

# **Solar PV where the sun doesn't shine: Estimating the economic impacts of support schemes for residential PV with detailed net demand profiling**

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## **Abstract**

Countries with low irradiation and solar PV adoption rates are increasingly considering policy support for solar PV, although consumer electricity demand and solar generation profiles are often mismatched. This paper presents a methodology for policymakers in such conditions to examine more precisely the financial performance of residential solar PV from the consumer perspective as part of an ex-ante policy assessment. We model a range of prospective policy scenarios and compare policy mechanisms that compensate homeowners for generation, those that reduce their upfront costs, and those that assist with financing, using Ireland as a case study. The results confirm the intuitive notion that more generous financial remuneration schemes provide quicker payback; however we observe that in low irradiance regions there is little difference between upfront grants and feed-in-tariffs to accelerate payback timeframes. We also show the importance of retail tariff structure in consumer payback for solar PV systems, with one-part tariffs generating shorter paybacks than two-part tariff structures, although the latter is more likely to secure revenue for electricity infrastructure investment. Drawing from this analysis, the paper proposes some options for the design of policy supports and tariff structures to deliver a sustainable residential renewable electricity system in low-irradiance regions.

Keywords: Energy policy; energy economics; residential solar PV; electricity rate structure; financial performance; distributed generation

## **1. Introduction**

Solar photovoltaic (PV) technology has experienced a dramatic reduction in installed costs in recent years, falling more than 80% since 2008 (IRENA, 2015). As the technology becomes more competitive with conventional generation sources, deployment has increased sharply, reaching 177 GW total installed capacity worldwide in 2014 (REN21, 2015). The majority of deployment thus far has naturally been concentrated in locations with some combination of a strong solar resource or sufficiently generous policy supports, which in some cases have created windfall benefits for asset owners at high public cost, ultimately leading to unstable, boom-and-bust market dynamics (De Boeck et al, 2016). As PV costs continue to fall, policymakers in countries with lower solar irradiation are also beginning to consider whether solar PV might be a viable renewable energy resource and worthy of policy support. In the development of such policies, these late-adopters have significant opportunity to avoid the mistakes of others in the design of policy support mechanisms and pricing through learning from other countries' experiences. Careful analysis is thus required to assess whether solar PV is an appropriate technology justifying policy support in such countries.

In carrying out ex-ante solar PV policy assessment, policymakers should consider a range of key factors, including the system value of increasing the share of solar PV on the electricity system, the current and future economics of solar PV for different customers—residential, commercial, and utility-scale—and the environmental and other impacts of increased solar PV electricity generation. Of these, this paper focusses on the assessment of consumer economics of residential solar PV using Ireland as a case study, and examines the effect of remuneration schemes, tariff structures, and financing mechanisms on financial

performance. It follows a related paper on the system value of utility-sale solar PV (Ryan et al., 2016).

Many existing papers offer comparative analysis of financial performance under various support mechanisms between different countries with varying costs, irradiance profiles, and other market conditions (see for example: Couture and Gagnon, 2010; Sarasa Maestro et. al., 2013; Campoccia et al., 2014; Dusonchet and Telaretti, 2015; de Boeck et al., 2016; Lacchini and Ruther, 2015). As of 2015, feed-in tariffs (FiTs) were in place in 108 national or state jurisdictions around world (REN21, 2015). While some research shows that feed-in tariffs “consistently delivered new renewable energy (RE) supply more effectively, and at lower cost, than alternative policy mechanisms” (Couture and Gagnon, 2010), others offer more cautionary comments regarding the dangers of overly generous FiTs that are costly to governments (and ultimately, to ratepayers), and can yield windfall profits for investors (Sarasa Maestro et. al., 2013). Lacchini and Ruther (2015) find, on the other hand, that policies should be focussed on reducing upfront investment costs rather than providing generation-based remuneration. Given the lack of universal agreement on the type of policy most effective and efficient for solar PV, it is clear that optimal design should be informed by the solar resource and other market characteristics in the individual country.

A consideration for policy makers in new solar PV jurisdictions, and also the focus of a growing academic literature, is the detrimental impact of high shares of distributed solar PV on supplier revenues. In many countries, the costs of distribution, transmission and generation of electricity are recovered through retail tariffs levied on a volumetric basis (Darghouth et al., 2016). In such cases, solar PV customers who demand less electricity from the grid also avoid paying for electricity system costs. With net metering policies, under which PV customers are paid the retail rate for the total amount of electricity they generate, this effect is particularly acute, and constitutes an implicit subsidy by which customers are

effectively paid for distribution, transmission and generation services that they do not provide (Kirsch and Morey, 2015).<sup>1</sup> In a world with higher shares of distributed renewable generation, another form of tariff will likely be needed to recover fixed costs of grid services (Sioshansi, 2016). One option is a two-part tariff that includes a fixed charge for grid services and a volumetric electricity charge (Darghouth et al., 2011). In any case, the design of the tariff has a strong impact on the financial performance of PV systems and therefore both the current and potential future structure of retail tariffs should be considered by policymakers in assessing the economics of solar PV policies.

The cost of financing also exerts a strong influence on the financial feasibility of solar PV projects (Ondraczek et al. 2015; Tao and Finenko, 2016). Intuitively, it follows that localities that offer financial incentives experience increased rates of PV deployment, as confirmed by Jacobsson and Lauber (2006), Sarzynski et al (2012), and Crago and Chernyakhovskiy (2017). Notably, the financing conditions and hence options for residential consumers are different than those applicable to commercial investors. Households may have significant savings and prefer to pay for a PV system in cash, especially when deposit interest rates are low. Others may be more likely to use debt finance, in which case lending rates will determine the cost of servicing that debt. It is critical also to recognise that households use different decision-making criteria for capital budgeting decisions compared with commercial entities, and financial performance must be evaluated accordingly. Faiers and Neame (2006) find that payback period (PBP) is the metric that holds the greatest sway over homeowners' decision-making process when considering an investment in rooftop PV. Lee et al. (2016) also use payback period, citing Rai and McAndrews (2012), who find that households require a payback period of seven to ten years in order to proceed with rooftop PV investment.

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<sup>1</sup> Conversely, distributed generation may also provide some ancillary services for which asset owners are not adequately remunerated.

Scarpa and Willis (2010) find an even shorter required timeframe of between three and five years, though a ten year maximum is perhaps more appropriate in the context of an immature market such as the one examined herein.

Many researchers have provided a critical contribution with regard to the retrospective assessment of customer economics in a range of policy environments. Necessarily, however, much of the existing research and ex-post policy analysis examines conditions in countries where the combination of strong solar resources and supportive policies led to early adoption. We believe that a more targeted approach is appropriate for the purposes of identifying, ex-ante, the effect of these policies on prospective PV uptake in the residential sector. Economists have pointed out that electricity is a heterogeneous product in time, space, and lead-time dimensions (Hirth et al., 2016; Borenstein, 2012; Joskow, 2011). Therefore, since the value of electricity and the amount of solar PV generation changes over time, biases occur when financial performance is based on average values, as is often the case in the existing solar policy literature. This may be particularly important in jurisdictions where there is a mismatch between the timing of electricity demand and solar generation, such as in countries in the northern hemisphere with low solar irradiation and large variations between the length of day in winter and summer.

While we find no commonly-used scale or ranking for “low irradiance” in the literature, Ondrecek et al (2015), using data compiled by Breyer and Gerlach (2013), show that the lowest solar resource of any region in the world is found in Northern European countries with maximum irradiance of 1,000 kWh/kWp per annum. These countries include the Netherlands, Belgium, Denmark, Lithuania, Latvia, Ireland, UK, Estonia, Sweden, Finland, and Iceland (JRC, 2017). While some literature explores the deployment of PV in these countries (see: Huijben and Verbong, 2013; Leloux et al, 2012; Martins, 2017) - particularly in the UK (e.g. Colantuono et al, 2014; Balta-Ozkan, et al 2015), which has offered considerable incentive

programmes - none, to our knowledge, focus specifically on the low-irradiance characteristics of these markets, such as the differences in load profile, seasonal peak demand, and effect on consumer financial performance.

In this paper we present a methodology for assessment of the financial performance of a rooftop PV installation from the system owner's perspective with detailed profiling using hourly generation and demand patterns for the entire system lifetime. Given the sensitivity of residential solar profitability to self-consumption rates, our detailed analysis offers a more accurate estimate of self-consumption and net export than is presented in much of the existing literature, which tends to feature broad assumptions about net output and self-consumption proportions. Here, we explore potential profitability with greater precision by focussing on the example of Ireland, which features one market with relatively consistent costs, irradiance, and consumer profiles in a low solar irradiance location without a solar PV support mechanism. This approach improves upon previous papers' findings, which may be of diminished utility due to the presence of heterogeneous market conditions. Finally, we examine the influence of the significant determinant factors discussed above on residential solar PV economics, including remuneration policy supports, different household financing options and the electricity tariff structure using some traditional discounted cash flow metrics (net present value and internal rate of return), but with a particular focus on payback period.

Section 2 of the paper provides additional background on the factors affecting financial performance of residential PV, as well as the renewable energy policy and context in Ireland. Section 3 details the data and methodology employed; Section 4 presents overall findings and discussion; and Section 5 concludes with observations on policy implications arising from our results.

## **2. Background – Solar PV in Ireland**

We examine Ireland as a case study for late adoption of solar PV. Ireland has a relatively low solar resource and only a negligible amount of residential PV currently exists; its government is in the process of a multi-stage consultation on prospective renewable energy support schemes (SEAI, 2013; DCENR, 2015). In Ireland, renewable electricity has mainly been generated by onshore wind, supported by a feed-in tariff since 2006 (DCENR, 2013). By end of 2015, 21.1% of electricity in Ireland was produced from wind, with 2,440 megawatts (MW) of wind energy installed in the Republic of Ireland (SEAI, 2016).<sup>2</sup>

The European Union (EU) has set a target of 27% renewable energy by 2030, which will require additional renewable capacity in Ireland. While it is technically feasible to meet the target with on-shore wind alone,<sup>3</sup> it is likely to be challenging: the current level of public acceptance of new wind generation and associated infrastructure is low, which may limit the commissioning of new wind plant. Strategically, solar energy could have several advantages for Ireland as a way to diversify the fuel mix and renewable electricity portfolio, reduce dependence on imported fuels - Ireland imports 88% of its total energy fuels at a cost of €4.6 billion in 2015 - and as a pathway to meeting its EU targets (SEAI, 2016). Solar energy may also provide benefits in reducing wind curtailment if there is a different temporal profile of solar PV generation compared with wind (Ryan et al., 2016).

As residential PV may be considered as a potential recipient of policy support, it is timely to examine the economic value currently available to homeowners who might consider installing solar, and how the asset owners' financial gains could be affected under different

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<sup>2</sup> In order to meet 2020 renewable energy targets, Ireland needs to produce 40% electricity from renewable sources. The share of wind is normalised in line with EU reporting requirements to take account of different heating degree days year on year. Another 445 MW and 1,357MW of wind generation have been contracted for connection by end 2016 and 2017 respectively.

<sup>3</sup> It should be noted that wind curtailment poses an increasingly important issue for wind energy producers. Wind curtailment is when wind energy is available but cannot be produced because of power system limitations

policy schemes. Such analysis may also inform any deliberations regarding whether and how to implement policy support schemes.

Previous analysis of the economics of solar PV in Ireland has found that Irish residential PV was not profitable even with some level of subsidy. For example, Li et al (2011) estimate that even with a large upfront grant or a generous FiT, residential PV projects in Ireland never achieve a positive NPV or IRR, and ultimately do not pay back over their lifetime. Ryan et al (2016) examine the economics of utility-scale PV in Ireland, finding that a relatively high tariff is required to render projects profitable, however the analysis was only conducted for utility-scale projects. With substantially altered market conditions in contrast to Li et al, and extending the work of Ryan et al (2016), this paper updates and extends previous work on Ireland and is likely to be of interest to policymakers, especially in other below-average irradiance locations where similar dynamics are at play.

### **3. Data & Methodology**

The analysis begins with the development of a model to estimate the hourly generation of solar electricity and household electricity demand (the net production model). The cost figures used are based on data collection and interviews with active market practitioners. Combining these, we model scenarios of various remuneration and financing strategies and examine their impacts on the financial performance.

#### *3.1 Net Production Model*

We use detailed production time series data to model the generation arising from a PV installation in Ireland, and compare this to hourly household demand data to ensure an accurate estimation of self-consumption and net export potential. Generation data is obtained using the National Renewable Energy Laboratory (NREL) System Advisory Model (SAM)



(NREL, 2015).<sup>4</sup> Within the SAM tool, generation data was queried for Dublin, Ireland. We selected three plausible size scenarios for which to obtain generation profiles, based on interviews with Irish PV installers currently active in the residential PV market. The sizes range from a relatively small system sized at 3 kWp, to a mid-size system at 4.5 kWp, to the maximum size allowable before triggering additional planning costs, 6 kWp.

All other parameters for production are automated by SAM, which applies the PVWATTS production model<sup>5</sup>. Given that the purpose of this paper is to examine typical residential PV economics under different support structures, rather than to examine results that are technology-specific or which arise from modifications to system design, we do not adjust performance specifications beyond the suggested settings provided in the model.<sup>6</sup> SAM generation data is produced using a “typical year” methodology, which analyses a multi-year data set to select the most representative month from the multi-year set (NREL 2015). The data for Dublin thus represents the most typical values for each month dating from when Dublin weather data was available in the SAM system. We selected the capital city of Dublin for modelling generation, as Dublin is home to nearly one third of Irish households, and because there is relatively low variation in irradiance within the country (CSO, 2016).<sup>7</sup> The SAM tool produces an hourly generation profile for the year, indicating

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<sup>4</sup> SAM is an open-access performance modelling tool that is widely used for PV research purposes by both academics and practitioners (<https://sam.nrel.gov/>). While SAM has the capability to vary a range of technical inputs for specific PV, inverter, and racking hardware, as well as to provide financial modelling given local policy circumstances, for the purposes of this analysis, we simply obtain a data set indicating the kWh output for each hour of a typical year in Dublin, Ireland, as described in the text.

<sup>5</sup> PVWATTS, a web-based simulation model also developed by NREL is the underlying production model used to estimate generation, given a specific range of parameters, within the SAM system (<http://pvwatts.nrel.gov/>).

<sup>6</sup> Standard assumptions include inverter efficiency of 96%, fixed open rack array type, 20 degrees tilt, 180 degrees azimuth, total system losses of 14%, and no shading.

<sup>7</sup> According to PVGIS maps available from the E.U. Joint Research Council (JRC), optimised solar in much of Ireland ranges from approximately 1000 - 1200 kWh/m<sup>2</sup>, with up to 1400 in coastal locations. However, compared with utility-scale solar, which might be sited in the most commercially apt locations, the decision to install rooftop PV would be undertaken by households across the country, not strictly in the most favourable locations. Thus, a representative, non-optimised locational selection was appropriate for this work.

the kWh of generation in each of 8,760 hours. The SAM model estimates that annual energy yield from solar PV in Dublin is 865 kWh/kWp.

Demand data used in the analysis was obtained from network operator ESB's Standard Load Profiles (SLPs), which draw from a sample of metered residences, and produce a unitised profile, such that the values for each 15-minute increment of each year reflect the proportion of electricity consumed during that increment. The load profiles are thus customisable for any annual demand magnitude by multiplying all 15-minute usage values by a selected annual total use. Profiles are developed annually using the sample meter data from the previous year. This analysis uses the derived load profiles for 2015. We selected Load Profile 1 (LP1), derived from users on a 24-hour urban domestic tariff.<sup>8</sup> We select high, middle, and low annual usage scenarios from national average values, obtained from (CER 2016), as outlined in Table 1:<sup>9</sup>

**Table 1. Annual Household Electricity Demand Scenarios**

Low Usage	Mid Usage	High Usage
3,100 kWh	5,300 kWh	8,100 kWh

These values serve as the total electricity consumption for households before PV generation is considered. Figures 1 and 2 illustrate the diurnal and annual distributions of Irish solar PV generation and household electricity demand produced from the sources described above. In Figure 1, it is clear that daily peak household electricity demand does not

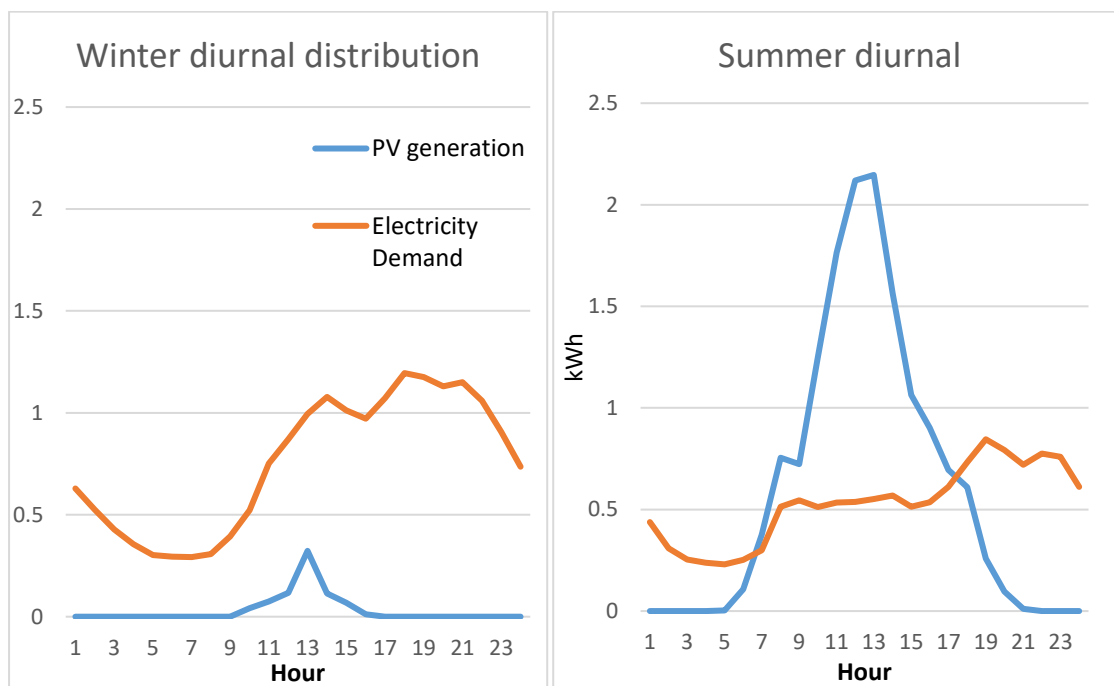
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<sup>8</sup> The 24-hour urban domestic tariff was selected instead of the Nightsaver tariff, which provides a cheaper night-time electricity rate, as in practical terms, the presence of a Nightsaver rate may incentivize load-shifting.

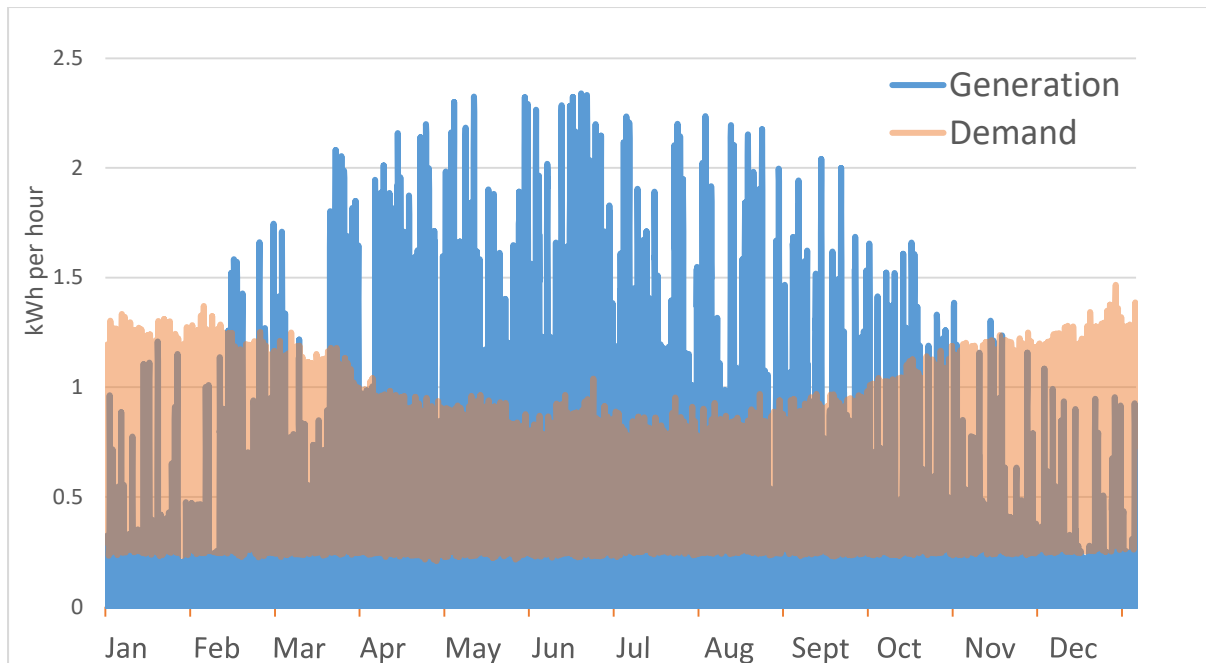
<sup>9</sup> Average electricity figures are for a 1-bedroom, 3-bedroom, and 5-bedroom household, respectively, as indicated by the Commission on Energy Regulation (CER) and an accredited electricity supplier aggregator. Practical limitations of residence size with regard to spatial feasibility of, for instance, a 1-bedroom home hosting a 6 kWp solar PV installation are outside the scope of this paper; we assume that all hypothetical residences modelled could accommodate PV systems up to 6 kWp.

coincide with the timing of peak PV generation in either winter or summer. Solar PV generation is higher in summer than in winter and occurs over a much longer portion of the day, which is typical of countries at higher latitudes. Annually, there is also a relatively poor match between the seasonal PV generation and household electricity demand with more solar electricity generated in summer, yet demand is consistently higher in winter (Figure 2). This is significantly different to the situation in hotter climates, where peak load frequently occurs in summer due to air conditioning and its timing coincides relatively well with high solar PV generation.

**Figure 1: Sample of Winter and Summer Daily Distribution of PV and Electricity Demand**



**Figure 2: Annual Distribution of Household Electricity Demand and PV Generation**



### 3.2 Costs

Based on a survey of residential solar installers currently active in the Irish market, we determined the approximate cost-per-kilowatt for a fully installed rooftop PV array on a typical home to be €1,744. Table 2, below, shows the total installed cost, including VAT for each system.

**Table 2. Total PV System Installed Cost**

Scenario Assumptions	3 kWp	4.5 kWp	6 kWp low
<b>Total Cost ( with VAT)</b>	<b>€5,231</b>	<b>€7,847</b>	<b>€10,463</b>

Cost assumptions are outlined in Table 3. We assume a 25-year lifetime for the total PV system, with a module lifetime of 25 years and an inverter replacement required in Year 12 at a cost of €1,475, according to industry quotations for typical system design. We also assume a Year 1 cost of €50.00 for operations, maintenance and insurance, as in Li et al (2011) and Georgitsioti et al (2013). This amount escalates annually at the rate of inflation.

**Table 3. Key Assumptions**

Assumptions	Value	Source
<b>Annual Rate of Usage Increase (%)</b>	0.00%	<a href="#">Dennehy and Howley (2013)</a>
<b>Degradation Rate</b>	0.70%	<a href="#">Bazilian et al. (2013)</a>
<b>Inflation (general)</b>	0.73%	<a href="#">5-year average</a> for Ireland
<b>O&amp;M/Insurance</b>	€ 50.00	<a href="#">Li et al. (2011)</a> and <a href="#">Georgitsioti et al (2013)</a>
<b>Inverter Replacement Cost</b>	€1,475.33	Industry quotations
<b>Retail Price Annual Increase (%)</b>	4.00%	Historical EU Average EU Commission (2014)
<b>VAT (%)</b>	13.50%	<a href="#">Department of Revenue</a>
<b>Retail Rate (€)</b>	€0.133	<a href="#">Howley and Holland (2016)</a>
<b>1st Year PSO Levy (€)</b>	€60.09	<a href="#">Commission for Energy Regulation (2015)</a>
<b>Standing Charge (€)</b>	€132.16	Survey of published supplier quotations
<b>Discount Rate</b>	0.55%	Survey of commercially available savings deposit rates

The retail rate in Ireland includes a volumetric tariff plus a fixed standing charge and fixed Public Service Obligation (PSO) levy. We assume an energy-only retail rate of €0.133, as noted by the SEAI in Howley and Holland (2016), and confirmed by a search of publicly available electricity supplier quotations on accredited price comparison sites. We use the disaggregated retail rate information for the most recent period available, the second half of 2015.<sup>10</sup> Retail prices are assumed to rise by 4% each year, according to historical EU average

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<sup>10</sup> The SEAI, using Eurostat data, calculates the disaggregated retail rate for band DC, up to 5,000 kWh per year. Because disaggregated data is not available for Band DD (5,000-15,000 kWh/year), and because the rates are

cited in EU Commission (2012). We acknowledge that forecasting retail rates is complex, and therefore our results present sensitivity analysis for prospective changes to retail rates.

The annual standing charge, which covers a range of supplier and network costs and which may not be offset by self-consumption of solar, was surveyed from publicly available commercial quotes at a rate of €132.16, excluding VAT. VAT is added at a rate of 13.5% to all on-bill charges, including electricity consumed at the retail rate, the standing charge, and the PSO a levy on all electricity customers which is used to fund existing support schemes, and which also may not be offset by self-consumption of solar. We begin with a Year 1 PSO charge of €60.09, the amount applicable for 2016. Because the PSO changes in accordance with the remuneration programmes it funds, forecasting future increases in PSO is outside the scope of this work. The same is true of the relationship between network costs and the standing charge, and therefore we apply only the inflation rate to both the PSO and standing charge. In any case, because the PSO and the standing charge are fixed amounts charged on bills with and without PV, the actual amount of these charges does not change the amount of savings possible from PV self-consumption, and thus does not change the outcome of these results (see equations 3 and 3a in Section 3.3 below).

### *3.3 Savings*

The electricity that households generate with solar PV for self-consumption offsets their demand for household grid electricity, which reduces their electricity bills with their electricity supplier. We refer to the reduction in grid electricity as the self-consumption or savings and this represents positive cash flows for the household via electricity bill savings. In order to calculate the savings for the PV cases, as well as to calculate the amount of hourly net PV export, the quarter-hourly demand data was summed to provide hourly demand

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similar in these rate bands, we use the rate for Band DC. Rate accuracy was checked through a public query of an accredited electricity supplier comparison site.

values, and compared to the hourly generation data. To ensure that each year reflects the correct proportion of PV generation self-consumed net of module degradation, we calculate the PV generation in each of 8,760 hours in the first year and degrade the yearly output by 0.70% for each of the following 24 years of the system lifetime. For each hour of each year, the amount of PV self-consumed by the household in hour  $h$  ( $SC_h$ ) is calculated as either the full amount of generation in the hour, if generation is less than demand, or the total amount of demand in the hour if generation exceeds demand, as in Equation 1.

$$\text{Equation 1: For } G_h \leq D_{Th}, SC_h = G_h; \text{ For } G_h \geq D_{Th}, SC_h = D_{Th}$$

where  $D_{Th}$  = Hourly Household Electricity Demand

$G_h$  = Hourly PV Generation

Total self-consumption is then calculated for each year as the sum of hourly self-consumption. Annual grid demand net of PV generation ( $D_{PV}$ ) for each year  $n$  is calculated according to Equation 2:

$$\text{Equation 2: } D_{PV_n} = \sum_{h=1}^{8760} D_{Th} - \sum_{h=1}^{8760} SC_h$$

The difference between grid demand in households with PV ( $D_{PV}$ ) and without PV ( $D_T$ ), as well as the rate of self-consumption in Year 1 is shown in Table 4.

**Table 4. Annual Household Demand and Self-Consumption for First Year**

System Size (kWp)	3	3	3	4.5	4.5	4.5	6	6	6
Demand Size	Low	Mid	High	Low	Mid	High	Low	Mid	High
$D_{T1}$ (kWh)	3,100	5,300	8,100	3,100	5,300	8,100	3,100	5,300	8,100
$G_1$ (kWh)	2,594	2,594	2,594	3,891	3,891	3,891	5,188	5,188	5,188
$D_{PV1}$ (kWh)	1,950	3,635	6,001	1,848	3,399	5,574	1,791	3,261	5,309
$SC_1$ (%)	44%	64%	81%	32%	49%	65%	25%	39%	54%

We calculate annual on-bill savings ( $S_n$ ) as the difference between the annual household electricity bill with PV and the annual bill without PV. As described in Section 3.3, the annual electricity bill is calculated as total hourly grid demand multiplied by the retail rate, added to the standing charge and the PSO, all of which is multiplied by the VAT rate. The savings in year  $n$  with PV ( $S_n$ ) are calculated as in Equation 3:

$$\text{Equation 3: } S_n = [((D_{T_n} \times r_n) + N_n + P_n) \times v] - [((D_{PV_n} \times r_n) + N_n + P_n) \times v]$$

where  $D_{T_n}$  = Total household electricity demand (before PV)

$D_{PV_n}$  = grid demand net of PV self-consumption

$r_n$  = the retail rate in each year net of annual rate increase

$N_n$  = the standing charge in each year net of inflation

$P_n$  = the PSO levy in each year net of inflation

$v$  = the VAT rate

This can be simplified to read:

$$\text{Equation 3a: } S_n = (D_{T_n} - D_{PV_n}) \times r_n \times v$$

The simplification of Equation 3 demonstrates that the bill savings are calculated purely using the volumetric part of the tariff. While many studies use an aggregate retail rate which incorporates all taxes and charges, this component-based approach allows us to account for the fixed portion of Irish electricity bills which must be paid irrespective of the rate of self-consumption, giving a more precise estimation of annual savings. Indeed, we find that forecasts of financial benefits to PV system owners are markedly different when applying the existing 2-part tariff with fixed plus volumetric charges, rather than a 1-part, volumetric-only



charge, as is employed by many installers and industry publications (See: ISEA, 2015). Additional analysis on this point is included in Section IV.

Annual net export for each year  $n$  ( $NE_n$ ) of any excess PV generation not self-consumed is necessary for calculating cash inflows in scenarios with remuneration for excess generation. It can be calculated by subtracting the number of kilowatt hours self-consumed from the total generation, as in Equation 4:

$$\text{Equation 4: } NE_n = \sum_{h=1}^{8760} G_h - \sum_{h=1}^{8760} SC_h$$

### 3.4 Financial Model

We develop a cash flow model using the upfront costs and net cash flows for each combination of system size (3 kWp, 4.5 kWp, and 6 kWp) and annual household electricity demand (low, middle, and high) in Excel to calculate the **Net Present Value (NPV)** for each PV system size/demand scenario, according to Equation 5:

$$\text{Equation 5: } NPV = \sum_{n=1}^{25} \frac{S_n - C_n + (NE_n \times t)}{(1+d)^n}$$

where  $S_n$  is the savings calculated in year  $n$

$C_n$  is the system cost in year  $n$ , including capital costs in year 1, operating expenditures and inverter replacement where applicable

$NE_n$  is the net export, or amount of excess generation for which the system owner is compensated

$t$  is the rate at which net export is remunerated, and

$d$  is the discount rate.

When exported generation is remunerated, we assume it is at rate  $t$ . This is set equal to the retail rate,  $r$ , in the case of net metering; equal to the FiT rate in the case of a FiT; and

equal to zero in the case where no subsidy applies. Because we assume homeowners are making a binary decision about whether or not to invest in solar, and importantly, do not consider other investment options, we discount cash flows at the available deposit rate. We apply a discount rate of 0.55%, reflecting the mid-range of publicly advertised annual equivalent interest rates on savings accounts in Ireland.

Because homeowners do not typically make capital budgeting decisions on the basis of net present value, we also calculate the **Internal Rate of Return (IRR)**, indicating the returns that homeowners may realise over the lifetime of the project, and **Payback Period (PBP)**, which marks the year in which cumulative savings surpass the initial cost of the PV system.<sup>11</sup>

### *3.5 Scenarios*

We identify a base case that reflects a PV system purchased at full cost with no grants, funded with an outright cash purchase on behalf of the homeowner, i.e. a 100% equity purchase. The base case also reflects current policy and regulatory conditions, which allow for self-consumption to offset volumetric costs but provide no additional compensation for exported generation. There are currently no grants or financing incentives available for solar PV generation in Ireland. Incentivisation can be pursued through a variety of policy mechanisms; our analysis is focused on the effects of remuneration schemes, grants, and favourable financing options. By way of remuneration mechanisms, we model effects of a feed-in tariff (FiT) and net metering programme on consumer economics.

FiTs offer a guaranteed price for solar PV generation, either on a gross basis, by awarding a fixed tariff for every kWh generated, or on a net basis, by awarding a fixed tariff

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<sup>11</sup> In some cases, cumulative savings are positive in one year, but negative in the next due to inverter replacement which occurs in Year 12. We report payback as the number of years in which cumulative savings are positive, thus a payback of 13 years, for example, may mean that cumulative savings were positive in Year 11, then dipped to reflect inverter replacement in Year 12, and recovered to a positive status in Year 14.

for excess generation net of self-consumption from PV households (for more on feed-in tariff design see Couture et al. 2010, Langniss et al. 2009 and Lesser et al. 2009). Because we assume that households are permitted to self-consume PV, we employ the latter type. The fixed FiT scenario provides remuneration of excess generation throughout the project lifetime at a fixed tariff of €0.06635/kWh, reflecting the tariff available to other technologies under the most recent renewable energy feed-in tariff scheme in Ireland (REFiT) (DCENR, 2015).<sup>12</sup> The declining FiT scenario begins by compensating generators at approximately the retail rate, with a €0.05 ramp down every five years. This mechanism provides an upfront incentive while containing costs to government in the long term. Under the net metering scenario, the customer is permitted to sell excess generation back to the grid and receive compensation at the energy-only retail rate (as noted in Sections 3.2 and 3.3, fixed charges and levies may not be offset). These scenarios are summarised in Table 5, below.

**Table 5. Remuneration Policy Model Scenarios**

<b>Scenario</b>	<b>Remuneration Scheme</b>
<i>Base Case</i>	No remuneration for excess generation, funded through 100% equity finance
<i>Net Metering</i>	Remunerates excess generation at the retail rate of €0.133/kWh
<i>FiT-fixed</i>	Remunerates excess generation at a fixed tariff of €0.06635/kWh
<i>FiT-declining</i>	Year 1-5: €0.13/kWh Year 6-10: €0.08/kWh Year 11-15: €0.03/kWh Year 15+: none

Additional financing scenarios are modelled to explore the impacts of various financing schemes on financial performance. Under 100% equity financing, we assume that

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<sup>12</sup> The rate used here applies to large-scale generators under the REFiT scheme. While not necessarily appropriate for a residential generator, this offers a useful starting point for potential FiT rates.

the homeowner pays the full upfront cost of the PV installation in cash from savings. Feldman and Lowder (2014) note that solar home loan programmes are relatively uncommon, but cite the state of Hawaii as a notable exception; a search of publicly available loan rates indicates a typical rate of approximately 5.5%.<sup>13</sup> We model a financing case in which one half of the system cost is financed with debt at the 5.5% rate, while the remaining costs are paid in cash. We replicate this scenario with a 1% interest rate in order to examine the effect of a prospective public lending programme that could offer extremely low financing rates. Finally, all financing options are modelled alongside grant funding to reduce the upfront cost of the PV installation in increments of 5%, ranging from 0 to 30% of the total project cost. Financing scenarios are summarised in Table 6, below.

**Table 6. Financing Model Scenarios**

<b>Scenario</b>	<b>Financing Assumptions</b>
<i>100% Equity</i>	100% equity finance
<i>5.5% Interest Rate</i>	50% equity (from savings), 50% debt at an interest rate of 5.5%; debt tenor spans full 25-year project lifetime
<i>1% Interest Rate</i>	50% equity (from savings), 50% debt at an interest rate of 1%; debt tenor spans full 25-year project lifetime
<i>Grant Funding</i>	Grant funding in 5% increments from 0-30% of project cost

## **4. Results & Discussion**

### *4.1 Base case and Remuneration results*

Table 7 presents results for the remuneration policy model, which compares the Base Case, in which solar generation can only be used to replace household demand with no remuneration for excess generation, with the three forms of remuneration: net metering and

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<sup>13</sup> Capital costs of course vary considerably across jurisdiction and countries; we follow the example of the Hawaii programme because it is a real-world example with observable commercial rates.

two types of Feed-in-Tariffs (the details of which are provided in Section 3.5). These results indicate the NPV, IRR, and payback period for each combination of system size and annual household demand, and assume that installations are funded with 100% equity finance, i.e. cash paid by the homeowner.

**Table 7. Initial Financial Performance Results for All System and Size Scenarios**

Base Case									
System size	3 kWp	3kWp	3 kWp	4.5 kWp	4.5 kWp	4.5 kWp	6 kWp	6 kWp	6 kWp
Demand	Low	Mid	High	Low	Mid	High	Low	Mid	High
NPV	(€1,381)	€1,398	€3,626	(€3,374)	€212	€3,576	(€5,635)	(€1,556)	€2,569
IRR	-1.28%	2.16%	4.40%	-2.74%	0.73%	3.22%	-3.89%	-0.48%	2.07%
Payback Year	26	22	18	26	24	20	>25	>25	21

Net Metering									
System size	3 kWp	3kWp	3 kWp	4.5 kWp	4.5 kWp	4.5 kWp	6 kWp	6 kWp	6 kWp
Demand	Low	Mid	High	Low	Mid	High	Low	Mid	High
NPV	€5,783	€5,783	€5,783	€10,000	€10,000	€10,000	€14,217	€14,217	€14,217
IRR	6.39%	6.39%	6.39%	7.17%	7.17%	7.17%	7.55%	7.55%	7.55%
Payback Year	16	16	16	14	14	14	14	14	14

Feed-in Tariff - fixed									
System size	3 kWp	3kWp	3 kWp	4.5 kWp	4.5 kWp	4.5 kWp	6 kWp	6 kWp	6 kWp
Demand	Low	Mid	High	Low	Mid	High	Low	Mid	High
NPV	€576	€2,606	€4,228	€267	€2,890	€5,346	(€239)	€2,746	€5,761
IRR	1.28%	3.49%	5.02%	0.79%	2.85%	4.48%	0.38%	2.27%	3.86%
Payback Year	23	19	17	24	20	18	25	21	18

Feed-in Tariff - declining									
System size	3 kWp	3kWp	3 kWp	4.5 kWp	4.5 kWp	4.5 kWp	6 kWp	6 kWp	6 kWp
Demand	Low	Mid	High	Low	Mid	High	Low	Mid	High
NPV	€208	€2,404	€4,147	(€447)	€2,396	€5,052	(€1,320)	€1,921	€5,188
IRR	0.85%	3.47%	5.08%	0.06%	2.70%	4.52%	-0.63%	1.95%	3.84%
Payback Year	24	19	17	25	20	17	>25	21	18

We note that most scenarios indicate a positive NPV over 25 years. Cases with negative NPV occur almost exclusively in cases where low electricity demand diminishes the value to be gained from self-consumption. In the base case, which reflects the current set of circumstances for residential PV in Ireland, the best financial performance occurs in the case of the smallest size of installation, 3kWp, combined with high household demand, with IRR of 4.4% and NPV of just over €3,600. Payback period is calculated to occur in Year 18. This is intuitive, as the 3kWp has the lowest capital cost, while with high electricity demand, there is increased opportunity during the hours with solar generation to replace grid electricity with electricity from solar generation and generate positive cash flows. By the same logic, in the base case the worst NPV is the 6kWp system with low electricity demand. The level of household electricity demand and thus the potential for self-consumption of electricity generated is a key determinant of the financial performance of all sizes of PV installed for two reasons: (i) the retail tariff rate is likely to be higher than any remuneration for excess generation, and (ii) in low irradiance countries there is less excess generation available for remuneration.

Examining the scenarios in which PV owners are compensated for excess generation, it is clear that the net metering case offers the best performance of any other scenario studied, and that NPV and IRR increase with system size. With a net metering rate of €0.133, the payback period is calculated to occur in Year 16 for the 3 kWp system, whilst the 4.5 and 6 kWp systems pay back in Year 14, the shortest payback period possible under the modelled scenarios. As expected, we do not observe any difference in financial performance based on varying demand within the net metering scenarios, for a given PV size, as all kilowatt hours generated are compensated at the same rate, irrespective of self-consumption. From a consumer's perspective, with net metering it makes sense to install a larger size of PV system, 4.5kWp or 6kWp in the case modelled here, in order to benefit from the high rate of

remuneration for excess electricity generated and reduce the payback of the system to 14 years.

There was not a large difference between the fixed feed-in tariff and the declining feed-in tariff results for all sizes of PV systems. In particular, the IRR was nearly identical across the medium and high demand scenarios for all sizes, and payback periods tracked closely for every scenario. This indicates that a fixed tariff, which offers sustained support throughout the project lifetime, had approximately the same effect on financial performance as the declining FiT which began relatively higher, but was ramped down to zero after Year 15.

Overall, initial results indicate that while residential PV is a sound investment in many cases from a classical NPV-perspective, payback periods are well above what homeowners might require. In terms of policy supports, a net metering scheme that remunerates the household at the retail rate for excess generation not consumed has the most significant impact on financial performance. The gap increases further for net metering schemes with larger PV installations; however, even for 3kWp system with medium electricity demand the payback is three years shorter for net metering compared with both FIT designs (this reduces to one year difference with high electricity demand).

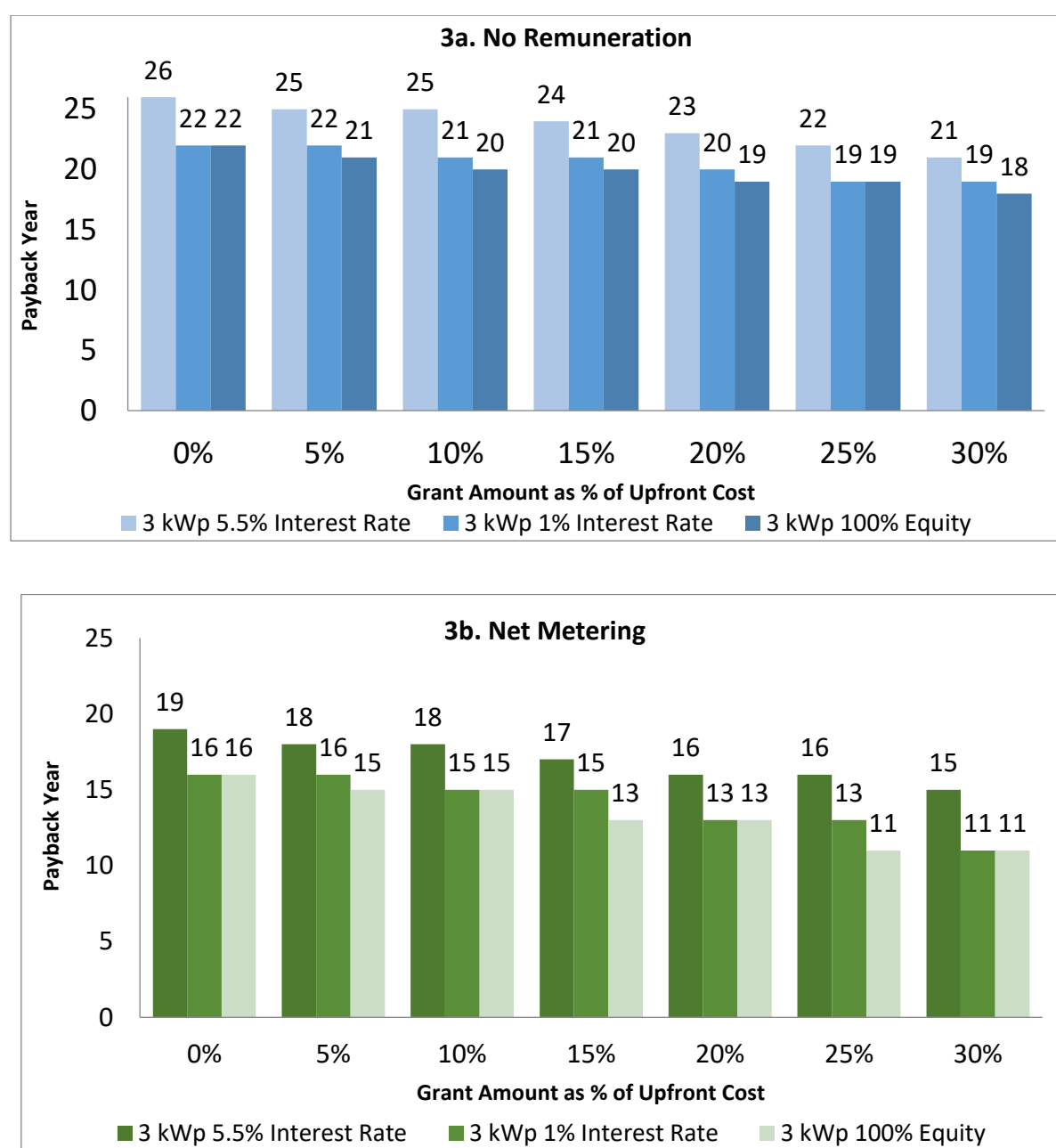
#### *4.2 Grant and Debt Scenario Analysis*

We present additional analysis to examine the impact of a combination of three parameters on the payback period:

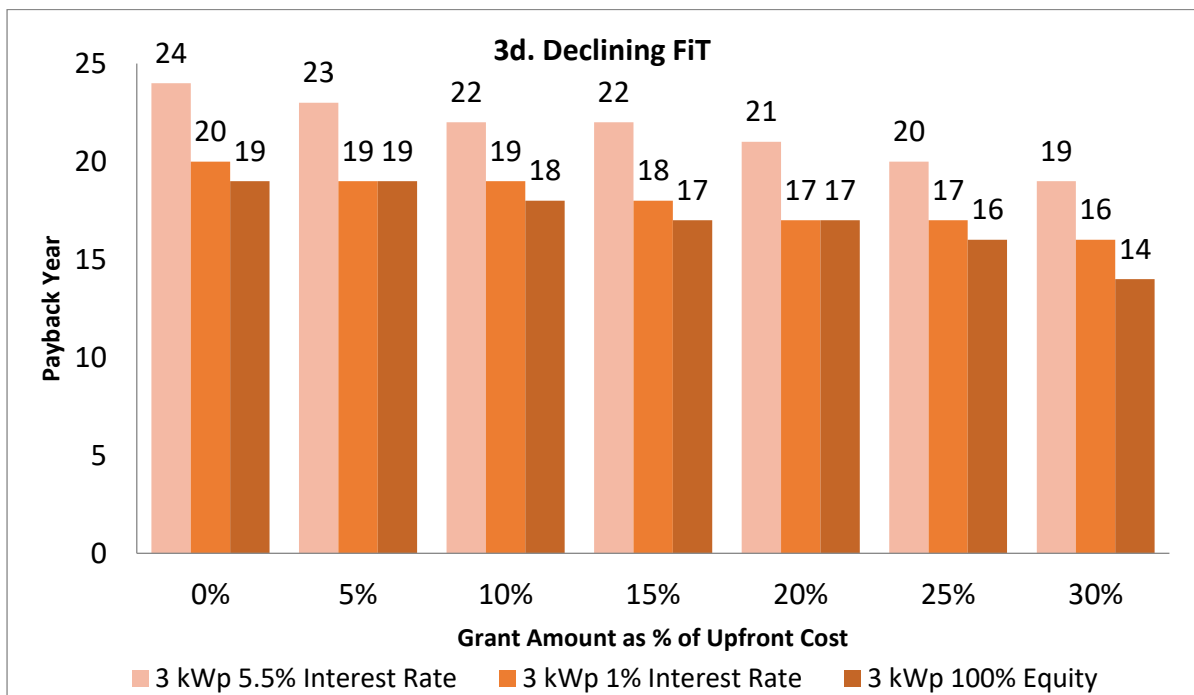
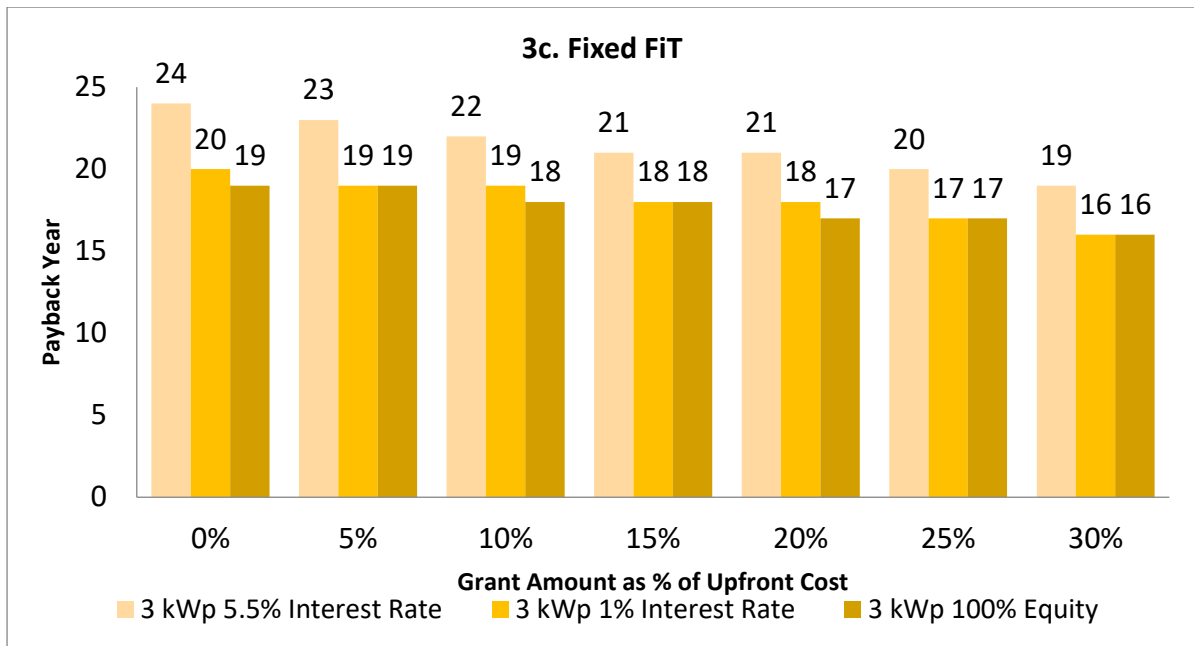
- Remuneration schemes: base, net export, and FIT design
- Level of grant: in steps of 5% up to 30% of the cost of solar PV installation
- Financing structure: 100% equity, debt finance with 1% and 5.5% interest rates

These parameters represent some of the choices facing policymakers and consumers and which could influence the attractiveness of solar PV. This analysis focuses on the 3 kWp PV system, as interviews with active market participants indicate that it is the most common size of system in the residential sector in Ireland. The grant included in the analysis is valued at a proportion of the system upfront cost in 5% increments from 0% through 30%. Results are presented in Figure 3.

**Figure 3. Effects of Grant Amount on Payback for 3 kWp System**







As expected, both scenarios in which debt financing is employed yield longer payback than the 100% equity scenarios for every remuneration scheme, and there are again few significant differences between the FiT scenarios. Notably, payback drops as low as 11 years in the net metering scenario with 30% grant provided, however only in the case where homeowners purchase PV with cash.

If we compare the results in Figure 3a for a grant with the three remuneration schemes (Figures 3b – 3d) at 100% equity, the net metering scheme has a greater impact in reducing payback periods than even a 30% grant, while both FiT schemes have a lower impact. For example, net metering (Figure 3b) enables a payback period of 16 years for the 100% equity 3 kWp mid-demand system, absent any grant, whilst the results show that a 30% grant applied to the base case achieves an 18-year payback period (Figure 3a). On the contrary, both FiT scenarios (Figures 3c and 3d) with 100% equity and no grant achieve a payback of 19 years, equivalent to the payback under a grant worth 20% of capital costs applied to the 100% equity base case scenario.

Of course, not all consumers are in a position to pay for a PV system with 100% equity. If we examine the results for 1% and 5.5% finance, the rankings in terms of payback do not change for 1% interest rate for debt finance. When the interest rate is 5.5%, without policy support the payback period is more than 25 years and therefore the debt renders a negative NPV to the project within its lifetime. A 30% grant or net metering can reduce the payback to be equivalent to the baseline 100% equity case. Comparing different policy supports within the 5.5% interest scenario shows that a grant of 30% (payback = 21 years) is not as profitable as net metering (payback = 19 years) but better than declining and fixed FiT (payback = 24 years). A combination of 30% grant and either FiT structure reduces the payback period to 19 years.

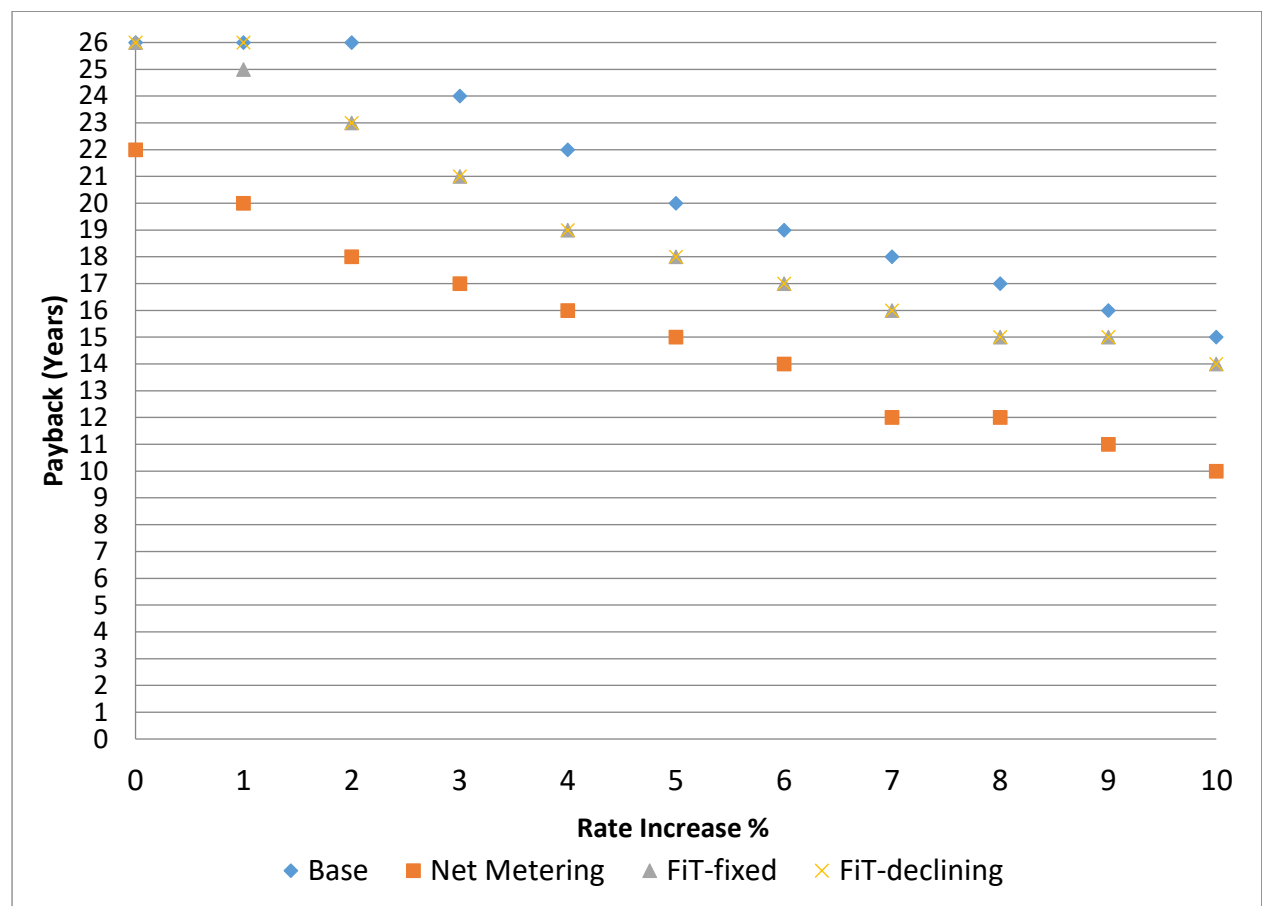
### *4.3 Sensitivity analyses*

#### *4.3.1 Effects of Rate Increase*

As noted in Section III, the financial performance of residential PV in the case of a household purchasing and owning its own PV system is derived from the savings that result from decreased grid electricity use. That is, savings are a direct result of self-consuming PV and off-setting the cost of kilowatt hours that would otherwise be purchased from a supplier

at the retail rate. As such, changes to the retail rate may have significant implications for the amount of those savings. We conduct sensitivity analyses to determine the effects of different rates of change in the retail rate, as shown in Figure 4.

**Figure 4: Effect of Electricity Tariff Increase on Payback Period for 3kWp system**



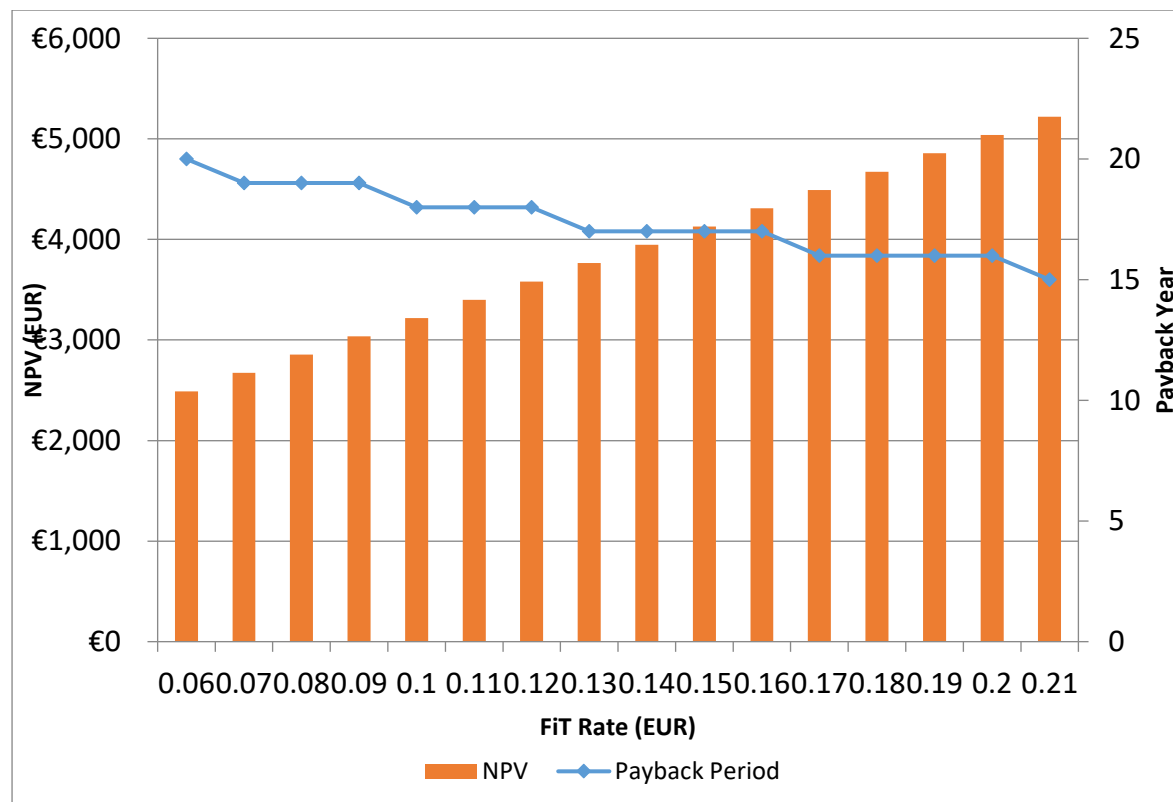
The results show, predictably, that higher retail tariffs make solar PV installations more profitable, as the self-consumption savings are worth more. In fact, the payback period falls by 1-2 years per 1% rate rise in the rate of tariff increase. Conversely, a lower than 4% increase diminishes performance relative to our base case results. While net-metering clearly performs better than the other scenarios, achieving a payback as low as 10 years under a 10% rate increase scenario, the relative benefits are approximately even across each remuneration case: total payback period improves by 11 years for the base case when the rate of change is

increased to 10% from 0%, and improves by 12 years for the three remuneration scheme scenarios.

#### 4.3.2 Effects of FiT Rate

Figure 5 illustrates the effects of the level of fixed FiT on both the NPV and payback period for a 3 kWp system under the 100% equity assumption. The descending blue line shows reductions in payback period for each €0.01 increase in the FiT rate, while the ascending orange bars indicate NPV.

**Figure 5. Effects of FiT Rate on Payback Period and NPV for 3 kWp system**

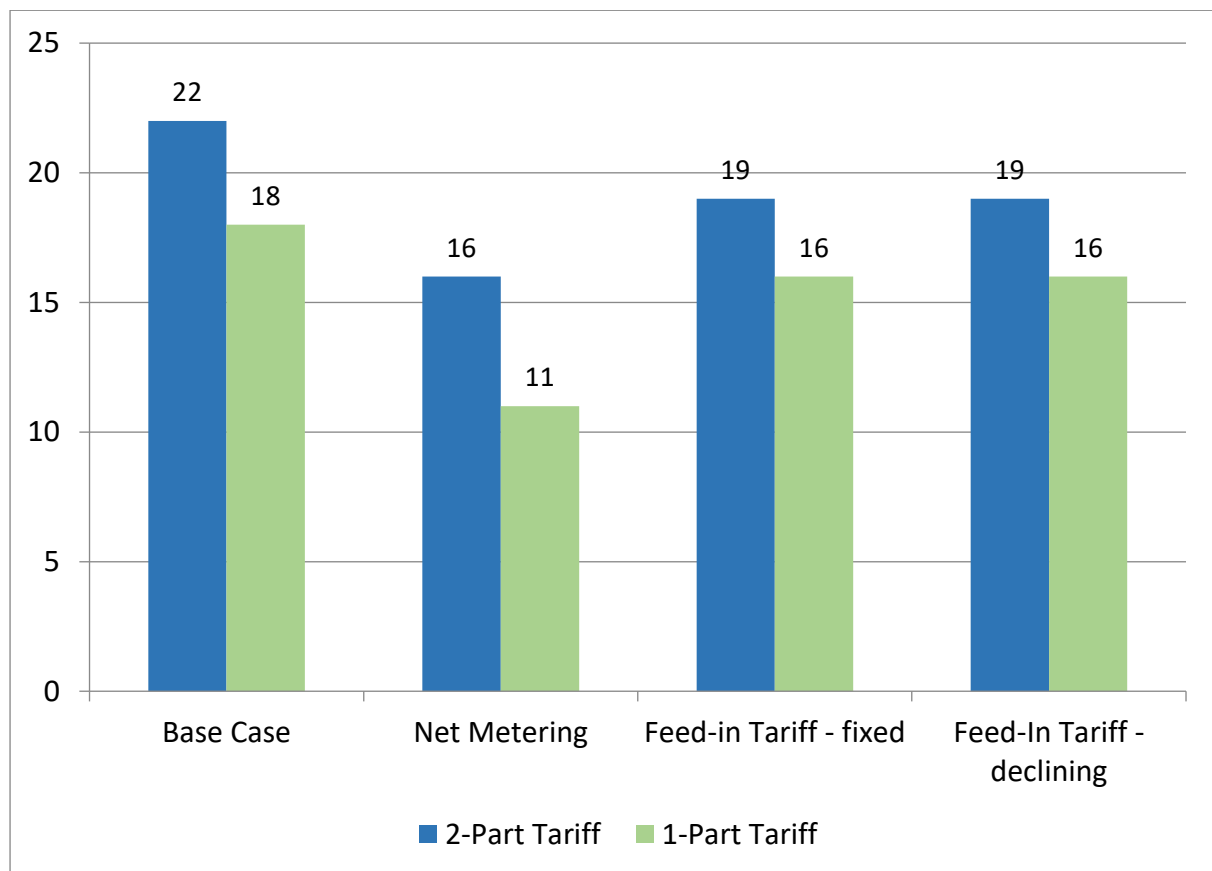


As FiT increases, there is a steady increase in NPV, matched by a slow, graduated decrease in payback period. Indeed, we note that the increase in FiT affects NPV and payback period at markedly different rates. For example, tripling the FiT rate from €0.06/kWh to €0.18/kWh produces a 47% increase in NPV, but only a 4-year improvement, or 20% decrease, in payback period from 20 to 16 years.

#### 4.3.3 Tariff Structures

As noted in Section 3.2, Ireland employs a two-part electricity tariff, consisting of a volumetric rate and a set of fixed bill components that cover network costs and fund support programmes. Because many academic papers and industry practitioners simplify their analysis by applying only a so-called “equivalent” 1-part volumetric tariff, we repeat our modelling using this approach to explore the sensitivity of the selected metrics to changes in rate structure. The one-part tariff applied here mirrors the two-part tariff as a per-unit aggregate rate, i.e. the sum of the fixed charges (approximately €200 per year) plus the volumetric charge (€0.133 per kWh) in the two-part tariff and divided across a typical household annual load (5,100 kWh) multiplied by VAT that gives €0.21 per kWh. Results are presented in Figure 6, below.

**Figure 6. Payback for 3 kWp System Under One- and Two-Part Rate Structure**



The results indicate that rate structure has a considerable impact on payback period, accounting for a 3-5 year difference depending on the remuneration scheme assumed. This is a significant difference: if installers quote savings in terms of an aggregate volumetric tariff only, prospective consumers would likely receive incorrect predictions for payback. The difference between the one-part and two-part tariff represents the amount of the fixed charges that the consumer pays regardless of the amount of PV generation; these charges pay for grid infrastructure and capacity, and householders are likely to continue to require access to the grid for the foreseeable future. This contribution to network costs will become more significant with greater shares of households with solar PV installations in order to avoid a situation in which residential revenues fail to cover required investments in the physical grid and generation infrastructure.

## **5. Conclusion and Policy Implications**

This paper presents the results of a detailed model of household electricity demand and PV generation based on Irish profiling data. The model allows us to model more precisely than other studies on the same subject the financial gains available to residential customers who install a rooftop PV system, and explore how those gains are affected by a range of policy supports and financing options under low-irradiance conditions.

We find that while solar PV is financially viable for Irish households under several scenarios, there are few circumstances in which payback periods are sufficiently short to be acceptable to homeowners. That is, even in cases where homeowners would recover their costs and make a return on their PV investment over its full lifetime, these benefits do not accrue quickly enough to pay back the customer with medium electricity demand in a period shorter than 22 years without any policy support, or 11 years under the most favourable policy scenario modelled. Households with higher electricity demand have the best chance of a shorter payback period, as they can self-consume a higher share of the solar electricity

generated. These results represent a significant departure from previous studies, which indicated that PV was not financially viable in Ireland by any metric over its assumed lifetime. This is an indication that falling PV costs are changing the value proposition of solar PV for consumers in Ireland, and thus similar market dynamics may be present in other low-irradiance countries. Furthermore, the fact that NPV and IRR are generally above the critical thresholds required in corporate decision-making (i.e. NPV is positive and IRR exceeds discount rate), but that payback periods—more salient for households—remain in double-digit figures, highlights the importance of examining a range of performance metrics.

We model economic policy instruments including financial remuneration and grants to investigate their impact on the financial performance for residential customers. The three remuneration policy scenarios modelled (net metering, fixed FiT, and declining FiT) reduce payback and improve financial performance compared with the base case with no explicit subsidy. Given the relatively modest FiT rates in both the fixed and declining scenarios, the result, as expected, is that net-metering provides the best financial returns to prospective consumers with PV with an improvement of 6 years in the payback period. We find that increasing FiT rate has a modest impact on payback, despite its relatively meaningful impact on NPV. This is due to the trade-off between the higher upfront cost from larger PV systems with future cash flows, and suggests that either further cost reductions of PV systems or higher support rates at the level of net metering tariffs are required to make PV attractive using FiT policy schemes. Smaller sized PV systems remain more lucrative than larger sized PV systems under the FiT schemes modelled here which is due to the low capacity factor of solar PV in low irradiance zones with low excess generation. This demonstrates that FiT schemes are less effective in generating positive cashflow than in regions with relatively higher solar electricity production and therefore smaller sized PV systems are economically more efficient under these conditions.

We also compare the effect of a policy of grants covering a range of shares of the upfront costs with the remuneration schemes. We find that a grant of 30% is required to deliver the same benefit to the consumer in terms of payback as net metering and a 20% grant is needed to provide the same payback period as the FiTs modelled (for a 3kWp system with medium demand). For a 6kWp system, a 30% grant never reduces the payback to the extent of FiT or net metering schemes. Therefore from a consumer perspective, in a low irradiance area our analysis shows that the effectiveness of grants and FiTs can be roughly equivalent in terms of delivering a reduction in payback periods for 3kWp systems. In regions with higher irradiance, there is likely to be a divergence in effectiveness between grants and FiTs or net metering, as customers with higher solar generation will benefit more from larger future cash flows from remuneration of excess generation. We have not considered the public policy costs or other non-financial characteristics associated with these schemes that may be important in a policy context for technology adoption. For example, grants may be more likely to motivate homeowners to explore PV by offering a clear, easily-understood incentive compared with remuneration schemes that provide future benefits.

Based on these findings, policymakers wishing to encourage the uptake of residential solar PV in low irradiance regions should give consideration to grant-based supports as well as FiT/net metering policies, as they may deliver equivalent benefits compared with remuneration schemes to consumers in terms of reducing payback period (though, from a public expenditure perspective, other factors such as cost to governments will also need to be considered). The primary value to consumers in these regions is self-consumption, as it is proportionately higher relative to the low amount of excess generation. That is, low excess generation reduces potential future cash flows from remuneration schemes, and consumers realise greater value in offsetting electricity bills, and in having their upfront PV costs defrayed by grant programmes. Conversely, in higher irradiance areas, remuneration schemes



for excess generation will be more effective in improving long-term financial performance, and grants deliver less relative value.

Another key finding is that the rate structure has a strong effect on financial performance. The one-part tariff structure used mainly in industry solar PV calculations gives estimates of shorter payback periods than the equivalent two-part tariff. This can be misleading for consumers in markets with two-part tariff structures therefore this finding may be relevant to regulators or consumer rights advocates in monitoring how installers market the benefits of their product offerings. It is also a particularly timely policy concern, given that policymakers in some mature PV markets are considering revisions to rate structures to ensure an equitable distribution of network and capacity costs. Additional analysis could add to the existing literature by examining the interplay between and potential optimisation of rate structures and network operations in order to determine the optimal share of solar PV and the associated policy implications. Further analysis would also be useful of the impact of time of use pricing in low irradiance regions where demand and generation profiles are not well-matched.

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