[redacted]

12 July 2024

Dear [redacted]

Re: Official Information Act Request: Smart EV Charger Modelling

Thank you for your message on Monday 10 June 2024, in which you requested information under the Official Information Act 1982. On Thursday 13 June 2024, you expanded your request.

Your request refers to EECA CE Dr Marcos Pelenur' s interview on RNZ on Monday 10 June, regarding smart EV charging. A recording of the interview can be found here https://www.rnz.co.nz/national/programmes/ninetonoon/audio/2018941979/should-ev-owners-get-smarter

You have requested the following information:

The following are the questions in the LinkedIn message that Jo Bye referred to you. Your response captured the first question. Can you please also address the second question as part of the response?

1. *Can EECA please share the modelling RNZ quotes EECA as saying has been done that widespread smart charger use could save the country $4billion by taking stress out of the national grid.*
2. ***What legislation is required to enable lines companies to use smart meters to control HW heating? If there isn't any then what is the situation regarding requiring the functionality to be implemented so they can use it now?***

The following questions reflect a request in my LinkedIn message for EECA to put out a clarifying media release. Can you please also address these questions as part of the response to the OIA request;

3. *What research has EECA done to ascertain the percentage EV driver that use timers to take advantage of off peak electricity tariffs when charging on a standard 3 pin plug?*
4. *What research has EECA done into the cost of purchasing and installing a Smart EV Charger in a standalone dwelling and in an apartment building and, if such research has been done what were the outcomes?*

5. *What restrictions, if any, is the UK introducing on charging an EV from a standard 10Amp plug?*

The following two questions are related to earlier questions and to the interview itself. Can they therefore please also be included in the same OIA Request?

6. *This question is related to my first question and Mr Pelenur' s statement that EV's could add 20% to New Zealand's electricity demand. My question is, can EECA please provide the calculations supporting the statement that EV could add 20% to New Zealand's electricity demand.*
7. ***Mr Pelenur referred to a strategy of using Smart EV Chargers to enable EV charging times to react to market pricing signals. Therefore, my questions are, given New Zealand's current electricity retailer environment,***
    a. ***can EECA please provide information on how a system enabling EV Charging to reflect real-time market prices for electricity,***
    b. ***what legislative and technical changes would be required to implement such a system and***
    c. ***has any country implemented such a system to date?***

On Thursday 27 June, EECA notified you that we had transferred parts two and seven (bolded above) of your request to the Electricity Authority (EA) as those aspects of your request better align with the EA's functions. The Electricity Authority will provide a response to those questions.

Please refer to **Appendix One** for EECA's response to the remainder of your request (questions 1, 3-6). We have also attached three supporting documents in response to your request.

You have the right to seek an investigation and review by the Ombudsman of this decision. Information about how to make a complaint is available at www.ombudsman.parliament.nz or freephone 0800 802 602.

Please note that it is our policy to proactively release our responses to official information requests where possible. Our response to your request will be published shortly at https://www.eeca.govt.nz/about/news-and-corporate/official-information/ with your personal information removed.

Yours sincerely

M. L. Bell

Murray Bell
Group Manager, Policy and Regulation

Appendix One: EECA's Response to questions

1. ***Can EECA please share the modelling RNZ quotes EECA as saying has been done that widespread smart charger use could save the country $4billion by taking stress out of the national grid.***

In response to question one, please refer to the following material:

Item #	Item name	Decision
1	EV Charging CBA 03.xlsm	Release in full
2	EV Charging CBA v01.docx	Release in full

3. What research has EECA done to ascertain the percentage EV driver that use timers to take advantage of off-peak electricity tariffs when charging on a standard 3 pin plug?

In response to question three, please refer to the following document links:

Item #	Item name	Decision	Notes
3	EECA Public Charging Research March 2023	A copy of the research report can be found here: https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/EECA-Public-Charging-Research-March-2023.pdf	Refer to pages 11-14.
4	Smart EV Charging Research April 2024	A copy of the research report can be found here: https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/Smart-EV-Charging-Research-April-2024.pdf	Refer to page 8.

Please note that this research did not ask specifically about timers but did ask about usage of off-peak pricing plans and three-pin charging cables. We expect that a reasonable portion of EV owners who charge using a three-pin plug and access off-peak pricing plans would use a timer to do so. This may be in the form of a timer plug, or an EV's built-in timer.

4. What research has EECA done into the cost of purchasing and installing a Smart EV Charger in a standalone dwelling and in an apartment building and, if such research has been done what were the outcomes?

EECA is yet to undertake research that specifically looks into the cost of purchasing and installing a Smart EV Charger in a standalone dwelling and in apartment buildings. However, EECA is in the early stages of a project, which will entail installing smart chargers in an apartment building, with the goal to avoid transformer updates which could be more expensive.

Following installation, EECA will receive six months' worth of operational data and a short report (these findings are expected to be shared with EECA in October 2024).

5. What restrictions, if any, is the UK introducing on charging an EV from a standard 10Amp plug?

Though EECA engages with and takes lessons from the UK government, any restrictions/regulations to EV charging in the UK is outside of EECA's jurisdiction. Please refer to the United Kingdom's Office for Zero Emission Vehicles for information regarding the UK's stance on EV Charging.
https://www.gov.uk/government/organisations/office-for-zero-emission-vehicles

6. This question is related to my first question and Mr Pelenur' s statement that EV's could add 20% to New Zealand's electricity demand. My question is, can EECA please provide the calculations supporting the statement that EV could add 20% to New Zealand's electricity demand.

In response to question six, please refer to the attached excel spreadsheet.

Item #	Item name	Decision
5	Full EV fleet electricity demand	Release in full

Cost-benefit analysis of policies to deliver increased controllability functionality for Mode 3 EV chargers

Prepared for EECA

4 July 2023

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Contents

1 Introduction and Summary

This report sets out the cost-benefit of potential policies to mandate or incentivise that mode 3 EV chargers entering New Zealand are controllable.

The fundamental building blocks of the analysis are:

- Project EV uptake and associated annual GWh electricity consumption
- Project the assumed effect of the policies on the proportion of EVs that are managed relative to a Base 'no policies' scenario
- Project the shape of EV demand for unmanaged and managed charging
- Project the generation supply costs for the different scenarios
- Project the network supply costs for the different scenarios
- Project the potential increase in charger costs and flexibility system costs for the different scenarios
- Calculate the present value of the cost projections for the different scenarios relative to the Base scenario

The results of the analysis indicate that the policy is likely to deliver net present value benefits of the order of hundreds of millions of dollars in terms of the reduction in electricity generation and network costs outweighing any potential increase in charger costs or flexibility system costs.

The balance of this report details the above individual steps in the analysis.

2 EV uptake and annual GWh electricity consumption

For this analysis, the uptake projections and associated GWh demand produced by the Climate Change Commission have been used. Two of the projections produced by the CCC have been used:

- Demonstration Path
- Tailwinds Path

It is possible to weigh the two projections on a scenario basis. The base assumption is that the projections are weighted 50:50 between the Demonstration and Tailwinds paths – noting that EV uptake in the last couple of years has been faster than projected in the Demonstration path.

It should be noted that these projections are for vehicles classed as Light Passenger Vehicles 'LPVs' (cars and SUVs) and Light Commercial Vehicles 'LCVs' (utes and vans). Vehicles classed as Trucks and Buses are assumed to be charged using Mode 4 chargers, and thus do not feature in this analysis.

3 Projecting the assumed effect of the policies on the proportion of EVs that are managed

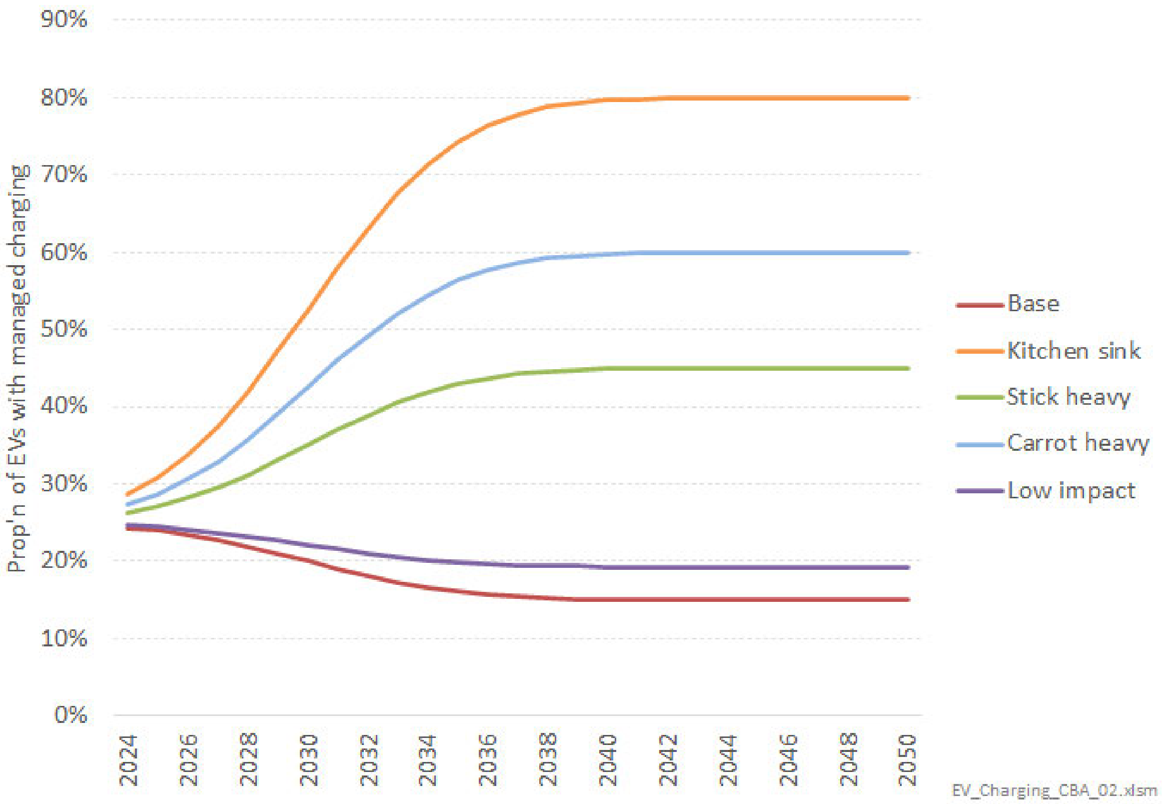
In conjunction with EECA staff, five scenarios have been developed to simulate possible futures in terms of the impact of the proportions of EVs that would have managed charging as a result of the policies:

- Base – the counterfactual scenario with no policies
- Stick heavy – outcomes mainly achieved through regulation
- Carrot heavy – outcomes mainly achieved through incentives to be managed

- Kitchen Sink – A combination of stick and carrot
- Low impact – A scenario where the proportion of EVs that are managed are only fractionally above the Base scenario. The purpose of this scenario is to test the likelihood that the policies will deliver a positive CBA.

The resultant projections are shown in Figure 1 below.

Figure 1: Proportion of EV charging that is managed



4 Generation cost impacts of altered EV management

4.1 Future NZ spot prices

The time-weighted average (TWA) market price is projected for three different representative locations: Otahuhu (Auckland), Haywards (Wellington), Benmore (mid-South Island). A composite NZ vehicle-weighted average subsequently calculated, with the weightings based on population numbers for each area.

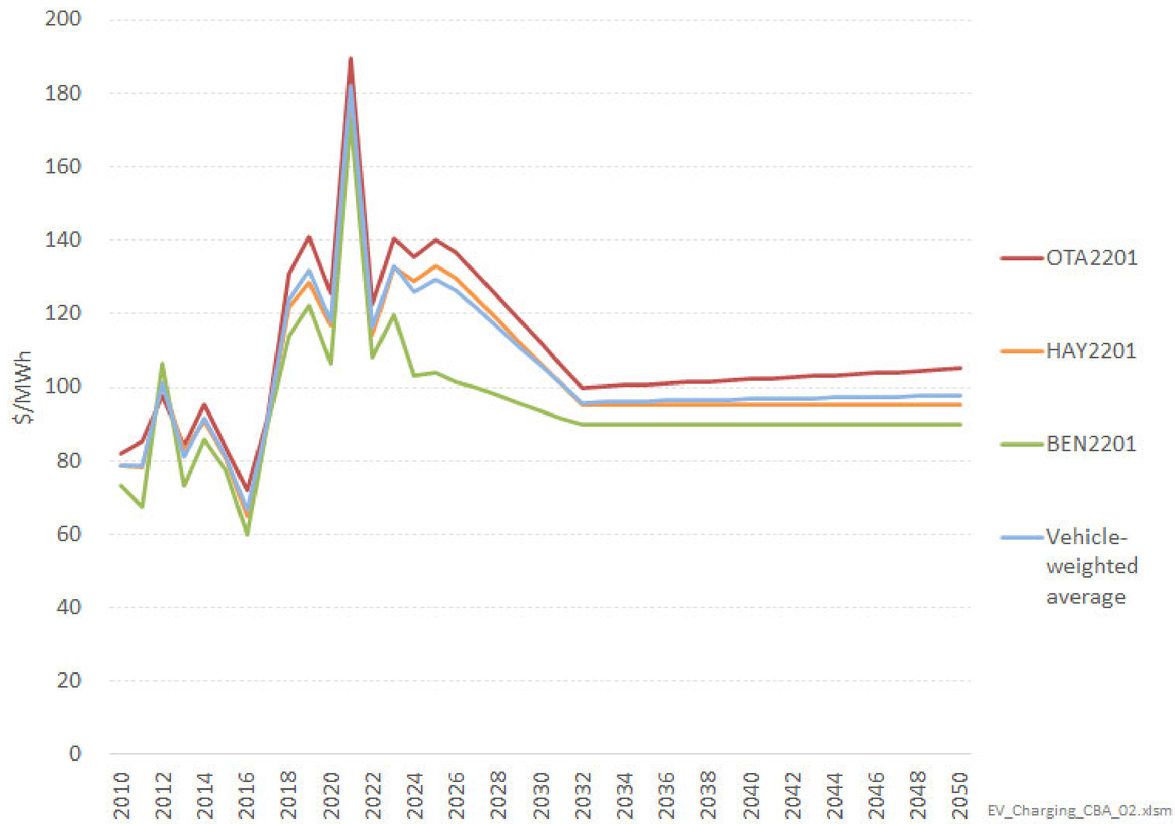
For the early years of the projection (up to 2026) the prices are the latest ASX hedge prices (brought back to $2022 values using the Reserve Bank's latest inflation projections).

For the latter years of the projection, the analysis assumes that renewable build will have 'caught-up' such that the supply/demand balance will be in equilibrium by 2032. In such an equilibrium state, the market price is set by the LCOE of the marginal new renewable plant, factored by the firming costs for variable renewables. Beyond this time, prices rise slightly as it is projected that the increase in firming costs associated with ever-higher proportions of variable renewables will outweigh the fall in the LCOEs of wind and solar.

From 2026 to 2032, prices are simply projected to move linearly between the two.

The resultant projection is shown in, which also shows historical spot prices (up to 2022) inflated using CPI to be in real $2022.

Figure 2: Time-weighted average prices (real, $2022)

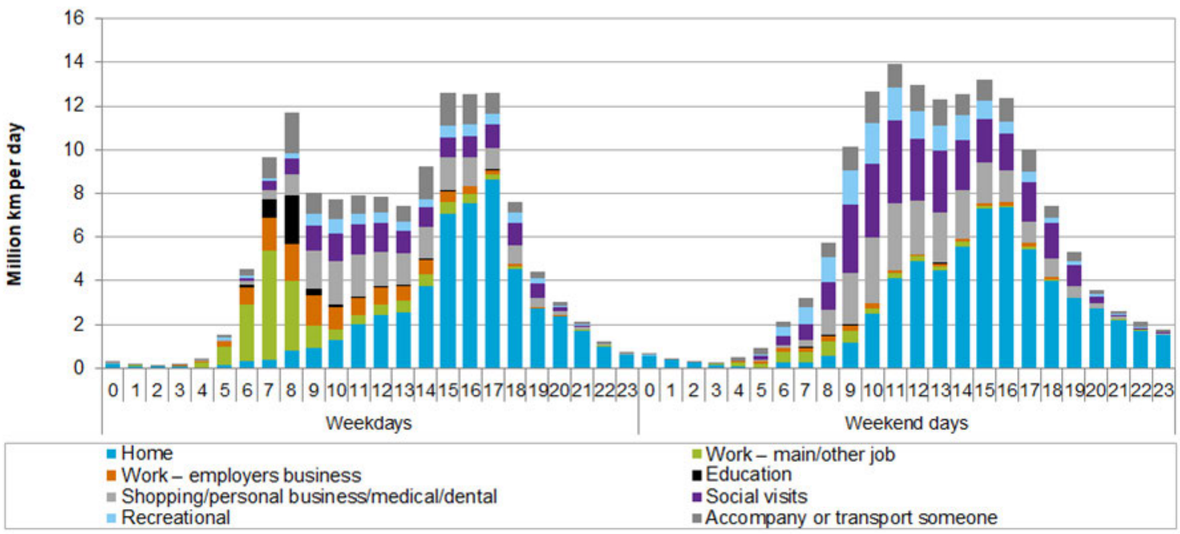


4.2 Projecting the shape of unmanaged EV charger demand

A model was developed which combined various pieces of information:

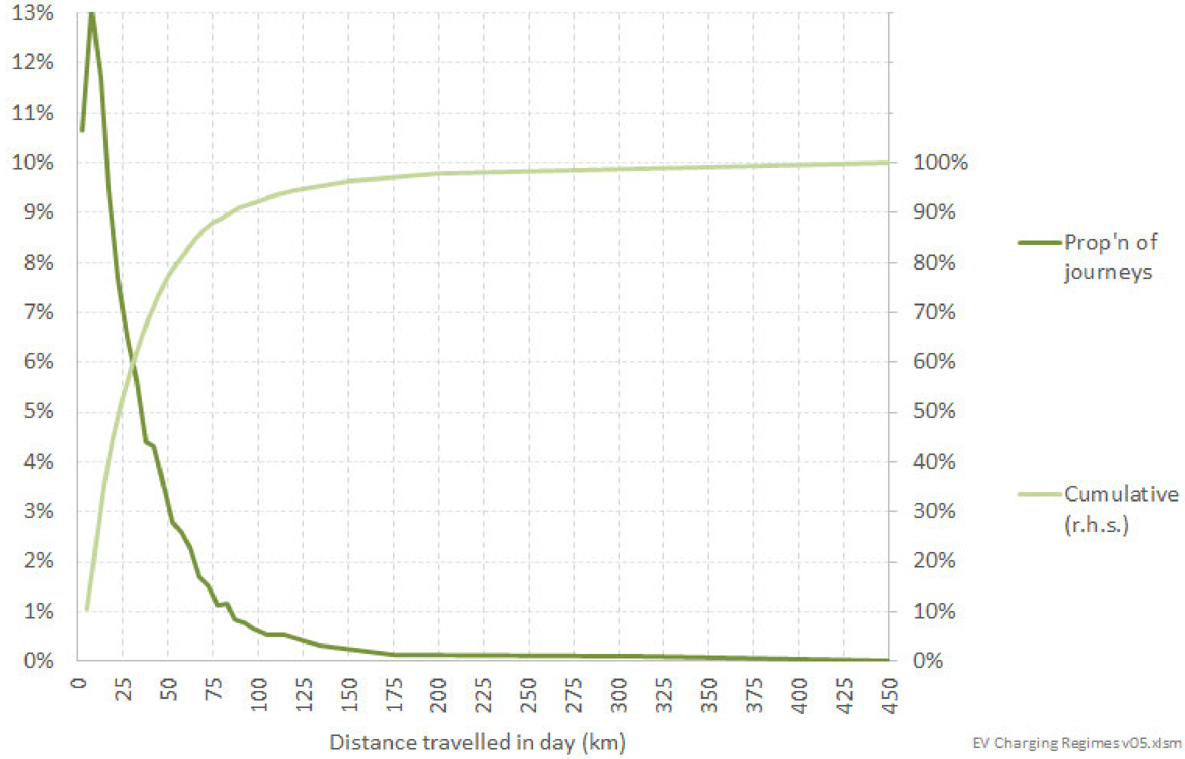
- Within-day vehicle travel patterns from the Household Travel Survey, as illustrated in Figure 3

Figure 3: Within-day vehicle travel patterns



- Distributions of daily vehicle travel from the Household Travel Survey, as illustrated in Figure 4

Figure 4: Distributions of daily travel by household light vehicles

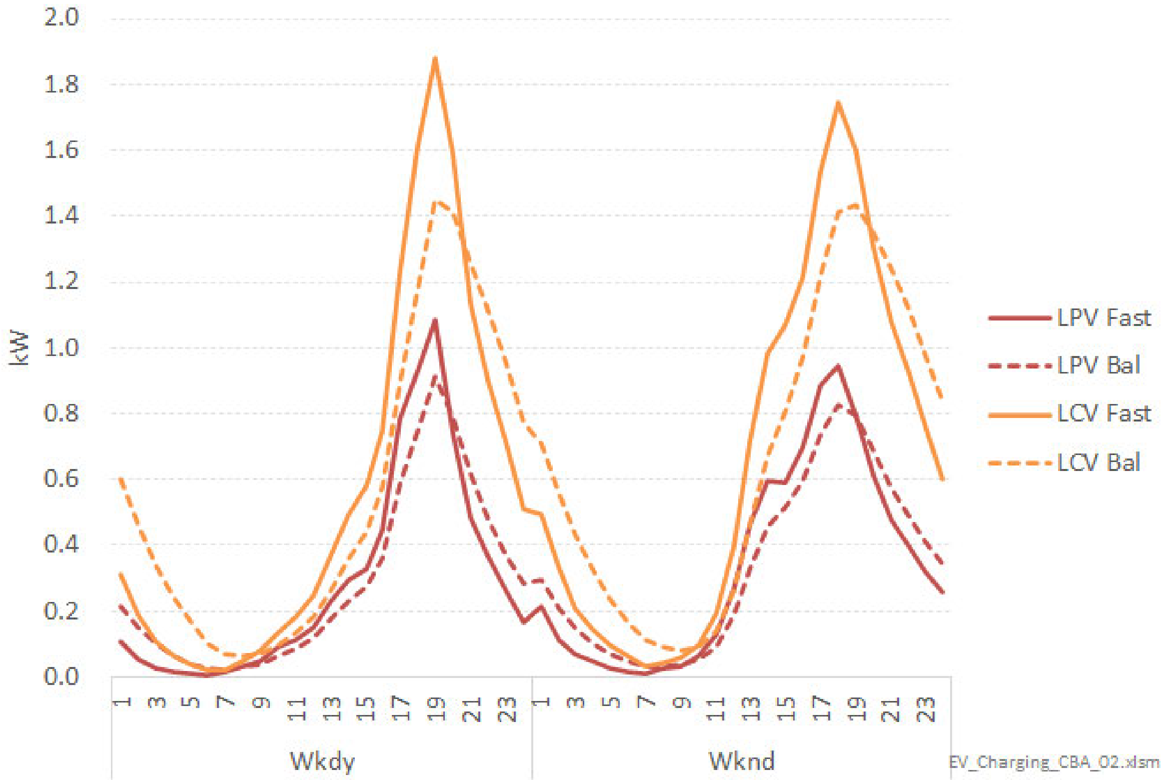


- MoT data on average distances travelled by LPV and LCV
- Scenario-based assumptions as to what proportion of LPVs and LCVs would be charged via Mode 2 and Mode 3 chargers. A 'balanced' scenario assumes a mix of approaches, whereas a 'Fast' scenario assumes that almost all would be Mode 3.

The resultant profiles are shown in Figure 5. The values for LPVs were cross-checked with data from EDB studies of real-world charging, which are showing very similar after-diversity[1] peak demands – Ie, approximately 1 kW per vehicle.

[1] 'After-diversity' means it is averaged across multiple vehicles.

Figure 5: EV charging profiles



For the central scenario, LPVs are assumed to have a 'Balanced' profile, whereas LCVs are assumed to have a 'Fast' profile.

4.3 Calculating a demand-weighted average to time-weighted average price ratio

The historical average within-day and within-week shape of spot prices for 2020 is combined with the EV charging profile calculated in section 4.2 above to give a resultant demand-weighted average price for *unmanaged* charging. When compared with the time-weighted average price for 2020, a DWA/TWA ratio is calculated.

For the central projection of unmanaged EV charging, the resultant unmanaged DWA/TWA ratios are 1.09 and 1.11 for LPVs and LCVs, respectively.

It is inherently hard to project the future shape of EV demand for *managed* charging. Accordingly, a scenario-based approach is taken which simply projected the outcome in terms of future DWA/TWA ratios. A central scenario DWA/TWA projection of 0.95 was chosen, with this also being capable of being varied on a scenario basis.

A more 'optimistic' DWA / TWA value of lower than 0.95 was not chosen on the grounds that:

- EV management will only be able to materially alter charging profiles on a within-day basis
- There are a growing number of other technologies that are cost-effective for meeting the need for flexibility on a within-day basis, not least of which are lithium-ion batteries, other forms of smart demand response.
- There are fewer flexibility options available to meet the demand for longer-duration flexibility (ie, for multiple days or weeks of relative scarcity, seasonal variation, or year-to-year hydro variation)

- The resultant returns for within-day flexibility will be less than for longer-duration flexibility.

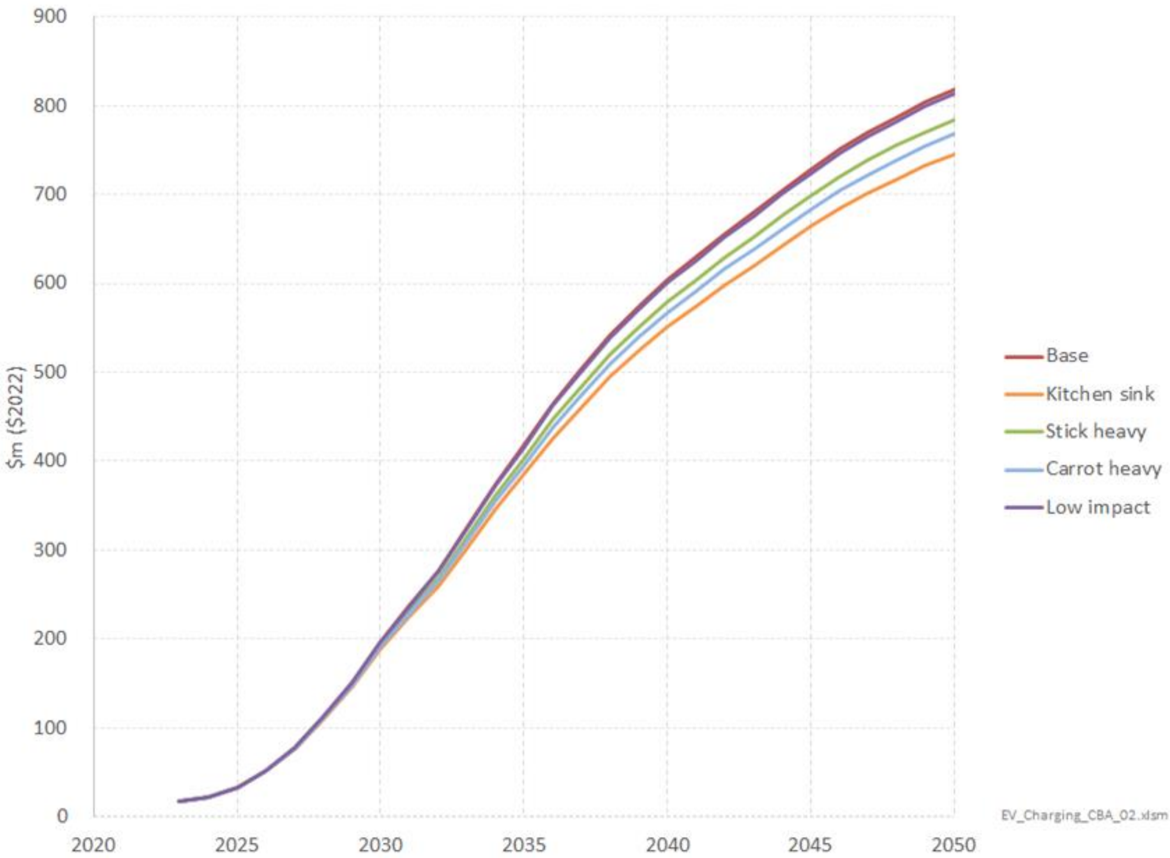
4.4 Calculating the subsequent generation cost for the different scenario projections

For each year in each policy scenario a weighted average DWA/TWA price is calculated from the relative proportions of unmanaged and managed chargers for each year (as shown in Figure 1, previously). This is multiplied by:

- the average time-weighted market price (as shown in Figure 2, previously); and
- the GWh demand for EV charging (as described in section 2, previously).

The resultant annual generation costs for the different scenarios are shown in Figure 6.

Figure 6: Projected generation costs



For each scenario, a present value (PV) of the costs over the whole projection is calculated. The difference between the PV for the Base scenario and each policy scenario represents the value of the avoided generation costs from the policy scenario.

5 Network cost impacts of altered EV management

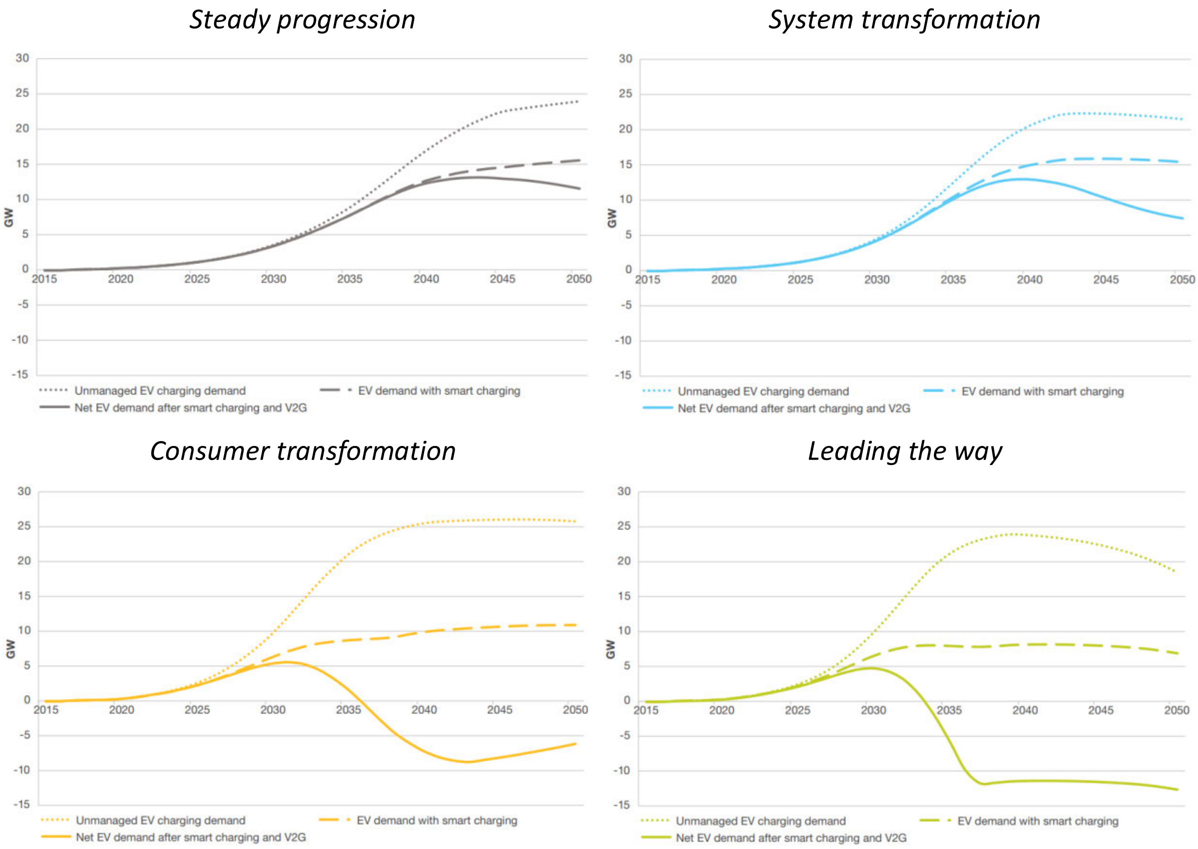
5.1 Estimating the per-vehicle contribution to network peak demand for unmanaged and managed vehicles

The analysis shown in section 4.2 was used to determine the after-diversity per EV increase in peak demand for unmanaged vehicles. For the central scenario this was estimated to be 0.91 kW for LPVs and 1.88 kW for LCVs.

The extent to which EV management would reduce the per EV contribution to peak network demand was estimated on a scenario basis. This is subject to significant uncertainty, not least due to uncertainties over the extent to which vehicle-to-grid EV management would complement smart charging to deliver significant reductions in per EV contributions to peak demand.

This uncertainty is illustrated in Figure 7 below, which shows the range of scenarios developed by National Grid UK for the impact of EV uptake on GB peak demand.

Figure 7: National grid scenarios for EV flexibility at Average Cold Spell winter peak system demand



Source: "*Future Energy Scenarios*", National Grid UK

Drawing upon these UK scenarios, the following NZ scenarios have been chosen as to the reduction in a vehicle's contribution to peak demand if it is managed, rather than unmanaged:

- Low = 40%
- Mid = 80%
- High = 120%

As can be seen, a value of 120% can only be achieved with some proportion of the reduction being achieved through vehicle-to-grid.

5.2 Calculating the increase in NZ peak demand due to EV uptake

For each policy scenario, an average per EV contribution to peak demand across unmanaged and managed vehicles is calculated and then multiplied by the projected number of EVs for each year. This gives a total NZ MW increase in peak demand due to EV uptake.

The difference in this peak demand value between one year and the next is assumed to be the quantity of network capacity that needs to be built to meet this increase in peak demand each year.

This is a simplifying assumption, but is considered to be a reasonable estimate over the duration of the projection.

5.3 Estimating the network cost of increases in peak demand

There is significant variability as to the electricity network costs of increased peak demand: A network with lots of spare capacity will incur little or no costs from demand increases, whereas a network with little spare capacity will incur significant cost increases.

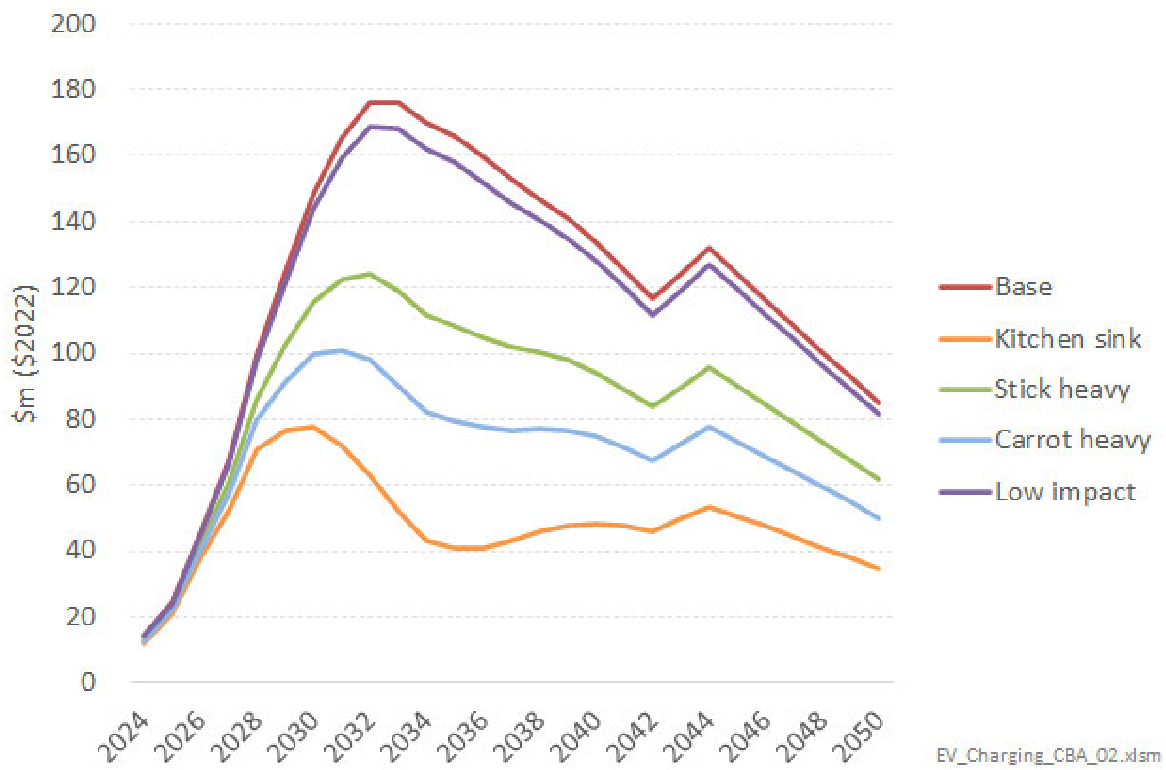
Appendix A details analysis that was undertaken to estimate the average costs of increased peak demand.

The analysis indicated that a central estimate of $125/kW/yr was appropriate. A scenario framework allows for lower and higher cost estimates.

This annualised value was converted to a $1,930/kW up-front cost, using the assumptions that network costs would be annualised over 45 years with a 6% discount rate. For each year, this up-front cost is multiplied by the increase in peak demand for that year – as described in section 5.2 previously.

The resultant projections of network costs for the different scenarios are shown in Figure 8.

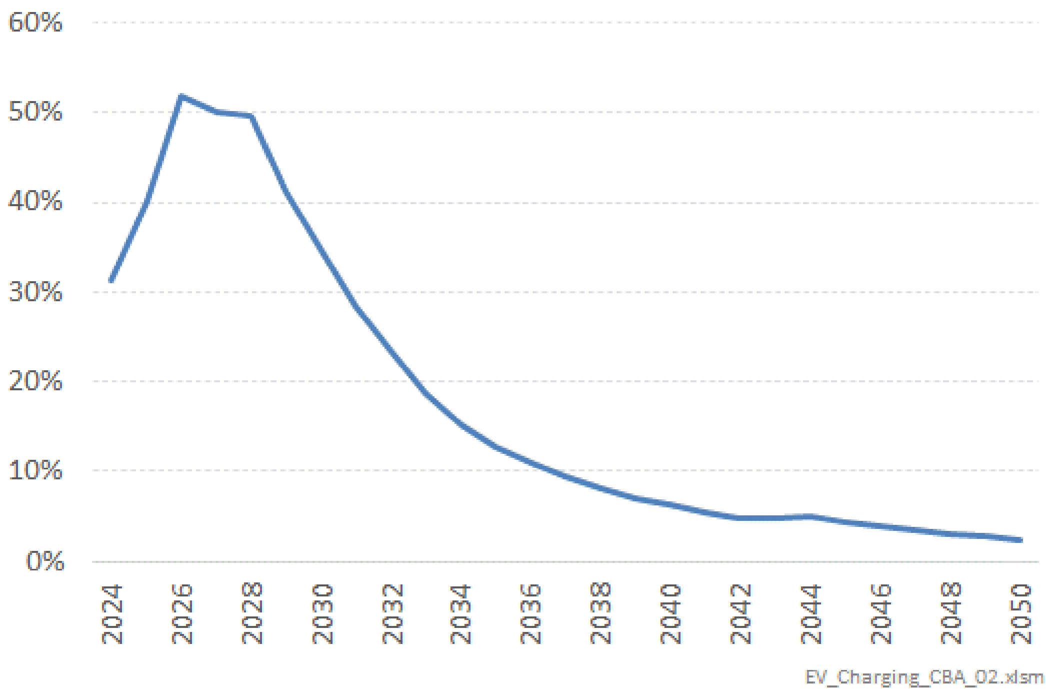
Figure 8: Projected network costs



For each scenario, a present value (PV) of the costs over the whole projection is calculated. The difference between the PV for the Base scenario and each policy scenario represents the value of the avoided network costs from the policy scenario.

Note: The funny kink in costs in 2042 and 2044 is due to the underlying CCC projection of EV uptake having discontinuities in the rates of EV growth in those years – as illustrated in Figure 9 below.

Figure 9: CCC projected rates of EV growth



6 Project potential increases in charger costs or flexibility system costs

It is potentially the case that chargers with superior functionality are more expensive than those which don't have controllability. Accordingly, a policy which resulted in more chargers with superior functionality would result in higher charger procurement costs.

Likewise, the systems to manage flexibility are not free. It is therefore possible that a policy which delivered a greater number of flexible devices to be managed (ie, EVs in this instance) would result in a higher cost associated with flexibility management systems.

Both these costs need to be accounted for in a cost-benefit analysis of improving demand flexibility.

In terms of increased costs of chargers capable of being managed, EECA advised that a central value of $100 per charger premium for managed charger should be used, with this assumption being capable of being altered on a scenario basis.

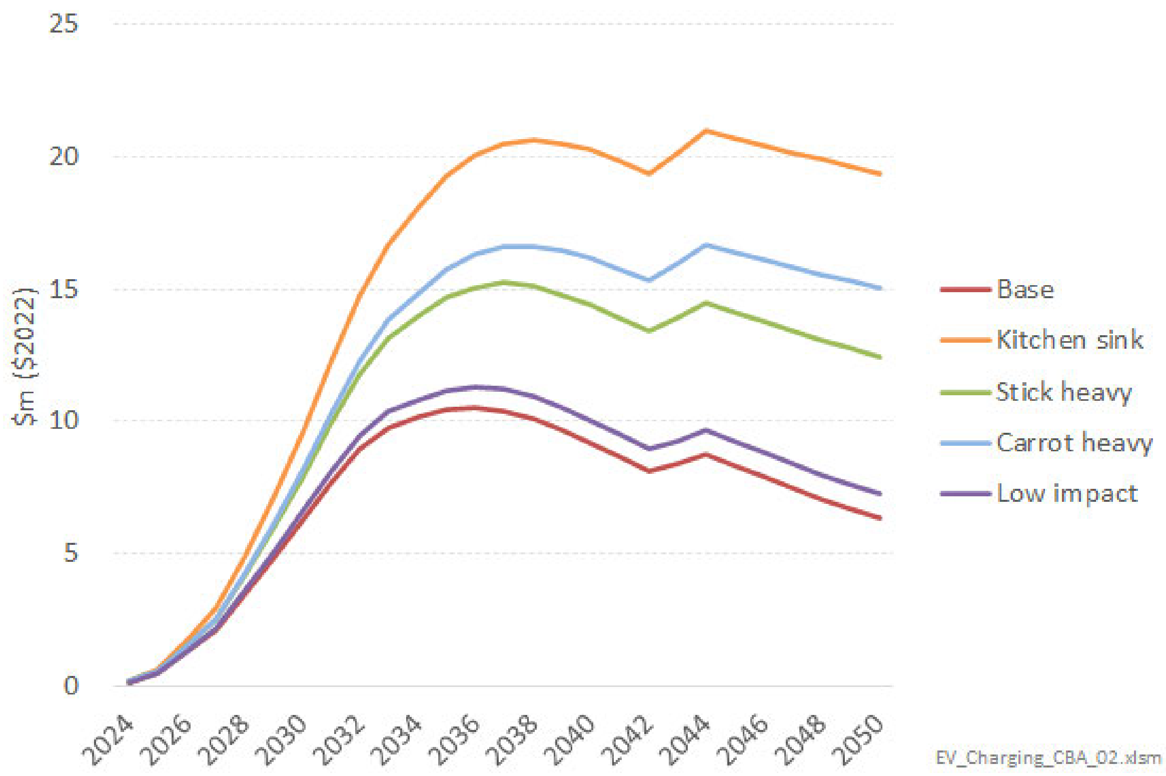
In terms of flexibility system costs, there is the possibility that this could be very low on a per EV basis if the system costs are largely fixed, thereby giving a zero incremental cost for each additional device that is managed by the system. On the other hand, if some aspect of the flexibility system is provided by third-party software which has a per-device licensing arrangement, there could be incremental costs.

Based on advice from EECA, a central value of $15 per managed EV is used, with sensitivities of $0 and $30. This compares with the cost of ripple control which was estimated to be approximately $10 to $19 per ICP.[2]

[2] Source: https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/Ripple-Control-of-Hot-Water-in-New-Zealand.pdf

These costs were applied to the projections of the numbers of Mode 3 charges installed in a year and number of managed EVs each year. The resultant costs are shown in Figure 10.

Figure 10: Projected increased charger and flexibility system costs

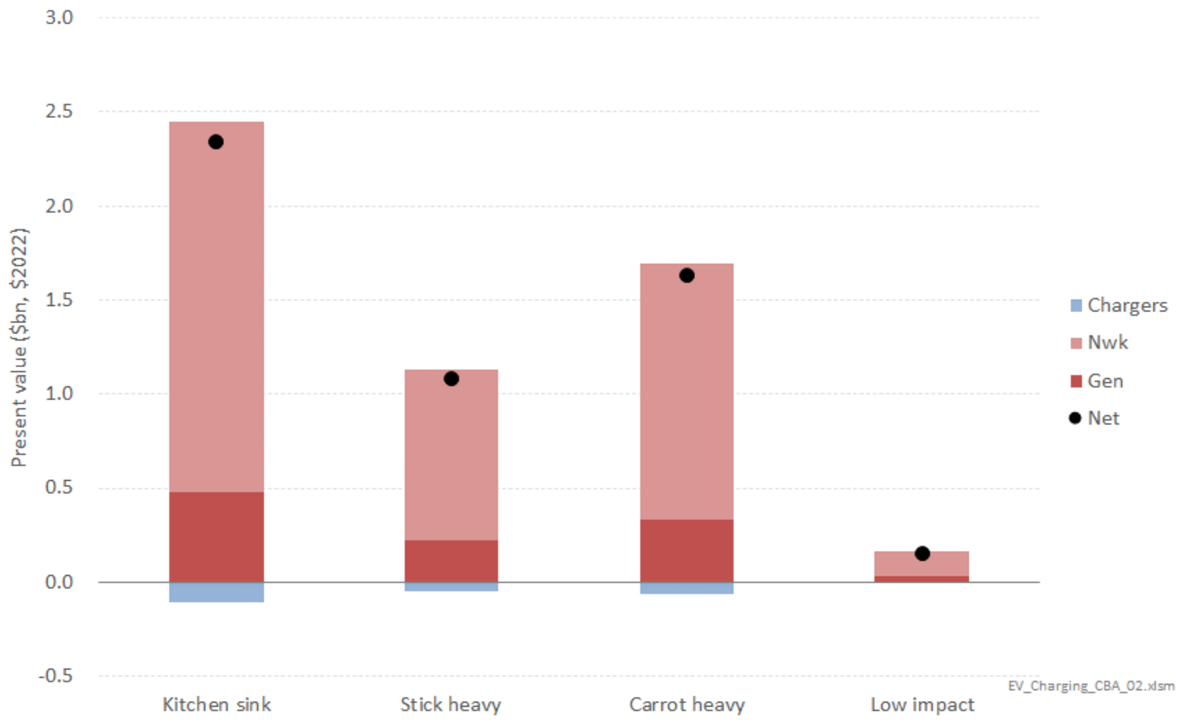


For each scenario, a present value (PV) of the costs over the whole projection is calculated. The difference between the PV for the Base scenario and each policy scenario represents the extra charger and flexibility system costs from the policy scenario.

7 Summarise all the costs and benefits

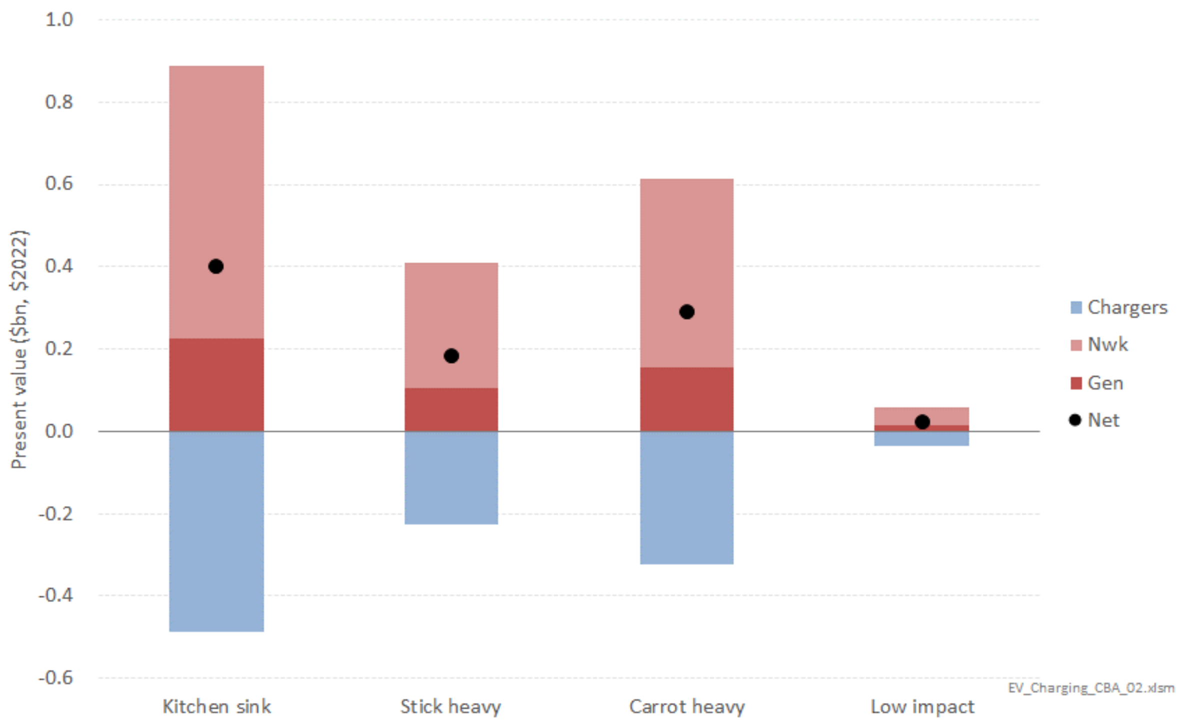
Figure 11 shows the present value of all the changes in generation costs, network costs, and charger/flexibility system costs for the four different policy scenarios relative to the Base scenario for the central values for the various cost components. It shows the policy to deliver positive benefits in all scenarios – even the low impact scenario.

Figure 11: Incremental costs and benefits relative to the Base scenario for central cost values



In the sensitivity for the cost components which would deliver the worst net benefit (ie, low network costs of meeting peak demand growth, reduced effect of management on EV peak demand and DWA energy improvement, and higher charger and flexibility system costs), the result is still a positive net benefit, as shown in Figure 12.

Figure 12: Incremental costs and benefits relative to the Base scenario for adverse-case cost values



Appendix A. Estimating the network costs of increased peak demand

The demand-driven component of distribution network costs principally relates to having sufficient network capacity to meet periods of peak demand. A variety of data sources were used to estimate the average cost of capacity – and therefore the potential benefits for flexibility being used to reduce peak demand.

Two approaches were taken to estimating the network costs of increased peak demand

- A first-principles approach to building up the costs of network investment, and the extent to which changes in peak demand will alter such investments
- Analysis of the implied costs of peak demand in electricity distribution businesses (EDBs) network tariffs

First-principles estimates of the costs of peak demand.

Two different network situations were considered:

- the costs of building a brand-new network
- the costs of increasing capacity for an existing network.

The demand-driven costs of a new network

The demand-driven costs of a new network is estimated to be approximately $110/kW/yr.

In other words, the costs of each extra MW of capacity built into a greenfield network would result in an increase in annual revenue recovery requirement of 1 MW x $110/kW/yr = $110,000/yr.

This represents the value that could be achieved for building new reticulated networks if pricing or other flexibility mechanisms were able to reduce the average kW demand per ICP on a sustained basis.

The derivation of this $110/kW/yr value is as follows.

The annual Commerce-Commission reported non-Opex revenue requirement was summed across all EDBs for each year from 2013 to 2022, inclusive. Ie, the annual revenue for a year less the Opex spend for that year.

This covers the return on capital for existing assets, plus cost recovery for additional capital spend. This captures all capital spend, including:

- building new networks to meet system growth, including consumer connection costs
- renewing / replacing existing network assets that have reached the end of their economic life
- other capital investments, including re-locating network assets, reliability/safety/environment costs, and non-network assets

For each historical year the values were inflated by CPI so that all values are in 2022-dollar terms.

These annual capex spend values were divided by the sum across all EDBs of the reported peak demand values for each year. The average across the resultant $/kW values for each of the ten historical years is approximately $200/kW/yr.

This represents a reasonable first-order estimate of the annualised costs of building a new 'average NZ' distribution network to meet current levels of average consumer peak demand.

However, not all of the costs of building a network are driven by the level of demand. A significant proportion of the costs are independent of demand. For example, the costs of poles or trenches are driven by the km of coverage, not by the MW capacity of the lines run along such poles or trenches. Likewise, there are fixed costs associated with transformers and lines, such that the costs of such assets do not scale directly in proportion to their MW capacity.

Orion has undertaken analysis[3] estimating that approximately 55% of the capital costs of their network are driven by peak demand (39% system peak demand, and 16% local peak demand for individual LV networks.)

Assuming this 55% is broadly representative of the extent to which NZ distribution networks are driven by demand, multiplying the $200/kW/yr figure by 55% gives a value of $110/kW/yr.

Three cross-checks have been performed to determine whether this value is likely to be broadly representative.

1) the equivalent value for Orion's network is $90/kW/yr. This takes their quoted $65/kW/yr for system peak-driven long-run costs, and scales this up to account for the local peak-driven costs quoted by Orion.
2) the annualised $110/kW/yr cost was converted into an up-front cost of $3,090/kW. This 'de-annualisation' assumed that average network capital costs were annualised over a 45-year life using a 6% real discount rate (giving a 6.5% annualization factor). This $3,090/kW compares with a quoted replacement cost per kW of $3,099 from Orion.
3) the $3,090/kW up-front cost was multiplied by the 7.0 GW sum of the quoted 2022 peak demands across all the networks to give a value of $21.6bn. This compares with the sum of the 2022 RABs across all the networks of $14.5bn.

The three cross-checks suggest that the value is broadly representative.

It should be noted that the cost of building a network is likely to be different for different network situations. Thus, relatively higher levels of network undergrounding, or relatively fewer ICPs per km of network, is likely to increase the cost of building a network to meet the average per ICP kW demand for that network. Conversely, networks that have lower levels of undergrounding, or more ICPs per km of network, will tend to have lower $/kW costs. However, the *demand-driven* components of such cost may not vary by as much. In other words, a dense network with relatively little undergrounding may have the *proportion* of costs driven by demand being higher than 55%, whereas a sparse network or one with higher levels of undergrounding may have the *proportion* of demand driven costs being lower than 55%, but the *$/kW* value of the demand-driven component of costs may be much more similar between networks. This is because the demand-driven component of costs principally relates to the sizing of transformer and the capacity of lines, the variation of which with size is broadly the same across networks, whereas the costs of the infrastructure in which to install these assets varies much more significantly across network situations.

The costs of increasing capacity of an existing network

The previous sub-section considered the demand-driven costs of building *new* electricity networks. In reality, the vast majority of demand, and any per-ICP demand growth, will occur on *existing* networks.

Most networks have been built with some capacity headroom to accommodate growth in demand – principally from 'infill' growth in ICP numbers within the network – such that, on average, there will be no need to replace network assets to accommodate demand growth before the time when such assets would anyway need replacing due to having reached the end of their life.

[3] Appendix H in https://www.oriongroup.co.nz/assets/Company/Corporate-publications/PricingMethodology.pdf

However, much faster than anticipated demand growth within a network (either due to electrification or ICP densification) could result in EDBs needing to upgrade network capacity before they would need to be replaced on an end-of-life basis.

The average present value cost of a 1 kW increase in demand 'now' depends on:

- when in the future an upgrade will be required
- whether it will be bringing forward the time when replacement investment will be required.

For example, building upon the values derived in the previous sub-section, if an upgrade is required 15 years in the future, the cost (in real, $2022) of the extra capacity needing to be built to accommodate a 1 kW increase in ADMD = $3,090/kW x 55% x 1 kW = $1,700. Using a 6% discount rate, the present value of this is $709. Converting this to an annualised value using the 6.5% annualization factor gives a value of $46/kW/yr.

However, this ignores the fact that the upgrade may be bringing forward the timing of replacing network assets.

For example, if demand growth hadn't required capacity upgrades in 15 years' time, and instead replacement of end-of-life assets (both demand-driven and non-demand driven) would have occurred in 25 years' time (ie, the demand growth brought forward the asset replacement by 10 years) the difference in the present value of the replacement costs 25 years' hence and that for 15 years' hence needs to be added to the extra capacity costs calculated for the 1 kW extra demand. This would increase the $46/kW/yr cost to $138/kW/yr cost.

As can be seen from the above example, the cost of an increase in demand on existing assets is sensitive to:

- when in the future a demand-growth-driven upgrade is required. Upgrades which are required further in the future cost less in present value terms than those which are required closer in the future.
- whether the upgrade is bringing forward the time that existing assets are being renewed/replaced. The greater the number of years renewal/replacement is brought forward, and the greater the proportion of existing assets needing renewal/replacement, the greater the effective $/kW/yr cost of the demand increase.

For example, if a 1kW increase in per ICP ADMD is bringing forward the time when 100% of assets (demand-driven and non-demand-driven) need to be replaced from 15 years' hence to 7 years' hence, the cost of the increase is $197/kW/yr.

However, if it only results in replacement being brought forward from 30 years' hence to 25 years' hence, and only 70% of non-demand-driven assets and 100% of demand driven assets need replacing at such time, the cost of the increase falls to $51/kW/yr.

The following calculations help give a feel for where the average cost of demand increase may lie.

The average reported remaining asset life (on a RAB-weighted basis) of distribution assets is 31 years.

The modelled average increase in residential pre-control per-ICP contribution to ADMD due to electrification of residential demand is 0.83 kW between the 29-year period from 2021 to 2050, being a rise from 2.44 kW/ICP to 3.28 kW/ICP. This accounts for increases due to EV uptake, and electrification of gas and LPG space and water heating. Offsetting this are improvements in appliance efficiency particularly for lighting, space heating, and water heating, plus improvements in insulation for space and water heating. If this increase happens linearly between 2021 and 2050, this equates to an average annual increase of 0.029 kW/ICP (being 0.83 ÷ 29 years).

If the average amount of spare capacity in networks before an upgrade is needed were 0.75 kW per ICP ADMD, the average time when an upgrade will be required is in 26 years' time – ie, 5 years' earlier. This is 0.75 ÷ 0.029.

If only 65% of non-load driven assets would need to be replaced/renewed at this time,[4] this gives a cost increase of $48/kW/yr.

If the average amount of spare capacity in networks were only 0.5 kW per ICP ADMD, this brings forward the average time an upgrade is required to 17.5 years' time – ie, 13.5 years earlier. This increases the cost of demand growth to $122/kW/yr.

Comparison with implied costs of demand growth in network tariffs

Three different aspects of EDB tariffs were examined to determine the implied costs of meeting peak demand:

- Peak / Off-peak differentials in time-of-use tariffs
- Differentials between controlled and uncontrolled tariffs
- Based on total consumer bills

Peak / Off-peak differentials in TOU

Analysis was undertaken of the implied cost of peak demand as represented by EDB's TOU prices.

For each EDB the implied cost of peak demand was calculated as

$(\Delta_{Pk\text{-}Off} * kWh_{Pk}) \div kW_{Pk}$, where

- $\Delta_{Pk\text{-}Off}$ is the differential between peak and off-peak prices from the EDB's time-of-use (TOU) tariffs
- kWh_{Pk} is the estimated consumption during periods classed as 'Peak' for the EDB's TOU tariff. The shape of consumption was based on actual half-hourly consumption from a residential-heavy zone-sub in the rough geographic centre of NZ, and the total annual consumption for the EDB was based on Electricity Authority reported data.
- kW_{Pk} is the estimated contribution to peak demand. This was derived from the shape of consumption from the residential-heavy zone-sub, factored by the EDB-specific average annual per household consumption. The average of this per household contribution to peak demand across all EDBs was 2.14 kW. This is understood to be a bit low, with an average of 2.25 to 2.5 kW/ICP being closer to the mark. As such, this approach is likely to over-estimate the implied cost of peak demand.

In other words, $(\Delta_{Pk\text{-}Off} * kWh_{Pk})$ represents the annualised costs an EDB is signalling arising from providing capacity to meet peak demand. When divided by the estimated per household quantity of peak demand, kW_{pk}, this gives the annualised costs of meeting peak demand in $/kW/yr.

The results for the different networks are shown in Figure 13. Networks with no value are those where no TOU tariff is published. The weighted average across all networks is $85/kW/yr.

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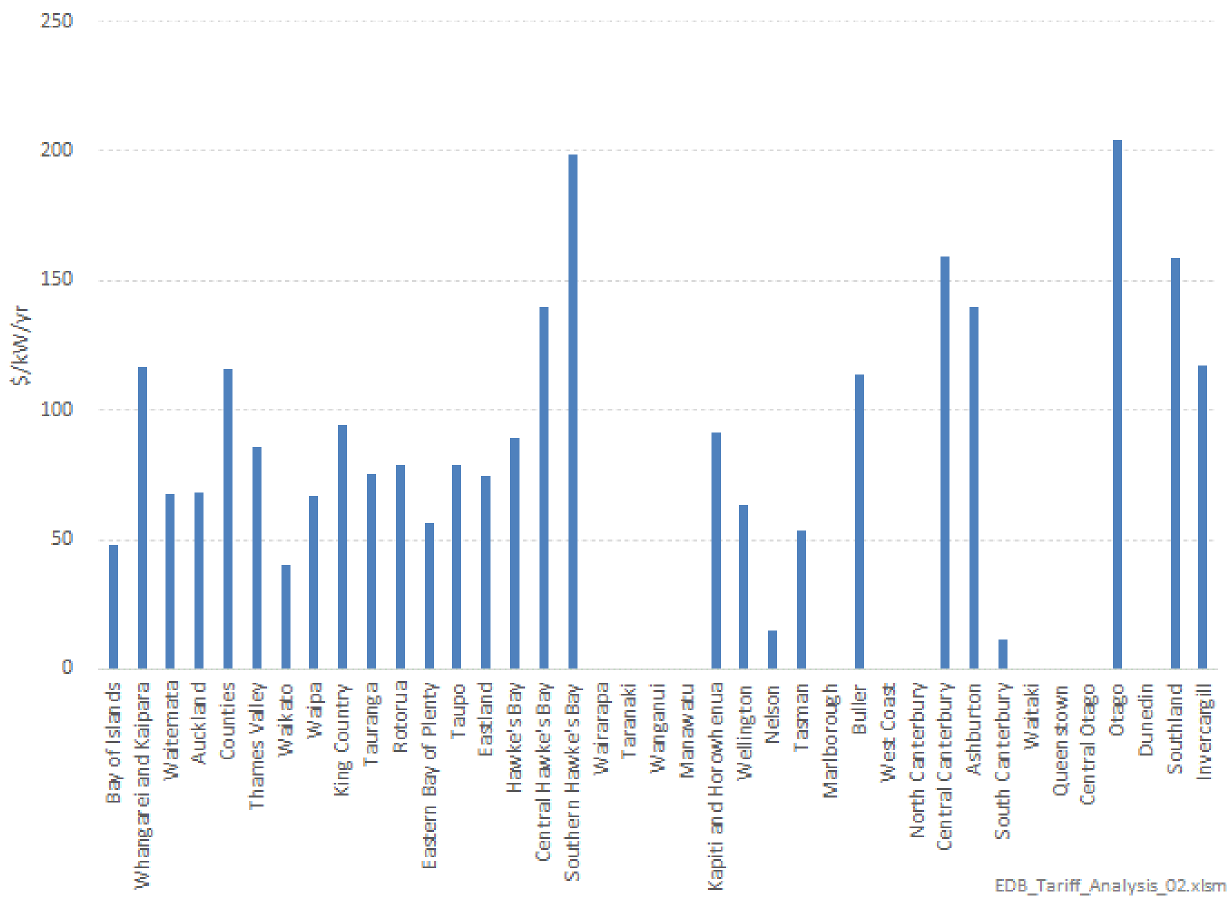
[4] This estimate has been based on the fact that

- most reliability, safety and environment costs, plus non-network asset costs, would not be required to be replaced at the time of network asset renewal, and such costs account for approximately 65% of estimated non-load driven costs
- it is possible that some proportion of original non-load driven costs may not need to be replaced / renewed.

Figure 13: Estimated implied cost of peak demand from EDB TOU tariffs



Controlled vs Uncontrolled tariffs

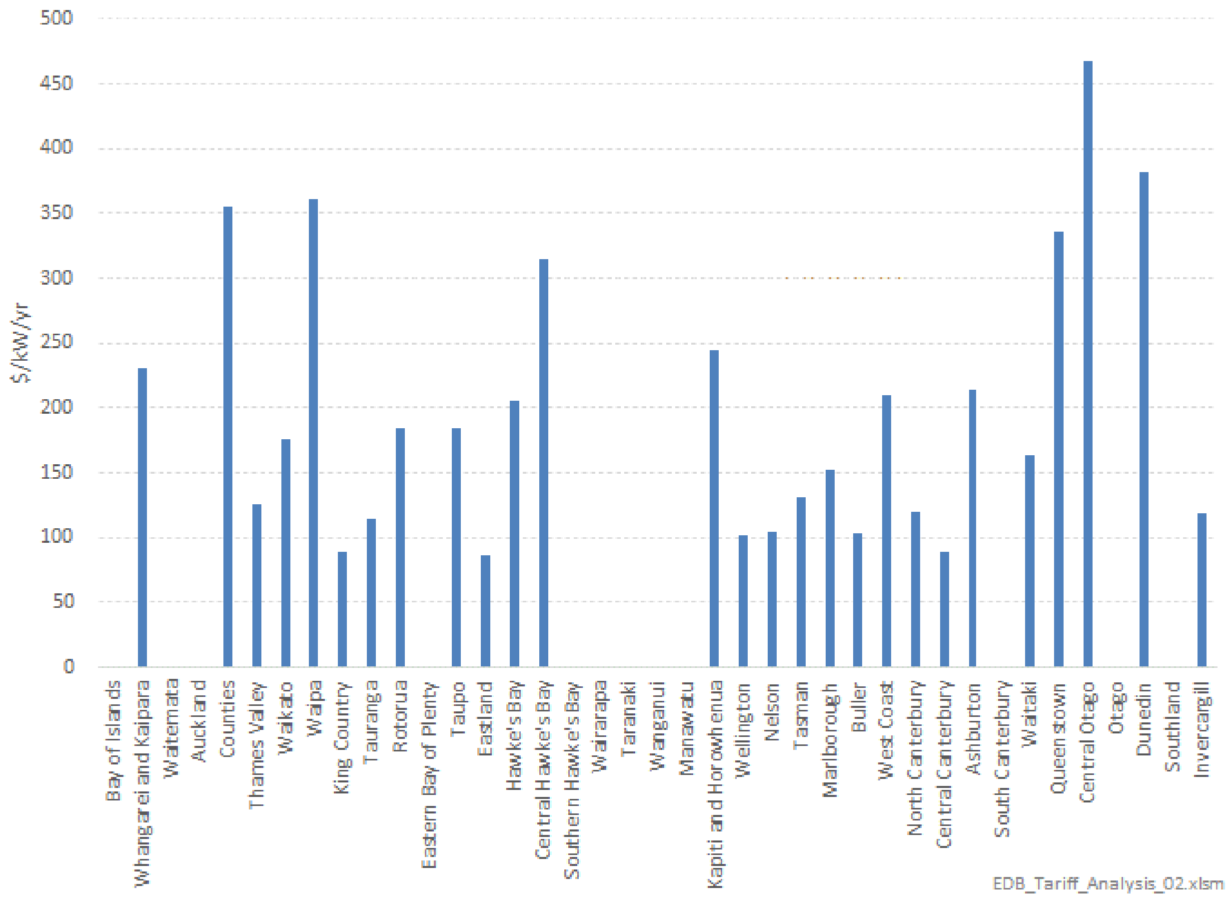
The implied cost of meeting peak demand from the discount between controlled and uncontrolled tariffs for each EDB, was calculated as:

$$((P_{Un} – P_{Cn}) * kWh_{WH}) \div kW_{WH}$$, where

- P_{Un} and P_{Cn} are the EDB's published uncontrolled and controlled 'anytime' (ie, non-TOU) prices, respectively
- kWh_{WH} is the estimated annual consumption of water heating. The average is estimated to be 3,200 kWh, based on EECA EEUD data
- kW_{WH} is the estimated kW of water heating demand the EDB can drop at times of peak. The average is estimated to be 0.7 kW.

In other words, $(P_{Un} – P_{Cn}) * kWh_{WH}$ represents the annual revenue the EDB is foregoing in order to be granted access to the amount of demand control represented by kW_{WH}. The resulting implied cost of peak is shown in Figure 14. The weighted average is $115/kW/yr.

Figure 14: Implied cost of peak from controlled vs uncontrolled tariff differentials



Network bills

A final estimate based on the total EDB bill for the average residential consumer in each network was calculated as

$$B_{avg} * Per_{Pk} \div kW_{pk} \quad \text{, where}$$

- B_{avg} is the average residential consumer bill for each EDB (based on their published tariffs, and EA published data on average residential consumption for each EDB)
- Per_{Pk} is the estimated proportion of network build costs which are estimated to be driven by peak demand, being 55%, as based on the Orion analysis set out earlier on page 12
- kW_{Pk} is the estimated average per household contribution to peak demand, as set out earlier on page 15.

The weighted average of this approach across the different networks gives a value of $93/kW/yr.