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Perspectives for PV Microgeneration in Cumnock

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ABSTRACT

In this dissertation, the applicability of widespread rooftop PV has been evaluated for the town of Cumnock, East Ayrshire, Scotland. The methodology used in this analysis involves modelling Cumnock's energy demand as well as its capacity for PV installation, drawing on both physical and technical factors as well as socio-economic circumstances. Analysing 3 modelled scenarios in addition to baseline, results show that installing rooftop PV could save between £119 and £163 per household per annum in Cumnock, with savings expected to increase as energy demand evolves in the future. Modelled payback periods are long, at around the 40 year mark, with one scenario not paying back in project lifetime. Finally, the merits of the methodology used are commented on, and the need to analyse potential storage methods in future work highlighted.

ACKNOWLEDGEMENT

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ACRONYMS

SDG – Sustainable Development Goals

PV – Photovoltaic

BOS – Balance of System

CZ – Czochralski

LID – Light induced degradation

Mono-si – Mono crystalline silicon

Poly-si – Poly crystalline silicon

A-si – Amorphous silicon

BIPV – Building integrated photovoltaic

CIS - Copper-indium-diselenide

CIGS – Copper-indium-gallium-diselenide

CdTe – Cadmium telluride

WAN – Wide Area Network

NAN – Neighbourhood Area Network

HAN – Home Area Network

ESS – Energy Storage System

FIT – Feed in tariff

SEG – Smart export guarantee

PPA – Power purchase agreement

GIS – Geographic information systems

SESH – Scottish energy statistics hub

SPF – Seasonal performance factor

RHI – Renewable heat incentive

NOCT – Nominal operating cell temperature

NPC – Net present cost

LCOE – Levelised cost of electricity

1 INTRODUCTION

1.1 Problem definition

As human population continues to grow, so too does global demand for the comfortable yet energy intense quality of life afforded by city living; today, more and more people are calling the urban environment their home. Whilst global in reach, the degree of urbanisation can be seen to vary between countries, with Europe currently the most heavily urbanised, with over 73% of its inhabitants living in towns and cities (Papa & Fistola 2016). It is expected that this trend will continue, with upwards of 80% of Europeans predicted to be living in cities by 2050 (Papa & Fistola 2016). However, with the bulk of urban growth set to occur outside of Europe (Nigeria, China, and India namely), it is clear that the growth of our urban centres is a truly global challenge. This phenomenon of urbanisation has been extensively studied and policy guidelines, such as the UN's Sustainable Development Goals (SDG), push cities to the centre stage (Armitage 2018). A prominent target of the established SDG's is the provision of "Clean and affordable energy" (UN 2020), and herein lies perhaps the salient challenge of the worlds growing urban population, and that is powering it (Sayigh 2019).

Traditionally, electrical demand is supplied by a small number of very intense (almost exclusively fossil fuel derived) sources of power (IEA 2009) and a high urban demand density, often between 10-100 W/M^2 (IEA 2009), means finding clean alternatives is a difficult challenge (Newton 2013). Part of the reason for this is the relatively low energy density of many renewable sources (Papa & Fistola 2016), with the energy density available from fossil fuels several orders of magnitude higher than that available from wind or solar (IEA 2009). This could be taken to mean that in order to sustainably power a modern town or city; a very large "catchment" area would be needed. Small scale renewable microgeneration could be a way to address this issue by expanding the catchment area to include the town or city, and it is expected to supply 30-40% of the UK's electricity demand by 2050 (Watson et al 2008). Within this broader family of renewable microgeneration, solar photovoltaics (PV) are thought to be the most applicable to the built environment, with ample roof space providing an ideal site for this low maintenance technology (Hong et al 2017) (Molin et al 2016).

Whilst the basic provision of electricity described above can be thought of as a primary driver to adopting solar microgeneration, there are a number of others, equally as important to facilitate a wider rollout of technology amongst consumers. One such group of drivers is those associated with energy security and resilience (Sheriff 2014). There is a persistent belief amongst consumers that electricity prices will remain high, or even increase (Karytsas et al

2019), and hence, the desire for secure independent sources of power for individual households and local areas is prominent (Sheriff 2014). Economic drivers are closely linked to reduced grid dependence, with these being amongst the most important to consumers (Sheriff 2014). In addition to the more obvious economic benefits arising from lower grid purchases and government incentives, there is evidence to show that behavioural changes can also contribute to savings (Bahaj and James 2007). These are often termed the “soft” benefits of microgeneration (Bergman & Eyre 2011) (Bahaj & James 2007) and include behavioural changes associated with a closer relationship to electricity production and consumption.

This change to a more informed relationship with domestic energy is closely linked with the third category of driver, environmental drivers (Sheriff 2014). Whilst being a comparatively weak incentive for most consumers compared with energy security and economic factors (Bergman & Eyre 2011), early adopters to solar microgeneration consistently mention environmental factors amongst their motivations (Sheriff 2014). Environmental drivers are most important however, at a policy level. As countries strive to reduce carbon emissions and increase renewables supply share; microgeneration, and in particular solar PV, has the potential to play a significant role in achieving those targets set (Gooding et al 2013). In order to increase uptake and fulfil this potential, governments commonly grants, subsidies and export tariffs to incentivise installation, with varying success dependant on the type of support offered (Praetorius et al 2010).

These measures encourage uptake of PV by addressing the most prominent barrier to installation among consumers, which is cost (Sheriff 2014). Whilst the cost of PV has decreased substantially in the past decade, it is still high enough to preclude the majority of homeowners from purchase (Bergman & Eyre 2011). Further constraints to PV adoption on the consumer side are closely linked to a lack of information regarding what is still a relatively new technology to many people. Particularly; information around cost and subsidies (Karytsas et al 2019) is commonly misunderstood, whilst specific information on the performance of solar panels and their incorporation into domestic energy is also lacking amongst the general public (Sheriff 2014)(Bergman & Eyre 2011)(Bahaj & James 2007). These consumer barriers considered alongside governmental targets for renewable energy highlight a further constraint to widespread PV adoption. That is, a conflict of interests which can occur between shareholders in the energy system. In some cases, this has resulted in subsidy funds being preferentially awarded to larger arrays over single household installations (Davies 2012).

These socio-economic barriers towards widespread adoption of PV are considered to be equally, if not more effective than the technical constraints to further microgeneration rollout

(Ellsworth-krebbs & Reid 2016), however, there are a number of physical and technical limitations to consider as well.

The existing building stock is one of these constraints, and this is something which can be felt strongly across Europe, which features a statistically high percentage of old, inefficient residential building stock (Sayigh 2019)(Papa & Fistola 2016). Age of building stock is considered to be a significant detail in the suitability of PV; with the type of available building stock also a major factor in the suitability of PV on a town or city scale, owing to historic development decisions of individual towns and cities (Davies 2012) (Gooding et al 2013).

Additionally, there is the technical challenge of grid degradation arising from an increased share of microgeneration. This is, in simple terms, due to an increased and reversed flow of electricity within the distribution network of the grid (Hinz et al 2018), for which it is not designed. Distribution through these lines is often costly and inefficient, and it will take a significant reform to allow electricity to flow in the opposite direction and without large losses (IEA 2009). As well as upgrading the grid, moving past this constraint rests on a principle of effective and instantaneous communication, and this is a pillar of smart grid technology (Hennig 2017). It is widely accepted that for microgeneration to be effective, it will need to be integrated into a renovated, smarter grid (IEA 2009),(Rutter & Keirstead 2012).

These drivers and constraints create a future for solar microgeneration which is difficult to predict, and yet it is imperative for a number of reasons that it can be. The wider adoption of microgeneration has strong implications for energy policy as well as the energy security and affordability of many (Bahaj & James 2007). There has been relatively little work done in collecting this wide range of factors for Scottish towns and cities, where the solar resource is not traditionally celebrated. By understanding and modelling the interactions between supply and demand under different scenarios, insightful perspectives are hoped to be gained for the role this technology could fulfil in Cumnock, with a view to applying this methodology elsewhere.

1.2 Aim

Moving away from reliance on fossil fuels and towards renewable sources of energy whilst still meeting growing energy needs, is a challenge which is felt globally. Specifically, with respect to the human and urban environment, large rooftop areas provide a great potential for PV microgeneration to help address this need. This project will aim to be able to provide perspectives for the town of Cumnock, and indeed similar environments, as they move towards transitioning to a low carbon energy system by investigating the potential for rooftop solar PV generation and its applicability to the local energy demand.

Key objectives:

- Asses the physical potential for deploying rooftop solar PV in Cumnock and determine the amount of electricity which could be generated using rooftop PV.
- Analyse present and future energy demand in Cumnock.
- Size the PV generation capacity under different parameters and evaluate its applicability to Cumnock now, and in the future.
- Reflect on the methodology used and its applicability in other locations.

1.3 Overview of methodology

The first step for this project is to conduct a literature review in order to inform the model building and analysis process. Most importantly, this will provide insights into; the most applicable technology, the range of factors which can act as drivers of and barriers to rooftop PV uptake, the suitability of different housing types for PV and information on energy demand including predictions for how it may change in the future.

The generation potential will be assessed, first by estimating the available roof space across the entire town, using the tool Google Earth Pro to determine average roof area. By using available sizing guides for rooftop PV, this will be used to determine the capacity for solar panel installation in Cumnock will be estimated. Using the energy modelling software Homer, generation capacity will be simulated for a small number of scenarios relating to the uptake of PV.

Energy demand will be modelled, using Scottish energy statistics and available data on East Ayrshire energy demand, in order to create a current demand profile across the full year. This profile will then be used to define scenarios relating to current and future energy demand which will be modelled further.

These scenarios will be designed to reflect; baseline conditions, a realistic installation of rooftop PV, an installation with a high renewable fraction target and a realistic installation with a future demand profile. Each scenario will be modelled and analysed in Homer to determine the viability of each option as well as its cost-effectiveness. Post analysis discussion will then be concentrated on the practical implications and likely social impacts of a PV project in Cumnock, such as impacts on the grid and on fuel poverty.

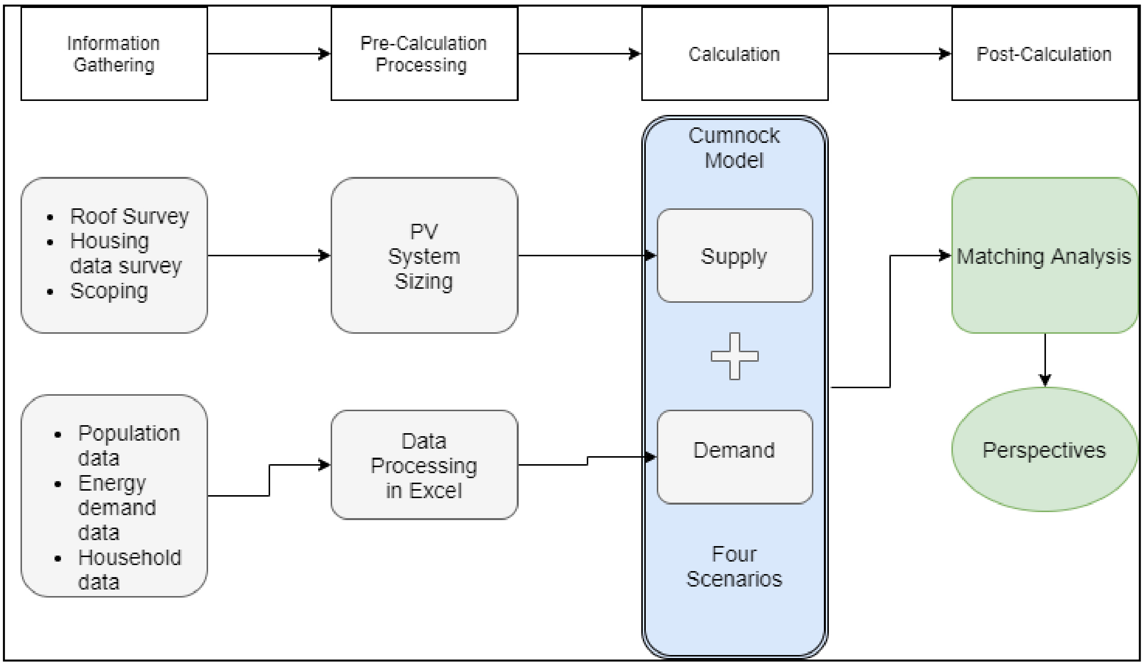

Figure 1 : Overview of the methodology

1.4 Scope

This thesis will be focussed purely on the application of PV panels on domestic rooftops in the town of Cumnock. While commercial rooftops also present potential sites for PV, this thesis will not consider them, with domestic rooftops judged to have a greater complexity and overall potential. It is also assumed that as Cumnock's energy demand evolves, cost will be accrued by the installation of heat pump technology, however this financial input will be considered outside the scope of this thesis.

1.5 Structure of the dissertation

This dissertation is structured in 5 main sections, in addition to this introductory section 1, as follows:

Section 2 comprises the literature review for this dissertation, covering a range of literature to inform later scenario work, and key considerations which should be taken when setting modelling parameters.

Section 3 covers the methodology developed, with this being split into six main areas after setting the objective. The first two areas are concerned with the supply and demand section of the model, with PV potential and energy demand analysis covered in 3.2 and 3.3 respectively. Next, key input data for later scenario work is stated for a range of parameters in 3.4, with 3.5 covering validation of the model. Section 3.6 briefly describes each of the scenarios to be modelled in Homer, with 3.7 covering assumptions and simplifications adopted in the making of the model.

Section 4 covers results, analysis and discussion; with results presented initially for each scenario under headings: Financial performance, renewable fraction and CO_2 emissions and grid interactions. Analysis and discussion then takes place under the same headings in section 4.5.

Finally, in section 5, final remarks and conclusions are presented, with limitations of this study discussed in addition to suggestions for further research.

2 LITERATURE REVIEW

2.1 Overview of literature review

In the following literature review, attempt will be made to cover the broad base of knowledge concerned with the application of PV microgeneration. First, the technologies themselves will be covered, with the relative applicability of several forms of PV being commented on. The problems facing integration of PV both in a technical sense and a socio-economic sense will also be included, with a focus on the effects of policy on the uptake of rooftop PV. Energy demand will also be considered, with trends in both Scotland and Cumnock's energy demand covered, before the social impacts of a high level of microgeneration are also touched on. Finally, methods for analysing the PV potential of a town or city will also be covered with a view to informing the methodology.

2.2 Solar technologies

2.2.1 PV and the role of silicon

The photovoltaic effect (Figure 2) was discovered by the French physicist *Alexandre-Edmund Bequerel* in 1839; and while a range of materials have been used to explore this phenomenon, the role of silicon, first realised in the 1950's, has become crucial (Petrova-Koch et al 2020). In simple terms, PV cells can be described as semi-conductor devices which convert light energy directly into electrical energy.

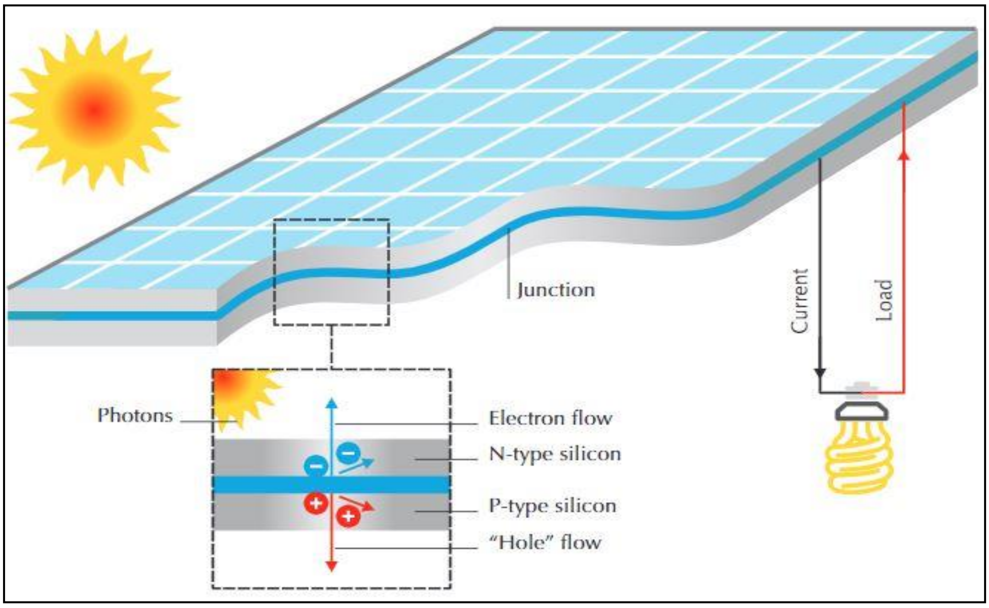

Figure 2: The Photovoltaic effect (Philibert 2011)

Using extremely high purity silicon, which has been "doped" by the injection of controlled impurities to modulate the resistance of cells (Junggil et al 2013), PV cells allow incoming photons to displace electrons from a molecular lattice. This leaves an electron "hole" and a corresponding freed electron pair. By creating this variation in charge across the junction of the cell, direct current (DC) electricity can flow (Philibert 2011).

The majority of commercial PV applications are wafer based crystalline silicon and thin film technologies (Philibert 2011), both of which will be described in greater detail in sections 2.2.2 and 2.2.3 respectively. In both forms, the silicon must be heavily processed in order to attain the parts per billion level of purity required for PV (Petrova-Koch et al 2020), and this process can have profound effects for the industry. Since the late 90's, silicon demand from the PV market has far outstripped the capability of computing by-products to supply it (which was initially sufficient) and there are strong, competing methods for doing so. The main feedstocks for these processes are quartz, wood-chips, coal, charcoal and coke; which are processed to create metallurgical grade silicon (~98% purity). With these precursors in mind, there is a common misconception that PV panels represent a highly sustainable technology, as silicon is one of the most abundant elements on earth. While silicon is indeed incredibly abundant, the high purity quartz required for the subsequent high purity silicon is limited to a small number of mines, primarily in Spain or Brazil (Petrova-Koch et al 2020).

Due, in part, to this highly competitive market for hyper-pure silicon, PV module costs have been able to fall substantially. This has been matched by the drop in inverter costs, however, it is expected that wider balance of system (BOS) costs will begin to take a larger share of overall cost (Phillibert 2011). Cables, mounting structures, inverters and casings (which account for BOS costs), rely on raw materials such as; copper, steel and stainless steel, which are not expected to enjoy the same drop in price as silicon.

2.2.2 Crystalline Silicon PV

Currently, around 90% of the worlds solar PV cells are fabricated using crystalline silicon (Yang 2019), and it is by far the most mature market for solar PV (Philibert 2011). Within this bracket exist mono-crystalline (mono-si) and poly-crystalline (poly-si) technology. In regard to PV, the main difference between mono-si and poly-si is in their efficiencies, with cell efficiencies for mono-si generally between 14-22%, with poly-si between 12-19% (Philibert 2011). This is due to the effect of being composed of a single or multiple crystals of silicon, which is a product of the manufacturing process.

For poly-si, the most dominant method of purifying metallurgical silicon is known as the Siemens method, which accounted for 94% of "hyper-pure" polysilicon produced in 2016 (Petrova-Koch et al 2020). This achieves the extreme purity required by converting metallurgical silicon into industrial agents known as Silanes, which can then be distilled until purity is reached. In the case of the Siemens method, deposition of hyper-pure silicon occurs in the presences of hydrogen on thin silicon rods which must then be removed (Petrova-Koch et al 2020). An alternative to this is fluidized bed deposition, which again functions the basis of distillation. In contrast to the Siemens method, silicon is deposited in granular crystals which can be removed whilst the process is ongoing. This continuous operation is one significant advantage, with the easier handling and lower specific energy consumption of granular silicon adding to the benefits (Petrova-Koch et al 2020). These methods and the casting which follows cost less time and energy than mono-si, and as a result, cheaper poly-si occupies 60% of the current market (Yang et al 2019).

Mono-si cells have a number of competing processes for manufacturing, but the dominant method is the Czochralski (CZ) method (Yang et al 2019). In this method, polysilicon raw material is heated in a crucible (usually quartz) under inert gas protection until it is completely molten. A seed is then dipped into the melt until it too begins to melt, at which point it is pulled upwards in order to grow a single crystal from the molten polysilicon. This pulling process is slow, with the seed being pulled at ~6mm/minute at its fastest, and the grown crystals being 1-2M in length (Yang et al 2019). The CZ method has other drawbacks, particularly the long machine idle time between crystal growths to allow for cleaning, dismantling and set up; again highlighting the costly and time consuming nature of this process. Future research hopes to find a way to make the CZ process continuous or semi continuous in order to boost efficiency as well addressing the light induced degradation (LID) of the cells during their lifetime. LID is due to reaction of high oxygen impurities in the silicon, which is caused by the reactions with the polysilicon melt and the quartz crucible (Yang et al 2019).

For both forms of crystalline silicon, module efficiencies tend to be slightly lower than the quoted cell efficiencies, with finer tuning of the manufacturing process surrounding surface contacts and coatings hoping to improve this (Philibert 2011). Other improvements are expected to be made in reducing the thickness of the silicon wafer used in the cell, allowing for a more efficient use of this expensive component (Philibert 2011).

2.2.3 Thin film PV

Thin film technology currently represents a tiny part of the overall PV industry, and refers to four main categories: amorphous silicon, multi-junction thin silicon, cadmium-telluride and copper-indium-diselenide/copper-indium-gallium-diselenide (CIS/CIGS) (Philibert 2011). They are made from thin layers of semi-conductors (not always silicon) deposited onto a low cost backing. In terms of their application, thin film PV performance differs from their crystalline counterparts in two fundamental ways. First, their efficiency is usually lower, with most technologies below 10% due to a much lower carrier mobility than crystalline cells (Yang et al 2019). Second, as thin films can be deposited onto a range of substrates, it opens new possibilities of flexible solar modules. This makes thin film PV especially relevant for building integrated photovoltaics (BIPV), with the film applied to building materials and tiles (Sayigh 2019).

Figure 3: BIPV in Manchester (Sayigh 2019)

Amorphous silicon (a-si) PV has a considerably easier manufacturing process than crystalline technologies and it has become highly automated in order to drive costs down further (Philibert 2011). A-si cells are made using variations of chemical vapour deposition (CVD), which involves precursor gasses (such as SiH_4 and H_2) being introduced to a low pressure chamber, before being diffused onto a hot substrate on which a thin film is formed (Yang et al 2019). For multi junction thin silicon, which involves the stacking of multiple layers of amorphous and micro-crystalline silicon, this process is generally done at a higher temperature (above 1,000°C) (Yang et al 2019). This gives multi-junction cells efficiencies which hover around 22-25% in lab tests (yang et al 2019), although this has yet to be fully rolled out; while a-si cells hover at around 8% (Philibert 2011).

CIS and CIGS cells are very similar, with the G (Gallium) representing a dopant which is added in order to increase the range of light which can be absorbed and converted to electrical energy (Petrova-Koch et al 2020). There are a number of methods for fabrication of this kind of cell and they differ marginally, however the main principles involve the procedural evaporation and deposition of each layer on a suitable substrate to a thickness of approximately 4 micro-meters (Petrova-Koch et al 2020). The substrate itself can be flexible and even mobile, widening the range of applications for this technology. Due its relatively high efficiency (~20%) and low energy of manufacture, CIS/CIGS films have a very fast energy payback rate of around 1 year (Petrova-Koch et al 2020).

Cadmium telluride (CdTe) cells are manufactured in a similar fashion to the CVD method described above, and have efficiencies which are now approaching 20% (Uchida et al 2016). Fundamentally, one factor which impedes the development of non-silicon thin films is the issue of scarcity (Uchida et al 2016). In the United States and Europe, Tellurium (Te), Indium (In) and Gallium (Ga) are all considered as “critical” in terms of their availability. Specifically with regard to CdTe cells, the inclusion of Cadmium poses serious risks due to its toxicity, which limits acceptance of this technology (Philibert 2011). Future research in recycling and reusing these toxic and scarce elements in a safe way would likely allow a larger market share.

2.2.4 Inverters

Inverters are required within a solar PV system in order to convert the generated DC electricity into the AC form on which most appliances run, and the necessary form for grid exports. Representing a large component of BOS costs, inverters have seen their price decrease at the same rate as PV module, exhibiting a steep learning curve on par with that of the industry as a whole (Philibert 2011). For residential applications, there are two main competing technologies on the market, namely micro-inverters and string inverters. In terms of their physical makeup, these two technologies differ most obviously in that string inverters can be connected to a large “string” of series connected PV modules, with an entire rooftop system usually served by one or two inverters; while micro-inverters are fitted to each individual module in the system (Harb et al 2013). Fitting a system with micro-inverters is therefore more expensive and labour intensive, as many more individual units must be purchased and installed, as a results they are generally more popular with smaller systems (Harb et al 2013). Advantages exist for micro-inverters as well, especially in terms of the component lifetime, with micro-inverters expected to last for around 25 years, whilst string inverters generally need to be replaced after 10-15 (Vekony 2020). The series layout of string inverters also makes them more susceptible and less tolerant to faults, as low performance in one module can cause a loss in generation for the entire “string” (Yuan et al 2019). Additionally, microinverters tend to have slightly higher efficiency at up to 97.5% (Yuan et al 2019) while string inverters generally sit between 93% and 96% (Vekony 2020). For these reasons, as well as a superior safety record (Harb et al 2013), it is expected that micro-inverters will at some point become the preferred technology for PV microgeneration. However, due primarily to the initial cost saving, string inverters remain the most common in the UK, with a replacement today generally costing between £500-£1,500 dependant on system size (Vekony 2020).

2.3 Grid integration

2.3.1 Smart grids

Regarding the broader topic of renewable microgeneration, or indeed microgeneration of any kind, it is clear that the electricity grid is not designed to accommodate it (IEA 2009). The grid in its current form, particularly with regard lower voltage distribution networks, would experience high levels of degradation and with a high enough uptake, would simply fail to function due to high levels of electricity flowing backwards into the distribution network from end users (Hinz et al 2018). These problems can be imagined simply as over-voltage and back-flow within the distribution network, with too much power in the wrong direction problematic for grid health (Rui & Wellssow 2015). The term “smart grid” has varying definitions; however, a central theme is that communication between sections of the grid must be instantaneous, with internet connection expected to be essential in modulating local supply and demand in order to keep the grid healthy (IEA 2009). Other common characteristics of imagined future smart grids include bi-directional energy and data flows, active networks functioning to stabilise voltage, active consumption with automatic and manual controls on household demand and a large proportion of poorly dispatchable generation (Rylatt 2015).

In practice, smart grid communication is supported by both wired and wireless media, and can be divided into three subsets of narrowing scope. Namely, wide area network (WAN) for scales of over 10km, neighbourhood area network (NAN) for scales of between 100m and 10km, and home area network (HAN) for scales of tens of metres (Muyeen and Rahman 2017). Arguably the most active of these networks is the HAN, which collects information and energy consumption data from within consumer premises. It is here that authorities and grid operators can implement dynamic pricing, demand-side management and integrate renewable microgeneration into the main grid (Muyeen and Rahman 2017). NAN can be thought of as an intermediate between HAN and WAN, allowing multiple HAN’s to connect to the larger scale WAN. While the WAN, also referred to as the core tier or network, creates a data path and connects the NAN’s to core utility systems (Muyeen and Rahman 2017).

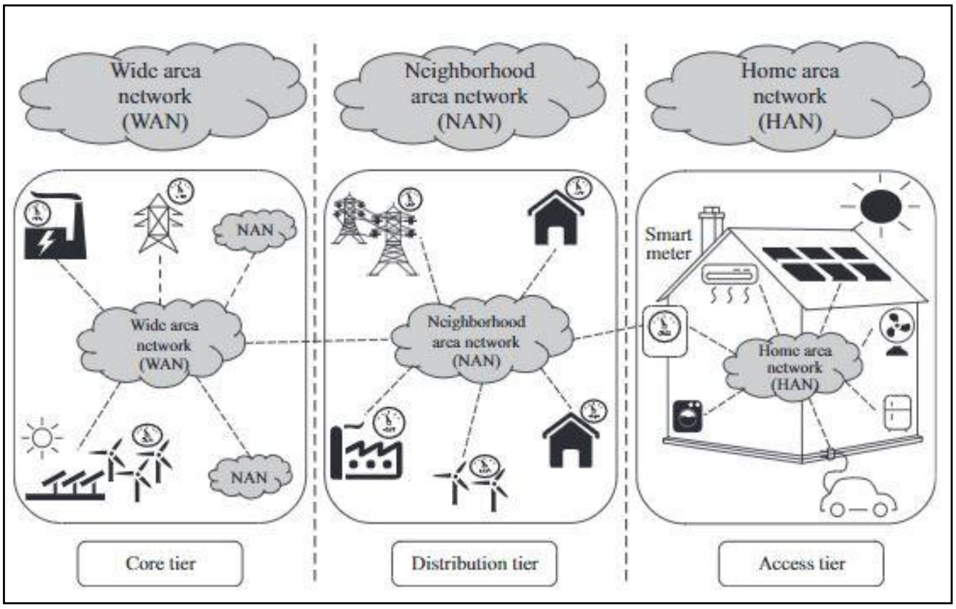

Figure 4: Schematic of smart grid communication networks (Muyeen and Rahman 2017)

A crucial component to this system is the widespread adoption of smart metering, or advanced metering infrastructure. This is primarily so that individual household energy data can be mapped, predicted and responded to by grid operators in order to maintain stability, but there are further consumer end benefits to smart metering (Brown 2012). These benefits are due to the expected behavioural changes associated with consumers becoming more aware of their relationship with energy, and are particularly relevant when considered alongside domestic microgeneration (Hennig 2017) (Bahaj & James 2007). These behavioural changes amount to load shifting behaviours, such as using high energy appliances during periods of higher domestic generation, which effectively lessens peak demand strain on the grid (Ellsworth-Krebs & Reid 2016). Furthermore, this kind of energy conscious behaviour due to smart metering has been shown to make noticeable differences to domestic demand, with one study in the US finding voluntary savings amounting to between 4-12% (Brown 2012).

In order to realise this idea of a highly connected smart grid with a large renewable generation share, the grid must overcome several challenges, especially if progress is not evenly spread. The German town of Niederstetten (Pop. 5,200) is a good example of how it can be done (Hennig 2017). Niederstetten has one of the highest rates of PV installation in Germany, averaging 2.3 kW of installed capacity per capita, and so has been forced to find a way to integrate this generation into the grid without a wider infrastructure already in place. The existing grid supplied customers through high (110 kV), medium (20 kV) and low (0.4 kV) voltage networks, and the solution involved integrating microgeneration into the 20 kV network. To maintain stability, two three-phase voltage regulators were added at strategic points in the network, and these use real time measurements from around the network to automatically moderate voltage to an acceptable level. These, in turn, are regulated by a regional controller substation which links the 20 kV network to the 110 kV network. There were a number of upgrades required to make this possible, with numerous substations within the 20 kV network being upgraded and fitted with advanced fault detection equipment. Additionally, a number of 20 kV – 0.4 kV substations were fitted with measuring equipment real time communication devices. This data is fed continuously to the regional controller, where a sophisticated regulation algorithm responds accordingly and automatically (Hennig 2017).

This represents a way in which individual towns can adapt their electricity grid to be more amenable to PV microgeneration without a wholesale overhaul of the electricity grid. As well as facilitating a high penetration of renewables, upgrading the grid in this way has consumer benefits such as increased reliability and the opportunity to export power to the grid for financial gain.

2.3.2 Storage systems

As well as effective, real time communication and a successful voltage regulation system, an efficient and practical energy storage system is an important part of smart grid integrated renewable generation. The fundamental benefit offered by energy storage is the ability to decouple supply and demand (IEA 2009), which is of great interest when considering non-dispatchable sources of energy like solar PV. As the generation from PV can be very intermittent and varies throughout the year, the interaction between load and grid management, transmission and storage must be well understood.

In decoupling supply and demand, energy storage systems (ESS) enable power systems to become significantly more efficient (Jeon & Mo 2018). Efficiency is increased as peak demand can be fulfilled, in part, by energy produced during off-peak hours, allowing peak demand to be supplied by a smaller capacity system (Jeon & Mo 2018). In doing so, and allowing more demand to be supplied reliably by renewable sources, ESS significantly reduces the reserve cost of a power system. That is, the cost of maintaining alternative power sources to allow for the variability of renewable energy (Jeon & Mo 2018).

There is debate as to where in the supply chain storage is most effective; with larger, utility scale storage still very expensive (IEA 2009). Larger scale community storage is still relatively rare, in part due to the prohibitive cost, but also due to the scattered, discontinuous nature of PV adoption (Barbour et al 2018). However, as PV adoption along with interest in smart grids increases, community storage is likely to become a more lucrative opportunity; with benefits due to economies of scale and an averaging out of short demand peaks (Barbour et al 2018). Community scale storage also tends to allow for a lower storage capacity than the additive household storage covering the same area, with Barbour's 2018 study finding an 8.5 MWh community storage system could equate to 13 MWh of household storage. This lower capacity was also found to be significantly more efficient, reducing imports and exports by 70% and 78% respectively, compared to 46% and 62% reductions using household storage (Barbour et al 2018).

2.4 Consumer Uptake among households

Regardless of the state of PV technology or the methods with which to integrate to the grid, understanding the drivers to consumer uptake, particularly among domestic households, is vital to the growth of the industry. These drivers are heavily influenced by policy and social effects, with technical aspects playing a minor role in uptake (Ellsworth-Krebbs & Reid 2016). In this section, the effect of policy on consumer uptake will be explored, specifically with respect to financial incentives.

2.4.1 Capital Grants for installation

When considering the barriers to wider public PV installations, cost is repeatedly mentioned as perhaps the single biggest obstacle for households to overcome. Despite the falling price of PV, the capital cost of a new system remains high, with solar panels for a 3 bed house costing £5,520-£6,040 (Solar guide 2020). Upfront costs are generally given more weight than potential long-term gains and there is a general consensus in the literature that consumers planning to install solar panels do not behave as "rational" economic agents (Bergman & Eyre 2011). A similar phenomenon occurs regarding home insulation, and in general, consumers appear to discount long term outcomes and do not consider future energy production and savings (Bergman & Eyre 2011). Policy tools which help with immediate costs and reduce the payback time of solar PV can therefore be seen as a major facilitator to wider PV adoption.

Capital grants are currently not offered for solar panel installation in the UK, however there is a history of their use as a policy tool. Discontinued schemes such as the low carbon buildings programme offered funds for householders to help with installation costs, with an initial £6.5 million available (Watson et al 2008). Due to high demand, this fund, which had been intended to serve a three year period, ran out after one month, prompting several revisions and tightening of restrictions around access to grants (Watson et al 2008). This stop-start behaviour is considered to have hampered uptake, and despite support loans being offered for a time afterwards as part of the green deal, feed in tariffs (FIT) and similar schemes have been preferred both in the UK and abroad (Sweetnam et al 2013).

Whilst grants are clearly effective in the short term at tackling cost barriers and increasing uptake of PV, they can be viewed as unsustainable in the long term (Watson et al 2008). In order to provide a more long term solution, the applicability of tax incentives for households installing PV has been considered, however the nature of these incentives would be expected to lead to inequality in terms of support to lower income households (Watson et al 2008). Both capital grants and tax incentives demonstrate a state-led approach to encouraging PV uptake, and this is something which governments can be seen to be moving away from, with a desire to include markets and companies in the direction and growth of the industry (Papa & Fistola 2016). Current schemes such as the SEG, in which export tariffs are decided by individual utility companies, can be seen as evidence of this way of thinking.

2.4.2 Effect of other policies on uptake

Whilst the development of PV microgeneration has been a policy aim in many countries, particularly in Europe, there has been a great deal of variation in how effective this has been. Germany currently has the largest market for PV (Philibert 2011), and is considered to be a great example of how to encourage effective microgeneration market growth through policy. In 2010, Germany had around 1,000,000 individual microgeneration units installed, compared to around 110,000 in the UK (Praetorius et al 2010) and has continued to grow ahead of the UK's market (Sweetnam et al 2013) despite the UK having a highly competitive and arguably better starting position (Praetorius et al 2010).

One particular reason for this disparity between two situationally similar countries is the level of uncertainty and public trust in the industry (Sheriff 2014)(Praetorius et al 2010). This well documented lack of public trust can be attributed to the effects of UK policy on the market, and in particular the stop-start nature of these policies, particularly aforementioned grant schemes (Praetorius et al 2010). This inconsistent nature of many UK policies applies not only to discontinued grant schemes, but also to soft loans policies, repeated revisions of the FIT and its eventual replacement, with this uncertainty considered to have directly impacted the market growth (Praetorius et al 2010).

The uncertainty fostered by changing policy has been complemented by an historic lack of properly accredited installation contractors, with only 400 registered in the UK in 2008 (Praetorius et al 2010). Training and accreditation courses which focussed on best practice were initially scarce and expensive in the UK, meaning that briefer, cheaper course run by manufacturers of specific components were seen as more attractive (Bergman & Eyre 2011). This further eroded public trust and a reputation for "cowboy" installers of microgeneration technologies developed, with high price variations, poor installations and false sales claims creating scattered and uneven market (Bergman & Eyre 2011).

While incentivising PV uptake with policies such as grants, soft loans or export tariffs can be understood to represent one part of governmental policy, another powerful tool is the enforcement of specific targets (Davies 2012). An EU 2020 target for new and refurbished buildings to be "zero or nearly zero" carbon is an example of this kind of enforceable policy, with new public buildings also expected to supply a significant proportion of the energy use from on-site renewables. Writing policies such a this into building requirements means that PV installations on public buildings will likely become commonplace (Davies 2012), with councils able to measure the contribution of onsite renewables and mandate for further installations if quoted targets are not being met (Hewitt 2009).

2.4.3 Tariffs for export

Along with capital grants or soft loans, generation and export tariffs for PV generated electricity are a common method incentivising their installation. In the UK, and indeed many other European countries (Sweetnam et al 2013), support of this kind was initially offered by the FIT, with a tariff payment to households based on both total electricity generated and electricity exported to the grid. In the UK this scheme was so successful at promoting market growth that payments had to be devalued in a move known as tariff degression (Sweetnam et al 2013), with further critics arguing that a generation tariff could act as an incentive to generate and waste power unnecessarily (Davies 2012). After a number of revisions, the FIT was replaced in the UK by the SEG which does not offer a generation tariff to consumers, with only grid exports incentivised (Cui et al 2020). Another key difference is that while the FIT value was set by government, the SEG value will be set by individual utility companies, with the consideration that it must remain above 0 (Cui et al 2020). Furthermore, the SEG policy does not include long term contract, meaning that while many utility companies are expected to simply offer a low, flat rate, some companies have responded by offering variable tariffs to consumers, allowing more conscious consumers to plan when they export to achieve the highest price (Cui et al 2020).

While the individual export rate offered by utility companies varies, they are generally lower than the most recent FIT rate of 5.5p/kWh (Ofgem 2020), with Scottish Power and SSE offering 4p/kWh and 3.5p/kWh respectively (Solar guide 2020). This devaluing of exports alongside removal of a generation tariff is expected to drastically increase payback times for domestic PV in the UK, with this being found to increase from around 9 years to up to 46 years (Cui et al 2020).

2.4.4 Contract structures for microgeneration

The most common contract structure surrounding PV currently is perhaps also the most obvious, whereby panels are bought outright by the consumer and installed at private expense to provide energy savings and tariff rewards, sometimes referred to as “plug and play” (Watson et al 2008). The primary drawback here is that the scale of the required capital investment excludes a majority of households, and is high enough often to dissuade even those who could afford it (Rai & Sigrin 2013). Despite the high investment costs, and the long payback times that can follow, the ownership of the system and the power it generates can allow consumers to become less dependent on the grid, which is often an attractive proposition (Watson et al 2008). The main alternative to this model is one in which the consumer occupies a more passive role in the process, supplying the site for third party solar panels and paying a small lease fee in return for lower energy bills, sometimes called a “company driven” model (Watson et al 2008). The structure of these lease arrangements can vary between a simple lease arrangement, in which the consumer pays a monthly flat fee, and a Power Purchase Agreement (PPA) (Zeng et al 2015) in which the consumer pays the third party according to their electricity use and according to a fixed or variable rate. In either simple lease or PPA arrangements, the aim is to expand the availability of rooftop PV to those who have a tighter cash flow situation, and in this sense they are generally successful (Rai & Sigrin 2013). In the United States, company driven models accounted for just over 50% of new installations in 2012 (Zeng et al 2015). This is yet to enjoy the same success in the UK, although reductions in tariff support could mean it becomes a more attractive option, as payback times for leased panels tend to be shorter than outright purchases (Rai & Sigrin 2013).

2.5 Building requirements for rooftop solar

Aside from the effects of policy and various financial barriers and incentives, the building stock of a particular town or city has a strong effect on the applicability of rooftop PV. This can be due to social factors associated with homeownership as well as the physical makeup and suitability of different building types. In this section, the relationships between these factors and PV uptake will be explored.

2.5.1 Ownership

Homeownership is a wide and important factor towards the uptake of rooftop PV, in one sense, because it allows for a simpler situation with fewer shareholders. There is a common difficulty across the subject of urban development of split incentives (Philibert 2011) with such high population density, and rooftop PV can exacerbate these opposing viewpoints. In rented accommodation, this can be hard to manoeuvre as landlords are unlikely to be motivated towards paying the investment costs while the tenants would recoup the majority of the benefits, such as lower electricity bills (Philibert 2011). Potentially, the landlord would only be able to recoup the investment paid upon selling the property, whereby the added value of PV could fetch the property a higher resale value (Sayigh 2019). This however, may be an attractive offer for some landlords, with the potential to add tens of thousands of pounds to the property value (Sayigh 2019). This is especially attractive to the landlord when considered alongside third party ownership schemes, in which case the tenant may shoulder more burden, being subjected to unwanted and disruptive installation. In general however, there are greater benefits, especially in the short term, to the occupiers of a rented property with rooftop PV than to the landlord, making rented accommodation a difficult market.

In another sense, this difficulty is ultimately financial, with homeowners typically in a much more secure position than renters, and therefore much more likely to be able to afford costly installation (Karytsas et al 2019). In particular, younger homeowners, who are generally more environmentally conscious more aware of PV technology, exhibit most willingness and ability to install PV (Karytsas et al 2019). Due to this financial position, as well as the split incentives between landlords, renters are far less likely to have the means or roof access to install solar panels than homeowners, with this particularly true for those renting flats rather than houses (Gooding et al 2013).

2.5.2 Building Stock

This disparity in terms of access to roof space between houses and flats is pertinent, as it serves to limit the applicability of solar panels between different towns and cities. In fact, when assessing the solar potential of a city, the building stock has been found to be one of the most significant factors to consider (Gooding et al 2013). The proportion of houses to flats, and the character of flats within a city has a strong effect and for this reason, Scottish cities have been estimated at having a lower PV potential. This is due to historic development decisions that meant cities in Scotland favoured multi-storey tenement flats with many dwellings sharing roof space, whereas bungalows and terraces were a more common choice in England (Gooding et al 2013). Houses and bungalows, with their larger roof space (figure 5), have significantly higher PV potential per capita, and hence many newer build homes of these types could be expected to have a strong potential.

Figure 5: Approximate roof area for different house types (Clay Ridge Roofing 2017)

These factors generally lead to only larger, owner occupied houses being suitable for PV, however an exception to this rule occurs when councils decide to install solar panels on social housing (Gooding et al 2013) (Sweetnam et al 2013). This practice is relevant primarily in dense urban areas, where high levels of social housing could support a wide rollout of rooftop PV, whilst also delivering utility savings to those most in need of them (Sweetnam et al 2013). However, and more relevant to this project, this demonstrates how PV could be routinely included in new house building, thereby removing the need for disruptive installation at a later date. This could prove to be an effective way to achieve microgeneration targets (Watson et al 2008), with the effect being to widen the uptake of PV without renovation of old buildings.

2.6 Energy Demand

2.6.1 Scottish Demand

Similar to many post-industrial countries, Scottish electricity demand has traditionally been fulfilled by few, intense sources of power, with this changing in recent times to include a higher share of renewables than in the rest of the UK (Telford et al 2019). There is also a strong seasonal aspect to Scottish energy demand, with dark and cold winters meaning demand far exceeds that of summer (Scottish Energy Statistics Hub 2020). This seasonality is more pronounced with regard to gas than it is for electricity, with gas demand peaking in winter at five times the summer level, in comparison to a roughly two-fold increase in electricity (Scottish Energy Statistics Hub 2020). Overall, domestic energy use makes up around 40% of a total of 110,188 GWh of final energy demand in Scotland, with heat and electricity making up 78% and 22% of domestic demand respectively (Energy statistics database 2019).

Since 2008, there has been a consistent fall in total Scottish energy demand; with a 12% target intended for 2020 being surpassed as early as 2013 (Energy statistics database 2019). Both domestic and non-domestic sources have contributed to this reduction, with both sectors now more stable, keeping pace with the 2020 target (Energy statistics database 2019). However, this reducing trend may not continue into the future, as domestic demand is likely to see a shift in coming years (Telford et al 2019). It is expected that there will be some degree of evolution to reduce dependence on gas for domestic space and water heating as the country moves towards more low carbon, electrical heating solutions (Robertson & Galloway 2017). Specifically, it is expected that the use of heat pumps will be instrumental in moving away from gas and towards more renewable sources of heat (Robertson & Galloway 2017). Changes to housing regulations in an attempt to build more eco-friendly homes are also expected to lower domestic energy demands (Bergman & Eyre 2011), although this effect of reducing demand will be balanced by other advances, such as an increase in electric vehicle uptake (Kufeoglu & Politt 2019). Additionally, any changes in population will have corresponding effects on domestic energy demand, with Scotland's population predicted to grow overall by around 2.5% to 5.57 million by 2043, the rate of growth is expected to slow as time progresses until stalling at zero by the end of that year (NRS 2019).

2.6.2 Cumnock Demand

With a current population of around 8,600 (statistics.gov.scot 2020), Cumnock represents a statistically tiny part of Scotland's domestic energy demand. As a result, it can be expected to behave independently of the wider Scottish demand, and this contradiction can currently be seen in the population projections. While Scottish population is expected to steadily increase in coming decades, this increase will be powered by net migration into larger economic centres such as Glasgow or Edinburgh (NRS 2019). Without a stream of migration, many less urbanised parts of Scotland, such as Cumnock, are expected to see their population decline (NRS 2016).

2.7 Social impacts of widespread uptake

2.7.1 Financial Impacts

A significant social impact of PV uptake, and perhaps the most important to consumers, is that of the economic benefit (Sheriff 2014). Fuel poverty is defined in Scotland if, in order to properly heat the property, a household is required to spend more than 10% of their income of energy (Roberts et al 2015); and PV is well placed to help alleviate this. This can and has been done through schemes which install PV within social housing (Sweetnam et al 2013)(Bahaj & James 2007). While PV has little scope to address the highest periods of demand in winter, high contributions during the summer months mean that across the year as a whole, the burden of energy costs can be reduced (Bahaj & James 2007). Recent studies show that while household savings under the SEG are not as substantial as under the FIT, annual savings of between £84 and £146 can still be made through PV installation (Cui et al 2020). While some of the problems associated with installing PV in rented and social housing were covered in *2.5.1*, overcoming these problems would be highly beneficial not just for the tenants, but for national microgeneration as a whole as this can provide a high potential for installation (Sweetnam et al 2013). Encouraging landlords, and in particular social landlords to consider installing solar panels would therefore be a way to alleviate both financial burdens on some of the most vulnerable, but also to advance renewable targets in the UK (Sweetnam et al 2013).

Financial benefits can also extend further than simply the electricity produced, with the installation of solar panels often leading to more energy saving behaviours (Bahaj & James 2007). These are often termed the "soft" benefits of microgeneration (Bergman & Eyre 2011) (Bahaj & James 2007) and include behavioural changes which can reduce household energy demand further, leading to more financial savings.

2.7.2 Behaviour and Prosumption

These behavioural changes or "soft" benefits associated with installing PV can be thought of as the result of a more involved, and less passive relationship which the new owner of solar panels develops with energy (Bergman and Eyre 2011). This can include relatively simple behaviours such as turning off unnecessary lights, but can also extend to more conscious activities such as using washing machines and other high energy appliances during peak production times (Bergman and Eyre 2011). In both cases, the visibility of solar panels is considered to be a strong driver towards more conscious behaviour (Abreu et al 2019), and these can be considered evidence of energy prosumption. Prosumption is a relatively recent phenomenon, it is a combination of the words production and consumption and describes an individual both consuming and producing energy (Ellsworth-Krebs & Reid 2016). According to prosumption, owners of PV panels will change their routines in order to maximise the use of their own produced electricity and minimise imports, with this action reinforced by the visibility of the panels and adding to the "use-value" associated with PV (Ellsworth-Krebs & Reid 2016). There is, however, debate on how long these behaviours persist after installation, with Bahaj & James noting in 2007 that within a year of installation, initial energy saving behaviours had disappeared entirely. This particular study concluded that the notion that visible panels could permanently change behaviour was wishful thinking, particularly in situations where the occupants had not directly paid for the installation.

2.8 Methods for assessing PV potential

2.8.1 GIS

Previous literature has regularly sought to develop a method for accurately assessing the PV potential of a town or city without the need for physical survey (Molin et al 2016)(Gooding et al 2013)(Hong et al 2017), with some form of Geographic Information System (GIS) often used. Initial analysis using GIS software can then be followed up by socio-economic analysis to determine the true potential of a town or city, separate from the absolute physical capacity (Gooding et al 2013). This absolute physical capacity is determined by computing the available rooftop area of the chosen environment using a GIS software and combing this with a data package of the existing solar resource (Hong et al 2017). There are a range of GIS software which is applicable to rooftop area analysis such as this, with Google Earth, LIDAR packages and 3D models of entire towns being used (Molin et al 2016)(Gooding et al 2013). Where more detailed physical models of the target environment have been built, rooftop area can be found as a basic program analysis, with the building of the model being the most painstaking part of the process (Molin et al 2016). Alternatively, conducting analysis on a smaller localized area and then approximating this data for a larger scale is also common practice (Hong et al 2017).

Further to this area analysis, consideration must also be given to the degree of shading experienced by rooftops. This shading consideration is most important in highly urbanised environments (Hong et al 2017), where high rise buildings can create complex shadows which can severely limit PV potential. As a result, in these environments, shade can be accommodated into simulations using hill-shade GIS packages (Hong et al 2017), or through separate algorithmic means (Molin et al 2016). By contrast, in less urbanised and rural environments, shading is far less of an issue as surrounding buildings are much shorter and do not provide the same obstacle to light (Hong et al 2017).

While GIS based methods can be thought of as providing a realistic estimate of rooftop area, they are not without limitations. Particularly, the accuracy of input data can be lessened by the effect of human error during surveying, as well as by ambiguous building and roofing characteristics (Bergamasco & Asinari 2011). Additionally, as usually only a small portion of a larger environment is surveyed, the model can be unintentionally misleading, as well as these methods being amongst the most labour intensive (Hong et al 2017).

2.8.2 Socio-economic Estimates

Socio-economic factors can be considered a key component of an environments PV potential in order to add accuracy (Gooding et al 2013), but they also have application in initial estimates of rooftop area (Hong et al 2017). By using available information such as; land-use data (Singh & Banerjee 2015), population and building densities (Izquierdo et al 2008), income and education (Gooding et al 2013), available rooftop can be either estimated outright or earlier estimates updated. These methods can be of particular use if GIS data is not available at a reasonable accuracy or unavailable altogether; however there is a significant margin for error involved, especially in case where GIS is not available (Hong et al 2017). In isolation, these methods, while useful for very large scale analysis, do not operate accurately enough at individual town/city scale to provide more than approximations (Hong et al 2017).

2.9 Conclusions

From the literature review conducted, a number of important conclusions can be drawn. First, with regard to the most applicable technology to Cumnock it can be seen that poly-crystalline silicon panels present the most appropriate balance of cost, efficiency and availability. It can also be concluded that string inverters are the most likely choice for a project of this kind, with their market share, cost and ease of installation outweighing several shortcomings against competing technology.

Insights can also be drawn on the socio-economic factors behind solar panel installation, with building type and home-ownership being found to be determinants of PV uptake. Furthermore, the kind of support and incentives and the level to which they are available for installing solar PV has been determined, with this being essential for modelling in later sections. A downwards trend in Cumnock population has been established with this, as well as other insights derived from the literature, having repercussions for future demand profile building. Social impacts of a high rate of PV installation have been considered, highlighting parameters such as annual per-household saving which will be useful in determining the value of modelled scenarios to individuals. The impermanent nature of behavioural change or “soft” benefits associated with PV has also been covered.

Finally, the importance of considering GIS and socio-economic factors together has been highlighted, which will improve the subsequent methodology.

3 Methodology and Model Building

3.1 Object

The purpose of this model is to represent the energy system of Cumnock, and to simulate the integration of rooftop solar PV with future demand variation. By assessing the results of these simulations, the feasibility and applicability of PV to the town of Cumnock will be determined, giving perspectives not just for Cumnock, but for similar environments across Scotland.

In order to run simulations on the chosen modelling software (Homer), parameter data must first be determined for both PV generation potential and the current energy demand of Cumnock.

3.2 PV Generation Potential Analysis

3.2.1 Building Stock Overview

There are a range of domestic building types in Cumnock, and in order to properly estimate the PV bearing potential of rooftops in the town, and overview of the existing stock was first established.

Housing data was acquired (statistics.gov.scot 2020), with Cumnock being statistically split into two separate "intermediate zones". Intermediate zones are simply small geographical areas for which various public data can be grouped, and in this case Cumnock is made up of Cumnock North and Cumnock South and Craigens. This housing data groups the total number of dwellings listed in Cumnock by housing type with; detached, semi-detched, flats and terraced housing categories represented. This data is shown below in table 1:

Table 1: Cumnock Housing Data

Zone	Total Dwellings	Detached	Semi-detached	Flats	Terraced
Cumnock North	1,884	607	478	430	369
Cumnock South & Craigens	2,342	186	570	683	903
Total	4,226	793	1,048	1,113	1,272

3.2.2 PV Potential

The first stage to analysing Cumnock's potential for supporting rooftop PV was to determine the amount of roof space which is available for installation. In order to estimate this, Google Earth Pro was used to measure the area of domestic rooftops. Measurements were taken in five separate "sets", in which fifteen individual roofs were measured using tools embedded in Google Earth Pro. In each set, an average of the fifteen roofs was taken, with a final average then being taken from the five sets, shown below in table 2.

Table 2: Results of roof area survey

	Set					Average
	A	B	C	D	E	
Area (M^2)	64.8	68.9	77.1	85.6	71.4	73.6

Using this roof area of 73.6 M^2, the next step was to determine the size and capacity of the PV system which could be supported, on average, in the town of Cumnock. Whilst the size of solar panels vary slightly between manufacturer, on average they tend to measure around 1.6 M^2 (Energy savings trust 2015), and in the case of residential panels are almost always rectangular in shape. Using a 2015 sizing guide available from the energy savings trust, it was calculated that the average roof in Cumnock would be able to support a 4 kW PV system, consisting of 18 individual panels. The principle used in this sizing guide was to take half of the available total roof area, selecting for the most southerly facing slope, then removing 20% of the remaining area to account for chimneys and edging to the roof.

The next stage was to scale up this single roof capacity in order to represent the entire town's capacity under this standard sizing guide. By using the housing data acquired from statistics.gov.scot, the initial process was to multiply the single house 4kw system by the total number of domestic dwellings in Cumnock, with the logic being that each dwelling has a corresponding roof. However, it was decided to exclude dwellings listed as "flats" from this process for two primary reasons. The first of these was due to the uncertainty concerned with flats and their associated roof area, with roof area being shared by between 2 and 4 stories in Cumnock. This made it difficult to accurately estimate the total roof area associated with flats based on the total number of dwellings of this type.

Figure 6: Highlighting the inconsistent dwelling to roof area ratio between two common flat types in Cumnock (Google Earth Pro)

The second reason concerned several key issues raised by the literature review around hosting rooftop PV in flats. These included; contractual and ownership issues caused by multiple shareholders having access to only one roof, a lower rate of homeownership amongst flats and the associated complications, and a lesser ability to shoulder any financial burden associated with the panels. Therefore, 1,113 dwellings listed as flats were scoped out from the calculation; however these could be reconsidered for any future work. This leaves 3,113 dwellings (consisting of terraced, detached, and semi-detached houses) being considered and by this method, the maximum total installed capacity of PV in Cumnock is 12, 452 kWp.

In order to represent the range of roof orientations which exist within Cumnock, this capacity had to be processed further. In order to represent this on Homer, the total capacity was split into several smaller arrays. It has been assumed that roofs in Cumnock will be randomly orientated through the 8 points of the compass, and as such, these arrays will need to represent this range. However, as the sizing guide used earlier in the process stated that the most southerly facing half of the roof would always be preferentially used, it was possible to rule out installing PV panels facing directly North, North-East and North-West. The total capacity was therefore split five ways between South, East, West, South East and South West, resulting in representative PV arrays of 2490.4 kWp in each orientation. Consideration was also given to the tilt of the PV panels to be installed in Cumnock, which is highly dependent on roof slope. The average slope for a domestic roof in the UK is between 40° and 50° (Davies 2013), and in the interests of ensuring the wider relevance of this model and preserving its simplicity, a median value of 45° is used for each of the 5 PV arrays.

To represent the solar resource in Cumnock, data available within Homer was used. This data, which was downloaded after defining the projects location, was taken from the NASA surface meteorology and Solar Energy Database. This data takes into account both the daily solar radiation and the clearness index (the fraction of solar radiation which passes through the atmosphere) and uses monthly averaged values over a 22 year period. There is a clear seasonality to the solar resource shown below in figure 7, and this is mirrored in the PV generation totals during later scenario work.

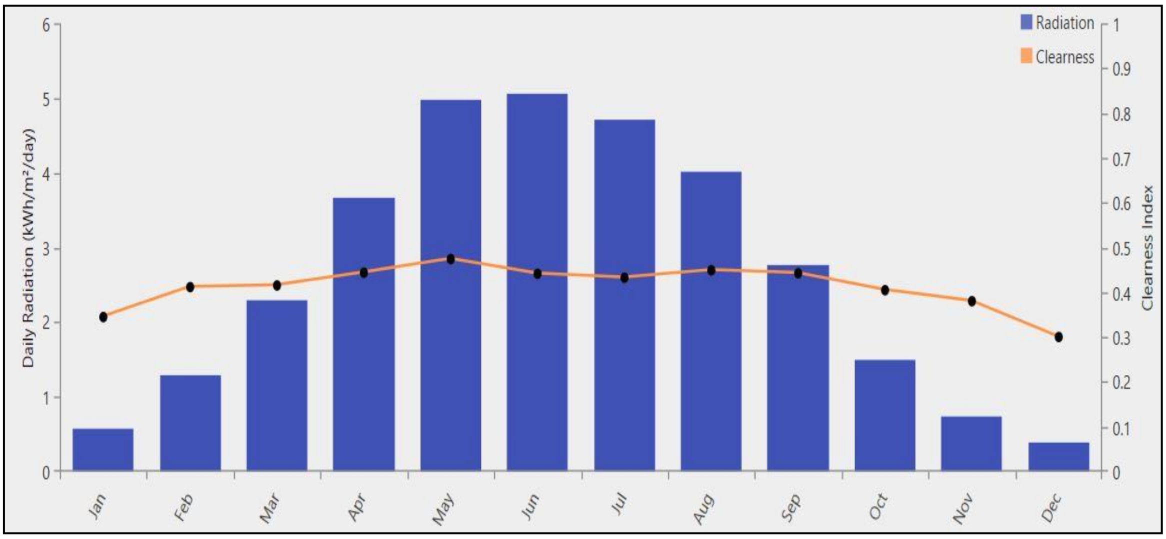

Figure 7: Solar Resource for Cumnock used in Homer

3.3 Demand Analysis

3.3.1 Demand Profile Building

In order to understand the applicability of solar PV to Cumnock, a model to represent the total energy demand would first need to be developed. For this purpose, energy demand data was sourced from both Energy statistics database and the Scottish Energy Statistics Hub (SESH), with the goal of creating an annual hourly demand profile for both electricity and gas in Cumnock.

The process for defining demand profiles followed a near identical methodology for both gas and electricity, with both completed on Microsoft Excel. First, 2019 daily demand totals for both gas and electricity were downloaded from SESH, and scaled down to represent the East Ayrshire domestic demand. This was done by comparing annual domestic demand data for Scotland, East Ayrshire (Cumnock's council area) and total daily Scottish demand (Energy statistics database 2019); using this comparison, national demand totals were modulated down to reflect East Ayrshires domestic contribution to total Scottish demand. Next, this data was scaled down again in order to represent domestic demand in the town of Cumnock. This was done by reducing the East Ayrshire daily demand totals proportionally to the ratio of domestic dwellings registered in East Ayrshire and Cumnock in 2019 (Statistics.gov.scot 2020). Using this methodology, daily domestic demand totals for gas and electricity in Cumnock were determined.

Next, in order to create hourly profiles representing domestic gas and electricity use in Cumnock, these daily totals were fit against existing hourly profiles. This was done using a Scottish daily demand profile, taken from Energy statistics database, for both electricity and gas on a particular day in 2019. By comparing the total demand for the selected days profile (29th of January for electricity and 31st of January for gas) with the given hourly demand, it was possible to scale the demand profile according to any daily total. Hence an approximate hourly demand profile could be made by scaling the available profile using the daily totals for gas and electricity in Cumnock. Whilst approximate, this model describes the seasonal variation in demand as well as showing peak hours of demand throughout the day. The electricity and gas profiles used in scenarios 1-3 are shown below in figure 8 and 9 respectively.

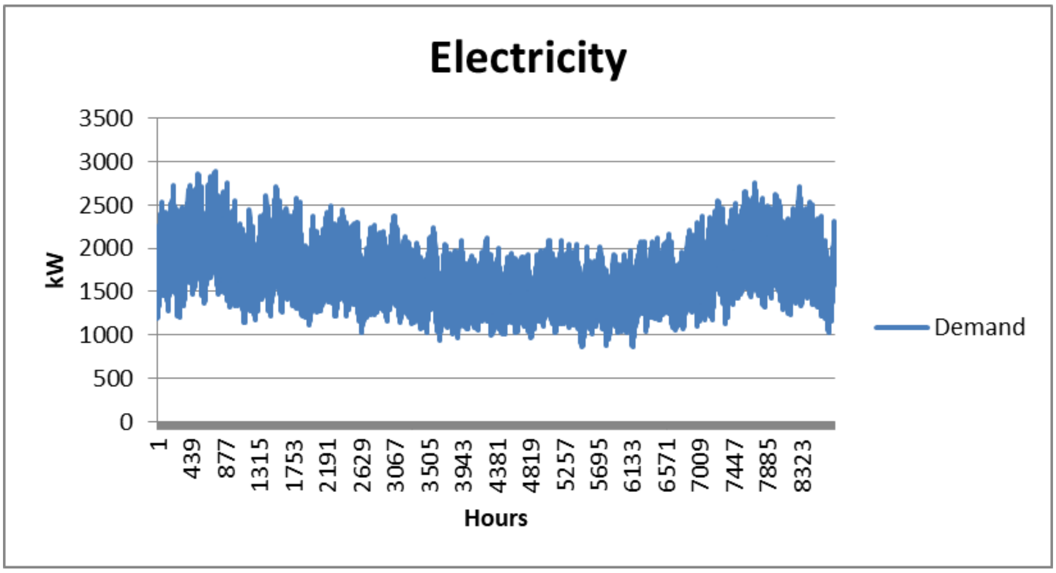

Figure 8: Annual modelled electricity demand

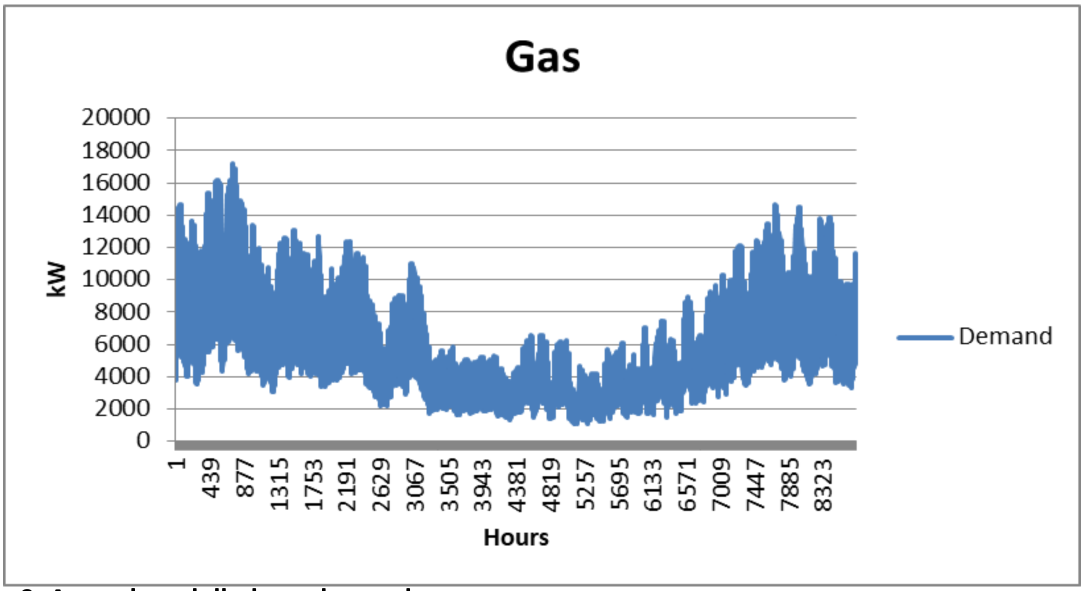

Figure 9: Annual modelled gas demand

3.3.2 Future Demand Profile

The model of energy demand shown above represents Cumnock as it currently exists, but as time progresses, this will almost certainly change. In order to assess how the widespread installation of rooftop PV would serve local needs, this dynamic nature to energy demand must be considered. In order to do this, a *future demand* profile was determined, taking into account projected changes in population and heating systems. This profile will be designed to represent the midway point of the project, 25 years from the start date (2045).

First, population and household projections for Cumnock were considered, using available data from the National Records of Scotland (NRS). While the population for the whole of Scotland is expected to grow by around 2.5% up until 2043 (NRS 2018), this trend is not consistent throughout the country. Projection data specific to Cumnock is not available, however a 2016 report by the NRS considered Cumnock and New Cumnock together as one entity, and produced the population and household number projections shown in figure 10.

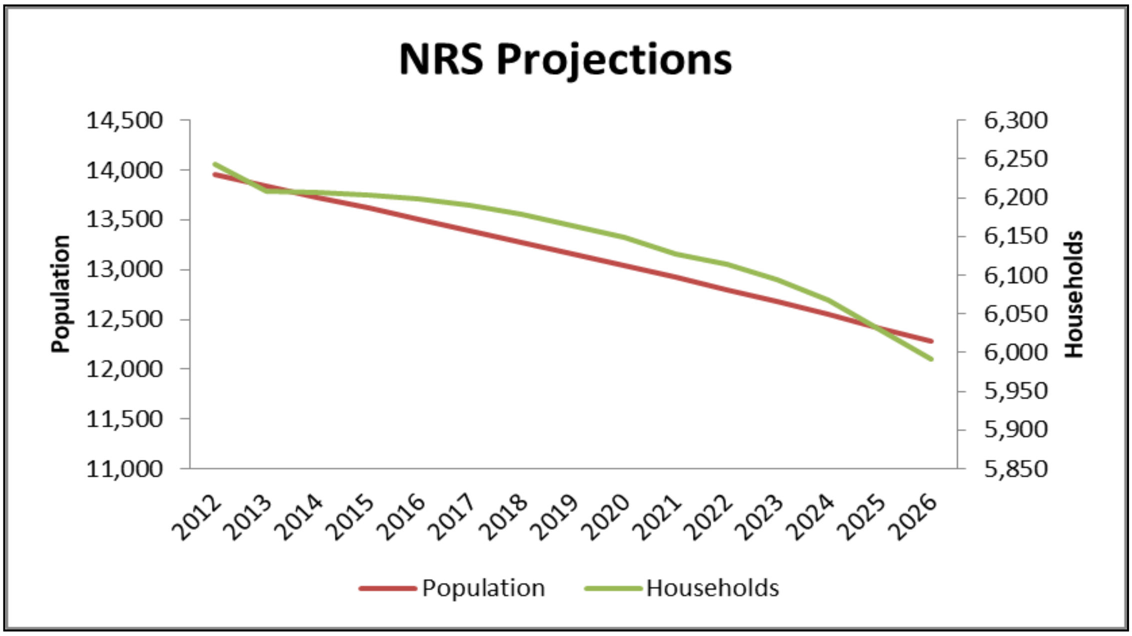

Figure 10: NRS population projection for Cumnock & New Cumnock

From 2012-2026, the data in figure 10 shows an expected drop in both population and households by around 3.5%. The report shows population falling at an almost constant rate while number of households appears to plateau initially before a steeper decline, possibly due to housing being a lagging indicator behind population. While absolute values cannot be taken from this source, the declining trend is applicable, and represents a wider expectation that rural and western parts of Scotland are expected to see population decline in coming decades (NRS 2016). By applying and continuing this trend using an average of the year on year percentage loss, there will be an estimated reduction of 266 dwellings from Cumnock by 2045, leaving a total of 4,000.

Another important feature of future energy demand is the evolution of the heating system. Currently, space and water heating demand is served largely by gas, however, as the UK moves to decarbonise its energy supply, a section of this heating demand will likely be fulfilled by electricity using heat pump technology. For this study, it will be assumed that air source heat pumps are most likely to be installed, as they are understood to be the most financially credible option to the residential market (Kelly et al 2016). A seasonal performance factor (SPF) of 2.5 will be used during calculations, drawn both from the literature (Lerch et al 2015), and the qualifying requirements for the renewable heat incentive (RHI) (Ofgem 2020). For the future demand profile, the effects of an installation rate of 15% will be investigated. The cost of this modernisation is not to be included in the financial modelling of any scenarios, as this is considered to be beyond the scope of this project.

In order to create a future demand profile, the original Cumnock demand determined in 3.3.1 was first scaled down. This was done in excel with both gas and electricity profiles, so that both profiles now represented a town of 4,000 dwellings. Next, in order to represent a 15% divestment from gas fired space and water heating, the hourly gas demand totals were reduced by 15%. This heat demand was then added to the corresponding electricity total, factoring in the effect of an SPF of 2.5. With an SPF of 2.5, each kWh of electricity will generate 2.5 kWh of heat, and hence the demand to be added to electricity total was amended accordingly.

3.4 Key input data and simulation settings

In addition to the electricity supply and demand inputs described above, there are a number of other parameters which are key to simulation results. The values to these inputs have been determined as a result of material consulted during the literature review, and have been altered in some cases due to decisions made with the aim of developing a representative and informative model.

3.4.1 Project Lifetime

The lifetime of this project has been set at 50 years in Homer, which equates to double the lifetime defined for the solar panels themselves. There are two primary reasons for this long project lifetime. Firstly, it allows the effect of different component lifespans and replacement costs to be shown in results, with the steep reduction in PV costs over recent decades meaning this could become particularly relevant. In addition to this, the long project lifetime reflects the fact that due a relatively low solar resource, rooftop PV arrays in Scotland are likely to have very long payback times, if they payback at all (Gooding et al 2013). Hence, it is likely that a project of this kind would require a long lifetime in order to having any chance of becoming a worthwhile endeavour.

3.4.2 Solar Panel Specifications

From material covered in the literature review, the most applicable technology to this project is poly-crystalline silicon PV. This is due to the balance being struck between cost, efficiency and sustainability. While poly-crystalline panels are less efficient than mono-crystalline, they are significantly less energy intensive and time consuming to produce, meaning capital expenditure and life cycle impact will be lower. An efficiency of 15% has been chosen in order to represent modern poly-crystalline silicon panels, with a derating factor (which simulates a reduced PV output due to real-world conditions) set to 80%. Temperature effects are also considered, with the Nominal Operating Cell Temperature (NOCT) set to 47°C and the temperature coefficient set to -0.5 (meaning that cell power output decreases by 0.5% for every degree above NOCT). Both of these values are stated in the Homer manual as having resulted from a survey of commercially available PV modules. The price of each 4kw system has been set to £6,040 (solar guide 2020), with a replacement cost of £3,020 after a 25 year lifetime, representing a continuing fall in price. This includes all module, installation and BOS costs as well as inverter costs, however the replacement costs of inverters will be modelled separately.

3.4.3 Inverter specifications

Inverter costs represent a significant part of total PV costs, due not only to their high (but rapidly decreasing) costs but also their lifespan, which is generally much shorter than that of solar panels. Therefore, it is beneficial to model this component and its costs separately from the rest of the PV system. For the following simulations, a string inverter will be modelled, with an initial capital cost of £0, as the initial expenditure is covered by the solar panel costs and a replacement cost of £800 for each 4 kW system. The modelled lifespan of this component is 15 years, with a consistent efficiency of 95%. Due to the particularities of Homer and the built model, the inverter capacity which would, in reality, be spread between every PV array, must be represented in a single component. Therefore, this inverter component is to be sized at 12,452 kW, denoting a 4 kW inverter on each household's system.

3.4.4 Energy Import and Export Rates

Energy prices for import and export will be an important factor towards the viability of this project, as the profitability of many domestic PV systems relies on exporting to the grid. Under current policy, export prices will be covered by the smart export guarantee, whereby energy suppliers have an obligation to purchase energy from microgeneration sources, and can set their own price providing it is above 0. For the following simulations, and export price of 4p per kWh is assumed, this is the export price currently offered by Scottish Power (Solar guide 2020), which is a likely supplier for consumers in Cumnock. The import price for electricity is set at 13.97p per kWh, representing the average electricity cost in southern Scotland (Ukpower 2020). The import price for gas, meanwhile, is set to 32p per cubic meter (Business energy 2020) on Homer, reflecting the approximate price in the UK.

3.4.5 CO_2 Emissions

By using renewable, locally generated electricity, it is expected that Cumnock will be able to significantly reduce its carbon footprint. To facilitate this comparison, the grid carbon dioxide intensity value must be set. Scotland has a relatively low CO_2 intensity in comparison to the rest of the UK, with an approximate CO_2 intensity of 100g/kWh compared to a UK average of 241g/kWh (Electricity info 2020). This input of 100g/kWh will be used in all following simulations.

3.4.6 Discount Rate

As the financial performance of each scenario will be a significant factor towards its viability, the discount rate is an important parameter to set. The discount rate governs the rate at which money can be borrowed in order to finance the project, and is crucial to Homer's calculation of the *real discount rate*. Real discount rate is calculated by homer using both the expected inflation rate and nominal discount rate, and it is this value which homer uses when defining results such as net present and annualised costs. Nominal discount rates for solar energy products vary between project and country, and in the UK tend to range between 5.5%-6.5% (Grant Thornton 2019) (Hawkins 2020). Inflation rates also show variation, reacting to world events such as Brexit or the COVID-19, with the Bank of England currently setting a target of 2% (Bank of England 2020).

Drawing on this information, the nominal discount rate for this project will be set at 6%, with inflation rate aligning with Bank of England target, at 2%. This will give a real discount rate, used by Homer, of 1.33%. These values will be kept consistent for each modelled scenario.

3.5 Software adopted and validation

In order to ensure the model created for this project was reasonably valid; data produced was compared against known values to check their accuracy. For the energy demand model, this was done by comparing the daily Cumnock demand per household for gas and electricity against average UK consumption values. Sourced from *Ukpower.co.uk,* the average household's daily energy usage is 33-38 kWh and 8-10 kWh for gas and electricity respectively. While there is variation throughout the year, generally the modelled data for Cumnock falls within these ranges. While the Homer model results cannot be explicitly validated in the same way as they are hypothetical, Homer as a program is validated against real values in order to maintain its soundness. Additionally, by comparing baseline operating costs per household to real UK average (Ovo energy 2020) an acceptable agreement was found.

3.6 List of experiments conducted

3.6.1 Scenario 1: Baseline

Scenario 1, or baseline, represents Cumnock as it exists today with no installation of solar PV. In this scenario, the entire electrical demand is supplied by the grid, with the thermal demand being satisfied entirely by a gas boiler component. Results from this scenario will be useful primarily by way of comparison to check whether later scenarios offer any improvement.

3.6.2 Scenario 2: Baseline + Realistic Solar panels

Scenario 2 represents Cumnock under baseline demand conditions with the addition of 12,452 kWp of solar PV using the sizing guide described in section 3.2.2, which represents reasonably efficient use of roof area. In this scenario, panels have been installed on all available rooftops, excluding flats, using only the most southerly facing side of the roof. For scenario 2, the grid is still available to satisfy part of the electrical demand, and the thermal demand is supplied entirely by a gas boiler component.

3.6.3 Scenario 3: Baseline + Extensive Solar Panels

Scenario 3 represents Cumnock, again under baseline demand conditions with the addition of 24,904 kWp of installed solar PV. This represents a scenario where renewable fraction considered as a target above cost, with panels being installed on both slopes on all available roofs, excluding flats. Rather than the 5 arrays used in scenario 2 to represent different orientations, 8 arrays will be used to represent all directions. As in scenarios 1 and 2, grid and boiler components are connected to serve residual electrical and thermal load

3.6.4 Scenario 4: Future Demand + Realistic Solar Panels

Scenario 4 represents Cumnock in 2045, in which the population has decreased and 15% of the thermal load has been electrified. Solar panels are installed in a realistic manner as in scenario 2, and grid and boiler components remain connected in order to serve any additional load.

3.7 Assumptions and simplifications adopted

A number of assumptions and simplifications have been necessary in order to proceed with building the models for this report. In the demand model, the scaling of a single demand profile for each day of the year represents a major simplification, limiting the day to day variation and likely over-estimating summer thermal load. When estimating the future demand model, assumptions were also made in continuing the recent decline in Cumnock's population as well as the uptake of heat pump technology in the town. In estimating the roof area available for PV, flats were excluded both under the assumption that installation would be problematic, and to simplify the calculation for Cumnock's total roof area. Further simplifications were made when considering the orientation and pitch of the roofs in Cumnock; with roofs assumed to be evenly orientated around the points of the compass and roof slope simplified to a consistent 45°. When modelling energy costs and export tariffs, an assumption was made that these would remain consistent for the duration of the project, due to the software package used; these values were locked in for the full span of the simulation.

4 RESULTS

The key results, in reach scenario, are taken to be: financial performance of the system, renewable fraction and Co_2 emissions associated with Cumnock and the grid interactions with the system as a whole.

4.1 Scenario 1: Baseline

This scenario is intended to describe the situation in Cumnock as it currently exists, with the entire energy demand served by grid and gas boiler components. Further scenario's results will be measured against these baseline values to determine if they represent a valuable alternative.

4.1.1 Financial Performance

Shown below in Table 3 is a selection of the most important financial results from the baseline scenario.

Table 3: Main financial results from Baseline

NPC	Operating Cost (a + b)	Annual Electricity Charge (a)	Annual Gas Charge (b)	Initial Capital	Operation and Maintenance
£91.41 m	£4.198 m/year	£2,134,969	£2,063,020	£0	£0

In this scenario, there has been no investment in new infrastructure as the grid and gas boiler network are already present in Cumnock. Therefore, the net present cost (NPC) is determined entirely by the annual gas and electricity charges incurred in meeting thermal and electrical demand. A breakdown of NPC is shown below, in figure 11, with costs over the 50 year period split almost exactly equally between the grid and boiler components. This relationship is also represented in the breakdown of annualised costs, which is this scenario are equal to the annual operating costs.

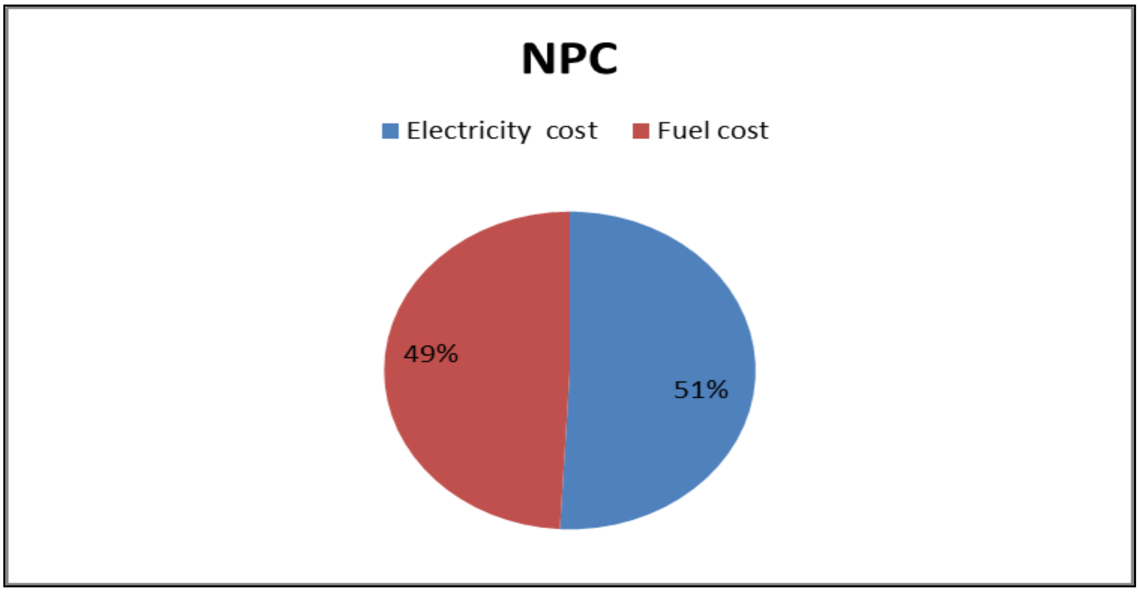

Figure 11: Breakdown of NPC in scenario 1

As electricity is supplied entirely by the national grid, the levelised cost of electricity (LCOE) remains at the price set in the simulation settings (13.97p/kWh). This is, in fact, slightly cheaper than the average UK electricity cost of 14.37p/kWh (Ukpower 2020), with southern Scotland experiencing the second cheapest electricity of the 14 regions described.

4.1.2 CO_2 Emissions & Renewable fraction

In the baseline scenario, Cumnock's electricity demand is entirely served by the national grid, and as such, the energy system has a renewable fraction of 0%. In meeting its electricity demand, Cumnock has associated CO_2 emissions of 14,040,256 kg per year, which over the course of the 50 year lifetime equates to 702,012,800 kg. Using 2019 housing statistics, this means that on average, each dwelling in Cumnock is responsible for around 3,291 kg of CO_2 per year in meeting its electricity demand.

4.1.3 Grid interactions

Expectedly, the grid interactions of scenario 1 are very simple, with electricity always flowing from grid to consumer, serving the entirety of the Cumnock demand. This relationship is shown below in figure 12, with energy purchased and charge shown on different scales for the sake of readability.

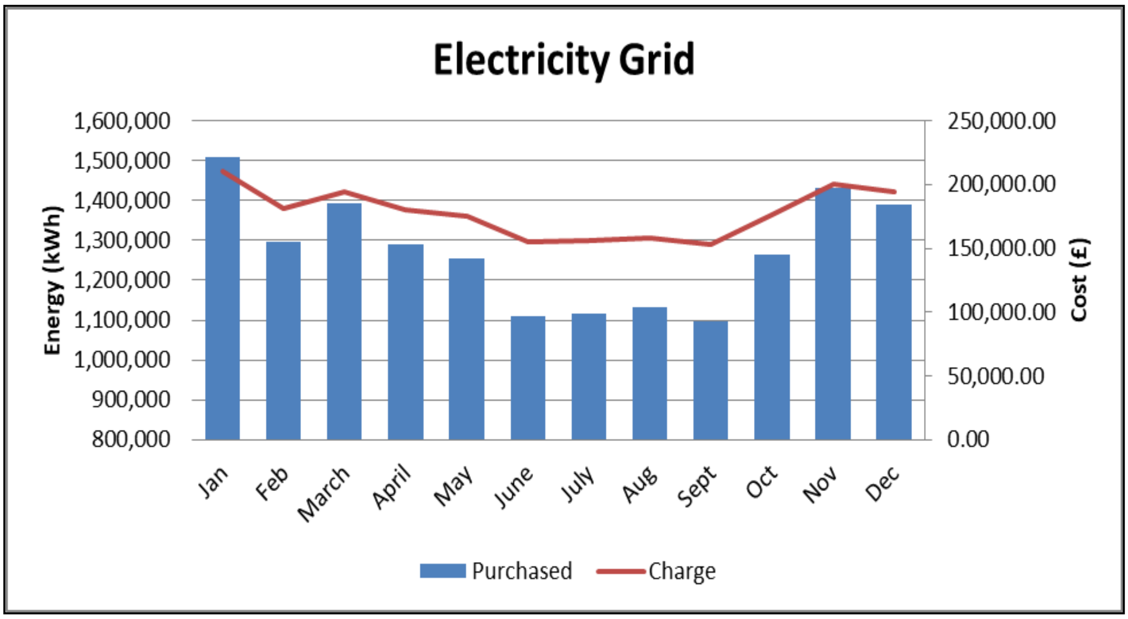

Figure 12: Showing grid purchases and associated cost throughout the year

Across the entire year, scenario 1 sees Cumnock purchase 15,282,530 kWh of electricity from the grid, with the corresponding annual cost being £2,134,969.38. There is a clear seasonality to the data shown above, with the highest monthly electricity purchase occurring in January (1,507,299 kWh) and the lowest coming in September (1,096,583 kWh). The month of February is something of an outlier to this trend, seeing a surprisingly low level of grid purchase.

4.2 Scenario 2: Baseline + installation of PV

The scenario represents Cumnock with a realistic installation of rooftop PV panels. In the following simulation, panels have been installed according to an Energy Savings Trust guide, with North facing roof surfaces not considered. Dwellings listed as flats have also been excluded from installing solar panels, as deploying PV in this setting is potentially problematic. The resulting PV system modelled in Homer consists of 5 separate PV arrays representing likely grouped orientation, each representing an equal share (2490.4 kWp) of the total.

4.2.1 Financial Performance

Table 4, below, highlights some of the key financial results from scenario 2. The capital expenditure on the PV system and its subsequent electricity contribution has a significant impact on both the NPC and operating cost, with a per-household annual saving of £124.

Table 4: Main Financial Results from scenario 2

NPC	LCOE	Operating Cost (a+b+c)	Initial Capital	Annual Electricity Charge (a)	Annual Gas Charge (b)	Operation & Maintenance (c)
£98.78 m	12.58p/kWh	£3.673 m/year	£18.8 m	£1,180,133	£2,063,020	£155,560

The LCOE in scenario 2 has fallen significantly from baseline, which is an encouraging result considering the substantial investment which has taken place to install PV. Operating cost has reduced by a considerable amount, with the annual figure in scenario 2 being £525,000 lower than baseline. NPC in scenario 2 is around £7.37 million higher than baseline, with the systems lower operating cost counteracting the initial outlay of £18.8 million. Figure 13 breaks down the NPC below, showing how the share of grid costs have shrunk dramatically, due to reduced grid imports and a correspondingly lower annual electricity charge. This is outweighed, however, by the contribution of the PV system, which occupies just over a quarter of the overall NPC with costs attributed to initial investment, replacement costs and maintenance.

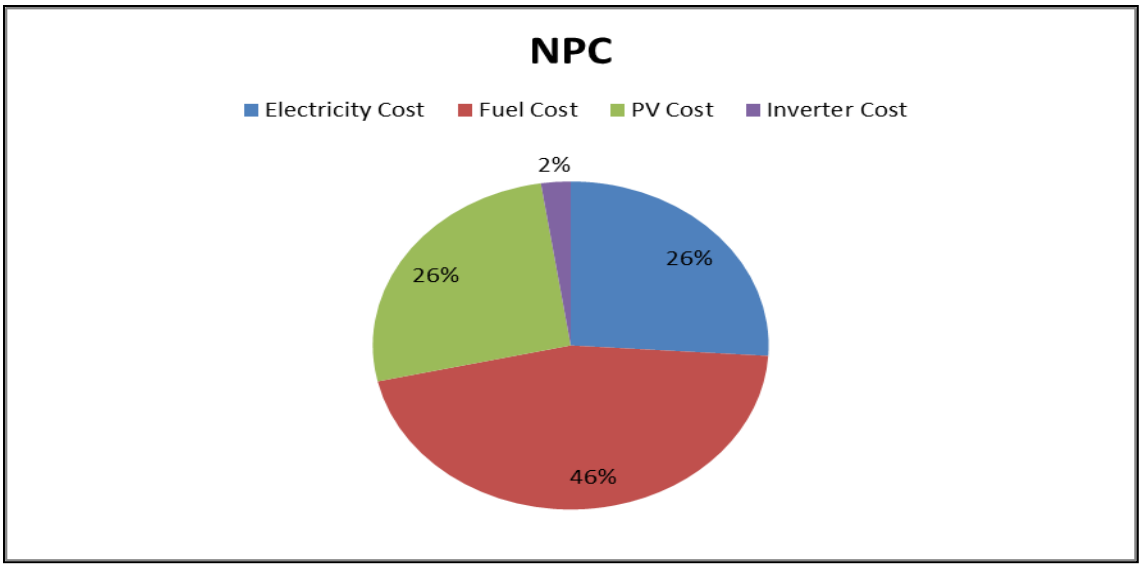

Figure 13: Breakdown of NPC in Scenario 2

Inverter costs have a small contribution towards the overall NPC, with the associated salvage value at the end of the 50 year project alleviating a small portion of the cost. The most significant portion of NPC is now fuel costs associated with the gas boiler heating system, with this value unchanged from baseline.

In comparing the cumulative nominal cash-flow of scenario 2 to that of baseline, it can be seen that despite the initial outlay of £18.8 million, a simple payback of the investment is achieved. This comparison is shown below, in figure 14.

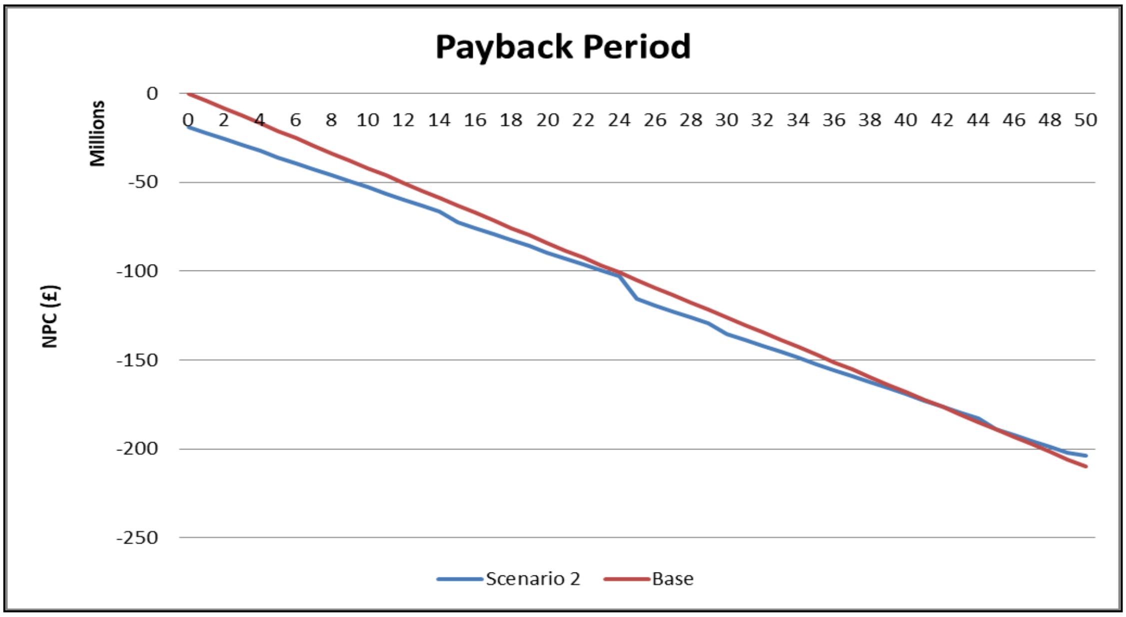

Figure 14: Comparing the cumulative cash-flows between baseline and scenario 2

This payback time is hampered severely by expensive replacement costs for both the main PV system at 25 years, and inverters at 15, 30 and 45 years. At the end of the 50 year project, scenario 2 is cheaper by £5,944,559, with the project paying back after 41.52 years by this measure.

4.2.2 Renewable Fraction & CO_2 Emissions

With the installed PV system, Cumnock now has a renewable fraction of 13.5% considering the both gas and electricity. This figure increases greatly when focussing only on the electrical system, rising to 50.7%. This reduced level of grid imports had a corresponding effect on the CO_2 emissions associated with Cumnock, with this figure at 13,482,187 kg per year. This represents an annual saving of 558,069 kg of CO_2, or almost 30 million kg over the project lifetime.

4.2.3 Grid Interaction

The installation of solar panels in Cumnock has a dual effect on the grid relationship, reducing grid imports and allowing energy to be exported to the grid for financial gain, with both actions reducing the associated energy charge. The relationship between grid imports, grid sales and cost is shown below in figure 15.

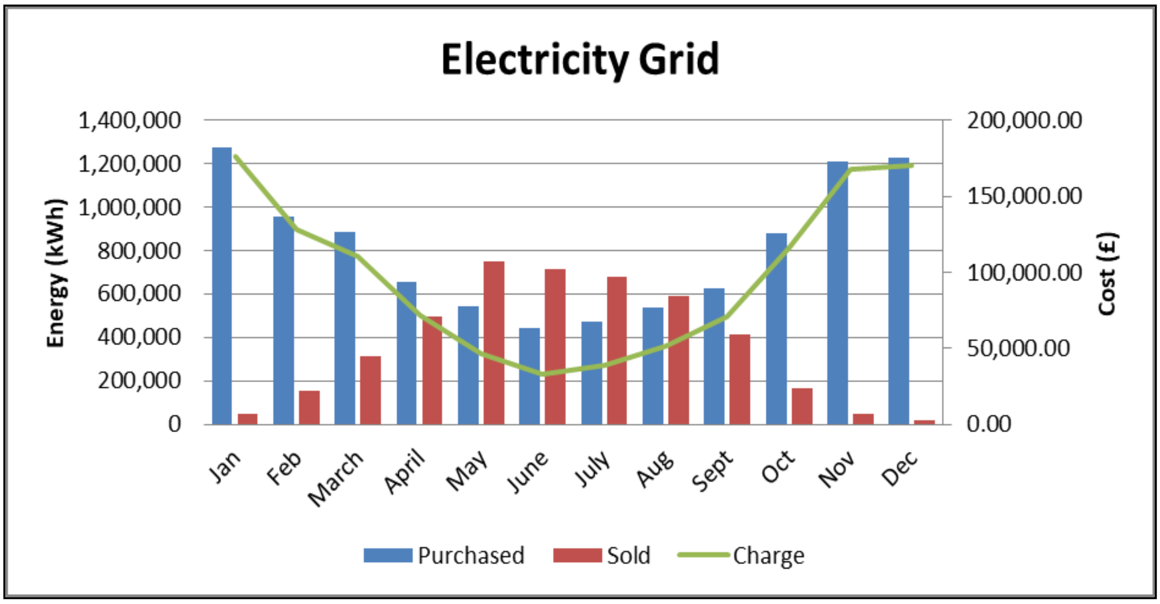

Figure 15: Grid interactions in scenario 2

As is to be expected, the effect of solar panels is greatest during summer months, where generation is much higher than in the winter. Across the year, however, grid imports are substantially lower, with each month seeing a reduction of between 163,753 kWh (December) and 710,800 kWh (May), with an annual reduction of 5,580,688 kWh. This reduction in imports, plus 4,380,334 kWh of sales to the grid (amounting to £175,213) reduce the annual electricity charge by £954,836. This highlights the relatively low value of sales to the grid, which is due to the low export tariff under the SEG.

The grid interactions can also be viewed at a much smaller scale, shown below in figure 16 for a summer week. Here, the effect of the PV system can be seeing, effectively reducing grid purchases to zero for five days out of seven. Cloudy days can be seen to dampen the effect of the PV system on June 25th and June 26th, with these days experiencing around a quarter of the peak generation seen in other, clearer days of the week. The high degree of grid sales can also be seen at higher detail, with total renewable output far outstripping demand (AC Primary Load) for five of the seven days selected. There is a reasonably good agreement between the morning rise in demand and the onset of the days generation, with less harmony between supply and demand in the evening, with demand peaking as daylight begins to fade. The interactions shown in figure 17 for a winter week highlight the seasonal difference in performance. Low generation across the week means that demand is served almost entirely by grid purchases, with small reductions in day time imports over four of the days covered. On Dec 21st and 26th, generation exceeds demand for a small portion of the day, with a low level of grid exports occurring. However, this is on a much smaller scale than summer, with peak generation less than half of that experienced in June.

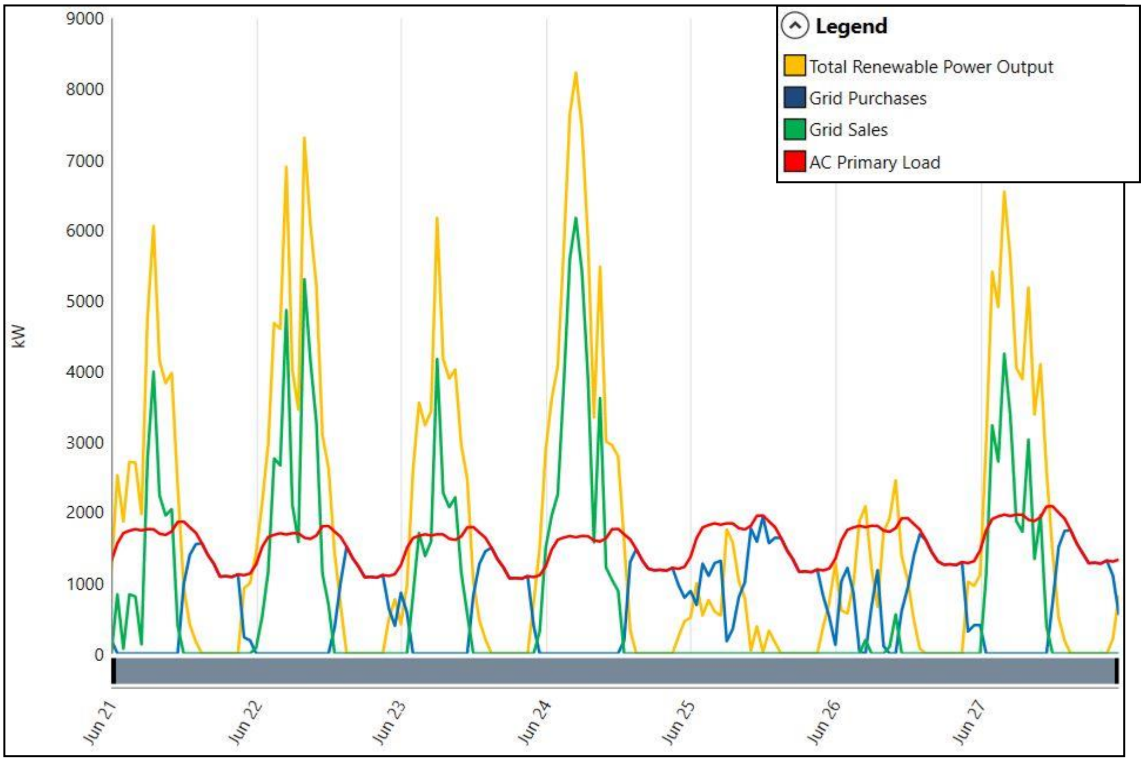

Figure 16: Grid interactions from June 21st to June 27th

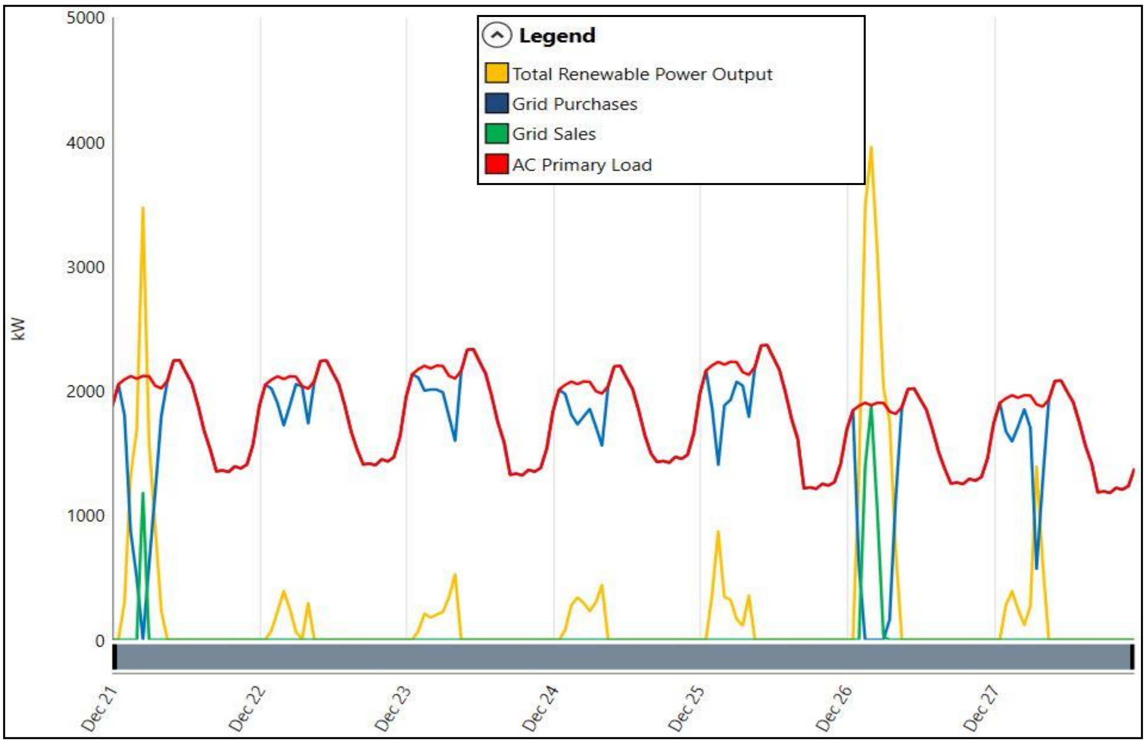

Figure 17: Grid interactions from December 21st to December 27th

Additionally, when considering figure 17, it is important to note that on both clear and cloudy days, peak generation occurs for a short while in the middle of daylight hours. This is a poor match to the hours of peak demand, especially with regard to the evening peak, with this occurring after hours of daylight. This poor match is particularly shown on December 27th, where peak generation occurs during the lowest daytime demand.

4.3 Scenario 3: Baseline + Extensive Solar Panels

In this scenario, solar panels have been installed in Cumnock with the aim of increasing the renewable fraction as much as possible, but still without including roof area of flats. To this end, panels have been installed on all available roof area rather than always selecting for the most southerly facing slope, effectively doubling the installed capacity of PV. This results in a total of 24,904 kWp installed in Cumnock, split in Homer into 8 arrays of 3,113 kWp for each point of the compass. Results from this scenario will shed light on the impact and effectiveness of further installation from scenario 2, with comparisons between scenario 2 and 3 forming an important part of the overall analysis.

4.3.1 Financial Performance

Table 5 below highlights some key financial results of scenario 3. This scenario is defined by very high up-front costs and slightly lower operating costs, with a per-household annual saving of around £119.

Table 5: Main financial results from scenario 3

NPC	LCOE	Operating Cost (a+b+c)	Initial Capital	Annual Electricity Charge (a)	Annual Gas Charge (b)	Operation & Maintenance (c)
£118.69 m	12.7p/kWh	£3.693 m/year	£37.6 m	£764,420	£2,063,020	£311,300

The cost of energy in scenario 3 can be seen to fall significantly in comparison to baseline, with a small increase in comparison to scenario 2. The NPC in scenario 3 shows a very steep rise, increasing by £19.91 million from scenario 2, and £27.28 million above the baseline value. Operating costs have reduced by £505,000 in comparison to baseline, with a £20,000 increase from scenario 2, with the drop in annual electricity charge being offset by an increase in maintenance costs. Figure 18 breaks down the NPC below; showing PV costs as the largest contributor to the projects overall costs, with grid costs now only 14% of the total. It is important to remember however, that these represent proportions of a larger total, and do not show absolute values.

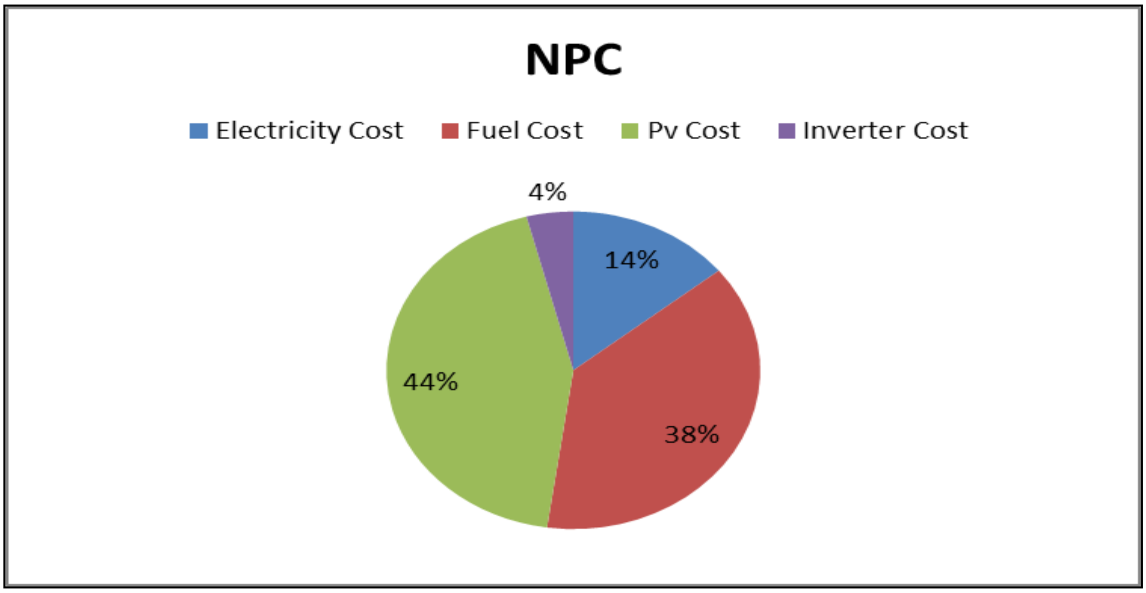

Figure 18: Breakdown of NPC in scenario 3

The cash flow comparison between scenario 3 and baseline is shown below, and it can be seen that this scenario does not pay back during the 50 year lifetime of the project.

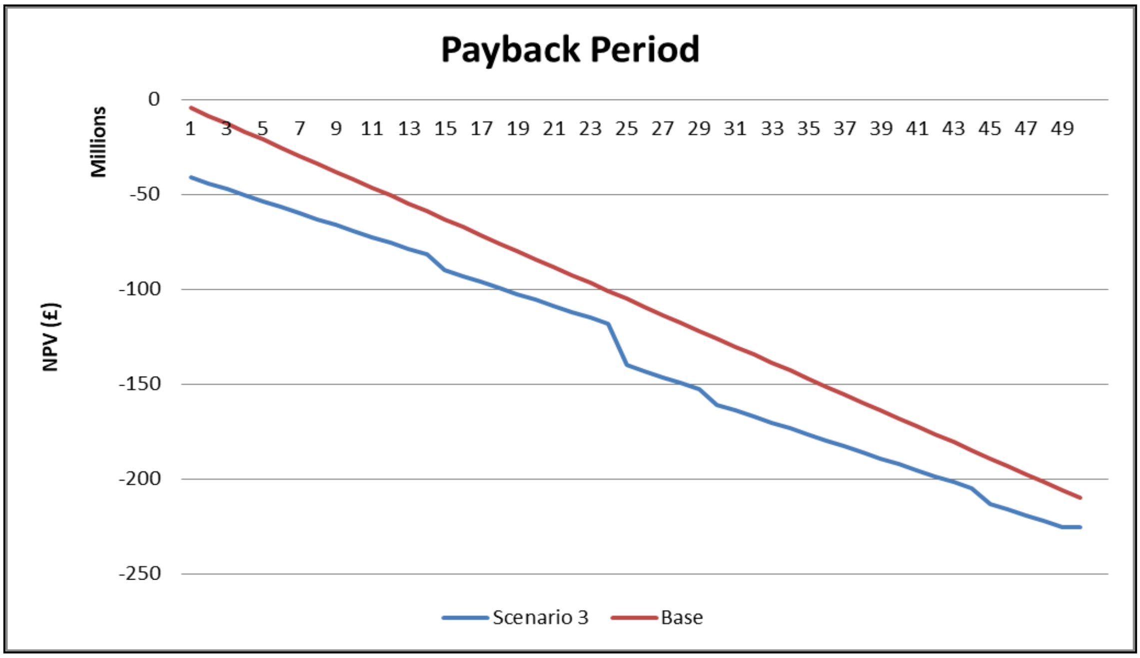

Figure 19: Nominal cash flows of scenario 3 against baseline

From figure 19, scenario 3 is shown failing to approach payback at any point during the 50 year period, coming closest in the final year at which point salvage value associated with the systems inverters helps close the gap to £15,316,993. While the operating cost of scenario 3 is lower than baseline, the high cost of first installing, then replacing the towns PV system means that scenario 3 is of a consistently lower value than baseline.

4.3.2 Renewable Fraction and CO_2 Emissions

With the higher rate of installations in scenario 3, the renewable fraction of Cumnock's energy system has risen to 22% of the total supply. When considering only the electrical system, this figure rises to 67%. CO_2 emissions are also seen to fall to 13,381,322 kg/year, representing a further annual saving of 100,865 kg to scenario 2, and a total annual saving of 658,943 kg from baseline. Considering the large increase in investment costs and renewable fraction from scenarios 2 to 3, this CO_2 saving could be considered quite marginal. It also suggests that while renewable fraction has increased substantially, there has been a less substantial decrease in grid imports, with grid exports making up a large portion of the increase in renewable fraction.

4.3.3 Grid Interaction

As was suggested by the results in *4.3.2*, the defining feature of the grid interactions from scenario 3 was a steep increase in the level of grid exports. These interactions are shown below in figure 20.

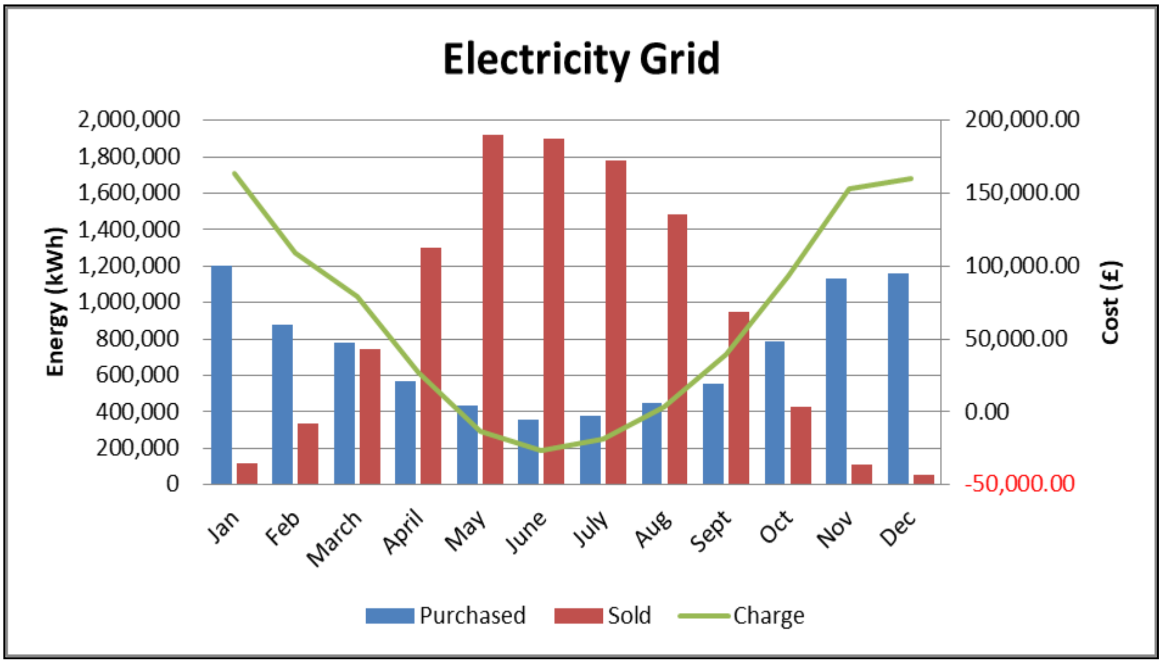

Figure 20: Grid interactions in scenario 3

Grid sales, which already exceeded grid purchases over May, June, July and August in scenario 2 have grown across every month of the year, but have increased the most over the summer months. As a result, supply now exceeds demand for 6 months of the year and in general, the effect is lopsided between summer and winter, with the increased capacity having a much smaller impact on the energy system during winter months. Considering the year as a whole, grid imports stand at 8,693,190 kWh, which is a saving of 6,589,340 kWh from baseline, and a saving of 1,008,652 from scenario 2. Exports now exceed imports across the year, with a total of 11,125,449 kWh being sold to the grid and so much being sold during May, June and July that an overall profit of £58,832 is made over these months. However, the uneven impact means there is a relatively small reduction in imports during the winter, where the majority of the year's demand occurs. As a result, the annual charge of £769,420.71 can be seen as a relatively modest reduction from scenarios 1 and 2, given the level of grid exports.

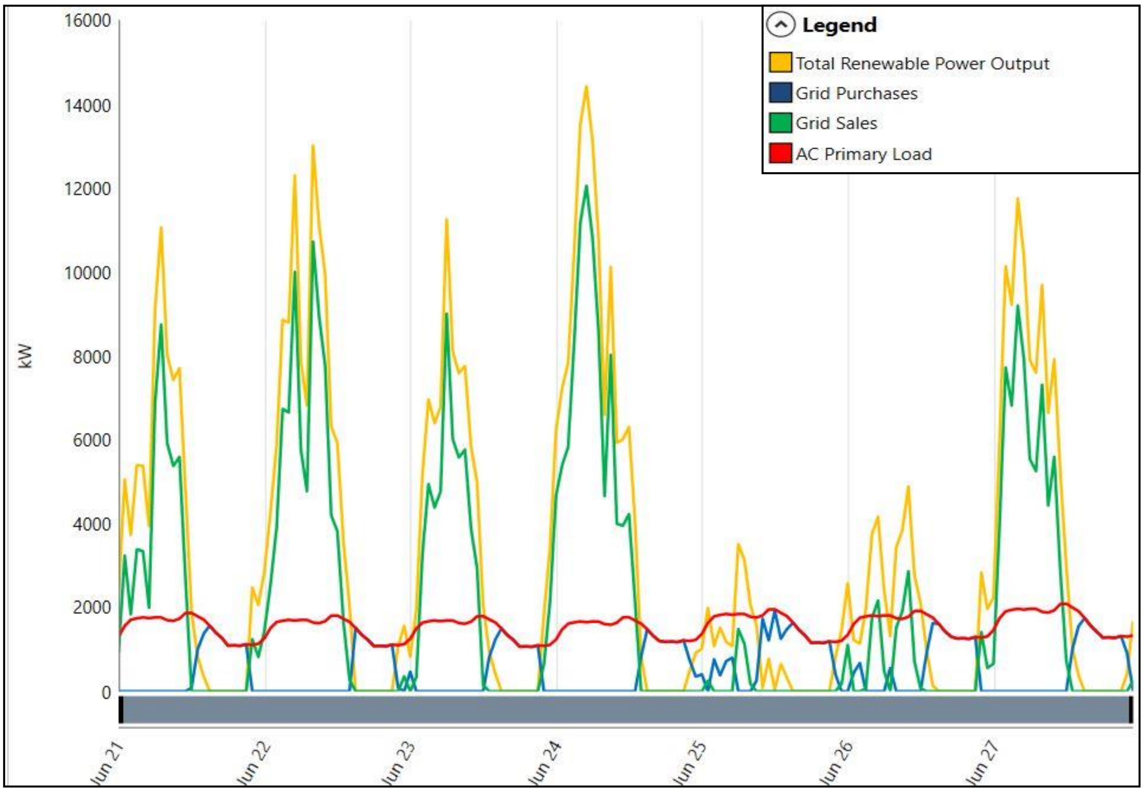

Figure 21: Grid interactions from June 21st to June 27th

Shown in figure 21 in closer detail, the effect of the larger PV system in scenario 3 can clearly be seen. Peak daytime generation of around 5 times the electrical demand results in astronomical daytime grid exports on the four clear days in the week surveyed, with grid purchases only necessary for a few hours during night time hours on these days. A broad base to the shape of the clear day generation graph covers both morning and evening peaks of demand, with generation rising far ahead of the morning peak, and falling immediately after the evening peak. On the two cloudier days (25th and 26th), the size of the system means that generation still manages to eclipse demand for a few hours, with grid purchases significantly reduced from baseline levels. The effect of intermittent cloud is apparent, causing spikes in generation, purchases and sales.

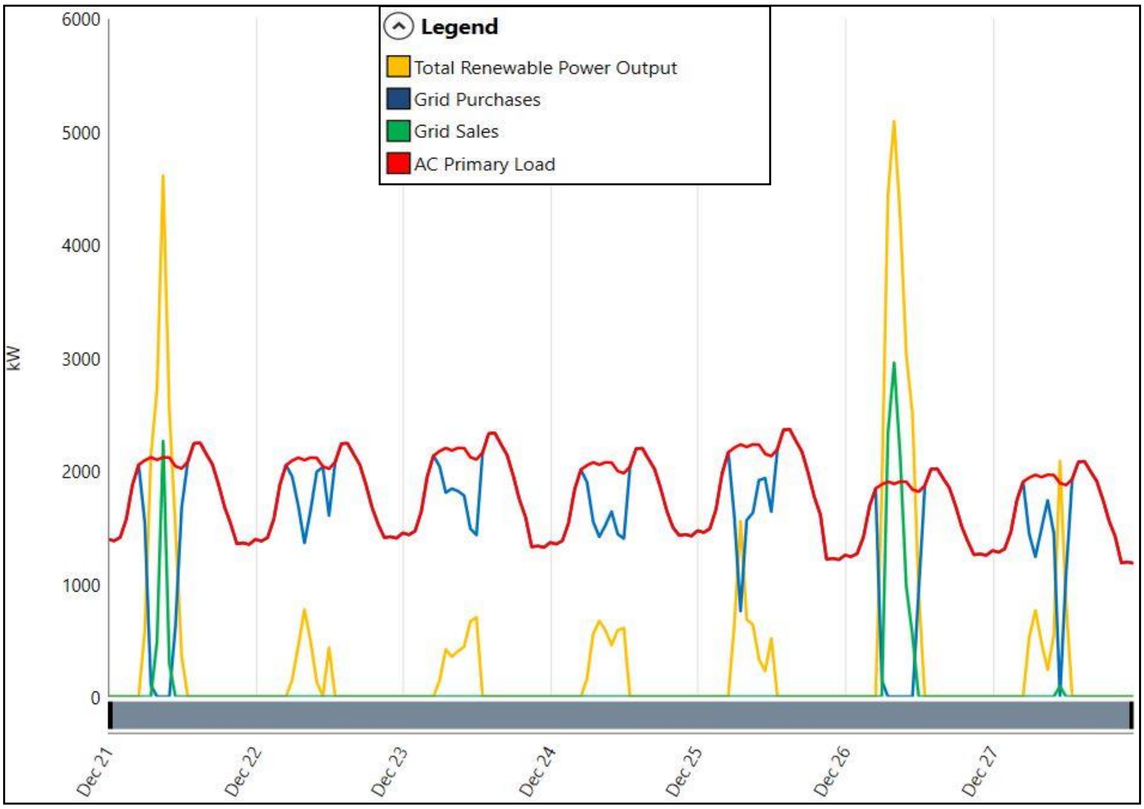

Figure 22: Grid interactions from December 21st to December 27th

In figure 22 above, the uneven impact between summer and winter is highlighted further, with this effect especially pronounced in scenario 3. In this winter week, despite the high capacity system, the lower solar resource during winter means that generation level does not approach demand on four of the seven days, although there is a greater PV contribution throughout the week than scenario 2 or 4. On the clearer days on the 21st and 26th, higher generation can occur, with this peaking at around 1000 kW higher than the same week in scenario 2. A similar problem exists however with the timing of peak evening demand and generation, as the higher capacity is of no use when daylight begins to fade.

4.4 Scenario 4: Future Demand Profile + Realistic Solar Panels

This scenario includes an estimated demand profile for the year 2045 (the mid-point of the project) by using trends in population and modelling the effect of a partially electrified heating system. Solar panels have been installed in the same way as scenario 2, and these results hope to inform how the performance of the PV system in scenario 2 might fare under slightly different demand conditions.

4.4.1 Financial Performance

Table 6 shows a selection of key financial performance. Scenario 4 is characterised by a lower annual gas charge, low operating cost and relatively low NPC, with a per-household annual saving of £163.

Table 6: Main financial results from scenario 4

NPC	**LCOE**	**Operating Cost (a+b+c)**	**Initial Capital**	**Annual Electricity Charge (a)**	**Annual Gas Charge (b)**	**Annual Operation & Maintenance (c)**
£95.193 m	12.76p/kWh	£3.508 m/year	£18.8m	£1,434,026.96	£1,644,225.96	£155,650

The significant drop in annual gas charge is considered to be the main factor behind the low operating cost in scenario 4. The shifting of heating load to electrical demand has seen the associated annual charge increase with respect to scenarios 2 and 3, with the levelised cost of electricity showing another large reduction from baseline. The NPC, which is broken down in figure 23, shows that the cost is split almost equally between grid, boiler and PV. NPC itself shows the smallest increase from baseline of all the scenarios modelled, with these financial results indicating that the financial performance of the Cumnock PV system may improve over time as energy demand evolves.

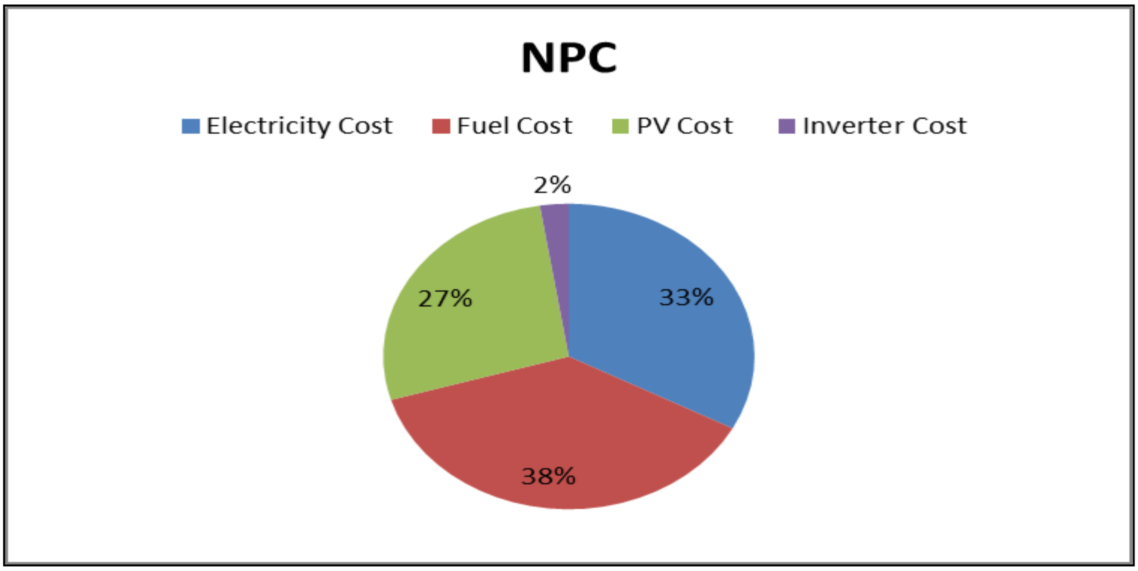

Figure 23: Breakdown of NPC in scenario 4

This improved financial performance is shown again in figure 24, which demonstrates how the nominal cash flows differ in scenario 4 between its respective base case and with installed PV. Payback time in scenario 4 is 39.6 years, with a saving of £7,858,808 by the end of the 50 year project. Payback is very nearly achieved much earlier, in year 24, however replacement costs associated with the PV system mean this milestone is delayed.

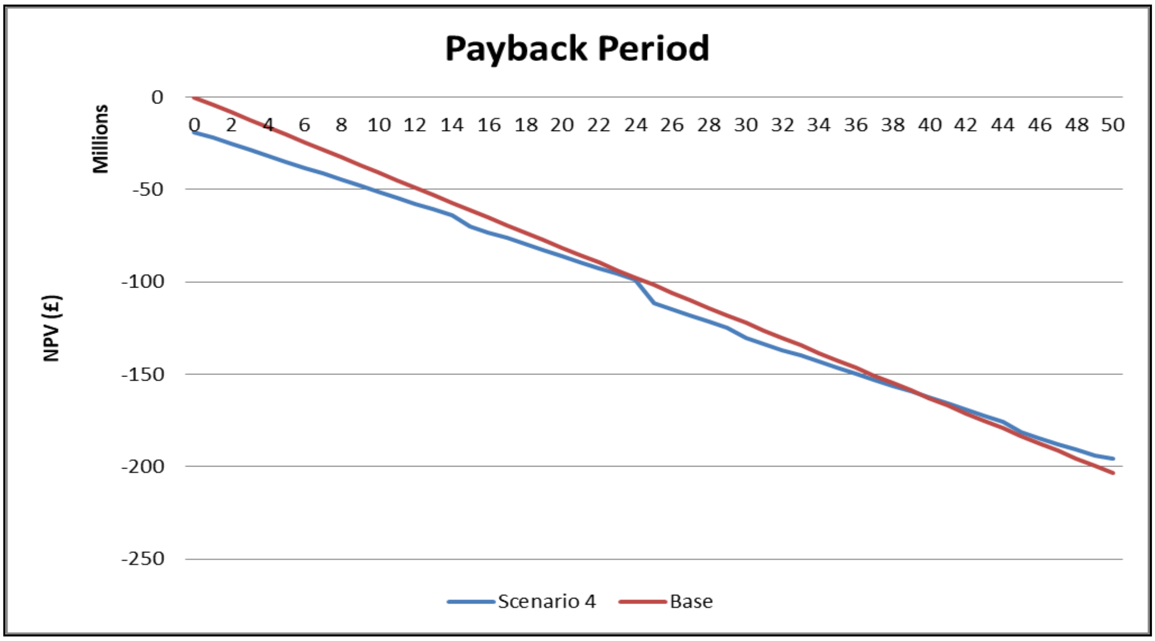

Figure 24: Nominal cash flows in scenario 4 against baseline

4.4.2 Renewable Fraction and CO_2 Emissions

The renewable fraction in scenario 4 is 15.4%, which is 1.9% higher than in scenario 2, despite having an identical PV system. This increase is due to the reduction in gas demand, and if the scenario is considered purely on its electrical system, the fraction is in fact lower than in scenario 2, at 46.6%. This respective drop can be attributed to higher grid purchases in order to meet the increased electrical demand. Despite these higher grid purchases, CO_2 emissions in scenario 4 stand at 11,112,990 kg/year, with the effect of a lower gas demand outweighing that of increased grid purchasing.

4.4.3 Grid interactions

In scenario 4, electrical demand is higher than in baseline, with winter months seeing a larger rise is demand as there is a greater need for newly electrified heat. Annual grid purchases stand at 11,309,307 kWh, which is higher than scenarios 2 and 3, whilst still representing a decrease with respect to baseline. Total annual sales stand at 3,996,332 kWh, which is the lowest of the scenarios incorporating PV, as the increased electrical demand means there are fewer instances of energy surplus. As a result, there is a higher proportion of the electricity being generated by PV being used on site in Cumnock.

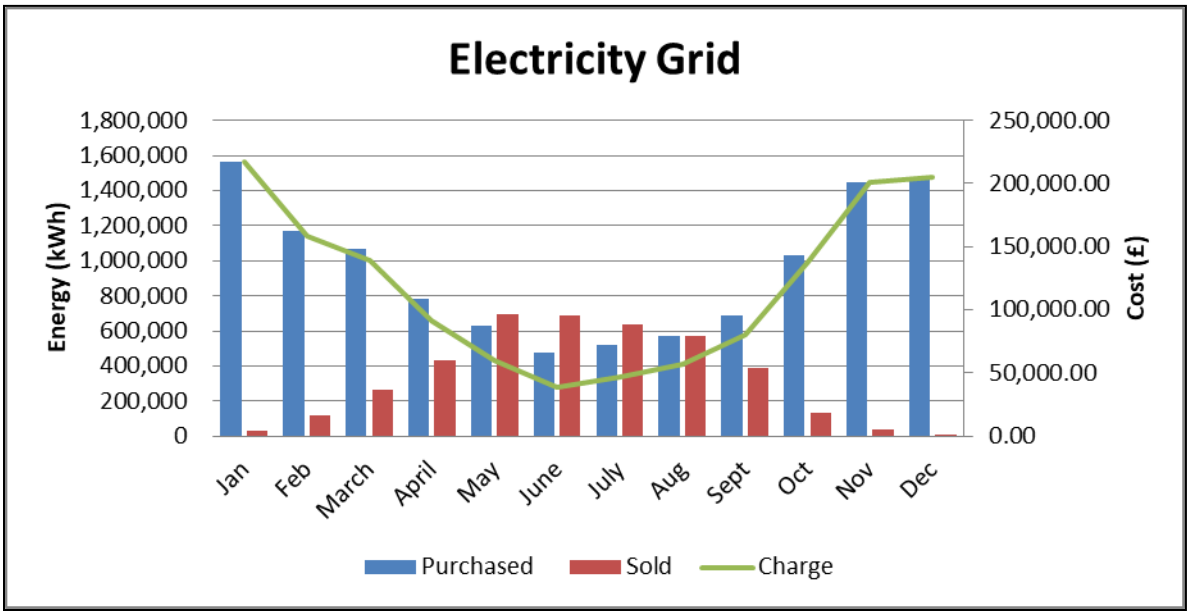

Figure 25: Grid interactions in scenario 4

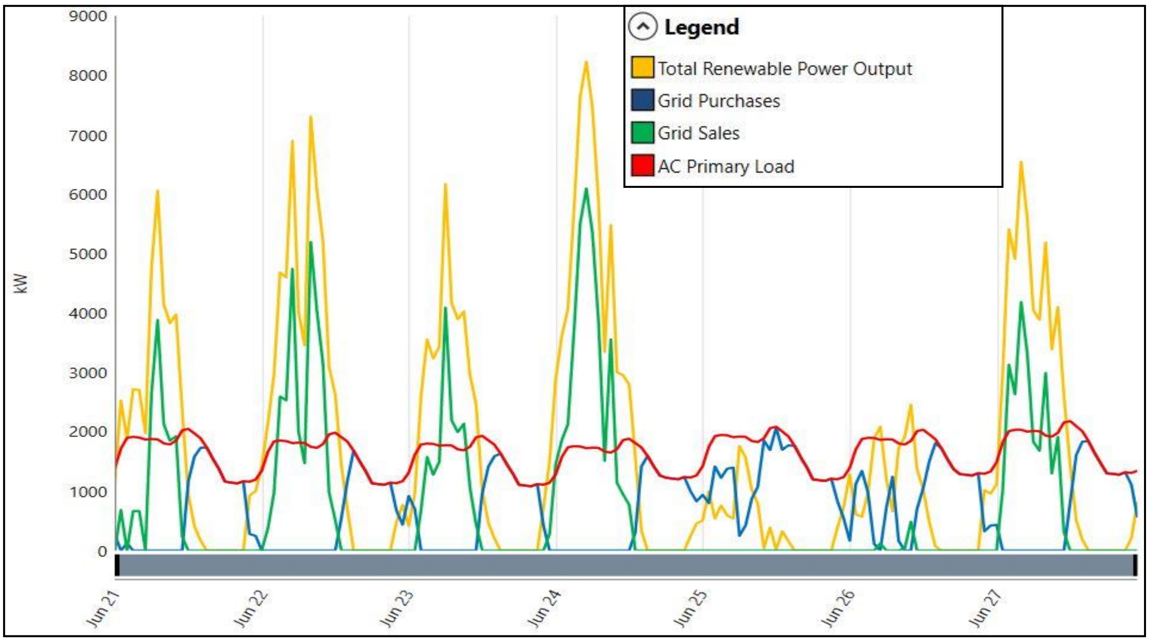

Figure 26: Grid interactions from June 21st to June 27th

Seen in figure 26 at a higher resolution, summer grid interactions in scenario 4 can be seen to show relatively little deviation from that in scenario 2. While some heating demand has been electrified, the very low summer heat demand means that the subsequent increase in electrical demand is almost imperceptible. As a result, a similar pattern is followed, with the contribution from the PV system exceeding demand for the majority of daylight hours during clear days, meaning that grid purchases remain at zero during these hours with a large volume of grid sales. During these clear daylight hours, morning generation begins to ramp up in broad agreement with an increase in demand, however the evening peak of demand occurs as generation is beginning to fall, with grid purchases rising to make up this gap in supply.

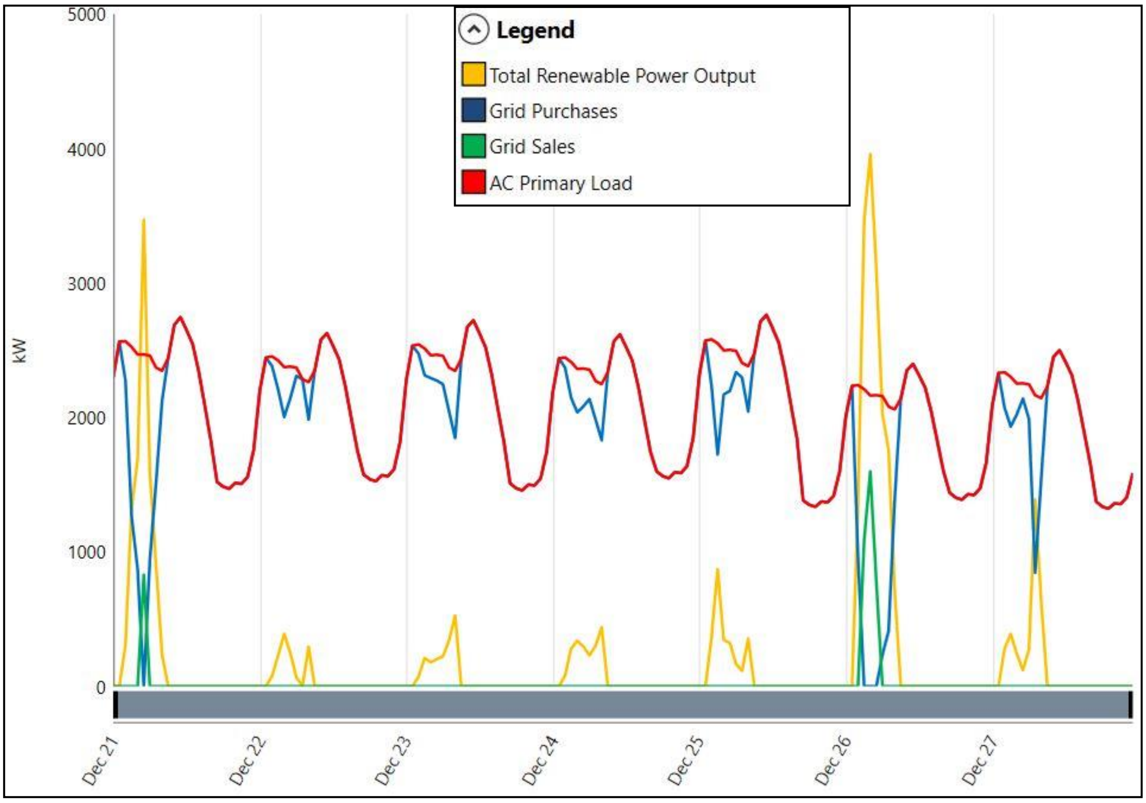

Figure 27: Grid interactions from December 21st to December 27th

In the winter week shown in figure 27, the effect of electrified heat is more noticeable. Daytime demand is higher than in earlier scenarios and as such, there is a larger gap between generation and demand during cloudy days. On sunny days (21st and 26th), while generation is able to rise, higher demand means lower grid exports, with exports on the 21st especially small. As has been the case with every scenario, this again demonstrates a poor agreement between peak evening demand and peak generation during winter months.

4.5 Results Analysis and Discussion

In this section, the main results from each scenario will be compared and the factors behind them discussed. Most attention will be paid to the key result categories of financial results, renewable fraction/CO_2 emissions and the grid interactions of the system. Attempt will also be made to evaluate any likely impact from these results to the population of Cumnock.

4.5.1 Financial Results

While the financial results varied greatly between scenarios, there were some consistent characteristics between them. NPC was seen to increase from baseline in each scenario, with large lifetime PV costs (including capital investment, maintenance and replacement) outweighing a drop in operating costs, which was also seen across the board. This is shown in figure 28, with operating cost and the main components of NPC highlighted for the four scenarios. The highest NPC by some distance is in scenario 3, with very large lifetime PV costs outweighing electricity savings made by the oversized PV system; this is also reflected by a small rise in operating costs when compared to its near identical neighbour, scenario 2. This can be thought of as a less efficient installation of PV, with further investment from scenario 2 not translating to further benefits. This can also be demonstrated by the average capacity factor of the sub-arrays in both scenarios, with scenario 2 panels having an average of 9.6%, whilst scenario 4 panels sit at 8.5%.

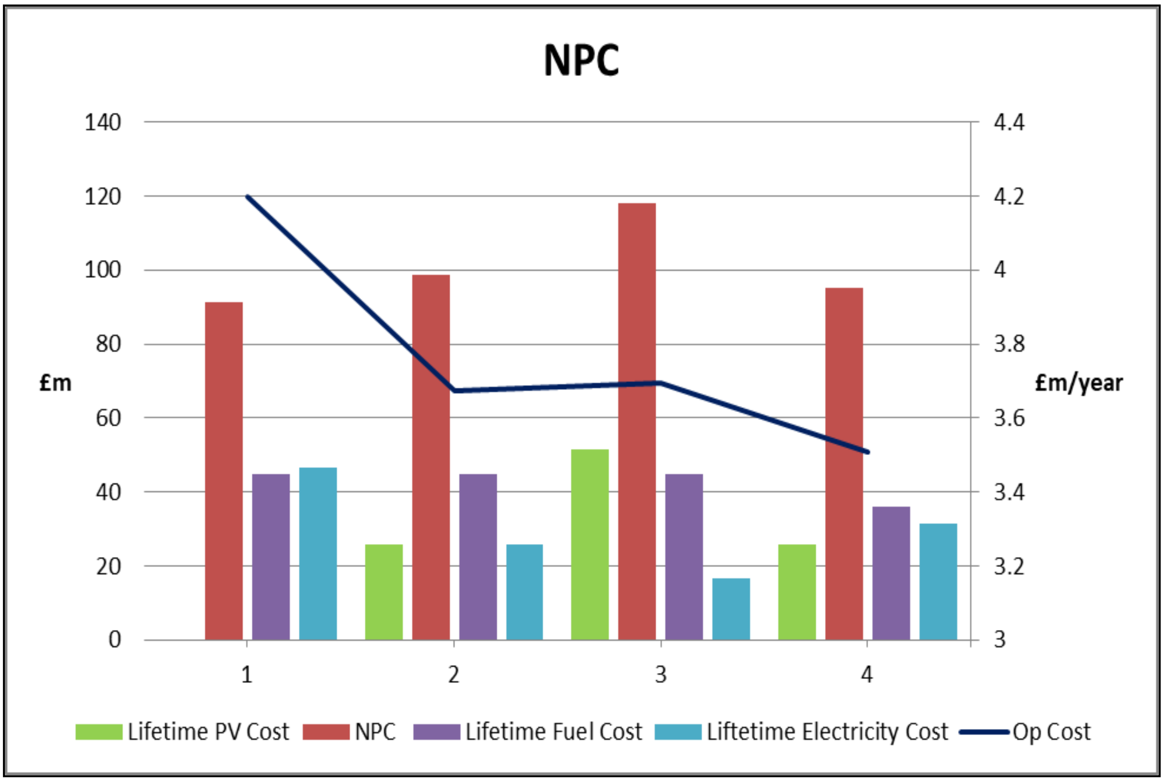

Figure 28: Comparing the main components of NPC between scenarios

Also visible on figure 28, is the effect of the *future demand* between scenarios 2 and 4, with parameters for these scenarios are identical in every sense other than demand profile. The impact of a proportionally more electrified and slightly smaller demand has been a significant reduction in lifetime fuel costs, and a smaller increase in lifetime electrical costs, with this reducing the operational costs and leading to a small reduction in NPC.

Lower operating costs, and correspondingly higher annual savings compared to baseline, also mean that scenario 4 experiences the shortest payback rate, with 39 years compared to 41 years in scenario 2, whilst scenario 3 does not payback. This payback period is much longer than examples found in the literature, even for rooftop PV in Scotland, which has previously been estimated at 9-13 years (Gooding et al 2013). This, at first appearance, seems peculiar, given that larger systems are generally expected to payback faster than smaller ones. However, it is likely due to the effect of the SEG, which offers a lower financial incentive for export than previous policies, with no incentive for generation. This demonstrates that, even with a community scale system, payback times for rooftop PV under the SEG are likely to be very long. These results are in broad agreement with the literature, with a similar study finding payback periods under a fixed SEG of 46.85 years (Cui et al 2020), with a variable tariff shortening this to 26.3 years in that particular study.

Some consistency can also be found in the LCOE results, with this falling from baseline in each scenario from between 1.39 and 1.21p/kWh. It could be assumed that the pattern of this reduction might follow NPC, with high or low expenses reflected throughout the scenario results; however this is not the case, as shown in figure 29.

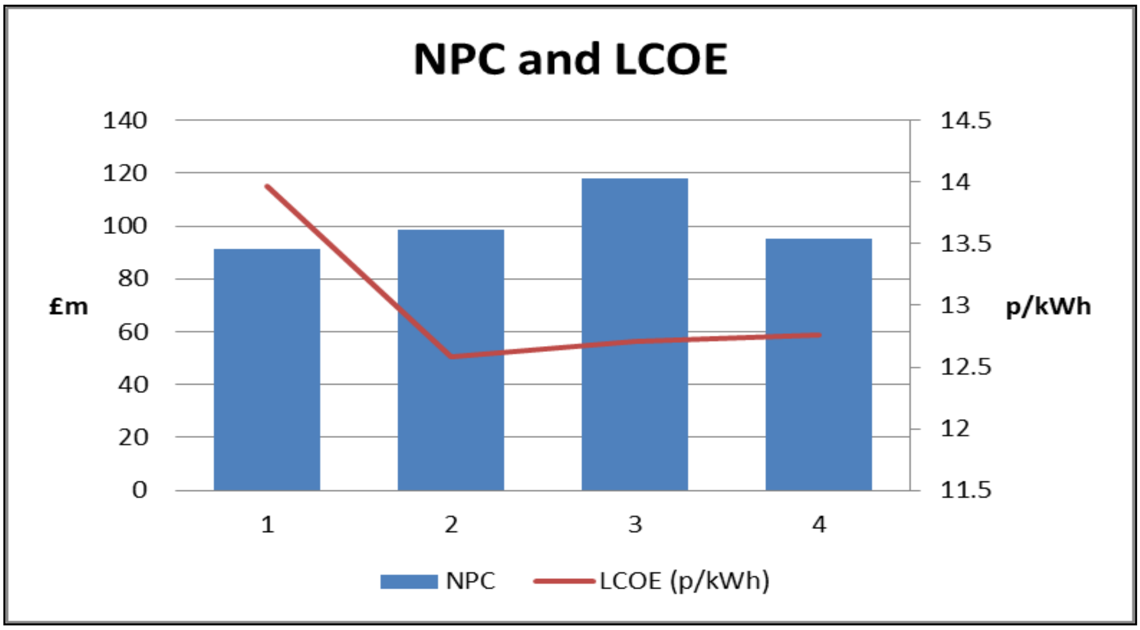

Figure 29: Showing the discontinuity between NPC and LCOE

The reason for this is the way in which Homer derives the LCOE. The formula used in Homer for calculating LCOE is shown below, with a number of different factors behind the final value.

$$COE = \frac{C_{ann,tot} - c_{boiler} H_{served}}{E_{served}}$$	**Equation 1: LCOE in Homer**

Where

- COE is the cost of energy
- $C_{ann,tot}$ is the total annualised cost of the system
- C_{boiler} is the marginal boiler cost, which is identical for each scenario
- H_{served} is the thermal load served by natural gas
- E_{served} is the electrical load served, including exports any thermal electrical load

The cost of the system still has a considerable influence on the LCOE, but along with the annualised costs, the thermal gas load and the electrical load also have a significant input. These individual components are shown in figure 30 for each scenario, including baseline (1) for reference.

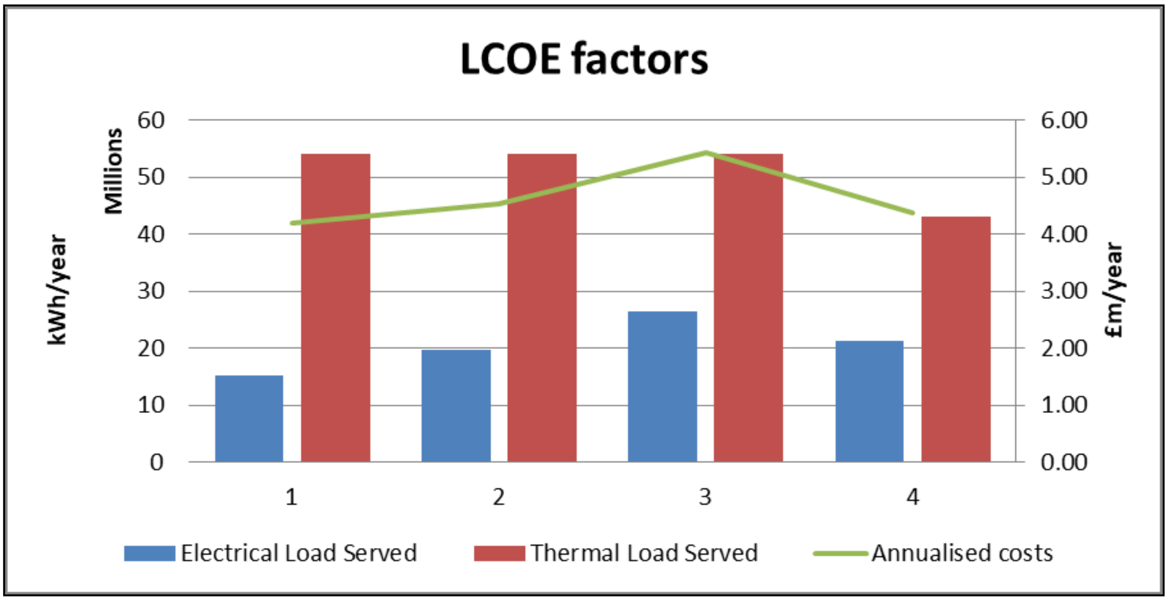

Figure 30: Showing the determinant factors behind LCOE for each scenario

Scenario 2 has the lowest LCOE at 12.58p/kWh, with the increased electrical load being a large driver of this. The *electrical load served* in figure 23 includes grid exports, and as such, modelled scenarios all have a higher value for this result, allowing LCOE to reduce across the board. This same effect is the main reason scenario 3 has a relatively low LCOE (12.71 p/kWh) despite having annualised costs far higher than any other scenario. With a very high annual electrical load, driven by extremely high grid exports, the impact of high annualised cost is reduced and LCOE remains low. In scenario 4, annualised costs can be seen to come down as the heating system partially electrifies, but this is not reflected in the LCOE which stands at 12.76p/kWh, the highest of the modelled scenarios. In fact, the reason LCOE is not lower in scenario 4 is also linked to this difference in demand, with a lower thermal gas load meaning that the numerator (see Equation 1) is higher than in scenario 2 despite lower annualised costs. By this measure, it appears that as time progresses, the LCOE in Cumnock will probably increase marginally, but would likely remain well below baseline.

Broadly, these results indicate that the cost of electricity could be significantly lowered for the inhabitants of Cumnock by installing rooftop PV. This would benefit individual households through a financial saving on their energy bill, with per-household savings of between £119 and £164 a year meaning that residents would be at significantly lower risk of fuel poverty. Local economic benefits would also exist due to the installation of so many rooftop PV systems. While the majority of costs are associated with expensive modules and BOS components; labour and installation make up around 20% of the total expenditure (Priceyourjob 2020). With such high levels of initial capital involved, this would result in a significant cash injection to the local economy over the period of installation. Due to the long payback times shown in these results, it is also likely that the cost of this project would need to be heavily subsidised or entirely funded by the government. Consumers generally place little value in delayed returns, and heavily favour a short payback period (Bergman & Eyre 2011) (Rai & Sigrin 2013) and as such, would be unlikely to have the desire to participate in this project using their own funds. In terms of feasibility, it can be concluded that scenario 3 is not cost-effective.

4.5.2 Renewable Fraction and CO_2 Emissions

As well as financial incentives, the environmental drivers to PV microgeneration are some of the most commonly mentioned by consumers (Sherriff 2014). In the literature, it was estimated that microgeneration could meet between 30-40% of UK electrical demand (Watson et al 2008) and in this sense; Cumnock's PV system has performed above expectations. The renewable fraction of each modelled scenario is shown for both the entire system and electrical system only in figure 31.

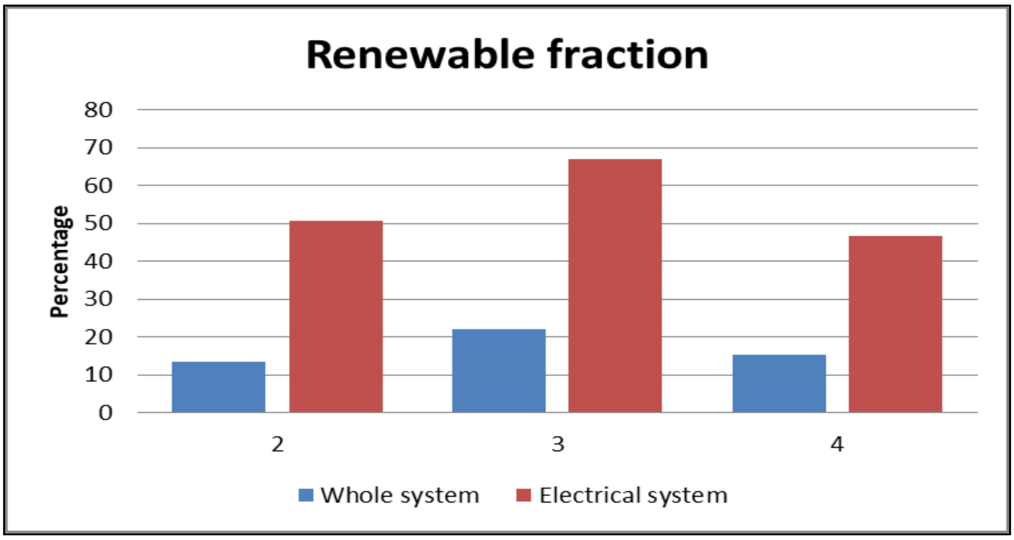

Figure 31: Comparing renewable fraction between modelled scenarios

Considering figure 31 at face value, it appears that scenario 3 has the most desirable results, with relatively little to split scenarios 2 and 4. Across the board, the renewable fraction within the electrical system is significantly higher than the 30-40% ballpark in the literature. However, a high renewable fraction in Homer does not necessarily reflective of useful power generated, as grid exports make up a significant portion of this measure. This can skew the results to disproportionately favour over-sized system which can export a great deal, but without effectively serving Cumnock's needs. This effect is shown below in figure 32.

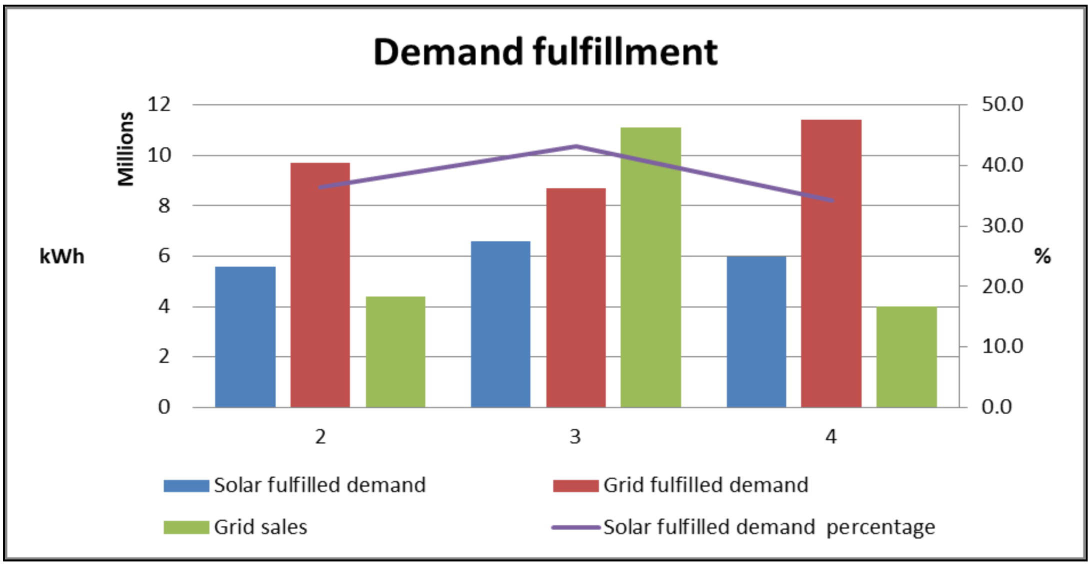

Figure 32: A more accurate view on renewable fraction

Considering figure 31 and 32 together, the skewing effect of grid exports on renewable fraction can be clearly seen. A more accurate measure of the local renewable fraction, which does not take into account grid sales, is shown as *Solar fulfilled demand percentage* on figure

32. By this measure, results from the three modelled scenarios can be seen to be in better agreement with the literature. While scenario 3 still has the highest renewable fraction, it is only a marginal improvement on 2 and 4, demonstrating again that the additional financial outlay in scenario 3 would not be considered worthwhile.

The CO_2 emissions are seen to decrease with each subsequent scenario modelled (figure 33), with scenario 4 showing the largest departure from baseline, saving 2,927,266 kg annually. This increased saving in scenario 4 can be attributed to its lower gas demand and a subsequent drop in emissions from gas fired boilers. While there is a visible drop in emissions from baseline in both scenarios 2 and 3 (558,069 & 658,934 kg respectively), these are fairly marginal reductions considering the level of investment and the renewable fraction.

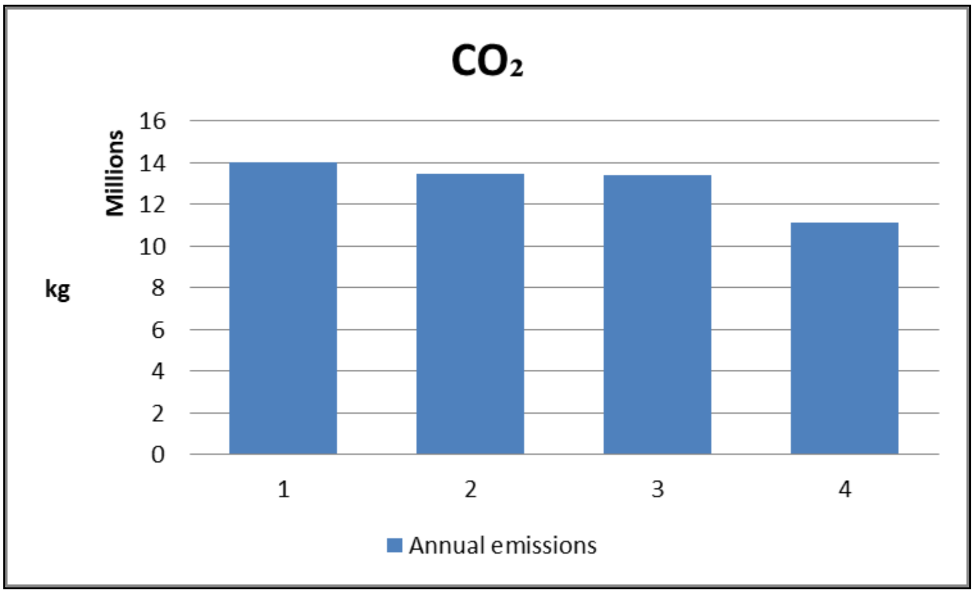

Figure 33: Annual CO_2 emissions in Cumnock

The reason behind these marginal savings is the low carbon intensity of Scotland's electricity grid. While the grid CO_2 intensity for Cumnock is set at 100g/kWh, the UK average is significantly higher, with 2019's average recorded at 241 g/kWh (Electricity info 2020). This is due to a much lower proportion of gas powered generation in southern Scotland, with gas contributing around 25% of the grid's electricity in comparison to 61% across the UK (Electricity info 2020). Renewable energy makes up much of this gap in supply, meaning that only a small CO_2 saving is made by using local microgeneration. This indicates that while CO_2 savings are often a prominent part of the environmental drivers toward PV microgeneration, they should perhaps not be considered as such in Scotland.

4.5.3 Grid Interactions

The grid interactions of each modelled scenario heavily influence the results produced in this study, with the level of grid imports and exports especially affecting financial results. As solar energy is a highly seasonal resource in Scotland, the grid interactions of each scenario also show a high degree of seasonal variation, shown in figure 34 below.

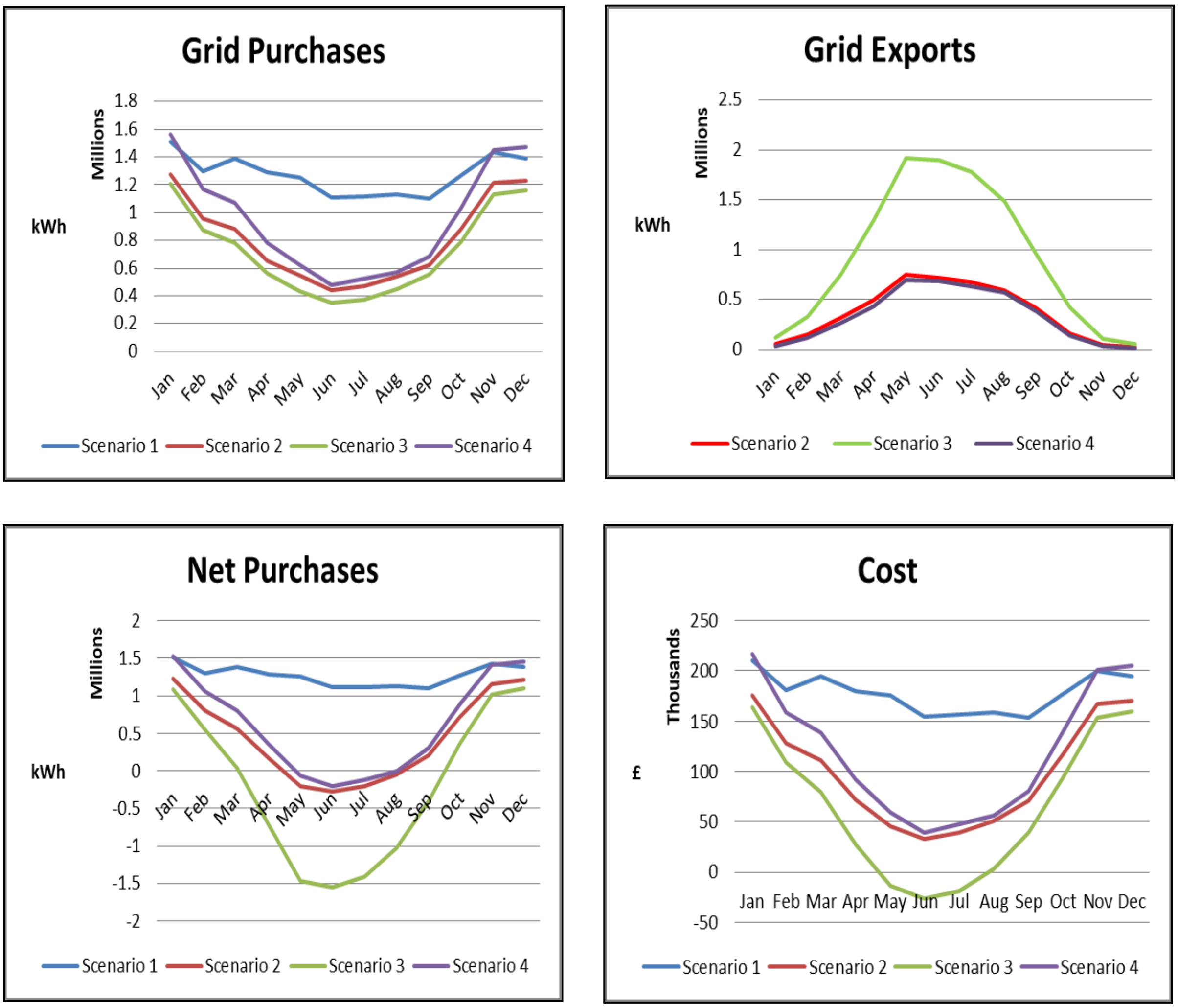

Figure 34: Clockwise from top left, comparing: Grid purchases, grid exports, net purchases and associated costs across a calendar year between scenarios

Further similarities exist between the modelled scenarios in the sense that grid purchases have decreased; there is a significant degree of grid exports, and a corresponding cost saving which is seen to varying extents.

The effect of the PV system is, by all measurements, more pronounced during the summer months, with this behaviour even more apparent in scenario 3. The higher capacity of scenario 3 means that summer exports climb to more than double those achieved in either scenario 2 or 4 whilst grid purchases also fall to their lowest level, albeit by a much smaller margin. Correspondingly, the energy cost falls through the summer months and even turns negative in scenario 3 due to the level of exports, while other scenarios see a similar but lesser effect. The contrasting behaviour of summer grid purchases and exports in scenario 3 further highlight how poorly sized this system is for serving the needs of Cumnock, with a doubling of capacity doing very little to lessen the dependence on the electricity grid. Comparing the purchases and exports graphs also serves to demonstrate a problem with using PV for this kind of domestic generation in Scotland. That is, that peak seasonal demand and generation are directly opposite within the calendar year. This is less of a drawback in summer, where excess generation is easily exported, but during winter means that despite large and expensive PV systems, in all scenarios Cumnock remains heavily dependent on the electricity grid. This effect is most pronounced in scenario 4 where, due to a partially electrified heating system, grid purchases, net purchases and cost are all seen to rise above baseline in January and November. The steeply sloped shape of scenario 4, which comes as a result of an electric heating demand, could indicate that PV may become even less effective during winter months as electric heat becomes more commonplace. Conversely however, lower exports in scenario 4 could also be taken to indicate that PV may become more applicable with an electrified heating budget, with fewer exports reflecting a more efficient local use of the generated power.

Analysing at a higher detail (figures 16, 17, 21, 22, 26, 27) further highlights the seasonal imbalance in PV performance, with poorer weather and shorter days limiting winter generation in all scenarios. This lessens the effect of higher capacity in scenario 3, although generation still peaks above that of scenario 2 or 4. On clear days, winter generation in all scenarios is able to climb above demand during the middle of the day; however this timing of peak generation is also universally problematic. In winter, shorter days mean that PV makes no contribution to peak evening demand, whereas in summer, generation is falling as demand peaks, meaning that grid purchases are necessary to satisfy demand. The exception to this is scenario 3, where higher capacity is able to satisfy most of the evening peak.

More broadly, these results suggest that by installing rooftop PV, Cumnock's grid imports and reliance on the electricity grid could be reduced, especially in summer; and that the need to accommodate high grid exports would accompany this benefit. A lower level of reliance on the national grid would be beneficial due to the "price-fixing" effect of partial grid independence. That is, that Cumnock would be less affected by rises in electricity costs due to high level of self-generated power, particularly over the summer months. This is of particular benefit to Cumnock and similar small, semi-rural towns as inhabitants here are considered to be more vulnerable to energy price increases (Roberts et al 2015). This protection against price increases would subsequently offer the most vulnerable inhabitants of Cumnock some protection against fuel poverty.

The level of exports could potentially be reduced by a further electrified heating system, thereby finding ways to use power locally; however this would exacerbate the seasonal mis-match of generation and demand which is already experienced. Alternatively, energy storage could be used to reduce grid exports, with this also having the potential to reduce grid reliance to an even lower level. Finding local uses for power, be it through electrified heating demand or storage, would be a primary obstacle for Cumnock regarding it's grid interactions. If local uses are not found, significant upgrades to the grid would need to be made, as has been done in Niederstetten (Hennig 2017) to avoid damage due to excessive exports into the low voltage network. Considering the daily interactions, results suggest that energy storage would be extremely beneficial to Cumnock in reducing grid purchases, especially during the summer. This would allow excess summer daytime generation, which is high in all scenarios, to serve the evening demand peak, which occurs as daylight and generation begins to fall. Depending on the size of the ESS, stored electricity could also be used to power night time demand in Cumnock, further reducing grid dependence. By minimising Cumnock's dependence on grid imports in this way, it is likely that many of the financial benefits described in this thesis would be enhanced, although this would require further analysis to fully determine.

5 FINAL REMARKS

5.1 Conclusion

The aim of this project was to provide perspectives to the town of Cumnock with regard to the applicability of wide-spread rooftop PV microgeneration. As a result of the data and analysis reported in this dissertation, the following central perspectives can be given:

- Installing rooftop PV in Cumnock will likely reduce grid dependence, LCOE and the annual energy bill to households in Cumnock, with a per-household saving of between £119 and £163 annually
- Payback times are expected to very long, with scenarios 2 and 4 around the 40 year mark, while scenario 3 does not payback.
- The match between supply and demand is expected to improve in the future as demand evolves.
- CO_2 emissions vary marginally between scenarios and should not be considered as an important driver to PV microgeneration in Scotland
- High summer exports are ubiquitous and require an adequate solution, be it local use or storage, or an upgraded local electricity grid to accommodate them.
- Excessive installation (as in scenario 3) is not cost effective and should be avoided

Considering these perspectives, it can be concluded that installing rooftop PV would provide a way for Cumnock and similar environments to become more independent of the electricity grid, increasing power security and reducing vulnerability to fuel poverty as a result of energy price rises. Costs are high, and while this means that payback times are long, it would also result in a significant boost to the local economy due to the level of installation work. Results also show that performance will likely improve as time progresses, specifically with regard to efficient local use of generated power. A considerable upgrade is also likely to be necessary for the local electricity grid to be able to accommodate the high summer exports from the system.

With regard to the methodology established in this thesis, certain aspects are stronger than others. There have been a number of simplifications and assumptions which have been necessary due to constraints of time, tools and expertise; and therefore there are definite improvements which could be made in terms of accuracy. However, strength in this methodology exists in terms of its simplicity, as well as its applicability to other towns of similar size to Cumnock. Using this methodology, reasonable estimations can be made on the applicability of widespread rooftop PV installation to a given town.

5.2 Limitations of this study

Due to the way in which the demand model has been determined, there is a limited day to day variation in energy demand profile, with each days profile having the same shape. While this allows analysis at the scales described in this study, a further detailed analysis at a resolution of hours would not be possible. Analysis of this level of detail would give a deeper understanding of the grid interactions and supply/demand balance throughout the course of the day. Limitations are also to be found in the initial rooftop area survey, and this could be made more reliable by physically surveying rooftops in Cumnock rather than using Google Earth Pro. The functionality of Homer was found to be limiting in some aspects of analysis, particularly with regard to energy import and export prices, which remained locked to a single value for the project lifetime. With additional time, a software tool without these limitations could be utilised to produce more robust results.

5.3 Direction for future investigations

Further work on this subject should be directed towards solving the problem of high summer grid exports. A number of possible solutions should be considered, such as an effectively sized storage system or improvement of the local electricity grid. Particularly with regard to energy storage, this would likely allow for further grid independence and should be thoroughly analysed in any further work. In order to clarify and improve on some of the results provided by this study, a more accurate model of demand should also be pursued. Furthermore, the effects of variable energy import and export prices through the lifetime of the project should be considered, which would give a far clearer picture of the long term applicability of PV in this situation.

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