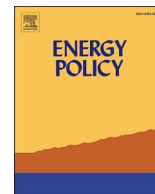




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Evaluating consumer investments in distributed energy technologies

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ABSTRACT

The adoption of solar photovoltaic and electrical energy storage by end users depends on their economic attractiveness, which is typically assessed with metrics of future cash flow such as Net Present Value (NPV). Yet analyses using NPV typically do not account for the evolution towards low-carbon electricity systems in the short and long term. We show this to be of critical importance for accurately calculating the profitability of these technologies.

By linking an energy system model with a power system model, we observe substantial differences between NPV estimates calculated with and without representing potential evolutions of the electricity system. Our results suggest that not accounting for short- and long-run changes in the electricity system could underestimate the NPV of an investment in photovoltaic and storage by around 20%, especially in scenarios with high levels of renewables, moderate flexibility, and high electrification in the energy system. Using system-dependent cash flow metrics can have a major impact on end-users' energy technology profitability.

1. Introduction

Many governments are subsidizing renewable energy-based electricity generation to meet national energy and environmental policies and to reduce greenhouse gas emissions (Williams et al., 2012). More decentralized energy systems are evolving (UKERC, 2018), and solar photovoltaic (PV) has been widely deployed in many countries over recent years (DECC, 2016). Solar PV generation does not usually correlate with peak electricity demand (Pfenninger and Staffell, 2016), especially in high-latitude countries such as the UK. Hence, electrical energy storage (EES) is being pursued as a key option to shift excess electricity generated during the day to meet evening peak demand (Ofgem, 2013; US Department of Energy, 2013). This will help end users to improve their energy independence and to minimize curtailment of renewable energy (Li et al., 2019). Yet, the adoption of solar PV and/or EES onsite depends on the financial benefits of those investments for end users (Borenstein, 2017; Hoppmann et al., 2014; Rodrigues et al., 2016; O'Shaughnessy et al., 2018a,b).

Current metrics used to assess the financial benefit of these technologies are based on net discounted cash flow, with Net Present Value (NPV) the most widely used (Chesser et al., 2018; Comello et al., 2018).

If these metrics are not backed by a representation of the underlying electricity system, they will not account for possible changes over time in energy supply and demand, distorting the perception of value of these technologies to consumers. This could potentially mislead the investment decisions of consumers, resulting in suboptimal policies and a reduction in private and social welfare. Distributed energy technologies such as solar PV and EES can improve the affordability, security and sustainability of electricity supply for consumers who operate these technologies, as well as the whole electricity system. Hence, ensuring that such investments are financially attractive will be critical toward their deployment and success of related energy policies.

In this paper, we show that evaluations of the profitability of solar PV and EES that account for changes over time in the underlying electricity system lead to very different conclusions to those that do not. We develop a holistic modelling framework to compare how differently one would perceive the financial viability of an investment in these technologies in the presence or absence of detailed electricity system modelling. In so doing, we demonstrate the importance of considering short- and long-run changes in electricity supply and demand, as these largely affect the value of distributed energy technologies over time.

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1.1. Metrics to evaluate investments in distributed energy technologies

Different metrics can be applied to evaluate the economic feasibility of investments in distributed energy technologies, either from the investor (electricity consumer) or the system-level viewpoint. In a study comparing different feed-in-tariff (FiT) schemes for solar PV, the total cost-revenues of the system was annualized for different FiT assumptions, and a payback period was estimated for the consumer's investment (Muhammad-Sukki et al., 2011). Estimating the opportunity cost of investment in distributed renewable energy technologies is another method to account for system-level environmental and social benefits of such technologies. For example, the economic profitability of solar PV can be estimated by calculating the levelized cost of each unit of electricity (LCOE) from fossil fuel sources being replaced by solar PV (opportunity cost) (Ramadhan and Naseeb, 2011). Poullikkas (2009) applied a parametric cost-benefit analysis that accounted for different up-front capital, module characteristics, as well as a proxy for carbon emissions being mitigated by installing solar PV. Different metrics of cost-benefit analyses of solar PV for consumers were compared in O'Shaughnessy et al. (2018).

NPV is a well-known metric used to calculate the monetary value of an investment in solar PV and EES (Cucchiella et al., 2016; Dietrich and Weber, 2018; Hoppmann et al., 2014). NPV is the difference between the present value of cash inflows and outflows over a certain time period. These inflows and outflows depend on the supply, demand, and price of wholesale electricity, among other factors. Residential consumers are not normally exposed to day-to-day price volatility, as electricity retailers buy from wholesale markets and sell electricity with different tariffs both at a fixed or volatile price to consumers. Nevertheless, consumer prices are revised every week (dynamic) or 3 months (static) as wholesale prices vary, depending on the pricing scheme. More dynamic pricing schemes such as time-of-use (ToU) or even hourly tariffs are being adopted in different countries to mobilize demand response and promote peak shaving.

Return on Investment (ROI) and Internal Rate of Return (IRR) are also commonly used metrics to analyze the cost-benefit of investment in distributed energy technologies (Benis et al., 2018). ROI is a measure of the return on a particular investment relative to the investment's cost, while IRR is the rate of growth a project is expected to generate. Relevant examples using either metric are Padmanathan et al. (2017) and Formica and Pecht (2017), respectively.

To assess the financial case of a consumer's investment in EES (or PV, or both), studies typically compare the cost of electricity for consumers with and without the technology, where EES is used to increase the uptake of onsite PV-generated electricity. Bost et al. (2011) use the 'grid parity' concept to evaluate the profitability of PV and storage by considering the levelized electricity cost. A similar approach is taken by Braun et al. (2009) and Colmenar-Santos et al. (2012), who calculate IRR of hypothetical EES investments. A few studies (Bost et al., 2011; Braun et al., 2009; Clastres et al., 2010; Hoppmann et al., 2014) compute revenues from storage and PV investments.

1.2. Using the metrics: accuracy and perspective

NPV and other measures of discounted cash flows, including ROI and IRR, are widely used to determine the profitability of solar PV and EES. These metrics compare the energy costs of consumers against income generated from electricity sales to the grid. Although these metrics are regularly used to inform governments, consumers, and energy companies about the expected value of these technologies, we have identified two important deficiencies in the way they are used for this purpose:

- **Accuracy.** Cost-benefit studies (e.g. Li et al., 2019; Ross, 2018; Schwarz et al., 2018) do not directly account for short- and long-run changes in the price of electricity for consumers (i.e. households and commercial/industrial end users) who ultimately pay for price

changes either dynamically or through monthly or quarterly updated tariffs. Bost et al. (2011) and most of the studies reviewed in Hoppmann et al. (2014) assume electricity prices levels or variations to be fixed in time, which is the same as assuming an invariant electricity system. These studies do not consider changes in the supply and demand of electricity in the wider electricity system over time and under different scenarios. By not applying an electricity system model for this purpose, studies (e.g. Boampong and Brown, 2020) do not incorporate a detailed representation of the underlying electricity system and its future development. Other examples include Muhammad-Sukki et al. (2011), who compare the feasibility of investments in solar PV in the UK and Malaysia by applying exogenously assumed FiT values over the lifetime of the technology, and Martin and Rice (2018), who consult stakeholders to derive future FiT rates.

- **Perspective.** Studies typically consider a simple business case that does not reflect a certain evolution of the energy system into the future. In other words, the electricity system is assumed virtually static in time. For example, they consider a certain power capacity mix (Ramadhan and Naseeb, 2011) or are based on present day power grid characteristics (Martin and Rice, 2018). Those studies that do assume that the system will evolve implement changes as exogenous model assumptions, for example as a set of predefined future electricity prices or tariffs (Boampong and Brown, 2020).

In the future, the move to low-carbon generation, and a loss of flexible generation (caused by high renewable deployments), could lead to both higher overall electricity prices and substantially greater price volatility. Yet a consistent implicit assumption of these studies assessing the private value of distributed energy technologies (here, solar PV and EES) is that the electricity system will remain static, with most authors assuming a constant increase in retail prices over time (Hoppmann et al., 2014; O'Shaughnessy et al., 2018; Varghese and Sioshansi, 2020).

In this study, we propose a variant of NPV called *System NPV* (SNPV), which is defined as the NPV of a distributed energy technology based on a certain evolution path of the electricity system. The metric introduced in this work is used to account for the wide variations in the electricity price that occur over time (Joskow, 2011), which we hypothesise will have a profound impact on the monetary value of distributed technologies to consumers.

1.3. Aims and structure of the paper

The paper aims to determine how differently a consumer would evaluate the monetary benefit of investing in solar PV and EES if it considers the underlying future evolution of the energy system. Using an electricity dispatch model to address the accuracy and perspective deficiencies of past studies, we measure how important it is to consider the potential future evolutions of the whole energy system. We show that accounting for changes in the electricity system over the short- and long-runs is critical to accurately identify the value of distributed energy technologies to consumers who invest in them.

This study focuses on NPV because it is the most commonly used and understood metric, yet the lessons from our work extend to all other widely used metrics, as they are based on discounted cash flows. The remainder of this paper is structured as follows. Section 2 describes the methodology and data. Section 3 reports our main results, which are discussed in Section 4. Conclusions are drawn in Section 5.

2. Methods

2.1. Deriving future electricity prices and tariffs

Although wholesale electricity prices vary over time, electricity supply companies have traditionally held the risk from this volatility and charge consumers fixed prices per kWh of electricity consumed.

Over periods of months, changes in wholesale prices are passed through to electricity consumers integrating them into retail prices and electricity tariffs. More recently, flexible dynamic tariffs are increasingly being introduced exposing consumers to more dynamic pricing schemes. In either case, the main component of consumers' electricity bills is the wholesale cost (Ofgem, 2017). To get a full understanding of how wholesale costs affect the NPV (or other metrics) related to a consumer's energy technology investment, one needs to compute wholesale electricity prices for future energy scenarios, then transform them into retail prices, and finally estimate the electricity tariffs paid by consumers for buying electricity.

We focus on the value of consumer investments in solar PV and EES, optimizing the consumer's monetary utility based on the lifetime of the individual systems. Modelling electricity demand in the wholesale market over long periods requires the use of an energy system model to represent changes in electricity demand and in the electricity generation portfolio. We therefore soft-link an energy system model, UK TIMES (UKTM) to a power system model to calculate equilibrium prices in the electricity wholesale market, using a similar modelling approach to Castagneto Gisse and Dodds (2017). By this soft-linkage, fuel prices, annual electricity demand, and power generation capacities under different energy scenarios will be fed as input to the electricity dispatch model. The electricity dispatch model, which has a high tempo-spatial resolution of the GB electricity system, is then run with the specified capacities to meet electricity demand. The output, which is hourly wholesale electricity prices is used to calculate the retail prices as shown in Appendix F. Fig. 1 illustrates the overall methodology.

2.2. Power system model and future energy scenarios

We model the UK power system by using the following data and assumptions. Electricity generation costs are from the UK TIMES energy system model (UKTM) (UCL, 2014), while electricity demand, generation capacities, and fuel prices are from National Grid's Future Energy Scenarios (FES16) (National Grid, 2016). National Grid is the System Operator and owner of the high-voltage power transmission network in England and Wales, and due is in contact with different stakeholders, including the private sector and the public. We examine the four distinct scenarios of the energy system from FES16, as National Grid has developed these by conducting an extensive data collection and stakeholder engagement involving more than 362 organizations in the process. Moreover, these scenarios cover a wide range of futures represented in a matrix with two dimensions of Green Ambition and Prosperity. The document describing these scenarios has been reviewed by the GB Office of Gas and Electricity Markets (Ofgem), the National Regulatory Authority in this domain, stating that a wide range of views have been taken into account. The scenarios are:

1. *Gone Green*, which presents an ambitious renewable expansion scenario where national renewable targets are met;
2. *Consumer Power*, in which energy security and reducing generation costs are primary concerns;
3. *Slow Progression*, where there is a reduced progression towards decarbonization; and
4. *No Progression*, where the generation portfolio is relatively unchanged.

Table 1 reports the key statistics for each scenario in a sample year, 2030. Gone Green has the largest generation share from renewables and storage capacity, while it also has the lowest fossil generation and carbon intensity. No Progression is similar to the existing energy system and has the lowest values in all these areas. The other two scenarios lie in between.

Gone Green meets electricity demand by 2040 with 34% of the total share coming from renewables due to the growth of wind, bioenergy and PV. The slower progress in the building and transport sectors implies the

scenarios reach the UK's overall target of 15% renewable energy later than the EU-agreed 2020 deadline, ranging between 2022 in Gone Green and 2029 in No Progression.

The examined scenarios have different underlying socio-economic assumptions that drive the society's approach to energy use, which causes electricity demand to vary in the long term. In the Slow Progression scenario, end users are knowledgeable about their energy use and green technologies and look for opportunities to reduce their energy use and associated emissions. As such, electricity demand is the lowest compared to other scenarios. In the No Progression scenario, however, energy users focus on reducing the cost of their bills, adopting a business-as-usual approach with little interest in green products and little incentive to replace old products until they break. Heating and transport demands are mainly met by traditional methods, with little progress in electrification. On the other hand, Gone Green represents a society that is active in reducing emissions. Hence, knowledge on green technologies and the adoption rates are high, including in the electrification of the transport and heating sectors. This results in high installation rates of home energy management systems and domestic batteries, and an increased electricity demand overall.

We use a novel electricity system management model, ESMA (Castagneto Gisse et al., 2019) with the electricity system structured as illustrated in Fig. 2. Detailed information about ESMA is provided in Appendices A–H in the Supporting Information. ESMA minimizes electricity costs and calculates electricity wholesale prices under the assumption of consumers' self-operation of their solar PV and energy storage devices (see Appendix E). Retail prices are calculated by assuming a time-varying mark-up over the marginal cost of retail supply, or the wholesale price, which proportionally accounts for network fees, taxes, and other costs (Ofgem, 2017). More information about our methodology for calculating wholesale and retail electricity prices is in Appendix F. Retail prices are used to derive static and dynamic time-of-use (TOU) electricity tariffs following calibration on historical tariff data (ONS, 2015).

2.3. The consumer

We consider the profitability of solar PV and EES, both alone and in combination, for a UK domestic electricity consumer under different evolutions of the system. Solar PV generation and electricity consumption are based on a typical UK consumer, and vary by hour. We model a three-bedroom dwelling with a load profile displaying mean percentage night consumption of 30% and 55% under static and Economy7 TOU tariffs, respectively (Ofgem, 2013). This type of household has an annual electricity consumption between 3084–4399 kWh/a (on average 71–79 kWh/m²/a) according to UK Electricity Survey Data.¹ The household's electricity bill is sensitive to both the load profile and solar generation in cases where the consumer is assumed to operate a solar PV system. The average load factor for solar PV in the UK was around 12% in 2015–2019. The peak load occurs typically between 5 PM and 8 PM in weekdays and seasonally in a winter evening. We account for intra-day, monthly and seasonal variations in these variables.

Consumers using solar PV are assumed to receive the generation and export feed-in tariff (FiT) subsidies, and no subsidies at all in one case. We assume a generation tariff of £0.049 kWh⁻¹ decreasing on an annual basis as specified by Ofgem (2016). The export tariff is assumed to pay £0.043 kWh⁻¹ for electricity exports to the grid (Boxwell, 2017). In scenarios where the consumer operates PV and/or EES, we consider a 4-kW polycrystalline PV system, and a 6.4 kWh–3.3 kW EES stationary battery, with a lifetime limit of 5000 cycles and a maximum of one cycle a day.

¹ https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/208097/10043_R66141HouseholdElectricitySurveyFinalReportissue4.pdf.

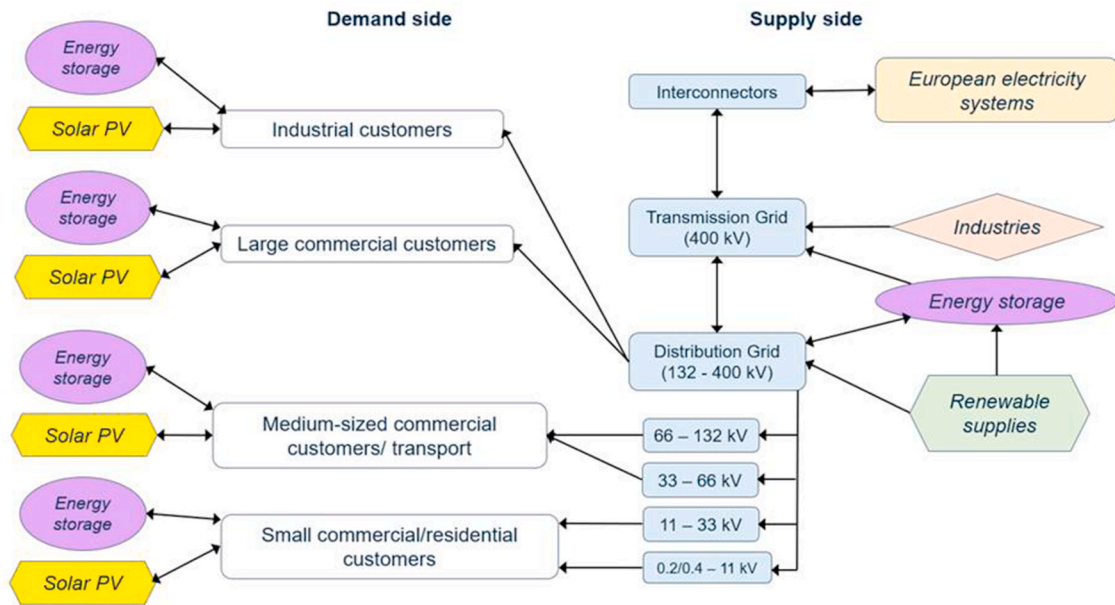


Fig. 2. Representation of electricity flows in the GB electricity grid in the ESMA model.

Table 2
Different feed-in-tariff (FIT) schemes examined today and in future.

Tariff scheme	Base value, 2016 (£ kWh ⁻¹)	Future value
Static	0.15	Based on quarterly average of modeled electricity prices ^a
Dynamic (ToU) (Economy7)	Night (0–7 h): 0.07 Day (7–24 h): 0.16	Proportional to corresponding static tariff

^a These prices are endogenously calculated from the results of the electricity system model for the future years.

2.4. Modelling scenarios

We calculate NPV for four consumer technology combinations: (1) no technology; (2) an EES system alone; (3) a solar PV system alone; and, (4) a combined solar PV and EES system (PV + EES). We also examine the use of both static and dynamic TOU tariffs, and four potential evolutions of the future energy and power system: (i) Gone Green; (ii) Consumer Power; (iii) Slow Progression; and, (iv) No Progression.

2.5. Electricity bills and financial case

Annual electricity costs are estimated based on a simple accounting exercise and are calculated for each scenario relative to the reference case (1), in which the consumer pays static tariffs that grow 5% per year (Braun et al., 2009; Kaldellis et al., 2009) and has neither generation nor storage assets. Investment and management costs, and other data used in this study, are reported in Appendix H. Based on the cost optimization model, the consumer minimizes electricity costs every hour. We assess the financial case for PV + EES, yielding the NPV of the investment for each scenario. Hourly savings, and other revenues and costs, are then aggregated to an annual level to yield NPV. We assume no debt financing and investment costs arising in January 2015, with a technology-optimal horizon of 26 years–2040. The starting year of 2015 was chosen in line with data linked to the ESMA model (see Appendix A-D). The discount rate is assumed at 5% per year, following CCC (2013).

In scenarios where solar PV is present (Scenarios 3 and 4), we consider a typical, 3.99 kW polycrystalline system, because PV systems

under 4 kW are eligible for feed-in tariffs (Department of Energy and Climate Change, 2013). (Department of Energy and Climate Change, 2013), producing averages of 0.8 kW at peak output and 8.92 kWh per day total output, corresponding to 3256 kWh of electricity generated per year. Solar generation data is derived using monthly data from the Energy Saving Trust (2011). The cost of a typical domestic solar PV system is estimated at £8080 (Department of Energy and Climate Change, 2013).² We assumed variable costs of £1000 for inverters with a 10 year-lifetime, insurance of £7/month (The Eco Experts, 2016), and 90% efficiency (SolarTherm UK, 2016). Additional costs include one-off payments for grid usage of £101 per year and for grid connection of £80 (EDF Energy, 2016). A typical solar PV system lifetime is 20–25 years (National Renewable Energy Laboratory, 2016). Decreases in solar PV costs of 70% are assumed relative to 2016 levels by 2030 (DNV GL, 2016).

Scenarios involving EES (Scenarios 2 and 4) employ data from Tesla (2016) with respect to the Tesla Powerwall v1, which was commercialized in late 2016. This is a 6.4 kWh-3.3 kW stationary battery, with round-trip efficiency of 92.5%, intended for daily cycle applications. We also considered an additional battery size of 13.5 kW. The battery’s capital cost, including installation and necessary accessories,³ is £6991 (SolarTherm UK, 2016). The battery’s depreciation and its efficiency losses represent the main operating costs of the storage device. The battery is able to withstand a maximum of 5000 cycles for a warranted time period of 10 years, after which the purchase and installation of a new battery will be necessary (Zakeri and Syri, 2015). Hence, we assume a linear depreciation of the battery, which yields an average O&M cost of £5.48 cycle⁻¹ over Tesla’s 10-year warranted time period (calculated by the authors).

Assuming that one battery has a lifetime of 13 years (5000 cycles), so that two batteries last 26 years, and that manufacturers usually offer

² For installations sized between 0 and 4 kW, the mean cost per kW was £2,020, which includes the cost of solar PV generation equipment, plus direct costs of fixing panels to roof/ground mount, any performance displays and connecting to electricity supply, including VAT.

³ Accessories include the following items: 15no. P300 Power optimisers, 1 × S/E 3680 SolarEdge inverter, 1 × Wi fi unit and connection, 1 × Tesla Powerwall, 1 × StorEdge system and components, 1 × Connection to the SolarEdge portal, and necessary scaffolding.

solar panels along with a 20 to 25-year warrantied period, we fix the time horizon to 26 years, which is optimal from the perspective of the combination of the two technologies. This determines an optimal investment horizon of 26 years.

2.6. NPV and system NPV

The NPV of an investment is the difference between the present value of cash inflows and outflows over a given time period and is estimated for a given technology P as shown in Eq. (1):

$$NPV_P = \xi_P - \eta_P \quad (1)$$

where the input parameter ξ_P is total discounted revenues in years $1 \dots T$, and η_P showing the total discounted costs.

We define the 'System NPV' (SNPV) of an investment as the NPV calculated using an endogenous price of electricity throughout the calculation period. In the SNPV, the cost of importing electricity from the grid reflects a system-dependent electricity price, which is internally consistent with a future energy scenario representing a specific evolution of the electricity system. The opportunity cost of such an investment may be the net value of grid electricity imports (if the investment is in solar PV or EES alone) or the net value of PV alone (if we are analyzing the viability of an investment in the integrated PV + EES system).

For an investment in a technology P , SNPV is then calculated through Eq. (2):

$$SNPV_P = SNPV(P) - SNPV(E) \quad (2)$$

The input parameters in Eq. (2) are $SNPV(P)$ as the absolute NPV of investing in technology P (gross of the NPV of the discounted cost including the cost of electricity imports from the grid) and $SNPV(E)$ showing the NPV of purchasing electricity from the grid without operating any electricity generation or storage technology. This accounts for the fact that consumers aim to invest in technology to minimize the cost of electricity, whereas grid imports are their second-best choice. The same line of reasoning is applied when calculating the associated NPV of an investment in solar PV.

A similar approach can be used to find the SNPV of an investment in EES or, in other words, the extra value contributed by EES when pairing solar PV with EES. This difference shows the value of storage as intended to increase the value of solar PV. The metrics could also be expressed as ratios, but considering differentials is more useful because it defines the excess monetary value relative to achieving break-even. Once again, we use the same approach when calculating the associated NPV of an investment in PV + EES.

In order to understand the degree by which using SNPV improves the accuracy of a technology's profitability measure, we compare SNPV with NPV. When calculating NPV, we do not employ an electricity system model and simply assume that average electricity retail prices increase by 5% per year. This is based on a general practice in most studies evaluating technology profitability, such as Braun et al. (2009); Kaldellis et al. (2009); (Lyon, 2016; Ross, 2018; Schwarz et al., 2018). Hence, the main difference between SNPV and NPV in our analysis is that the price of electricity for SNPV is endogenous, i.e. calculated based on future energy scenarios and accounting for their impact on the electricity system, while in NPV the electricity prices are exogenous and are assumed to grow by 5% per year.

2.7. Model evaluation

We evaluate our model using sensitivity tests that vary several key input parameters. Following Hoppmann et al. (2014) and Castagneto Gisse and Dodds (2017), we consider the changes in the SNPV of an investment in PV + EES that are associated with changes in financial case components with the highest shares in total costs and revenues. In particular, we vary: the nominal discount rate; battery future investment

costs; potential increases in global installed PV capacity; PV inverter costs; O&M costs for solar PV; and O&M costs for EES.

3. Results

In this Section, the results of our analysis are presented in two parts. First, we discuss the results of SNPV and compare that with a NPV analysis to understand the financial feasibility of investment in distributed energy technologies under different future scenarios for the energy system and retail tariffs. Second, we conduct a sensitivity analysis to evaluate the impact of main parameters on the results.

3.1. System NPV

Table 3 reports the System NPVs (SNPVs) for investments in different combination of distributed technologies (i.e. no investment, EES only, PV only, and PV + EES) for the period between 2015 and 2040. The value of each investment is examined compared to a case with no investment (i.e. buying electricity entirely from the grid). The value of investment in each technology configuration is shown for two electricity tariffs (static and TOU), and under four different future scenarios for the energy system. Negative values indicate the unprofitability of that technology compared to the case buying electricity from the grid. These values are calculated without considering any subsidies for investment in distributed technologies.

3.1.1. Individual energy technology investments

The estimated value (SNPV) of an energy technology for a consumer is the additional value of that technology compared to importing all of electricity needs from the grid, including the time value of the cost of this electricity imports.

In 2015, investment in solar PV was marginally unprofitable for the typical UK consumer and required an increase in its value relative to grid imports by between £0.4k–£1.4k to become profitable (see Table 3, results for PV-only). This occurs as a result of low insolation in the UK in combination with the typical consumer's load profile. The highest SNPV for solar PV-only relates to the Gone Green and Consumer Power scenarios, under TOU tariffs. In these scenarios, solar PV was closest to being profitable relative to simply importing electricity from the grid, by a margin of £400, because grid imports were more expensive. The higher profitability of PV-only investments under TOU compared to a Static tariff is because solar generation mostly occurs in peak hours with higher prices under TOU.

In general, SNPV decreases as the consumer becomes more independent of the grid. The results also show that the SNPV of an investment in EES-only must have been between £3k–£7k for EES to have become a viable solution for the consumer when operated without solar PV. The TOU tariff shows slightly better profitability than the static tariff when investing only on EES, as the price difference between day and night makes energy arbitrage possible in this case, even without onsite generation.

3.1.2. Pairing solar PV with EES

To show whether pairing PV with EES would be profitable for the consumer, we consider the SNPV of an investment in PV + EES. When the consumer operates PV + EES, an additional £3.8k–£4.4k was required to achieve parity relative to grid imports (see Table 3, results for PV + EES). Similar to investment in PV-only, the consumer has a lower loss of value in the case of PV + EES under Gone Green and Consumer Power scenarios, a net value loss of £3.9k–£4.0k compared to £4.2k–£4.4k in No- and Slow Progression. However, in contrast to the case of investment in PV-only, installing PV + EES is slightly more profitable under static tariffs. EES is mainly deployed to store electricity generated by solar panels during the day and shift that to the evening and, in some days, to night hours. Since the price of electricity at night for the static tariff is almost double than that of TOU, using EES for day-

Table 3

System NPV (SNPV) indicators in £k. Investment value indicators are reported for each technology combination, type of electricity tariff, and future evolution of the energy system. (SNPV: absolute SNPV. $SNPV_P$ = Relative SNPV for a technology P: net of the value of that technology relative to the case of only importing electricity from the grid).

Electricity tariff	Consumer technology	Future Energy Scenario							
		No Progression		Slow Progression		Gone Green		Consumer Power	
		SNPV (£k)	$SNPV_P$ (£k)	SNPV (£k)	$SNPV_P$ (£k)	SNPV (£k)	$SNPV_P$ (£k)	SNPV (£k)	$SNPV_P$ (£k)
Static	None	-9.5	N/A	-9.6	N/A	-8.8	N/A	-8.6	N/A
	EES-only	-16.2	-6.7	-16.4	-6.8	-15.0	-6.2	-14.7	-6.1
	PV-only	-10.9	-1.4	-11.0	-1.4	-10.1	-1.3	-9.8	-1.2
	PV + EES	-13.7	-4.2	-13.9	-4.3	-12.7	-3.9	-12.4	-3.8
TOU	None	-9.0	N/A	-9.2	N/A	-8.4	N/A	-8.1	N/A
	EES-only	-12.8	-3.8	-13.1	-3.9	-11.9	-3.5	-11.5	-3.4
	PV-only	-9.5	-0.5	-9.7	-0.5	-8.8	-0.4	-8.5	-0.4
	PV + EES	-13.3	-4.3	-13.6	-4.4	-12.4	-4.0	-12.0	-3.9

to-night energy arbitrage makes more benefits for PV + EES under the static tariff.

An increase in absolute SNPV of £2.6k–£3.8k is needed to enable the PV + EES system to be as valuable as an investment in PV alone. This could have been achieved by a subsidy of 36%–56% of the capital cost of the first installed battery, which suggests that EES is not yet financially viable for a typical UK consumer.⁴ This indicates that if the UK authorities had subsidized around half of the capital cost of the initial battery (in 2015) required over the 26-year period, the PV + EES system could have reached parity with the value of grid imports.

Fig. 3 shows the estimated breakdown of the discounted costs and revenues for a typical consumer operating a PV + EES system under TOU tariffs in 2015. Two batteries were required to store electricity from solar PV during the 26-year lifetime of the PV system, with the cost of the second battery incurred after 13 years and assumed to cost 70% less than the first battery due to technological innovation driving down capital costs (DNV GL, 2016). The discounted cost analysis of this system suggests that the battery capital costs made up a third of the total costs to the consumer, with the capital costs of the solar PV system covering a similar share. The cost of importing electricity from the grid amounted to 8% of total expenses. Reduced electricity imports accounted for 89% of consumer revenues, with the remaining 11% from generation tariff payments.

To account for the removal of feed-in tariffs in 2019, Appendix I reports results for absolute and relative profitability by scenario in the absence of generation and export feed-in tariffs. The core results of this study, reported in Section 3.1.3, are unaffected from varying assumptions of feed-in tariffs since their use in calculating SNPV and NPV remains unvaried across different scenarios.

3.1.3. Comparison of NPV with system NPV

SNPV is found to always exceed NPV, meaning that estimation of consumer benefits with typical NPV calculations is likely to understate the profitability of investments in solar PV and EES. Fig. 4 illustrates the percentage difference by which SNPV exceeds NPV. It therefore shows the magnitude by which NPV was underestimated compared to using an SNPV approach by way of assuming a static future electricity system. There are differences between SNPV and NPV ranging between 1 and 21% of the value of NPVs.

The difference between SNPV and NPV varies strongly between the examined electricity system scenarios. There are substantial and consistently larger differences between SNPV and NPV in scenarios with increasing shares of renewables (Gone Green and Consumer Power) and those with dynamic tariffs. The former implies strong changes in electricity prices, whereas the latter means that consumer tariffs are more

responsive to daily changes in consumer load or solar PV production, which amplifies the impact of system variables on SNPV, hence the difference with NPV.

Table 4 shows the percentage levels by which NPV is underestimated relative to SNPV in scenarios involving low and high renewable shares in total generation. Here, ‘Low renewables’ is the average of No Progression and Slow Progression scenarios, in which the share of renewables and level of electrification is low. ‘High renewables’ averages over Gone Green and Consumer Power, which are the scenarios with the highest renewable share, electrification, and retail electricity prices. It should be noted that the difference between SNPV and NPV in “No technology” is merely related to different electricity prices, which results in different net present values of the costs for importing electricity from the grid. This underestimation of SNPV ranges between 1% and 21%, with a larger gap showing in high-renewable scenarios.

3.1.4. Future electricity prices

In Section 2.1, the method for deriving future electricity prices and tariffs in a SNPV method are described. Fig. 5 compares the consumer electricity prices between future scenarios of the SNPV method (i.e. high-renewable scenarios Gone Green and Consumer Power) with the other two low-renewable scenarios, and with a fixed increase in electricity tariff (or the NPV method). The high renewable scenarios have the highest differences between SNPV and NPV. Both high-renewable scenarios show a dynamic behavior starting with higher prices in the beginning while flattening towards the end of the examined period. While the average electricity price over the technology’s lifetime in a fixed-growth tariff may be close to the average prices in dynamic scenarios, the impact on discounted cash flow calculations is different when considering the variations in annual values. As dynamic scenarios overall show higher discounted electricity prices, they offer a more attractive investment in distributed technologies (PV and EES) for end users. The linear, fixed growth of electricity prices only exceeds dynamic prices towards the end of investment horizon with a relatively lower impact on net present values. Hence, even with the highest absolute prices in 2040, the fixed tariff does not capture the dynamics of price evolution accurately and as such NPV calculations based on this simple assumption differ from SNPV.

It should be noted that the examined future scenarios here both represent a high share of variable renewable energy (VRE), which is expected to result in lower electricity prices due to the merit-order effect of wind and solar PV. However, this does not hold true, as: (i) the electricity demand also increases under these scenarios due to higher electrification of the transport and the heating sector; (ii) a higher share of VRE increases the need for flexibility and backup generation endogenized in electricity prices; and, (iii) a higher tax is imposed to end users to account for additional investment needs for integration of VRE (e.g., National Grid assumes a 60% increase and grid taxes due for subsidizing VRE in Consumer Power scenario). Hence, lower wholesale

⁴ The value of PV + EES should improve, relative to PV, as export tariffs are removed in April 2019 (Ofgem, 2018).

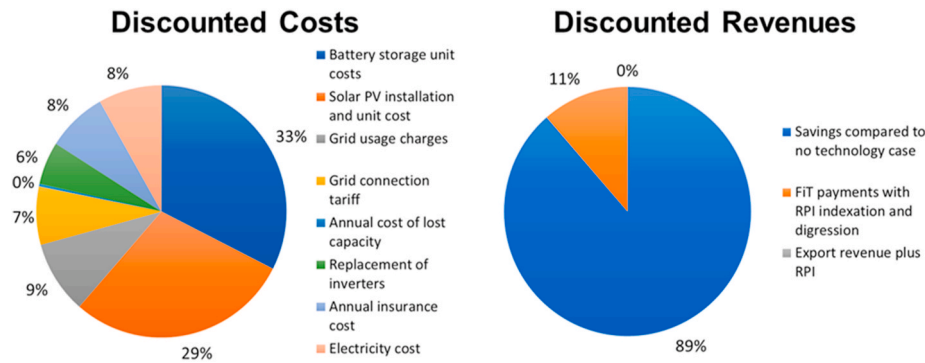


Fig. 3. Typical component shares of discounted costs and revenues for an investment in PV + EES in 2015. Savings are calculated relative to the same consumer with no technology at its disposal (i.e. neither PV nor EES). The above example considers the case with FiTs.

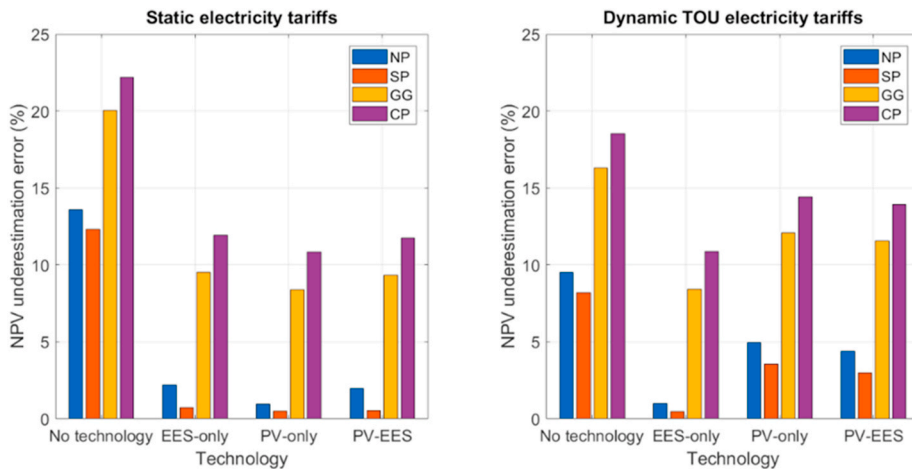


Fig. 4. Percentage difference by which SNPV exceeds NPV. Positive values indicate percentage underestimation of NPV when not implicitly assuming a changing future electricity system between 2015 and 2040. The x-axis indicates the technology scenarios as: (i) No technology; (ii) EES-only; (iii) PV-only; (iv) PV + EES. The bars indicate future energy scenarios: NP=No Progression; GG = Gone Green; CP=Consumer Power; SP=Slow Progression. Note that the difference between SNPV and NPV in “No technology” is due to different electricity prices, which leads to different costs of importing electricity from the grid. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 4
Percentage underestimation of SNPV relative to NPV. ‘Low renewables’ is the average of No Progression and Slow Progression scenarios, while ‘High renewables’ averages over Gone Green and Consumer Power.

Electricity tariff	Technology	Low renewables share	High renewables share
Static	None	13%	21%
	EES-only	2%	11%
	PV-only	1%	10%
	PV + EES	2%	11%
TOU	None	9%	18%
	EES-only	1%	10%
	PV-only	5%	13%
	PV + EES	13%	21%

electricity prices in high-renewable scenarios does not directly translate to lower retail electricity prices for end users.

3.2. Sensitivity analysis

The robustness of our results is verified by calculating the change in SNPV for an investment in PV + EES subject to uncertainties in several key parameters, in the spirit of Hoppmann et al. (2014). Here we consider the most likely evolution of the energy system by accounting for the cost of electricity averaged across the No Progression and Consumer Power scenarios. The sensitivity analysis, summarized in Fig. 6, demonstrates that the results are robust to changes in key parameters and assumptions. The results of the sensitivity analysis for the examined parameters show that the impact of variations ranging between -100% and +100% in the input parameters changes the calculated SNPV in a

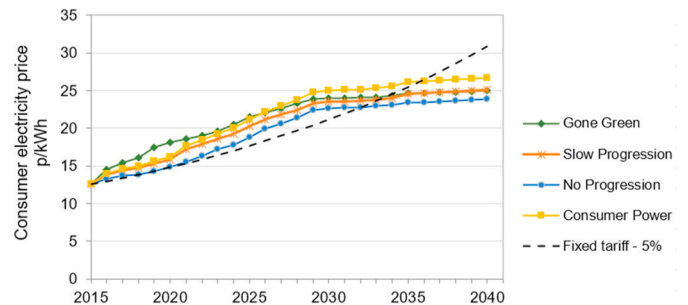


Fig. 5. Comparison of scenario-driven electricity prices in the Gone Green, Slow Progression, No Progression, and Consumer Power scenarios used in SNPV calculations, versus a fixed tariff increasing 5% per year, which is used to calculate NPV. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

range between -20% and +20%. In this sensitivity analysis, we change the value of input parameters in intervals of 33%, 66% and 100% relative to the base values, which was used in calculations so far. Considering a 100% higher and lower range offers a wide range for assessing the sensitivity of the results. The sensitivities show that absolute SNPV varies the most with the mean electricity tariff level, and the least with the negligible EES O&M costs.⁵ Also, the results show

⁵ We assume that the second battery’s capital cost does not enter the balance sheet as O&M cost, but as a capital cost.

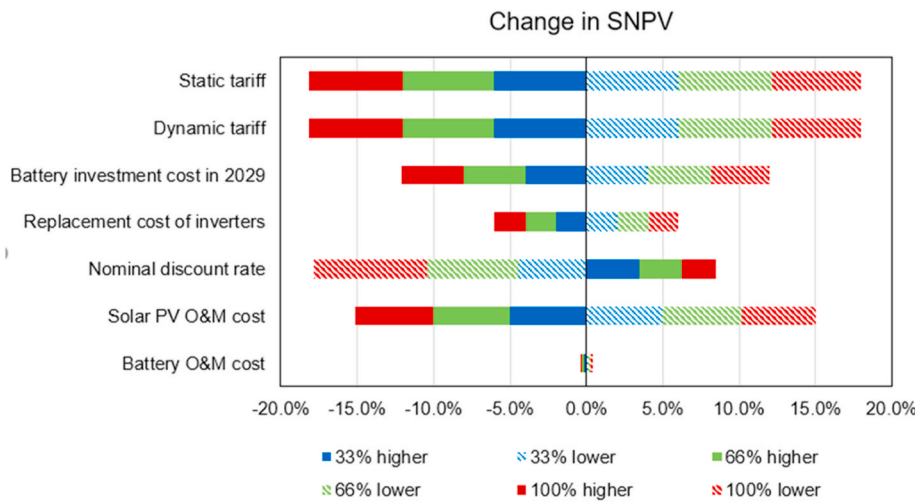


Fig. 6. Sensitivity analysis. Percentage change in SNPV for each 2016£ invested in EES, in relation to a typical consumer’s investment in PV + EES. Higher values show +33–100% change in Financial Case, while lower values represent -33–100% change in Financial Case Variable. Except for the change in the static tariff, for which the base case applies, all other variable sensitivities assume the use of TOU tariffs. This approach is used as a result of the verified, higher impact of TOU tariffs on the consumer’s savings using PV + EES. Solar PV O&M costs include the replacement costs of inverters and insurance. Battery O&M costs include the replacement costs and loss of capacity over time.

SNPV will shrink by 7.4% if the nominal discount rate is doubled to 10% per year.

4. Discussion

Evaluations of the economic viability of a consumer’s investment in new energy technologies using discounted net cash flow metrics such as NPV are highly dependent on assumptions of cash flow in the future, over the lifetime of the technology investment. Thus, these calculations are inaccurate if based on an implicit assumption that electricity price variations in the future: (i) are fixed and will not vary in the short- and long-run; and/or, (ii) are independent of the development of the electricity system over a long period. Studies typically assume a constant price growth rate and do not consider wider electricity system scenarios where the electricity price can be modeled as part of a certain evolution of the energy system. O’Shaughnessy et al. (2018) lists a number of studies in which the electricity price is subject to a mean annual escalation or a flat rate when calculating cash flows. For example, Li et al. (2019) assumes an incremental increase of electricity prices from 0.2 to 0.4 \$/kWh as an explicit assumption for estimating future cash flows. In order to overcome this limitation, we linked the calculation of NPV with a dynamic model of the power system that explicitly considers the time-dependent nature of electricity wholesale costs, depending on future evolution of the electricity system. We apply this method for calculating future electricity prices as one of the important input parameters for estimating NPV of distributed technologies such as PV and EES.

Here, we discuss that why a SNPV results in a much different understanding of the profitability of distributed technologies compared to typical NPV calculations. Related metrics of discounted cash flows, such as Return on Investment (ROI) and Internal Rate of Return (IRR), are also commonly used to analyze the financial attractiveness of an investment from similar perspectives. Examples using either metric are Padmanathan et al. (2017) and Formica and Pecht (2017), respectively. Like NPV, these metrics can be also improved by considering more realistic and dynamic assumptions of input values for future cash inflow/outflows.

4.1. Profitability of distributed energy technologies: the role of the underlying electricity system

Accounting for the future evolution of the energy system is an important factor when assessing the NPV of a consumer’s energy investment. Neglecting changes in the wider system can lead to a risk of underestimating the profitability of technologies such as solar PV and

battery storage, hence, discouraging investment in such technologies. This is especially the case as we move toward an electricity system that is substantially different from the current one. Widespread adoption of electric transport and electric heating will increase electricity demand and prices, and it will also impact their short-term and long-term variability. The integration of high shares of variable renewable energy and distributed energy generation is another transition that will impact electricity prices, by increasing the share of near-zero marginal cost generation in the system but also the need for flexibility, backup power plants, and grid integration and management costs. These evolutions in an energy transition pathway are too complex to be represented by simple price assumptions as input to NPV calculations. The estimation error is up to 21% of the value of the NPV.

4.1.1. Differences between future scenarios

The results show different levels of profitability in investment in distributed energy technologies under different future energy scenarios. Table 6 depicts these differences by analyzing transitions in each scenario with respect to six key parameters: annual electricity demand, level of electrification, share of VRE, retail prices of electricity, installed capacity of storage, and economic growth. This will help to draw policy recommendations that can be applied beyond the focused energy system. The most promising scenarios for investment in solar PV and EES proved to be Gone Green and Consumer Power (see Section 3.1), the two scenarios with a high economic growth. Looking under the hood, these two scenarios also represent the highest level of VRE, electricity

Table 6

Main differences between future energy scenarios, based on (National Grid, 2016).

Key parameters	Future Energy Scenario			
	No Progression	Low Progression	Gone Green	Consumer Power
Electricity demand	Low	Low	High	Moderate ^a
Electrification	Low	Moderate	High	Moderate ^b
Share of wind and solar PV	Low	Moderate	High	Relatively high
Retail electricity price	Low	Low	High	High
Installed capacity of storage and interconnector	Low	Low	Average	High
Economic growth	Low	Low	High	High

^a The residential electricity demand grows but there is significant reduction in electricity demand in the industry due to fuel switching as gas prices are cheap.

^b While the share of electric vehicles grows significantly, electric heating not that much due to low gas prices and use of micro CHP.

demand, and electrification among four examined scenarios. Electrification and higher demand for electricity increases electricity prices, so creates a better financial case for investing in distributed energy technologies versus buying electricity from the grid. Higher shares of VRE in these two scenarios will slightly reduce wholesale electricity prices. However, consumers ultimately need to pay for higher retail electricity prices due to the integration of VRE. This is to compensate for subsidies paid to wind power installations and additional system costs such as grid extensions and flexibility needs for balancing VRE. Therefore, according to the underlying assumptions from [National Grid \(2016\)](#), scenarios with higher shares of VRE introduce higher retail electricity prices to end users. This assumption is consistent with the observed trends in countries like Denmark and Germany, where the retail electricity prices have grown steadily as the share of VRE increases in the system.

Between Gone Green and Consumer Power, the former shows a higher profitability for investment in solar PV and EES. Because not only Gone Green has the highest share of VRE, it has lower levels of storage compared to Consumer Power. As such, the system needs more storage, and this is paid through electricity price signals that encourages investment in PV + EES to shift electricity use from peak hours. In other words, in systems that central electricity storage solutions are not enough to accommodate the needs of the system in high VRE scenarios, investment in PV combined with EES at the household level is more economically attractive. However, the retail tariffs such as TOU or more dynamic like hourly tariffs are needed to signal this need to the distributed generators and storage providers.

4.1.2. NPV or SNPV?

The energy system is expected to depart dramatically from the present determinants of demand and supply ([National Grid, 2016](#)), affecting the level and variations of electricity prices. Therefore, the fact that studies using NPV normally make an explicit assumption that retail tariffs will not vary considerably in the future ([Hoppmann et al., 2014](#)), or will vary at a fixed rate, may misrepresent the profitability of energy technologies.

In the future, consumers could provide several technical services to the electricity system, including various capacity and ancillary services ([Burger et al., 2017](#)), such as congestion relief. Providing these services could contribute dramatically toward system balancing and security when scheduled independently or via aggregators ([He et al., 2011](#)). These services may have high value if scarce, but low value if abundant. Their abundance will depend on the level of VRE which, at scale, would imply that electricity supplies from distributed energy resources, such as solar PV or EES, could have greater private and system value. Considering how consumer technologies are affected by the differences between future energy scenarios is likely to become gradually more important as more non-synchronous penetration come online. Accurately predicting the profitability of consumer technologies will increasingly depend on which other technologies are deployed, and improvements in short-run forecasting, as these factors all affect the normal operation of electricity markets at various timeframes (including forward, day-ahead, intraday and balancing), to which distributed resources could sell valuable electricity system services ([US Department of Energy, 2013](#)). These factors can only be accounted for if SNPV is used rather than NPV.

Upon purchase of solar PV or EES, governments should provide consumers with a clear understanding that the profitability of their technology is uncertain and strongly varies according to the potential future evolution of the energy system. The contribution of end-user energy technologies toward the electricity system via aggregation has been shown to be potentially meaningful toward reducing electricity prices and improving security of supply, whilst increasing the system's sustainability ([Castagneto Gisse et al., 2017](#)), and this further emphasizes the importance of using a reliable underlying system model. Failing to ensure that consumers get an accurate estimation of the economic profitability of investment in new technologies may limit the

deployment of technologies that could otherwise deliver important system-level benefits. This might also partially reverse some social benefits obtained with a feed-in tariff system. To encourage deployments, it is necessary to inform consumers about the potential benefits their technologies could deliver through increased private savings. This study showed it is possible to demonstrate a wider range of monetary benefits under various scenarios. It is not only necessary to incentivize the use of system-enhancing technology but it is also required to ensure that consumers understand the range of savings (and risk of loss) associated with their energy investments. This is particularly true as the grid develops and locational signals assume increased importance.

Due to the computational burden of using electricity system models, a potentially useful approach could be for governments to provide on-line scenario simulators for technology sellers to provide system-backed estimates of NPV, which could become a key marketing tool. For example, the US Department of Energy's System Advisor Model (SAM) ([NREL, 2018](#)) is a techno-economic computer model that calculates performance and financial metrics of renewable energy projects. While the project could be useful to address this purpose, it does not at present consider a spectrum of future energy scenarios.

4.2. Drawbacks and future work

Provision of appropriate software by governments for this purpose could improve transparency in relation to the calculation of final prices, which is an interesting topic for future work. The concept of SNPV relied on the assumption of retail electricity tariffs varying proportionately to the retail electricity price. Modelling this variation based on historical data of retail price mark-ups would improve the accuracy of our work. Yet this data is typically confidential and is difficult to find from reliable sources, which is why we did not undertake this option. As wholesale costs are the largest component of consumer bills with a share of over a third in Great Britain ([Ofgem, 2017](#)), we considered systemic impacts as those on wholesale prices.

We did not assume that EES could be used by consumers for economic purposes other than electricity bill management through arbitrage, so we excluded the potential future provision of balancing and ancillary services to the grid through aggregation, or management for non-economic purposes such as energy security. Wider consumer preferences can be important, but we considered financial benefit as the only determinant of adoption. Consumers could invest in storage for security reasons, environmental friendliness or simply because they are enthusiastic early adopters ([House of Commons, 2007](#)), and may make decisions irrationally ([Sargent and Wallace, 1976](#)), which are aspects we did not consider. We examined the capacity of solar PV and storage size within the threshold for benefiting from governmental subsidies. Expanding this range to include different sensitivities to the size of storage and considering different weather years could improve the robustness of the results.

5. Conclusions and policy implications

National energy policies are increasingly centered on increasing the share of renewable energy in the energy system, for example by encouraging end users to invest in new distributed energy technologies such as solar PV and energy storage. The economic viability of such investments, which is one of the main parameters in the decision to deploy any such technologies, is typically assessed using Net Present Value (NPV) or other metrics of discounted net cash flows. Yet the input assumptions for calculating these measures do not commonly account for electricity price dynamics over the lifetime of the technology investment, which is a critical component in the determination of future cash flows. We proposed a holistic, integrated framework to model different scenarios in the whole electricity system over multiple decades. We assessed the impact of accounting for these potential system

evolutions on electricity price formation and NPV calculations in relation to end-user energy technology investments.

Taking Great Britain as an example, we showed that failure to account for the future evolution of the underlying electricity system can underestimate the profitability of solar PV and EES by up to a substantial 20%. We concluded that future electricity systems with high levels of variable renewable energy and distributed generation have the largest likelihood of under-estimation. Using electricity system-dependent net cash flow metrics is essential to ensure the accuracy of profitability estimates and may improve consumer confidence in new energy technologies, which could help spur investments that could help reduce the cost of future electricity systems.

The potential financial benefits of end-user from investment in energy technologies depends on a range of parameters that are not easily captured in simple cash flow analyses. These include electricity price dynamics caused by changes in the total electricity demand and its variability; the share of renewable energy in the system; the share of flexible generation, interconnector and storage in the system to balance variability; and the possibility for end users to sell ancillary services to the grid, among other things. Hence, a whole-system, model-based analysis of NPV can explore different energy scenarios and systematically estimate the impact of such scenarios on customer energy investments. This will provide the customer with additional information on system-wide evolutions that can offer more financial benefits when investing in distributed energy technologies. Hence, by providing end users with these insights, energy policy makers can reach a two-fold goal: (i) improve the confidence of end users in investment in green technologies that can ultimately help the system-level targets; and, (ii) attract the support of end users for certain energy transition pathways that has higher potential benefits for their energy investments; for example, scenarios with a high share of renewable energy.

To achieve this, policy makers could provide the end users with easy-to-understand and user-friendly tools and modelling interfaces. In this respect, the use of open data and open energy models play an important role (Pfenninger et al., 2017; Ringkjøb et al., 2018). Since the electricity models are rather complex with a large number of assumptions that are not easy for end users to investigate, efforts would ideally be focused to develop open, user-friendly interfaces that the user can understand, navigate, and use to change some key input parameters in order to estimate the output. Presenting a better financial case to consumers, together with reliable tools to assess this profitability, would arguably encourage distributed energy investments that could contribute toward a more sustainable, lower-cost and secure power system.

CRedit authorship contribution statement

Giorgio Castagneto Gissey: Conceptualization, Writing, Funding acquisition, Methodology. **Behnam Zakeri:** Writing, Methodology, Data curation. **Paul E. Dodds:** Writing - review & editing. **Dina Subhankulova:** Modelling.

Declaration of competing interest

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

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Appendix A. Supplementary data

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