the upper tariff rate in San Diego until around Q3 2011 (Figure 26). Between Q3 2011 and Q4 2013, the tariff rates and LCOE increasingly overlapped, and since that time the LCOE of solar PV in San Diego has fallen firmly within the tariff range, making solar PV a very promising financial investment for residents of San Diego.

In Q1 2014, the median LCOE (USD 0.30/kWh) fell for the first time bellow the high electricity rate boundary (USD 0.31/kWh) and has consistently stayed below it ever since. In Q1 2015, the median LCOE (USD 0.26/kWh) fell for the first time below the estimated average electricity price during solar PV generation (USD 0.29/kWh), and the two have fluctuated around similar levels ever since.

With a change in tariff structures, during Q2 2014, the high LCOE boundary (USD 0.38/kWh) fell for the first time below the high electricity rate boundary (USD 0.46/kWh). Since Q4 2014, it also has consistently stayed below it, and their differential was USD 0.04/kWh in both Q1 and Q2 2016.

LCOE development

The median LCOE of residential PV in San Diego dropped from USD 0.49/kWh in Q1 2010 to USD 0.27/kWh in Q2 2016 (a 45% reduction). The low and high range boundaries (the first and ninety-ninth percentiles) decreased during this time frame by 74% and 56% respectively, from USD 0.31/kWh to USD 0.08/kWh and from USD 0.97/kWh to USD 0.42/kWh, respectively.

Electricity rates

San Diego Gas & Electric Co (SDG&E) offers the Domestic TOU for Households with a Solar Energy System (DR-SES) tariff schedule. This schedule is used in this edition as a basis for calculating the indicator on average electricity price during solar PV generation. The schedule is very similar in structure to LADWP's Residential TOU R-1B schedule.

SDG&E's DR-SES schedule changes according to three different TOU periods "On-Peak", "Semi-Peak" and "Off-Peak" that vary depending on the day (weekday or weekend/holiday) and for two distinct yearly seasons[40]: a summer season running from May through October and a winter season that covers the rest of the year. The Summer "On-Peak" period (with higher prices) runs from 11 a.m. to 6 p.m. during weekdays. The schedule does not change with increasing consumption (no tiers apply).

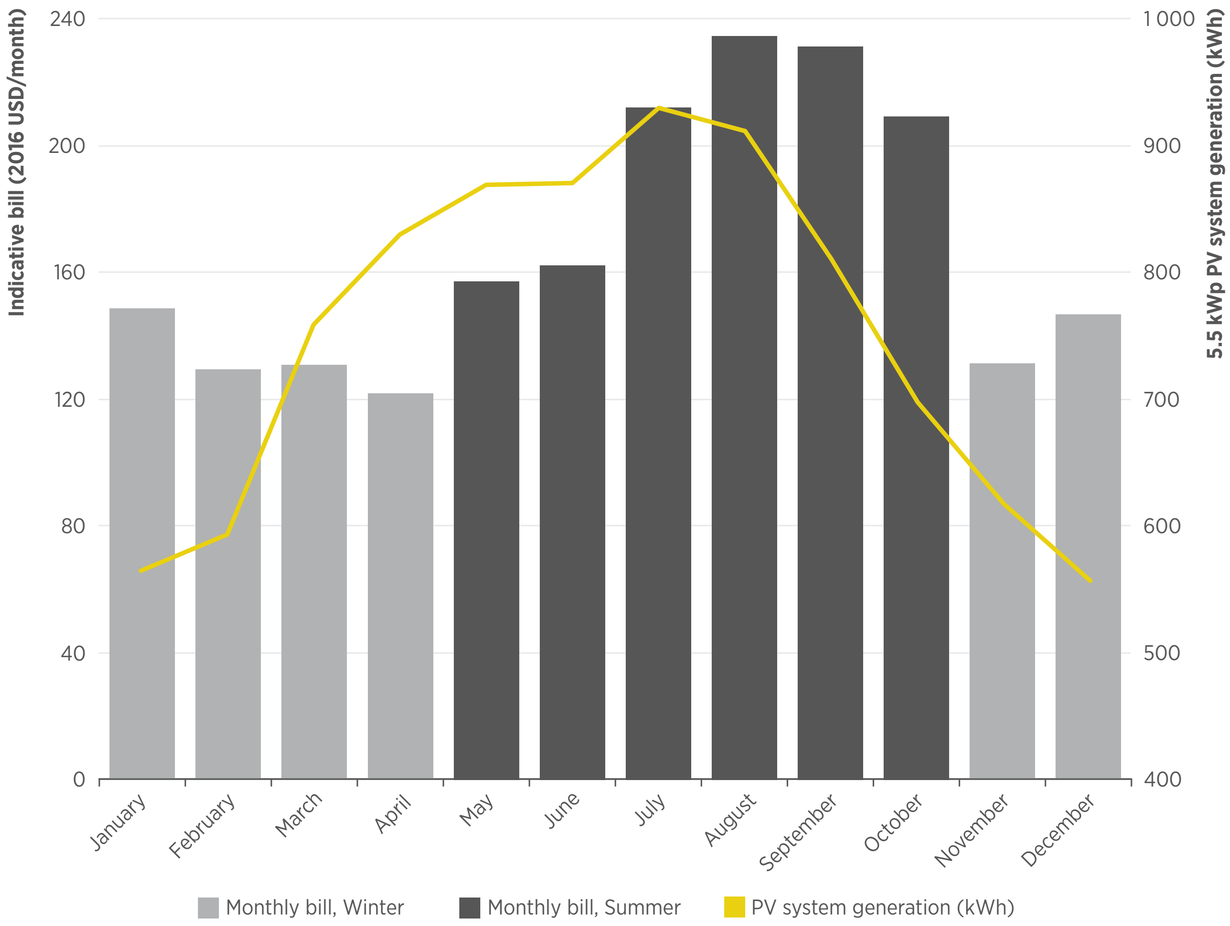
Figure 27: Quantity of hours in each TOU period for a weekday in June (summer season) and December (winter season) on SDG&E's residential TOU schedule DR-SES

Source: IRENA analysis based on SDG&E, 2016.

40 A more detailed description of the schedule can be found in Annex II.

Electricity expenditure for a household in San Diego under this schedule tends to be higher than average during the summer season, due to higher consumption and TOU prices. As can be seen in Figure 28, the highest PV generation months also overlap with the months with higher bills.

Figure 28: Indicative residential monthly electricity bill for SDG&E's residential TOU schedule DR-SES without PV and typical PV output

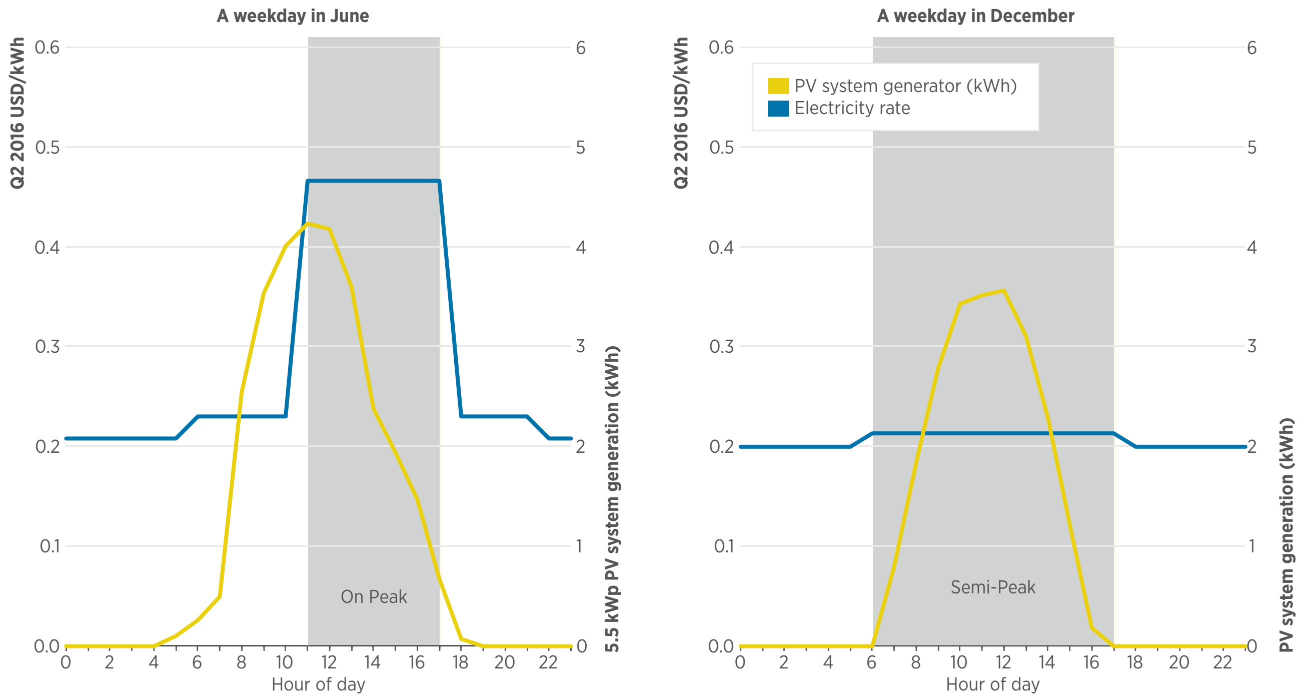


Source: IRENA analysis based on SDG&E, 2016.

Figure 29 shows the PV system generation profile for a weekday in June and in December (602 kWh and 709 kWh of monthly consumption, respectively), as well as the electricity rates[41] for schedule TOU schedule DR-SES in place for those months. In June, when the higher summer rates are in place, more than half of the daily solar PV output falls under the highest, peak rate.

In winter, solar PV generation is lower, but all of the output of solar PV systems comes under the higher daytime rate in winter, even though this rate is only slightly higher than the evening/night-time rate.

Figure 29: Electricity rates and PV output for June and December in SDG&E's residential TOU schedule DR-SES

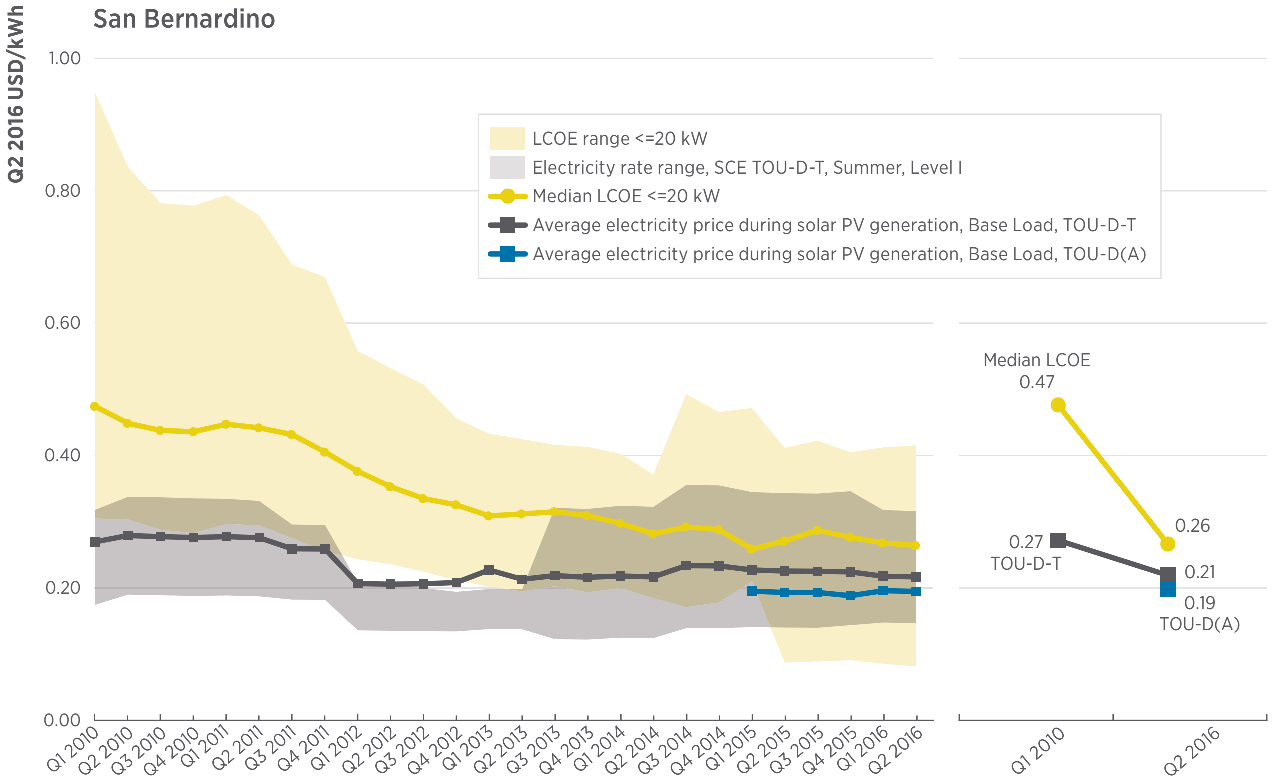


Source: IRENA analysis based on SDG&E, 2016.

41 As effective in Q2 2016.

SAN BERNARDINO

Figure 30: Residential LCOE, average electricity price during solar PV generation and electricity rates in San Bernardino



Source: IRENA analysis based on CEC and CPUC, 2016a; SCE, 2016.

The low LCOE boundary of residential PV systems in San Bernardino has (with the exception of 2012 and Q1 2013) stayed within the TOU Domestic-Tiered (TOU-D-T) low-to-high electricity rate boundaries, or below the TOU-D-T lower boundary for the period under consideration, starting in Q1 2010.

In Q3 2013, the median LCOE (USD 0.31/kWh) fell for the first time bellow the high electricity rate boundary (USD 0.32/kWh) and has consistently stayed below it since then. The median LCOE also has been approaching the level of the estimated average electricity price during solar PV generation for the base load case and a 5.5 kW PV system under the TOU-D-T rate. Their differential dropped from USD 0.21/kWh in Q1 2010 to USD 0.05/kWh in Q2 2016 (a 77% reduction).

The LCOE upper boundary displayed a USD 0.53/kWh reduction for the full period under consideration (Q1 2010 to Q2 2016). The LCOE boundary also has been approaching the level of the upper boundary of the considered electricity rate. Their differential dropped from USD 0.63/kWh in Q1 2010 to a much lower USD 0.10/kWh in Q2 2016 (an 84% reduction).

Starting in Q1 2015, Figure 30 also shows the modelled average electricity price during solar PV generation for option A of the more recently introduced residential schedule TOU-D (option A). This schedule is similar in its tier structure to PG&E's E-TOU (option A), but it differs from it in that it has three (not two) TOU periods.[42] During Q2 2016, the estimated average electricity price during solar PV generation under SCE's TOU-D (option A) schedule was USD 0.19/kWh. This is 10% lower than the estimated average electricity price during solar PV generation under the older TOU-D-T schedule, which is still open to new SCE customers.

42 The summer "on-peak" period in SCE's TOU-D (option A) schedule runs from 2 p.m. to 8 p.m. during weekdays.

LCOE development

The tariff range and median tariff while solar PV is operating currently fall within the range of solar PV system LCOE results. Some systems' LCOEs are above and some are below; however, there remains a significant gap between the median values of each.

Since Q3 2013, the LCOE range for solar PV systems and the range for TOU tariffs have experienced significant overlap. The median LCOE of residential PV systems in San Bernardino dropped 45%, from USD 0.47/kWh in Q1 2010 to USD 0.26/kWh in Q2 2016 (Figure 30). The low and high LCOE range boundaries (first and ninety-ninth percentiles) decreased during this time frame by 74% and 56% respectively, from USD 0.30 to USD 0.08/kWh and from USD 0.95 to USD 0.41/kWh, respectively. Between Q1 2010 and Q2 2016, the difference between the LCOE's lowest and highest ranges fell by nearly half (48%), from USD 0.65/kWh to USD 0.34/kWh.

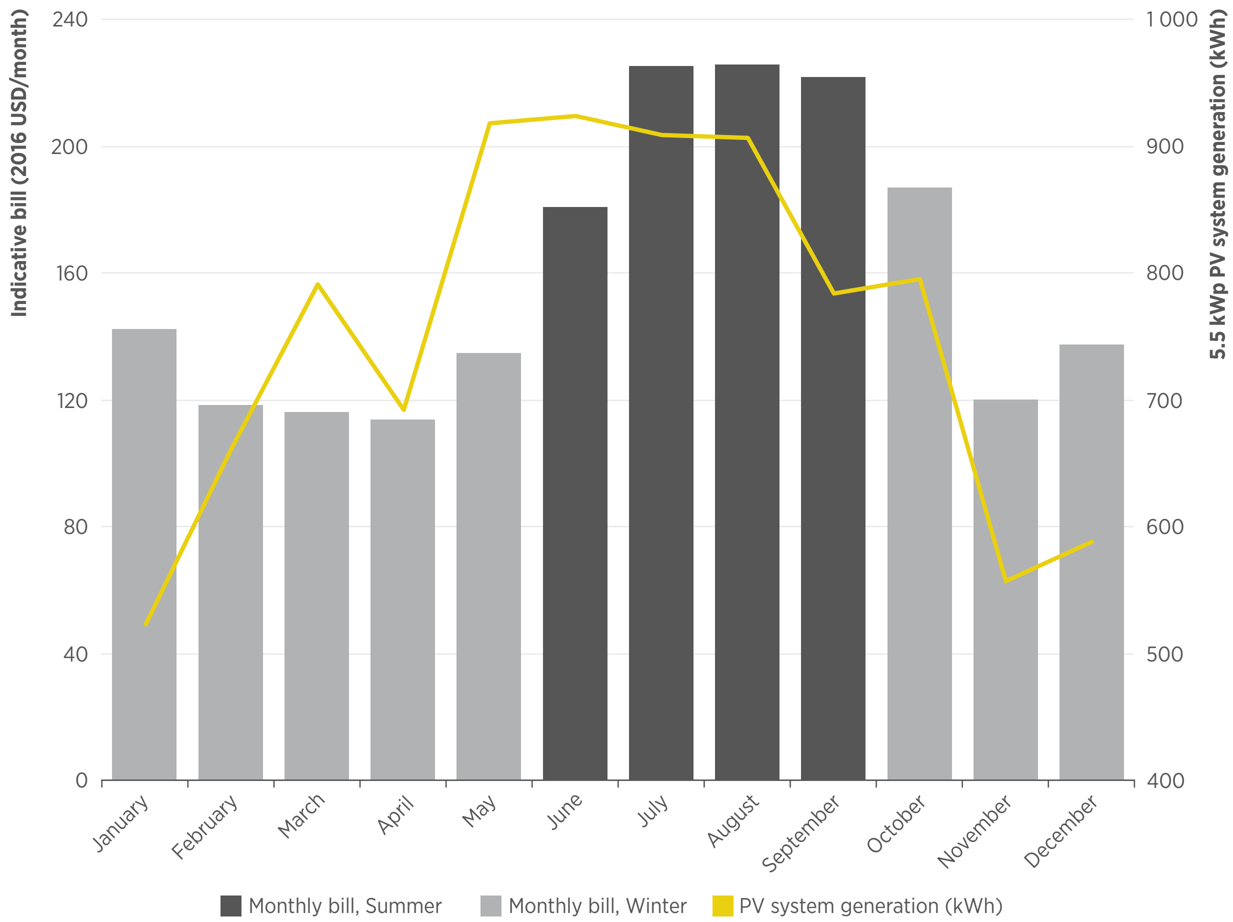
Electricity rates

SCE's TOU-D-T schedule changes from both a TOU perspective (On-Peak and Off-Peak), as well as with increasing block/tier rates, which are referred to as "levels". As electricity consumption increases beyond the allotted baseline quantity, the energy charge moves to the next consumption level and its corresponding higher energy charge. The Level I consumption threshold roughly corresponds to tiers 1 and 2 in the schedules of other investor-owned utilities in California. Level I consumption extends from 0% to 130% of the baseline quantity allocated for that territory. All consumption above 130% of the baseline is categorised under Level II (see more details in Annex II: California).

Baseline allocations differ for the summer and winter periods and by location. Predefined weather zones in SCE's service area, called "baseline territories", determine the baseline allocation levels. In addition to this, the baseline quantities also vary by electric code (e.g., households using electricity to heat water fall under a code called "all electric", instead of the "basic" code).

Figure 31 presents the monthly modelled bills without solar PV and the monthly solar PV output.

Figure 31: Indicative residential monthly electricity bill for SCE's TOU schedule TOU-D-T without PV and typical PV output



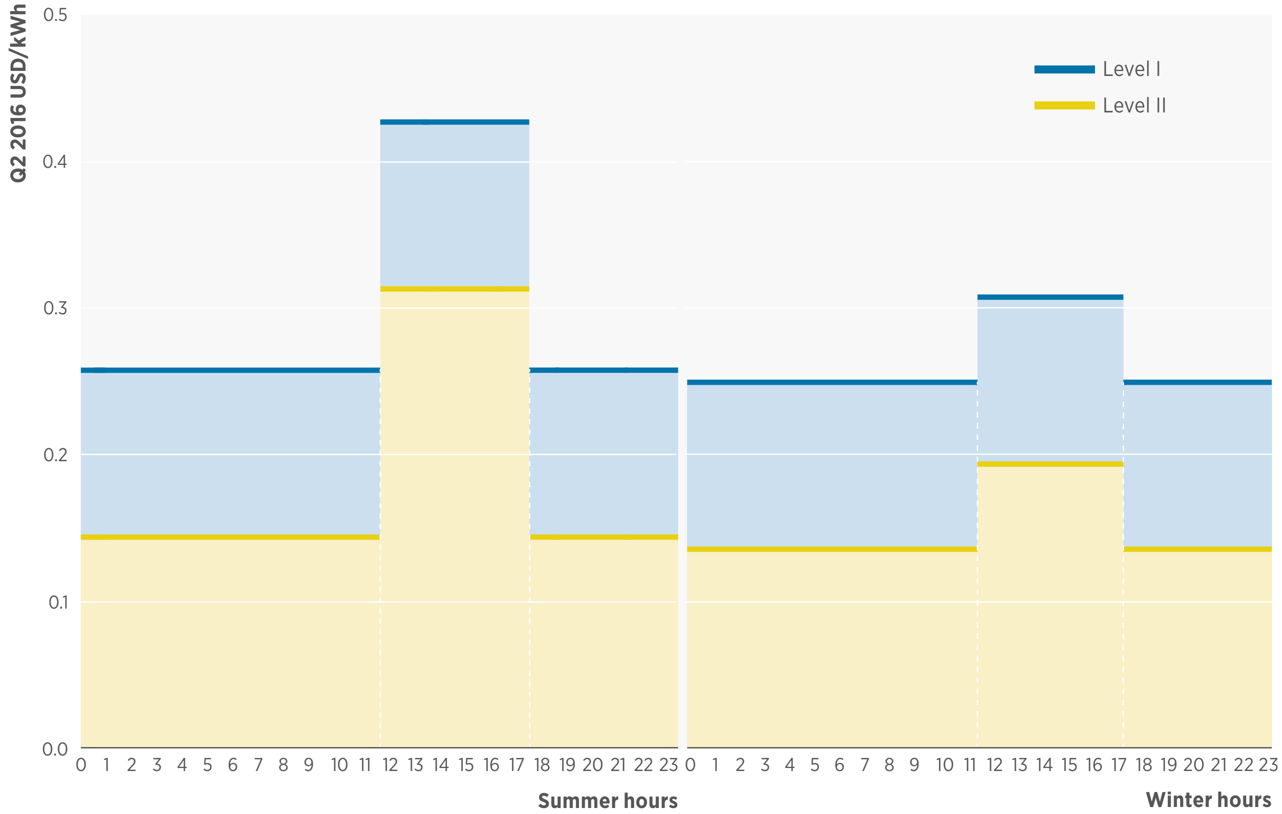
Source: IRENA analysis based on SCE, 2016.

Figure 31 shows that electricity expenditure in this schedule tends to be higher than average during the summer season, which also corresponds with the higher PV generation months.

With increasing cumulative monthly consumption, the level pricing changes. For example, for June, a household without a PV system in place and annual consumption of 9 327 kWh has a modelled monthly electricity consumption of 833 kWh. Under these model assumptions, the household will exceed its baseline allocation at the end of day 18, while Level I consumption (130% of baseline) is exceeded on the morning of day 23 – and therefore, the rest of the month would be charged at the higher, Level II rates.

In SCE's TOU-D-T schedule, the higher "on-peak" energy charges occur during the peak hours of 12 p.m. to 6 p.m. in both the winter and summer seasons.

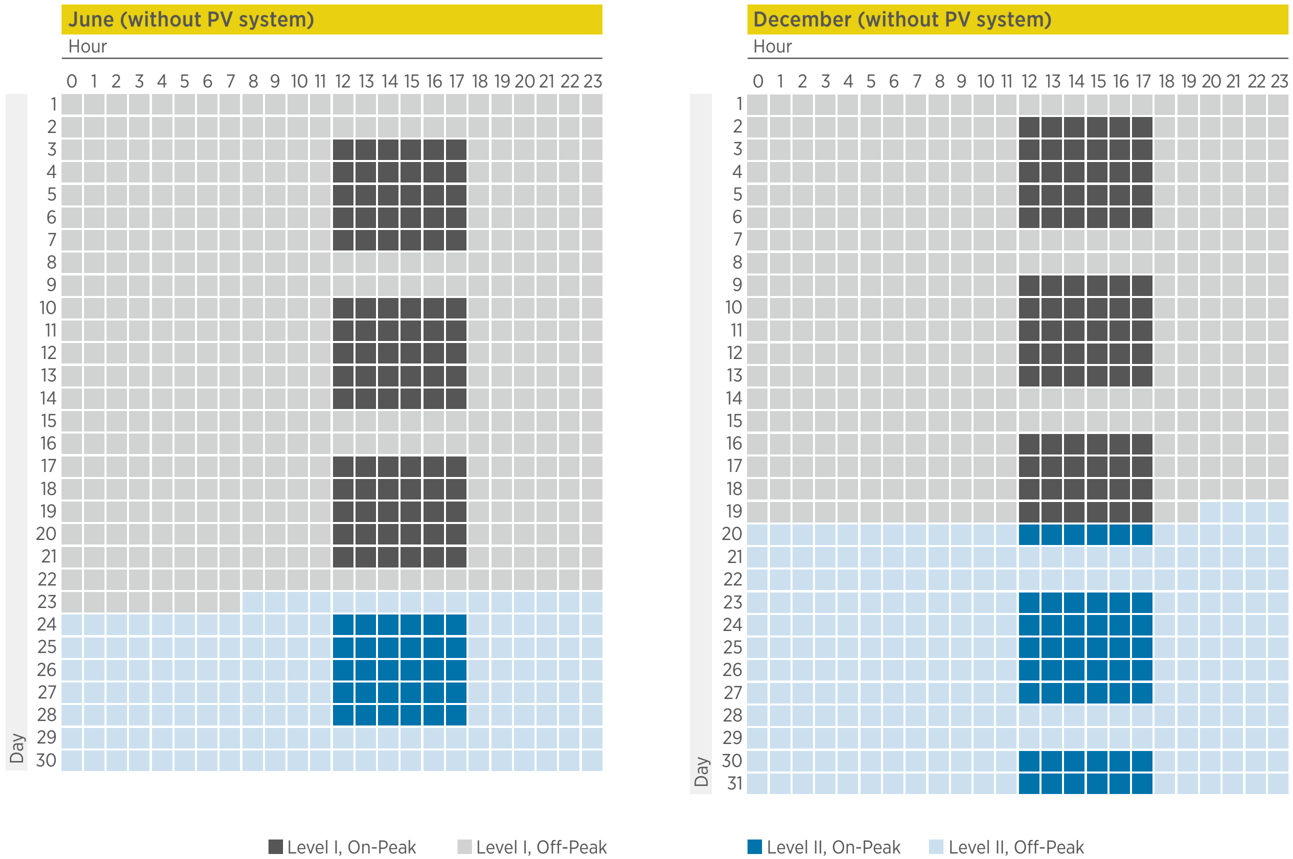
Figure 32: SCE TOU-D-T rate values by season and TOU for a weekday in Q2 2016



Source: IRENA analysis based on SCE, 2016.

Figure 33 shows the impact of the modelled electricity consumption over the months of June and December. This highlights how the active level changes for a household with annual consumption of 9 327 kWh. In June, consumption is 833 kWh, and in December, it is 723 kWh. The baseline allowance in December is lower than in June, leading to a situation where the higher, Level II charges are reached earlier in December than in June. For example, Level I is exceeded in day 19 during December, as opposed to day 23 in June. This case shows that predicting the actual energy rates can be complicated at times, due to the many variables in place and the need to assess their interactions and their effect on the energy charges.

Figure 33: Comparison of quantity of hours in each TOU period and "level" for a weekday in June vs. December without PV on SCE's residential TOU-D-T schedule in San Bernardino

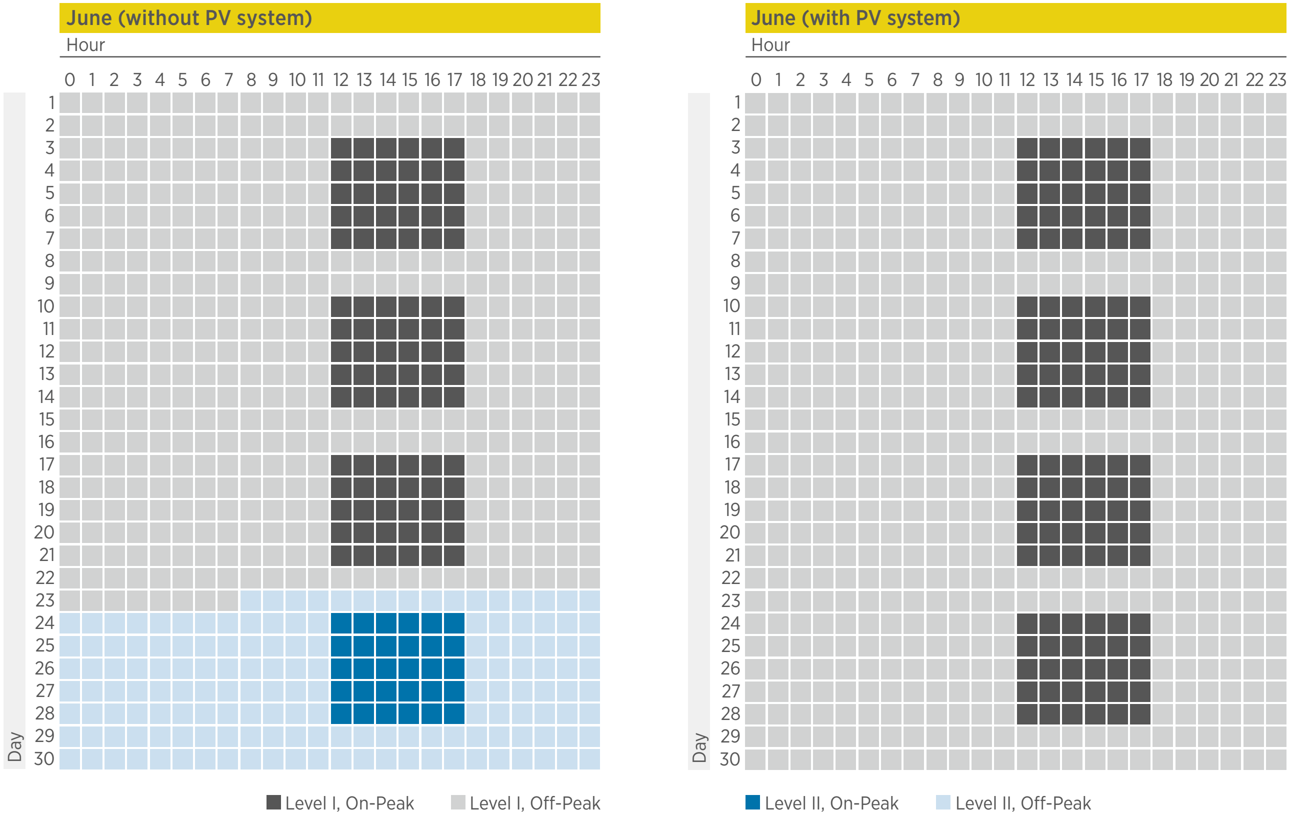


Source: IRENA analysis based on SCE, 2016.

PV can help avoid higher Level II charges especially in the high irradiation and high energy consumption months (Figure 34).

In this case Level II (and its higher energy charges) are not reached in the PV case, while in the without PV case, Level II is reached on day 23, as mentioned previously.

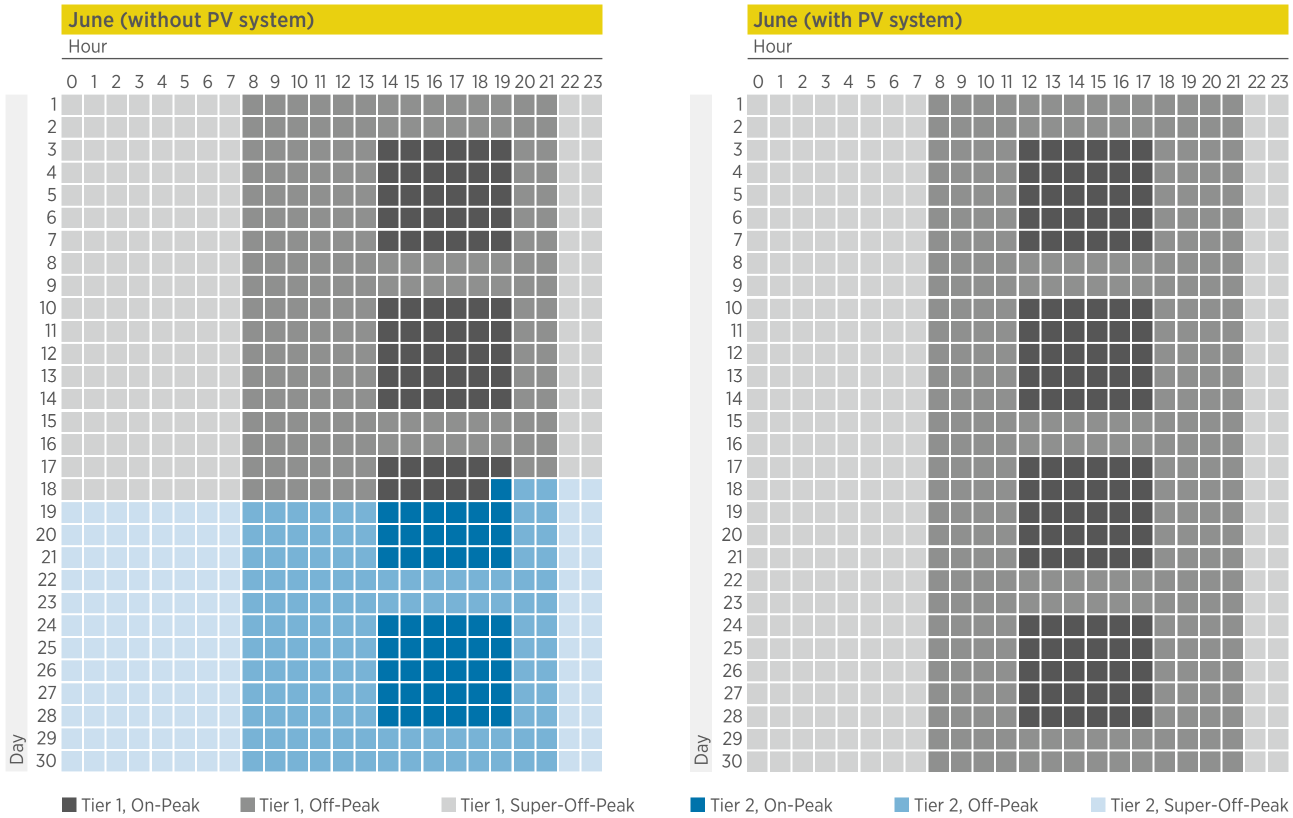
Figure 34: Comparison of quantity of hours in each TOU period and tier for a weekday in June without PV vs. with PV on SCE's residential TOU-D-T schedule in San Bernardino



Source: IRENA analysis based on SCE, 2016.

Figure 35 shows this situation for the more recently adopted TOU-D (option A) schedule. As with PG&E's E-TOU (option A), this schedule also can be modelled as a two-tiered scheme, with a different price for consumption below and above the baseline allowance threshold. It has three TOU periods (On-Peak, Off-Peak and Super-Off-Peak), and during summer the On-Peak period runs from 2 p.m. to 8 p.m. Without a PV system in place, the baseline allowance (and the corresponding switch to the higher electricity pricing) is reached towards the end of day 18. In the PV case, the higher pricing is not reached.

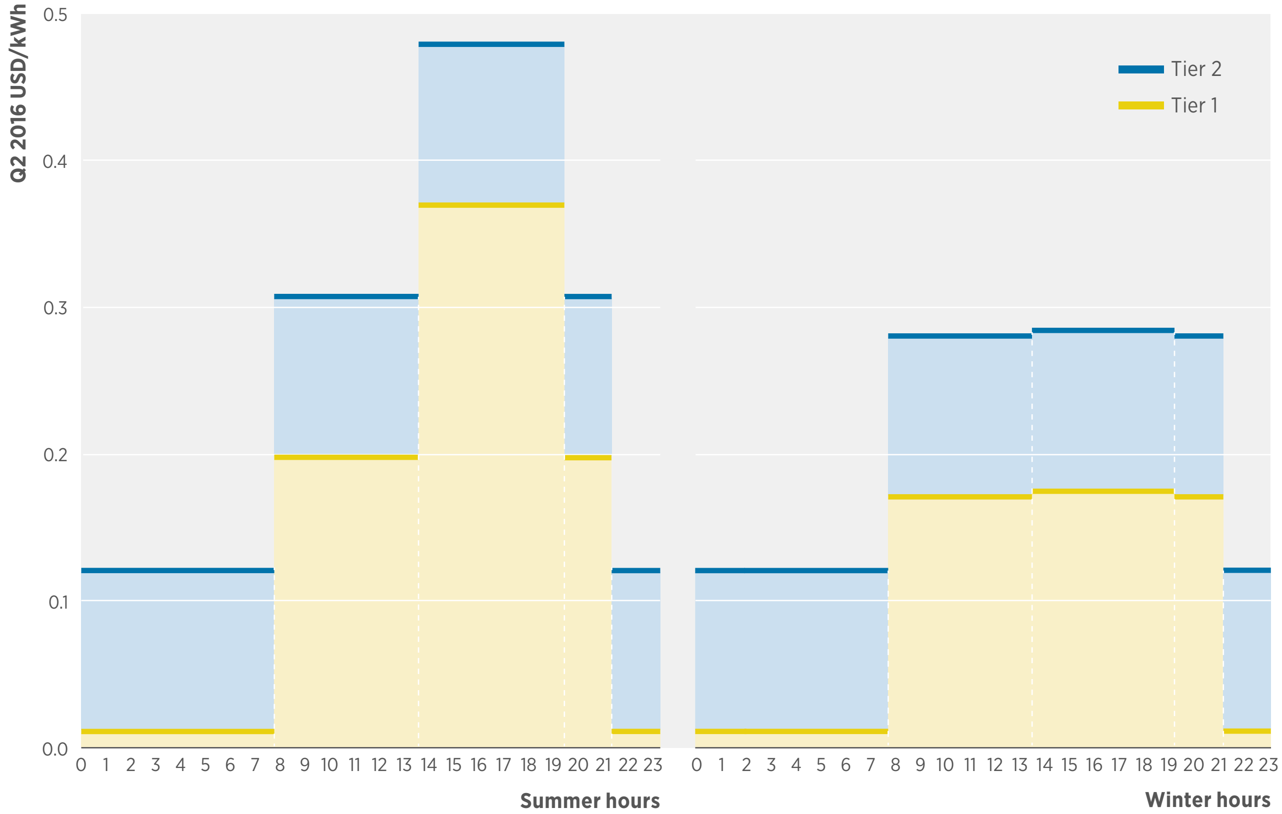
Figure 35: Comparison of quantity of hours in each TOU period and tier for a weekday in June without PV vs. with PV on SCE's residential TOU-D (option A) schedule in San Bernardino



Source: IRENA analysis based on SCE, 2016.

Figure 36 shows the weekday rates for the TOU-D (option A) schedule as valid through Q2 2016.

Figure 36: SCE TOU-D (option A) rate values by season and TOU for a weekday in Q2 2016



Source: IRENA analysis based on SCE, 2016.

IC&CI Rooftop Solar PV:

GERMANY

INTRODUCTION TO GERMANY'S PV MARKET

Germany is a global leader in the deployment of solar PV. The country has progressed substantially in its transition to a renewable energy future, also known as *Energiewende*.

This IC&CI report focuses solely on PV competitiveness (presently within the residential segment), but other work by IRENA provides more detailed analysis of the progress to date in Germany's energy transition. This progress demonstrates that on the whole, the benefits of energy transition outweigh its costs (IRENA, 2015b).

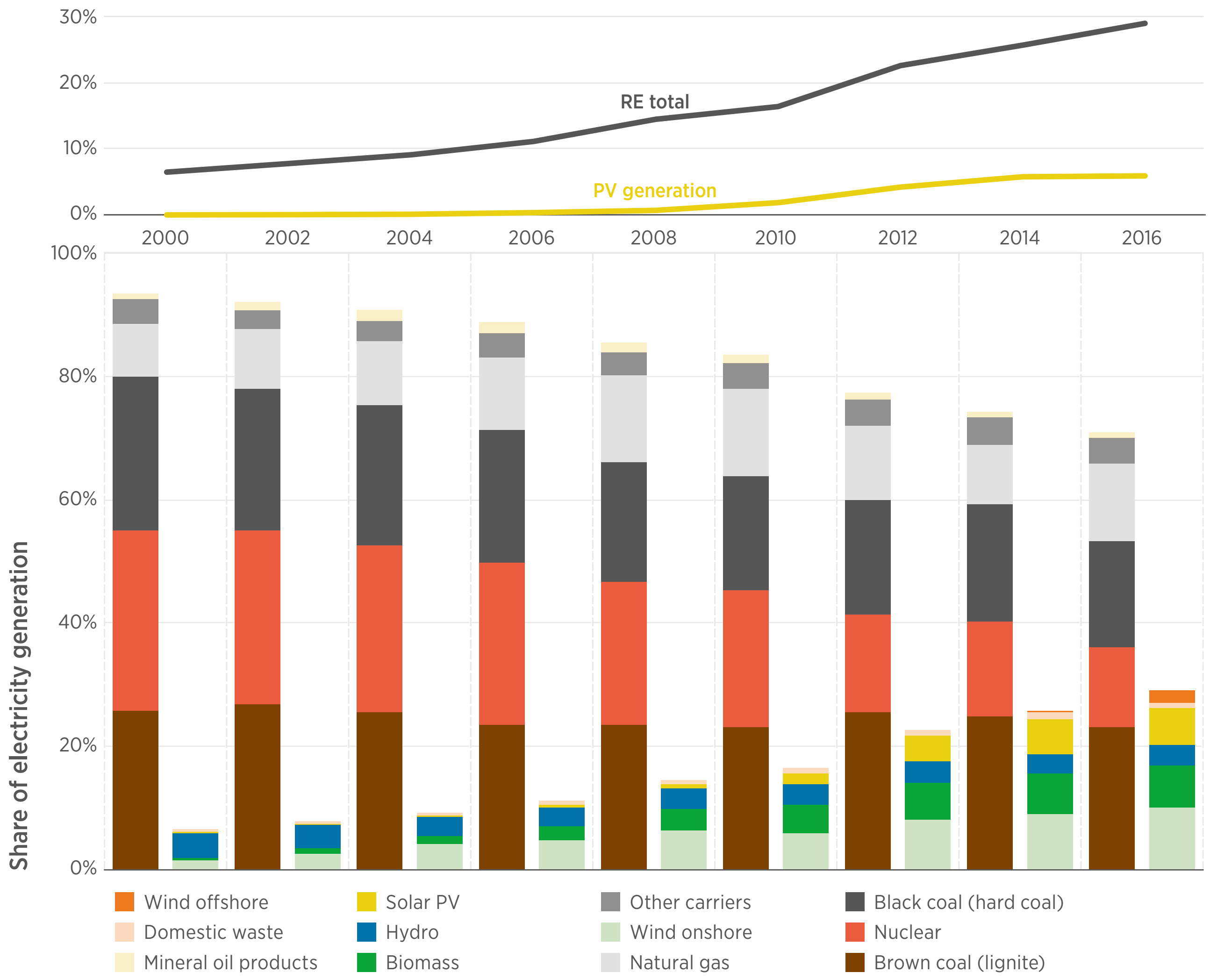
Much of the growth in renewables in Germany – and of PV in particular – has been driven by clear long-term energy policy goals. These have been supported by specific policy measures to accelerate deployment, thereby increasing the effectiveness (IRENA, 2015c).

The Renewable Energy Act (*Erneuerbare-Energien-Gesetz*, or EEG) was adopted in 2000 and set elements of the overall framework for the support of renewable energy policy. The EEG stipulated feed-in tariffs (FITs) that provided investors with certainty, while at the same time providing the mechanism to apportion the costs to electricity users. This was in order to ensure the stability of payment mechanisms.

During the period 2000–2016, the contribution of renewables to Germany's gross electricity generation grew from 7% to 29%. Solar PV's share of gross electricity generation countrywide exceeded 1% in 2009 and reached 6% in 2016 (Figure 37).

Solar PV growth accelerated between 2010 and 2012 as solar PV module prices fell rapidly. This saw Germany lead the world in cumulative deployment, an achievement only recently surpassed by China. The FIT values offered decreased from EUR 0.51/kWh[43] (Q2 2016 USD 0.70/kWh) in January 2000 to EUR 0.12/kWh (Q2 2016 USD 0.14/kWh) in June 2016 (according to the month the system went into operation).

Figure 37: Electricity generation by source in Germany, 2000–2016

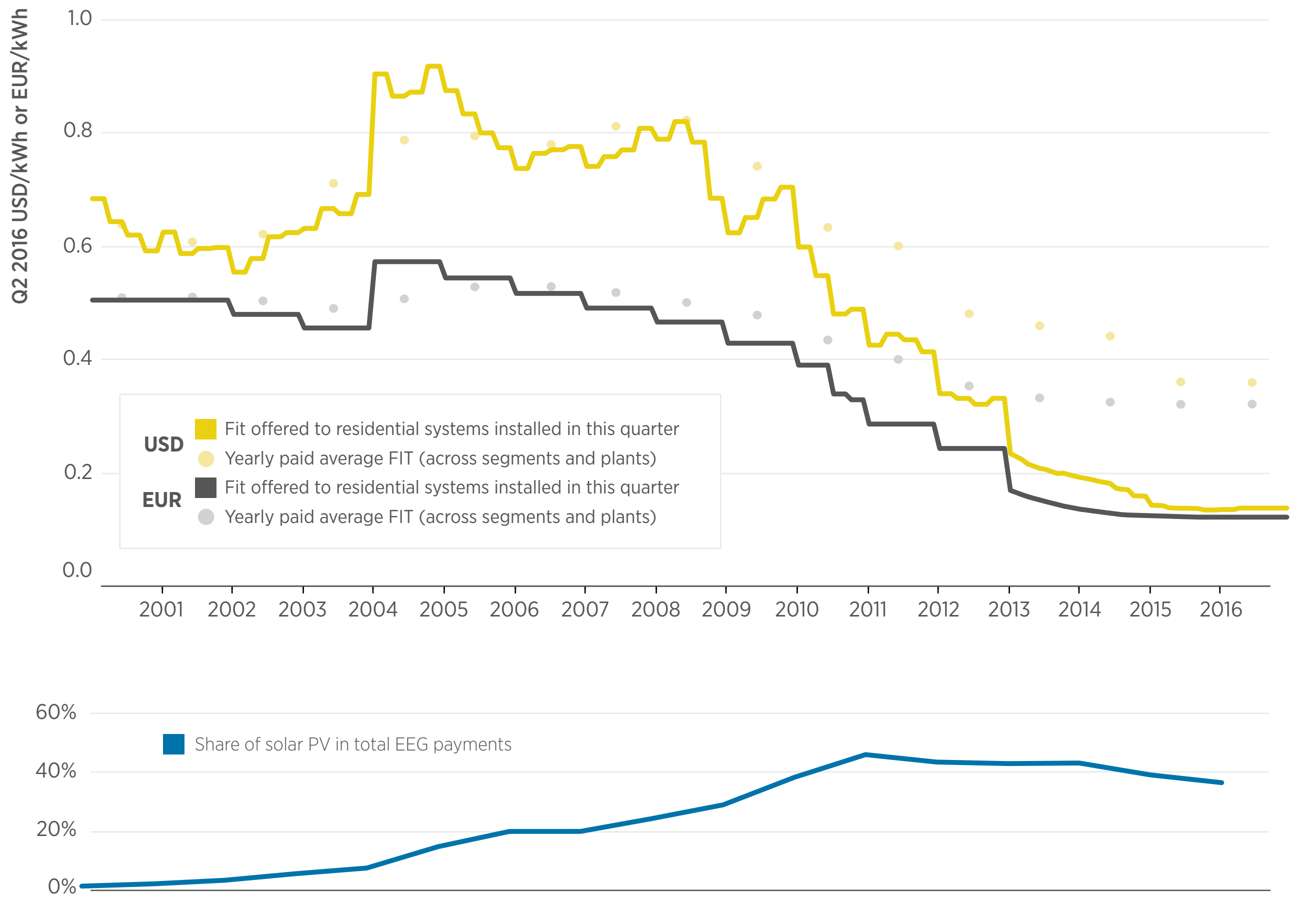


Source: IRENA analysis based on AG Energiebilanzen, 2017.

43 Expressed in nominal euros.

The average FIT compensation for all installed PV plants across all segments, not just residential systems, decreased from EUR 0.51/kWh (Q2 2016 USD 0.64/kWh) in the year 2000 to EUR 0.32/kWh (Q2 2016 USD 0.36/kWh) in June 2016[44]. Solar PV's share of total EEG remuneration payments in 2016 was 37% (Figure 38).

Figure 38: Available FIT, yearly paid FIT average and share of PV in total EEG charges, 2001–2016



Source: IRENA analysis based on BDEW, 2016b; Bundesnetzagentur, 2017; Netz-transparenz.de, 2016; BMWi, 2016a.

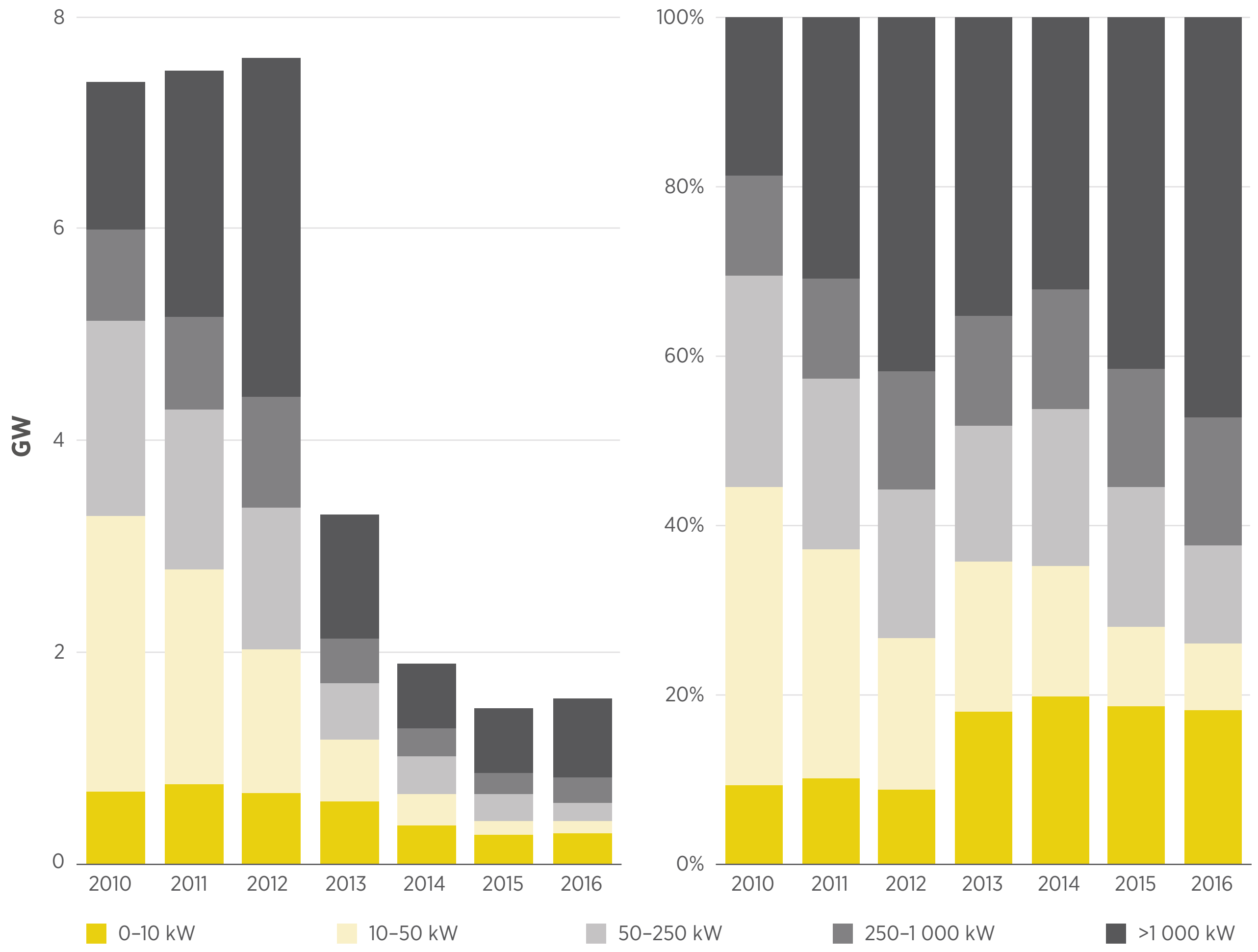
44 This value is the sum of the capacity added by market segment multiplied by the FIT value for the period that system commenced operation.

The German PV market experienced spectacular growth between 2010 and 2012. The 22 GW of systems installed during this period accounted for about 55% of the total cumulative installed PV capacity in Germany at the end of 2016.

During 2010–2016, about one-third of the total installed volume corresponded to large-scale plants (>1 000 kW), with plants between 10 kW and 1 000 kW contributing another 56%. About 12% of the installed volume was in the less than 10 kW size class, which traditionally has been used as the threshold to define the residential system in Germany.[45]

Although the newly installed residential volume in 2016 was about 80% less than in 2010, residential's decline has been less than in other sectors, and its share of new capacity additions has doubled from 9% in 2010 to 18% in 2016 (Figure 39).

Figure 39: German net PV additions by segment, 2010–2016



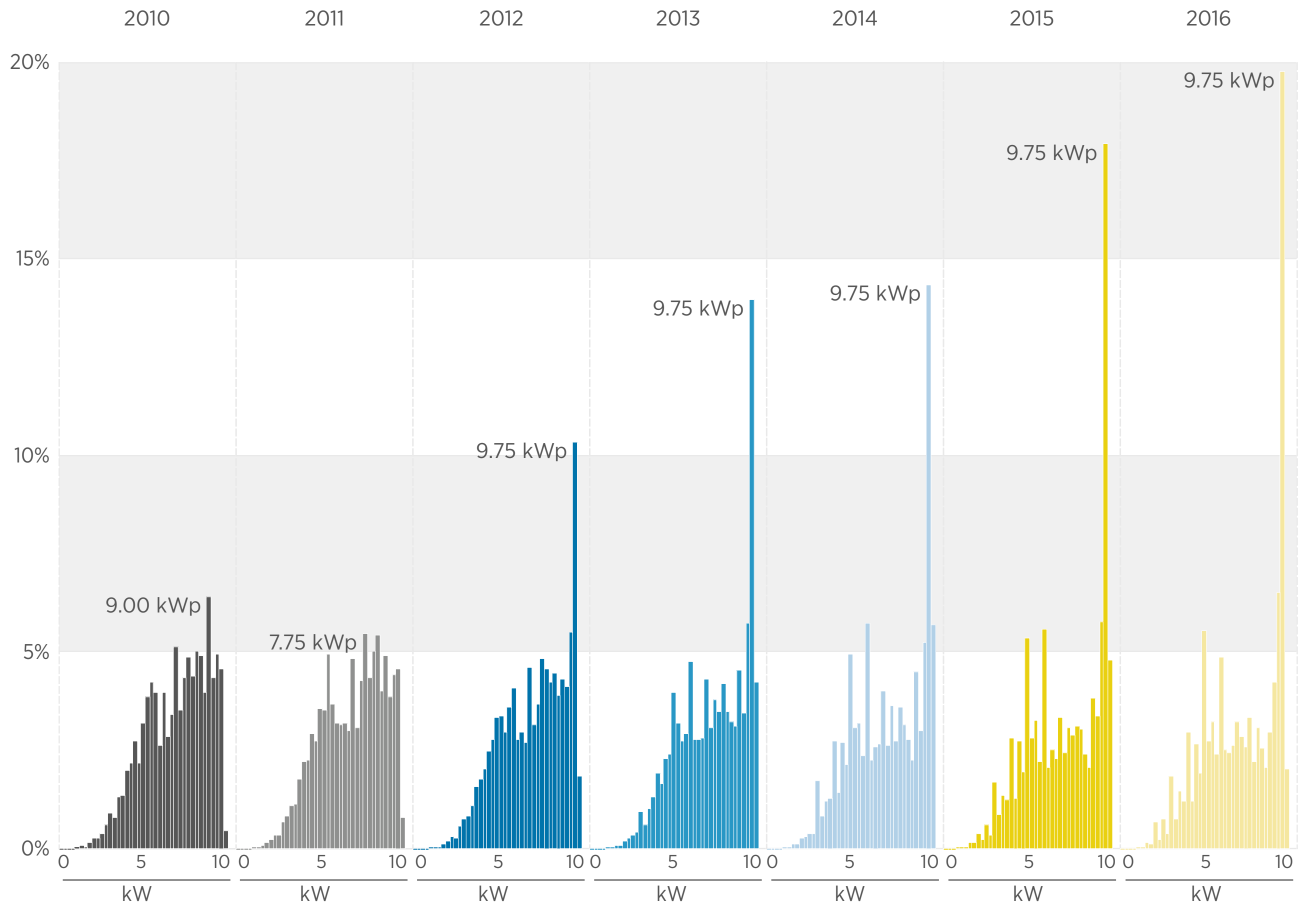
Source: IRENA analysis based on EuPD Research, 2017b; Bundesnetzagentur, 2017.

45 Some residential systems may of course exceed the 10 kW threshold, but both roof space limitations and the historical FIT structure definition point to this limit (see also Figure 40).

The contribution of German PV systems to the global cumulative connected PV capacity increased from 14% at the end of 2000 to 45% at the end of 2010. By the end of 2016, this share had fallen to 14%, returning the share to the level of 2000. This was driven by both a slowing in Germany's PV additions and by the welcome broadening of the PV market and increased deployment outside Europe.

Figure 40 shows the distribution of newly installed residential (less than 10 kW) systems each year, in bins of 0.25 kW size during the period 2010–2016.

Figure 40: Percentage of newly installed German PV capacity for systems below 10 kW by system size bins, 2010–2016



Source: IRENA analysis based on EuPD Research, 2017b; Bundesnetzagentur, 2017.

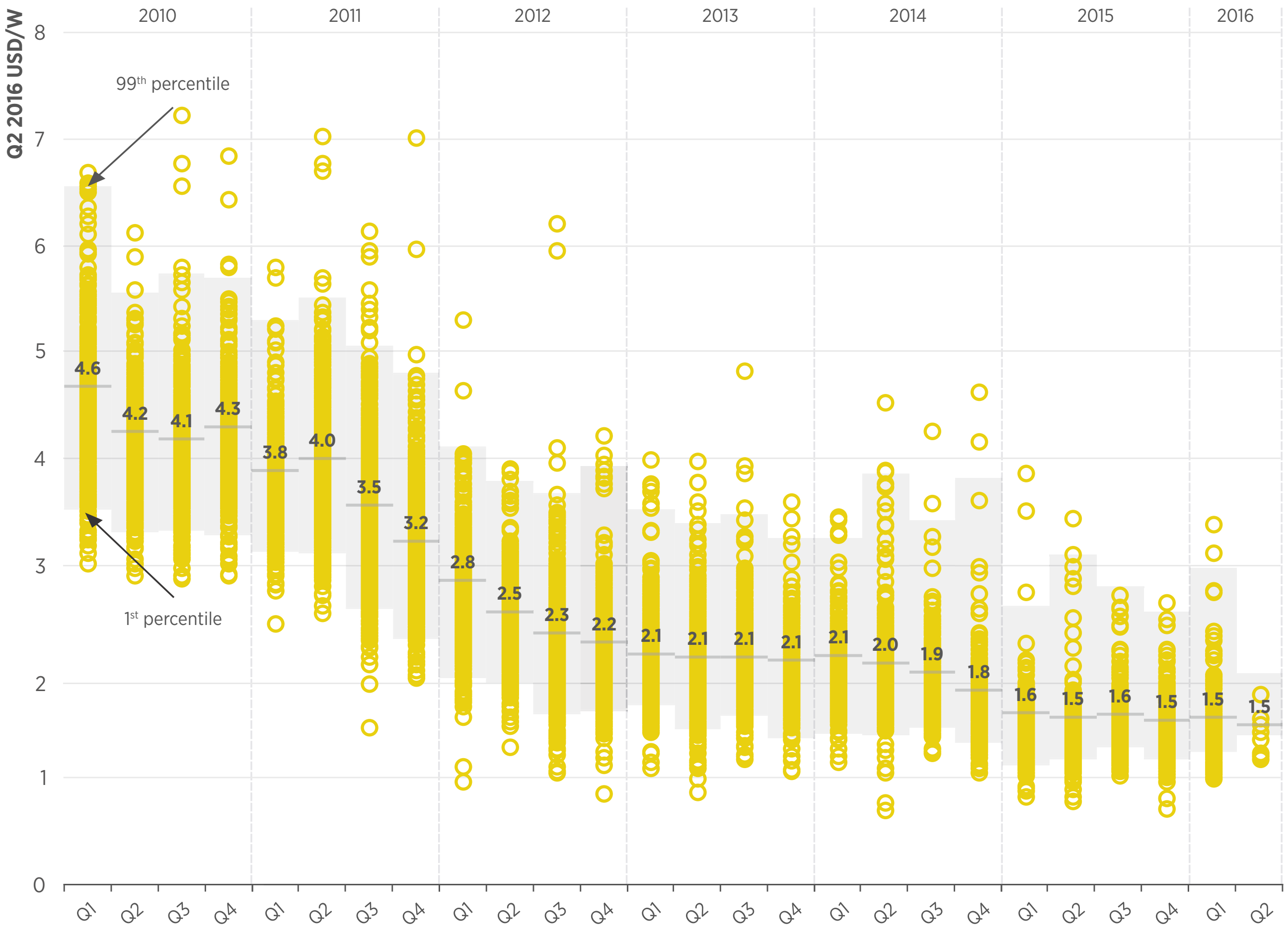
During the period displayed in Figure 40, 84% of the cumulative installed volume in the residential (below 10 kW) segment occurred in system sizes above 5 kW. During each year between 2013 to 2016, systems between 9 kW and 10 kW represented more than 30% of the installed volume in the residential segment. The median system size for the under 10 kW residential segment from 2010 to 2016 was 6.4 kW, and this experienced little change year-on-year.

The German Renewable Energy Act has been revised by the government on various occasions. The newer revision in effect from January 2017 and known as the EEG 2017 establishes an annual solar PV target of 2.5 GW. FITs with 20 years' duration continue to be in place for newly installed residential PV systems and for all newly installed systems up to 100 kW. New systems between 100 kW and 750 kW of capacity are required to sell their energy through direct marketing and are remunerated through the market premium model. Ground-mounted systems above the 750 kW threshold need to participate in a competitive auction model through which the level of funding is stipulated (BMWi, 2017; Bundesnetzagentur, 2017; Fraunhofer ISE, 2017).

PV system costs in Germany

This analysis is based on a dataset of offers presented by installers to end-customers that contains more than 19 000 records with cost data from 2010 to Q2 2016 (EuPD Research, 2017a). This rich dataset contains a wide range of information, from proposed module choice and location, to anticipated commissioning date. The dataset also includes responses to questions about financing costs and other variables. It shows that the median installed residential cost in Germany decreased from USD 4.68/W in Q1 2010 to USD 1.50/W in Q2 2016, a 68% decrease (Figure 41).

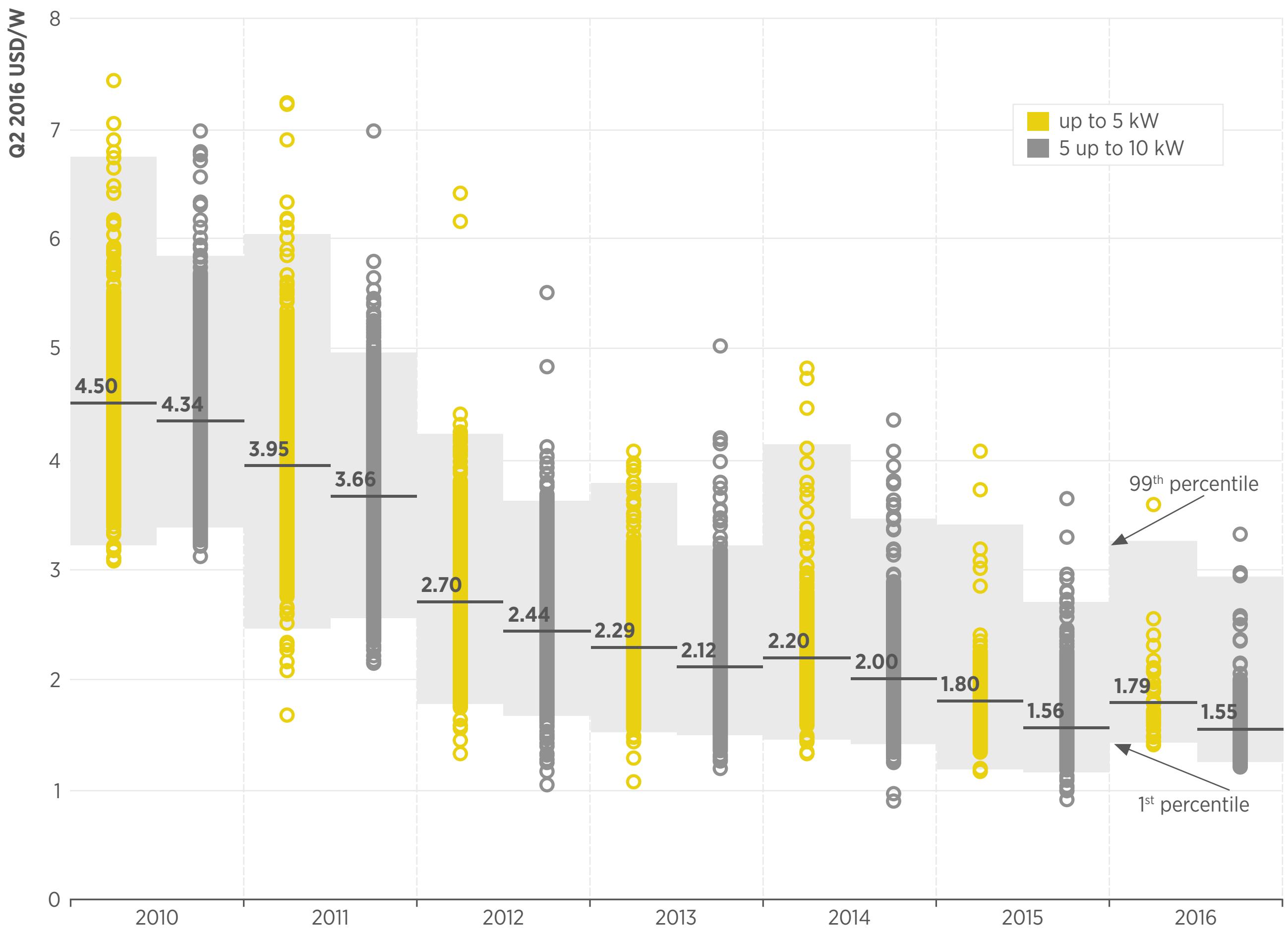
Figure 41: Residential PV system costs in Germany



Source: IRENA analysis based on EuPD Research, 2017a.

Small economies of scale are observed in the residential segment in Germany. In 2010, for example, the median cost of PV systems in the 5–10 kW class was 4% lower than the median of the smaller, sub-5 kW size category. With time, this difference has increased and ranged between 7% and 9% during 2011–2014, while during 2015 and early 2016 it reached around 14%. The median installed residential cost for systems in the small category decreased from USD 4.50/W in 2010 to USD 1.79/W in 2016 (a 60% decrease). The median cost for the larger 5–10 kW class experienced a 64% reduction during the same period[46], from USD 4.34/W to USD 1.55/W in 2016 (Figure 42).

Figure 42: Residential PV system costs in Germany by size category

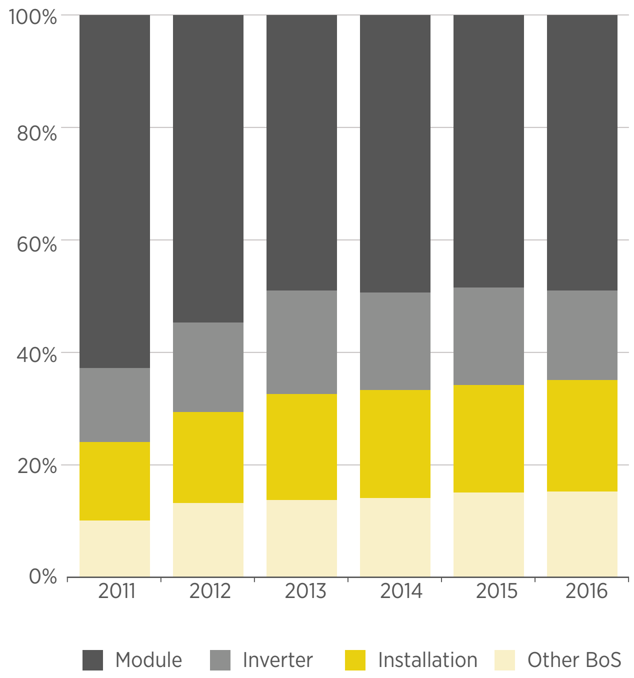


Source: IRENA analysis based on EuPD Research, 2017a.

46 Includes Q1 2016 and preliminary Q2 2016 data.

Data from a survey of German installers show that the contribution of the module to total system costs declined from 63% in 2011 to 49% in 2016. This highlights the increasing importance of balance of system costs in more mature markets. The combined contribution of the installation and balance of system cost components increased from 24% in 2011 to 35% in 2016. The inverter's contribution also increased, if more moderately, from 13% to 16%, over the same time frame (Figure 43).

Figure 43: Distribution of main cost components for residential PV systems in Germany, 2011–2016

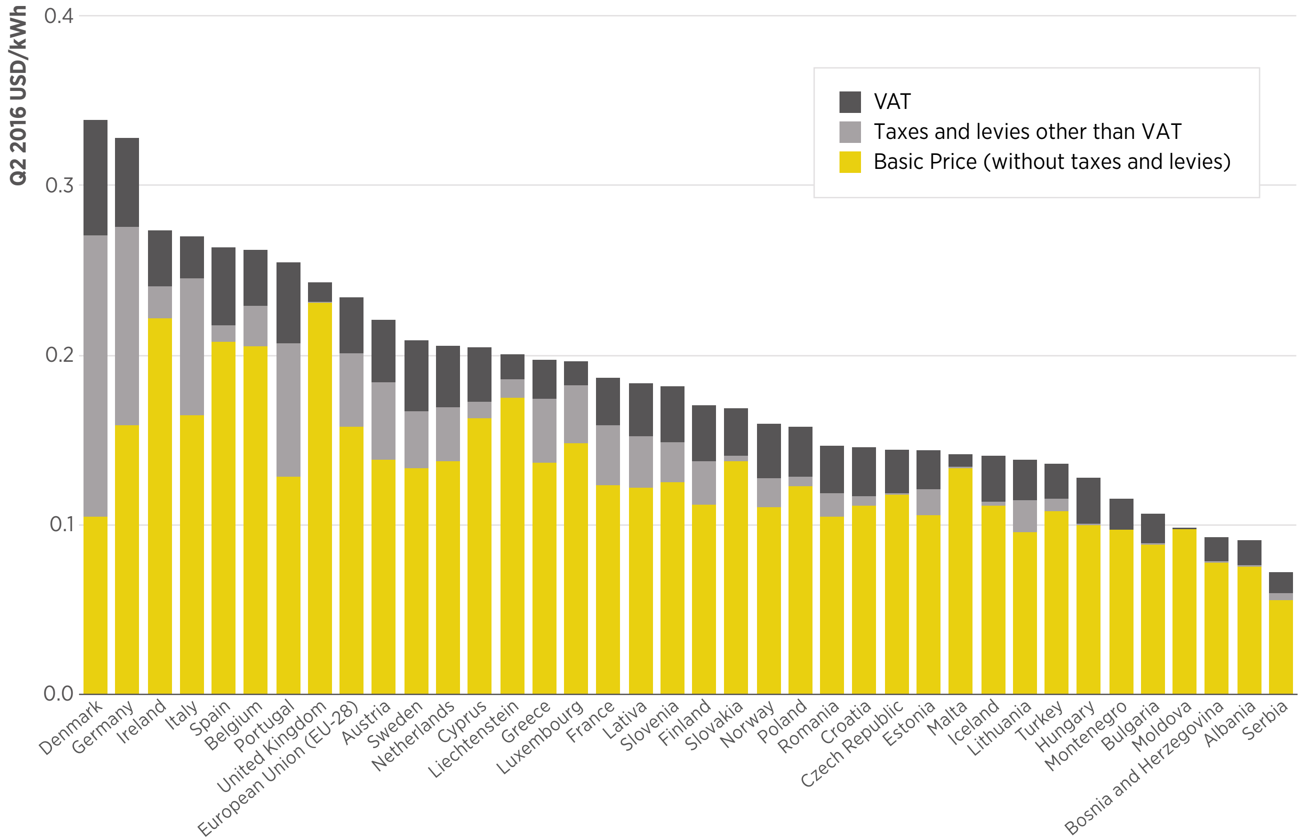


Source: IRENA analysis based on EuPD Research, 2016.

Conventional residential electricity rates

Germany has some of the highest residential electricity prices in Europe. This is due in large part to the level of taxes and levies borne by residential consumers.

Figure 44: Electricity prices in Europe[47], H2 2016



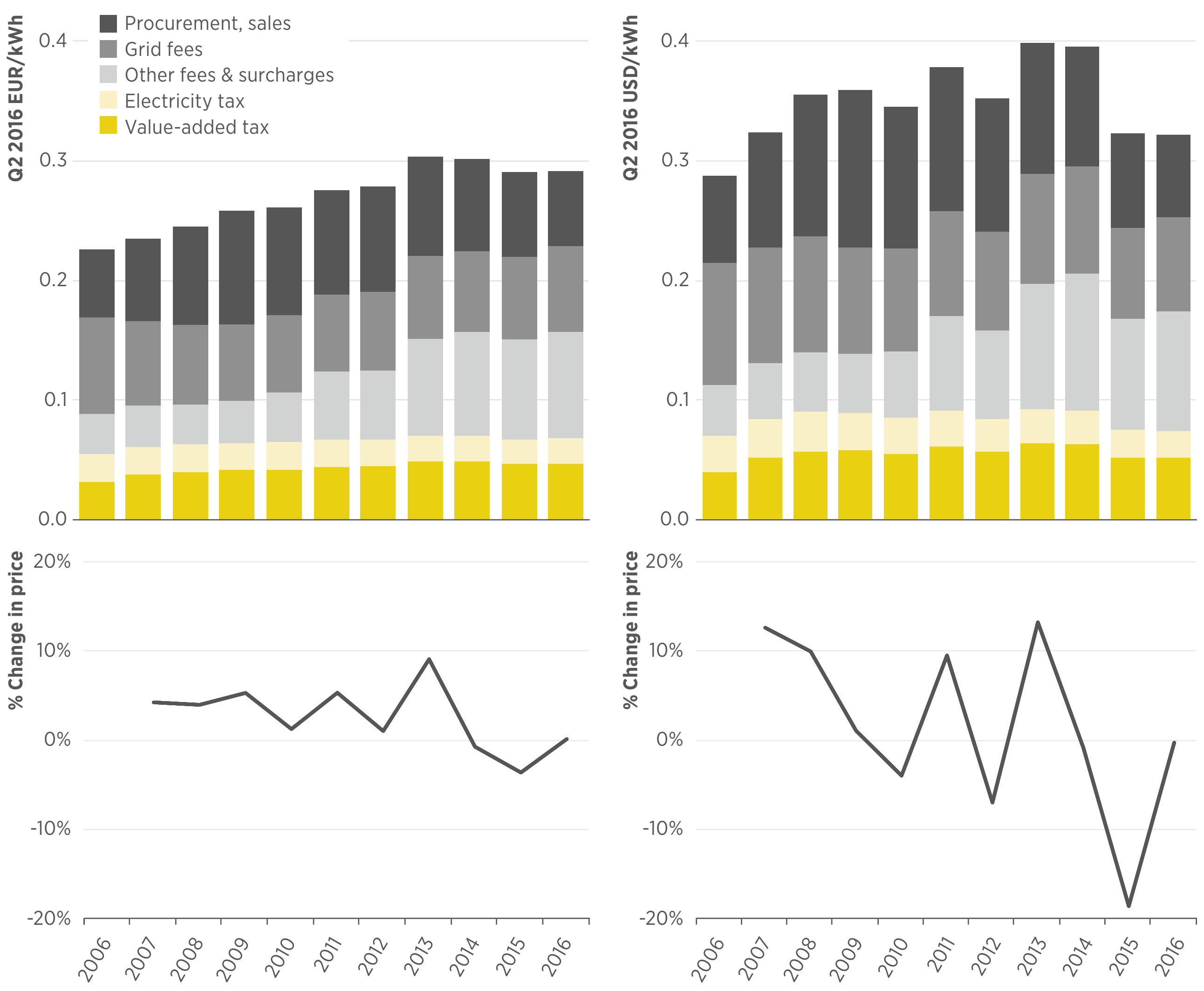
Source: IRENA analysis based on Eurostat, 2016a.

47 The designations employed and the presentation of materials in this report do not imply the expression of any opinion whatsoever on the part of the International Renewable Energy Agency concerning the legal status of any country, territory, city or area or of its authorities, or concerning the delimitation of its frontiers or boundaries.

The German Association of Energy and Water Industries (BDEW) keeps a dataset with electricity prices that can provide deeper insights into the breakdown of the electricity cost structure in Germany.[48]

Although a detailed analysis of electricity price structures in the country is beyond the scope of this report, Figure 45 shows the key cost groups in recent years, expressed in both real Q2 2016 EUR and real Q2 2016 USD per kWh, along with the year-on-year percentage changes for each.

Figure 45: Household electricity prices in Germany by cost groups and year-on-year percentage change, 2006–2016



Source: IRENA analysis based on BDEW, 2016a.

48 Some cost components vary by region according to local tariffs and specific grid areas. Shown here, however, are the federal weighted average rates (excluding “special” tariffs such as “green electricity tariffs”, “heating tariffs”, etc.).

In real Q2 2016 EUR terms, the electricity price in the BDEW dataset (all taxes and levies inclusive) grew from EUR 0.23/kWh in 2006 to EUR 0.29/kWh in 2016 (a 48% increase). The latter corresponds to a 2016 value of USD 0.32/kWh in real USD terms.

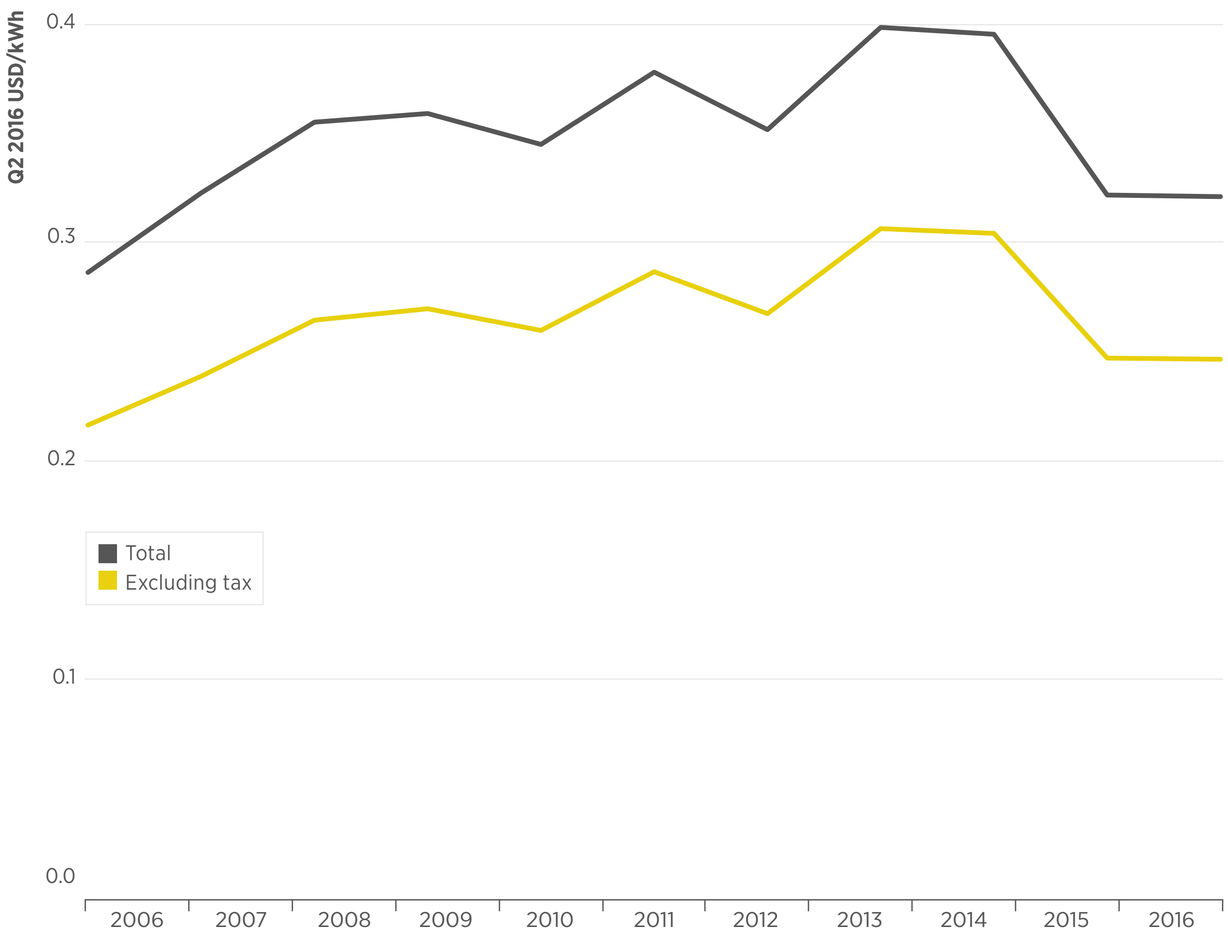
The development of the following cost component groups has been as follows:

- Procurement/sales: supplier's acquisitions cost for procuring wholesale power on the market and the profit margin. This component is shaped by competition among electricity providers and wholesale power costs. They accounted for between 21% and 37% of total costs during 2010–2016 (21% in 2016). This component is not regulated by the state in any way.
- Grid fees: Charges for use of the power grid, which are set by the Federal Network Agency, *Bundesnetzagentur* (BNetzA). The category also includes charges for reading, invoicing and metering point operation. Grid fees accounted for between 23% and 36% of total costs during 2010–2016 (25% in 2016).
- Electricity tax: introduced in 1999 via the Electricity Tax Law (*Stromsteuergesetz*), which aimed to support climate policy through a more economical use of electricity. Tax revenue is partially used to reduce the contribution rates for social security.
- Value-added tax: This turnover tax applies also to services supplied by businesses to customers (as defined under the 1994 Turnover Tax Act). For electricity, it is set at 19% and applies to the total amount, made up of generation, supply, network tariffs and other state-introduced cost components.

During the 2006–2016 period shown, taxes[49] represented between 23% and 26% of the total electricity cost (Figure 46).

In the following IC&CI analysis section for the German locations, electricity prices are presented with and without these tax-related cost components.

Figure 46: Household electricity prices in Germany with and without tax component, 2006–2016



Source: IRENA analysis based on BDEW, 2016a.

49 The "value-added tax" and "electricity tax" cost components are considered as tax components in the analysis.

The remaining electricity cost components in Figure 45 are displayed together under the "other fees and surcharges" group. As with the "grid fees" and "tax" components, components under this cost group are set by the federal government or one of its entities. The group can be broken down further into the following individual cost components, which also are displayed in Figure 47:

- **EEG surcharge (*EEG Umlage*):** Originally, the Renewable Energies Act (EEG) gave power plant operators a fixed tariff for every kWh of renewable power that they fed into the grid over a 15- or 20-year period. The tariff was paid by a transmission system operator (TSO), which then sold the power on to a power exchange. Since 2012 (EEG 2012), operators also could opt for a market premium instead of the fixed FIT. In this case, the operators, or specialised traders (direct marketers), sold the electricity themselves and received a premium from the TSO that was equal to the EEG tariff minus the market price.

  After the entry into force of the EEG 2014 (in August 2014) all new plants above 500 kW in size were under an obligation to directly market their electricity. This did not, however, apply to the existing plant stock (it did not apply retroactively).[50] The difference between the expenses for all types of remuneration payments made out to EEG plant operators and the TSOs' income from sales revenues of the EEG electricity in the wholesale market (also known as "EEG differential costs") is divided up across the EEG-liable power consumers.[51] The resulting amount is the EEG surcharge. Since the determination of the electricity generation from EEG subsidised plants and the remuneration costs have their own uncertainty and the electricity price in the wholesale market do not depend only on the renewable capacity, a special balance account with a cash reserve is held to balance out discrepancies between forecasted versus actual TSO revenues and payments discrepancies.[52]

  Every year, no later than 15 October, in consultation with recognised research institutions, Germany's four TSOs forecast their expected EEG compensation and their expected revenues from the sale of power into the power exchange. The EEG surcharge for 2017 has been set at EUR 0.069/kWh (an 8% increase from EUR 0.064/kWh[53] in 2016). The sum of the electricity price and the EEG surcharge, however, which is relevant to the electricity consumer, decreased about 1% (BMWi, 2016b). EEG surcharge costs accounted for 21% to as much as 75% of total "other fees and surcharges" costs during 2010–2016 (72% in 2016).

- **Concession Levy (*Konzessionsabgabe*):** This is for the use of public rights of way and is paid by grid operators to municipalities. Within this cost group, in 2016 the concession levy reached its lowest relative contribution, at 19%. Yet it also represented 52% to 58% of the group's total costs during the 2006–2009 period.

- **CHP Surcharge (*KWK-Aufschlag*)**: This was introduced in 2002 via the Combined Heat and Power Act (*KWK-Gesetz*). Combined heat and power (CHP) plant operators can qualify to receive premiums for CHP power, if they satisfy certain criteria. During the last decade, the relative contribution to the cost group of this surcharge has not exceeded the 2006 level of 12% and was at 5% in 2016.

- **Section 19 subsection 2 Electricity Network Charges Ordinance Levy (*§ 19 Abs.2 StrmNEV-Umlage*):** Introduced in 2012, this allows electricity consumers that fulfil certain criteria to request an individual grid fee (which may be lower than the typical grid fees). This may result in losses to distribution system operators (DSOs) and TSOs, which are both required to balance this fee between them. The resulting lost revenue is distributed among consumers in the form of this levy. Within its cost group, the levy represented between 1% and 4% of the group's total costs during the 2006–2016 period.

- **Offshore Liability Levy (*Offshore-Umlage nach § 17f Energiewirtschaftsgesetz, EnWG*):** This was introduced in 2013 to provide clarity between the compensation paid to TSOs and to plant operators. Grid operators must pay compensation due to delays or technical problems with their connections to offshore wind energy plants. The levy allows part of these costs to be passed on to consumers. The levy is capped at EUR 0.0025/kWh. In 2016, the levy's value was EUR 0.0004/kWh. This levy once reached a maximum contribution to the cost group of 3%, but in 2016 it contributed only 0.5% to the total "other fees and surcharges" costs.

- **Interruptible Loads Levy (*§ 18 AbLaV-Umlage*)**: Started in 2014, the purpose of this levy is to cover the costs of interruptible loads which support grid and system reliability. The levy's contribution to the "other fees and surcharges" cost group has not exceeded 0.11%, and its value was zero during 2016.

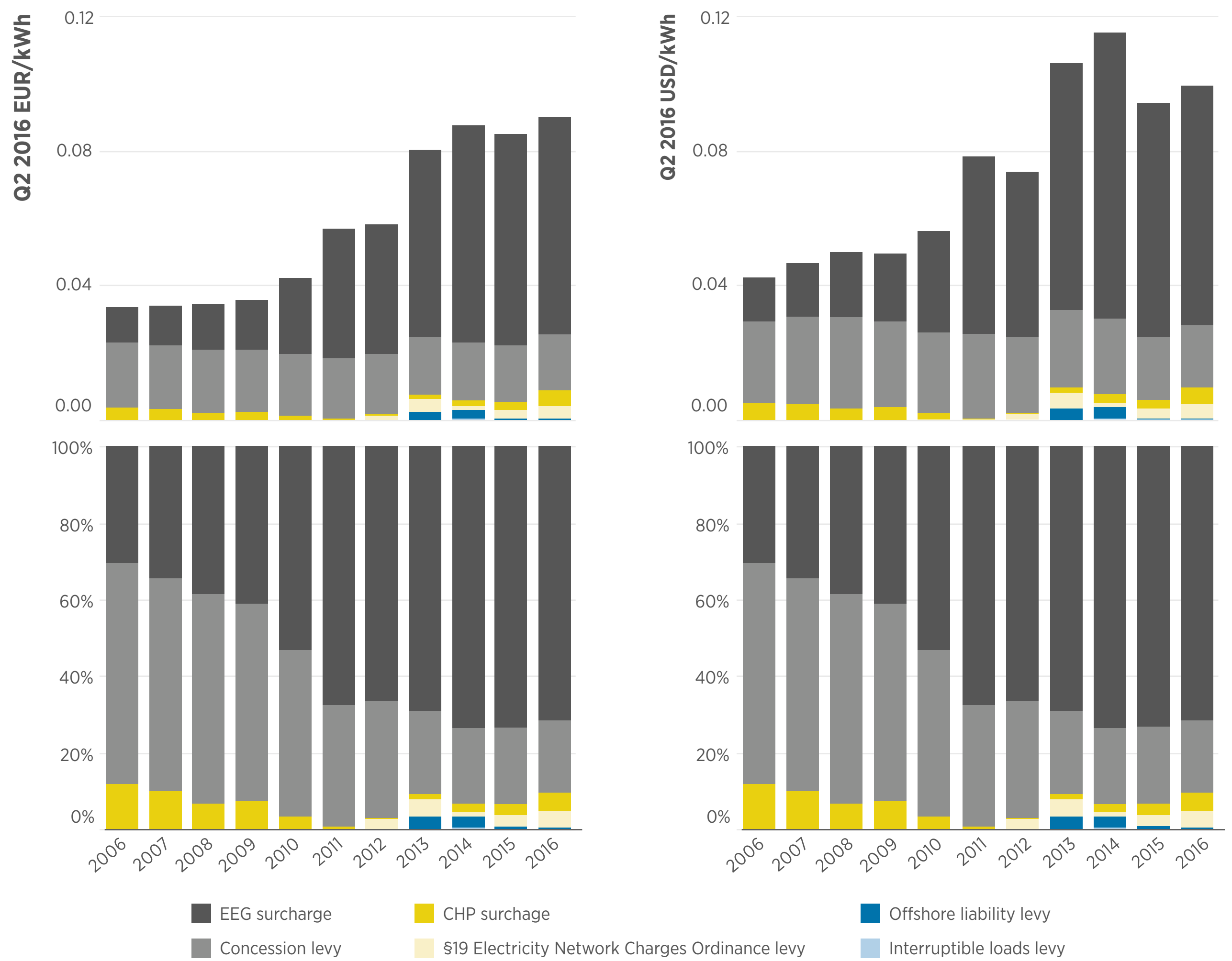
50 Since January 2016, new plants above 100 kW are obliged to participate in the direct marketing model.
51 Only the EEG-liable consumers are charged (that is, those who are not fully or partially exempted from the EEG surcharge under special regulations).
52 The liquidity reserve is set to be able to balance up to 10% of the difference between revenues and payments.
53 In nominal terms.

In terms of contributions to the total electricity cost, the most relevant cost components within the "other fees and surcharges" group have been the EEG surcharge and the concession levy. The EEG surcharge has contributed between 5% and 22% to the total electricity cost (22% in 2016), while the concession levy has accounted for between 6% and 9% of the total electricity cost (6% in 2016).

Among all "other fees and surcharges" cost categories, the EEG surcharge changed the most between 2006 and 2016, increasing more than four-fold during that period. In real terms, the absolute EEG surcharge change from 2006 to 2016 was USD 0.06/kWh (EUR 0.05/kWh). A recent projection sees the EEG surcharge continuing to increase up until 2022 to a value of EUR 0.072/kWh and starting to decrease from that year onwards to a value of EUR 0.053/kWh in 2030 (Agora, 2016).

From 2006 to 2016, in real USD and real EUR terms, the "grid fees" category decreased 23% and 11% respectively. The Section 19 subsection 2 Electricity Network Charges Ordinance levy and the Offshore Liability Levy do not appear in the 2006 data, since they were introduced only in 2012 and 2013, respectively.

Figure 47: Other fees and surcharges in household electricity prices in Germany



Source: IRENA analysis based on BDEW, 2016a.

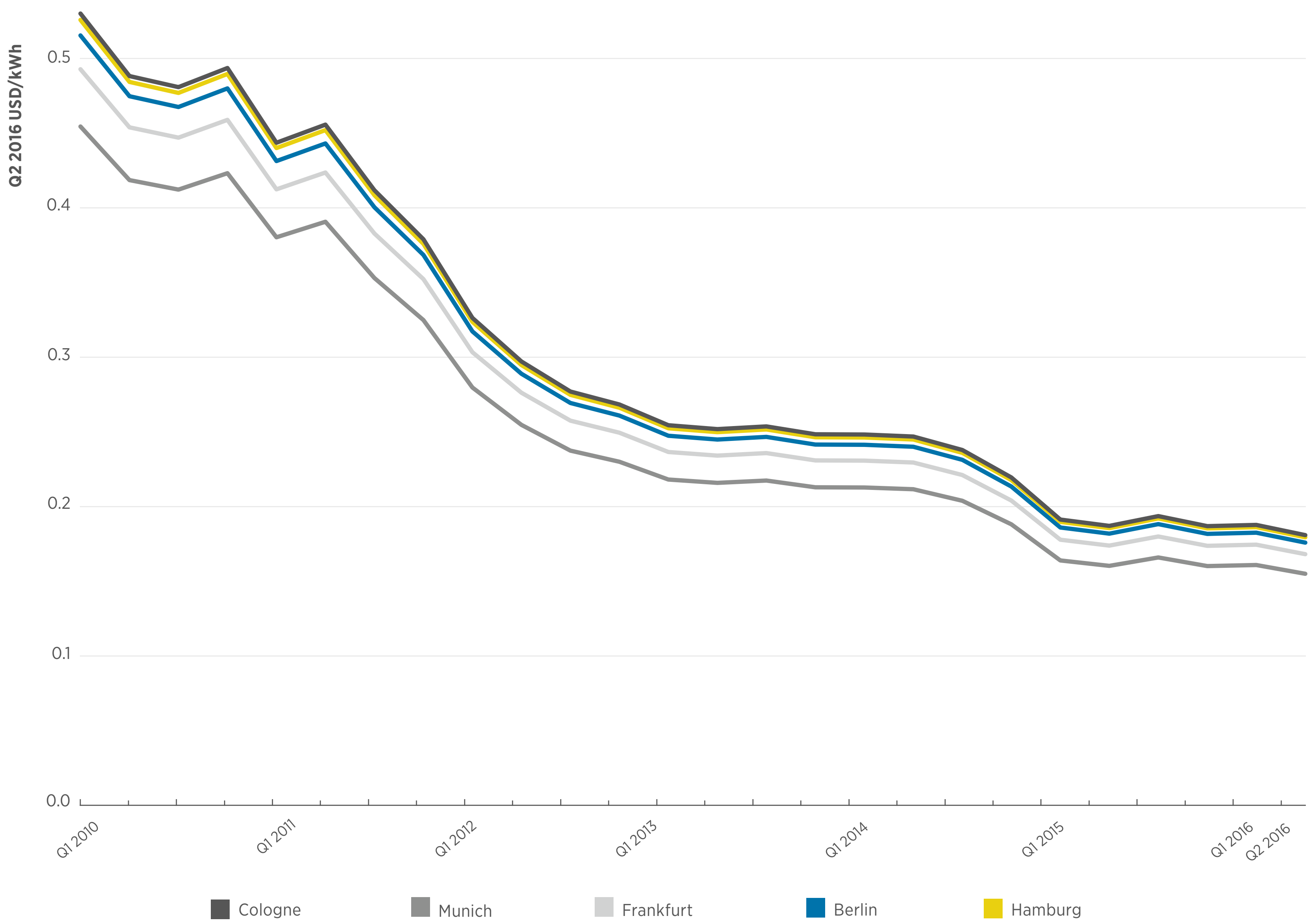
IC&CI ROOFTOP SOLAR PV ANALYSIS:

MAJOR METROPOLITAN AREAS IN GERMANY

SUMMARY LCOE RESULTS

The residential PV LCOE for the five largest populated metropolitan areas in Germany has been calculated on the basis of the total installed costs previously discussed. Based on the median capital costs, the LCOE results ranged from USD 0.45–0.53/kWh in Q1 2010 to a narrower range of USD 0.16–0.18/kWh during Q2 2016. This amounts to a 66% LCOE reduction during the period under consideration (Figure 48).

Figure 48: LCOE of residential PV in different locations in Germany



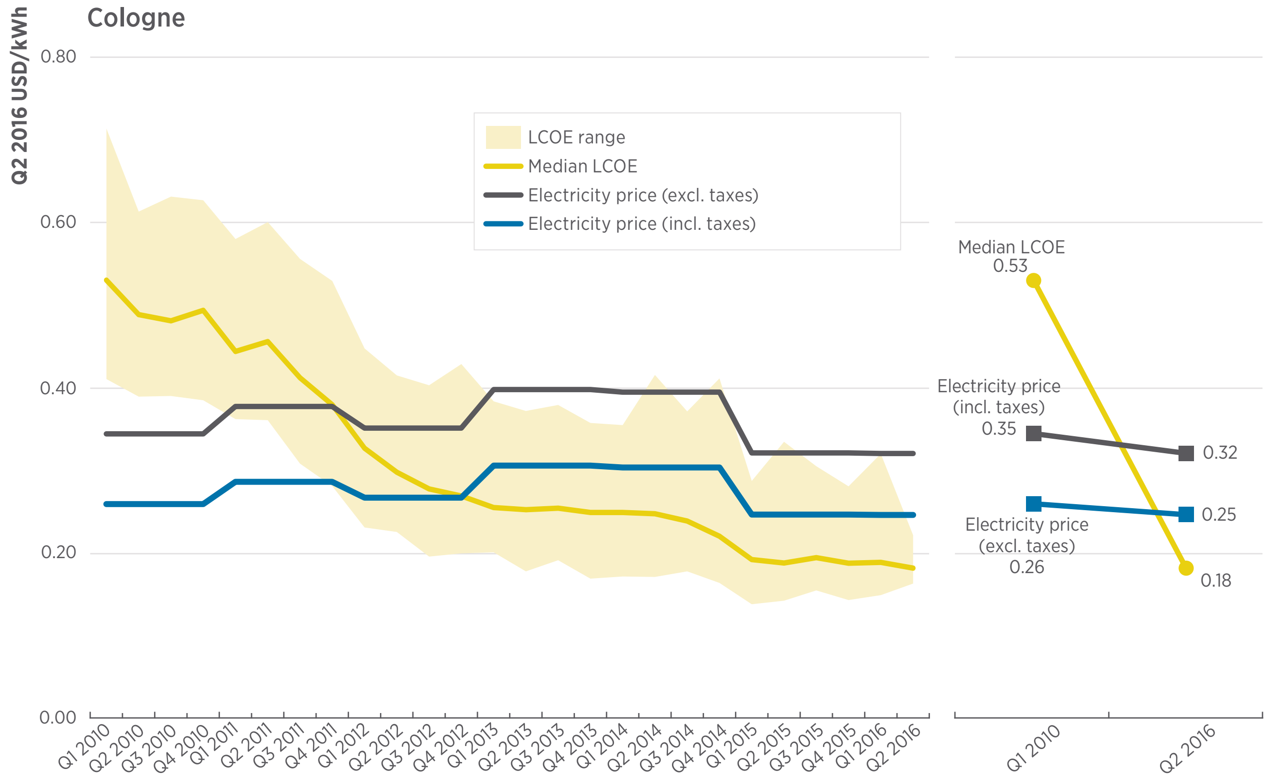
Source: IRENA analysis based on EuPD Research, 2017a and BDEW, 2016a.

The following sub-sections summarise the results for each of the locations evaluated. They compare the PV LCOE range and the electricity price[54] development from Q1 2010 to Q2 2016 expressed in real USD terms from Q2 2016.

Cologne

The residential PV LCOE value estimated for Cologne decreased from USD 0.41–0.71/kWh in Q1 2010 to a range[55] of USD 0.16–0.22/kWh during Q2 2016 (Figure 49).

Figure 49: Cost and Competitiveness Indicators in Cologne



Source: IRENA analysis based on EuPD Research, 2017a and BDEW, 2016a.

54 The LCOE range for each location is estimated with the same country-level capital expenditure dataset, without accounting for regional differences. The same applies for electricity prices. See Annex III: Germany for a more detailed discussion of the methodology.

55 Ranges are calculated using the first and ninety-ninth percentile of the installed costs time series (as with the locations in the US).

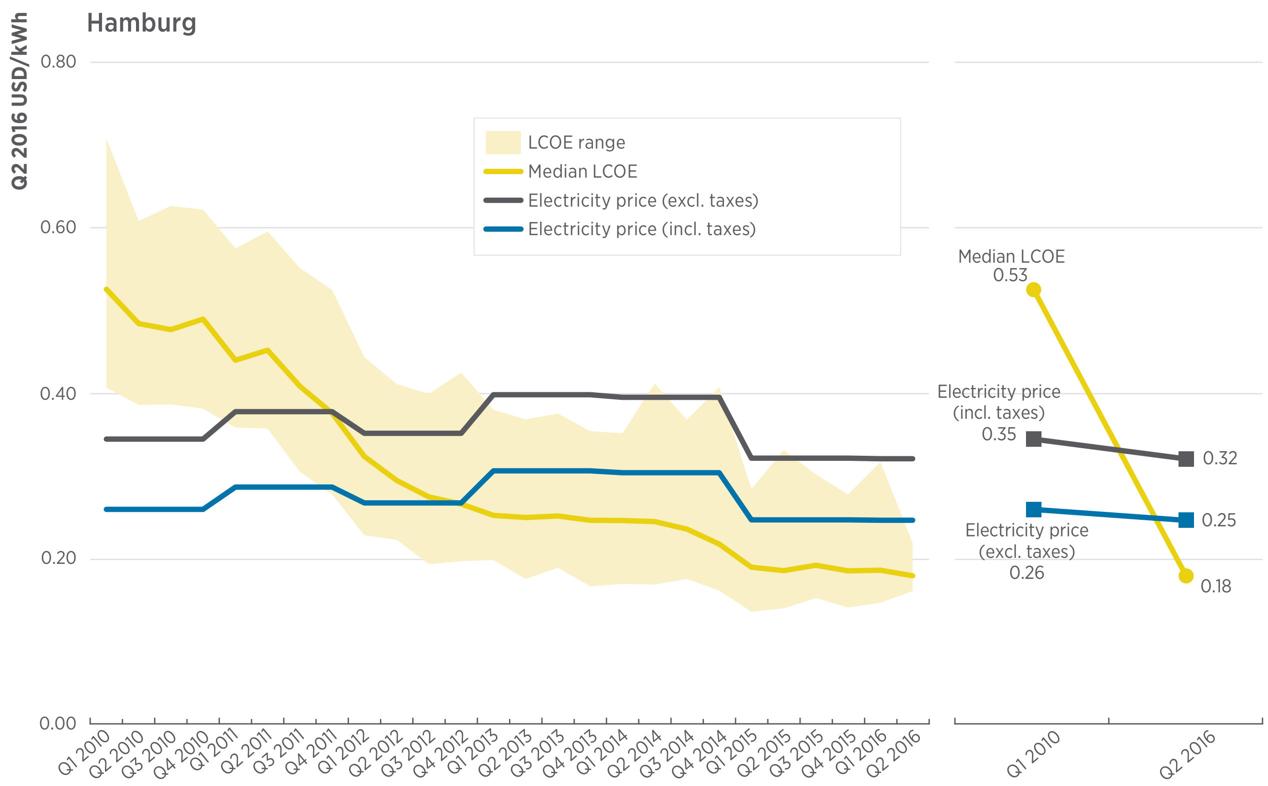
The estimated LCOE fell below the electricity tariff in Q4 2012 in that region (excluding the tax cost components of the electricity price). From Q1 2010 to Q2 2016, the central LCOE estimate in Cologne decreased from USD 0.53/kWh to USD 0.18/kWh.

The difference between the central LCOE estimate and the electricity price (without tax components) amounted to USD 0.07/kWh during Q2 2016.

Hamburg

The residential PV LCOE estimate for Hamburg decreased from a range of USD 0.41 to USD 0.71/kWh in Q1 2010 to a range of USD 0.16 USD 0.22/kWh during Q2 2016. The region presents very similar results to Cologne, and from Q1 2010 to Q2 2016, the central LCOE estimate in Hamburg also decreased from USD 0.53 to USD 0.18/kWh (Figure 50).

Figure 50: Cost and Competitiveness Indicators in Hamburg

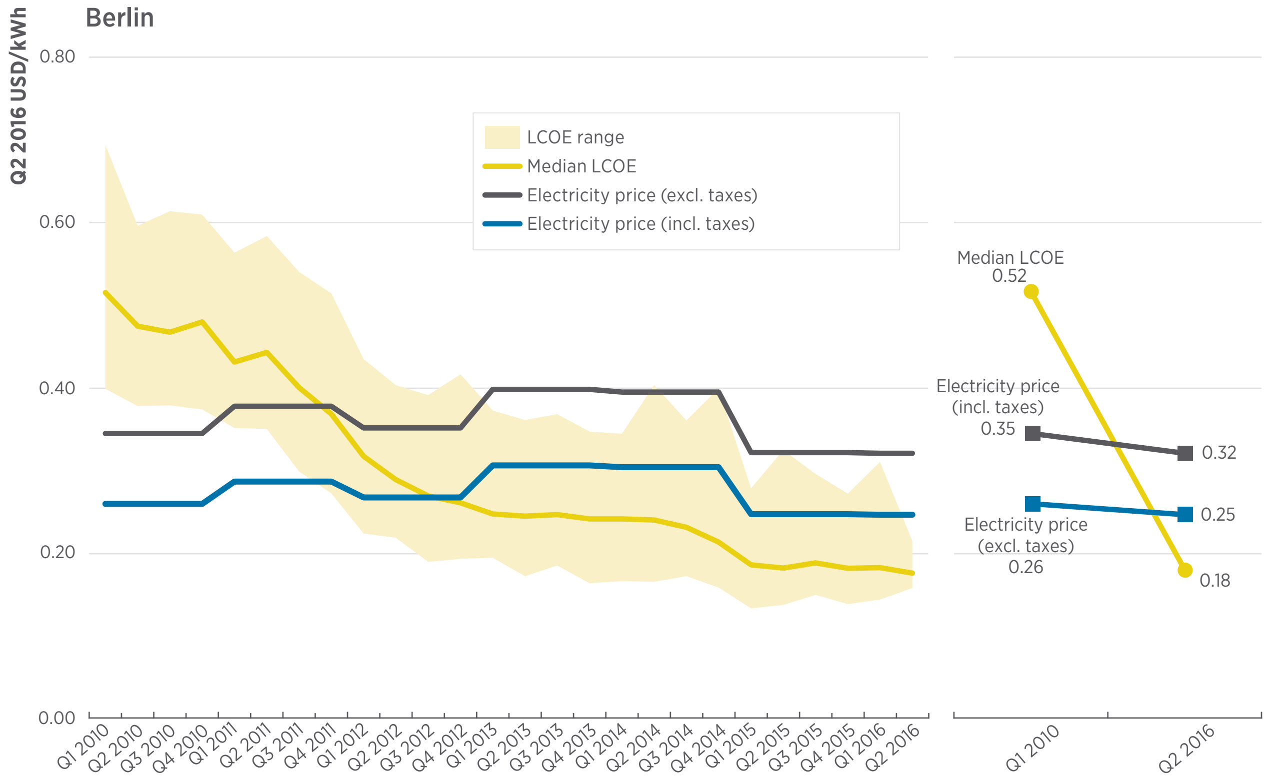


Source: IRENA analysis based on EuPD Research, 2017a and BDEW, 2016a.

Berlin

The residential PV LCOE for Germany's capital city decreased from a range of USD 0.40 to USD 0.69/kWh in Q1 2010 to a range of USD 0.16 to USD 0.22/kWh during Q2 2016. During this time frame, the central LCOE estimate in Berlin decreased from USD 0.52 to USD 0.18/kWh. These results suggest that, excluding the effect of the tax components on the electricity price, the estimated LCOE of residential solar PV fell below tariff levels in Berlin as early as Q4 2012 (Figure 51).

Figure 51: Cost and Competitiveness Indicators in Berlin

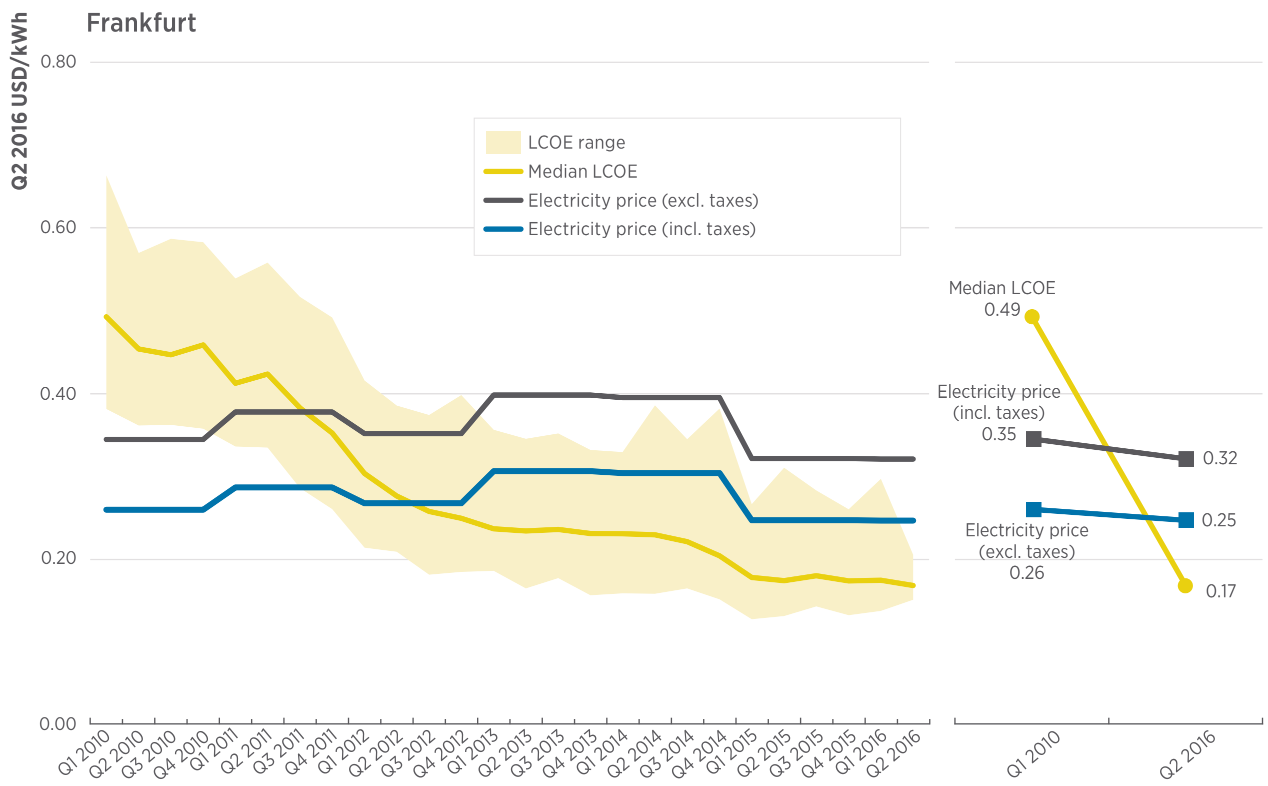


Source: IRENA analysis based on EuPD Research, 2017a and BDEW, 2016a.

Frankfurt

In the case of Frankfurt, the residential solar PV LCOE estimate fell below tariff levels three months before that (taking as a reference the electricity price without taxes). With slightly better irradiation levels, the residential PV LCOE in Frankfurt decreased from USD 0.38 to USD 0.66/kWh in Q1 2010 to a range of USD 0.15 to USD 0.21/kWh during Q2 2016. During this period, the central LCOE estimate in Frankfurt decreased from USD 0.49 to USD 0.17/kWh. The difference between the central LCOE estimate and the electricity price (without tax components) amounts to USD 0.08/kWh during Q2 2016 (Figure 52).

Figure 52: Cost and Competitiveness Indicators in Frankfurt



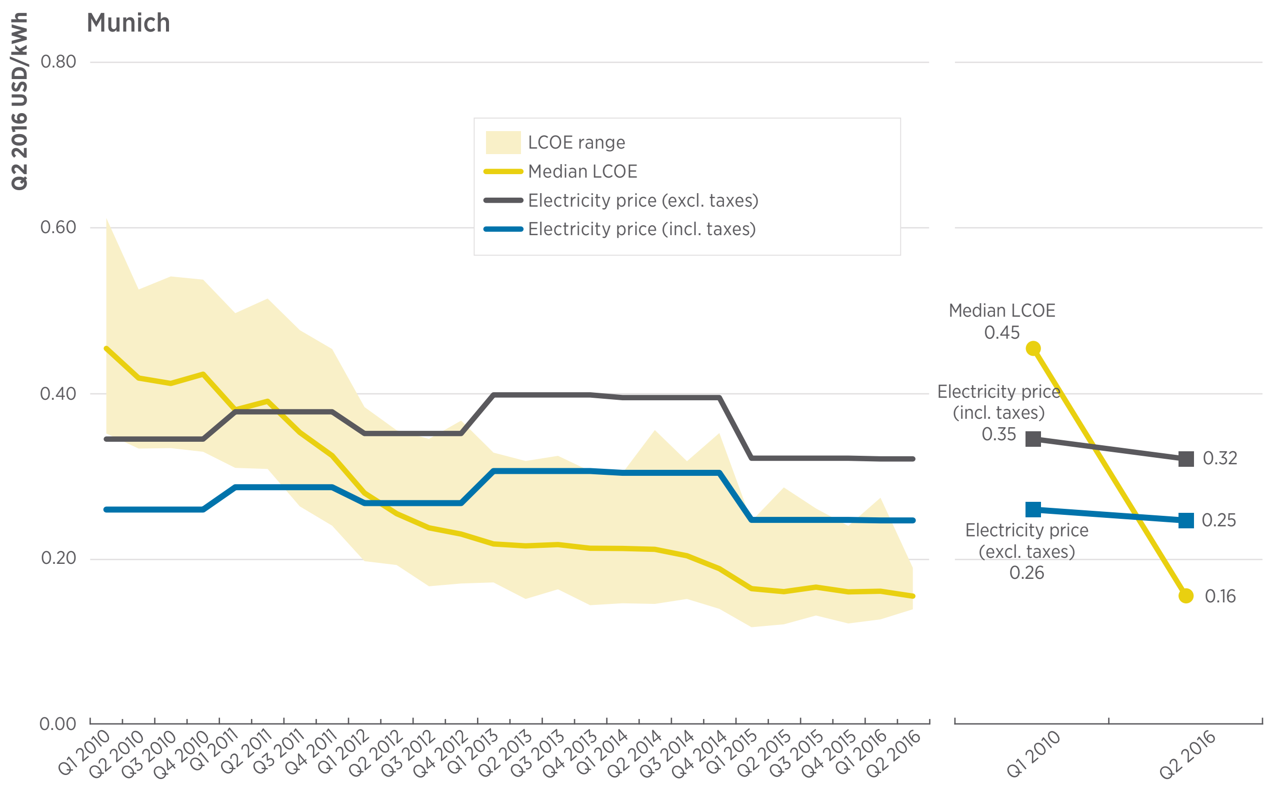
Source: IRENA analysis based on EuPD Research, 2017a and BDEW, 2016a.

Munich

With the highest irradiation of the locations evaluated in Germany, Munich has the lowest LCOE levels for solar PV.

The city's residential PV central LCOE estimate was calculated at USD 0.16/kWh during Q2 2016. This represents a USD 0.09/kWh difference from the "no taxes" electricity rate and a USD 0.30/kWh difference from the central LCOE estimate, during Q1 2010. The residential PV LCOE estimate fell below tariff levels in Munich as early as Q2 2012, taking as reference the "no taxes" electricity price (Figure 53).

Figure 53: Cost and Competitiveness Indicators in Munich



Source: IRENA analysis based on EuPD Research, 2017a and BDEW, 2016a.

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ANNEX I: METHODOLOGY

This Annex presents the general methodology applied throughout the IC&CI series. Should the methods of analysis for a specific metropolitan area deviate from this general approach, this will be properly noted in the subsequent Annex sections, which contain more specific information on the assumptions and data collection for each edition of the IC&CI analysis.

For simplicity, only the solar PV LCOE and the retail electricity prices of the respective locations are compared and closely monitored, to indicate the trend of PV competitiveness.

The LCOE of solar PV, without financial support and excluding taxes, is calculated over the period during which solar PV generates electricity.

LEVELISED COST OF ELECTRICITY FOR SOLAR PV

In line with other studies within IRENA's cost analysis programme, the formula used in this report for calculating the LCOE is:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

LCOE = the average lifetime levelised cost of electricity generation [USD/kWh];

I = investment expenditures in year t [USD];

M_t = operations and maintenance (O&M) expenditures in year t (includes insurance costs) [USD];

F_t = fuel expenditures in year t [USD].

E_t = electricity generation in year t [kWh] (AC output, after inverter losses);

r = discount rate; and

n = life of the system.

The LCOE gives an idea of the cost of electricity produced by the PV system and is often used to compare different energy generating systems.

There are different ways to calculate the LCOE with a variety of variables that can be considered. The approach taken in this case, however, is based on a discounted cash flow (DCF) analysis and kept simple for easier understanding and higher transparency.

Unless otherwise stated for a specific metropolitan area or edition, the following assumptions are made for the LCOE calculation throughout the IC&CI analysis series:

- The discount rate (r) is 5%.
- The PV system has a useful economic lifetime (n) of 25 years.
- The inverter is replaced once during a PV system's lifetime at t = 15 years.
- PV degradation is assumed to be 0.5% per year.
- Unless more specific, reliable data for insurance costs can be found for a certain metropolitan area, these are assumed at: 1% of installation cost per year (see also Annex II).
- Unless more specific, reliable data for O&M costs can be found for a certain metropolitan area, an estimated reference level is derived from the next higher geographical level of data available (also see Annex II).

All values in this report are expressed in real terms (i.e., taking into account inflation) except where explicitly mentioned. The analysis does not include any estimates of the impact of any incentives or subsidies for solar PV on the LCOE. Similarly, the analysis does not take into account any of the avoided externalities from incumbent electricity generators displaced by solar PV (e.g., from avoided carbon dioxide emissions and local pollution health costs).

Location-specific capacity factors and hourly output from the specific PV system have been calculated using an indicative resource for the city modelled. The AC output of the PV system (the output after PV inverter losses) is used in all cases.

Investment costs

For every location analysed, total installed system costs are taken from the best source available, since these costs are an important driver for LCOE results. Primary data sources are always preferred over secondary.

PV installation costs refer to the installation of the entire PV system. This includes components such as modules, inverters, support structures and installation labour costs.

In each quarter of each year and for each metropolitan area examined, three LCOE calculations were made using three different corresponding investment cost references, taken from the available primary dataset (Table 4).

Table 4: Investment cost references used to calculate LCOE in the IC&CI analysis

	Reference		
	Low	**Median**	**High**
Used investment costs	1^{st} Percentile	50^{th} Percentile	99^{th} Percentile

For the time being, these LCOE calculations were made for a unique residential size category of systems (and systems above 20 kW are excluded from the analysis). Future editions or studies, however, might explore more detailed cost analyses that assess the effect of system size within more granular categories.

Appropriate assumptions for inverter replacement costs in year t = 15 are made for each metropolitan area examined and can be found in the subsequent annexes.

Maintenance costs

Residential PV systems are characterised by very low operating costs, which usually comprise just a few hours per year of regular maintenance of the modules (e.g., cleaning) and inverters.

Insurance costs may vary by region, but for residential systems, annual insurance costs of 1% of installed cost are assumed, unless more specific regional data is available.

Fuel costs

Fuel costs are assumed to be zero in this analysis.

PV electricity generation

The performance of the PV system and its yearly electricity generation was estimated using software developed by the US National Renewable Energy Laboratory (NREL). The System Advisor Model (SAM) software[56] has weather files available for a wide range of locations and is a renewable energy focused performance and financial model. It calculates PV output as well as levelised costs based on the provided financial input assumptions (NREL, 2014a).

The software contains various performance models, but for simplicity, SAM's PVWatts performance model is used. This model (as with other SAM models) uses data from a weather file to represent the renewable resource and ambient weather conditions that affect the system's performance. A SAM weather file contains one year's worth of data, with this describing the solar resource, wind speed, temperature and other weather characteristics at a particular location. This is based on a "typical meteorological year".

An hourly simulation is run for the purpose of this analysis. The simulation takes into account module degradation over time, assuming a set decline of 0.5% per year. Specific details on the weather files used for each edition can be found in the following annexes.

56 Detailed documentation of NREL's SAM software can be found at: https://sam.nrel.gov/sites/sam.nrel.gov/files/content/documents/pdf/sam-help.pdf.

Table 5 displays the characteristics of the standard crystalline module used in the PV output calculations during this analysis, in accordance with the selected PVWatts performance model.

Table 5: Module characteristics assumed for the PV output calculation

Module type	Approximate nominal efficiency	Module cover	Temperature coefficient of power
Standard (crystalline silicon)	15%	Glass	-0.47%/°C

Source: NREL, 2014b.

A fixed roof-mount PV system and default system losses of 14.8%, along with SAM's default DC-to-AC ratio of 1.1, were used to estimate the PV output.

Real vs. nominal dollars in LCOE calculation

In IRENA reports, LCOEs and installed cost data are presented in real currency terms (that is to say, after inflation has been taken into account for the costs). An alternative to this approach is to use the nominal dollar value of the LCOE (the value expressed in terms of the specific years to which the LCOE refers, without adjusting for inflation).

The appropriate choice of real or nominal depends on the analysis but should be kept consistent. Since the purpose of this report is to indicate PV competitiveness trends – which involves comparing the LCOE of residential PV systems with the prevailing retail electricity rates – and since the real terms provide more consistent comparability for cost reduction trends analysis, the IC&CI analysis for each metropolitan area is presented here in real, Q2 2016 USD. Prices also are benchmarked to their values in that quarter. Electricity rates in the analysis also have been converted to real terms on the basis of the same quarter. Table 6 shows the deflator series used for the conversion.

Table 6: Deflator USD series

Period	Deflator
Q1 2010	100.522
Q2 2010	100.968
Q3 2010	101.429
Q4 2010	101.949
Q1 2011	102.399
Q2 2011	103.145
Q3 2011	103.768
Q4 2011	103.917
Q1 2012	104.466
Q2 2012	104.943
Q3 2012	105.508
Q4 2012	105.935
Q1 2013	106.349
Q2 2013	106.570
Q3 2013	107.084
Q4 2013	107.636
Q1 2014	108.117
Q2 2014	108.709
Q3 2014	109.165
Q4 2014	109.300
Q1 2015	109.310
Q2 2015	109.919
Q3 2015	110.253
Q4 2015	110.504
Q1 2016	110.630
Q2 2016	111.258

Source: BEA, 2016.

DC vs. AC costs

Within this report, unless otherwise stated, all costs per unit of PV-generated power (costs per watt) are uniformly expressed in nominal USD per watt, peak direct current and noted as "USD/W".

ELECTRICITY PRICES

To accurately estimate PV competitiveness for retail customers, residential electricity tariffs need to be identified for the location of the PV system. In those locations where data is available, the IC&CI analysis takes a localised approach. Where a dominant electricity supplier exists, this supplier's rate structure is used. In more fractured, liberalised markets, the utility with the highest share of electricity distribution is chosen to reflect the price paid by the average household for grid electricity in the given location.

Whenever territories are allocated to different utilities, these are examined and the correspondent utilities are used for the specific metropolitan area analysed. Both investor-owned utilities as well as publicly owned utilities are examined according to the territory of analysis. In the absence of access to a geographically localised dataset, the next higher available granular level of data is utilised (e.g., state or country).

TOU and tiered electricity rates

For locations where TOU electricity rates are in place, they typically vary based on the time of day (hour periods or day/night, week/weekend), the month or season in the year, or sometimes a combination of these factors.

Electricity rates also can be tiered, which means that the energy charges vary with the electricity load over one or more periods. Tiered rates (also known as inclining block rates) have an increasing charge per unit of energy as the consumption of energy increases above a certain tier (block). Typically, a base consumption is allocated by the utility (delimiting the first tier), and the upper tiers are structured in reference to this baseline allocation. Electricity rates can be designed to both change according to the TOU, as well as depend on the level of electricity consumption (tier).

This can lead to quite complicated rate structures that need to be addressed carefully to evaluate the impact on the value of the electricity produced by the PV system.

Value-added tax (VAT) is excluded from calculations referring to electricity rates to keep homogeneity with the LCOE calculation methodology.

Average electricity price during solar PV generation under TOU/tiered rates

For locations where TOU electricity or TOU/tiered rates are in place, it is possible to model yearly equivalent reference electricity rates (USD/kWh) that are applicable only while the solar PV system is generating.

Such a model is based on hour-by-hour calculations, generating a set of 8 760 hourly values for all modelled parameters representing a single year. Equivalent rate values are modelled using, as input, the corresponding TOU or TOU/tiered schedules applicable in each quarter and for the analysed location. The different TOU types derived from the energy charge schedules (e.g., peak, off-peak) are accounted for, as well as the changing charges with seasons, weekday types, etc. The equivalent rate values are calculated for a full year, using the different utility schedules applicable in each quarter, so that the resulting equivalent rate represents the cost equivalence for a specific quarter. In this way, average yearly equivalent electricity rates can be estimated.

The result of this analysis is an indicator of the average electricity price during solar PV generation in the context of the different applicable TOU/tiered electricity schedules. Such an indicator, as measured by mapping the hourly output of the PV system to TOU/tiered tariff rates (if in effect) over the 8 760 hours in an average meteorological year, can be compared to quarterly developments in the estimated LCOE values.

The following equation shows how such an indicator is calculated in the IC&CI series:

$$\begin{matrix} \textit{average electricity price} \\ \textit{during solar PV generation} \end{matrix} = \frac{\sum_{h=1}^{8760} (R_h)(E_h)}{E}$$

Where:

R_h = the applicable electricity rate for the individual hourly period h [USD/kWh];

E_h = the PV output of the PV system in the hourly period h [kWh];

E = the yearly output of the PV system [kWh].

Since varying electricity schedules often depend on the household's electricity consumption, equivalent rate values and the average electricity price during solar PV generation are calculated for three different load profiles (high, base and low) for each location. More details on the load assumptions made for each metropolitan area analysed can be found in the annexes below.

ANNEX II: CALIFORNIA

This annex looks at the data collection and specific assumptions made in this report when analysing residential PV costs and competitiveness trends in the four selected metropolitan areas of California.

LCOE CALCULATION FOR SOLAR PV

For all California locations, the LCOE for solar PV was computed with the same formula and general guidelines described in Annex I.

Investment costs

In an effort to make LCOE estimates as reliable as possible, cost data from real applications were used for PV system price calculation. Data on system prices in California were collected from California Solar Statistics (CSS), the official public reporting site of the California Solar Initiative (CSI).[57] These data are presented jointly by the CSI programme administrators and the California Public Utilities Commission.

Since the CSI is in its final stages, its statistics have transitioned from the original CSI dataset towards the newer, NEM interconnection dataset. For the present analysis, a combination of both datasets has been used. This combined dataset contains all the available investment cost information from CSS. Specifically, data were obtained from the CSI Working Data Set, which excludes what CSI considered critical errors in the raw dataset.

The CSI Working Data Set version from 20 July 2016 was used for the analysis. The combined dataset also contains data from the Currently Interconnected Data Set version from 31 May 2016. This provides information about interconnected solar PV (NEM) systems within the PG&E, SCE and SDG&E service territories.

Maintenance costs

- For the full period under consideration (Q1 2010 to Q2 2016), assumed O&M costs range between USD 20.00/kW and USD 38.79/kW per year (CREARA, 2016). These values compare well with NREL, 2016a and Lazard, 2015.
- The assumed replacement costs for the inverter range between USD 150/kW and USD 210/kW, depending on the quarter evaluated (Photon Consulting, 2016; NREL, 2016b). It is assumed that the inverter is replaced in year 15 of the system's lifetime.

PV electricity generation

In line with the methodology described in Annex I, NREL's SAM software was used to perform the PV electricity generation calculations. SAM's default tilt of 20° and Azimuth orientation of 180° (true South) were chosen.

The weather files described below – and thus the solar irradiance and temperature assumptions for each specific location – were utilised for this analysis. This was done in conjunction with the collected costs for the LCOE computation of each of the Californian metropolitan areas under analysis.

57 More information about the CSI Statistics can be found at: https://www.californiasolarstatistics.ca.gov/.

Table 7: Weather data file information and modelled PV electricity output in analysed locations in California

	Los Angeles	San Francisco	San Diego	San Bernardino
Weather station name (TMY3)	Los Angeles International Airport	San Francisco International Airport	San Diego Lindbergh Field	March Air Force Base
Weather station code (TMY3)	722950	724940	722900	722860
Average temperature [°C]	16.8	13.8	17.7	17.3
Global horizontal irradiation (GHI) [kWh/m²/day]	5	4.7	5.14	5.44
PV system yield, year 1 [kWh/kW]	1 586	1 530	1 627	1 673

Source: NREL, 2015b; NREL, 2015c.

Table 8: Abbreviations in California utility service areas map

Abbreviation	Meaning
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
MID	Modesto Irrigation District
PG&E	Pacific Gas & Electric
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
SPP	Sierra-Pacific Power
TID	Turlock Irrigation District

Source: CEC, 2015c.

ELECTRICITY PRICES

The IC&CI analysis involves comparing the LCOE estimates at each location with an indicator of the electricity rate. This rate is measured by mapping the hourly output of the PV system to the TOU tariff rates (if in effect) over the 8 760 hours of an average meteorological year.

California is divided into different electricity utility service areas, as can be seen in Figure 54. The utilities analysed here operate in metropolitan regions, while also representing the four largest utilities in the state, in terms of total electricity consumption.

For each utility selected, the relevant schedules have been used to estimate the electricity rate indicator and the average electricity price during solar PV generation. Historical rates, starting in Q1 2010, were compiled to track the development of these indicators.

The IC&CI analysis has been made on a quarterly basis, so electricity rates also have been evaluated on this basis.[58]

Table 8 shows the abbreviations used in the map in Figure 54.

In terms of electricity schedules, for each of the metropolitan regions analysed, the assumptions made were as follows:

Los Angeles

For the metropolitan region of Los Angeles, LADWP was used as a reference utility for the indicator estimates.

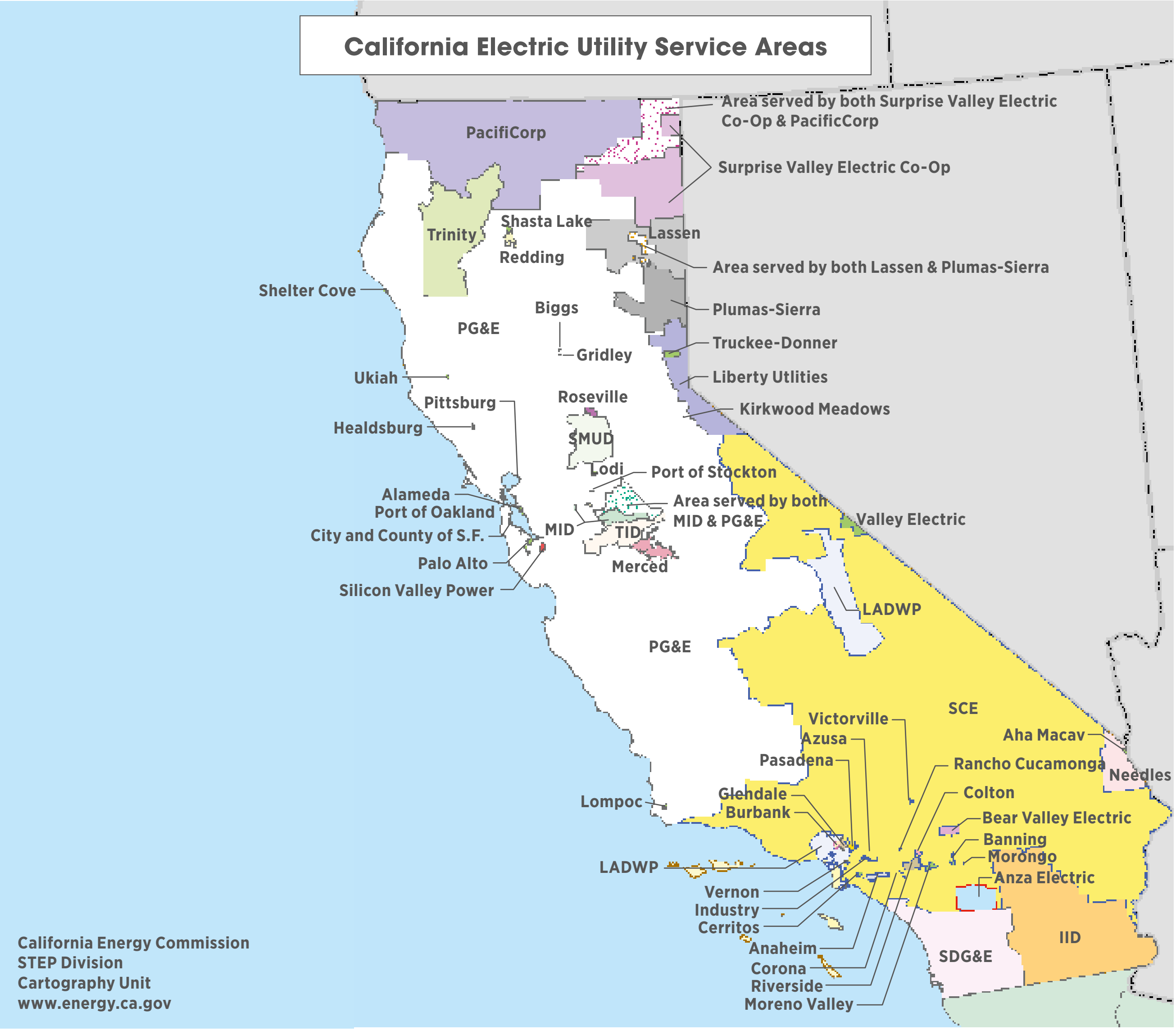
Under LADWP's Residential Time-of-Use R-1B schedule, rates change according to three different TOU periods (High Peak, Low Peak and Base). They are defined as follows (LADWP, 2016):

- **High Peak:** 1 p.m. to 5 p.m., Monday through Friday
- **Low Peak:** 10 a.m. to 1 p.m., Monday through Friday, and 5 p.m. to 8 p.m., Monday through Friday.
- **Base:** 8 p.m. to 10 a.m., Monday through Friday, all day Saturday and Sunday.

There are two distinct yearly seasons in the state: a high season, running from June to September, and a low season for the rest of the year. These seasons also affect the electricity rate value, while the schedule does not change with increasing consumption (no tiers apply). The billable rates under this schedule are determined by the existing electricity rate ordinance, for which billing has been capped, plus the newer incremental electricity rate ordinance. For the purposes of this IC&CI analysis, a "total rate" consisting of the addition of these two rate elements was used.

58 Whenever rates in a certain schedule changed within the quarter, the prevalent rate in the second month of the quarter was used as the reference rate for the quarter.

Figure 54: California electric utility service areas



Source: CEC, 2015c.

Table 9 shows the total rate assumed for the Q2 2016 calculations according to each season and time-of-use period combination.

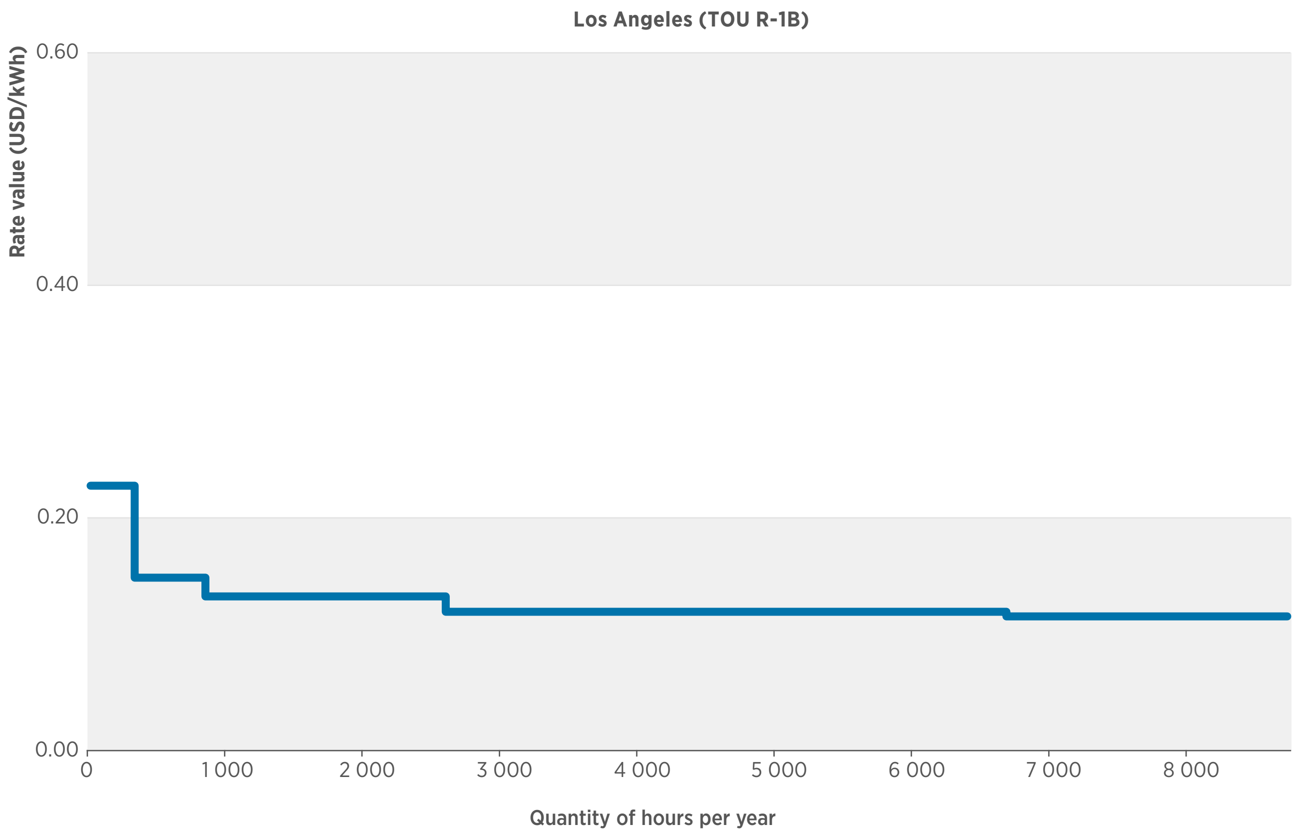
Table 9: Rate values for LADWP's TOU R-1 (B), applicable in Q2 2016

Season	TOU	Total rate [USD/kWh]
High	High Peak	0.2309
High	Low Peak	0.15173
High	Base	0.11828
Low	High Peak	0.13544
Low	Low Peak	0.13544
Low	Base	0.12218

Source: LADWP, 2016.

Different rate values apply throughout the individual hours of the year, depending on the season and TOU. Figure 55 shows the quantity of hours under each rate value annually, given Q2 2016 electricity costs with no PV system in place.[59]

Figure 55: Rate values throughout the year in Los Angeles under LADWP's TOU R-1B schedule, no PV system in place



Source: IRENA analysis based on LADWP, 2016.

59 Electricity consumption for each location is modelled according to load profiles described later in this Annex.

San Francisco

PG&E was chosen as a benchmark for grid electricity prices in San Francisco, as this utility supplies 75% of the area's electricity (SFPUC, 2011). PG&E also provides a variety of electricity schedules with specific residential TOU rates.

Historical data (Q1 2010 to Q2 2016) for electricity schedule E-6 have been retrieved and included in the San Francisco analysis. This represents the grid electricity price in the Cost and Competitiveness Indicators.[60] Schedule E-6 has electricity rates that change according to three TOU periods.

During the summer season (1 May through 31 October):

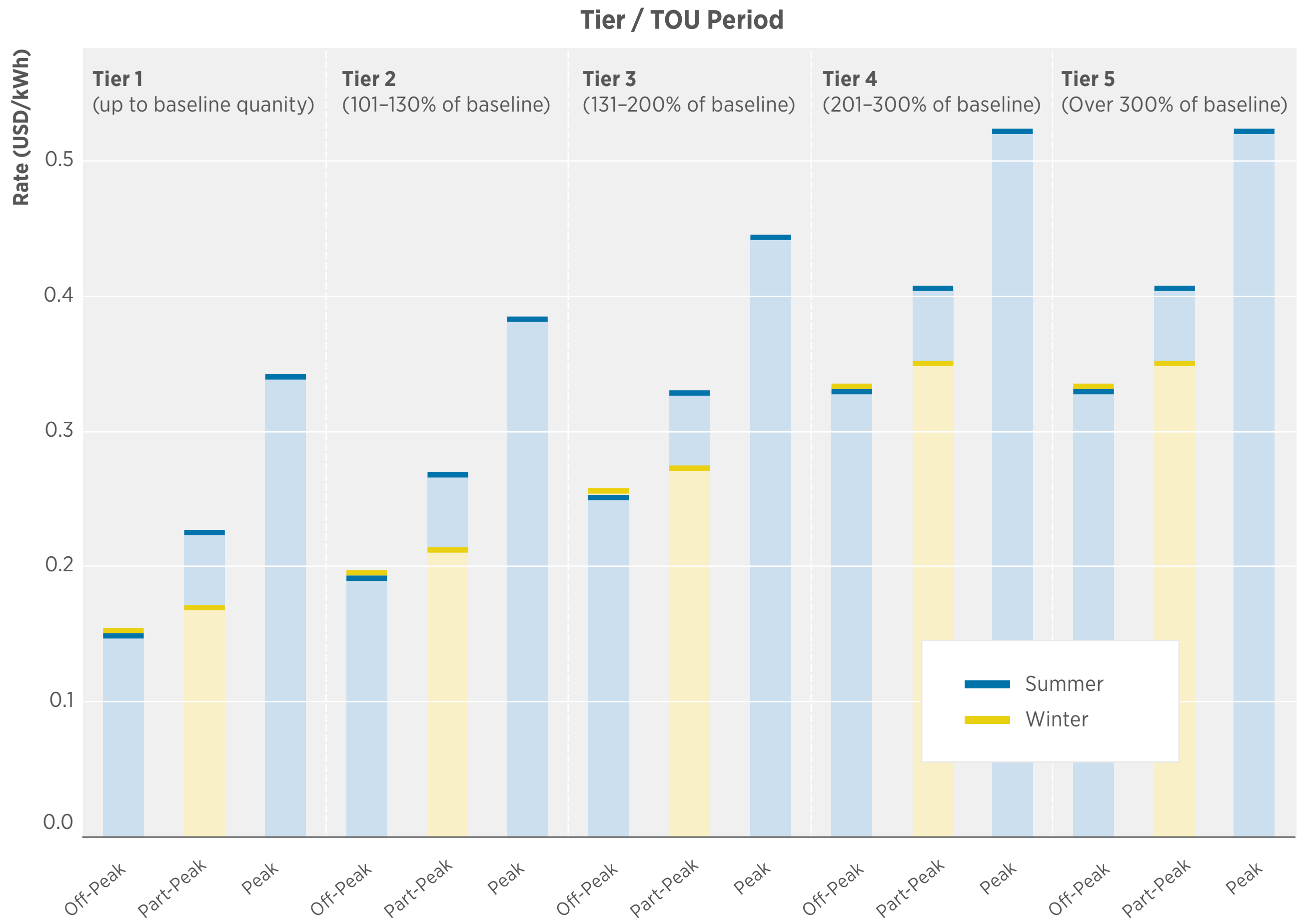
- **Peak:** 1 p.m. to 7 p.m., Monday through Friday.
- **Partial-Peak:** 10 a.m. to 1 p.m., Monday through Friday, and 7 p.m. to 9 p.m., Monday through Friday, plus 5 p.m. to 8 p.m., Saturday, Sunday.
- **Off-Peak:** all other times.

During the winter season (1 November through 30 April):

- **Partial-Peak:** 5 p.m. to 8 p.m., Monday through Friday.
- **Off-Peak:** all other times.

Rate values also change depending on the consumption level (tier) and on the season of the year (summer, winter). Figure 56 shows a summary of the schedule, including the charges per tier for the example of Q2 2016.

Figure 56: PG&E Schedule E-6, Q2 2016



Source: IRENA analysis based on PG&E, 2016.

60 Starting in Q1 2016, the more recently introduced schedule E-TOU (option A) is also included in the analysis, as described later in this Annex.

The tier structure is based on baseline quantities, which are electricity consumption allowances per tier. These vary according to weather-defined territories in PG&E's service area. The upper tiers are determined in reference to the baseline (tier 1). The baseline territories in PG&E's service area are displayed in Figure 57.

Figure 57: Territories in PG&E's service area

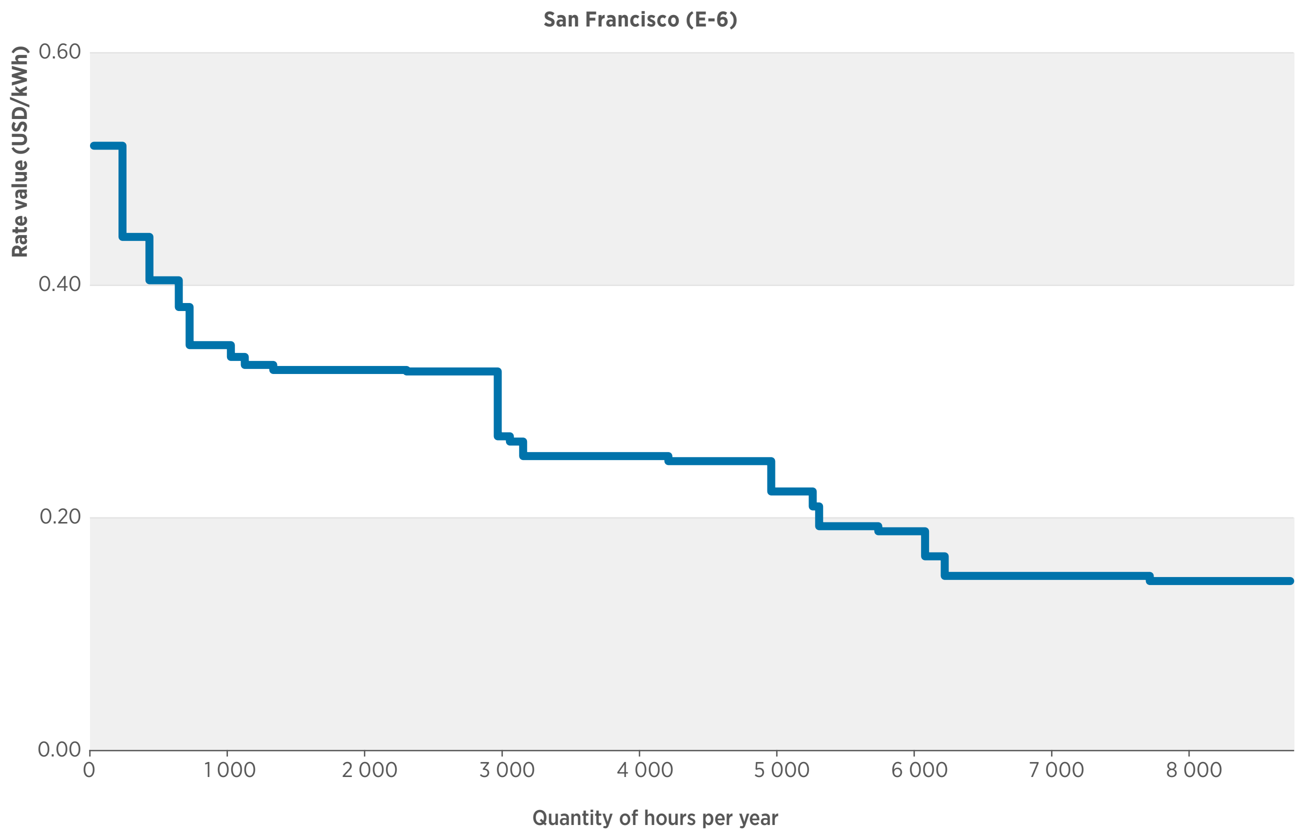
Source: PG&E, 2015.

Each territory is assigned a baseline (tier 1) consumption level, in the form of a daily quantity of kWh of electricity consumption. This baseline quantity is charged at the baseline (tier 1) rate.

For calculations in the San Francisco metropolitan area, Territory T was assumed. Baseline quantities also change according to the electricity code, and a different code applies for households using electricity more heavily (e.g., for water heating). For the IC&CI analysis, however, the basic electricity code B has been assumed. Accordingly, for San Francisco a daily baseline quantity of 7.0 kWh in the summer and 8.5 kWh in the winter was assumed during Q2 2016.[61]

Different rate values apply throughout the individual hours of the year, depending on the season, TOU period and active tier. Figure 58 shows the quantity of hours under each rate value for a year, given Q2 2016 electricity rates under schedule E-6.

Figure 58: Rate values throughout the year in San Francisco under schedule E-6, no PV system in place

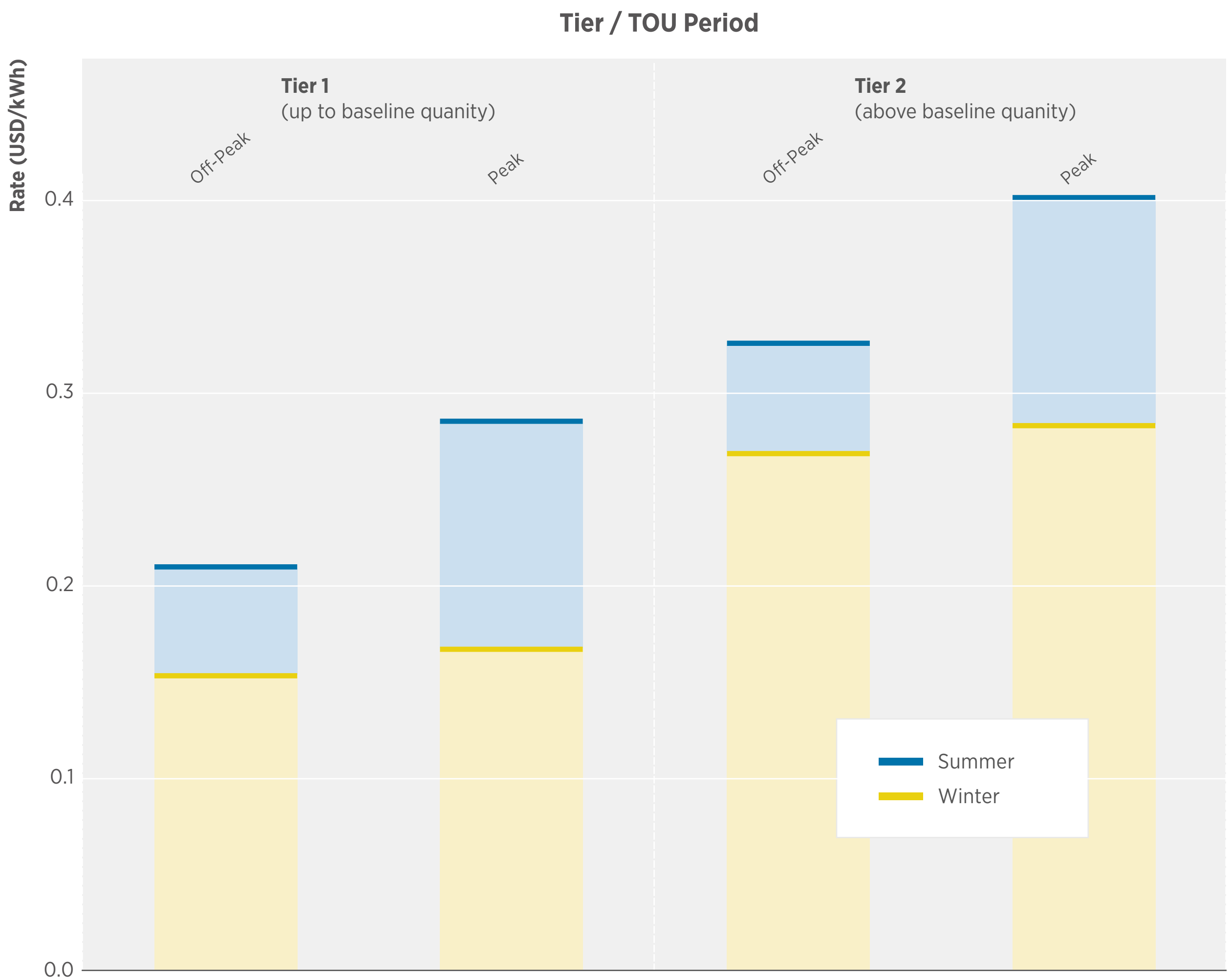


Source: IRENA analysis based on PG&E, 2016.

61 Baseline quantities are not often revised, but whenever this has happened during the analysis period, such changes also have been taken into account in the IC&CI calculations.

In line with the progress of residential rate reform in California, new TOU schedules have been introduced. Starting in Q1 2016, this report includes PG&E's schedule E-TOU (option A) in the analysis for San Francisco. In option A, this schedule can be interpreted as having two tiers defined by the baseline allowance threshold.[62] This is a more simplified structure, down from the five-tier structure of schedule E-6. Schedule E-TOU also defines only two TOU periods (peak and off-peak) as opposed to the three period structure of schedule E-6. Figure 59 shows the rates for this schedule, according to TOU period and season.

Figure 59: Schedule E-TOU (option A), Q2 2016

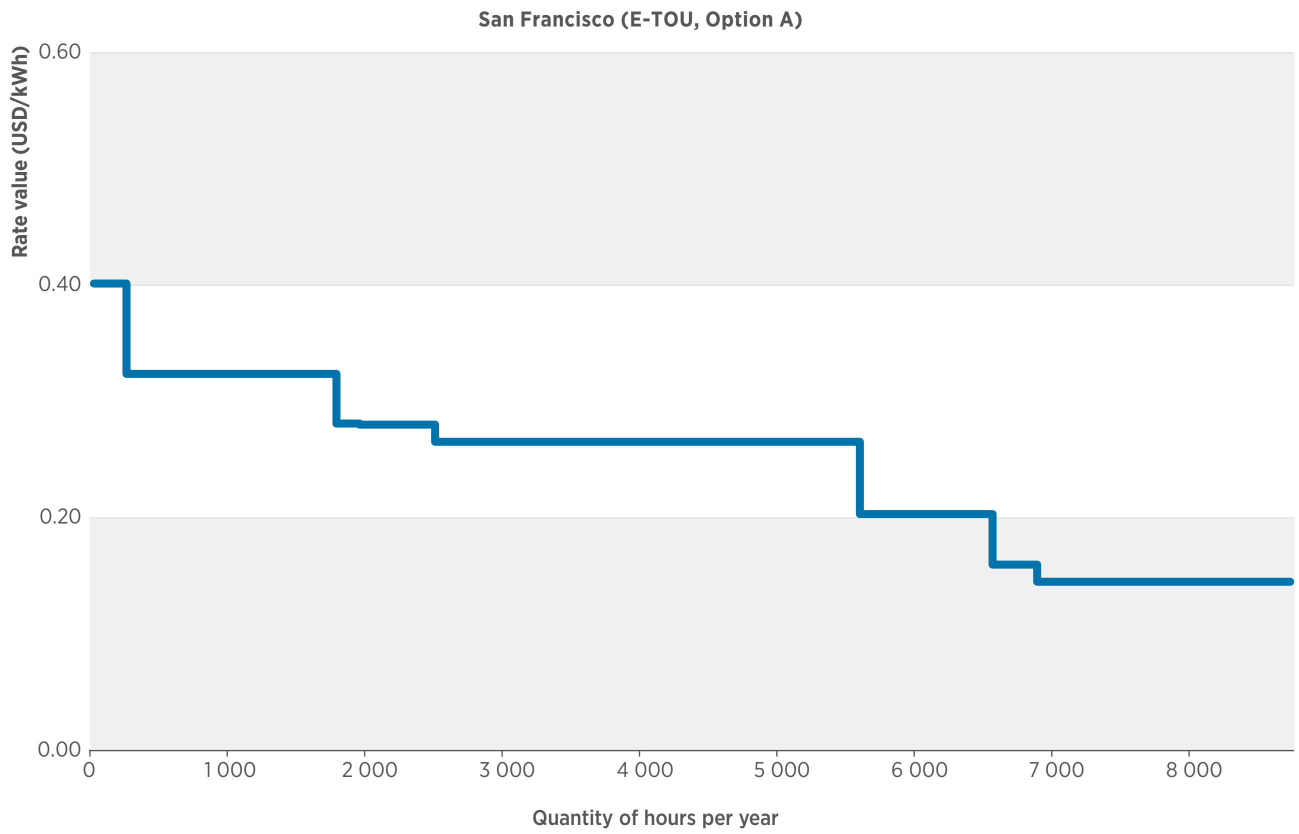


Source: IRENA analysis based on PG&E, 2016.

62 Option B is not tiered; that is to say, prices do not change with consumption, only with time-of-use and season. More detailed information about the schedules can be found at: https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/time-of-use-base-plan/time-of-use-plan.page.

Figure 60 shows the quantity of hours under each rate value for a typical year, given Q2 2016 costs.

Figure 60: Rate values throughout the year in San Francisco under schedule E-TOU (option A), no PV system in place



Source: IRENA analysis based on PG&E, 2016.

San Diego

SDG&E's Domestic TOU for Households with a Solar Energy System (DR-SES) schedule was assumed for this IC&CI analysis.

This schedule also changes according to three different TOU periods ("On-Peak", "Semi-Peak" and "Off-Peak"). Two distinct yearly seasons – a summer season running from May through October and a winter season during the remaining months – also affect the rates.

The TOU periods in this schedule are defined as follows:

During the summer season (1 May through 31 October):

- **On-Peak:** 11 a.m. to 6 p.m., Monday through Friday (excluding holidays).
- **Semi-Peak:** 6 a.m. to 11 a.m., and 6 p.m. to 10 p.m., Monday through Friday (excluding holidays).
- **Off-Peak:** 10 p.m. to 6 a.m., weekdays, and all hours on weekends and holidays.

During the winter season (1 November through 30 April):

- **Semi-Peak:** 6 a.m. to 6 p.m., Monday through Friday (excluding holidays).
- **Off-Peak:** 6 p.m. to 6 a.m., weekdays, and all hours on weekends and holidays.

The schedule does not change with increasing consumption, and therefore no tiers (or baseline quantities) apply.

Table 10 displays the applicable assumed rates during Q2 2016 under the DR-SES schedule.

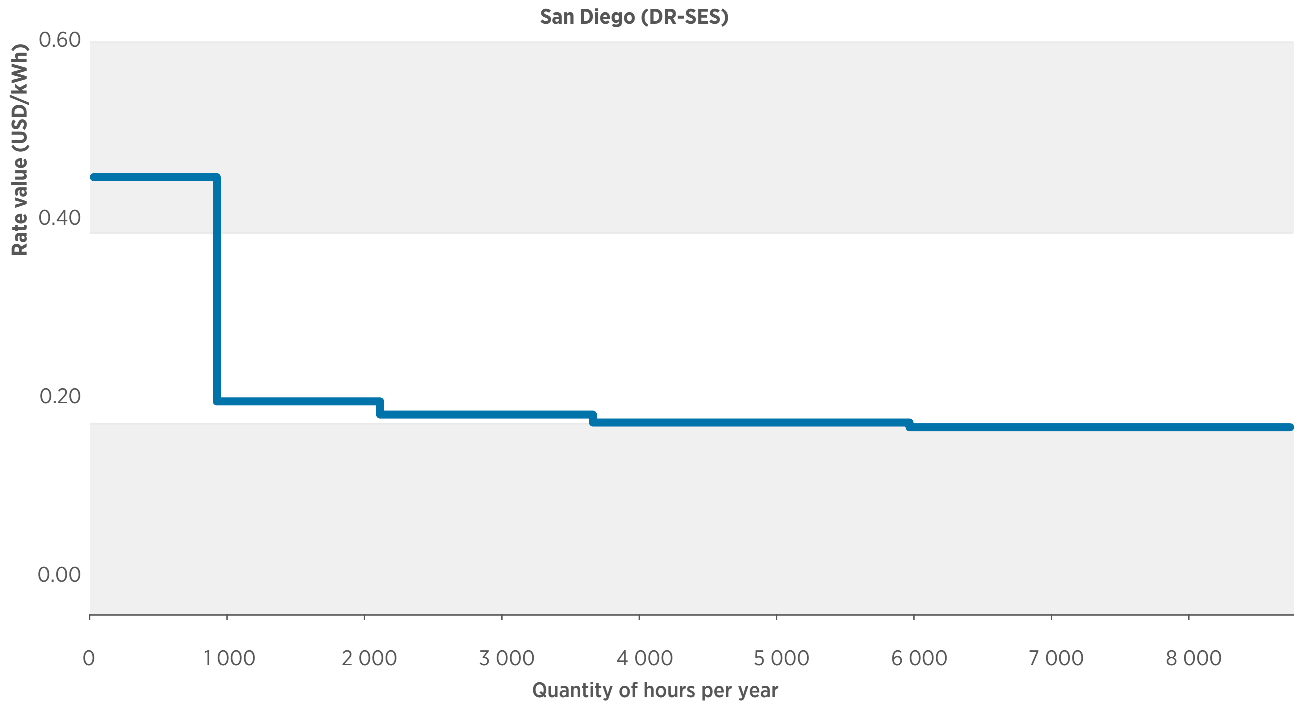
Table 10: Rate values for SDG&E's DR-SES applicable in Q2 2016

Season	TOU	Total rate [USD/kWh]
summer	on-peak	0.46397
summer	semi-peak	0.22904
summer	off-peak	0.20706
winter	semi-peak	0.21533
winter	off-peak	0.20200

Source: SDG&E, 2016.

Different rate values apply throughout the individual hours of the year, depending on the season and TOU period. Figure 61 shows the quantity of hours under each rate value.

Figure 61: Rate values throughout the year in San Diego under schedule DR-SES



Source: IRENA analysis based on SDG&E, 2016.

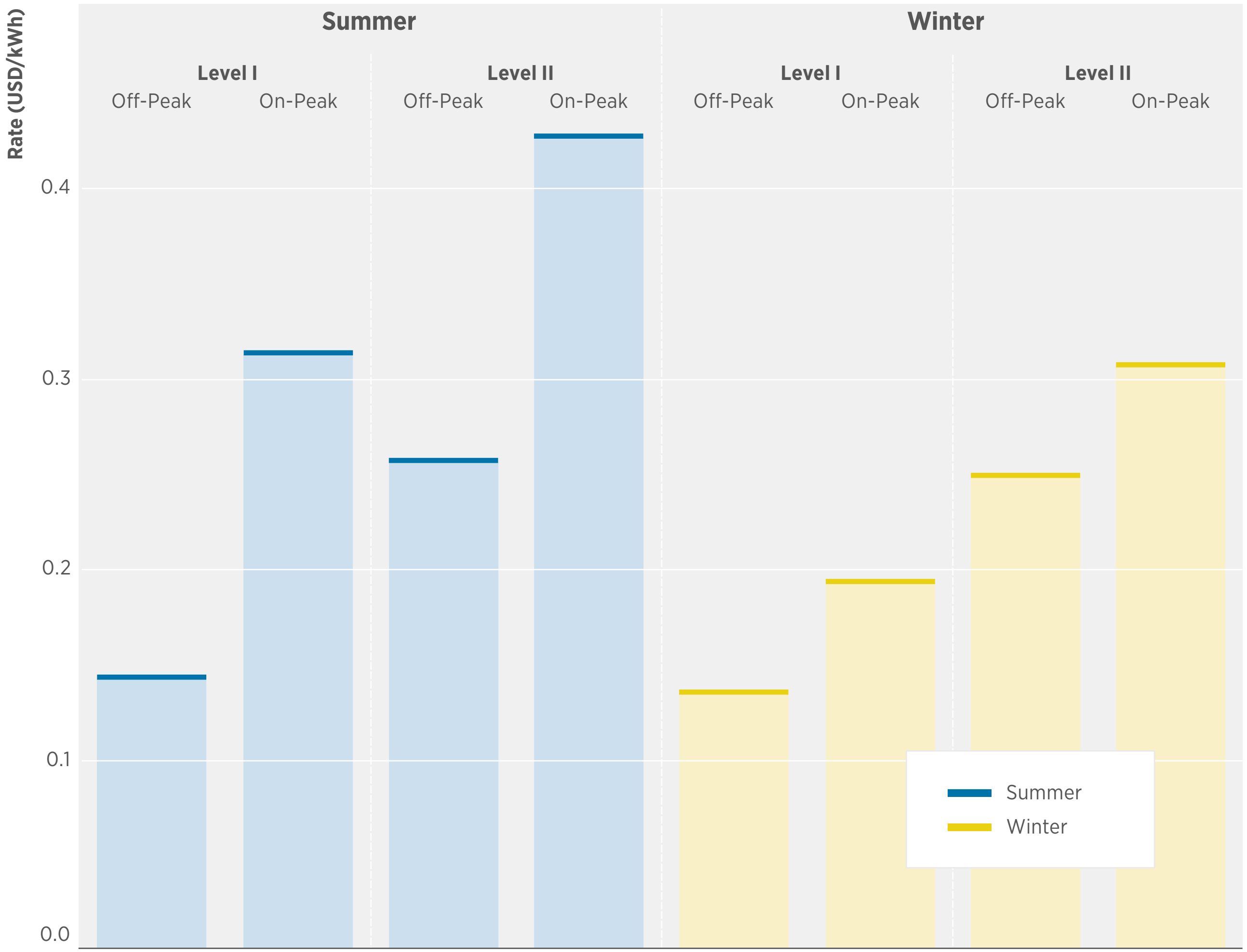
San Bernardino

Historical data (Q1 2010 to Q2 2016) for SCE's TOU-D-T electric schedule have been retrieved for inclusion in the IC&CI analysis for San Bernardino.[63]

The TOU-D-T schedule changes both with TOU (On-Peak, Off-Peak) and with increasing block rates.

Consumption up to 130% of the baseline level is charged at Level 1 rates. The Level 1 limit corresponds with the tier 2 limit of other block rate schedules in the state (e.g., PG&E's E-6 schedule). All consumption above 130% of the baseline is charged at Level II rates. A summary of the schedule for Q2 2016, including the charges per level, can be seen in Figure 62.

Figure 62: SCE's schedule TOU-D-T during Q2 2016

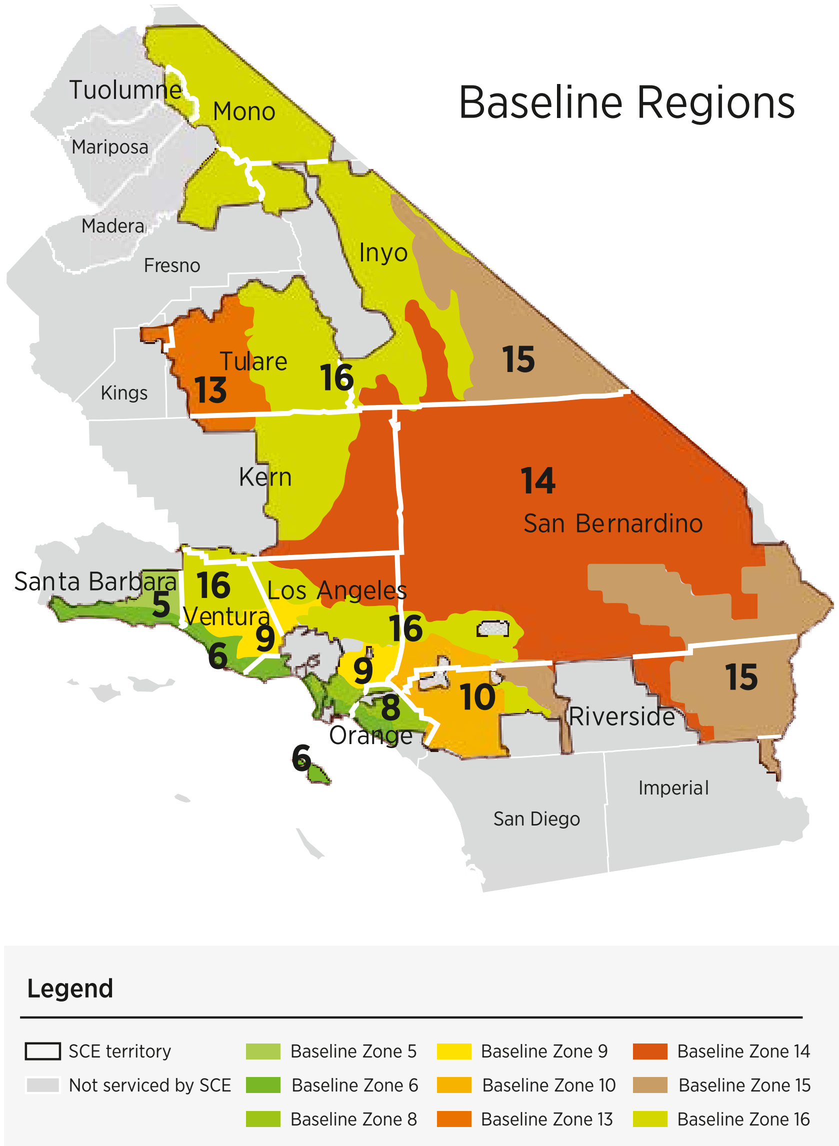


Source: IRENA analysis based on SCE, 2016.

63 Starting in Q1 2015, the more recently introduced SCE schedule, TOU-D (option A), also is included in the analysis and is described later in this annex.

The level rate structure is based on baseline quantities, which are electricity consumption allowances per level. These vary according to weather-defined territories in SCE's service area. Figure 63 displays the baseline territories in SCE's service area.

Figure 63: Territories in SCE's service area



Source: SCE, 2016.

Each territory is assigned a baseline (tier 1) consumption level, in the form of a daily quantity of kWh of electricity consumption, and this "baseline quantity" is charged at the baseline (tier 1) rate.

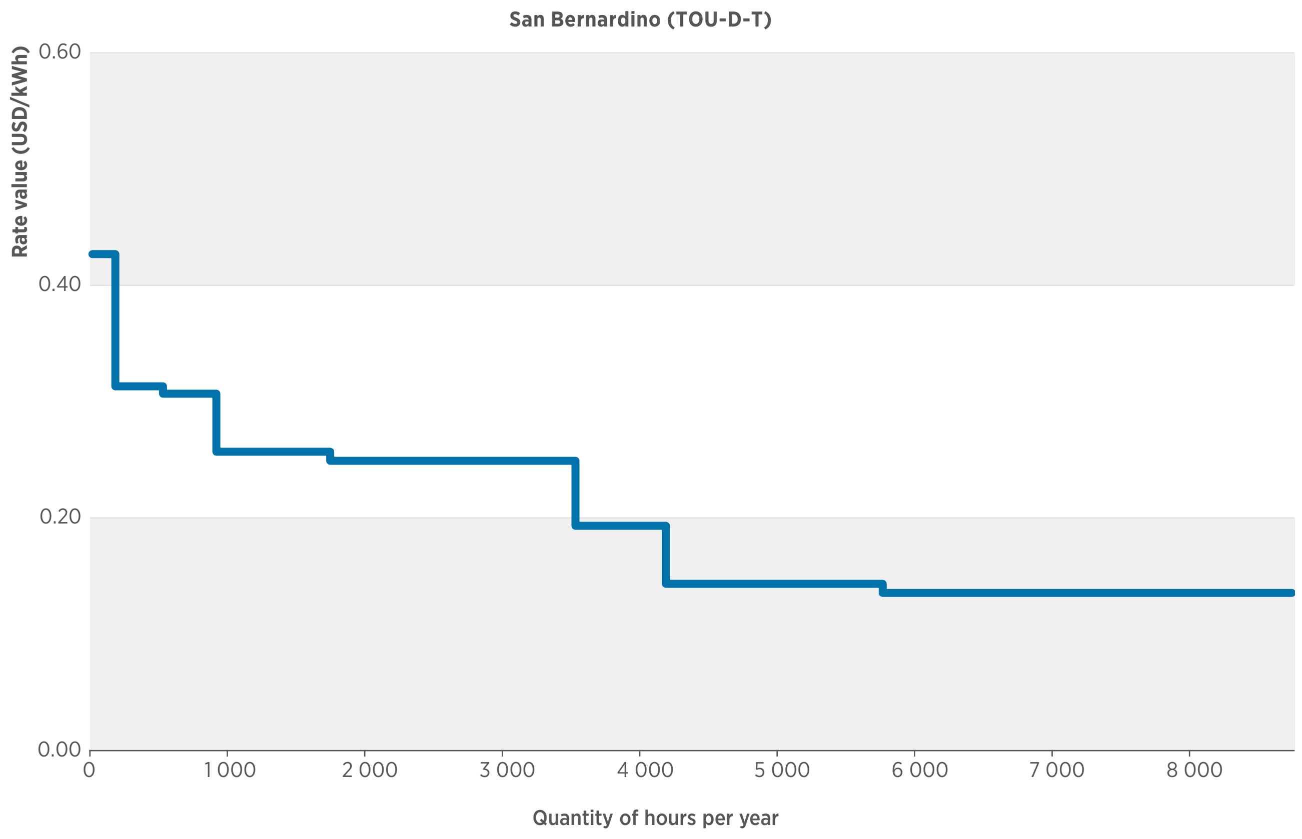
For calculations in the San Bernardino metropolitan area, Zone 10 was assumed. Baseline quantities also change according to the electricity code, and a different code applies for households using electricity more heavily (e.g., for water heating). For the IC&CI analysis, however, the basic electricity code has been assumed. Accordingly, a daily baseline quantity of 15.5 kWh in the summer and 11.0 kWh in the winter was assumed during the Q2 2016 period.

TOU periods for schedule TOU-D-T are defined as follows:

- **On-Peak**: 12 p.m. to 6 p.m., summer and winter weekdays, except holidays.
- **Off-Peak**: all other hours – all year, everyday.

Different rate values apply throughout the individual hours of the year, depending on the season, TOU period and active tier. Figure 64 shows the quantity of hours under each rate value, assuming the base load profile described later in this annex.

Figure 64: Rate values throughout the year in San Bernardino under SCE's schedule TOU-D-T, no PV system in place



Source: IRENA analysis based on SCE, 2016.

Starting in Q1 2015, this report includes SCE's TOU-D (option A) schedule in its analysis for San Bernardino.

TOU periods for schedule TOU-D are defined as follows:

- **On-Peak**: 2 p.m. to 8 p.m., summer and winter weekdays, except holidays.
- **Super-Off-Peak**: 10 p.m. to 8 a.m. – all year, every day.
- **Off-Peak**: all other hours – all year, every day.

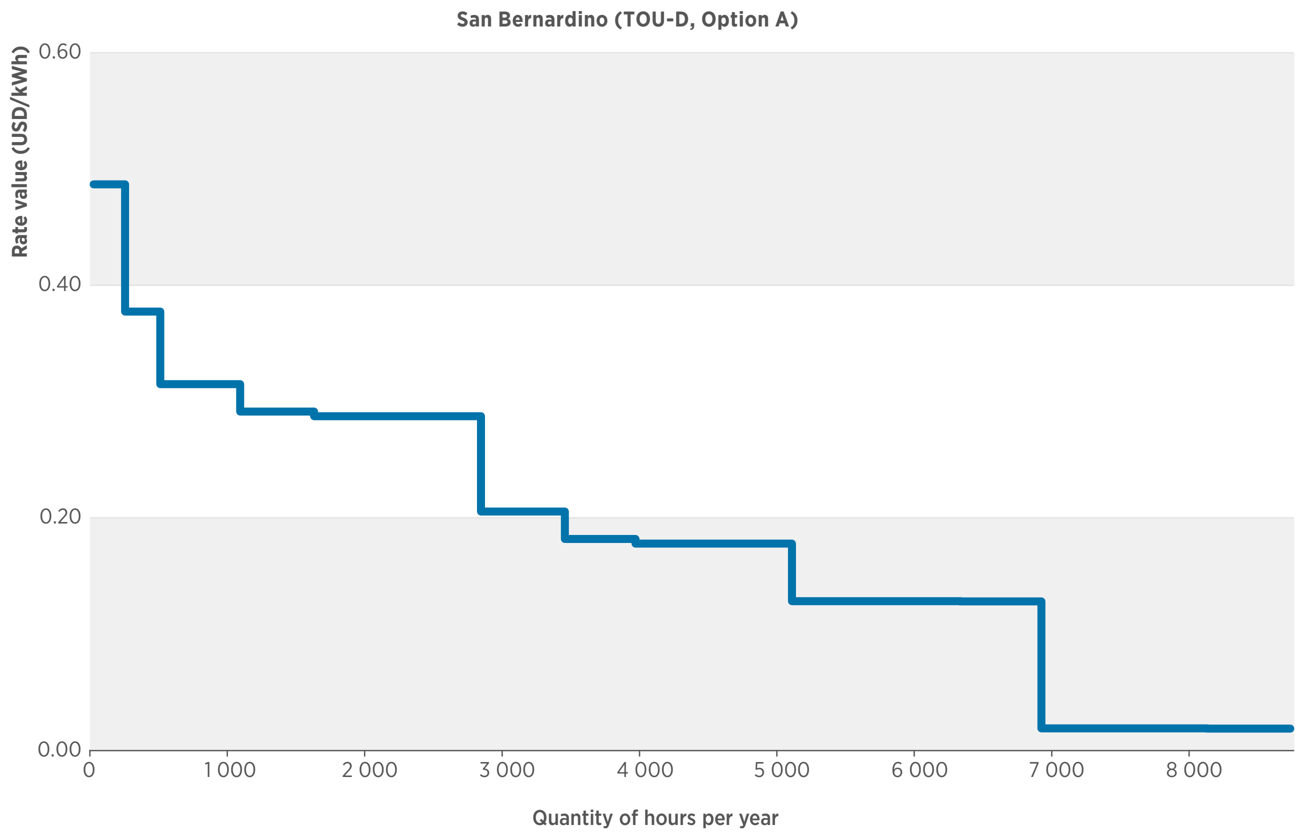
In option A, this schedule can be interpreted as having two tiers, defined by the baseline allowance threshold. Figure 65 shows the rates for this schedule according to TOU period and season.

Figure 65: Schedule TOU-D (option A), Q2 2016

Source: IRENA analysis based on SCE, 2016.

Figure 66 shows the quantity of hours under each rate value, assuming the base load profile described later in this annex.

Figure 66: Rate values throughout the year in San Bernardino under SCE's schedule TOU-D (option A), no PV system in place



Source: IRENA analysis based on SCE, 2016.

LOAD PROFILES (CALIFORNIA)

For the metropolitan regions analysed, electricity load profiles have been obtained from the NREL OpenEI residential and commercial building load database. These have then been imported into the calculation model. The database contains hourly load profiles for residential and commercial building types in Typical Metrological Year Version 3 (TMY3) locations in the US. Using representative TMY3 locations, the base case load profile data were used for the calculations in the present edition.

Table 11: Assumption for yearly household building consumption in the metropolitan areas analysed in California

Metropolitan region	Base load [kWh/year]
Los Angeles	7 930.23
San Francisco	7 562.59
San Diego	8 218.78
San Bernardino	9 326.62

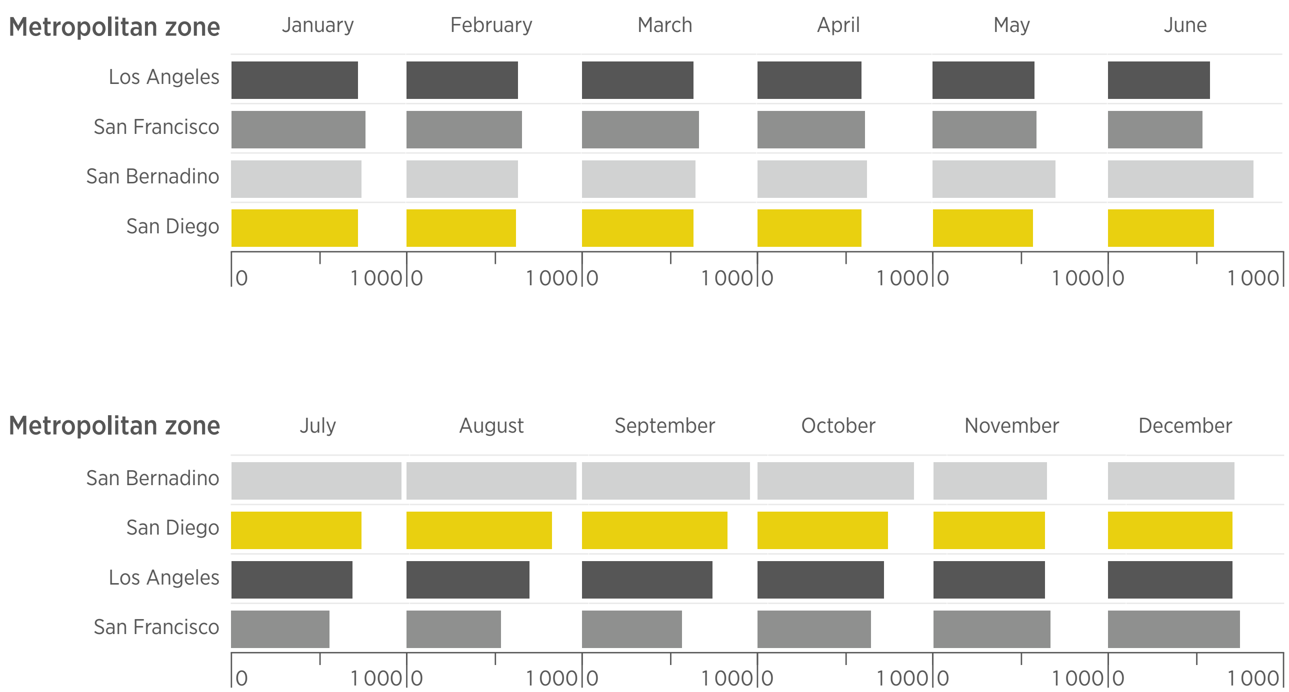
Source: EERE, 2015.

Figure 67 shows a comparison of the base case monthly load totals for each of the four metropolitan locations.

The following figures show different household consumption profiles for the base load case in the four metropolitan areas under analysis.

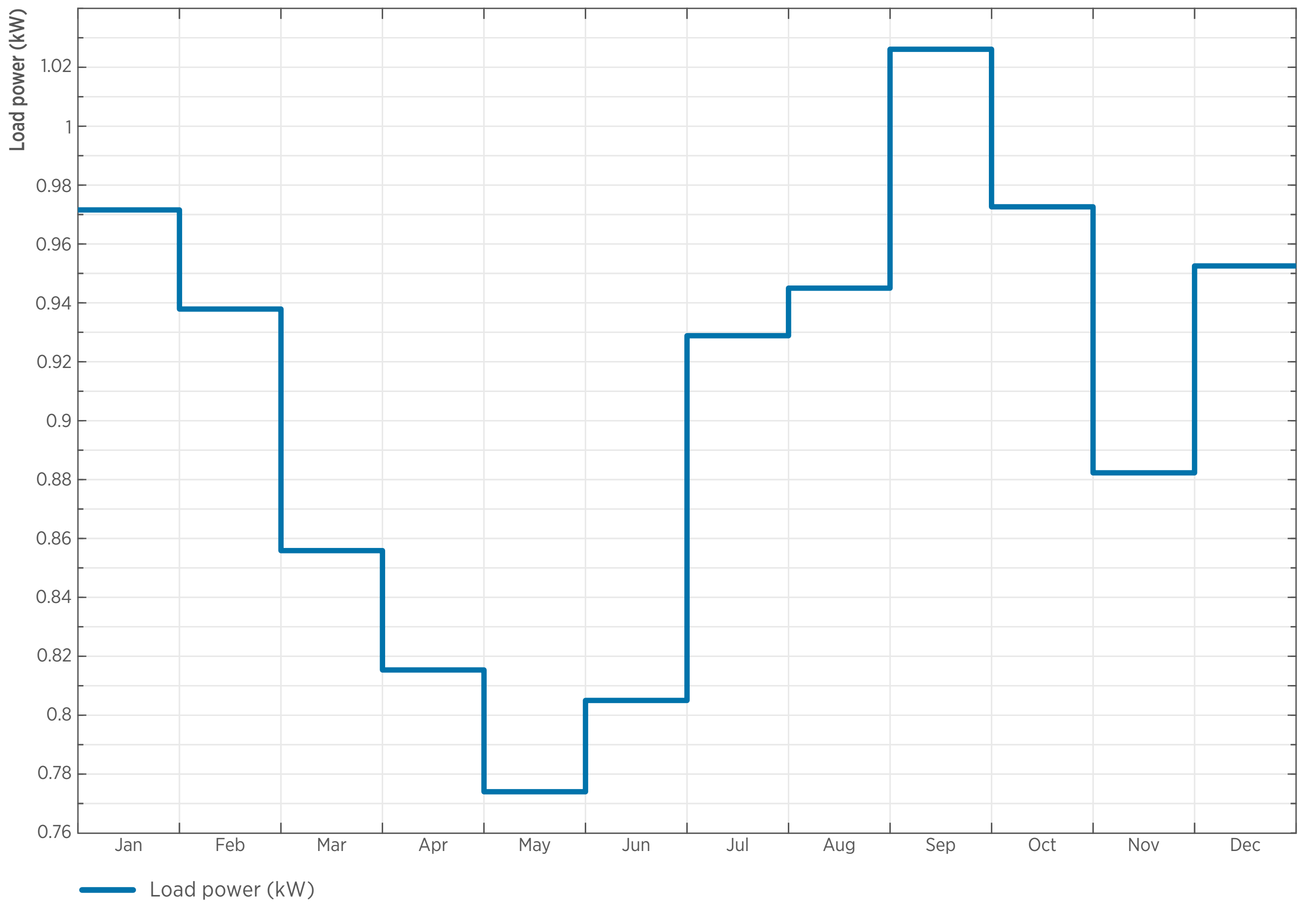
The charts show three types of load profiles. The first shows each month's average hourly loads. The second chart type, often called a "heatmap", shows the individual hourly load values distributed throughout the year, represented by a colour code. Finally, a third chart shows the hourly average load consumption distributed through the hours of the day in each month. All charts show the load power expressed in kW.

Figure 67: Comparison of total monthly base load assumptions for the metropolitan regions analysed in California



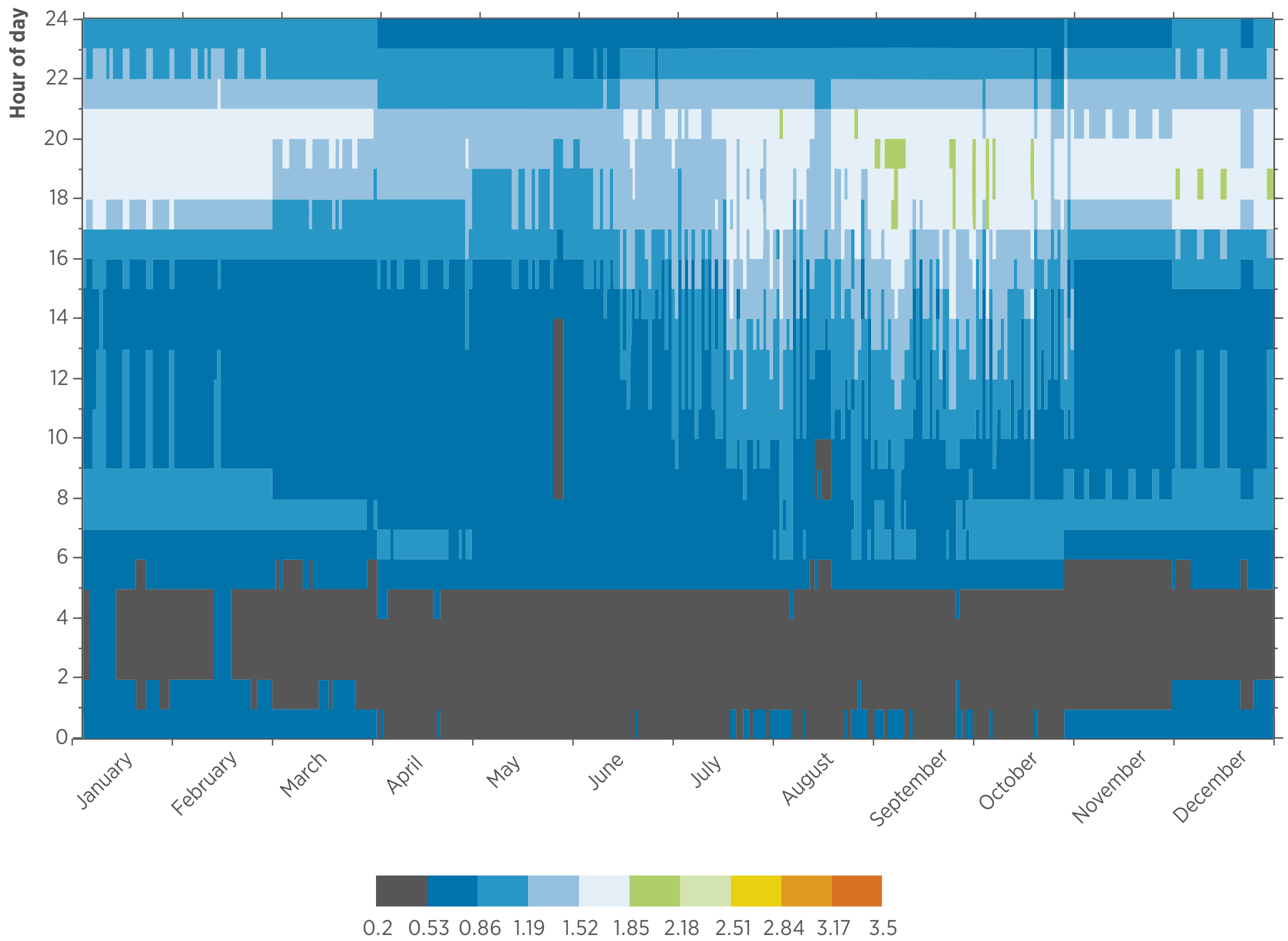
Source: EERE, 2015.

Figure 68: The average hourly load profile for each month assumed for Los Angeles



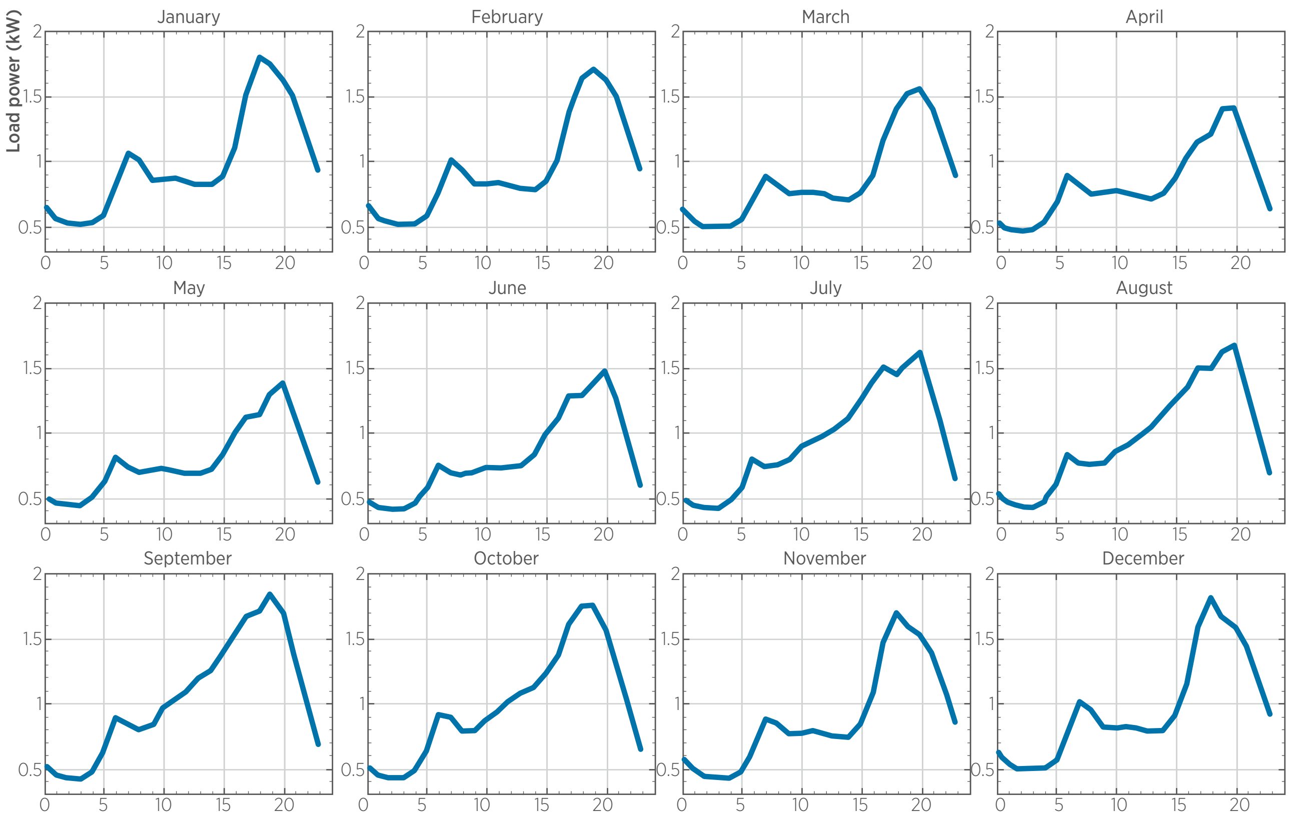
Source: EERE, 2015; NREL, 2015c.

Figure 69: Heatmap of hourly load values assumed for Los Angeles



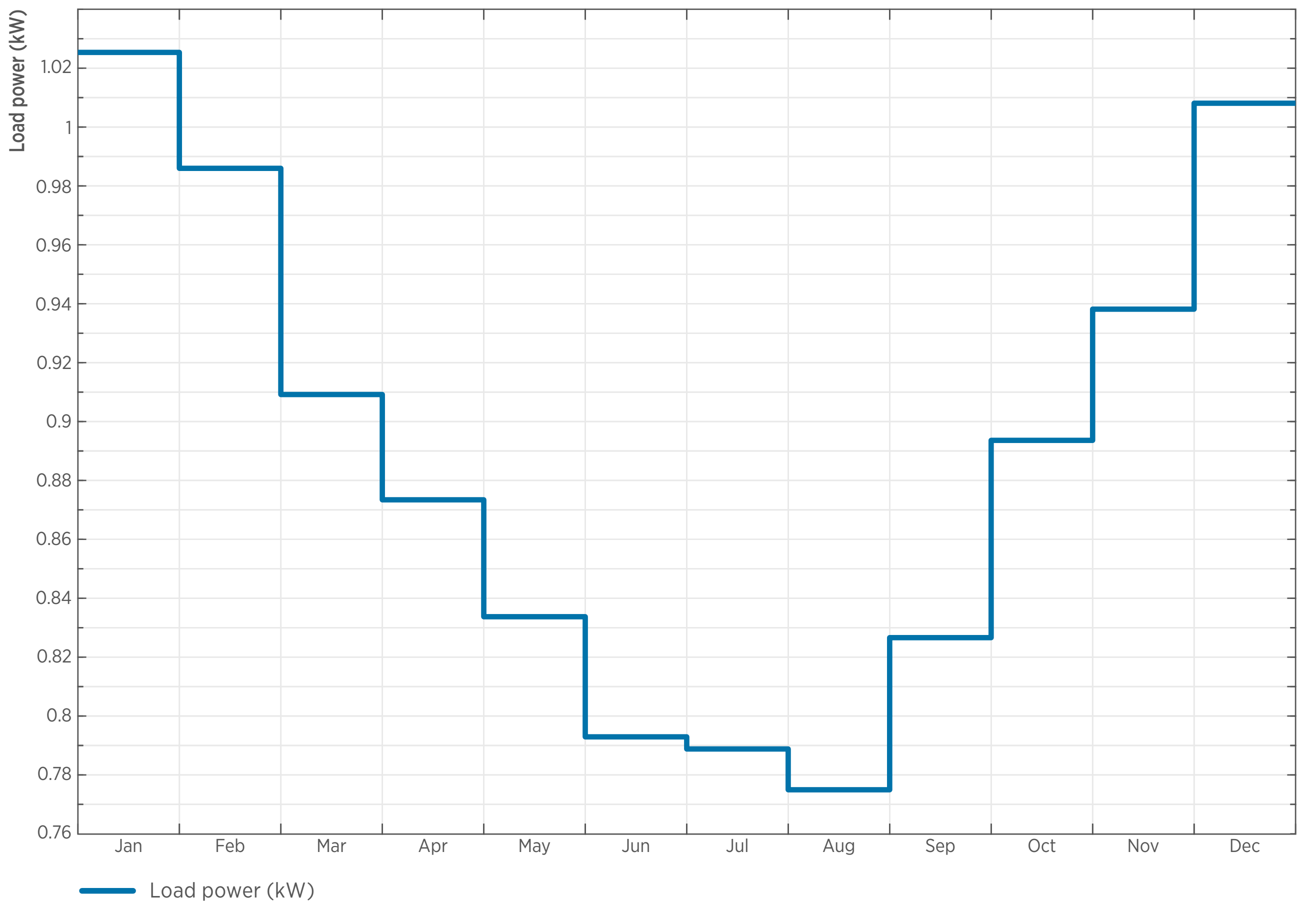
Source: EERE, 2015; NREL, 2015c.

Figure 70: Average hourly load profile for each month assumed for Los Angeles



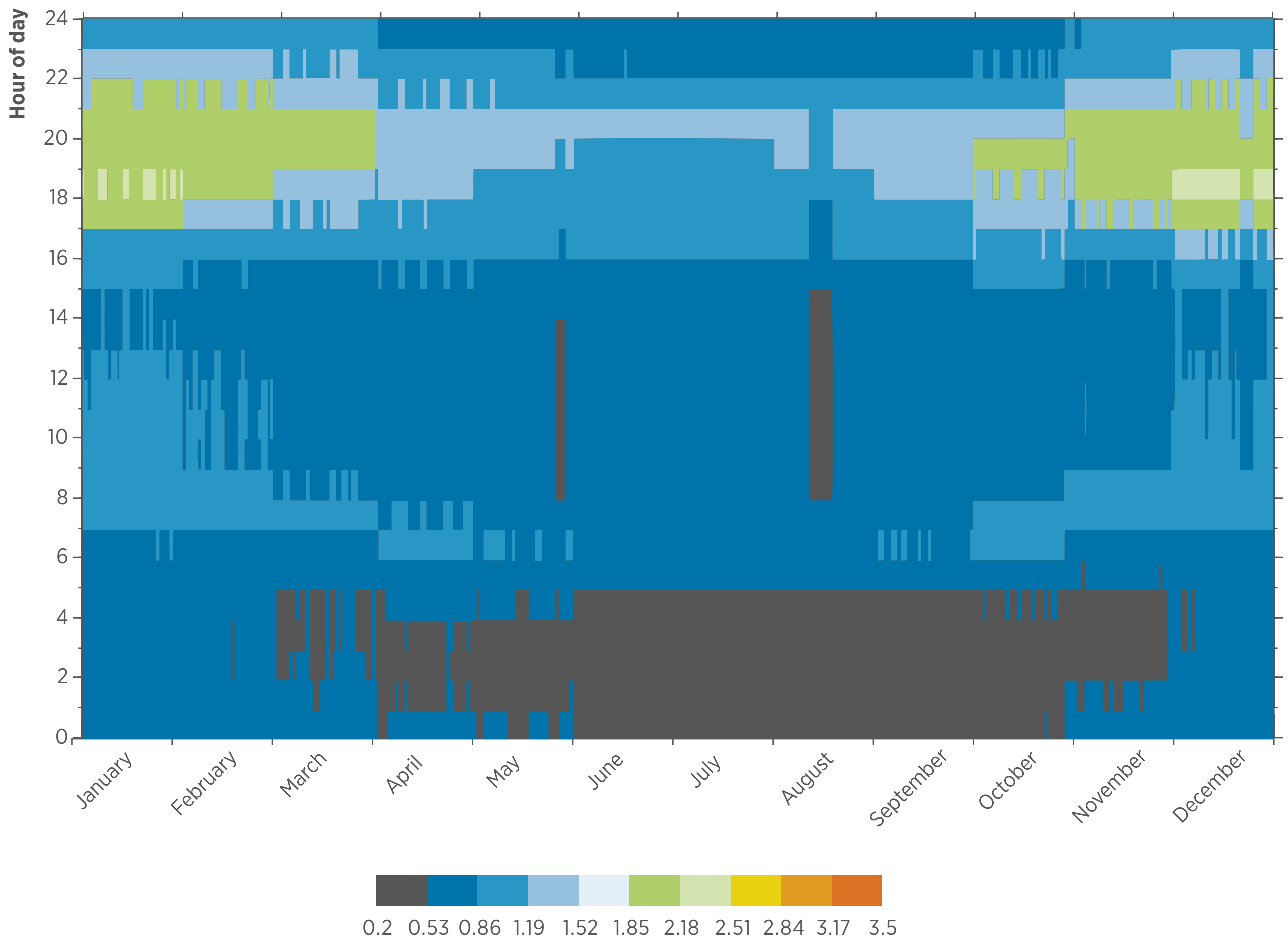
Source: EERE, 2015; NREL, 2015c.

Figure 71: Average hourly load profile for each month assumed for San Francisco



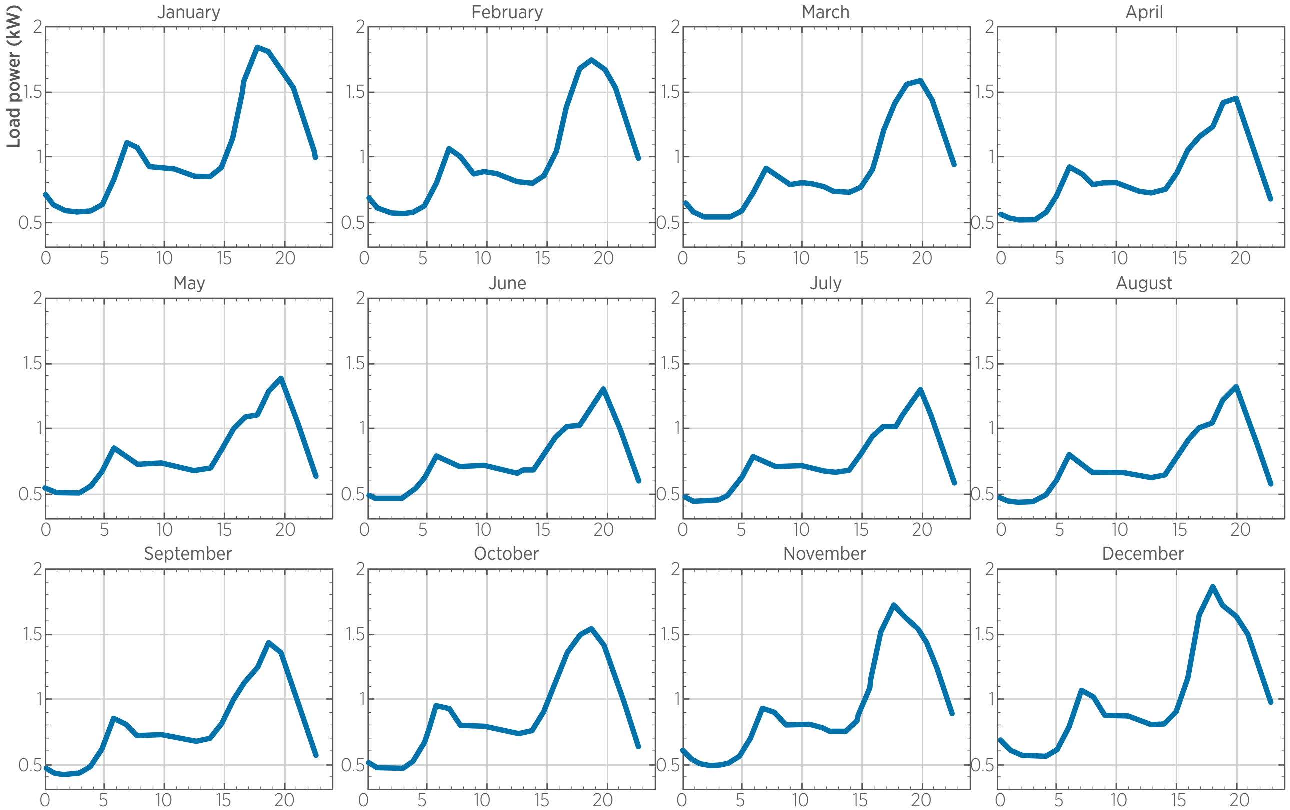
Source: EERE, 2015; NREL, 2015c.

Figure 72: Heatmap of hourly load values assumed for San Francisco



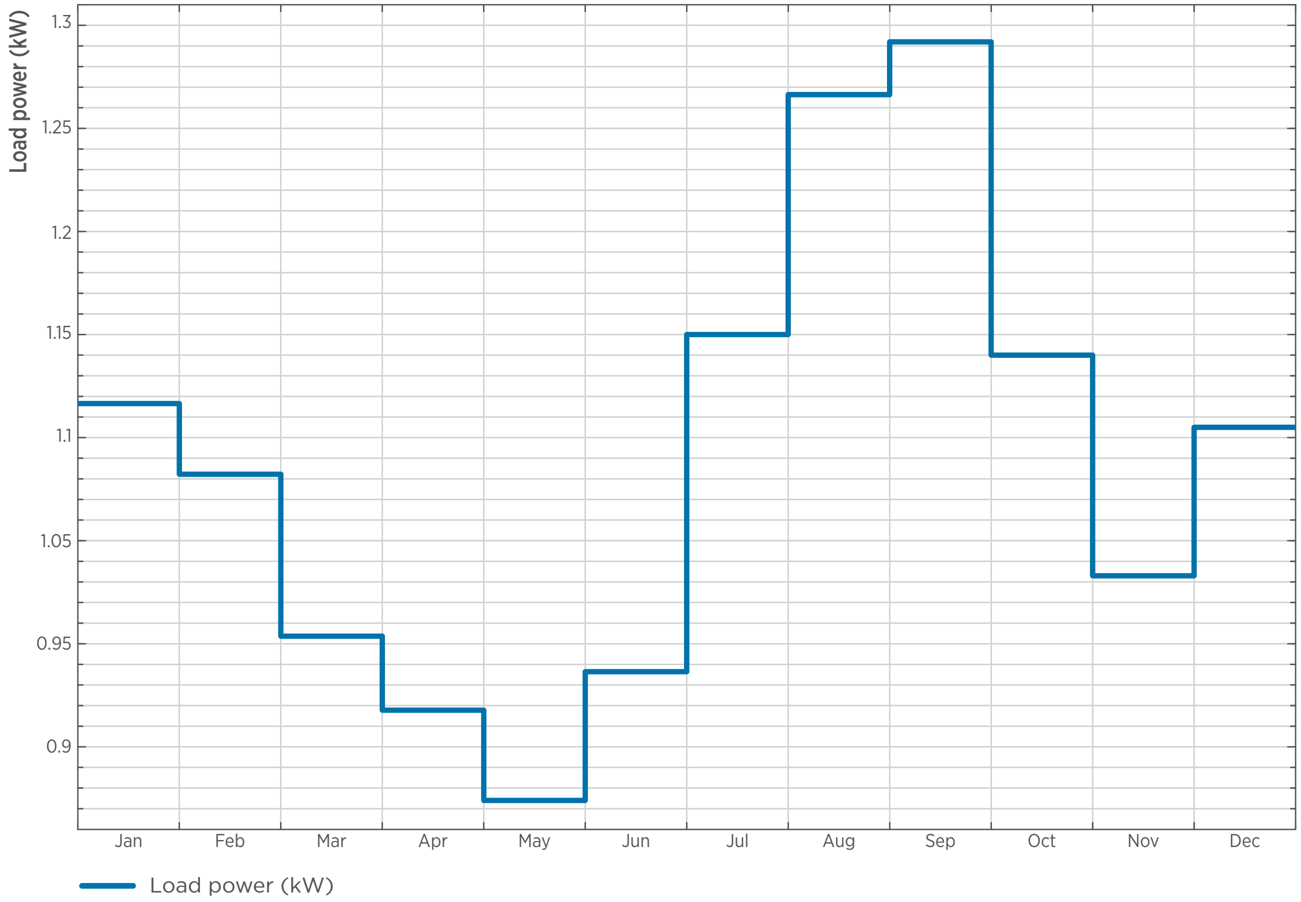
Source: EERE, 2015; NREL, 2015c.

Figure 73: Average hourly load profile for each month assumed for San Francisco



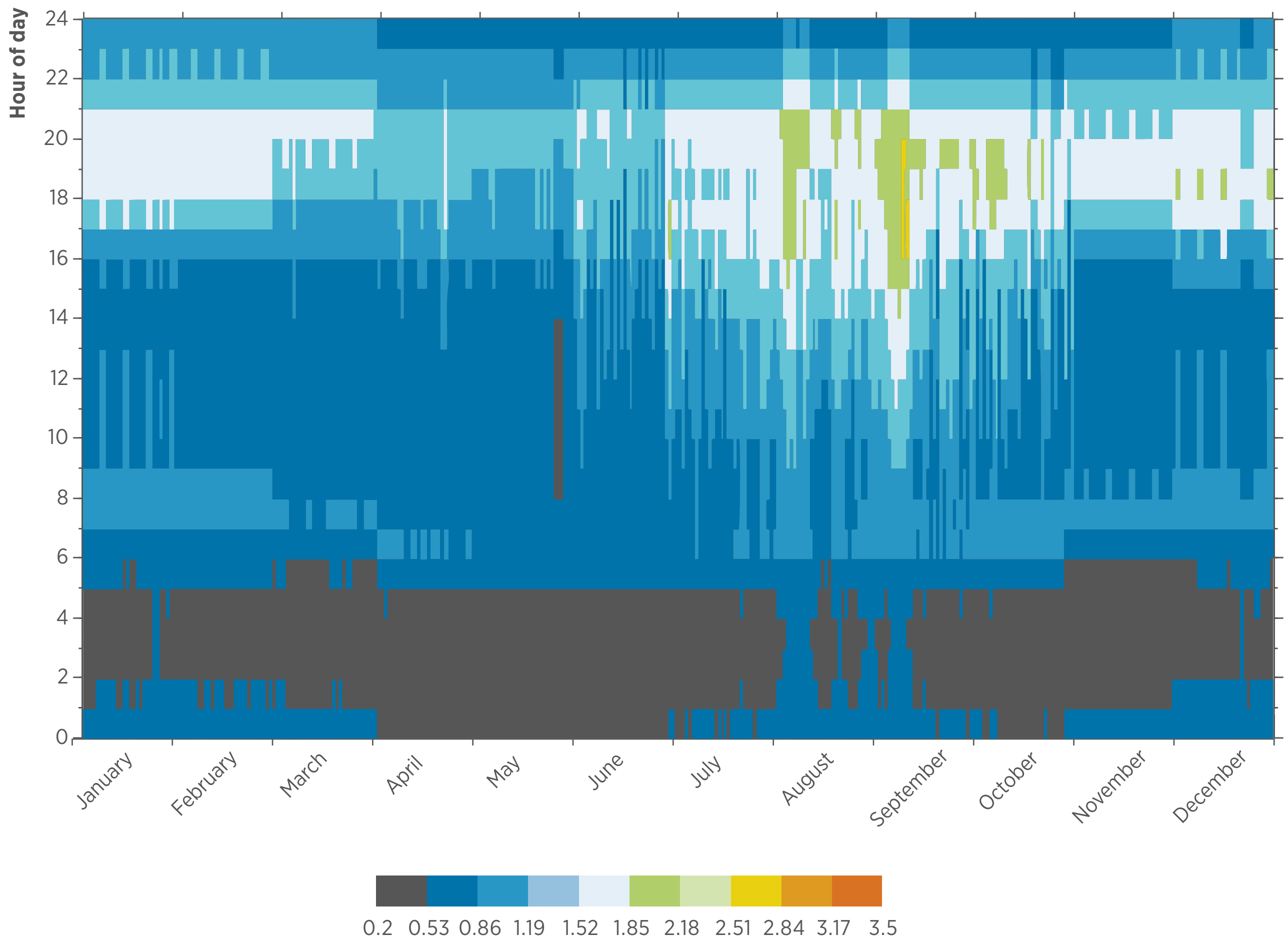
Source: EERE, 2015; NREL, 2015c.

Figure 74: Average hourly load profile for each month assumed for San Diego



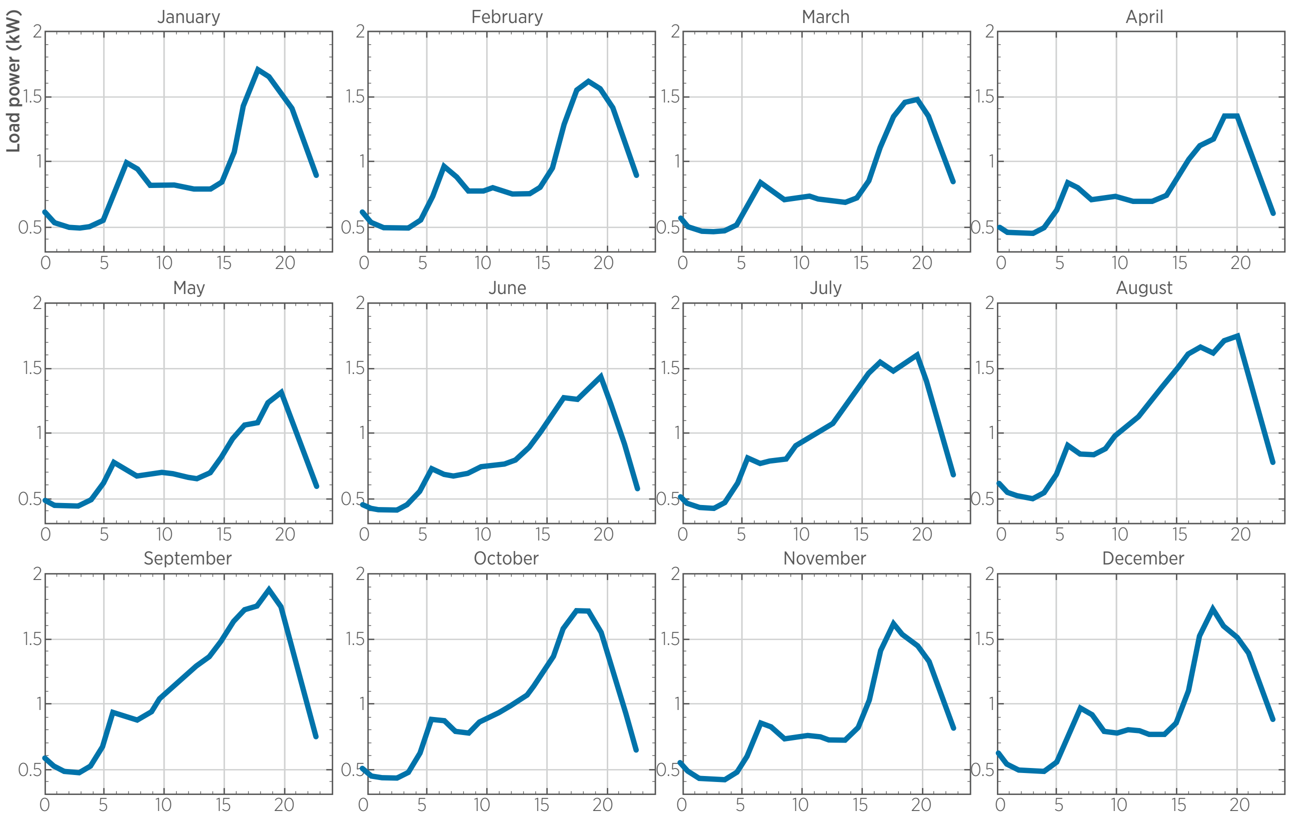
Source: EERE, 2015; NREL, 2015c.

Figure 75: Heatmap of hourly load values assumed for San Diego



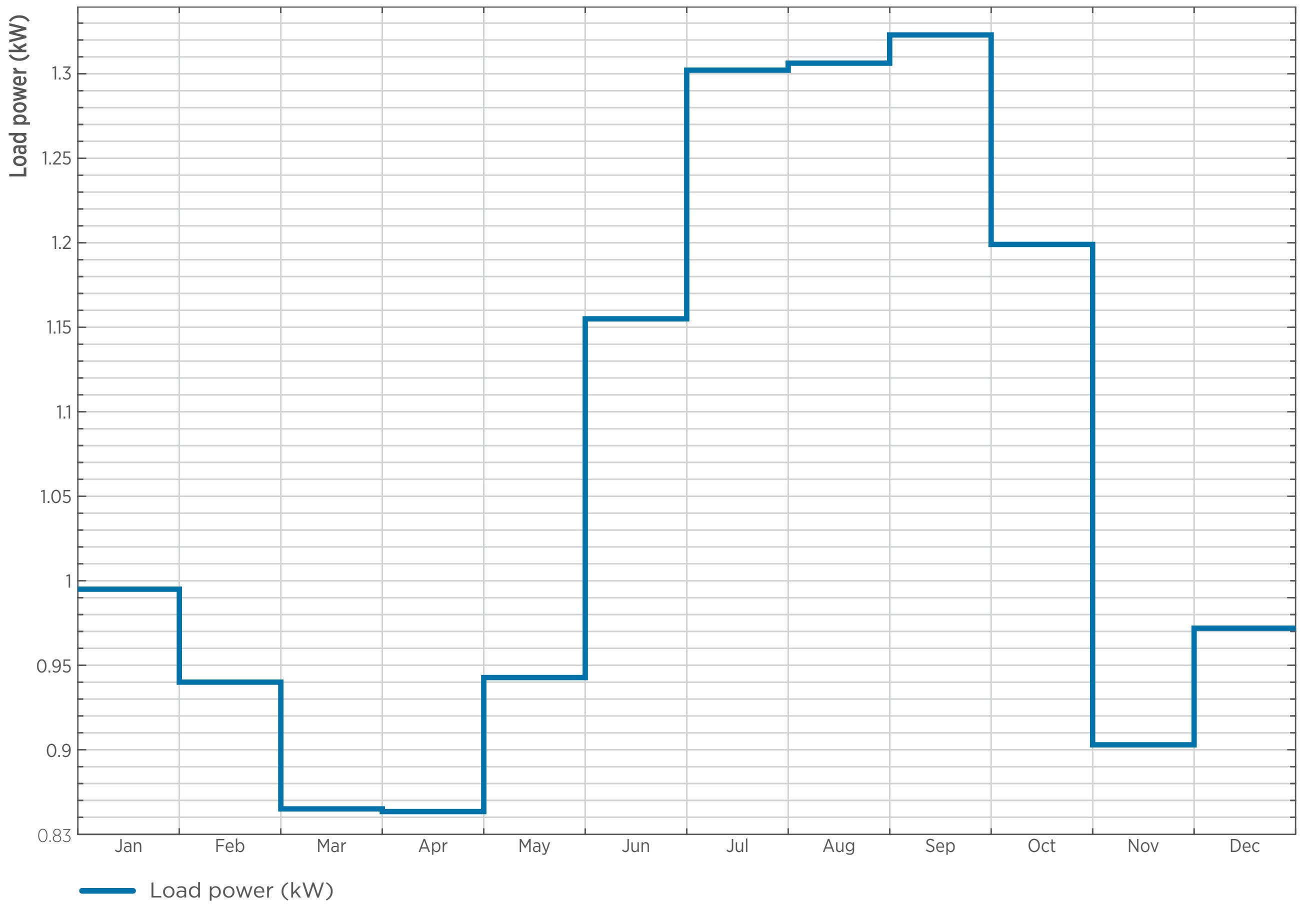
Source: EERE, 2015; NREL, 2015c.

Figure 76: Average hourly load profile for each month assumed for San Diego



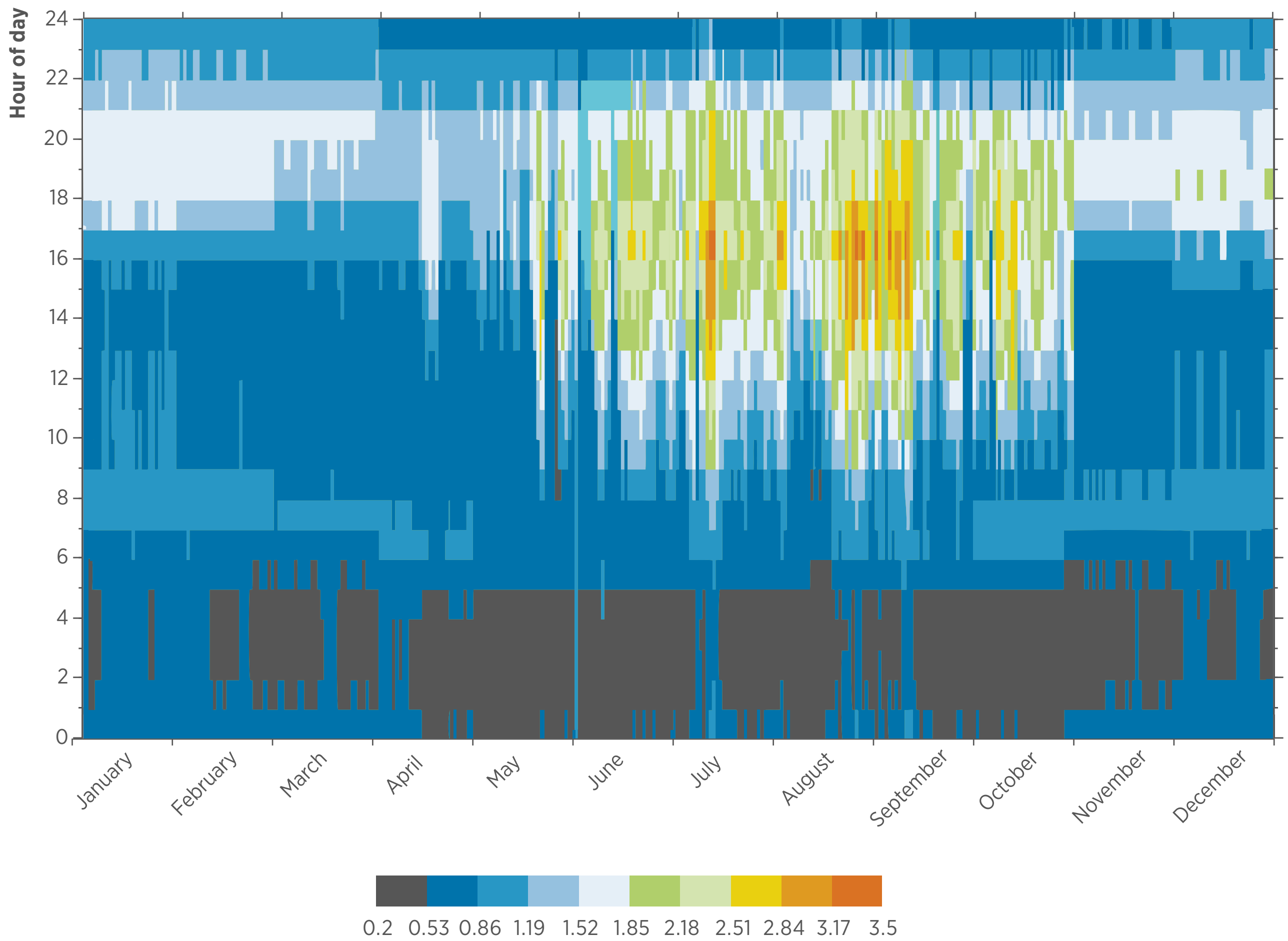
Source: EERE, 2015; NREL, 2015c.

Figure 77: Average hourly load profile for each month assumed for San Bernardino



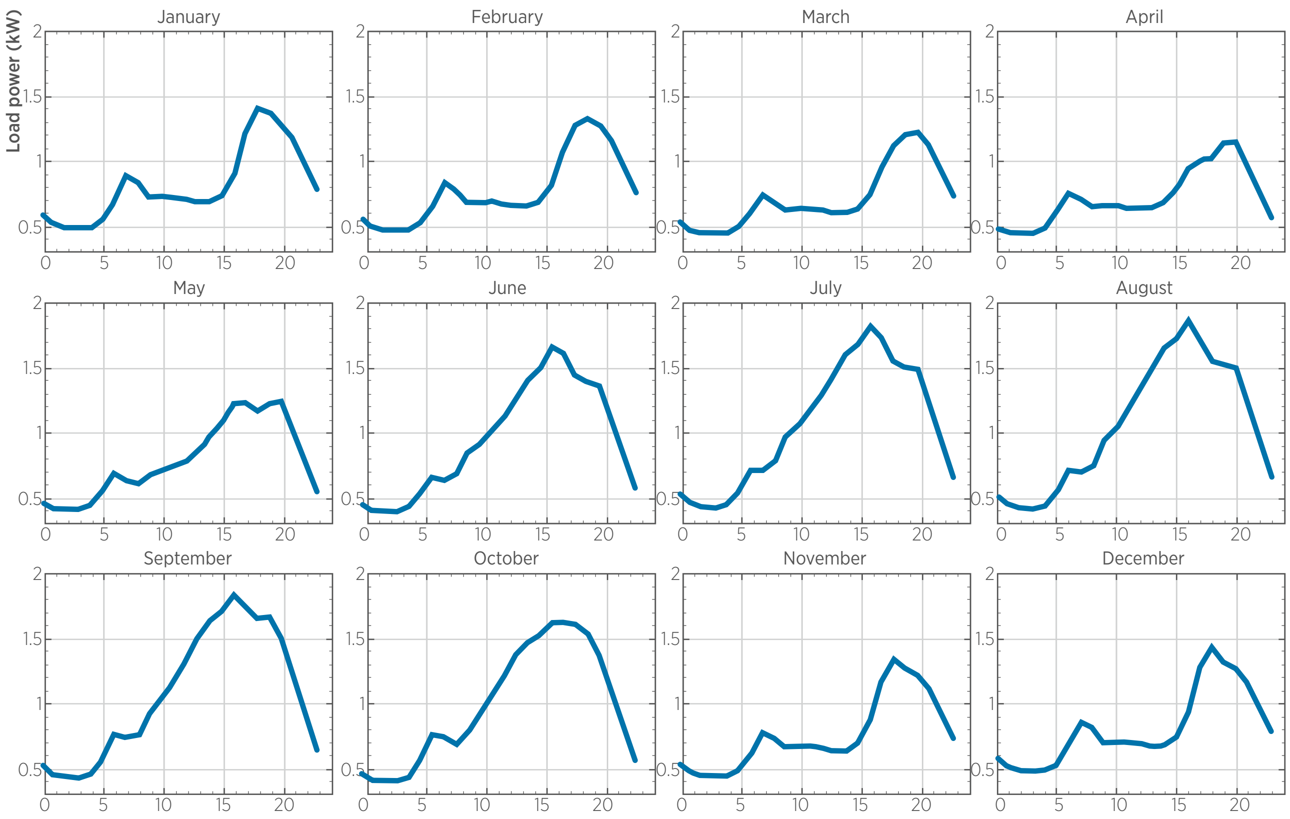
Source: EERE, 2015; NREL, 2015c.

Figure 78: Heatmap of hourly load values assumed for San Bernardino



Source: EERE, 2015; NREL, 2015c.

Figure 79: Average hourly load profile for each month assumed for San Bernardino



Source: EERE, 2015; NREL, 2015c.

ANNEX III: GERMANY

This annex contains information about data collection, along with the specific assumptions made for the present edition when analysing residential PV costs and competitiveness trends in the five German metropolitan areas selected for study.

LCOE CALCULATION FOR SOLAR PV

Maintenance costs

O&M costs are assumed to be 1% of total system costs. For the Q1 2010 to Q2 2016 period analysed, O&M costs range between USD 14.18/kW and USD 35.77/kW per year. These values are in line with those reported elsewhere for residential PV systems in Europe (Theologitis and Masson, 2015; Vartiainen et al., 2015).

PV electricity generation

For the German locations, electricity generation is modelled according to the methodology presented in Annex I. This uses the following weather files as inputs into NREL's SAM software, while SAM's default tilt of 20° and Azimuth orientation of 180° (true South) settings also were chosen.

Table 12: Weather data file information and modelled PV electricity output for the German locations analysed

	Cologne	Hamburg	Berlin	Frankfurt	Munich
Weather station name	Germany DEU Koln (INTL)	Germany DEU Hamburg (INTL)	Germany DEU Berlin (INTL)	Germany DEU Frankfurt_Am_ Main (INTL)	Germany DEU Munich (INTL)
Weather station code	105130	101470	103840	106370	108660
Average temperature [° C]	9.9	9	9.8	10.1	8
PV system yield, year 1 [kWh/kW]	850	857	874	914	991

Source: NREL, 2015b; NREL, 2015c.

ELECTRICITY PRICES

Dataset

The electricity cost dataset from the German Association of Energy and Water Industries (*Bundesverband der Energie- und Wasserwirtschaft – BDEW*) was used for comparison with LCOE estimates. Federal weighted average rate estimates were then used in each of the analysed locations. Regional differences exist across the country, and they are more significant in some of the cost components than in others, notably in "procurement/sales" and "grid fees". This is because different territories may have different providers and network operators and grid fees, which may shift prices. A detailed analysis of the German regional pricing differences is beyond the scope of this report, and such regional pricing differences have been ignored for now. They may, however, be analysed in later editions, as data availability and resources allow.

Real vs. nominal euros

Electricity prices were obtained in nominal euros and were converted to real euros, as of Q2 2016, using the following deflator series.

Table 13: Deflator EUR series

Period	Deflator
Q1 2010	97.9
Q2 2010	99.9
Q3 2010	100.7
Q4 2010	101.5
Q1 2011	103.3
Q2 2011	103.5
Q3 2011	104
Q4 2011	104
Q1 2012	104.4
Q2 2012	104.5
Q3 2012	104.7
Q4 2012	104.2
Q1 2013	104
Q2 2013	104.9
Q3 2013	105.4
Q4 2013	105.8
Q1 2014	106.4
Q2 2014	106.3
Q3 2014	106.6
Q4 2014	107.5
Q1 2015	107.7
Q2 2015	108.2
Q3 2015	108.5
Q4 2015	108.9
Q1 2016	109.6
Q2 2016	110.1

Source: Eurostat, 2016b (reference: Germany).

www.irena.org