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Estimating the diffusion of rooftop PVs: A real estate economics perspective

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1. Introduction

Urbanisation is accelerating the growth of cities; as a result, the built environment already receives over half of all new global investments. On the other hand, buildings consume roughly 40% of final energy and produce 40% of carbon emissions [1]. Decentralised on-site renewable energy production is often suggested as an interesting option for buildings to reduce their carbon footprint significantly. However, investments into on-site production have not picked up the pace necessary for efficient climate mitigation, and subsequent climate policies are lacking. One obvious reason is that on-site solar production is considered more expensive than conventional off-site production. The cost comparison between different electricity generation technologies is typically calculated using the levelized cost of electricity (LCOE) approach. Accordingly, current on-site implementation schemes are estimated based on optimising the LCOE rather than understanding how on-site production creates value for the energy user, i.e. customer.

Vimpari and Junnila [2] recently published an article that questions the use of the LCOE in the case of rooftop solar photovoltaic (PV) investments. The article claims that the LCOE approach is based on an outdated transformation concept of mass production. The paper presented an approach based on customer value logic, where the goal of decentralised energy investments is to satisfy customer needs. In the case of rooftop PVs, the customer is the property owner, whose value is driven by real estate economics. When properly assessed, the on-site production in urban areas increases the value of the underlying properties more than the capital cost of the on-site production investment. If this decision metric is acknowledged, it could speed up significantly the capital flow into on-site installations and reduce the climate change impact of the built environment.

This article continues to develop the customer value logic concept, where the PV investment is based on the value that the produced energy creates for the underlying property and where the investment models typical for real estate economics are utilised for a profitability evaluation. As spatial locations drive the economic analysis of real estate, the concept implies that the spatial locations should drive the economic analysis of decentralised on-site energy investments as well.

To understand the background of this study, two main lines of literature are briefly covered here: how the economics of rooftop
solar PV investments is analysed in the current literature and, concurrently, how subsidy schemes affect the economics. The literature provides a rationale for why different kinds of profitability analyses are carried out by different authors. The subsidy schemes are assessed to collect argumentation concerning why net metering (NM) is a lucrative alternative to increase the diffusion of rooftop PVs. Prol and Steininger [3] assessed the PV self-consumption regulation in Spain and conducted a profitability analysis based on alternative regulation schemes. They chose the internal rate of return (IRR) as the methodology to compare the profitability of PV with that of other investment types in different regulation landscapes. IRR was chosen because it is a relative measurement not requiring an estimation of the discount rate, as necessitated by the net present value (NPV). The following schemes were assessed and defined in their paper. These definitions are used later in this paper as well:

- NM: both self-consumed electricity and surplus electricity are valued at the same price
- Net billing (NB): surplus electricity is valued at a lower price than that at which it is bought from the grid.

The authors found that under Spain’s regulation, rooftop PVs are only profitable for residential customers. The commercial and industrial segments could realise profitability by introducing a dynamic NB price, where the surplus energy would be valued somewhere between the wholesale and retail prices. In addition, charges for self-consumption should be avoided to maximise self-consumption.

Orioli and Di Gangi [4] analysed the changes in Italian policies for PV generation. They conducted an extensive review of different support policies for PVs in both Italy and globally, mostly focusing on feed-in-tariff (FIT) policies but also on other supporting policies, such as NM. The paper also presents an overview of different methods for measuring the economics of PV systems, identifying the NPV, IRR, discounted payback (DPB) and LCOE as potential methods. The paper questions whether the LCOE is the most suitable method for an economic analysis of rooftop PVs. Instead, they mostly focus on DPB, which measures the break-even time for the NPV to calculate the moment when grid parity is reached. Grid parity is defined as the time when the cost of the energy produced by renewable energy sources becomes competitive with conventional electricity. They concluded that policy changes may increase the economic profitability of PVs in urbanised areas, but currently, the LCOE of rooftop PVs is not competitive with conventional electricity generation.

Dufo-López and Bernal-Agustín [5] conducted a comparative assessment of NM and NB policies, and they discussed their relevance compared to the new Spanish self-consumption regulation. The paper develops and uses a rigorous mathematical methodology for an economic evaluation of rooftop PVs. Ultimately, it was used to calculate the LCOE of rooftop PVs under different scenarios. They conclude, ‘A real net metering policy (like in many states in the United States) where the energy exported is valued the same (1:1) as the energy imported would imply a much higher profitability for the PV system and would encourage the development of the PV sector’ [5].

Eid et al. [6] explain quite thoroughly how different NM schemes work and which network costs are related: cross subsidies, distribution system operator cost recovery, distributed generalisation incentives, self-consumption and storage incentives, cost causality and renewable energy. The paper addresses carefully how network costs under different rolling credit lengths (i.e. for how long the excess energy is remunerated) affect the profitability of solar PVs. The paper then evaluates which network costs or tariffs should be implemented for the optimal diffusion of PVs. In addition, the effect of network costs as a motivation to install on-site energy storage is analysed. The type of network costs determines whether the network itself could be used as energy storage rather than separate storage by individual customers. The study concludes by providing recommendations regarding grid tariffs and metering policies to increase the understanding of the potential of rooftop PVs.

Chiaroni et al. [7] focused also on the role of self-consumption when evaluating the profitability of rooftop PVs. In their paper, they used NPV and DPB for an economic evaluation and assessed industrial and residential customers as their own segments. They conclude, ‘An increase in self-consumption share is a key strategy that could be used in a mature market. The improvement of consumption behaviours can significantly contribute to a country’s environmentally sustainable energy practices and define a country as more sustainable’ [7].

Spretino et al. [8] analysed the profitability of rooftop PVs in Italy and Germany under different FIT regulations. The paper conducts a profitability analysis with both IRR and NPV. Interestingly, different interest rates are chosen for residential and commercial rooftop PV investments. This is important when the NPV is chosen as a method for a financial evaluation. The study found that for the assessed period of 2006–2012, the profits of rooftop PV systems in Italy (IRR –20%) were almost double those in Germany (IRR −10%), depending on the system size and regulations.

Darghouth et al. [9] examined what affects the electricity bill savings under current NM rules in California based on three alternative rules. A careful analysis of technical PV characteristics was used to create production profiles, which were then used to analyse the economic benefits of self-consumption and compensation for excess generation sold to the network. The paper highlights how a rolling credit period and self-consumption or the PV-to-load ratio affects the profitability of rooftop PVs. The paper also discusses which kind of NM rule would be best for the optimal diffusion of rooftop PVs.

Three main issues affecting the profitability of rooftop PVs were identified from previous research. First, the relationship between self-consumption and excess production has a significant effect on profitability. Second, the compensation scheme for excess production affects how much economic value is created for the rooftop PV owner from self-production and from excess consumption. In addition, the role of the compensation mechanism for key stakeholders—i.e. network owners (e.g. lost revenue) and/or the government (e.g. lost taxes)—is important. Third, the final deductions based on the PV investment’s size and economic performance are influenced by the approach selected. Currently, the economic performance is predominantly calculated using the LCOE approach, but the closely related IRR, NPV or DPB approaches are also suggested in the literature. This paper follows Prol and Steininger [3] and Vimpari and Junnila [2], as they suggest that the LCOE is not a suitable approach when evaluating rooftop PV investments.
However, we would like to claim that viewing rooftop PVs as only an energy production investment is too simplistic and that the proper economic value and climate mitigation potential of rooftop PVs can be assessed only if the market mechanisms and characteristics of the underlying building stock are understood better. First, we need to utilise building-specific location-dependent property market information about expected returns on property investments, i.e. property yields in real estate economics. This gives us the correct discount rates for an investment evaluation. Second, solar energy production's potential and the energy consumption profile of each building need to be collected and connected to real property-specific yields. Third, PV plant size-dependent capital expenditure (CAPEX) and operating expenditure (OPEX) cost structures have to be utilised. Finally, building user-sensitive electricity pricing should be used, as the end user price variation is high. These improvements allow us to optimise the correct plant size for each building and conclude the economically rational mitigation potential of the urban setting.

The purpose of this paper is to use a customer-driven investment model to examine the feasible market potential of rooftop PV installations in the built environment. The aim is to optimise the economic profitability of the large-scale adoption of on-site solar production in a metropolitan region. In terms that are more technical, the study optimised the NPV for solar production so that it maximises the absolute returns for the property owners in the Helsinki Metropolitan Area (HMA), Finland. Together, this allows us to calculate economically the lucrative adoption rate of rooftop solar PVs under the current regulation scheme and to later compare it with the suggested NM policy. Finally, the economic costs and benefits of NM are estimated for key stakeholders (individual property owners, network distributors and the government) at the system level.

The paper conducts a detailed analysis of all residential, industrial, office and retail buildings in the HMA. The solar production potential and economic returns of PV installations are calculated for 89,000 buildings (83% of the total building stock in HMA) separately. Several sources of information are drawn together for a detailed technical and economic analysis of every individual building within the area. After comparing the solar returns to the underlying spatial property returns, the adoption years of rooftop PVs for different areas in the city are estimated. The implications for CO2 emissions are estimated, and the impact of an NM policy on the rate of adoption is calculated.

The results imply that in Finland, rooftop solar PVs are already profitable for a third of the residential building stock and will be profitable for a fourth of the commercial building stock by 2025. The market size for rooftop PV installations in the HMA is roughly 1 billion €, equalling the implemented capacity of approximately 1 GWp. Finally, the NM implication scheme could increase substantially the diffusion rate of solar PVs in the coming years, where increases of over 40% for residential properties and over 60% for commercial properties could be seen.

The results also suggest that even under Finnish conditions, where both electricity prices and solar irradiation are among the lowest in the world, rooftop PVs are a lucrative opportunity for climate mitigation. The methodology and results presented are also important for both academia and practice, as it is the first large-scale study to connect real estate to energy economics.

2. Research methodology and data

This article continues to develop the customer value logic concept presented by Vimpari and Junnila [2]. The concept posits that PVs should be considered a part of the underlying property, as its technological lifecycle and risk levels are similar to the property itself. With the concept, the PV investment should be valued similarly to the underlying property, and thus, investment models typical for real estate economics should be utilised when analysing the profitability of rooftop PV systems. As spatial locations drive the economic value of real estate, similarly, the location should drive the economic analysis of decentralised on-site energy investments. This has important implications; namely, rooftop PV investments are most profitable in dense urban cores instead of more remote or industrial locations; thus, the current trend of urbanisation seems to strengthen further the profitability of rooftop solar power.

Real estate economics are utilised for analysing the adoption of rooftop PVs. The data are gathered from several sources covering property market information from private data producers, technical building data from the city’s building surveying departments, hourly electricity consumption data from energy distributors and hourly solar production data from solar irradiance providers.

The building technical property information dataset includes the following data entries for every building in the cities of Helsinki, Espoo and Vantaa (HMA); property identifiers, date of construction, frame construction material, floor space, number of floors, heating type, type of use, address and postal code. The data have been gathered from the surveying units of the accompanying cities [10–12] and the corresponding commercial offices (logistic, retail). industrial locations; thus, the current trend of urbanisation seems to strengthen further the profitability of rooftop solar power.

The methodology and results presented are also important for both academia and practice, as they cover all commercial (office, logistic, retail) and residential buildings in the HMA: 89,000 buildings and 71 million square metres (sqm). There are over one million residents in the HMA, and the data cover 83% of all buildings in the area. Buildings that are not included are public (schools, transportation, hospitals, museums, sports, etc.), agricultural and vacation properties. These were excluded, as these property types are not considered investment-class properties; consequently, there is no property market information available for these properties.

2.1. Available roof area for solar

A building’s roof size is approximated by dividing the floor area by the number of floors. The number of floor data for logistic buildings were adjusted so that all logistic buildings have only one floor. This was done because most logistic buildings are one floored, but they often have a separate, small two- or three-floored office on one side of the building (the original data show only the number of the floor of the highest part of the building). Once the roof area was defined, the available roof area (ARA) for solar PV had to be estimated, as not all of the area is suitable for solar PVs. Previous researchers have provided a methodology and estimates concerning this. Nowak et al. [13] presented a methodology for estimating the ARA by calculating the architecturally suitable area where shading, inclination and different physical obstacles, such as heating, ventilation and air conditioning (HVAC) systems are considered. Furthermore, only roof areas where 80% of the maximum annual local solar irradiance is received were accounted for in the ARA. As a result, Nowak et al. [13] proposed the use of a coefficient of 0.4 as a rule of thumb for calculating the average ARA. Many studies have used this coefficient; for example, Defaux et al. [14] estimated the technical potential of solar PVs in EU 27 countries. More recently, Singh and Banerjee [15] provided a great compilation of other studies that have analysed the ARA coefficient. Based on 11 research papers, it was found that the coefficient ranges from 0.145 to 0.95 in different countries. In their own study [15] to analyse solar potential in Mumbai, India, they decided to use a coefficient of 0.28, a more conservative number. Meanwhile, Wiginton et al. [16] analysed the solar potential in Ontario, Canada. Under a conservative approach, they decided to use a coefficient of 0.3 for flat roofs (large buildings) and 0.15 for peaked roofs (residential and smaller buildings), where only 50% of the roof is assumed to be on a good
inclination. Similarly, Bergamasco and Asinari [17] used a coefficient of 0.145 for residential buildings and 0.405 for industrial buildings. Previous research has often first estimated the building size and then the ARA. It is worth noting that in this study, the building size is known, so uncertainty comes from the coefficient used.

It seems that previous studies often use different coefficients for residential and non-residential premises. In this study, non-residential premises are further divided into office, retail and logistics. This division is done because the amount of rooftop obstacles differs between commercial building types (e.g. offices having more HVAC systems than industrial buildings). This has also been verified by analysing dozens of satellite pictures of different types of buildings and measuring the available space for rooftop PVs. Based on the previous literature and our own analysis of rooftops, ARA coefficients of 0.15, 0.175, 0.2 and 0.3 are used for residential, office, retail and logistics buildings, respectively. To clarify, these coefficients are expected to include the area needed for the installation and servicing of the PV system.

2.2. Roof PV system size

The calculated surface for solar is converted into the solar PV power capacity by dividing the ARA (sqm) by the number of sqm needed for 1 kWp of solar. This number is related to the efficiency and type of panel used. Currently, crystalline-based solar PV panel types have a market share of over 90% [18]. A common panel size nowadays is 1.6 sqm, and the nominal power range is between 260 and 285 Wp per panel. Therefore, 1 kWp requires approximately 6 sqm of area. Finally, the equation for calculating the nominal power capacity (kWp) potential of solar PVs per building type (PVu) is as follows:

\[
PVu = \frac{\text{number of floors} \times ARA}{6}
\]

where \( u \) represents whether the building is residential, office, retail or logistics and \( ARA_u \) is the respective coefficient of usable rooftop space for PVs.

2.3. Electricity consumption and solar electricity production

The electricity consumption per building type was estimated from real energy consumption data provided by a large Finnish energy company. Vantaa Energy [19] provided hourly electricity data for the year 2016 for different types of buildings. Due to customer privacy restrictions, the consumption data were provided by aggregating the consumption data of 10 buildings (of each type) together and providing the aggregate number for each hour of the year. As the aggregated building floor area for these buildings was also provided, the electricity consumption, tracked as kWh/sqm/hour, could be defined for each building type. The electricity data provided were for buildings under district heating. Buildings using electric heating naturally have a higher electricity consumption. To account for this, Vantaa Energy [20] also provided hourly heat consumption data so that it could be used to calculate how much more electricity is consumed by buildings using electric heating instead of district heating, as the building data identify the heating source. The hourly heating data were converted into the increased electricity demand with a ratio of 1:1, i.e. one kWh of heating increases the electricity demand for one kWh for the accompanying hour.

Fig. 1 presents these hourly consumption profiles for each building type for one week of June 2016, where the eh in the figure stands for buildings that use electric heating. In addition, solar production per panel sqm (i.e. ~167 Wp) is presented in the figure. Vartiainen et al. [21] estimated that the average annual solar yield is 930 kWh per kWp in Helsinki, Finland. However, as a conservative approach, this number is multiplied by 90% to calculate the average solar yield, i.e. in this study, 837 kWh per kWp is used. Solar production has been calculated for every hour of the year 2016 based on real hourly irradiance data for a measurement spot in the city of Vantaa [22], but it has been scaled so the average solar yield is 837 kWh/kWp per annum.

The figure can be used to interpret the relationship between floor area and panel area. The lower the ARA (ARAu coefficient) compared to the floor area, the lower the amount of solar production per sqm. It can be observed that the consumption for non-residential buildings matches the solar production rather well if the system size is measured properly. Yet, on the weekends (the hours between 120 and 168), it is observed that consumption is especially lower for offices and industrial activities, i.e. there is more excess production than consumption.

2.4. CAPEX and OPEX

The Fraunhofer Institute of Solar Energy Systems in Germany publishes a quarterly report covering, among other data, the price developments of rooftop solar PV plants. In their February 2018 report [18], they estimated the investment cost of rooftop systems sized 10–100 kWp to be 1150 €/kWp for Q4/2017. Because the PV market is developing so rapidly and the cumulative amount of solar PVs installed is constantly underestimated, as presented by Creutzig et al. [23], many of the scientific papers estimating the solar PV CAPEX can become outdated rather quickly. Thus, estimates in this paper are based on Fraunhofer’s [18] findings, as well as on discussions with rooftop solar PV installers in Finland. Table 1 presents the plant size range in kWp and the accompanying price per kWp (EUR/kWp). Residential buildings have a separate price, as their price includes the value-added tax (VAT) (24%, which is non-deductible for consumers). Furthermore, in Finland, only commercial PV systems are eligible for an investment subsidy of 25% over the total investment cost. The prices in the table are unsubsidised prices; however, the subsidy is considered in later calculations. The OPEX is expected to be 1.5% of (unsubsidised) the CAPEX annually based on the previous literature [2,3,21,24]. In the analysis, it is expected that the CAPEX will have an annual decrease of 3.0% based on Vartiainen et al. [21] and market observations.
distribution fees for self-consumption. Residential buildings are expected not to have to pay taxes and owners paying taxes and distribution costs. However, there are residential apartment building blocks cannot distribute the electricity consumed on site, are also seen in other European countries, such to the electricity tax [29]. Similar restrictions, tied to the amount 800 MWh per year, then the entire produced amount is subjected However, in Finland, there is a law that if you produce more than distribution, as these have important implications for the analysis. The taxes part in the table represents the Finnish electricity tax, and the distribution part (i.e. network costs) for commercial users has been calculated by deducting the taxes and spot price from the total price. In the empirical analysis, electricity prices are expected to have an annual increase of 2.5% in real terms. For example, in Germany, the consumer price index (CPI) has increased annually by 1.4% [27], where the CPI for consumer electricity prices has increased annually by 4.1% in the same period [28]. Similarly, consumer electricity prices in Finland have increased more rapidly than the CPI [25].

Total electricity prices are broken down to taxes, energy and distribution, as these have important implications for the analysis. In Finland, when you generate PV electricity for self-consumption, the value of the electricity is the total electricity price for the proportion that is used for self-consumption. The surplus sold to the grid receives only the spot price. Thus, self-consumption is much more valuable, as the building owner avoids taxes and distribution costs. This kind of regulation is often defined as NB (e.g. Ref. [3]). However, in Finland, there is a law that if you produce more than 800 MWh per year, then the entire produced amount is subjected to the electricity tax [29]. Similar restrictions, tied to the amount consumed on site, are also seen in other European countries, such as Austria, Germany and Italy [29]. In addition, in Finland, residential apartment building blocks cannot distribute the electricity to individual apartments in the building without the apartment owners paying taxes and distribution costs. However, there are already policy suggestions to remove this obstacle. In this article, all residential buildings are expected not to have to pay taxes and distribution fees for self-consumption.

2.5. Electricity prices

The electricity prices for different consumer types and consumption amounts are presented in Table 2. The prices are the average national prices for different consumer types in Finland in 2017 [25]. In addition, the average Nordpool [26] hourly spot price for Finland is listed in the table. The residential prices include VAT. The curves show that setting the surplus to 0% does not maximise the NPV. This is because self-consumption keeps increasing as the plant size increases. Once the tangent of self-consumption starts flattening, the NPV starts decreasing because the surplus role in the valuation increases. If a lower discount rate is used (i.e. the future cash flows have a higher present value due to discounting), the whole curve is shifted, and a larger PV system is recommended with a higher surplus.

The ratio between self-consumption and surplus production has the largest effect on the calculations as an example, if self-consumption is low in the summer and during weekends, a larger part of the production is sold to the grid. Thus, in this study, the building-specific consumption information is used together with the PV production information to calculate the optimal ratio for every building in the dataset. Finally, the NPV formula with the}

<table>
<thead>
<tr>
<th>Type of user</th>
<th>kWh (min)</th>
<th>kWh (max)</th>
<th>CAPEX (EUR/kWp)</th>
<th>OPEX (EUR/kWp p.a.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>0</td>
<td>4999</td>
<td>1600</td>
<td>240</td>
</tr>
<tr>
<td>Commercial</td>
<td>0</td>
<td>20</td>
<td>1300</td>
<td>19.5</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>100</td>
<td>1100</td>
<td>16.5</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>300</td>
<td>1000</td>
<td>15.0</td>
</tr>
<tr>
<td></td>
<td>300</td>
<td>900</td>
<td>900</td>
<td>13.5</td>
</tr>
</tbody>
</table>

2.6. Optimising the economically best plant size

The economic value difference for self-consumption and surplus production leads to important implications for scaling the system, as the owner starts to minimise the surplus consumption along with growing value differences. The owner aims to construct a system that maximises profits. Therefore, the optimal system size is one that maximises the NPV for the owner. The NPV is one of the most common metrics for measuring and comparing investments, as it is used to calculate the present value of all future cash flows and deduct the initial investment from the present value (see Eq. (2)). The decision boundary for the NPV is as follows: if the NPV is positive, invest; otherwise, do not. The NPV is used instead of another common comparison method, the IRR, because the plant size is optimised based on the property yield (discount rate).

\[
NPV = -CAPEX + \sum_{t=1}^{T} \left( \frac{(E_{se}^*P_{se} + E_{su}^*P_{su})^*(1 - d) - O_t)}{(1 + r)^t} \right), \tag{2}
\]

where CAPEX is the initial investment cost of the PV system, t is the lifecycle of the investment, \(E_{se}\) and \(E_{su}\) are the respective amounts of electricity generated for self-consumption and surplus, \(P_{se}\) and \(P_{su}\) are the respective prices of electricity for self-consumption and surplus, d is the annual degradation of the system production, O is operating costs and r is the discount rate.

The economic lifecycle, t, for PV systems is often considered 30 years [21,30], and it is used in this paper as well. The annual degradation is assumed 0.5% [31]. The discount rate is the property yield, which is presented in more detail in the next section below. As the net cash flow is based on the value of the electricity, the relationship between self-consumption and surplus generation is important to understand, as well as how the discount rate affects the NPV. Fig. 2 is used to demonstrate how the NPV maximises the relationship between surplus electricity and economic profitability with two different discount rates.

The curves show that setting the surplus to 0% does not maximise the NPV. This is because self-consumption keeps increasing as the plant size increases. Once the tangent of self-consumption starts flattening, the NPV starts decreasing because the surplus role in the valuation increases. If a lower discount rate is used (i.e. the future cash flows have a higher present value due to discounting), the whole curve is shifted, and a larger PV system is recommended with a higher surplus.

The ratio between self-consumption and surplus production has the largest effect on the calculations as an example, if self-consumption is low in the summer and during weekends, a larger part of the production is sold to the grid. Thus, in this study, the building-specific consumption information is used together with the PV production information to calculate the optimal ratio for every building in the dataset. Finally, the NPV formula with the

![Fig. 2. Illustration of plant optimisation based on the NPV.](image-url)
building-specific yield is used for optimising the PV plant size for each building. As can be seen from the figure, the discount rate has a significant effect on the system size. Interestingly, if an NM scheme is allowed, the building-specific production-to-consumption ratio does not have an influence on optimisation, as both electricity fractions have the same value.

2.7. Property yield

Property market information is used to define the correct discount rates for the analysed buildings. As explained by Vimpari and Junnila [2], the location drives the discount rate in real estate economics. In practice, property market professionals and researchers estimate correct discount rates for different locations, and these are used as a basis for property investment decisions. In this study, property market information is provided by Datscha [32], which is a map-based property database, where large property consultants and researchers provide property yields and other relevant information for different locations. The yields are estimated for certain locations (areas) within the city. The specific yield for a certain location represents the risk-return level of a property investment within the area. The particular data used in this study are provided to the service by Newsec, which is the largest property consultant in Nordic countries. Table 3 provides a compilation of the data used.

Newsec’s data in the HMA cover a different number of locations for different types of properties. For example, office properties have 40 different yield areas in the HMA. In these areas, the office yields (for buildings constructed in 2010–1) range from 4.0 to 7.8%, depending on the risk level. For instance, the Helsinki central business district has the lowest yield (4.0%), because there, the risk is the lowest, whereas the highest office yield (7.8%) is in a more remote location in the city of Espoo, where the office market does not function that well. The yields defined by experts do not follow the postal code area of the same location, but rather the district characteristics. In this study, the district-based yield was converted into the most relevant postal code location to connect a specific property to a specific yield. This is not observed to have a significant impact on the interpretation of the results of this study.

2.8. Property value increase

A property is expected to invest in solar when the economic solar yield is higher than the property yield. According to Vimpari and Junnila [2], when this happens, the property value increases from the rooftop PV system are higher than the investment required for the system. The property value increase is calculated using the direct capitalisation method, as presented by Vimpari and Junnila [2]: ‘The property value increases because the produced electricity decreases the operating expenses of the property. This is explained with the following direct capitalization property appraising formula:

\[
\text{Property value} = \frac{\text{Net rental income} - \text{Operating expenses}}{\text{Property yield}}
\]

(3)

the property appraising logic indicates that if the PV yield is higher than the respective property yield, the property value increase is higher than the investment cost for the PV system. This creates extra value for the property owner due to the electricity generated by the PV system.

2.9. Adoption year

If CAPEX is expected to decrease and electricity prices to increase in the long term, the adoption rate of solar PVs can be calculated. Above, the expected CAPEX decrease (3% p.a.) and electricity price increase (2.5% p.a.) have been presented. The property yields are expected to remain unchanged in the long term based on historical data (e.g. Ref. [33]). In the results, the year of the adoption of solar is calculated for every building in the dataset until the year 2040.

2.10. Net metering: benefits and costs

The results are also calculated under an NM scenario, where the surplus production also receives the full price, i.e. it is assumed that the solar production is net-metred between the grid and the buildings under an annual rolling credit. This scenario allows for the calculation of the fastest adoption rate and the benefits gained from it, as well as the amount of extra costs it would generate to different parties. The benefits for the property come from the income from electricity generation and increased property values, costs from investments in the rooftop PV system. It is questionable whether there are any benefits to the network operator, but costs certainly arise from lost distribution fees. The extra costs for the government are from lost income on electricity taxes and more subsidies on investment aid (commercial properties). In addition, there are losses on the income VAT for residential properties, but there are also benefits from an increased VAT from residential rooftop investments. Another benefit is the saved CO₂ emissions, which can be calculated by defining the CO₂ savings and then setting a value for the saved CO₂.

2.11. Social cost of carbon

The climate mitigation influence is estimated by comparing the average CO₂ emissions of rooftop solar PVs to marginal emissions from the Finnish electricity system. For rooftop solar PVs, 42 CO₂g/kWh is used based on Schrömer et al. [34]. Recently, Bakhtyer et al. [35] used 32 CO₂g/kWh for solar PVs; however, 42 CO₂g/kWh is used, as production in Finland is on average less than in southern

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1 It is noted that Newsec provides three observations (max, median and min) for two construction decades (buildings constructed prior to 1990 and after 1990). Thus, in this paper, the construction years of 2010–present, 2000–2009 and 1990–1999 are based on the three observations, but the yields before 1990 have been defined by adding 0.2% to each yield location per every decade. This was done to increase the risk-return levels for older buildings, as the technical data include the construction year for every building.
countries. The above numbers are based on a lifecycle analysis, i.e. including all emissions of the system from production to disposal. Saikku et al. [36] calculated how much solar PVs reduce CO2 emissions in the Finnish electricity system, and they pointed out that the real savings come from the emissions of marginal CO2 production. They estimated that solar PVs could save 750–800 CO2g/kWh in Finland based on data representing the year 2011. Fraunhofer [18] showed that solar PVs on average save 580 CO2g/kWh. The average emissions of Finland’s electricity system were approximated as 164 kWh/kg by Motiva [37]. However, Motiva has shown that the marginal emissions per kWh are as high as 600 CO2g/kWh. As Saikku et al. [36] clarified, past research has shown that estimating the true savings is not that straightforward. In the empirical analysis, 558 CO2g/kWh is used as the saved emissions from solar PVs (i.e. the difference between 42 CO2g/kWh and 600 CO2g/kWh). Because the electricity markets in Europe are likely more united in the long term (as has been already determined for the case of Nordic markets), the average saved emissions that is closer to European markets (e.g. Fraunhofer’s [18] estimate in Germany) could be also justified.

As this paper aims to estimate the total cost-benefits from solar PVs, the social cost of carbon (SCC) is used to calculate the value of saved emissions. Tol [38] has described the SCC as an estimate of a Pigou tax that should be placed on carbon dioxide emissions. Tol [38] analysed 211 studies on the SCC and found that it is increasing over time and there are uncertainty factors for measuring the correct SCC. The Gaussian mean for the SCC in studies was 88 USD/tCO2 and tCO2 with a standard deviation of 243 USD/tCO2. Ackerman and Stanton [39] similarly found that there is much uncertainty in measuring the SCC, and it is expected to grow over time. They found that the SCC could be as high as 900 USD/tCO2 in 2010, when high climate sensitivity, high damages and low discount rates are considered. They also suggest that spending up to 150 to 500 USD/tCO2 is justified, past research has shown that estimating true savings is not that straightforward. In the empirical analysis, 558 CO2g/kWh is used as the saved emissions from solar PVs (i.e. the difference between 42 CO2g/kWh and 600 CO2g/kWh). Because the electricity markets in Europe are likely more united in the long term (as has been already determined for the case of Nordic markets), the average saved emissions that is closer to European markets (e.g. Fraunhofer’s [18] estimate in Germany) could be also justified.

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2.12. Scenarios

Finally, three main scenarios are analysed to estimate the diffusion of rooftop PV systems.

- Zero surplus: the system is sized by constructing a maximum-sized system that produces no surplus energy.
- NB: the system is sized by maximising the NPV of the system, i.e. optimising the ratio between self-consumption and surplus production. It is referred to as an NB scenario, as the self-consumed and surplus energy have different prices. The surplus energy is valued at the energy (spot) price, while the self-consumed energy is valued at the total electricity price, i.e. energy + taxes + distribution.
- NM: NM is allowed, i.e. a maximum-sized system should always be constructed, as the surplus energy has the same value as self-consumption, and the CAPEX of the system decreases for larger systems (commercial only). This results in maximising the system’s profitability.

In addition, it is assessed how removing the above-mentioned 800 MWh p.a. production taxation would affect the profitability and adoption rate.

3. Results

3.1. Maximum rooftop PV capacity

Table 4 presents the descriptive statistics for all 89,000 buildings in the dataset. The calculated ARAD and PVP represent the maximum electricity production for all buildings, i.e. if the full ARA is utilised. Accordingly, solar production from these rooftop PV installations could cover 15% of all electricity consumption in the HMA. The electricity consumption is the approximated consumption of the properties in the HMA, as it is based on the constructed electricity consumption profiles.

The commercial buildings count for over half of the full potential, even though there are only 5000 commercial buildings and almost 84,000 residential buildings. The average plant size of commercial buildings is much larger than that of residential buildings. Especially, in industrial buildings, the average plant size is almost 20-fold larger than residential buildings (four-fold to office buildings) due to larger building sizes and higher roof-to-floor ratios. In addition, the consumption profiles for commercial buildings are better suitable for solar in the dataset, as is often the case in the literature.

In the following sections, the market-driven capacity installations of rooftop PVs are analysed by comparing the economic solar yield with the property yield; i.e. if the former exceeds the latter, the system is installed. This analysis will be done annually until 2040 for every single building in the dataset.

3.2. Market-driven capacity installations

Fig. 3 presents the market-driven capacity installations (MWp) dynamically until 2040 for the different scenarios. The impact of sizing PVs and regulations are clearly visible in the diffusion graphs.

Sizing the system based on the zero surplus scenario does not result in the maximal deployment of solar PVs, as it does not maximise profitability. If the system is optimised based on the NPV, then the adoption rate will increase dramatically. This NB scenario represents the market-based diffusion graph of rooftop PVs in Finland under the current regulation and assuming that the profitability of PVs is evaluated based on the underlying property variables. Finally, if NM were adopted, it would again increase diffusion dramatically. The diffusion increases over time, as expected, because annually decreasing CAPEX costs occur simultaneously with annually increasing electricity prices. It is observed that by approximately 2036, all roofs could be constructed under the NM scenario and by 2040 under the NB scenario. Interestingly, these fall close to EU target years for climate mitigation of 2020, 2030 and 2050.

If the 800 MWh p.a. self-production tax is removed, the years of full adoption will be 2029 and 2036. When analysing the data behind the figure in more detail, it is seen that industrial buildings (with the largest roofs and lowest electricity prices) are most sensitive to this tax. Thus, removing the tax increases dramatically the sizes of the systems for industrial buildings (dashed lines from 2026 to 2036). The effect of this is seen later, as the industrial properties start their installations later due the low electricity prices and higher property yields (compared to other property classes).

3.3. Net billing vs net metering

In the following, the NB and NM scenarios are assessed in more detail to separate the effect of NM on the current best scenario (NB).
Both scenarios are assessed under the assumption that the 800 MWh p.a. tax is removed to isolate fully the effect of NM between scenarios. The results are divided into commercial and residential sectors because of their many differences as property asset classes. The commercial sector has lower electricity prices and CAPEX, higher property yields, higher self-consumption and larger roofs and PV system sizes; in addition, it does not pay VAT and is eligible for investment subsidies. Furthermore, the commercial sector is professionally managed, which likely has practical implications, especially regarding the understanding of the used NPV approach. Fig. 4 presents the produced electricity and reduced CO2 emissions of the installed PV plants under the two scenarios.

The commercial sector starts rather slowly in its implementation of the PV capacity due to lower electricity prices and higher property yields than the residential sector. Once the electricity CAPEX decreases and electricity prices increase over time, the adoption rate will increase dramatically, starting from 15% in 2021 and ending at 65% until 2032. When the NB scenario has reached the same level of production as the NM scenario, it will be the same year, signifying that in 2032, the NM regulation would not be needed anymore, as all systems will have a high enough profitability without the NM subsidy.

The residential sector behaves quite differently. The PV adoption potential was quite large already at the beginning of 2018. The NM policy could increase investments by approximately an additional 45% in the beginning and maintain a much higher investment level until around 2025. The adoption rate differences are expected to level out by the year 2035, after which the NM policy does not have an impact on market-based adoption any longer.

Comparing the NB scenarios of the commercial and residential sectors provides interesting results. During the first eight years, the residential sector provided a greater share of the solar power by a large margin. By the year 2029, the commercial sector will close the gap and produce roughly half of the total solar energy. The commercial sector will peak in the year 2032 and the residential sector in 2034, with annual productions of 450 GWh and 370 GWh, respectively. In the next chapter (Fig. 5), how many new investments (CAPEX) are required to reach the solar production levels presented above is investigated. Similarly, the associated (theoretical) property value increase for the underlying properties is calculated.

The cumulative CAPEX in commercial systems (approx. 300 MEUR) is much lower than in residential systems (approx. 700 MEUR), even though the electricity produced by the commercial systems will be greater by 2027 for NM and 2029 for NB scenarios.

### Table 4
Descriptive statistics of the building database.

<table>
<thead>
<tr>
<th>Type of use</th>
<th>All</th>
<th>Commercial</th>
<th>Residential</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Retail</td>
<td>Office</td>
</tr>
<tr>
<td>Floor space (sqm)</td>
<td>88,696</td>
<td>965</td>
<td>1423</td>
</tr>
<tr>
<td>Roof area (sqm)</td>
<td>71,458,981</td>
<td>3,818,244</td>
<td>9048,771</td>
</tr>
<tr>
<td>ARAu (sqm)</td>
<td>31,072,710</td>
<td>1,520,320</td>
<td>1839,445</td>
</tr>
<tr>
<td>PVu (kWp)</td>
<td>6,125,340</td>
<td>304,658</td>
<td>322,529</td>
</tr>
<tr>
<td>Mean (kWp)</td>
<td>1,020,890</td>
<td>50,776</td>
<td>53,755</td>
</tr>
<tr>
<td>Median (kWp)</td>
<td>12</td>
<td>53</td>
<td>38</td>
</tr>
<tr>
<td>Max (kWp)</td>
<td>4</td>
<td>20</td>
<td>29</td>
</tr>
<tr>
<td>Min (kWp)</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Solar production (GWh p.a.)</td>
<td>854</td>
<td>42</td>
<td>45</td>
</tr>
<tr>
<td>Electricity consumption (GWh p.a.)</td>
<td>5697</td>
<td>619</td>
<td>932</td>
</tr>
<tr>
<td>Production per Consumption</td>
<td>15%</td>
<td>7%</td>
<td>5%</td>
</tr>
</tbody>
</table>

![Fig. 3. Installed capacity (MWp) under different scenarios (dashed lines represent the scenarios when the over-800 MWh p.a. Finnish production tax is removed).](image1)

![Fig. 4. Commercial and residential electricity production (GWh) and reduced emissions (1 kg CO2-ekv) under NM and NB schemes (Com. = commercial properties, Res. = residential properties).](image2)

![Fig. 5. Cumulative commercial and residential CAPEX and property value increases under NM and NB schemes.](image3)
The CAPEX for commercial systems is lower, as the average plant size is larger and commercial investments are made later (more capacity with the same amount of money, as the CAPEX per unit installed reduces over time). The property value increases for the underlying properties are larger than the CAPEX of the installed PVs, reaching a premium (value increase per CAPEX) of 55% (NM) and 46% (NB) for commercial systems and 94% (NM) and 86% (NB) for residential systems by 2040. The premiums increase over time, as the value of the systems rises via higher electricity prices and lower CAPEX. The property value premium is higher for residential buildings, as residential property yields are lower and electricity prices higher. However, because the residential market is mostly not managed professionally, as opposed to the commercial market, the property value premium is highly theoretical in the residential sector.

3.4. Costs and benefits of net metering

Based on the above findings, NM can increase significantly the adoption rate of rooftop solar PVs. Now, the extra costs and benefits of NM for core stakeholders in the electricity system are analysed, i.e. property owners, the government and distribution network operators (DNOs). Conventional (centralised) electricity producers are not included, as their role in the local system is not as relevant as other stakeholders because electricity is transferred over longer distances and often traded over (inter)national electricity exchanges. Thus, their lost revenue is not seen as relevant in this context. Four relevant costs were identified:

i) The DNO’s lost revenue for surplus production,
ii) Investment subsidy costs for the government (commercial only),
iii) The government’s lost electricity tax for full production and.
iv) The government’s lost VAT (residential only).

In addition, three relevant benefits were identified:

i) The saved SCC for full production,
ii) The value of produced energy minus the OPEX of the rooftop PVs (net benefits to the property owners),
iii) The VAT benefits (residential only) and

The property value is not included, as it is not a recurring yearly income but rather a theoretical calculated value that may be realised when the property is sold. Figs. 6 and 7 present cost–benefit analyses of commercial and residential properties, respectively. The recurring benefits outweigh the costs from the year 2023 onwards. During approximately the first 10 years, the highest costs arise from investment subsidies, which are one-off costs. Once the subsidies have been mainly consumed, the ratio of benefits to costs increases, as costs mainly arise from lost electricity taxes and the DNO’s lost revenue on surplus production (NM only). The lost electricity taxes are approximately one third of the energy production benefits and half of the saved SCC. The DNO’s lost revenue is much greater for residential properties compared to the benefits created. It is important to discuss the findings in the context of both these sectors and how NM should be implemented.

4. Discussion

This paper finds that the understanding of the market mechanisms and characteristics of the underlying building stock significantly influences both the profitability and diffusion rate of PV investments. If rooftop PV returns are properly evaluated with the location-specific market characteristics of the underlying
properties, under the current NB regulation, rooftop PVs are already profitable for a third (165 MWp) of the residential properties in the HMA. This metropolitan region's profitable capacity alone is two and half times higher than the currently installed capacity (approximately 70 MWp) for all of Finland. If the most probable PV and electricity price trends are included in the calculation, 80% of the properties (380 MWp) will be profitable by 2023. By 2035, all residential properties should adopt rooftop PVs based on economic criteria, resulting in approximately 472 MWp of PV capacity. For commercial properties, only under 2% (10 MWp) of the properties are profitable enough today. However, only a small reduction in CAPEX and increase in electricity prices will move the market forward quite fast; by 2025, one fourth (140 MWp) of the commercial properties will be profitable, and by 2030, 90% (493 MWp) will be profitable enough. The maximum potential of 549 MWp is reached in the year 2040.

NM would increase the diffusion rapidly. Over half (239 MWp) of the residential properties would be profitable already now, and by 2022, all residential properties could adopt rooftop PVs. For commercial properties, NM would not change today’s adoption rate, but the increase would be exponential during the next few years; by 2025, 40% (227 MWp) will be profitable enough and by 2030, all residential properties should adopt rooftop PVs based on economic profitability.

The paper also analysed the benefits and costs of NM to different key stakeholders: property owners, the government and DNOs. The findings suggest that the overall benefit-to-cost ratios are high. At the individual stakeholder level, property owners and society in terms of carbon mitigation are the beneficiaries, and the DNO and tax authorities carry the cost burden. A practical way of promoting NM could be a benefit-sharing scheme that shifts some of the benefits from property owners to the DNOs. The scheme would guarantee that property owners receive a decent return on the investment, so that PV installations could be justified from the real estate economics perspective, but also that distribution companies would be compensated for some of their losses from the NM policy. One reasonable approach would be that once the location-relevant property yield (plus maybe a small premium) is reached, the subsidies and NM are phased out so that everybody receives a decent return on the investment. When deciding on the correct level of profit sharing, the composition of grid costs to the DNO should be opened under close inspection, as Eid et al. [6] propose. It is worth mentioning here that Spertino et al. [8] noted that during 2008–2009 in Italy and Germany, there were significantly high profits realised by panel manufacturers due to over-generous FITs and fast investments in solar PVs. This should be remembered when adjusting the regulations if it would increase the diffusion of rooftop PVs in the market rapidly. Furthermore, if regulations are changed, they should be different for commercial and residential properties, as their benefits and costs differ.

The approach suggested here of comparing the profitability of rooftop PVs to that of the underlying property is a straightforward way of defining the appropriate subsidies for solar, as the property defines the correct return for the investment. This could help in defining the correct dynamic pricing model for different regulations, as presented by Prol and Steininger [3]. The NM scheme could eventually convert into NB once the property owners have reached a profitability level for the underlying properties. Ultimately, this paper raises the question of whether the grid parity for rooftop PVs could be based on property yield levels rather than the LCOE. Because the property market already works rather well, it might be natural for the property yield levels to control the subsidy levels, as well, for on-site generation.

Some limitations are identified in this study. First, it is questionable whether residential owners will behave according to the presented findings, as the property value theory is more suitable for commercial buildings, where decisions are made more analytically. On the other hand, often, private citizens require an even lower profit for their excess capital; thus, the yields required from residential rooftop PVs could be even lower. For example, if residential rooftop PVs could be examined as a fixed part of the underlying property, mortgage financiers could provide low interest capital for financing. Second, in practice, the real consumption profile for every building is unique and does not follow the profiles based on building typologies constructed in this study. However, we think the results are accurate for the purposes of this study, as the actual consumption profiles have been carefully created for the different building types, and they include separate information regarding electrical heating. We are also analysing 89,000 buildings separately, where the large amount of data should be able to average out individual differences between unique consumption profiles. Finally, the electricity prices are averages and in practice, there is some volatility between different sub-user groups; however, on a system level, this should not be a large problem. It is also mentioned that the available roof area coefficients are approximations and the most accurate approximations would probably require satellite imagery with a machine learning approach. For the purposes of this study, we think that the used coefficients are accurate enough, because they are based on previous literature together with our own analysis of rooftops. We also think that four coefficient categories increase the accuracy instead of using just one or two (i.e. residential and commercial).

The methodology and results presented are a new addition to the literature covering the economics of rooftop PVs. Further research could focus on the property investment perspective, namely, on how property investment professionals view rooftop PV investments in practice and how this view has changed over the past few years. In addition, the identified profit-sharing scheme could be analysed between governmental tax authorities and DNOs. Furthermore, debt financiers could be interviewed from the perspective whether buildings could integrate solar with the same finance terms as the building itself. This is a highly interesting topic, as it could unload a huge amount of private capital into financing the renewable revolution. As PV technology matures, there is also great potential in building integrated solutions to generate electricity from solar facades. This is especially important in dense high-rise urban settings where the amount of available rooftop is low. Recently Chen et al. [40] published a rigorous methodology to calculate the potential of solar facades in optimising building energy performance and the findings suggest significant reductions in energy demand. This topic is highly interesting when analysing the total potential of solar PV in dense urban core.

Finally, the results of this study should be presented to policymakers to help them understand how the customer-driven value understanding of renewable energy production could rapidly change the renewable energy landscape and promote a substantial increase in renewable energy production and climate mitigation. Particularly, the study calls for a new ‘urban energy policy’, where cities, instead of being a major threat to climate mitigation, could actually be seen as a platform for profitable large-scale solar PVs and other on-site renewable generation installations. For example, the attractiveness of decentralised clean urban energy production investments could be increased through urban zoning measures focusing on increasing the above-mentioned ARA coefficients for rooftop PVs. A traditional centralised energy policy might focus on lowering the LCOE for larger regions, rather than understanding the specific needs of individual properties in urban settings. More work and focus understanding this difference should be done to clearly communicate this to the policymakers.
5. Conclusions

Cities are already responsible for the majority of climate emissions, and they are constantly growing. Buildings alone consume roughly 40% of energy and produce 40% of carbon emissions. The built environment has thus far mostly been considered an energy consumer in energy system evaluations. However, buildings could, if correctly understood, produce a large part of a city’s energy demand themselves through renewable on-site energy production. For example, building-integrated PVs alone are estimated to be able to provide over 20% of all electricity consumed in Europe [14]. This already equals the EU 2020 target levels.

The property market is likely the oldest investment sector in the world, and there is much private capital available for seeking new investments in the sector. For private capital to flow from traditional investments into this new asset class within the building sector, stakeholders must understand the risk and value creation logic behind these investments. This paper provides a rationale and investment criteria for building-integrated PV systems as a new market-based profitable asset class in the built environment. The paper assesses the economic potential of rooftop solar PVs by utilising the location-sensitive investment logics of the underlying property investment. The paper also examines how NM would increase the diffusion of rooftop PVs, as well as the related benefits and costs.

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