Ministry for Regulation
Te Manatū Waeture

Solar review: cost-benefit analysis

July 2026

1. Introduction and summary

As part of the Ministry for Regulation's solar review, we conducted a cost-benefit analysis (CBA) of the Ministry's package of recommendations that are aimed at simplifying the system, reducing delays in solar installations, and speeding up approvals. Our CBA does not analyse the costs and benefits of any one recommendation; rather, it analyses costs and benefits considering the implications of the package as a whole. The exception is the Ministry's recommendation related to plug-in solar, for which we prepared a separate CBA.

The anticipated effect of the package of recommendations for regulatory change is to speed up the installation time for rooftop solar installations and lower electricity inspection costs.

We incorporate the improvement in installation speed in our CBA by modelling an average two-month reduction in the solar installation time. We model this by 'bringing forward' in time by two months the stream of net benefits (over 10 years) that would otherwise be achieved absent regulatory change. When calculated in 2026 present value terms, a stream of net benefits that occurs earlier in time has a higher value, because of the time value of money (one dollar received today is worth more than a dollar received tomorrow). The difference in present value between slower and faster net benefit streams is a measure of the net benefit of reduced regulatory delay.

We model the lower electricity inspection costs through a $250 reduction in inspection costs. This reflects cost savings from fewer in-person electrical inspections, based on the recommendation to shift from all solar installations requiring in-person inspections to only some requiring inspections through spot checks. We also incorporate some partially offsetting cost increases that arise from a higher risk of defects from reduced in-person inspections. Further details are provided in Appendix B.

In our base case model specification, we assume these changes do not lead to any new solar installations; rather, they simply speed up and lower costs for installations that would have occurred otherwise. Based on our central forecasts of future solar installations, **we estimate a net benefit to New Zealand over 10 years of $23m**, in 2026 net present value (NPV) terms (with a range of $15m-$30m to reflect uncertainty in our forecasts).

We also model an alternative scenario where the faster install time and lower installation cost lead to some new solar installations that would have otherwise not occurred. This reflects a proposition that faster installation processes and lower installation prices would be passed through to households as lower installation prices, which would induce a demand response. Drawing on the international literature and overseas evidence, we assume a 3.5% increase in the number of new solar installations each month from those that would have otherwise occurred.

To put this increase in installations in context, solar uptake in March 2026 is 3.8% of all electricity connections. We forecast this to increase to 8.7% by March 2036 without any regulatory change. If regulatory change leads to an increase in solar installations, we forecast solar uptake of 9.0% by March 2036.

This increase in installations is combined with the two-month reduction in delay and $250 decrease in installation costs. **In this alternative scenario, we estimate a net benefit to New Zealand of $46m** in NPV (with a range of $18m-$70m).

Due to data limitations, our net benefit numbers are based only on residential solar connections, which are mostly small-scale installations. However, this is conservative, because the Ministry's recommendations apply also to medium-sized solar installations, for which we have not calculated net benefits.

We also separately estimated the net benefit from the Ministry's recommendation to permit plug-in solar. We forecast market growth in plug-in solar connections, albeit with considerable uncertainty given there is no existing domestic market and very few international comparisons. We then calculate the benefits and costs of this market growth and estimate a net benefit over 10 years. The central result is **a net benefit from plug-in solar of $4.6m over 10 years** in NPV. The range of net benefits is wide, from -$281m to $396m, reflecting forecasting uncertainty. The negative net benefit arises because the cost of purchasing plug-in solar is incurred upfront, but the benefits accrue over time. As a result, not all future benefits are captured within the 10-year analysis period, causing costs to exceed benefits over this period.

Combining the net benefits of reduced regulatory delay and lower installation costs with the net benefits of plug-in solar, the total central net benefit result is $28m without an increase in rooftop solar installations, or $50m with an increase in rooftop solar installations.

These results imply that the Ministry's package of recommendations will be welfare-improving to New Zealanders. An important caveat is that this analysis includes a number of assumptions and simplifications, such as incorporating forecasts of future solar connections, assuming behaviour for an average household (including the reduction in regulatory delay), and using various proxies or best estimates for certain data points. These aspects of the modelling are necessary for simplicity and tractability, but do not detract from its analytical rigour.

2. Overview of our approach

Our CBA models a factual scenario where the Ministry's package of recommendations is implemented, and this has the effect of reducing delays in solar installations and lowering inspection costs. We refer to this as the ‘main CBA’ and discuss our approach for this CBA here. A separate discussion of our CBA for plug-in solar is in Appendix C.

We model this factual scenario over a 10-year timeframe and compare it with a counterfactual scenario that is a forward-looking projection of the status quo i.e., where the Ministry’s recommendations are not put in place and the regulatory framework for solar installations remains unchanged.

To calculate the benefits and costs of the factual relative to the counterfactual, we start by calculating a counterfactual net benefit path. This is a calculation of the benefits and costs of installing solar in the counterfactual, relative to not installing solar. These benefits and costs are described in more detail in Appendix A, and include the savings arising from reduced grid-electricity consumption, the avoided costs of investment in peak electricity generation, and the real resource costs of the solar installation process. We calculate these benefits and costs on a monthly basis over the 10-year period of our analysis.

In the factual, we model a regulatory change that speeds up the installation time for residential rooftop solar and lowers inspection costs. We model this by bringing forward the counterfactual net benefit path by two months, and decreasing net installation costs by $250 (reflecting separate modelling of the lower installation costs, net of increased costs from a higher risk of defects, from the recommended changes to the inspection model, set out in Appendix B). This means that the net benefits that were occurring in, say, December 2027 in the counterfactual now occur in October 2027 in the factual, and so on. That is, we effectively just take the counterfactual net benefit path and shift it forward in time, with the inclusion of the decrease in net installation costs, to give us the factual net benefit path.

We then calculate the sum of the present value of the counterfactual and factual net benefit paths over a 10-year timeframe. The overall net benefit of regulatory change is the difference between the factual and counterfactual net benefit present values. We conduct sensitivity analysis by independently varying each of the parameters used in this base case calculation within plausible bounds.

We also run an alternative scenario where, along with the two-month reduction in regulatory delay and $250 decrease in net installation costs, we assume a 3.5% increase in solar installations.

Further detail on our approach in this main CBA is provided in Appendix A and B.

Appendix A. Detailed methodology

A.1 Overview

In this Appendix, we set out our detailed methodology for calculating the net benefits of the recommendations in our main CBA. Our approach involves:

- Forecasting solar connections in the counterfactual – we explain our forecasting approach in section A.2.
- Calculating the net benefits of installing solar in the counterfactual (relative to not installing solar) – section A.3.
- Bringing forward the counterfactual net benefits and reducing net installation costs to calculate the factual net benefits – section A.4.
- Calculating the net benefit as the difference between the factual and counterfactual net benefits in NPV terms – section A.5.
- Calculating the net benefit for an alternative scenario with an increase in installations in the factual – section A.6.
- Undertaking sensitivity testing – section A.7.

A.2 Forecast solar connections in the counterfactual

A.2.1 Historic connections data

To forecast residential rooftop solar connections in the counterfactual, we use Electricity Authority data on installed solar installation control points (ICPs),[1] which measures solar connections to the electricity network. The data are monthly from September 2013 to March 2026 by segment (residential, small/medium enterprises, commercial, and industrial), and we focus only on the residential segment (all remaining references to the Electricity Authority data in this report are to the residential segment only). The data include the number of ICPs, the solar uptake rate (solar ICPs as a percentage of all ICPs connected to the electricity network), and the average and total installed capacity of solar connections.

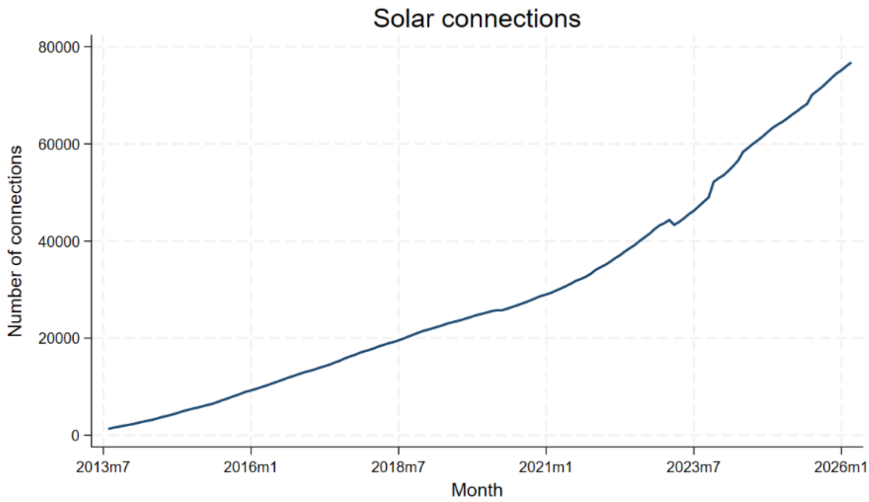
While the Ministry's solar review covered both small and medium sized solar installations (up to 100 kilowatt (kW) capacity), we restrict our analysis to only the residential segment in the Electricity Authority data. We do so because it is difficult to know which solar installations in the small/medium enterprises, commercial, and industrial segments would be considered medium sized. Furthermore, other data that we use for inputs to our CBA are more widely available for residential solar installations. The focus only on the residential segment is conservative, because we do not include any benefits from regulatory change that affect medium-sized solar installations.

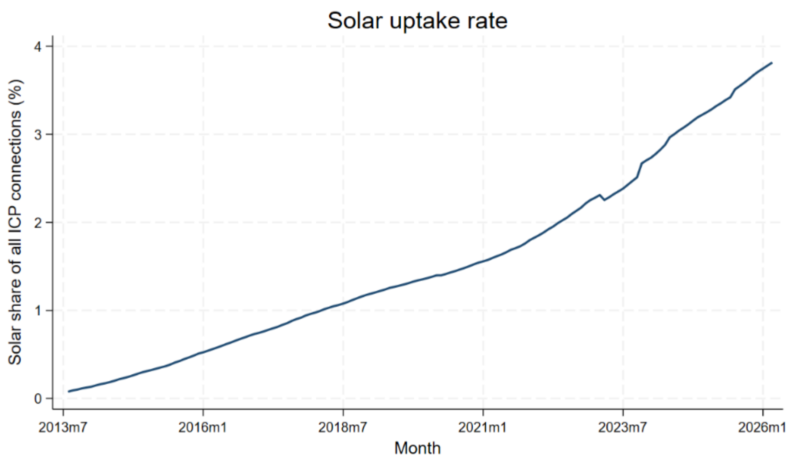
[1] Electricity Authority - EMI (market statistics and tools)

The Electricity Authority data are also split into solar without-battery and solar with-battery ICPs. The split into with and without batteries was only added to the data from November 2023, so data prior to that month are an aggregate.

In Figure 1 we show the number of connections (top panel), the uptake rate (middle panel), and the average installed capacity (bottom panel) for all solar connections (which aggregates the connections with and without batteries). Solar connections have been growing steadily over the time period, to around 77,000 in March 2026, which is approximately 3.8% of total ICPs. Average capacity fluctuated initially, but then grew steadily, to around 5.6kW by March 2026.

Figure 1: All solar connections (with and without batteries) – connection numbers (top panel), uptake rate (middle panel), average capacity (bottom panel)





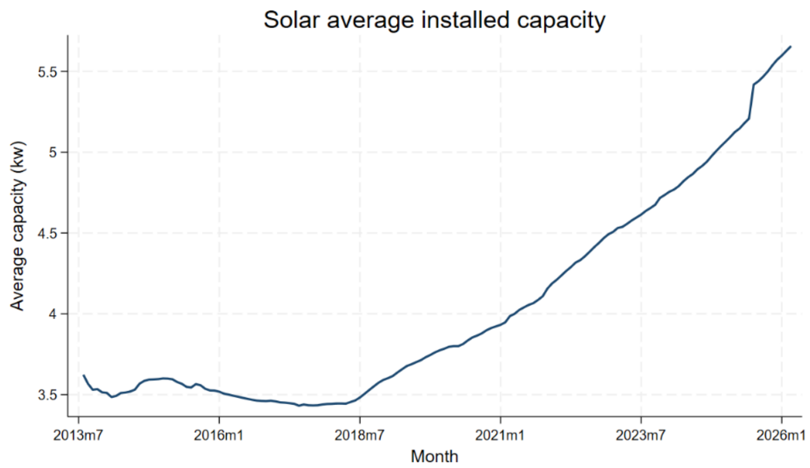
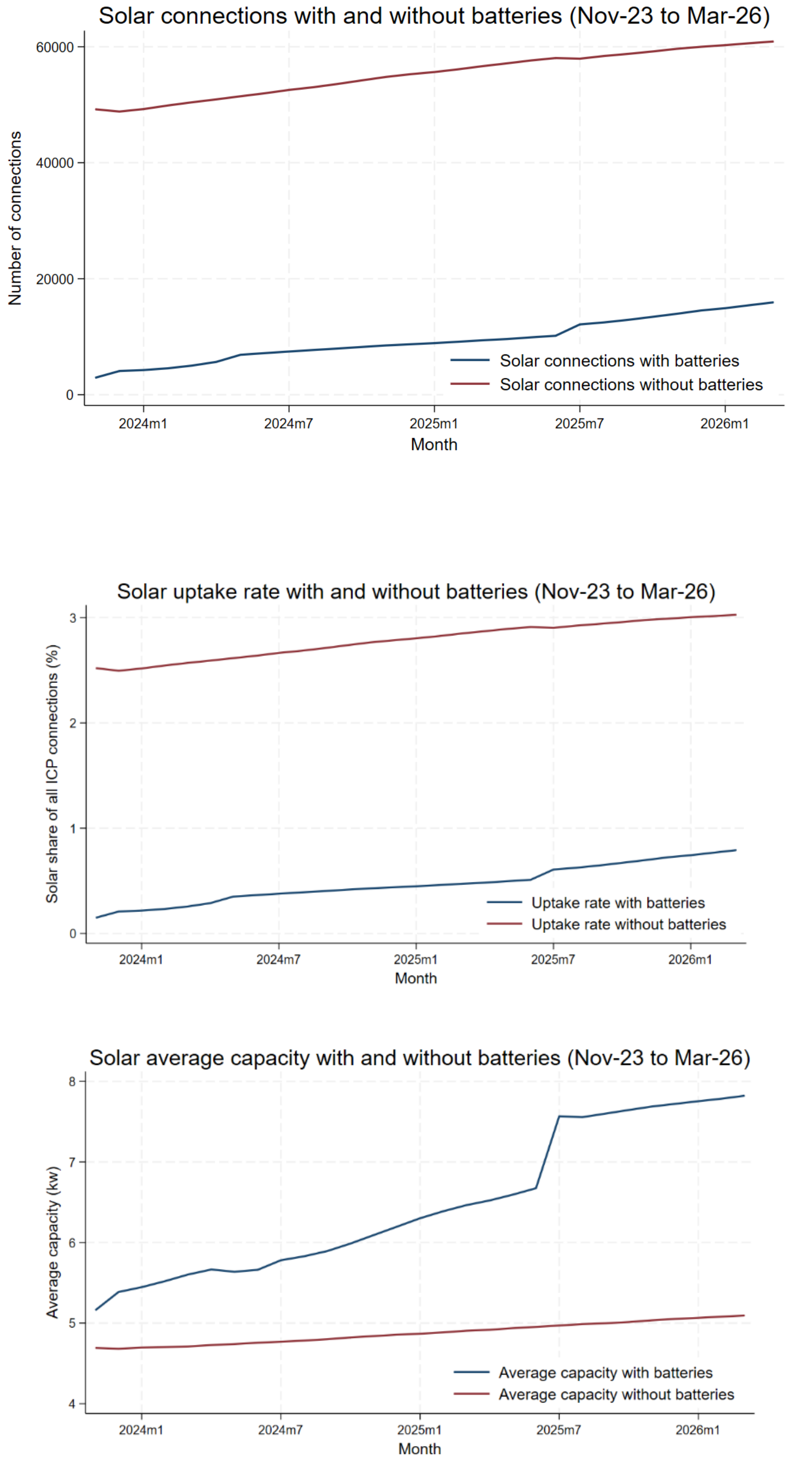


Figure 2 shows the split of solar connections into with and without batteries.[2] Solar connections without/with batteries reached around 60,000 and 15,000 respectively by March 2026, or 3.0%/0.8% of all ICPs. Average capacity for solar connections without batteries is around 5kW in March 2026, while capacity with batteries is much higher, at nearly 8kW (likely reflecting the ability to utilise the battery to store the greater production from higher capacity solar).

Figure 2 also shows a jump in the solar with-battery data, and a slightly smaller drop in the without-battery data, around July 2025. There is a large increase in the number of with-battery connections, with a large installed capacity that pushes the average up. The without-battery data shows a small drop in connections in July 2025. It is not clear from the data what these changes are attributed to. To address this, and reflect that there appears to be a change in the slope of the connection lines at this point, we establish some sensitivity bounds around our solar connection forecasts using July 2025 as a break point (explained in more detail in the next section).

[2] The Electricity Authority data for solar with-battery connections does include some data entries prior to November 2023. However, since connection numbers are very low, and the Electricity Authority state that any categorisation of these was inconsistent prior to November 2023, we drop them from the dataset.

Figure 2: Solar with- and without-battery connections (post Nov-23), connection numbers (top panel), uptake rate (middle panel), average capacity (bottom panel)



A.2.2 Forecast solar connections in the counterfactual

We forecast the path of monthly solar connections in the counterfactual separately for connections with and without batteries over the next 10 years. To do this we use ordinary least squares regression, regressing connection numbers on a linear time trend, and use the estimated relationship to forecast connection numbers in each month over the next 10 years.[3] We retain the slope coefficient from the regression results but adjust the intercept so that the forecast values start from the last actual value (to avoid any discontinuity where the forecast values start).

We acknowledge that this is a relatively simplistic forecasting approach and we have not, for example, assessed regression diagnostics or considered more sophisticated regression specifications. Nonetheless, we consider that this simple linear extrapolation of historic trends is a suitable and proportionate approach to making forecasts for our purposes.

Our linear forecasting approach also does not account for any flattening out of connection numbers as uptake reaches higher levels. Some models of solar uptake fit s-shaped models to connection numbers, allowing for a slow start in connections, followed by rapid uptake, then a levelling out.[4] However, the historical connections data in the previous section shows a generally linear trend, including over relatively long time periods. This may be because these s-shaped models are best applied to very new technologies, and solar has now been available for some time (despite uptake remaining relatively low). Furthermore, our results below show uptake does not reach implausible levels when based on a linear forecast.

We also include some confidence bounds around our forecasts, to account for uncertainty. In particular, we calculate an upper and lower bound by splitting the series at July 2025 (the point where there is a sudden jump in the data and a change in the slope, as discussed earlier), running a regression on each of the split series, and forecasting using the estimated regression relationship. In the with-battery data, the post-July 2025 regression line sets the upper bound, because it has a steeper slope than the pre-July 2025 regression line (which thus sets the lower bound). The opposite applies to the without-battery data: the post-July 2025 regression line has a flatter slope, so sets the lower bound (with the pre-July 2025 regression line setting the upper bound).

Figure 3 shows actual and forecast solar connections for solar with (top panel) and without (bottom panel) batteries. Our approach results in a central forecast of connections by March 2036 of approximately 67,000 with batteries (with lower and upper bounds of approximately 59,000 to 74,000), and 115,000 without batteries (lower and upper bounds of

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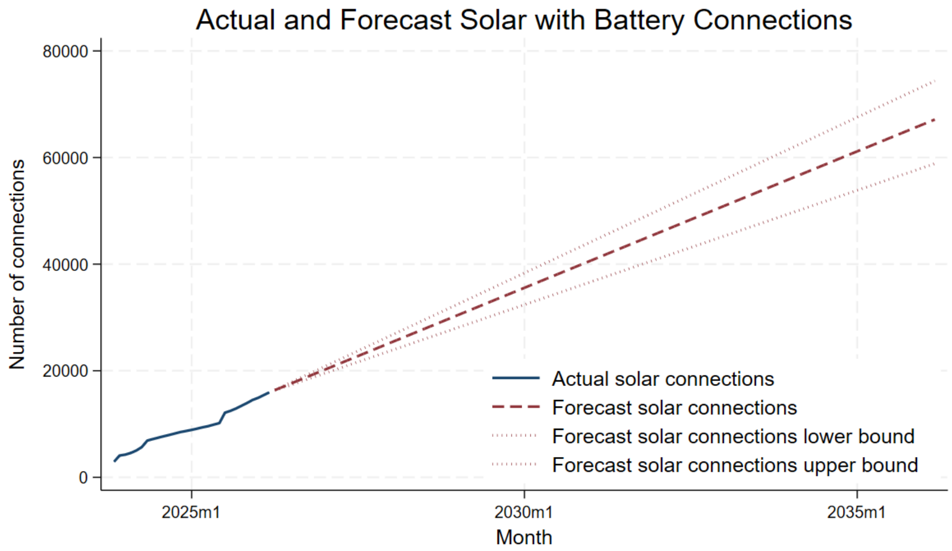
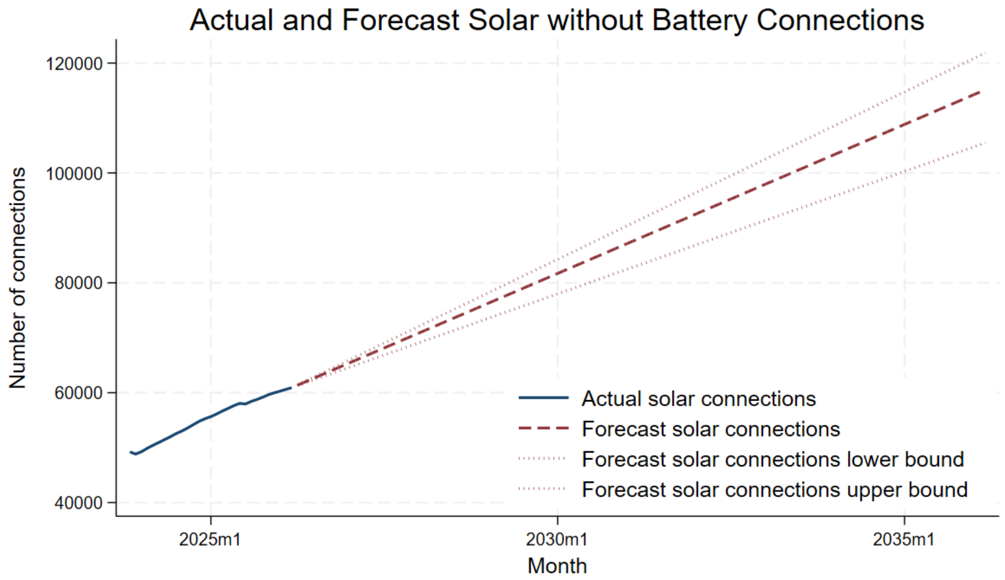
[3] The coefficients on the slope and constant are statistically significant at the 1% significance level for both the with and without batteries regressions. The R-squared is 0.9903 in the without-battery regression and 0.9750 in the with-battery regression.

[4] See, for example in the New Zealand context, Allan Miller, John Williams, Alan Wood, David Santos-Martin, Scott Lemon, Neville Watson, and Shreejan Pandey (2014), "Photovoltaic Solar Power Uptake in New Zealand", EEA Conference and Exhibition, 18-20 June, Auckland.

105,000 to 122,000). In March 2026, with-battery connections are 21% of all solar connections, but that is forecast to increase to 37% by March 2036 (in the central case).

Figure 3: Actual and forecast solar uptake rate with batteries (top panel) and without batteries (bottom panel)



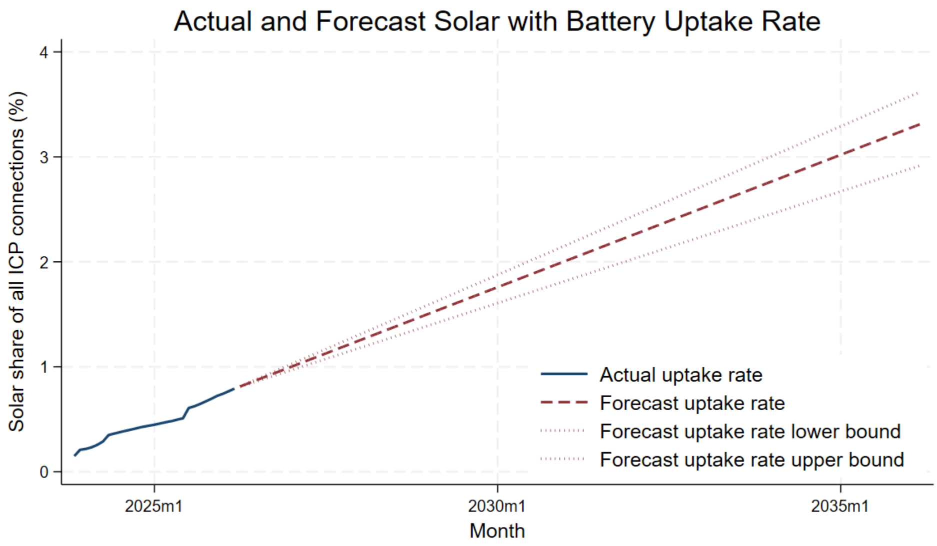


We use the same linear regression approach to forecast the uptake rate and total capacity (from which we calculate average capacity per connection[5]). Figure 4 shows actual and forecast uptake rate, which reaches 3.3% for with-battery connections (lower and bounds of 2.9% to 3.6%) and 5.4% for without-battery connections (lower and upper bounds of

[5] The lower bound average capacity connection is calculated as lower bound capacity divided by upper bound connections (and vice versa for upper bound average capacity per connection).

4.9% to 5.8%). In Figure 5 we present actual and forecast average capacity per connection. By March 2036, average capacity of solar with battery connections is 8.6kW (5.9kW to 10.7kW) and without battery connections is 5.9kW (5.3kW to 6.6kW).

Figure 4: Actual and forecast solar uptake rate with batteries (top panel) and without batteries (bottom panel)



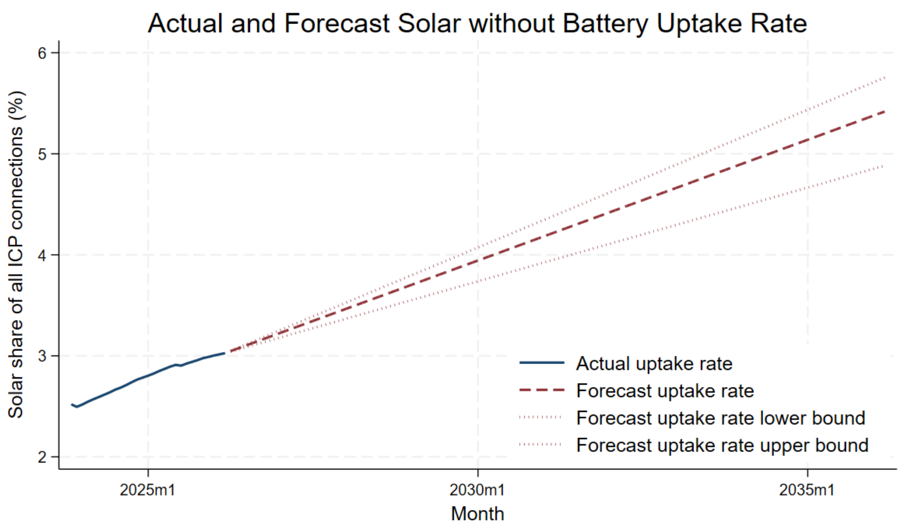
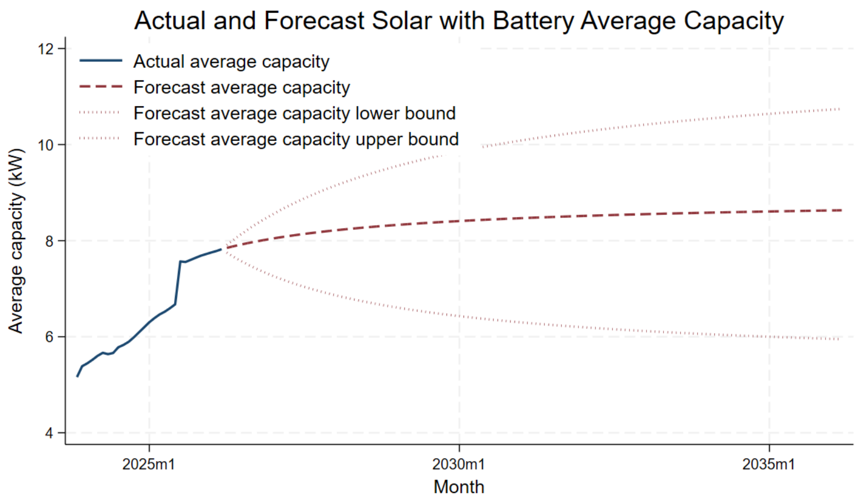
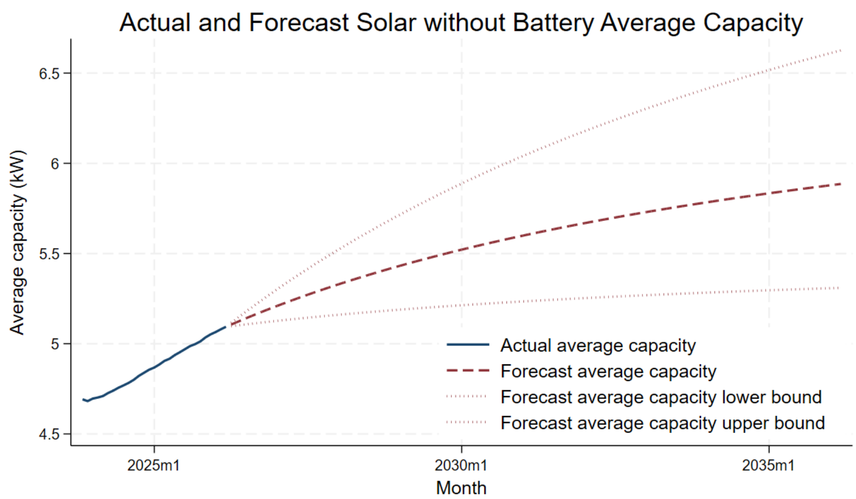


Figure 5: Actual and forecast solar average capacity with batteries (top panel) and without batteries (bottom panel)





A.3 Calculation of counterfactual net benefit path

A.3.1 Overview

We calculate the net benefits in each month over the 10-year time period of our analysis in the counterfactual i.e., the status quo scenario without any regulatory change. These are the benefits and costs of installing solar versus not installing it. Consistent with the standard approach to CBA,[6] we calculate these benefits and costs based on welfare impacts

[6] See, e.g., Anthony E. Boardman, David H. Greenberg, Aidan R. Vining, and David L. Weimer (2018), *Cost-Benefit Analysis: Concepts and Practice*, Fifth edition, Cambridge University Press.

and the real resources consumed or saved from solar installation, rather than financial transfers. The benefits and costs are:

- The costs of installing solar.
- The benefits related to reduced grid-electricity consumption, from household electricity consumption savings and solar production sold back to the grid.
- The benefit from avoided peak electricity generation and network investment.
- The welfare (profit) benefit to solar installers.

We provide more detail on the nature of these benefits and costs and their calculation in the sections below.

We have not quantified any benefits from reduced greenhouse gas emissions, which may occur if solar generation by households offsets non-renewable electricity generation. Electricity emissions are covered by the emissions trading scheme (ETS). If the ETS cap is binding and fixed, then emissions reductions in electricity generation will be reallocated to higher emissions in other sectors, such that there is no reduction in emissions. We recognise there are nuances in the operation of the ETS that mean this may not always be the case, but to be conservative for present purposes, we do not quantify any benefit from reduced greenhouse gas emissions.

A.3.2 Cost of installing solar

In this section we calculate the cost incurred by a household to install solar. This cost equals the profit earned by solar panel manufacturers and solar installers, plus the real resource costs of manufacturing and installing solar. The profit component therefore needs to be removed to determine the real resource cost for solar. We separately describe our calculation of the offsetting profit benefits later in our report, and at this stage just focus on the calculation of the household's total cost to install solar. However, in aggregate, our CBA captures the real resource cost for a solar installation (for further detail see section A.3.5).

The cost of installing rooftop solar depends on factors such as the size of the system and whether it includes a battery. From the connections data analysed in the previous section, the capacity of solar with/without battery connections is approximately 8kW/5kW in March 2026. EECA has data on typical installation costs for 3kW, 5kW, and 10kW with/without battery solar systems.[7] For the without-battery system installation cost, we use the EECA installation cost for a 5kW system of $11,500. For the with-battery system installation cost, we linearly interpolate between the EECA 5kW and 10kW installation costs (of $21,500 and $40,000 respectively) to estimate a cost for an approximately 8kW system of $32,600.

We understand that rooftop solar requires very little ongoing maintenance cost, so we do not include any such costs in our modelling. However, a solar system is likely to need a

[7] Breaking down home solar costs and savings | EECA

replacement inverter after approximately 15 years, at a cost of $3,700.[8] For modelling simplicity we add this inverter cost to the upfront cost of installing solar, discounted by 15 years (using an 8% discount rate) of $1,200.[9] We do not include any costs related to obtaining consent: many residential solar installations do not require consent, and where they do it is likely included in the bundled installation price.[10] The total solar installation cost is therefore $33,800 for with-battery installations and $12,700 for without-battery installations.

The average real price for solar panels has been falling over time, consistent with a 'learning curve' where prices fall by approximately 20% for every doubling of global cumulative capacity.[11] Battery prices show similar learning curves (20% for every doubling in capacity).[12] Solar capacity is forecast to double in the next five years,[13] which with a 20% price fall over this time implies an annual decrease of 4.4% per annum.[14] We assume a similar annual price decrease applies to batteries, which is conservative (leads to a higher cost) based on our understanding that battery technology has been improving at a faster rate than solar panel technology.

This decrease only applies to the panels and batteries, not to other parts of the installation cost (e.g., labour costs). In addition, since the average capacity of with- and without-battery installations in our analysis is forecast to increase, we would expect an offsetting increase in installation cost over the time period of our analysis. For these reasons, rather than the full 4.4% decrease, we therefore assume a small 2% decrease per annum in the overall solar installation cost over the time period of our analysis (which converts to a monthly decrease of 0.168% per month).

We apply these installation costs to the *new* solar connections in each month, based on the difference in the month-on-month forecast connection numbers.

A.3.3 Benefits and costs related to household electricity consumption

Overview

Households that install solar can cover some of their electricity consumption with the electricity produced by the solar system. If households overall consume less grid-produced

[8] Josh Ellison, Jenny Sahng, Nicole Kirkham, Ben Fahy, Dave Karl, and Dr Saul Griffith (2026), "Electric Homes and Vehicles: The opportunity of running on New Zealand-made energy", Rewiring Aotearoa, June. These authors present the inverter price as $3,000 for a 5kW system and $4,400 for a 9kW system (p.101). For simplicity, we use a value of $3,700.
[9] Whether we discount over 15 years to year zero ($1,166) or year one ($1,260) is likely within measurement error for our analysis, and we therefore use a rounded value of $1,200.
[10] Breaking down home solar costs and savings | EECA
[11] Solar panel prices have fallen by around 20% every time global capacity doubled - Our World in Data
[12] Micah S. Ziegler and Jessika E. Trancik (2021), "Re-examining rates of lithium-ion battery technology improvement and cost decline", *Energy and Environmental Science*, 4.
[13] Solar - IEA
[14] Using formula for the compound annual growth rate (CAGR) over 5 years, of $CAGR = (\frac{End\ value}{Start\ value})^{1/5} - 1$, where $\frac{End\ value}{Start\ value} = 0.8$ for a 20% price decline.

electricity, there is a benefit from the real resource cost savings of generating and distributing that electricity.

Households may also produce electricity from their solar system that is not used to cover their consumption, but can be sold back to the electricity grid (to earn the household additional income). The additional solar production offsets grid-produced electricity, which again is a benefit from the real resource cost savings of not generating and distributing that electricity.

We explain how we monetise these benefits (reduced grid-electricity consumption, net of solar rebound effects that we explain below, and excess solar production) in the following sections.

Reduced grid-electricity consumption

We monetise the benefit of reduced grid-electricity consumption by multiplying the electricity consumption that is offset by solar production by the variable-component of the retail electricity price. This assumes that the variable component of retail electricity prices is an appropriate proxy for the marginal cost of producing and delivering electricity. We exclude the fixed component of retail electricity prices. This assumes that the fixed component reflects, for example, sunk network costs and retailer fixed costs that are not avoided when a household reduces its grid-electricity consumption.

We use a value of 26c per kilowatt-hour (kWh) for the variable component of the retail electricity price, calculated by Ellison et al (2026).[15] This value is derived from MBIE's most recent Quarterly Survey of Domestic Electricity Prices (February 2026), which removes Ellison et al's estimate of fixed costs (of approximately 12c/kWh) from the total (fixed plus variable) retail electricity price of 40.6c/kWh.[16]

All dollar values in our model are in real terms (i.e., adjusted for inflation), and we assume that the variable electricity price remains constant at 26c/kWh in real terms over the time period of our analysis. This is equivalent to assuming that nominal retail electricity prices increase at the rate of inflation. This is a conservative assumption; if electricity prices are expected to increase faster than inflation, then the benefit of reduced grid-electricity consumption will increase over time.

We assume that a household installing solar uses the New Zealand-average annual electricity consumption per household of 6,999.5kWh.[17] Assuming an even distribution of consumption throughout the year, this amounts to approximately 583kWh per month. While an even distribution of consumption is not likely to be realistic (since more electricity will be consumed in the colder winter months), for modelling purposes this is unlikely to

[15] Estimate drawn from Josh Ellison, Jenny Sahng, Nicole Kirkham, Ben Fahy, Dave Karl, and Dr Saul Griffith (2026), "Electric Homes and Vehicles: The opportunity of running on New Zealand-made energy", Rewiring Aotearoa, June, p.67.

[16] Quarterly survey of domestic electricity prices

[17] Average consumption for the year to 31 December 2025, available at Electricity Authority - EMI (market statistics and tools), accessed 31 May 2026.

have a material effect on our results. This is because the undiscounted value of reduced grid-consumption will be the same with either an even or uneven consumption distribution and any differences due to discounting within a year will be small.

We assume that household consumption remains constant over the 10-year timeframe of our analysis (although we do separately account for a rebound effect from installing solar, discussed later). While total electricity consumption across all households in New Zealand is projected to increase over the next 10 years, a key driver of this is an increase in population,[18] and therefore we assume that consumption *per household* remains constant.

We then determine how much of this grid-electricity consumption is covered by solar production. Total solar production will depend on various factors like the number of sunlight hours (which in turn will depend on where in the country the household is located, placement of the panels, shading, etc) and the capacity of the system. One estimate for New Zealand is that every installed kilowatt of solar produces 1,300-1,650kWh per year.[19] To be conservative, we take the lower bound this range, such that a 5kW system would produce 6,500kWh per year and an 8kW system would produce 10,400kWh per year. The 5kW result is consistent with other evidence of production of 6,000-6,500kWh per annum for a 5kW system (or 1,200-1,300 per kWh).[20] We assume this production is distributed evenly throughout the year i.e., 542kWh per month for the 5kW system and 867kWh per month for the 8kW system, which (as with consumption) is not realistic but simplifies the modelling and is unlikely to make a material difference to our results.

For the 5kW without-battery system, not all of household electricity consumption will be covered by solar production. This is because some of the solar production will occur at times (e.g., during the day or summer months) that do not align well with household demand (e.g., during the evenings or in winter). Ellison et al (2026) assume that 50% of consumption is covered by solar production.[21] Miller et al (2025) give some examples of a typical solar system without a battery, where between 30% and 70% of consumption is covered by solar production (the midpoint of this range being 50%).[22] Based on this evidence, we assume that 50% of total monthly consumption (of 583kWh) is covered by solar production from the 5kW without-battery system i.e., approximately 292kWh per month.

For the 8kW with-battery system, solar production that occurs at times of low demand can be stored in the battery and used when demand is higher. However, there is still likely to be some consumption that is not covered by production, because battery storage is limited,

[18] MBIE (2024), "Electricity Demand and Generation Scenarios: Results summary", July, at p.35, available at: Electricity Demand and Generation Scenarios: Results summary July 2024.
[19] How Much Solar Power Can My Roof Generate in New Zealand?
[20] How Much Power Does a 5kW Solar System Produce? | Apollo Energy
[21] Josh Ellison, Jenny Sahng, Nicole Kirkham, Ben Fahy, Dave Karl, and Dr Saul Griffith (2026), "Electric Homes and Vehicles: The opportunity of running on New Zealand-made energy", Rewiring Aotearoa, June, p.95.
[22] Allan Miller, Tim Crownshaw, and Gareth Gretton (2025), "Understanding the value of residential solar PV and storage in New Zealand: An analysis of solar generation and demand data across regions under various price pathways", report prepared for EECA, available at: Understanding-the-value-of-residential-solar-PV-and-storage-in-NZ.pdf, at page 45.

making it difficult to store over long periods of time (e.g., from summer to winter). We are not aware of evidence on the proportion of consumption covered by production when there is battery storage, although Ellison et al (2026) note that it will be more than 50%. In our model we assume a value of 75% of total monthly consumption is covered by solar production from the 8kW with-battery system i.e., approximately 437kWh per month.

The benefit from reduced grid-electricity consumption is therefore calculated as the variable component of the retail electricity price multiplied by the electricity consumption that is covered by solar production i.e., 26c/kWh x 437kWh in each month for the with-battery system and 26c/kWh x 292kWh in each month for the without-battery system.

Solar rebound effects

Electricity consumption can increase after installing solar because of a 'solar rebound' effect, where households use more consumption because of the lower effective price of electricity and the increased income from selling electricity back to the grid.[23] There will be a welfare benefit to households from increased electricity consumption, being the additional consumer surplus from the use of electricity.

To quantify the consumer surplus benefit, we calculate the area of the consumer surplus triangle (in a standard price-quantity model with linear demand) as one-half the difference in price multiplied by the increase in consumption. We assume that the effective price of electricity for a household installing solar falls from 26c/kWh to zero, since households generate electricity from solar at zero marginal cost. The literature finds that the solar rebound effect ranges from an increase in consumption of approximately 10% to 30% of pre-solar consumption.[24] We therefore use a value of 20% (being the midpoint of this range from the literature) for the increase in consumption due to the solar rebound.

If some of the additional consumption is covered by grid-produced electricity, then there could potentially be a producer surplus benefit to electricity generators. However, our earlier assumption is that the electricity price reflects the marginal cost of supply, and we are implicitly assuming that this applies across the entire range of output (i.e., a constant marginal cost curve). Under these assumptions, producer surplus would be equal to zero, and we therefore do not monetise it in our CBA.

Excess solar production

The difference between solar production and electricity consumption that is not covered by solar production is sold back to the electricity grid. This offsets grid-produced electricity, which again is a benefit from the real resource cost savings of not generating and distributing that electricity.

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[23] Patrick Bigler (2025), "Magnitude and decomposition of the solar rebound: Evidence from Swiss households", *Journal of Environmental Economics and Management*, 133, 1-31.

[24] See Bigler (2025), *op cit.*, and Erdal Aydin, Dirk Brounen, and Ahmet Ergun (2023), "The rebound effect of solar panel adoption: Evidence from Dutch households", *Energy Economics*, 120, and references therein.

The marginal value of solar production sold back to the grid is not necessarily equal to the marginal cost of grid-produced and distributed electricity (which was proxied above by the variable component of the retail electricity price). This is because of a timing effect: solar electricity is produced during the day and in summer, when the marginal generation costs are low,[25] so the value of electricity sold back to the grid at this time will also be low.

This may explain why the buy-back rate for solar production sold to the grid is low relative to retail electricity prices. The buy-back rate ranges from approximately 8c/kWh to 23c/kWh, depending on the retailer and plan type.[26] We assume that the buy-back rate is a valid proxy for the marginal value of solar production sold back to the grid. To monetise the real resource cost savings from excess solar production sold back to the grid, we use a value of 16c/kWh (the approximate midpoint of the above range), which is also consistent with that used by Ellison et al (2026).[27]

Evidence from Australia is that the buy-back rate has been falling over time. This has been attributed to both increased supply of solar electricity into the grid pushing wholesale electricity prices lower and to early subsidies offered to encourage solar uptake.[28] It is therefore unclear how much of this decrease can be solely attributed to the high levels of solar uptake in Australia, and whether this same result would play out in New Zealand with lower levels of uptake.

Our approach is therefore to assume that the buy-back rate does not change over the 10-year period of our model. This assumption ensures consistency with our assumption of constant real variable electricity prices.

We therefore calculate the benefit from the real resource cost savings from the excess solar production that is sold back to the grid at the rate of 16c/kWh, which remains constant in each month over the time period of our analysis.

A.3.4 Benefit from avoided peak electricity generation and network capacity

As residential solar uptake occurs in the counterfactual, there may be benefits to the electricity system. The electricity system includes peaking generators (often with high marginal costs) and network capacity that is built to accommodate peak loads. By allowing electricity to be shifted away from peak periods, solar (particularly those with batteries) can result in these investments in new peaking generation or network capacity being deferred or avoided altogether.

There could potentially be an offsetting cost from additional investment needed in electricity networks to handle solar production sold back to the grid, particularly if this

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[25] For simplicity, we abstract from considerations on the impact of lake levels and the option value of water on marginal generation costs. For a discussion see Lewis Evans and Graeme Guthrie (2009), "How Options Provided by Storage Affect Electricity Prices", *Southern Economic Journal*, 75(3), 681-702.
[26] Buy-back rates are February 2026 rates, sourced from Solar buy-back rates — Powerswitch NZ.
[27] Josh Ellison, Jenny Sahng, Nicole Kirkham, Ben Fahy, Dave Karl, and Dr Saul Griffith (2026), "Electric Homes and Vehicles: The opportunity of running on New Zealand-made energy", Rewiring Aotearoa, June, p.96.
[28] See Solar Battery vs Feed-in Tariffs Australia (2026 Guide) and Solar feed-in tariffs plunge up to 99.93pc in 15 years as market saturates - ABC News.

exceeds local network capacity. We have not included this cost in our analysis. The evidence from Australia (where solar uptake is materially larger than that forecast in our model) is that only 1% of capital and operational expenditure of distribution businesses is spent on providing export services.[29] We therefore assume any such costs are unlikely to be material. We also sensitivity test a scenario where there is no benefit from the avoided cost of peaking investment, which could also amount to an assumption that any additional investment costs fully offset these benefits.

Including the avoided costs of peaking investment as a benefit from uptake of residential solar in the counterfactual would amount to an implicit assumption that the costs of peaking investment are not reflected in retail electricity prices. This would be the case if retail electricity prices do not reflect long-run marginal cost (LRMC). LRMC includes a return on investment, so prices that do not reflect LRMC do not cover the costs of peaking investment. Electricity prices do appear to reflect short-run marginal costs, at least at the wholesale level[30] (and this is reflected in our earlier assumption that prices reflect marginal cost). However, it is less clear whether electricity prices reflect LRMC. On the one hand, the Electricity Authority has found that sustained high electricity prices and pricing for hedge market contracts may support recovery of LRMC over time.[31] On the other hand, the recent finding in Frontier Economics' review of the electricity market is that pricing has not supported investment in new electricity generation in recent years, predominately due to uncertainty.[32] [33]

Our approach, for our preferred model specification, is to implicitly assume that retail electricity prices do not reflect LRMC. Our CBA therefore includes the benefit of the avoided costs of peaking investment. However, we also subject this to sensitivity testing, where these benefits are excluded and assumed to be reflected in retail electricity prices (thus being already captured in the benefit from reduced grid-electricity consumption).

To estimate this benefit, we draw on Reeve, Stevenson, and Comendant (2021), who calculate that the annual benefit for 1 megawatt (MW) of avoided peak in 2021 is $240,447.[34] This is the avoided cost of peak thermal generation and network capacity investment that comes from the use of distributed generation such as residential solar (with batteries),

[29] Australian Energy Regulator (2024), "Insights into Australia's growing two-way energy system", Export services network performance report 2024.
[30] See the Electricity Authority's discussion at: [How marginal electricity spot pricing reflects cost | Electricity Authority]().
[31] The Electricity Authority makes the point re sustained high prices here: [How marginal electricity spot pricing reflects cost | Electricity Authority](), and discusses prices for hedge contracts here: [Electricity hedge prices compared to new estimate of the LCOE | Electricity Authority]()
[32] Frontier Economics (2025), "Review of Electricity Market Performance", Final report to Ministers and MBIE, 23 May, at p. 28.
[33] We can conceptualise this as uncertainty increasing the option value of investment. The value of the option to invest is an important component of LRMC (see Avinash K. Dixit and Robert S. Pindyck (1994), *Investment Under Uncertainty*, Princeton University Press), and Frontier Economics' finding suggests that electricity prices have not reflected the value of this option, and therefore do not reflect LRMC.
[34] David Reeve, Toby Stevenson, and Corina Comendant (2021), "Cost-benefit analysis of distributed energy sources in New Zealand", Report for the Electricity Authority, 13 September.

smart home management, the use of electric vehicle batteries, and commercial solar. Since this is a 2021 value, we inflate it to 2026 using the Consumers Price Index.[35] Dividing by 12, we use a monthly benefit of $25,122 per 1MW of avoided peak.

The benefit from avoided peak investment is most likely to occur for solar systems with batteries, since peaks tend to occur in winter and evening periods when the sun is not shining, but the battery allows the household to store solar-produced electricity for these peak times. We therefore apply this benefit only to the capacity of solar with-battery installations.

Furthermore, 1MW of solar with battery capacity does not avoid 1MW of peak electricity consumption, since rooftop solar production is concentrated in daylight hours and batteries do not have unlimited storage capacity. To reflect this, we assume that only a small proportion of solar capacity results in avoided peak generation. For this we draw on Jacobs (2026), who estimates that around 25% of peak electricity demand could be reduced from demand-side flexibility measures such as rooftop solar with batteries.[36] We use 25% as the best available proxy for the proportion peak generation capacity avoided by 1MW of solar capacity. We therefore multiply the $25,122/MW by 25% to estimate the benefit of avoided peak from solar with batteries.

We use the forecast values for total installed capacity for solar with batteries, and multiply monthly installed capacity by 25% of $25,122/MW to give a monthly benefit from avoided generation and network investment. As noted, we do not apply this benefit to solar installations without batteries.

A.3.5 Surplus benefit to solar installers

Solar installers will benefit from the producer surplus (effectively profit) they earn on each additional solar install in the counterfactual. The profit earned is the revenue (R) from selling an additional solar installation less the installer's costs of installation (C) i.e., profit is $P = R - C$. In undertaking this calculation, we are mindful of double counting. The revenue earned by a solar installer is equal to the cost paid by the household for installation, which is already captured above as a negative impact in our model. However, the key measure we are after is the real resource cost of installing solar i.e., C. This can be calculated as the revenue earned less the solar installer's profit, $C = R - P$. Therefore, since we have calculated R earlier (i.e., the installation cost), we calculate P in this section, and our overall calculation effectively subtracts P from R to give the real resource cost of installing solar.

[35] We adjust by the ratio of the CPI for quarter 1 2026 of 1339, to the CPI for quarter 1 of 2021 of 1068.

[36] Jacobs (2026), "The full potential of flexible electricity use in New Zealand: Summary and insights report", January, available at: The-full-potential-of-flexible-electricity-use-in-New-Zealand-Summary-and-insights-report-2026.pdf

We assume that all installers are New Zealand-owned, and we therefore include profit benefits to domestically-owned firms in our CBA.[37] [38]

To estimate the benefit to solar installers, we use evidence on gross profit margins for solar installers. The gross profit margin is the gross profit (revenue minus variable cost) as a percentage of revenue. This is the metric typically used to measure profit impacts for CBA purposes, because it reflects the additional revenue less the additional variable costs for selling the marginal solar install. An installer's fixed costs are excluded, because by definition, these do not vary with the number of installs. One estimate for the gross profit margin gives values in the range of 20%-40%,[39] and another estimate gives values in the range of 10%-35%.[40] While neither of these are New Zealand-specific estimates, we are not aware of any evidence on margins in New Zealand, so assume that they are similar to overseas estimates. Based on the midpoint of the entire gross margin range (of 10%-40%), we assume a gross profit margin of 25%.

We apply the 25% margin to the revenue that a solar installer receives from each install (which is equal to the cost incurred by the household) i.e., revenue of $33,800 for with-battery installations and $12,700 for without-battery installations. We multiply by the forecast number of new solar installations in each month to get the total monthly profit benefit to solar installers in the counterfactual.

A.3.6 Summary of calculation of the counterfactual net benefit path

In each month, we calculate the net benefit of solar installations in the counterfactual, which gives us a counterfactual net benefit path over the 10-year time period of our analysis.

The (gross) benefits are:

- Reduced grid-electricity consumption.
- Consumer surplus benefit from solar rebound.
- Excess solar-produced electricity sold to the grid.
- Avoided peak generation and network investment (for solar with battery only).
- Profit to solar installers.

The costs that are netted off are:

- Solar installation costs.

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[37] We recognise there are nuances around the incorporation of profits to domestically-based but foreign-owned firms in CBA. A discussion of these nuances is beyond the scope of our report.
[38] Solar panels are manufactured overseas. This means that some of the real resource costs of installing solar accrue to foreign-owned and located firms. For simplicity, we do not account for the implications of this in our modelling.
[39] Solar Panel Profit Margins | How Much Can You Really Earn
[40] Solar Installer Profit Margins 2026: Revenue, Costs & Benchmarks | SurgePV

We calculate the benefits and costs based on connection numbers for our central forecast, and lower and upper bound forecasts. The net benefit in the central case is calculated as the benefits minus costs in the central forecasts. The lower bound net benefit is the lower bound costs minus upper bound benefits, while the upper bound net benefit is the upper bound benefits minus lower bound costs.

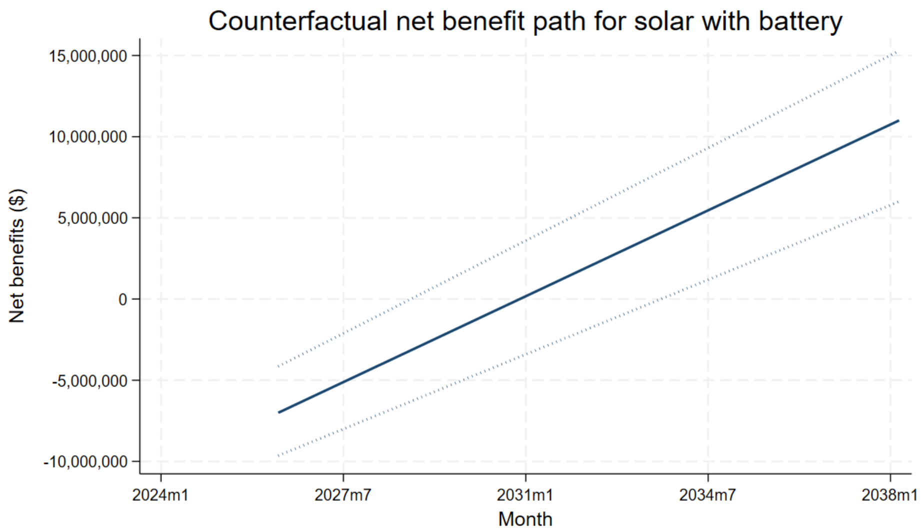
Figure 6 shows the monthly net benefits for the with (top panel) and without (bottom panel) battery scenarios. Net benefits are increasing over time, as solar connections increase. In the with-battery case, net benefits are negative through to around late 2030. This arises because in the early part of the 10-year period the installation cost is relatively high and there is not a sufficiently large base of existing installed connections such that the benefits of these connections (reduced grid-electricity consumption, etc) outweigh the installation costs. As we get later in the period, however, the larger installed base of connections means the monthly net benefits of these connections start to outweigh the installation costs of the new connections each month. This does not arise in the without-battery case, because of the combination of lower installation costs and a larger starting installed base at the start of our series.

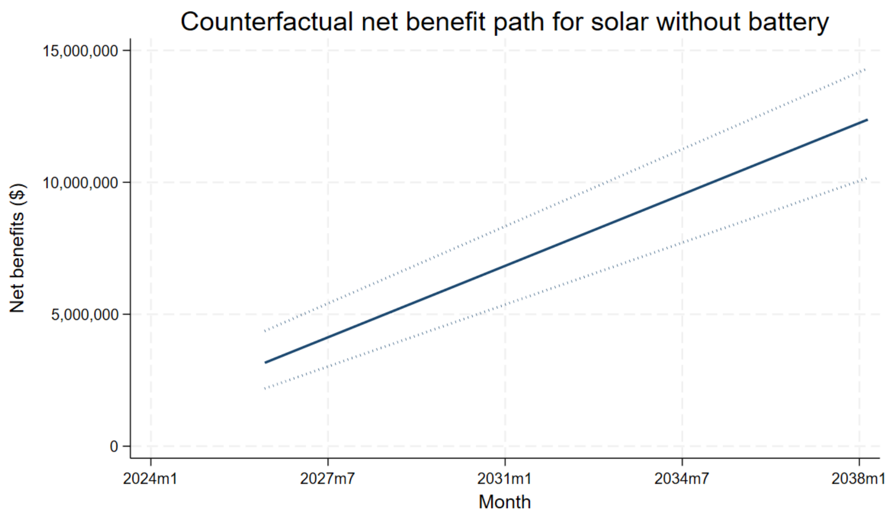
To account for benefits that continue beyond the 10-year modelling period, we include a terminal value representing the residual net benefits from solar connections after the end of the modelling period. We do this in a relatively simplified way, by taking the recurring monthly net benefits[41] in the final month of the counterfactual period and calculating the present value of these benefits over a further ten years. This is intended to capture the ongoing benefits from solar connections that remain operational beyond the 10-year modelling horizon.

The average lifespan of solar panels is around 25-30 years,[42] meaning that the remaining life of the solar connections in our model will vary considerably. Some connections from early in the (historical) dataset will have relatively little life remaining by the last month of the counterfactual, while more recent installations will continue generating benefits for much longer. However, to simplify the analysis we have used a single value for the remaining life of all solar installations and choose ten years as a reasonable value.

[41] That is, the benefit of reduced grid-electricity consumption, consumer surplus from the solar rebound, excess solar production sold back to the grid, and avoided peak generation and network investment.
[42] How Long Does A Solar Panel Last? | Harrisons Solar

Figure 6: Monthly counterfactual net benefits for solar with batteries (top panel) and without batteries (bottom panel)





A.4 Calculation of factual net benefit path

In the factual, we model a regulatory change that speeds up the installation time for residential rooftop solar and lowers inspection costs.

Evidence gathered as part of the review is that the time taken to install solar panels is variable, and depends on factors such as the nature of the system, the electricity distribution business and retailer, the location, etc. The nature of the Ministry's package of recommendations suggests this installation time will be faster. The Ministry's analysis shows that for a residential solar installation, the installation time could decrease from approximately 3 months in the counterfactual to 6 days in the factual i.e., a reduction of around 2 months and 3 weeks.

Public information on the time taken to install solar panels suggests it takes between 2-6 months.[43] In contrast, examples of timeframes elsewhere are approximately 1-2.5 months in Australia,[44] 1-3 months in the UK,[45] and 2-4 months in the US.[46] If regulatory change in New Zealand could replicate the approximate timeframes in these countries, then we might expect a reduction in the installation timeframe of 1.75 months.[47]

Our model uses monthly data, such that a reduction in regulatory delay is best incorporated as a reduction rounded to the nearest month. Based on the above information from the Ministry's analysis and public data, we use as our base case a two-month reduction in regulatory delay. While some solar installations will experience larger delay reductions and others will experience smaller (or no) reduction in delay, to keep our analysis tractable we apply a single average reduction in delay of two-months across all solar installations. We also undertake sensitivity testing of this assumption.

We also model a reduction in net installation costs, based on a reduction in the cost of electrician inspections from moving to a spot check inspection model. We include in this calculation an estimate of the cost of harm from undetected defects, which may increase if moving to a model where not every installation requires an inspection. The detail of our calculations is set out in Appendix B. We calculate a reduction in installation costs in the factual, net of costs from increased defects, of $250 per solar installation (for both with- and without-battery installations), and assume this represents a reduction in real resource costs.

There may also be costs in the factual incurred by electricity distribution businesses (EDBs) and retailers to alter their processes (e.g., to change their software or add personnel). As an indication, the cost of implementing an IT system can often be in the range of $40,000 to in excess of $100,000.[48] However, it is difficult to estimate these costs, because they are likely to be highly variable across EDBs and retailers depending on their existing processes. As a way of implementing these costs in our model, we assume that the total cost is equal to a one-off cost in the factual, incurred in the first month of our analysis, of $1 million (which we also subject to sensitivity testing).

In the factual, we bring the counterfactual path of solar installations forward by two months, re-calculate the net benefits, and include a $250 decrease in net installation costs. This means that the net benefits that were occurring in, say, December 2027 in the counterfactual now occur in October 2027 in the factual, and so on. That is, we effectively just take the counterfactual benefit path and shift it forward in time (with the inclusion of the decrease in installation costs). This makes the conservative assumption that any

[43] How Long Does Solar Panel Installation Take in NZ?
[44] Solar Installation Timeline Australia — From Quote to Switch-On | Solar Calculator Agent. See also Solar Panels Timeline & Process in Australia | Freedom Energy, with an estimate of 1-2 months.
[45] How Long Does It Take to Install Solar Panels?
[46] Solar Panel Installation Timeline: Week-by-Week What to Expect | Green Energy Calculators
[47] Based on the approximate difference between the midpoint of the New Zealand 2-6 month timeframe (4 months) and the average midpoint of the US, UK, and Australia timeframes (2.25 months).
[48] See, for example, Cost of Custom Software Development in NZ: The 2026 Guide

installation processes that are underway in the counterfactual at the time of the regulatory change do not to get any faster in the factual.

As discussed above, we calculated a ten-year terminal value to reflect benefits that continue beyond the 10-year modelling period. To be conservative, we do not bring forward this terminal value, so as not to artificially inflate net benefits. That is, we use the same terminal value in both the factual and counterfactual, so the difference nets to zero. The terminal value is used to present a more realistic view of counterfactual and factual net benefits, where the flow of benefits continues to occur beyond the modelling period. The terminal value does, however, make a difference to the net benefits in the alternative scenario (explained in section A.6), due to the higher number of solar connections.

A.5 Calculation of net benefits

To calculate the net benefit of regulatory change, we assume that any regulatory change would not be put in place until July 2027. Since we assume that regulatory change will speed up the installation process by two months, we therefore start the counterfactual net benefit path in September 2027 (two months after regulatory change occurs in the factual). We calculate the sum of the present value of this counterfactual net benefit path over a 10-year timeframe, discounted at an 8% discount rate to March 2026 present value.

Similarly, we calculate the sum of the present value of this factual net benefit path over a 10-year timeframe. The overall net benefit of regulatory change is the difference between the factual and counterfactual net benefit present values. We do this for both the with- and without-battery cases (and in the low, central, and high forecast scenarios). The results of this analysis are shown in Table 1.

Table 1 shows there is a wider confidence interval around the with-battery values compared to the without-battery values, which reflects a smaller installed base of with-battery connections and greater volatility in growth in the historic data.

The key result from Table 1 is that speeding up the installation time for residential solar installations by two months and lowering net installation costs by $250 gives **a net benefit of $23m** (with a range of $15m-$30m).

Table 1: Base case counterfactual and factual present value of net benefit and difference, with and without battery and total

	With-battery	**Without-battery**	**Total with and without battery**
Counter-factual net benefit	$773m ($390m-$1,109m)	$1,132m ($965m-$1,284m)	$1,906m ($1,354m-$2,392m)
Factual net benefit	$782m ($393m-$1,122m)	$1,147m ($976m-$1,301m)	$1,929m ($1,370m-$2,423m)
Difference between factual and	**$8.3m ($3.4m-$12.9m)**	**$14.8m ($11.8m-$17.4m)**	**$23.2m ($15.2m-$30.2m)**

counter-factual			

A.6 Alternative scenario with increased installations

We also model an alternative scenario where the faster install time and lower installation cost leads to some new solar installations that would have otherwise not occurred.[49]

Some international literature suggests that streamlining permitting processes for installing solar can lower residential solar prices. In particular:

- Dong and Wiser (2013) find that cities in California with more favourable permitting processes have 4%-12% lower average residential solar prices than cities with more onerous permitting.[50]
- Seel, Barbose, and Wiser (2014) find that residential solar prices are twice as high in the US than in Germany in 2014, attributed to higher 'soft costs' which include permitting and inspection procedures.[51]
- Burkhardt et al (2015) find that variations in local permitting and other regulatory processes lead to price differences of 8% between the more permissive and more onerous US jurisdictions.[52]

On the other hand, we note that White (2019) finds that more streamlined permitting has no effect on residential solar installation rates in California.[53]

Based on economic theory, we would expect that lower solar prices would induce a demand response. This might arise not only from the effect of streamlined permitting practices, but also to the extent that lower electrical inspection costs are passed through to households as lower installation prices. The gross reduction in inspection cost calculated in Appendix B is approximately $330 (this does not account for netting off costs related to an increased risk of defects in the factual, which yields the overall net result of $250). A $330 lower inspection cost amounts to an approximately 1-3% price decrease, if fully passed through, based on the with/without battery installation costs. If, in addition to this inspection cost decrease, prices also fall by around 8% based on a streamlined regulatory

[49] We assume that this increase in solar installations can be absorbed within the spare capacity of existing solar installers, such that there are no fixed costs associated with more installers being required in the factual compared to the counterfactual (case with extra installations only).
[50] Changgui Dong and Ryan Wiser (2013), "The impact of city-level permitting processes on residential photovoltaic installation prices and development times: An empirical analysis of solar systems in California cities", *Energy Policy*, 63, 531-542.
[51] Joachim Seel, Galen L. Barbose, and Ryan H. Wiser (2014), "Analysis of residential PV system price differences between the United States and Germany", *Energy Policy*, 69, 216-226.
[52] Jesse Burkhardt, Ryan Wiser, Naim Darghouth, C.G. Dong, Joshua Huneycutt (2015), "Exploring the impact of permitting and local regulatory processes on residential solar prices in the United States", *Energy Policy*, 78, 102-112.
[53] Lee V. White (2019), "Increasing residential solar installations in California: Have local permitting processes historically driven differences between cities", *Energy Policy*, 124, 46-53.

process (using the aforementioned result from the literature), then we may expect an approximately 10% decrease in price. However, to be conservative (and reflecting also that there may be less than full pass through, and that one study finds no impact of streamlining on installation rates), we assume only a 5% price impact.

To convert this to a quantity impact, we require an estimate of the elasticity of demand for solar. There is relatively limited literature to draw on here, but a US study estimates an elasticity of demand for residential solar systems of -0.651.[54] Using an elasticity of -0.651 implies an approximately 3.5% quantity increase for a 5% price drop.

It is useful to compare this quantity increase to Victoria, Australia, which started its Solar Homes Program in August 2018 offering up to a 50% rebate and a streamlined installation process. Using data on monthly small-scale solar installations from the Clean Energy Regulator, we estimate that average monthly solar installations increased by 63% from the pre-August 2018 period to the post-August 2018 period.[55] In the much narrower 3-month period either side of August 2018, average installations increased by 48%.[56] Much of this could be attributed to the rebate, although there could still be some increase in installations that arises from the streamlined process.

We assume a 3.5% increase in solar installations, which is combined with the 2-month reduction in delay and $250 decrease in net installation costs. We apply the 3.5% increase to the additional counterfactual solar installations in each month i.e., the additional factual solar installations are 3.5% higher than additional counterfactual solar installations in each month.

The results of this scenario are shown in Table 2. In this scenario, we estimate a net benefit to New Zealand of $46m, in NPV (with a range of $18m-$70m).

Table 2: Alternative scenario with 3.5% increase in additional solar installations: counterfactual and factual present value of net benefit and difference, with and without battery and total

	With-battery	**Without-battery**	**Total with and without battery**
Counter-factual net benefit	$774m (-$390m-$1,109m)	$1,132m ($964m-$1,284m)	$1,906m ($1,354m-$2,392m)
Factual net benefit	$794m (-$392m-$1,146m)	$1,157m ($981m-$1,317m)	$1,951m ($1,373m-$2,463m)
Difference in factual and	**$20.5m ($2.0m-$36.8m)**	**$25.1m ($16.1m-$33.0m)**	**$45.6m ($18.2m-$69.9m)**

[54] Kenneth Gillingham and Tsvetan Tsvetanov (2019), "Hurdles and steps: estimating demand for solar photovoltaics", *Quantitative Economics*, 10(1), 275-310.
[55] We calculate average monthly connections from January 2011 to July 2018 of 3,415, and from August 2018 to March 2026 of 5,578. The data are sourced from: Small-scale installation postcode data | Clean Energy Regulator
[56] From an average 3,315 installations per month for May-July 2018, to an average 4,632 installations from August to October 2018.

counter-factual			

A.7 Sensitivity testing

We have undertaken sensitivity testing by varying each individual parameter to an upper and lower bound of its range while holding all other parameters fixed at their base case value. We draw on the literature and other data and analysis used in setting each parameter to determine these bounds (with some exceptions where we have no range from the literature or data, so assume a relatively symmetric range around the central value).

In Table 3 we set out our sensitivity results. This table presents the central value of the net benefits (10-year NPV) for the base case (i.e., assuming only a reduction in delay and lowering of inspection costs, with no increase in solar installations) for different parameter variations. For comparison, we also repeat the base case central result in the second row of the table.

Changes in most of the parameters have relatively limited impact on the central net benefit. The largest impacts, which shift the central net benefit in the order of 15%-20% from its base case value, are changes to the reduced months of regulatory delay, the low with-battery installation cost, the high variable electricity price, the electrical inspection cost savings, the probability of fire risk, and the high one-off cost to EDBs and retailers. For all other parameter variations, the central net benefit value never moves by more than approximately 10%.

Table 3: Sensitivity of base case results to variations in individual parameters

Parameter	**Lower and upper bound of parameter sensitivities**	**Rationale for range of parameter sensitivities**	**Central net benefit NPV**
All base case parameters	*All base case parameters*	*N/A*	*$23.2m*
Reduced time of delay	1-3 months	Approximate difference between lower and upper bound time periods of NZ and other countries	$18.9m-$27.5m
Solar with battery installation cost	$41,200-$14,700 (high cost = lower bound NPV, etc)	Low and high end of EECA estimates of costs + $1,200 inverter	$21.1m-$28.4m
Solar without battery installation cost	$21,200-$9,700 (high cost = lower bound NPV, etc)	Low and high end of EECA estimates of costs + $1,200 inverter	$20.7m-$24.0m

Annual decrease in solar installation prices	1%-4% annual decrease	Assumed bounds around 2% central value	$22.4m-$24.6m
Variable electricity price	$0.21/kWh-$0.36/kWh	Low and high regional values from MBIE price data, less Rewiring Aotearoa estimate of fixed costs	$20.5m-$28.5m
Household electricity consumption	5,741kWh-8,130kWh per annum	Low and high regional values from EA regional data[57]	$22.2m-$24.0m
Consumption covered by solar production with battery	65%-85%	Assumed bounds around 75% central value	$23.0m-$23.3m
Consumption covered by solar production without battery	40%-60%	Assumed bounds around 50% central value	$22.8m-$23.5m
Rebound effect	10%-30%	Range of values from the literature	$22.9m-$23.4m
Solar production with battery	9,600kWh-13,200kWh	Bounds from literature of 1,200kWh per kW capacity to 1,650kWh per kW capacity	$22.7m-$24.8m
Solar production without battery	6,000kWh-8,250kWh	Bounds from literature of 1,200kWh per kW capacity to 1,650kWh per kW capacity	$22.6m-$25.2m
Buy-back price	$0.08/kWh-$0.23/kWh	Low and high ends of range from Powerswitch data	$20.6m-$25.4m
Value of avoided peak (with battery)	$20,098/MW-$30,146/MW	Assumed multiple of 0.8-1.2 times central value of $25,122/MW	$22.7m-$23.6m
Value of avoided peak also applies to non-battery	$25,122/MW applied to non-battery installations	Battery value also applies to non-battery	$26.3m

[57] Electricity Authority - EMI (market statistics and tools)

Value of avoided peak does not apply	No benefit from avoided peak	No benefit from avoided peak	$20.8m
Reduction in peak electricity demand from solar	20%-30%	Assumed range around central value of 25%	$22.7m-$23.6m
Installer profit margin	10%-40%	Range of values from margin data	$20.5m-$25.7m
Electrical inspection cost savings	$200-$320	Calculated based on Appendix B calculations using a range of inspection prices from $280-$400 as noted in Appendix B	$19.8m-$27.8m
Probability of fire	10%	Using a higher probability of fire from the UK value discussed in Appendix B. This decreases electrical inspection cost savings to $188	$19.0m
One-off cost to EDBs and retailers	$4m-$0.5m (high cost = lower bound NPV, etc)	Range of values around central value of $1m	$17.7m-$24.1m
Discount rate	2%	Alternative Treasury discount rate for non-commercial projects	$24.7m

Appendix B. Calculation of factual installation cost savings

B.1 Overview

This appendix sets out the methodology used to estimate savings in inspection-related costs in the factual relative to the counterfactual. The analysis compares the counterfactual (a universal in-person inspection), and a factual scenario based on the Ministry's recommendation for in-person spot checks.

All estimates are expressed on a per-installation basis and incorporated into the overall CBA. We calculate the total expected cost per installation in each of the factual and counterfactual as the real resource cost from the inspection process, plus the costs related to defects. The cost saving is the difference between the factual and counterfactual total expected cost per installation.

B.2 Inspection process costs

B.2.1 In-person inspection

The cost of an in-person inspection is estimated at $340 per installation. This is based on an observed price range for 1 to 2 hours of work ($280–$400) from publicly available data.[58] It is supported by consultations with the Electrical Inspector Association, who give a standard price of $300 with an additional $1.50 per kilometre travelled. We acknowledge that prices may be much more variable than this based on, for example, the region where the solar installation is undertaken and its complexity. However, the value of $340 gives us a tractable central value that is suitable for modelling purposes.

Under the counterfactual, this cost is applied to 100% of installations that take place, since all installations require an in-person inspection. Under the factual, we assume only 2.5% of installations will require a spot check in-person inspection. This is based on South Australian evidence on the proportion of random sample inspections undertaken.[59]

B.2.2 Expected inspection cost

The expected inspection process cost is calculated as:

(Probability of in-person inspection × in-person cost)

This results in a counterfactual cost of $340 per installation, and a factual cost of $8.50 per installation.

B.3 Defect detection

The differing inspection approaches will affect the probability that defective installations are identified. If there is a higher likelihood of defective installations, this will impose higher costs from either remedying defects or adverse consequences when the installation fails. In

[58] Photo Voltaic High Risk Inspection - Ultraflex Electrical
[59] Inspections update No. 24: Small-scale Renewable Energy Scheme 2024–25 inspections program

this section we set out how we estimate the probability of defection in the factual and counterfactual.

B.3.1 Baseline defect rates

We start by drawing on Australian audit data for solar inspections.[60] We use data on defect rates averaged across ACT, Tasmania, and Victoria for the counterfactual (universal in-person inspections), as these jurisdictions all undertake universal in-person inspections. For the factual (in-person spot check) scenario, we use data from South Australia, as we understand they employ the most similar method to the recommendation that underlies the factual scenario. The defect rates are:

- Substandard installations: universal in-person, 15.2%; spot check, 18.4%.
- Unsafe installations: universal in-person, 3.47%; spot check, 1.4%.
- Total defect rate: universal in-person, 18.67%; spot check, 19.8%.

The proposed recommendation that underlies the factual is for high-risk checks to be conducted alongside the random spot checks, which we understand is similar to the South Australian approach. However, due to limited data and difficulty of incorporating this into the analysis, the impact of high-risk checks cannot be reliably quantified and is therefore excluded from this analysis. As a result, our calculation assumes only random spot checks, which are likely less effective than a combined random and risk-based approach. This means the estimated outcomes are conservative and likely understate the true effectiveness of the factual.

B.3.2 Detection rates

Not all defects are likely to be detected. Detection rates are assumed to be 80% for in-person inspections. This is an approximation based on limited evidence. New York's solar subsidy programme, NY-SUN, found that 22% of installations have deficiencies that an in-person inspection missed.[61] In addition, based on industry consultation, we are aware that some inspectors do not upload failures into the database, which also implies less than 100% detection.

B.3.3 Effective detection

The effective detection rate is 80% under the counterfactual, because all installations are inspected and each inspection is assumed to detect 80% of defects. Applying this to the baseline defect rate of 18.67% gives a share of installations with defects that are detected of 14.93%, with the remaining 3.73% having undetected defects.

Under the factual, only 2.5% of installations receive an in-person spot check. Combining this with the assumed 80% detection rate gives an effective detection probability of 2% (2.5% × 80% = 2%).

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[60] Inspections update No. 24: Small-scale Renewable Energy Scheme 2024–25 inspections program
[61] Remote-Inspections-Whitepaper_Final-February-20-2026.pdf

Applying this to the baseline defect rate of 19.8% gives a detected defect share of approximately 0.4%. The remaining 19.4% of installations are treated as having undetected defects.

B.4 Cost of defects

We calculate three categories of defect-related costs:

- The cost of immediate remediation for a defect that is detected during the in-person check.
- The cost of subsequent repair for a defect that is undetected.
- The cost arising from the risk of fire from a defect that is undetected.

B.4.1 Immediate remediation (detected defects)

Detected defects are assumed to be repaired immediately at a cost of $340 per installation, representing the cost of engaging an electrician to fix the defect. We have assumed this cost to be consistent with the original inspector cost.

This leads to an expected cost of:

Factual: Detected defect share (0.4%) × repair cost ($340) = $1.35 per installation

Counterfactual: Detected defect share (14.93%) × repair cost ($340) = $50.77 per installation

B.4.2 Subsequent repair (undetected defects)

Undetected defects are assumed to be identified and repaired at a later stage. This identification may arise because of the emergence of some fault, the replacement of the inverter, or a building inspection undertaken upon property transfer. We assume a repair cost of $340 for subsequent repair.

This leads to an expected cost of:

Factual: Undetected defect share (19.4%) × repair cost ($340) = $65.97 per installation.

Counterfactual: Undetected defect share (3.73%) × repair cost ($340) = $12.69 per installation.

B.4.3 External harm costs

External harm costs are estimated using fire risk as a proxy for the safety impacts of serious undetected defects. This is because fire is one of the most observable outcomes that can result from a defective solar installation.

The assumed probability of fire occurring in a solar installation is 0.047%, based on UK data showing that fire services attended 171 solar-related fires in 2024[62] across 1,443,957 domestic solar installations.[63] We recognise that UK data may not be directly transferable to New Zealand, but this is the best estimate available in the absence of New Zealand-specific

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[62] UK fire services tackle a solar panel fire every two days - QBE - QBE European Operations
[63] Solar photovoltaics deployment - GOV.UK

evidence. We have also undertaken some sensitivity testing of this assumption. To approximate the fire risk associated with defective installations, the calculation assumes that 80% of solar-related fires are defect-related. Furthermore, we assume 20% of installations have defects, which is broadly consistent with Australian audit evidence.

Most reported incidents appear to be linked to installation issues, especially faulty inverters. The cost per serious undetected defect is represented by the estimated cost of a domestic house fire, using Sapere's (2021) estimate for Fire and Emergency New Zealand.[64] We estimate this cost, covering property and non-property damage costs from fire as $890,298, consisting of:

- Property damage costs of $241,187 per incident, calculated as the high damage cost in Table 27 of Sapere (2021), inflated to present-day values, and divided by 2,679 house fire incidents from Table 15 of Sapere (2021). This is likely an overestimate because the property damage costs cover all property fires, and not just house fires.
- Fatality costs of $601,235 per incident. This is based on 11 fire-related fatalities from Table 10 in Sapere (2021) (which may be an overestimate if not all of these relate to residential house fires); 304 severe house fires, from Table 15, which assumes that house fires with 0-20% of the structure saved reflects the bulk of fatalities, and a value of a statistical life of approximately $16m.[65]
- Injury costs of $35,230 per incident. This is calculated as the cost of fire-related injuries from Table 27 of Sapere (2021), inflated to preset-day values, divided by 2,679 house fire incidents, and scaled up threefold to conservatively reflect an assumption that solar panel fires may cause more harm. This is likely an overestimate because the fire-related injury costs cover all property fires, not just house fires.
- Vegetation and environmental costs of $12,647 per incident. This is calculated as the cost of damage to vegetation and environmental costs from Table 27 of Sapere (2021), inflated to preset-day values, divided by 2,679 house fire incidents. This is likely an overestimate because the Sapere cost estimates cover all property fires, not just house fires.

We note that this cost estimate does not cover the costs from undetected defects that do not relate to fire, such as electrocutions or electrical burns. However, we consider any such costs are likely to be effectively captured in our analysis from our incorporation of multiple conservative assumptions in our calculation of the fire-related costs.

The expected external harm cost is calculated as:

Factual: Undetected defect rate (19.4%) × fire probability (0.047%) × cost per event ($890,298) = $81.83 per installation

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[64] Report-193-The-Cost-of-Fire-in-New-Zealand.pdf

[65] Sourced from Treasury's CBAx tool, CBAx Spreadsheet Model | The Treasury New Zealand

Counterfactual: Undetected defect rate (3.73%) × fire probability (0.047%) × cost per event ($890,298) = $15.74 per installation

B.4.4 Total defect-related cost

Summing the above components for the preferred option:

Factual: Total defect-related cost = Immediate remediation ($1.35) + subsequent repair ($65.97) + external harm ($81.83) = $149.15 per installation.

Counterfactual: Total defect-related cost = Immediate remediation ($50.77) + subsequent repair ($12.69) + external harm ($15.74) = $79.21 per installation.

B.5 Total cost and savings

The total cost per installation is calculated as:

Factual: Inspection process ($8.50) + Defect-related costs ($149.15) = $157.65 per installation.

Counterfactual: Inspection process ($340) + Defect-related costs ($79.21) = $419.21 per installation.

The difference between the factual and counterfactual costs gives estimated savings of:

$419.21 − $157.65 = $261.56 per installation, which we conservatively round down to $250 (to reflect measurement error) for inclusion in the factual scenario in our CBA.

Appendix C. Plug-in solar cost-benefit analysis

C.1 Overview

This appendix sets out our approach to estimating the benefits and costs of the solar review's recommendation to permit plug-in solar by July 2027. We take as the factual the scenario where plug-in is permitted and the market grows over the 10-year period of our analysis, compared to a counterfactual where plug-in solar remains prohibited in New Zealand.

The challenge in estimating benefits and costs is that we need to forecast adoption for a technology for which there is no existing domestic market and very few international comparisons. The main such international comparison is Germany, where plug-in is relatively new so there are limited data.

To address this, we assume that the market grows according to a diffusion model for new technologies and establish relatively wide bounds for market growth to reflect a high level of uncertainty. Our approach is similar to the calculation of counterfactual net benefits in the main CBA discussed in Appendix A (although in this case these net benefits arise in the factual). We first forecast solar plug-in connections over the next ten years using a diffusion model. We then calculate the benefits and costs in terms of the welfare impacts and real resources consumed or saved from plug-in solar installations. For this we use similar benefits and costs to the main CBA:

- The costs of installing solar.
- The benefits related to reduced grid-electricity consumption, from household electricity consumption savings and solar production sold back to the grid.
- The benefit from avoided peak electricity generation and network investment (for solar plug-in systems with battery storage).
- The welfare (profit) benefit to domestic retailers of plug-in solar (similar in concept to the profit benefit to solar installers in the main CBA).

To be conservative, we do not quantify the consumer surplus benefit from a rebound effect, on the assumption that the much lower capacity of plug-in solar will result in a limited rebound effect.

To quantify these benefits and costs, we largely follow the approach and use similar data sources as for the main CBA. We provide an overview later in this appendix (where we note also where we have diverged from the CBA), but do not repeat the detailed description of our approach and sources here.

We aggregate benefits and costs over the 10-year timeframe of our analysis and calculate the net present value (in 2026 dollars) using an 8% discount rate. We also include a terminal value to reflect benefits that continue beyond the 10-year modelling period, and use the same approach as in the main CBA with the terminal value calculated over ten years (as we understand plug-in solar panels have a similar lifespan to rooftop panels). Note that this CBA differs from the main CBA, in that we are not accounting for any reduction in delay or decrease in electrical inspection costs. This is because we compare a factual scenario where there is a market for plug-in solar against a counterfactual of zero plug-in solar installations, such that there is no counterfactual delay or inspection cost that is altered in the factual.

C.2 Forecast solar plug-in connections

To forecast solar plug-in connections, we use a logistic diffusion model. In this model, cumulative plug-in connections follow an s-shaped curve, growing slowly at first, before experiencing a period of accelerating growth, and then slowing down as the market reaches saturation. This model is considered a relevant diffusion model for renewable energy technologies.[66]

The logistic diffusion model is given by:

$$q(t) = \frac{K}{1 + e^{-a(t-t_0)}}$$

where $q(t)$ is cumulative plug-in connections at time t; K is the long-run level of market saturation; a is a parameter for the speed of diffusion; and t_0 is the 'inflection point', the time at which uptake is the fastest.

To estimate a value for K, we note that plug-in solar is often considered to be an option for people living in apartments or renters, who may otherwise not be able to install a rooftop system. In New Zealand, approximately 32% of occupied dwellings are rentals,[67] while we estimate approximately 2% of occupied dwellings are apartments (in buildings of four or more stories).[68] This provides some evidence of the potential size of the market, although not all renters/apartment dwellers will be willing to purchase plug-in solar (and there may also be some non-renters or non-apartment dwellers who *are* willing to purchase plug-in solar).

In Germany, we estimate that plug-in solar uptake reached approximately 3% of households in 2025, after formal technical standards were introduced for it in 2017.[69] In our main CBA we forecast rooftop solar connections after 10 years reaching 3.3% for with battery connections and 5.4% for without battery connections. While these values do not necessarily imply market saturation, they nonetheless suggest the level of market saturation for plug-in solar in New Zealand may not be high.

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[66] Xin Li, Ruidong Chang, Jian Zuo, and Yanquan Zhang (2023), "How does residential solar PV system diffusion occur in Australia? A logistic growth curve modelling approach", *Sustainable Energy Technologies and Assessments*, 56, 1-9.
[67] Calculated as 565,974 rented occupied dwellings divided by total dwellings 1,780,104, using data from the 2023 Census reported in Statistics New Zealand (2025), *Housing in Aotearoa New Zealand: 2025*, Stats NZ.
[68] Calculated as 44,082 joined dwellings in 4 or more storey buildings (sourced from Stats NZ, Aotearoa Data Explorer) divided by total dwellings of 1,780,104.
[69] Based on data in Figure 5 of Renewable Energy Institute (2026), "Plug-in PV: How Germany Made Solar Accessible to All", March, and an estimate of the number of households in Germany.

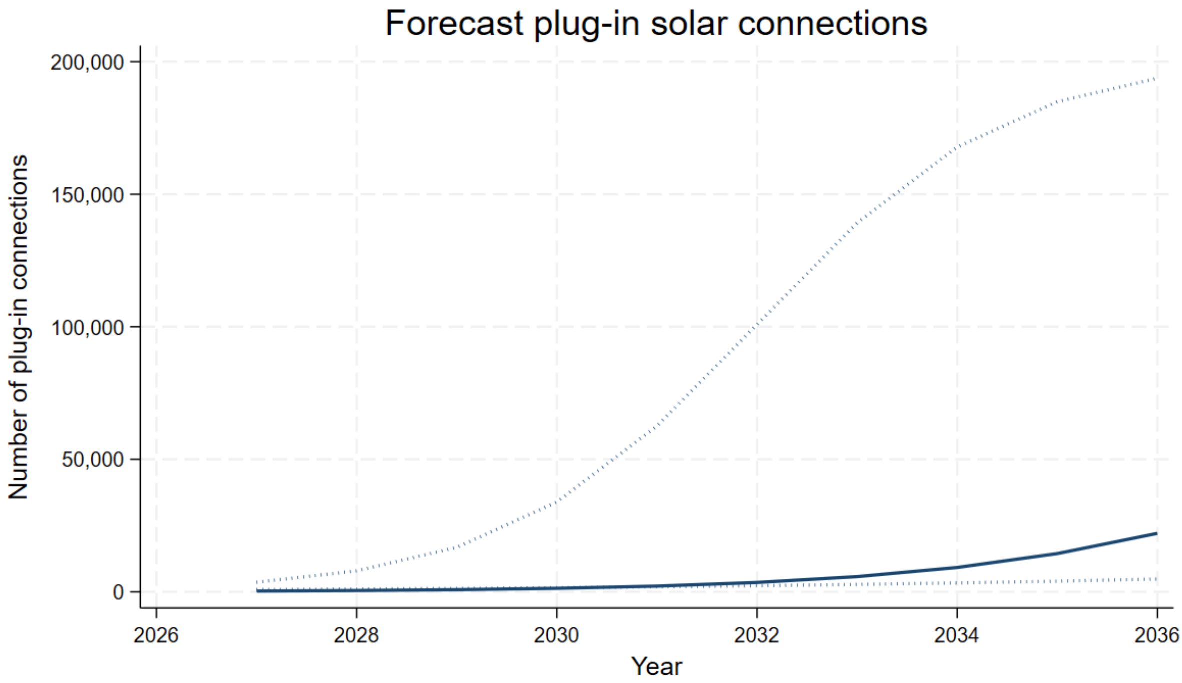
To establish some bounds for a value of K, we assume that plug-in solar reaches 2% of connections as a lower bound and 10% of connections as an upper bound, with a central value of 6%. We apply these percentages to current connection numbers (of approximately 2 million[70]). This will result in an underestimate of the market saturation if connection numbers are expected to increase, so is conservative (leads to lower net benefits).

For the two remaining parameters of the diffusion model (the speed of diffusion and the inflection point), we have not been able to determine specific parameters from either the literature or other data sources. Therefore, we assume a range of values that result in diffusion that varies between relatively slow and relatively fast. We use values for the speed of diffusion (a) of 0.2 to 0.8 (central value 0.5) and values for the inflection point t_0 of 20 years (in the slower diffusion case) to 6 years (in the faster diffusion case), with a central value of 13 years.

Using these values in the logistic diffusion model, we forecast solar plug-in connections over the next 10 years. We assume that plug-in solar is established by July 2027, and forecast connections on an annual basis through to 2036. Figure 7 shows the resulting central value (the solid line), and lower and upper bound forecasts (the dotted lines). Plug-in solar connections in 2036 are 22,000 in the central case. The s-shaped uptake curve can be seen most strongly for the upper bound (faster diffusion), with plug-in connections reaching 194,000 by 2036. In the slowest diffusion scenario, plug-in connections reach 5,000 by 2036. For comparison, rooftop solar connections reach approximately 182,000 (with and without battery connections combined) by 2036 in our central forecast in the main CBA.

[70] EA data on residential ICPs for May 2026, sourced from https://www.emi.ea.govt.nz/Retail/Reports/H3WIHL?DateTo=20260531&RegionType=ISLAND_1&MarketSegment=Res&Show=Count&_si=v|3

Figure 7: Forecast solar plug-in connections 2027-2036, central case with lower and upper bounds



C.3 Benefits and costs

To estimate the net benefit from plug-in solar, we use a similar approach to the counterfactual net benefit calculation in the main CBA (albeit in this case our net benefits apply in the factual scenario). That is, we calculate the benefits and costs in terms of the welfare impacts and real resources consumed or saved per plug-in solar installations, and multiply by the number of plug-in solar installations. For brevity, we do not repeat the description of this methodology here.

Table 4 sets out the various parameter estimates we use for this approach. In most cases, we use the same parameters as for the main CBA. One key difference is for the plug-in solar installation costs (with and without battery), where we estimate a cost for purchasing an 800W system based on prices in Germany. We assume that there are no additional costs associated with installation, other than the purchase price (i.e., the purchaser is assumed to install the system themselves).

The other key difference is that we assume that 24% of plug-in solar connections include a battery, based on evidence of a similar proportion in Germany. While it is possible that this percentage may change over time, in the absence of specific evidence we assume a constant percentage over the 10 years of our analysis.

There is also one difference from the main CBA in the calculation approach for the consumption covered by solar production. In the case of rooftop solar, we assumed household consumption of approximately 7,000kWh per annum, and solar production was assumed to be 6,500kWh for the without battery system and 10,400kWh for with battery system. The systems were assumed to cover 50% and 75% of consumption respectively. In contrast, the solar production of the plug-in system is assumed at 1,040kWh (both with and without batteries). Even at full production, the plug-in system would not cover 50%/75% of consumption.

Nonetheless, given that the timing of solar production may not be fully aligned consumption, it is reasonable to assume that not all plug-in solar production will be self-consumed. We therefore assume that 50% of production is self-consumed in the without battery case, and 75% is self-consumed in the with battery case.

We assume there are no costs associated with safety risks from plug-in solar, based on the finding in the review that plug-in solar is feasible with a defined regulatory framework that establishes safety requirements.

Table 4: Parameter estimates for benefits and costs for plug-in solar

Parameter	**Value**	**Source**
Solar plug-in purchase cost (with-battery)	$2,500	Based on price for 800W kit with battery of €1,229, converted to NZ dollars and rounded up to allow for some uncertainty and import costs[71]
Solar plug-in purchase cost (without-battery)	$1,500	Based on price for 800W kit without battery of €449)[72], although other data suggests a wider range of €500-€900. We use a slightly higher value of $1,500 to be conservative and allow for some uncertainty
Annual decrease in solar installation cost	2% per annum	See main CBA
Proportion of plug-in installations with batteries	24%, assumed constant over time	Based on evidence from Germany that 20%-28% of new installations have batteries, and taking the midpoint of the range[73]
Variable electricity price	$0.26/kWh	See main CBA
Household electricity consumption	6,999.5kWh per annum	See main CBA

[71] Enkhardt, S. (2025, June 25). *Ikea begins offering balcony solar kits*. pv magazine. https://www.pv-magazine.com/2025/06/25/ikea-begins-offering-balcony-solar-kits/
[72] Ibid
[73] Deye Technical Team. (2026, April 5). *Balcony power plant with storage: Complete guide for German apartments (2026).* DeyeStore. https://www.deyestore.com/en-nz/blogs/deye-smart-ct-unlock-the-new-solar-storage-system/balcony-power-plant-with-storage-complete-guide-for-european-apartments-2026?_pos=4&_sid=bdc681399&_ss=r

Self-consumption of solar production with battery	75%	Similar figure to main CBA, but it is applied as proportion of production that is self-consumed (rather than proportion of consumption covered by production)
Self-consumption of solar production without battery	50%	Similar figure to main CBA, but it is applied as proportion of production that is self-consumed (rather than proportion of consumption covered by production)
Rebound effect	0%	Conservatively assume no rebound effect due to the lower production of plug-in solar
Solar production (with and without battery)	1,040 kWh per annum	Based on 1,300kWh per kW capacity as in main CBA, assuming an 800W system (assume same system size both with and without battery)
Buy-back price	$0.16/kWh	See main CBA
Value of avoided peak (with battery)	$25,122 per 1MW of avoided peak	See main CBA
Reduction in peak electricity demand from solar	10%	Assume a lower value than in the main CBA (which was 25%), to reflect that plug-in solar may have less of an impact on peak demand
Retailer profit margin	25%	See main CBA
Discount rate	8%	See main CBA

C.4 Net benefit results

We calculate the net benefits over a 10-year period (with a terminal value for an additional ten years), and calculate the present value of the net benefits, discounted at an 8% discount rate to 2026 present value. We do this separately for the forecast plug-in solar connections in the with and without battery cases, and in the low, central, and high forecast scenarios. The results of this analysis are shown in Table 5.

The central result is a net benefit from plug-in solar of $4.6m over 10 years, in present value, aggregated across the with and without battery scenarios. The range of net benefits is wide, from -$281m to $396m, reflecting material uncertainty in forecasting uptake for a technology for which there is no domestic demand and few international precedents. The negative net benefit arises for similar reasons to that shown for counterfactual net benefits in the main CBA: the purchase price is high and there is not a sufficiently large base of existing installed connections early in the period to outweigh the installation costs. This is a consequence of constraining our analysis to a 10-year timeframe. While the terminal value goes some way towards addressing this, the ten-year period over which this value is calculated may not be a sufficient timeframe to fully reflect all the future benefits.

Table 5: Present value of net benefits, with and without battery and total

	With-battery	**Without-battery**	**Total with and without battery**
Present value of net benefit	-$0.7m (-$97.6m-$109.5m)	$5.4m (-$183.4m-$286.9m)	**$4.6m (-$281.0m-$396.4m)**

We have also undertaken sensitivity testing of the individual parameters, while holding all other parameters fixed at their base case value. We use the same ranges for these parameters as in the main CBA. The results of this are shown in Table 6.

This table presents the central value of the net benefits (10-year NPV) for different parameter variations. For comparison, we also repeat the base case central result in the second row of the table. In contrast to the main CBA, changes in some of the parameters have quite a large impact on the central net benefit. The results are most sensitive to variations in the solar plug-in purchase price (particularly without a battery), the variable electricity price, the rebound effect, and the retailer profit margin. Using a 2% discount rate also makes a large difference, as it drives a materially larger terminal value. These results are suggestive of a high level of uncertainty in our analysis.

Table 6: Sensitivity of base case plug-in results to variations in individual parameters

Parameter	**Lower and upper bound of parameter sensitivities**	**Rationale for range of parameter sensitivities**	**Central net benefit NPV**
All base case parameters	*All base case parameters*	*N/A*	*$4.6m*
Solar plug-in purchase price with battery	$3,000-$2,000 (high cost = lower bound NPV, etc)	Use +/- $500 around central estimate	$3.0m-$6.3m
Solar plug-in purchase price without battery	$2,000-$1,000 (high cost = lower bound NPV, etc)	Use +/- $500 around central estimate	-$0.5m-$9.8m

Annual decrease in solar purchase prices	1%-4% annual decrease	Assumed bounds around 2% central value	$2.9m-$7.9m
Proportion of plug-in installations with batteries	28%-20% (high percentage battery yields lower bound, etc)	Range from German data on percentage of new installations with battery	$4.2m-$5.0m
Variable electricity price	$0.21/kWh-$0.36/kWh	Low and high regional values from MBIE price data, less Rewiring Aotearoa estimate of fixed costs	$1.0m-$12.0m
Household electricity consumption	5,741kWh-8,130kWh per annum	Low and high regional values from EA regional data[74]	$4.6m-$4.6m (no change due to no rebound effect)
Self-consumption of solar production with battery	65%-85%	Assumed bounds around 75% central value	$4.3m-$5.0m
Self-consumption of solar production without battery	40%-60%	Assumed bounds around 50% central value	$3.7m-$5.6m
Rebound effect	10%	Include a positive rebound effect with the low end of the range from the literature in the main CBA	$16.1m
Solar production with battery	960kWh-1,320kWh	Bounds from literature of 1,200kWh per kW capacity to 1,650kWh per kW capacity	$4.1m-$6.6m
Solar production without battery	960kWh-1,320kWh	Bounds from literature of 1,200kWh per kW capacity to 1,650kWh per kW capacity	$3.0m-$10.3m
Buy-back price	$0.08/kWh-$0.23/kWh	Low and high ends of range from Powerswitch data	$0.05m-$8.7m

[74] Electricity Authority - EMI (market statistics and tools)

Value of avoided peak (with battery)	$20,098/MW-$30,146/MW	Assumed multiple of 0.8-1.2 times central value of $25,122/MW	$4.6m-$4.7m
Value of avoided peak also applies to non-battery	$25,122/MW applied to non-battery installations	Battery value also applies to non-battery	$4.8m
Value of avoided peak does not apply	No benefit from avoided peak	No benefit from avoided peak	$4.6m
Reduction in peak electricity demand from solar	0%-20%	Assumed range around central value of 10%	$4.6m-$4.7m
Retailer profit margin	10%-40%	Range of values from margin data	-$0.08m-$9.4m
Plug-in system capacity	300W-1300W	Assumed range around central value of 800W	$4.6m-$4.7m
Discount rate	2%	Alternative Treasury discount rate for non-commercial projects	$25.4m