Water Lane Smart Grid and Storage Project Summative Assessment Report

CENTRE FOR ENERGY AND THE ENVIRONMENT

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Cover image: Part of the Water Lane photovoltaic array.

Executive Summary

This summative assessment report examines the outcomes of the Water Lane Smart Grid and Storage ESIF-funded project as at March 2023. It has been prepared by the University of Exeter as an independent assessment of the project. The project comprises over 1.3 MW_p of additional solar photovoltaic generation capacity and 2.5 MW h of lithium ion phosphate battery storage capacity, together with smart grid control systems. The project aims to increase electricity generation from carbon free sources and reduce the peak burden on the national grid. It also provides 24 vehicle charging outlets with smart control systems to support the electrification of the vehicle fleet based at the council's Exton Road depot. Three innovative electric refuse collection vehicles now operate out of the depot; more are expected to follow in 2023.

Electricity is generated from the photovoltaic panels at zero marginal cost, reducing electricity costs, fuel costs for vehicles and generating income from the export of electricity. These cost reductions and income are essential to partially offset the significant cost premium of electrifying the vehicle fleet, as well as the maintenance of the installations. The project adds significantly to photovoltaic generation capacity in Exeter, increasing it by over 8%. The amount of battery storage provision in the city is not known, but it is very likely that provision under the project is the largest in Exeter. Added generation capacity is important given current grid constraints in the south west peninsula. Provision of battery storage greatly increases the flexibility of the electricity output of the project which would otherwise be dictated by local weather conditions. It therefore increases the value of the generation capacity to recharge the vehicle fleet outside of working hours in winter months, and to meet peaks in demand: potentially reducing demands upon short term operating reserve peaking generator plants which have particularly high carbon emissions per unit of electricity supplied.

The additional renewable energy capacity provided meets design targets, and renewable energy generation is also expected to meet targets. Design stage estimates of reductions in greenhouse gas emissions resulting from the project (based on an agreed, fixed, grid carbon intensity and an internal combustion-fuelled vehicle fleet) were also realistic. Nationally, government policy has brought about a relatively rapid decarbonisation of electricity supply that is set to continue, and is set to achieve a switch to zero emission vehicles over the life of the project. An alternative calculation of avoided greenhouse gas emissions against future grid average electricity emission factors and fleet average vehicle emission factors would return lower figures.

Delivery was adversely affected by the Covid-19 pandemic, work required to discharge planning conditions, unforeseen historic land contamination and congestion of existing underground services and issues with the connection agreement with the distribution network operator. The remote location of the selected contractor, coupled with the complexity of the project and the unforeseen challenges listed above made project management particularly challenging and led to delivery timeframes being extended from those originally anticipated. The absence of monitoring data as a result of these delays has impacted the ability to fully evaluate project performance in this summative assessment. Such an evaluation will only be possible after at least one year's data have been collected. Delays also impact upon greenhouse gas reductions if calculated on the basis of declining counterfactual grid electricity and vehicle emissions, as against fixed values for the life of the project. The project experienced a relatively small overspend on its budgeted capital cost, attributable to the reasons described above and additional remote disconnection equipment required under the renegotiated connection agreement.

Key lessons are that ambitious projects offering tangible environmental benefits can be delivered effectively. Careful consideration of the detail of counterfactuals is important when predicting reductions in greenhouse gas emission attributable to a project. Finally, renewable energy installations and battery storage projects have great potential to unlock additional benefits by facilitating early adoption of further low carbon technologies using offset costs and income generated from time-flexible renewable electricity generation capacity.

Contents

Introduction

This summative assessment report examines the outcomes of the Water Lane Smart Grid and Storage ESIF-funded Project as at March 2023. It has been prepared by the University of Exeter under contract from the grant holder (Exeter City Council (ECC)) and forms an independent assessment of the project based on information provided by the grant holder and access to the data collection systems that were operational at the time.

The project comprises the development and implementation of a 1.2 MW_p ground mounted solar photovoltaic (PV) farm co-located with a 2 MW h battery and a smart grid control system at the Water Lane site in Exeter. In addition to the grid connection, an 805 metre ,11 kV private wire connection is provided to the Council's Exton Road operations depot where the installation of 24 vehicle charging outlets with smart control systems supports the electrification of the vehicle fleet. There are thirteen 22 kW outlets for charging cars and light goods vehicles (LGVs) and eleven 400 kW outlets for charging refuse collection vehicles (RCVs).

The scheme also added 324 kW h and 216 kW h battery storage units with smart grid control systems to existing rooftop PV installations at the Exeter Livestock Centre and John Lewis car park respectively. The John Lewis car park site has a 100 m private wire link added to an adjacent car park site. A 120 kW_p rooftop solar PV system and 4.8 kW h of battery storage were added to the Riverside Leisure Centre. The leisure centre works were substituted for battery storage provision at Mary Arches car park owing to uncertainty over the future of that site. All sites are wholly owned by Exeter City Council (ECC), which has procured all works for the schemes.

The project aims to increase electricity generation from carbon free sources and reduce the peak burden on the national grid. Both of these intents contribute to local grid reinforcement in the short term and mitigate the need for additional capacity market generation that relies heavily on carbon intensive sources. The flexible source of electricity generation provided enables ECC to electrify its operational vehicle fleet, replacing diesel fuel used in vehicles and reducing environmental impact well beyond the defined project scope.

Detailed work on project feasibility commenced in spring 2019. Final commissioning of the installations was delayed from 2021 to late 2022, primarily due to the Covid-19 pandemic, work required to discharge planning conditions, unforeseen historic land contamination and congestion of existing underground services and issues with the connection agreement with the distribution network operator (DNO). Consequently, the monitoring data currently available to evaluate the scheme is of short duration. A full technical evaluation will be possible once data have been collected over a full year of operation.

1 Project context

This section considers the project context, objectives and rationale.

The project responds to the Heart of the South West ESIF Strategy Priority Axis 4, "Supporting the shift to a Low Carbon Economy" by procuring renewable generation capacity, battery storage and smart grid infrastructure, and facilitating a transition to battery electric light and heavy vehicles (BEVs) for council operations. 2020 targets set out in the UK Renewable Energy Road Map identify solar PV as a key renewable source of electricity and align with the Climate Change Act of 2008, national carbon emission targets for 2020, 2030 and 2050 and the Council's declared climate emergency and an associated target to be carbon neutral by 2030.

The project responds to the local priority of creating integrated smart grid and battery storage that offers improved capacity and distribution of renewable energy from diversified sources, as stated in the call. The project is innovative in its use of cutting-edge battery storage technology in conjunction with a smart grid control system. This technology has been identified by both the Department for Business, Energy and Industrial Strategy (BEIS) and National Grid as having a key role to play in enabling flexible networks. It also facilitates innovative use of electric 27-tonne RCVs. The pathway to the decarbonisation of heavy goods vehicles is in its infancy and Exeter's electric RCVs are among the first provided in the UK.

1.1 Review of market failures addressed, project rationale and design

Innovative technologies are often expensive due to research and development costs, and carry risks of underperformance and teething problems. Support from grant funding helps to mitigate these costs and risks, fosters technical development of the technologies, and creates opportunities for them to gain market acceptance and become economically competitive. Significant grid constraints remain in the south-west peninsula, hence renewable energy installations with battery storage and smart controls that facilitate maximisation of renewable energy export during demand peaks have an important role to play in the economic delivery of renewable electricity generation.

The rationale for the project remains compelling: the transition to a low carbon economy continues to be an acute and difficult challenge and the battery storage and smart control technologies supported are innovative and do not have a mature commercial market. The project design remains appropriate: spreading the project across four different sites each having different characteristics is advantageous in increasing potential to learn lessons about the effectiveness of the technologies in different contexts. The diversity of sites also mitigates risk to some extent. The characteristics of each site are:

- Water Lane – new ground-based PV array, battery storage and smart control system in close proximity to the Exton Road operations depot. A private wire connection to the depot and the provision of electric vehicle charging infrastructure facilitates vehicle fleet decarbonisation.

- Livestock Centre – battery storage and smart control retrofit to an existing PV array on a site with peaky energy demand (as an event venue the site experiences sporadic and intense patterns of consumption).

- John Lewis Car Park – battery storage and smart control system retrofit to an existing PV array on a site with predictable demand (lighting). There is potential to provide a public electric vehicle charging hub on the site. A private wire connection has been provided to another nearby car park site.

- Riverside Leisure Centre – new rooftop PV array, battery storage and smart control system on a site with significant, largely predictable, time-varying demand.

The project infrastructure has been delivered, albeit on an extended timescale (see Section 3.2) and with some relatively minor changes in response to the uncertain future of one of the sites originally included and requirements of the DNO.

1.2 Review of target indicators

Each of the project indicators has been examined to determine whether it was realistic and remains achievable given any changes in project delivery and wider circumstances.

The key quantitative target indicator outputs for the project (taken from ESIF-Form-2-019: ERDF Outputs) were:

- Additional renewable energy production (3.222 GW h over 10 quarters from 2021 quarter 3 to 2023 quarter 4).

- ER/C/O/34 Estimated annual decrease of greenhouse gas emissions (2.29 t CO_2 reduction over 10 quarters as above).

- ER/C/O/30 Additional capacity of renewable energy production (1.2 MW_p capacity installed).

There are also qualitative targets to facilitate electrification of fleet services and to demonstrate flexible energy system.

Each of these target indicators is considered in turn below. Firstly, the targets as originally set are independently evaluated against the potential of the project in its original form. Secondly the impact of modifications to the project as finally delivered is considered.

1.2.1 Renewable energy production

The renewable energy target indicator stated on ESIF-Form-2-019: ERDF Outputs varies seasonally as would be expected given the characteristics of solar insolation. There is also slight year-on-year variation in the figures stated for each quarter, to account for an initial 2.5% reduction in output compared to their rated capacity due to light-induced panel degradation and a further 0.5% reduction per annum to account for longer term ageing effects. Over the two full years (2022 and 2023) the target averages 1.306 GW h per annum. Figure 1 shows the target alongside the design predictions discussed below.

The full fund application (ESIF-Form-2-010) stated a predicted annual renewable energy output of 1.343 GW h. This figure is for the 1.2 MW_p Water Lane PV array and was produced using PVSyst software. PV arrays at the three other sites included in the bid were existing installations and their output is not included.

The operation and maintenance (O&M) manual for the Water Lane installation includes a report from the PVSyst software stating 1.262 GW h annual output. Before inverter losses, parasitic consumption at night and medium voltage transformer and line losses output is stated to be 1.324 GW h per annum, closer to the value stated in the bid.

The PVSyst model has been reconstructed as part of this summative assessment, predicting an annual output of 1.138 GWh per annum, about 10% lower than the figure reported in the O&M manual and 15% lower than the prediction stated in the bid. Variations between the modelled results could be attributable to slight differences in the many input variables including the meteorological data) and revisions to the software[*]. For comparison, the relatively simple online prediction software PVGIS[1] has been applied to the Water Lane scheme and predicted an annual output of 1.180 GWh per annum, close to the reconstructed PVSyst model.

Whereas the design prediction slightly exceeded the project target, the O&M report figure falls 3.4% short of the target. The models constructed independently show a 9.6% to 12.9% shortfall.

Modification to the project as delivered added a 120 kW_p rooftop PV array at Riverside Leisure Centre. The PVSyst model in the O&M manual for this installation predicts an annual output of 119 MW h per year, a reconstructed PVSyst model predicts 113 MW h per year and a PVGIS model predicts 99 MW h per year. On the basis of the O&M manual predictions the Riverside array more than makes up for the

[*]The software version was 7.2.8 for the O&M model and 7.3.2 for the reconstructed model.

shortfall in meeting the scheme energy production target. The reconstructed models indicate that the additional array will make up about one-half of the predicted shortfall. The size of the array at this site was restricted by the DNO (due to grid constraints and the presence of a combined heat and power plant at the site), and roof loading limitations. The battery was restricted by space constraints.

Differences between the predicted outputs stated above are relatively small given the complexity of PV prediction modelling, and the target appears to be realistic.

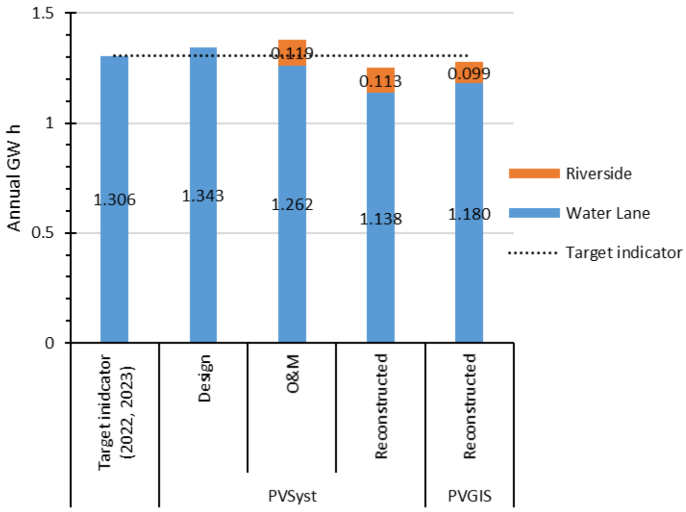

Figure 1. Predicted annual output for the two PV arrays installed under the project.

Due to delays in completing the installations, generation commenced at the Water Lane site in mid-December 2022 (with the private wire connection to the Exton Road depot following in mid-January 2023). There is therefore a large shortfall in generation to date compared to that originally envisaged in the bid (which forecast generation to commence in autumn 2021). This shortfall is expected to be regained over the fixed design life of the installations. The short period of operation to date limits the ability to verify the validity of predicted annual outputs; data collected so far is compared to design predictions in Section 2: Project progress, which considers project outcomes compared to targets.

In summary, the energy production targets were realistic and achievable given the project timescales originally proposed; due to delays in project delivery generation started 15 months later than forecast but the lifetime of the infrastructure and therefore lifetime generation are unaffected.

1.2.2 Additional renewable energy capacity

The 1.2 MW_p additional renewable energy capacity target indicator stated on ESIF-Form-2-019: ERDF Outputs matches the specification of the delivered Water Lane PV array. The target has been surpassed due to the addition of a 120 kW_p array at Riverside Leisure Centre, giving a total delivered capacity of 1.32 MW_p. On the form, 1.2 MW_p capacity has been entered against ten quarters; these values are summed to give a total delivered over the project of 12 MW_p. This is erroneous, the intent of the project as described in the full fund application (ESIF-Form-2-010) was clearly to deliver a single 1.2 MW_p array. To achieve the 12 MW_p total an additional 1.2 MW_p array would have to be installed *each quarter*. Entry of 1.2 MW_p against a single quarter when the array was forecast to be commissioned would have set a target indicator consistent with the full application form. The project inception visit form (ESIF-Form-4-004) correctly states 1.2 MW_p added in total, delivered in a single year.

In summary, the additional renewable energy capacity target as proposed in the full fund application (ESIF-Form-2-010) was realistic and achievable, but was entered incorrectly on ESIF-Form-2-019: ERDF Outputs leading to a total ten times the intended target for the project.

1.2.3 Decrease in greenhouse gas emissions

The CO_2 reduction target indicator stated on ESIF-Form-2-019: ERDF Outputs is 916 kg per annum, apportioned equally to ten quarters (229 kg per quarter). Equal apportionment between quarters is a simplification: the yield of the PV array will be highly seasonal and the battery storage provision is insufficient to provide seasonal storage; it is also affected be degradation over the life of the PV panels.

There is inconsistency between ESIF-Form-2-019: ERDF Outputs and the full fund application (ESIF-Form-2-010). The full application (in Section 6.0) correctly states the annual saving to be 916 t, three orders of magnitude greater than that stated on ESIF-Form-2-019: ERDF Outputs. The full application forecasts generation to commence at the end of quarter 1 2021, not the beginning of quarter 3, increasing CO_2 reduction in 2021 by 46%. The corresponding values on the project inception visit form (ESIF-Form-4-004) (which was signed off in February 2020) match those in ESIF-Form-2-019: ERDF Outputs, with the units correctly stated as tonnes.

The target was set by calculating the CO_2 emissions expected to be avoided by:

1. displacing grid electricity with electricity generated by the PV array: use of PV-generated electricity in place of grid electricity at the Council's Exton Road depot, and PV generation exported to the national grid.

2. Displacement of diesel fuel currently used in short term operating reserve peaking generator plants in the area with electricity exported to the national grid from the PV array. Peaking plants are used during periods of maximum demand when the grid is unable to provide sufficient electricity. Usage of these plants could be reduced due to the local grid reinforcement provided by the PV array, battery storage facility and smart control system.

3. Displacement of diesel fuel currently used in council vehicles (RCVs and LGVs) with electricity generated by the PV array. Fleet electrification is facilitated by the PV generation and charging infrastructure provided by the project.

Examination of the calculations confirms that the stated greenhouse gas reductions follow from the assumptions stated in the application. Some of the assumptions are open to question or are based on information that is now outdated; the impact of revising these assumptions is discussed below and revised greenhouse gas reductions are shown in Figure 2.

- Electricity consumed by electric vehicles was estimated assuming a diesel vehicle efficiency (fuel to drivetrain) of 30% (which is reasonable), but the calculation made no allowance for fuel to drivetrain inefficiencies in electric vehicles. There will be inefficiencies both in an electric vehicle's motor and in the battery charge and discharge cycle. Although these inefficiencies are far smaller for electric vehicles, ideally they should still have been taken into account. Assuming 90% fuel to drivetrain efficiency for an electric vehicle[*] would reduce the overall decrease in greenhouse gas emissions by about 3% to 888 t per annum. This confirms that the impact of this omission is insignificant.

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[*] Ballpark efficiencies are 90% for an electric motor and 90% for the battery charge/discharge cycle; gains from regenerative braking partially compensate for these inefficiencies.

- Complete electrification of the vehicle fleet was assumed to occur at commencement of PV output. In reality vehicles are being replaced gradually when contracts are renewed; three electric RCVs were introduced in August 2022 out of a fleet of 15. At about the time the original bid was submitted, ECC changed from an owned vehicle fleet to leasing vehicles on contract, and hence has less control over vehicle replacement. The availability of new vehicles has been impacted by the Covid-19 pandemic, other supply chain constraints, and the slow pace of development of electric vehicles (in particular larger LGVs and heavy goods vehicles (HGVs) where commercialisation is in its infancy and the technology is not well-established). Two-thirds of the overall decrease in greenhouse gas emissions was attributed to electrification of vehicles, due to the poor fuel to drivetrain efficiency of diesel vehicles resulting in a low overall efficiency and high greenhouse gas emissions per unit energy usefully delivered. The delayed introduction of electric vehicles significantly reduces the overall decrease in greenhouse gas emissions in early years of the scheme's operation: more PV-generated electricity will be fed into the national grid, with reduced carbon savings compared to displacement of diesel fuel for vehicles.

  In extremis, if no vehicles were electrified the overall decrease in greenhouse gas emissions would be reduced by 38% to 570 t per annum. However, delays to the introduction of electric vehicles are expected to be temporary so the impact will be lessened. Under the lease arrangement vehicles are replaced at end-of-life, and are replaced with electric vehicles (subject to availability). On a positive note the RCVs delivered have so far proved to be reliable and effective. Three further new electric RCVs are expected to enter the fleet during 2023 to replace existing diesel vehicles, increasing the proportion of electric RCVs to 40% of the fleet.

  Avoided diesel fuel costs and the availability of electricity generated at very low marginal cost help offset the cost premium of leasing electric vehicles, as discussed in Section 4.2, and are essential to the case for fleet electrification.

- The 52 t additional annual emissions from the purchase of grid electricity stated in the full fund application (ESIF-Form-2-010) is not clearly explained. On examination of the underlying calculations it compensates for double-counting of CO_2 reductions from (a) grid exports and (b) a reduction in diesel generator usage. Inclusion of this value therefore results in a correct calculation of the overall decrease in greenhouse gas emissions.

- The grid electricity and diesel emission factors are carbon dioxide-equivalent (CO_2e) factors (accounting for small contributions from methane and nitrous oxide emissions). These factors are slightly higher than CO_2 factors. The effect on the calculated results is not significant; the vast majority of emissions from diesel combustion and electricity generation occur directly as CO_2. Whether the target indicator pertains to CO_2 or CO_2e is ambiguous, stating "decrease of greenhouse gases" (implying CO_2e), but with the units stated as CO_2, not CO_2e.

- Calculations apply CO_2e emission factors (from DEFRA UK Government GHG Conversion Factors for Company Reporting[2]) dating from the 2017 release (electricity) and 2018 release (diesel). These factors were the agreed basis for the greenhouse gas emission reduction targets set in the bid.

  Rapid decarbonisation of national electricity supply during the period from 2012 to 2020 means that the current grid electricity emission factor is much lower than that used in the calculation. The value reported in the 2022 release is 193.38 g/kW h, 45% lower than the 351.56 g/kW h from which savings were calculated. In contrast the diesel emission factor has reduced by less than 3% over the same period. Recalculating the overall decrease in greenhouse gas emissions using the updated emission factors would reduce the value by 11% to 816 t per annum.

Emission factors for electricity supply are published by BEIS for future years for use in forecasting[3]; associated guidance dictates the use of long run marginal emission factors when assessing the carbon impact of small changes in demand due to a scheme. The pertinent factor for 2023 is 243.96 g/kW h, closer to the 2022 company reporting emission factor than the value used in the bid calculations. Recalculating the overall decrease in greenhouse gas emissions using this emission factor would reduce the value by 8% to 840 t per annum.

Significant decarbonisation of grid electricity could have been anticipated during the period of project delivery (and to continue over the lifetime of the asset, as discussed later in Section 4), and do have a moderate impact on calculated greenhouse gas reductions. There is, however, considerable uncertainty over the sources that will be displaced by the new generating capacity, and therefore any calculation of greenhouse gas reduction will be an approximation.

- Conversion of diesel vehicle fuel from volumetric units to energy used a value of 10.9 kW h per litre[*]. The DEFRA UK Government GHG Conversion Factors for Company Reporting data indicates a figure of 10.6 kW h per litre. Revised calculations using updated emission factors have included this revised value for energy density. The impact on the results of the calculations is not significant.

- The combined impact of the points noted above has the potential to further reduce the overall decrease in greenhouse gas emissions, e.g. a slow introduction of electric vehicles in conjunction with a reduced grid electricity emission factor.

The effect of applying these updated assumptions to the greenhouse gas reduction calculation are shown in Figure 2.

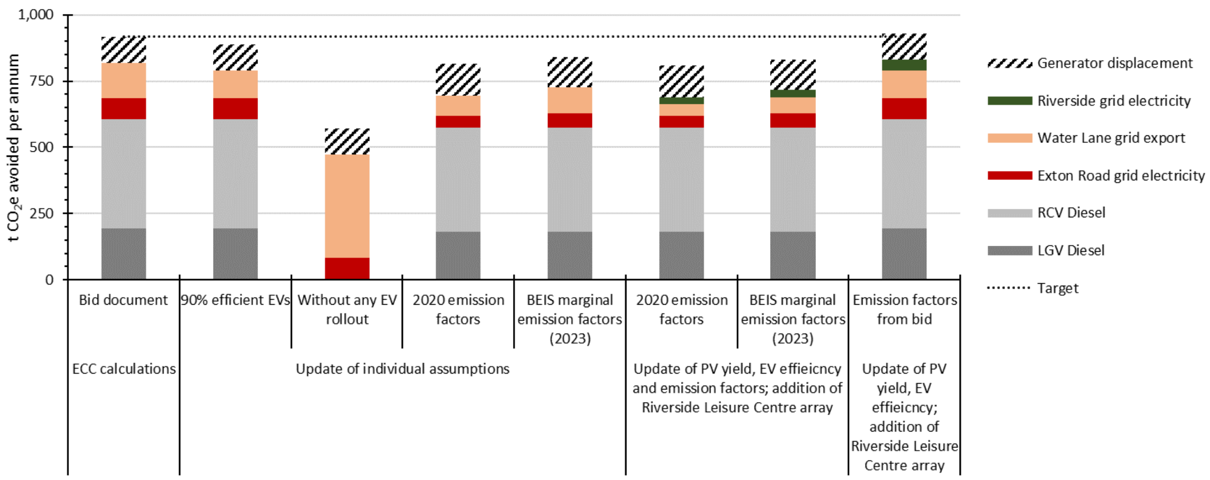

Figure 2. Comparison of calculated greenhouse gas reductions discussed in the text.

The project as delivered includes 120 kW_p rooftop PV array at Riverside Leisure Centre which was not foreseen in the bid calculations. This will lead to a further decrease in greenhouse gas emissions due to the displacement of grid electricity used in the leisure centre, and export of surplus generation (over and above the battery storage capacity) to the grid. The additional greenhouse gas reduction is 42 t per annum (using the grid emission factor from the funding bid), 29 t per annum (using the BEIS marginal grid emission factor) or 23 t per annum (using the updated 2020 emission factor). This has been included in the last three columns of Figure 2, which combine the revised assumptions discussed above.

[*] On a gross calorific value basis, which is consistent with the emission factors used.

In summary, the CO_2 reduction target set is consistent with project impacts, given the grid electricity and vehicle fuel emission factors used for the calculations. The grid electricity emission factor has fallen significantly in recent years (between bid submission and project delivery) and alternative calculations based on updated factors would return lower greenhouse gas emission reductions. It is acknowledged that modelling future scenarios can be difficult in an area where national targets and policy are developing rapidly.

1.2.4 Facilitation of electrification of fleet services

This unquantified target is intrinsic to the project design and was therefore realistic and achievable. It is achieved through:

- provision of physical vehicle charging infrastructure;
- provision of electricity generation infrastructure that delivers electricity to recharge vehicles at a low marginal fuel cost;
- provision of battery storage capacity and smart charging controls that enables generated electricity to be utilised for vehicle charging during the hours of darkness (required in particular in winter months);
- avoided fuel costs are essential to help offset the considerably higher costs of leasing electric vehicles compared to their internal combustion engined counterparts.

1.2.5 Demonstration of flexible energy system

This unquantified target is intrinsic to the project design and was therefore realistic and achievable. it is achieved through the provision of battery storage and vehicle charging infrastructure with smart controls to facilitate the optimisation of grid export and self-consumption of generated electricity, and vehicle charging times and rates.

1.3 Impact of changes during the course of the project

The context remained largely unchanged as the project progressed: the key drivers all remain valid. Delivery was affected by a number of factors:

1. There was reluctance to invest in infrastructure projects on the Mary Arches car park site due to uncertainty over its future. The Riverside Leisure Centre site was substituted. This had a positive impact on the project, adding greater diversity of site types and characteristics of the installations, and increasing the scope for lessons to be learned.

2. The Covid-19 pandemic severely impacted project delivery on the planned timescale. The construction phase was originally programmed to take place (as stated in the original bid) from August 2020 to mid-2021. During this period significant restrictions were in place affecting site work and the availability of materials.

3. Other factors impacting on project delivery included delays obtaining work required to discharge planning conditions, unforeseen historic land contamination and congestion of existing underground services and issues with the connection agreement with the DNO. These are discussed in detail in Section 3.2.

Although these factors have delayed delivery of the infrastructure funded by the project, they have not compromised the outcomes over the life of the assets.

The greenhouse gas emissions target (discussed in Section 1.2.3) is based on a dated grid average emissions factor. Use of a more recent factor would reduce the calculated decrease in greenhouse gas emissions owing to grid decarbonisation in the years from project inception to project delivery. Use of a grid average factor is itself an approximation, since the sources that will be displaced by the new generating capacity are unknown.

Greenhouse gas reduction has been calculated with updated inputs and assumptions as follows:

- annual PV array outputs for the Water Lane and Riverside Leisure Centre installations from O&M manuals;
- electric vehicles are 90% efficient from fuel to drivetrain due to motor and charge cycle inefficiencies;
- revised emission factors (CO_2e): either from the company reporting dataset (2022, based on 2020 data), or (for electricity) using the long run marginal electricity emission factor for 2023[3];
- the vehicle fleet is still assumed to be fully electrified on completion of the project infrastructure (some delays are likely but are expected to be temporary).

The results are shown in the sixth and seventh columns on Figure 2.

Using updated emission factors from the company reporting dataset, the resulting overall decrease in greenhouse gas emissions is calculated to be 808 t per annum, 12% below the target. Using the long run marginal electricity emission factor for 2023[3] the resulting overall decrease in greenhouse gas emissions is 830 t per annum, 9% below the target. These alternative calculations are useful in demonstrating the impact of grid decarbonisation in intervening years, which is shown to be relatively modest. However, it is important to note that the target was set and approved on the basis of the higher grid average electricity factor that reflected electricity supply at the time the application was made. The final column combines the impact of updated design predictions of PV yield, 90% EV efficiency and the addition of the Riverside Leisure Centre array with the emission factors used in the bid calculations, resulting in a reduction in greenhouse gas emissions of 930 t per annum, 1.4% above the target.

2 Project progress

The project infrastructure has been delivered, albeit with a delay of 15 months compared to original intentions. This had a major impact on renewable energy production and greenhouse gas emissions abated within the original timeframe of the target indicators (to the end of 2023). However, the delay is expected to only have a minor impact on outcomes over the 25 year life of the installation.

Capital expenditure slightly exceeded forecasts due to supply chain constraints and inflation increasing the cost of equipment, additional equipment required by the DNO when the connection agreement was re-negotiated, and additional unforeseen works required to address contaminated land, congested underground services and to mitigate ecological impacts. Total capital expenditure was £3,629,809, 10.6% over budget. In the absence of further grant funding the overspend was borne by ECC. Revenue expenditure was on target.

The renewable energy production target indicator is expected to be met on an annual basis going forward now that the infrastructure is complete. As discussed in Section 1.2.1 design-stage modelling has been independently verified and the results show reasonably close agreement with the figures in the funding bid and the target indicator. Monitoring of the electrical output of the completed installations is in place, which will allow progress to be compared to the target indicators over the first twelve months of generation, potentially continuing on a long-term basis to maximise lessons learned.

Data for the first two full months of operation of the Water Lane PV array during which the data collection system has been operational (February and March 2023) are now available (Figure 3). For February the system reports 58.3 MW h output for the month, 5.1% higher than the O&M model predicts†. On closer examination data capture was only 77% due to teething problems with the monitoring system; estimating the monthly output from the recorded 5 minute data* results in an estimated monthly output of 56.4 MW h, 1.8% higher than the O&M model predicts†.

For March 2023 the system reports 64.9 MW h of generation and data capture was 85%. Estimating monthly data from the recorded 5-minute data results in a monthly estimate of 71.5 MW h‡. These values are 40.2%b and 34.2% lower than the O&M model predicts for March.

Caution should be exercised when assessing performance over a short timescale due to the influence of weather conditions on solar insolation. Met office sunshine anomaly maps[4] indicate that sunshine hours in February 2023 were within 10% of the long term average (1991 to 2020), and therefore would not be expected to lead to a significant increase or decrease in output compared to design predictions. For March (when generation was well below design predictions), sunshine hours were 50 to 70% lower than the long-term average, explaining the low generation figures.

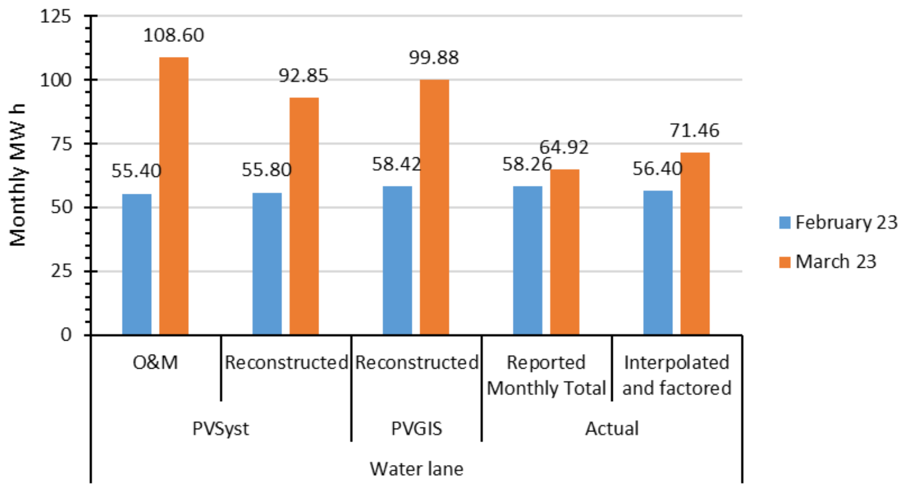

Figure 3. Predicted and measured output from the Water Lane PV array for February and March 2023.

Figure 4 compares actual monthly generation (estimated from available 5-minute data) to the O&M values, and O&M values adjusted to account for the monthly anomaly in sunshine hours. For February (when the anomaly in sunshine hours is small), all three values are similar. For March (when the anomaly is large), actual performance is below the O&M prediction, but above the adjusted O&M prediction. This is not surprising as output is not directly proportional to sunshine hours; reduced (not zero) output is obtained with an overcast sky.

* Total generation in the month has been estimated from the recorded 5 minute interval data (which sum to 43.88 MW h) taking into account both the duration and timing of periods of missing data (e.g. missing data at night are inconsequential since no generation would be expected at that time). The reported monthly figure significantly exceeds the sum of the data, and therefore must be an estimate accounting for missing data.

† A factor contributing to the difference between modelled and actual output is that the models include a small allowance for the degradation of PV panels over their lifetime, hence output when the panels are new would be expected to exceed the lifetime average.

‡ For March the sum of the 5-minute data is 60.7 MW h.

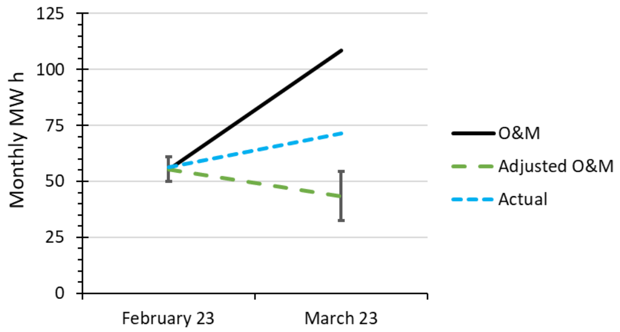

Figure 4. Comparison of actual monthly output, the O&M prediction and an O&M prediction adjusted to account for the anomaly in sunshine hours for the Water Lane PV array for February and March 2023.

This preliminary analysis (in particular for February when hours of sunshine were close to the long-term average) gives confidence that the PV installations are likely to meet or exceed design predictions of output. The additional renewable energy capacity indicator is expected to be met by the two installed PV arrays, the MW_p capacity of which exceeds the target indicator owing to the addition of the Riverside Leisure Centre array.

The annual greenhouse gas reduction target indicator is expected to be exceeded by about 1% (based on the emission factors used in the funding bid), as discussed in detail in Sections 1.2.3 and 1.3.

Performance against the project's target indicators is summarised in Table 1.

Table 1. Spend and output performance.

Indicator	Targets		Performance at Time of Evaluation		Projected Performance at Project Closure		Overall Assessment
	Original	Adjusted (if relevant)	No.	% of Target	No.	% of Target	
Capital Expenditure (£m)	3.283	-	3.630	111%	3.630	111%	
Revenue Expenditure (£m)	0.272	-	0.272	100%	0.272	100%	
Additional annual renewable energy production (kW h)	1,305,760[*]	-	69,420[†]	5%	1,381,000[‡]	106%	
C30 Additional capacity of renewable energy production (MW_p)	1.20	-	1.32	110%	1.32	110%	
C34 Estimated annual decrease of GHG (kg CO_2e)	916,000	-	-[§]	-	929,905[**]	101%	

Data is, or will soon be, collected by the following systems allowing a fuller evaluation of project performance once data have been collected over a full year of operation:

[*] Average over the two full years 2022 and 2023 (inclusion of part year 2021 quarters 3 and 4 would reduce the figure due to a lower than average yield in quarter 4).
[†] Recorded data for first month of operation of Water Lane site, adjusted to account for 84% data capture.
[‡] Detailed design predictions as included in O&M manuals. Monitoring data for February 2022 for the Water Lane site exceeds its design prediction by 25% giving confidence that the prediction will be met. Data are not yet available for the Riverside site.
[§] Insufficient data available to estimate as data monitoring of electric vehicle chargers is still being commissioned.
[**] Independently modelled revised estimate based on the emission factors in the approved funding bid, EV efficiency reduced from 100% to 90%, and PV yields from detailed design predictions as included in O&M manuals (including the additional Riverside Leisure Centre array (see Section 1.3).

- PV array output – SMA Sunny Portal operational since late January 2023 (Water Lane); expected April 2023 (Riverside Leisure Centre);
- Water Lane, John Lewis car park and Exeter Livestock Centre battery performance – WattStor Portal operational since mid-January (Livestock Centre), early February (Water Lane), being commissioned (John Lewis car park);
- EDF half hour consumption data – available for all sites;
- Kempower vehicle charger control and monitoring system – awaiting web access;
- Dennis Eagle portal for RCV performance – awaiting web access.

3 Project delivery and management

This section discusses the effectiveness of project delivery and management, highlighting lessons learned from the procurement and management of contractors.

3.1 Project management and governance

All procurement followed the terms and conditions set out in the grant agreement, with processes applied to comply with Public Procurement Law and the Treaty Principles and National Rules. To ensure compliance, tender exercises were extensive, sometimes resulting in procurement timeframes extending past planned delivery milestones.

Procurement support was delivered by ECC officers, but the cost of this was not supported by the grant. With two separate procurements, each subject to rigorous audits, officer time devoted to the task was extensive.

3.1.1 Selection of contractors

The procurement of the engineering, procurement, and construction (EPC) contract for the solar PV, charging infrastructure, battery storage and private wire aspects of the project received a lot of interest, with ten contractors attending the site visit on the 8th March 2021 despite Covid-19 restrictions being in force. Five bids were received.

3.1.2 Contractor performance

All contractors were easy to manage and have delivered, but some weaknesses in project management were experienced during delivery of the EPC contract. The contractor being located in Scotland and the complexity of the project led to project management suffering at times. Historic site contamination, the DNO connection agreement and private wire installations all had unforeseen complexities that made it more difficult to meet project milestones.

3.2 Project delivery

The grant application was submitted in November 2019 and approved in December 2019. Site surveys commenced in February to March 2020. The Covid-19 pandemic reached the UK in early 2020. Advisory restrictions on work and travel were introduced in mid-March followed by a stringent legally enforced stay-at-home order affecting all but essential occupations on 23rd March. The restrictions were gradually eased in late spring and summer 2020. The restrictions impacted directly upon work on project delivery during this period. Similar restrictions were in place in most other countries in Europe and globally, having wider impacts upon the procurement and delivery of key components required for the project.

In preparation for the project, a planning application had been submitted in September 2019 and was granted in October. This imposed conditions to mitigate potential ecological impacts and flood risk, work continued through the spring and summer of 2020 to conduct a detailed ecological survey and flood risk mitigation plan for the Water Lane site and to prepare the Local Environmental Management Plan (LEMP) that was required as a condition of the planning approval. Site surveys and subsequent site clearance in May 2020 and ground works in the autumn and winter of 2020 revealed significant, unforeseen, land contamination on the Water Lane and Exton Road depot sites that delayed works and added to costs.

The private wire route between the Water Lane site and the Exton Road depot follows an existing footpath for some of its length, and utilises the path's underpass under the main Exeter to Plymouth railway line. There were known to be medium pressure gas mains and 11 kV electricity cables along this route, but the space occupied by these services was greater than expected leading to delays and increased costs to accommodate the new private wire cabling. Additional underground services were also encountered on the Exton Road depot site similarly adding to costs and causing delays.

An agreement with the DNO for the grid connection had been signed in November 2019 in advance of the grant application. However, this was subsequently withdrawn in October 2021 on the basis of a revised evaluation of local grid constraints. Changes in staff at the DNO hampered renegotiation of the agreement, and to address the revised grid constraints additional restrictions were imposed. These required active network management capability, with a G100 export limitation relay being required to curtail export from the installation to the grid at times when it might impact upon the integrity of the local grid (this was estimated to reduce grid exports by about 0.5%, i.e. having only a marginal impact on the project). Delays and costs resulted from the need to renegotiate the agreement, and there were additional costs in the provision of the equipment required to facilitate remote disconnection.

3.3 Perception of stakeholders

The project has received positive publicity on BBC local news, raising its profile with local residents and clearly demonstrating the council's commitment to invest in projects working towards their climate emergency and net zero carbon emissions targets. Interest has also been received from various industry experts and bodies, such as the Energy Saving Trust.

4 Project outcomes and impact

This section considers project outcomes and income over the life of the delivered asset, taken to be 25 years. This lifespan is taken from the funding bid, and is reasonable for the PV array, high voltage infrastructure and vehicle charging points. The PVSyst model used to predict PV panel output makes allowances for degradation of output over the lifespan of a panel. The inverters (both associated with the PV arrays and the battery storage modules) and the batteries themselves are unlikely to achieve this lifespan. The battery specifications state a 15 year working life; this is also a reasonable assumption for inverters. For simplicity financial calculations in this section assume that batteries and inverters are replaced in year 13, half-way through the life of the installation as a whole.

The analysis in this section focuses on the target indicators adopted for the project, as discussed in Section 1.2. Indicators of wider impacts such as gross value added and employment have not been considered. Whilst the scheme has value in showcasing emerging technologies and encouraging uptake by example, these indirect impacts cannot be quantified with any confidence.

The funding bid stated estimated avoided greenhouse gas emissions over the life of the scheme to be 20,635 tonnes. This is 22½ times the stated annual saving, not 25 times: this is a consequence of the annual saving not including the impact of panel degradation, whereas this has been included in the lifetime figure. In the analysis below generation (and associated greenhouse gas reduction) is based on lifetime average panel efficiency.

In practice, emission savings in later years of the scheme's life would fall significantly against a realistic counterfactual case, as described below:

- further decarbonisation of national electricity supply is forecast; the effect of the significant fall over the period 2012 to 2020 has already been discussed in Section 1.2.3. Projected future long run marginal electricity emission factors fall to just 5.2 g CO_2e/kW h by 2047. This will reduce marginal emission reductions from PV generation compared to grid electricity. However, the argument is somewhat circular: it is projects such as this that are driving the reduction in the grid electricity emission factor.

- Road vehicles are expected to transition from fossil fuels such as diesel to forms offering the potential to have zero carbon emissions (such as electricity and hydrogen) over the lifespan of the project. Vehicle registration data for the Exeter area indicate that in 2022 quarter 3 1.05% of cars and 0.26% of LGVs were BEVs and no HGVs were BEVs[5] [6]. The Climate Change Committee (CCC) have assessed changes necessary to support a transition of the UK to net zero greenhouse gas emissions by 2050 in their Sixth Carbon Budget reports[7]. This forecasts a need for no new fossil-fuelled cars or LGVs to be on sale from 2032 and 68% fleet penetration of BEV LGVs by 2035. For HGVs 96% of all new vehicle sales need to be zero emission vehicles by 2035, with 33% fleet penetration by that date. By 2040 all new HGV sales need to be zero emission vehicles, with 67% fleet penetration by that date.

  National fleet penetration of BEV LGVs and HGVs has been estimated for each of the 25 years of the scheme's life by linearly interpolating and extrapolating the CCC targets above. The annual level of fleet replacement in the South West of England (8.6% for the LGV fleet and 7.8% for the HGV fleet, based on new vehicle registrations in 2021[8]) has been taken into account when forecasting forward from the point in time when new fossil-fuelled vehicles are expected to be discontinued completely. For simplicity zero emission HGVs are all assumed to be BEVs (as against other forms such as hydrogen, for which counterfactual carbon emissions would be very difficult to estimate). The resultant forecasts are shown in Figure 5 and suggest that in 2023 4.5% of LGVs will be BEVs (i.e. about 52% of the LGVs newly registered in 2023 will be BEVs). This is optimistic but not infeasible; the range of available vehicles is accelerating rapidly. 100% fleet penetration of BEV LGVs is forecast for 2039. For HGVs uptake is forecast to be negligible until 2031 with 5.8% market penetration in that year[*]. 100% fleet penetration is forecast for BEV HGVs in 2045.

[*] On the basis of linear extrapolation from the CCC 2035 and 2040 targets.

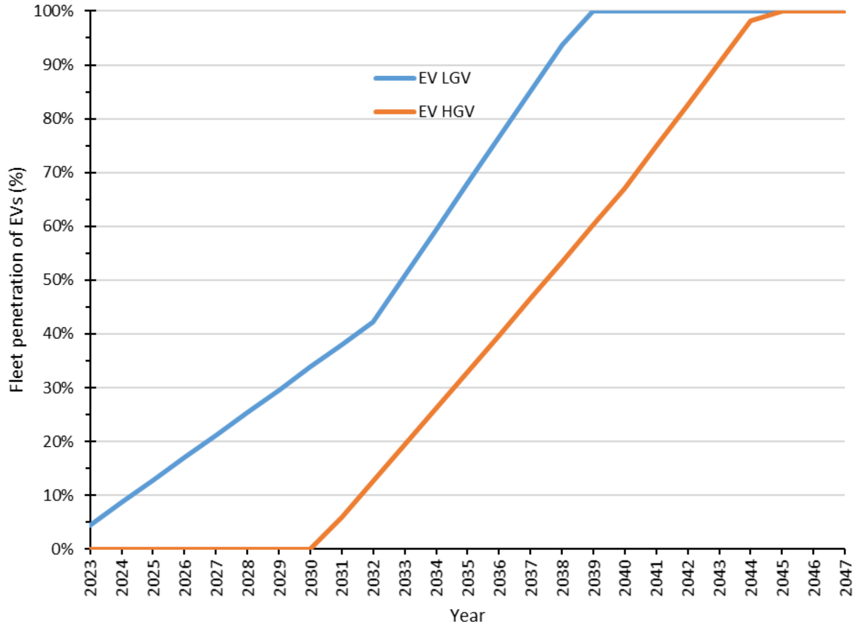

Figure 5. Assumed fleet penetration of BEV LGVs and HGVs in Exeter in the absence of the scheme.

The project facilitates a far more rapid switch to BEVs for both LGVs and HGVs in the ECC fleet as contracts are renewed. It was originally envisioned that all vehicles that were previously diesel would switch to BEVs as soon as the project infrastructure became live (at the start of 2023). Now that the fleet is contracted this is a slightly optimistic and simplified assumption, but in the context of the 25-year life of the project infrastructure a rapid switch is envisaged (as discussed in Section 1.2.3). The calculations in this section assume that all LGVs are switched to BEVs immediately, but (on the basis of progress to date) an additional 20% of HGVs (RCVs) are assumed to switch to BEVs per annum. Hence 100% of the RCVs will be BEVs in 2027. Zero emissions from BEVs in the ECC fleet is compared to a counterfactual in which they are the mix of diesel and BEV forecast above in that year for the country's vehicle fleet generally, charged using grid electricity.

The project offered the potential for the parks team depot to relocate to the Exton Road depot from Belle Isle Park, facilitating electrification of their fleet but this relocation has been abandoned at present due to a lack of funds.

Further assumptions for the counterfactual include:

- diesel and reserve peaking generator plant emission factors are assumed to remain unchanged during the lifespan of the project.
- In the absence of monitoring data for the installation at the time of writing, no grid exports are assumed from the Riverside Leisure Centre installation. From the building's 2017 Display Energy Certificate annual electricity usage is about 465.2 MW h. The estimated annual yield of the PV array at the site is 119 MW h, 25% of site electricity demand. Furthermore, the battery storage capacity at this site is very small.
- Supply chain (embodied) greenhouse gas emissions have not been considered, and were out of the scope of the required greenhouse gas reporting.
- Cost calculations are at today's prices (i.e. they do not include inflation or discounting). Guidance stated in the source of future fuel costs[3] to repeat calculations using low, central and high forecast costs (in view of the current volatility of fuel prices) has been followed. Fuel cost data used is

specific to the public sector, and is shown in Figure 6. The value of electricity exports from the Water Lane array has been estimated at 11.79 pence per kW h from actual income generated and amounts exported in January and February 2023. This amount has been factored by future forecast changes in fuel cost to account for potentially higher export income at present with atypically high wholesale electricity prices.

Whilst future fuel costs have been considered for the purposes of calculating the lifetime costs of the project, the project's target indicators did not include income generation or financial payback.

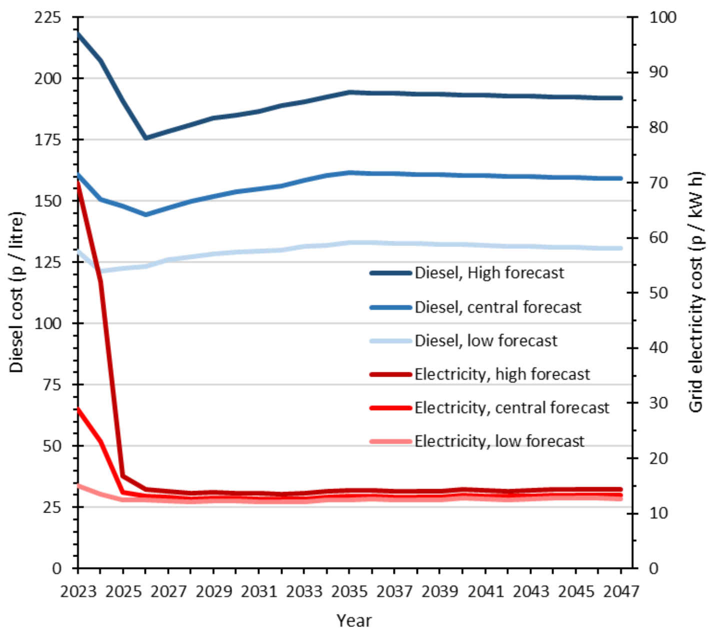

Figure 6. Assumed future fuel costs3.

- The John Lewis car park and Livestock Centre PV arrays are existing installations. Output from these has not been included in the calculations. The addition of sizeable battery storage capacity at these sites is expected to increase on-site consumption of PV-generated electricity and to reduce exports, with a financial benefit. In the absence of monitoring data for these installations at the time of writing, there is no basis on which to calculate this benefit. Greenhouse gas reduction calculations are not affected by this assumption.

- Feed-in-tariff (FiT) payments for generation and export of electricity from the existing PV array at Oakwood House (located on the Exton Road site) has been discontinued as a consequence of the connection to the Water Lane PV array. This is forecast to lead to a loss of income of about £5,043 per annum over the remaining life of the FiT contracts. This has not been included in the financial analysis in this report.

- The initial capital and revenue cost of the scheme is taken to be £3,901,999, which includes additional costs borne by Exeter City Council over and above the agreed grant funding (ERDF funding being £1,599,754; 45% of forecast costs). The cost of replacing components in year 13 has been estimated for the purposes of this analysis at £356,134 for the inverters (based on current market prices) and £1,150,759 for the battery storage facilities (based on a reference[9] forecasting future cost of battery storage as $408/kW h (£340/kW h at $1.2 per £1) for utility-scale Li Ion battery storage in 2035). Both cost estimates include a 33% uplift to cover installation. Other ongoing costs (e.g. administration, routine maintenance) are included in the lifetime cost analysis in Section 4.2. Operating and maintenance costs were estimated during development of the project at about £1.8 million[10], of which about £1.2 million was attributed to battery maintenance and replacement. A budget has been secured to cover maintenance costs and safeguard future operation of the project assets.

4.1 Greenhouse gas analysis

Cumulative savings in greenhouse gas emissions have been estimated and are shown in Figure 7 and Figure 8. Applying the emission factors used in the funding bid (Figure 7) total greenhouse gas savings amount to 17.8 kt CO_2e. This is 86% of the lifetime saving stated in the funding bid, as a consequence of future vehicle fleet decarbonisation (and electric vehicle inefficiencies) not having been taken into account in the funding bid figure and a staged transition to electric RCVs over a 5-year period.

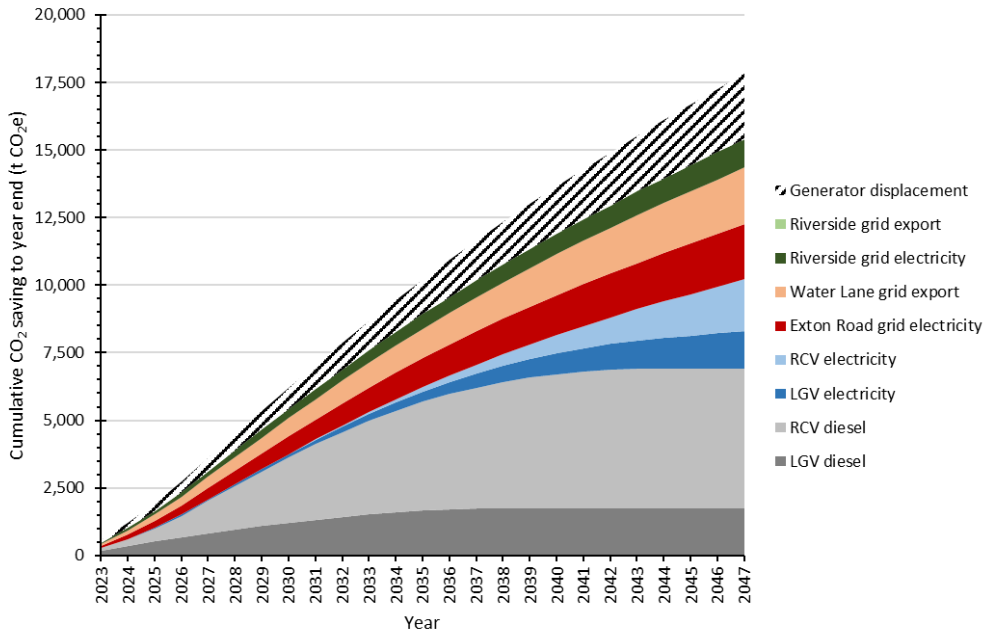

Figure 7. Cumulative estimated greenhouse gas savings over the lifetime of the scheme: emission factors as per funding bid.*

If the grid electricity emission factors against which greenhouse savings are calculated is taken as the BEIS long run marginal emission factor for the year in which electricity is generated (Figure 8), total greenhouse gas savings amount to 11.5 kt CO_2e, 56% of the lifetime saving stated in the funding bid. On one hand it is projects such as these that are driving down the grid average emission factor and displacing high emission generation; on the other hand a step reduction in the grid average emission factor is expected as a consequence of national energy policy regardless of whether an individual project goes ahead.

* RCV and LGV diesel are avoided emissions from diesel vehicles that would have remained at that point in time without the scheme in place. RCV and LGV electricity are avoided emissions from electric vehicles that would have been introduced at that point in time without the scheme in place, and would have been recharged using grid electricity.

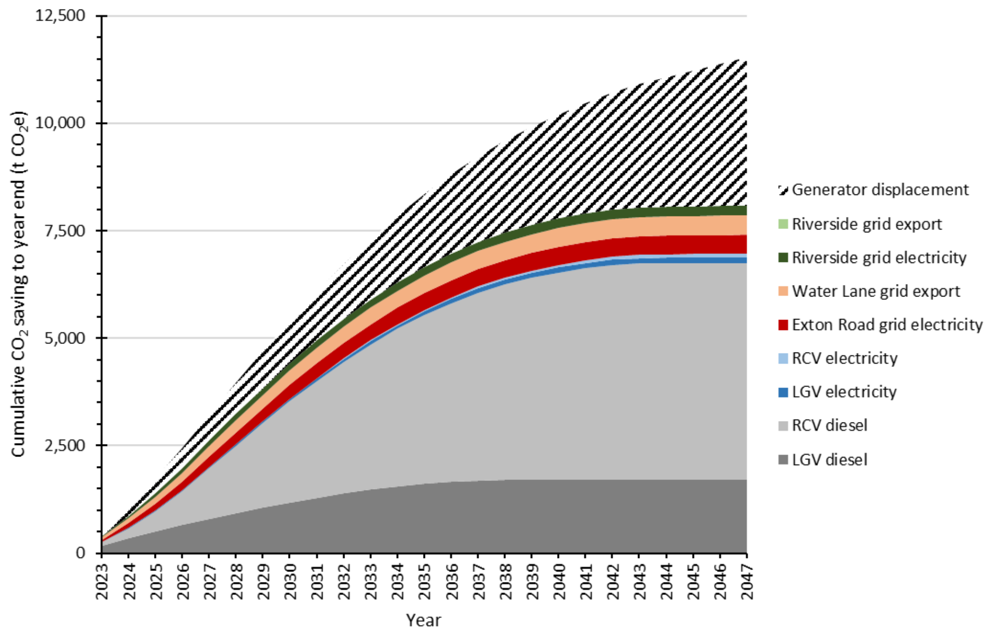

Figure 8. Cumulative estimated greenhouse gas savings over the lifetime of the scheme, applying the grid average long run marginal[3] emission factor for that year[*].

4.2 Cost analysis

Estimated cumulative net costs arising directly from the scheme are shown in Figure 9. The initial capital cost is allocated to the year in which the infrastructure was completed (2023), or to future years in the case of repayment of the ECC capital loan (£118,630 per annum at an interest rate of 3.5%). Other costs included are £32,000 per annum operating and maintenance costs (general maintenance of equipment, PV panel cleaning, insurance and accountancy fees) and the additional cost of procuring electric RCVs as against diesel vehicles (discussed below). Income from the sale of electricity to the grid and avoided fuel costs are subtracted from the capital cost figure. The scheme has an overall net cost of £1.9m, £3.2m or £3.9m with low, central or high fuel cost estimates respectively.

A key aim of the project is to facilitate a transition of the council's vehicle fleet from diesel-powered vehicles to electric vehicles. Electric vehicles are currently significantly more costly than their diesel counterparts. Estimates of this indirect cost of implementing the project have been included in the cost analysis for RCVs. The monthly lease cost for an electric RCV is £9,100 as against £5,100 for a conventional diesel vehicle (78% higher). The cost premium amounts to £720,000 per annum for the RCV fleet alone. Avoided diesel costs reduce this to £475,000 per annum, but it is still a considerable financial commitment.

The cost premium of an electric RCV is expected to fall as zero emission heavy goods vehicles become the norm as a consequence of advances in technology and legislative restrictions on new greenhouse gas-emitting vehicles. The Climate Change Committee Sixth Carbon Budget report[7] foresees that by 2035 96% of new HGVs will be zero emission vehicles. In the analysis of cumulative costs the cost premium for an electric RCV has been assumed to linearly reduce from the figure calculated above in 2023 to zero in 2035. As in Section 4.1, an additional 20% of the RCV fleet has been assumed to switch to electric vehicles per year (3 additional vehicles per year), resulting in the switch to electric RCVs being completed in 2027, at which point an electric RCV is still assumed to be 52% more expensive than a diesel RCV. A cost premium for electric cars and LGVs has not been included in the analysis.

Income generated from the sale of electricity to the grid and avoided costs of imported electricity and diesel fuel help fund the early transition to a fully electric vehicle fleet, and operating and maintenance costs of the scheme. These costs will greatly exceed the surplus resulting from savings made on electricity and diesel costs over the life of the scheme.

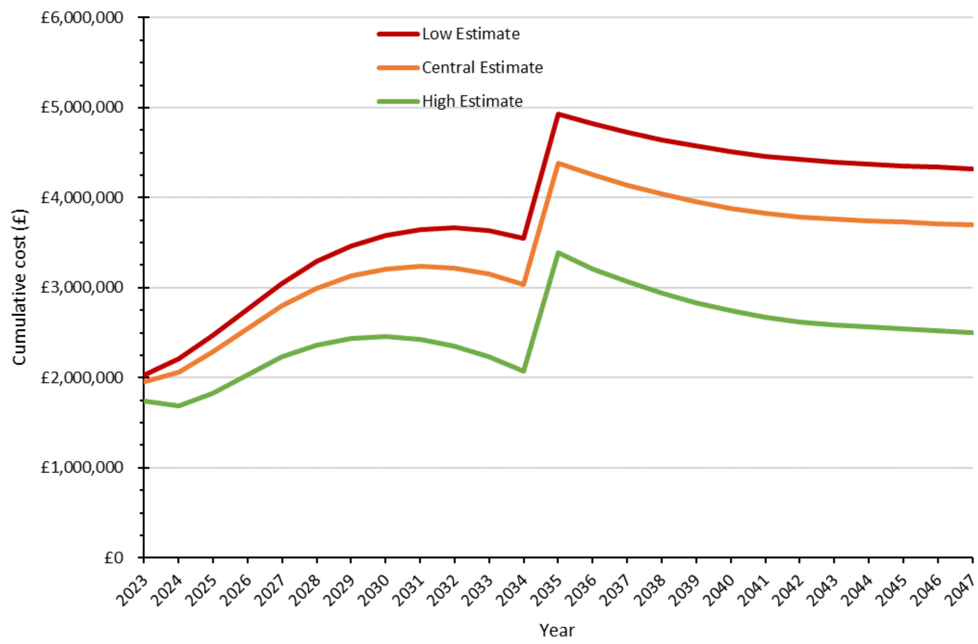

Figure 9. Cumulative estimated net cost of scheme over its lifetime.

Sources of cost savings and income are illustrated in Figure 10, Figure 11 and Figure 12 with low, central and high fuel cost estimates respectively. In all cases the majority of savings are from avoided diesel costs. Income from exports of electricity to the grid are lower for the central and high fuel cost estimates due to the steep decline in the value of electricity compared to the current situation in these scenarios (Figure 6). This is assumed to impact upon the future value of exported electricity.

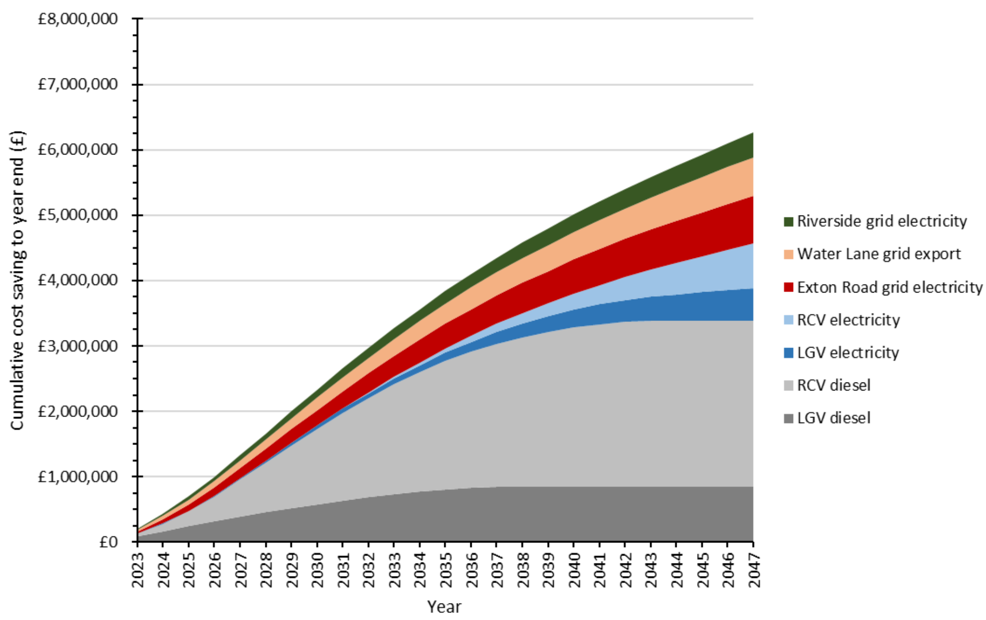

Figure 10. Cumulative estimated cost savings with low fuel cost estimates.*

* Graph excludes capital costs, operating and maintenance costs, and the cost premium of electric vehicles.

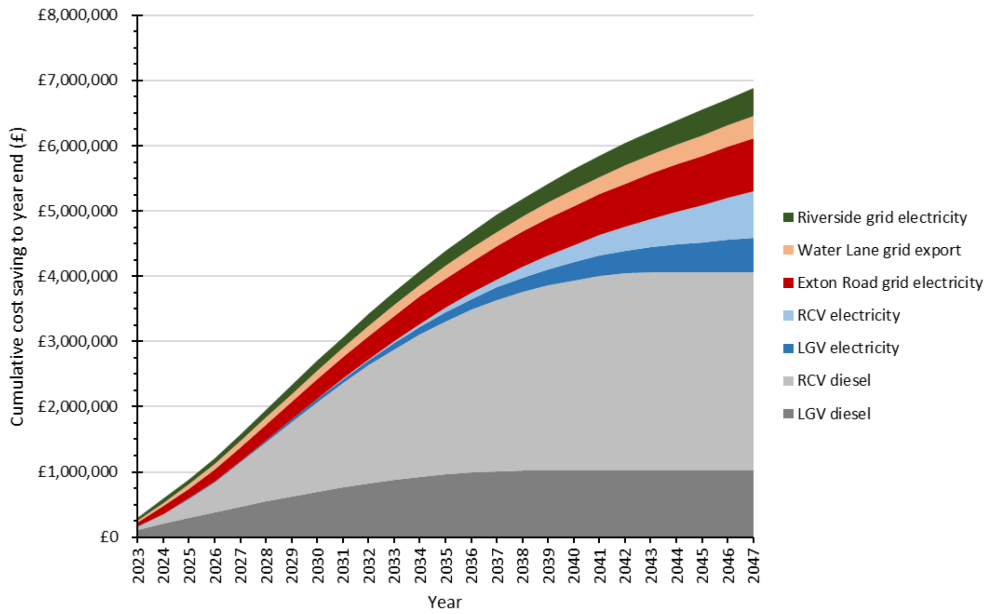

Figure 11. Cumulative estimated cost savings with central fuel cost estimates.*

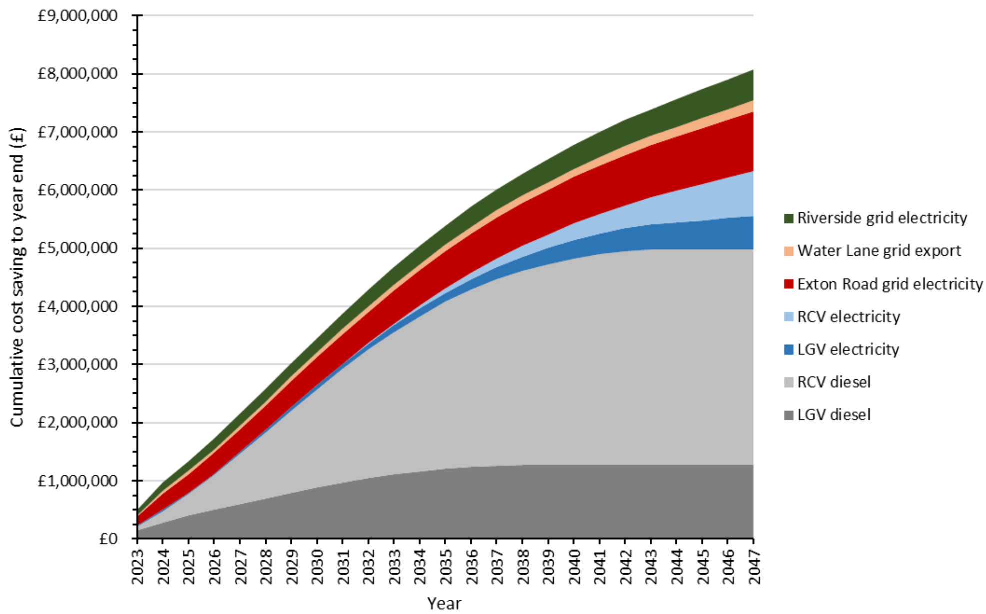

Figure 12. Cumulative estimated cost savings with high fuel cost estimates.*

4.3 Summary of outcomes and impact

The project has successfully delivered the infrastructure required to meet its intended outcome and impacts. The two PV arrays, four battery storage facilities and electric vehicle charging points are all in place. Generation of zero carbon electricity and storage of significant amounts of the electricity generated is now taking place at the scale envisaged by the bid. The provision of storage allows the generated electricity to be better used to reduce peak burdens on the national grid and provide grid reinforcement more generally; also to minimise use of grid electricity or to maximise income from exports to the grid. Provision of vehicle charging points for large and small vehicles facilitates a switch to BEVs; in particular a proactive and innovative switch to BEV RCVs well in advance of national uptake. The cost premium of switching to BEVs is partly offset by the zero marginal cost of electricity generated by the PV array, and avoided diesel fuel costs.

Changes to the project design (substituting the Riverside Leisure Centre site in place of the Mary Arches car park) does not significantly impact the outcome of the scheme, nor its key target indicators. Most of the greenhouse gas emission and cost savings are attributable to the electrification of the vehicle fleet facilitated by the scheme, which is only dependent upon the Water Lane PV array.

There are considerable environmental benefits to the scheme, as quantified above in the lifetime outturn of the project's key target indicators.

The scheme demonstrates strategic added value through its implementation of novel emerging technology (battery storage of electricity in a range of contexts, and facilitation of a novel fleet of electric RCVs). The installations will serve as an example from which lessons can be learned and successes demonstrated to interested parties.

Table 2 summarises the lifetime gross and net additional impact of the scheme against its key target indicators, including adjustments to account for deadweight, displacement, leakage and multiplier effects (which are described below).

Table 2. Gross and net additional impact of the scheme over its lifetime.

Indicator		Impact area 1: lifetime impact of scheme	
		Measure	Adjustment
Impact indicator: Additional renewable energy production Unit = GW h	Gross impact	34.5	
	Less deadweight / reference case	25.9	25%
	Less displacement / substitution	23.3	10%
	Less leakage	22.1	5%
	Net additional (plus multipliers)	31.0	1.4
Impact indicator: C30 Additional capacity of renewable energy production Unit: MW_p	Gross impact	1.32	
	Less deadweight / reference case	0.99	25%
	Less displacement / substitution	0.89	10%
	Less leakage	0.85	5%
	Net additional (plus multipliers)	1.19	1.4
Impact indicator: C34 Estimated annual decrease of GHG Unit = kt CO_2e	Gross impact	21.4*	
	Less deadweight / reference case	13.4†	38%
	Less displacement / substitution	12.0	10%
	Less leakage	11.4	5%
	Net additional (plus multipliers)	16.0	1.4

Gross impact is the impact before accounting for any additionality, e.g. a scheme may have been built (in whole or part) anyway without grant funding, grid decarbonisation and uptake of BEVs is forecast to occur in the medium term as part of the country's transition towards net zero carbon emissions. Gross impact has been taken as the forecast lifetime renewable energy generated, the megawatts of peak capacity installed, greenhouse gas savings assuming no further electric vehicle uptake.

The deadweight/reference case adjusts for outcomes that are likely to have been delivered anyway in the absence of grant funding. ECC has several arrays on its buildings and car parks, and it is therefore possible that a construction of a ground-mounted array might have been considered to support its

* This is the total carbon saving over the 25 year scheme lifespan, assuming no further decarbonisation of the country's vehicle fleet.

† Calculated lifetime carbon saving taking into account projected electric vehicle uptake in the national fleet of 17.844 kt CO_2e with a deadweight adjustment of 25% applied.

Exton Road depot. Battery storage is unlikely to have been funded due to high costs and the technology being in its infancy. An adjustment for deadweight of 25% has been estimated and applied to renewable energy production and capacity.

For greenhouse gas emissions avoided, deadweight is a combination of the difference between results calculated ignoring and including forecast electric vehicle uptake in the absence of the scheme (resulting in an adjustment of 17%), and the 25% assumed above to account for the likelihood of ECC investing in the PV array without support from grant funding. The combined adjustment is 38%[*].

Displacement adjusts for market share taken from other businesses, e.g. from commercial developments offering renewable energy capacity. Government statistics[11] report 11.36 GW h of electricity generated from PV in Exeter in 2021, and 14.4 MW_p of installed capacity. Most of this is in the form of small domestic and commercial rooftop arrays. There therefore currently appears to be little large-scale commercial provision of ground-mounted PV arrays (nor large scale battery storage) in Exeter. This is a consequence of severe grid connection constraints for installations with an installed capacity exceeding 1 MW_p, and limited site availability in a predominantly urbanised area. An adjustment of 10% has been estimated and applied for displacement.

Leakage adjusts for benefits occurring outside of the target area. This is likely to be small for the scheme; the area is a net importer of electricity generated in other areas of the country and there are significant local and regional grid constraints on the export of electricity. The amounts of generation and capacity added by the scheme are small in the context of total consumption: 513.7 GW h in Exeter in 2021[12], of which the annual generation from the scheme amounts to 0.27%. An adjustment of 5% has been estimated and applied for leakage, a typical figure applied in the evaluation of other schemes in the region[13].

The multiplier accounts for further economic activity stimulated by the direct benefits of an intervention. This is very difficult to estimate with any level of certainty and a typical figure applied in the evaluation of other schemes in the region has been applied (1.4).

5 Project value for money.

Value for money has been evaluated by estimating costs per unit output (Table 3) and comparing the results to published benchmark costs and forecasts.

Table 3. Costs per unit output calculated for the project.

Indicator	Net additional impact	ESIF funding	Public match funding	Total funding
Capital Cost		£1,599,754	£2,302,245	£3,901,999
Additional renewable energy production	31.0 GW h	5.16 p per kW h	7.43 p per kW h	12.59 p per kW h
C30 Additional capacity of renewable energy production	1.19 MW_p	£1,344 per kW_p	£1,935 per kW_p	£3,279 per kW_p
C34 Estimated annual decrease of GHG	16.0 kt CO_2e	£100 per t CO_2e	£144 per t CO_2e	£244 per t CO_2e

[*] 100 x (1 – ((1 – (17/100)) x (1 – (25/100)))).

5.1 Unit cost of renewable energy production

The estimated cost per kW h of additional renewable energy production for the project can be compared to electricity prices. The retail cost of electricity for non-domestic consumers with consumption categorised as small (20 to 499 MW h per annum) was 24.28 p/kW h (excluding the Climate Change Levy (CCL)) in the third quarter of 2022 (25.00 p/kW h including the CCL). The cost rose sharply from 14.62 p/kW h (exc. CCL) or 15.33 p/kW h (inc. CCL) in the third quarter of 2021[14]. For comparison the central forecast electricity unit rate in 2023[3] used in the lifetime cost analysis in Section 4.2 is 28.97 p/kW h, similar to the 2022 quarter 3 costs cited above.

Total capital funding costs for the project per lifetime kW h of additional renewable energy production are about 82% of historic (2021 quarter 3) retail electricity prices, and about one-half of 2023 quarter 3 prices. This indicates (as does the lifetime cost analysis in Section 4.2) that the cost of generated electricity is lower than the retail cost of grid electricity.

Net income[*] from exports from the Water Lane site averaged 11.79 p/kW h for January/February 2023, with half-hourly export tariffs varying from -9.57 to 31 p/kW h (although for the half-hour periods during which exports occurred the range was reduced to -1.45 to 29 p/kW h). For the Exeter Livestock Centre site net income from exports averaged 19.07 p/kW h for January 2023; export tariffs are defined for winter and summer and for day, night and weekend periods, and range from 15.59 p/kW h for winter weekends to 21.44 p/kW h for winter weekday daytime periods.

Total capital costs for the project per kW h of additional renewable energy production are similar to the average income per unit export for the Water Lane site, but lower than the average for the Exeter Livestock Centre site. The half-hourly unit rate varies widely at the Water Lane site, hence there is potential to increase income by using the storage provision and smart controls on the vehicle chargers (which allow the charging rate to be tailored) to maximise exports at times of high electricity prices. This strategy would also maximise avoided greenhouse gas emission by displacing use of peaking generator plants.

5.2 Cost per unit renewable energy capacity

The estimated cost per kW_p of additional renewable energy capacity for the project can be compared to BEIS electricity generation cost estimates[15]. These are forward forecasts for future schemes, the earliest commissioning date considered in the current version is 2025. The previous (2016) version[16] included forecast costs for scheme commissioned in 2020, with ground-mounted schemes of 1 to 5 MW (e.g. Water Lane) and smaller schemes of 100 kW to 1 MW (e.g. the Riverside installation) falling into different categories. The benchmark costs are summarised in Table 4.

[*] After deduction of fixed charges including reactive power charges and red, amber and green charges relating to peak times of usage (and therefore prices) on the network.

Table 4. Benchmark electricity generation costs for PV[15 16].

Cost Component	Cost estimate	2025 (Scheme > 50 kW)		2020 (Scheme 1 MW to 5 MW ground mounted)	2020 (Scheme 100kW to 1 MW)
Pre-development £ per kW	Low	10		60	0
	Medium	50		60	0
	High	120		60	0
Construction £ per kW	Low	400		600	800
	Medium	400		700	1,000
	High	500		800	1,200
Infrastructure £	Low	1,300,000		200,000	200,000
	Medium	1,300,000		200,000	200,000
	High	1,300,000		300,000	200,000
Total £ per kW	Scheme size	1.2 MW	120 kW	1.2 MW	120 kW
	Low	**1,493**	**11,243**	**827**	**2,467**
	Medium	**1,533**	**11,283**	**927**	**2,667**
	High	**1,703**	**11,453**	**1,110**	**2,867**

The cost estimates for PV generation capacity (based on a 1.2 MW scheme) are one-third of estimated project costs. Smaller schemes have a higher cost per kW, similar to the average project cost per kW, or higher still for the 2025 cost estimates which include a very high fixed infrastructure cost. The provision of battery storage will add significantly to the total cost but not increase the renewable energy capacity provided, and the cost of providing the battery storage needs to be taken into account to provide a comparable benchmark cost.

Cost assumptions for a range of battery storage technologies have been published by BEIS[17]. The closest examples to those procured for the project are 2.5 MWh lithium ion battery storage for industrial and commercial peak lopping, and 20 kWh lithium ion battery storage for domestic peak lopping. Benchmark costs for these examples are summarised in Table 5.

Table 5. Benchmark costs for lithium ion battery storage in 2020[17].

Cost Component	Cost estimate	5 kW / 20 kWh battery storage	1 MW / 2.5 MWh battery storage
Capital cost £ per kW	Low	935.7	720.3
	Medium	1,222.8	864.4
	High	1,309.9	1,008.5
Infrastructure cost £ per kW	Low	13.6	18.2
	Medium	27.3	45.5
	High	45.5	72.8
Total £ per kW	**Low**	**949.3**	**738.5**
	Medium	**1,250.1**	**909.9**
	High	**1,355.4**	**1,081.3**

The project delivered 1.32 MW_p of PV generating capacity and 1.364 MW of battery storage capacity. Benchmark costs per MW_p of installed PV generation capacity (including the cost of battery storage provided) has been calculated from Table 4 (2020 figures) and Table 5, resulting in Table 6.

Table 6. Benchmark costs for PV generation capacity including battery storage provision.

Item	Capital cost £		
	Low	Medium	High
Water Lane PV array (1.2 MW_p)	992,000	1,112,000	1,332,000
Riverside PV array (120 kW_p)	296,000	320,000	344,000
Water Lane battery storage (1 MW)	738,500	909,900	1,081,300
Livestock Centre battery storage (264 kW)	194,964	240,214	285,463
John Lewis battery storage (100 kW)	73,850	90,990	108,130
Riverside battery storage (2.4 kW)	2,278	3,000	3,253
Total Cost	**2,297,592**	**2,676,104**	**3,154,146**
Cost per kW_p PV generation capacity	**1,741**	**2,027**	**2,390**

The total benchmark capital cost is 60 to 80% of total project spend, and omits components such as the vehicle charging infrastructure and private wire cabling. The benchmark cost per kW_p of PV generation capacity is similarly 53% to 73% of the value derived from project spend. These results indicate that total project costs and costs per kW_p of PV generation capacity are reasonably close to expectations based on published cost estimates for PV and battery storage infrastructure.

5.3 Cost per unit reduction in greenhouse gas emissions

Cost per estimated t CO_2e of abated carbon emissions for the project can be compared to the carbon costs published for modelling purposes by BEIS[18]. These range from £15.68 per t CO_2e in 2023 to £42.66 in 2035 under the central scenario, zero in 2023 to £18.67 in 2035 under the low scenario and £31.37 per t CO_2e in 2023 to £84.61 in 2035 under the high scenario. These values are an order of magnitude lower than the project capital costs per t CO_2e abated, plus there are additional lifetime costs as discussed in Section 4.1.

A significant portion of project costs are for the large scale battery storage provision, which is a relatively new technology and therefore has a cost premium. As a result its inclusion in the project increases costs per target indicator unit, in some cases without increasing the net additional impact for the indicator. It is, however, key to increasing the flexibility of electricity generated to meet demand peaks and reduce the use of peaking generator plants which have particularly high carbon emissions per unit of electricity supplied. The benefits of the battery storage provision have been understated in the analysis as a consequence of operational data not yet being available. These data are necessary to evaluate the extent to which the storage provision changes the amount of generated electricity exported or used on site, and the income from exports that are subject to a half-hourly tariff.

6 Conclusions and lessons learnt

In conclusion the project has been successful in delivering over 1.3 MW_p of additional renewable electricity generation capacity from PV panels, 2.5 MW h of lithium ion phosphate battery storage capacity, two private wire links between sites and electric vehicle charging infrastructure. The project is proving invaluable in facilitating the transition of the council's road vehicle fleet operating from its Exton Road depot from diesel vehicles to battery electric types. The early adoption of battery electric refuse collection vehicles is particularly innovative. The project supports this transition not only through the provision of vehicle charging infrastructure but also by providing electricity to recharge the vehicles at zero marginal cost, reducing costs of electricity supply at all four sites and generating income from the export of electricity. These cost reductions and income help fund the cost premium of leasing battery electric vehicles and maintenance of the installation.

The project adds significantly to PV generation capacity in Exeter, increasing it by over 8%. The amount of battery storage provision in the city is not known, but it is very likely that provision under the project is the largest in Exeter. Added generation capacity is important given current grid constraints in the south west peninsula. Provision of battery storage greatly increases the flexibility of the electricity output of the project which would otherwise be dictated by local weather conditions. It therefore increases the value of the generation capacity to meet peaks in demand, potentially reducing demands upon short term operating reserve peaking generator plants which have particularly high carbon emissions per unit of electricity supplied.

The amount of electricity generated by the project infrastructure appears to have been estimated accurately, evidenced by independent verification of design calculations and by the first month's data recorded by the installation. This would be expected given the mature state of PV generation technology.

Design stage estimates of reductions in greenhouse gas emissions resulting from the project were correct given the emission factor for grid electricity at the time, but did not account for the rapid decarbonisation that had occurred by the time the project was delivered. Projected uptake of battery electric vehicles in the longer term in the absence of the project was also not taken into account. It is important that the counterfactual against which emission reductions are calculated is realistic; this can be difficult to ensure in an area where national targets and policy are developing rapidly. The calculation also included questionable assumptions for battery electric vehicle efficiency.

Another shortcoming of the project was delivery timescale, with the infrastructure delivered 15 months later than forecast. The delays were primarily due to the Covid-19 pandemic, work required to discharge planning conditions, unforeseen historic land contamination and congestion of existing underground services and issues with the connection agreement with the DNO. The absence of monitoring data as a result of these delays has severely impacted the ability to objectively evaluate project performance in this summative assessment. Such an evaluation will only be possible after at least one year's data have been collected. Delays also impact upon greenhouse gas reductions when declining counterfactual grid electricity and vehicle emissions are properly considered.

The tender process required more time and effort than anticipated due to compliance requirements and the number of bids received. The remote location of the selected contractor, coupled with the complexity of the project and a number of unforeseen challenges emerging during delivery, made project management particularly challenging and led to delivery timeframes being extended from those originally anticipated.

The project experienced a relatively small overspend on its budgeted capital cost, attributable to the reasons for late completion of the project described above and additional remote disconnection equipment required by the DNO under the renegotiated connection agreement. Project capital spend exceeds expected spend per unit delivered of each of the output target indicators of renewable energy generation, capacity and greenhouse gas emission reduction, but not excessively so given the innovative and emerging nature of battery storage provision.

A substantial portion of the cost of the project is attributable to the battery storage provision, but this has relatively little impact on the project target indicators (no impact on the renewable generation capacity or production; impact on decreased greenhouse gas emissions is through the ability to displace the operation of reserve peaking generator plants). This is a weakness in the target indicators set; on first examination spend per unit output could be greatly improved by eliminating the battery storage provision (which is a novel aspect of the project), but this would significantly impact the availability of generated output to recharge vehicles outside of working hours in winter months, provide local grid reinforcement and potentially reduce high emission peaking generator usage.

In summary, key lessons for the grant recipient are encouragements that ambitious projects offering tangible environmental benefits can be delivered, the need to carefully consider detail when modelling or estimating project outcomes to ensure that they are realistic, and lessons learned regarding procurement, project management, timescales and budgeting.

Lessons for those designing and implementing similar interventions include the need to carefully consider the detail of counterfactuals when predicting reductions in greenhouse gas emission attributable to a project, lessons learned regarding procurement, project management, timescales and budgeting.

Lessons for policy makers include the potential that renewable energy installations and battery storage projects have to unlock additional benefits by facilitating early adoption of further low carbon technologies using offset costs and income generated from the time-flexible renewable electricity generation capacity.

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