Shifting gear

How New Zealand can accelerate the uptake of low emission vehicles

Report 2: Consumer electricity supply arrangements

5 October 2021

About this report

This is the second of two reports about policies to support the rapid transition away from combustion engine vehicles required to meet New Zealand's environmental and economic objectives.

It is an independent report from Concept Consulting in association with Retyna, supported by the following organisations who have provided funding or data:

AA New Zealand, ChargeNet, Contact Energy, Drive Electric, Fuso New Zealand, Genesis Energy, Imported Motor Vehicle Industry Association, Mercury Energy, Meridian Energy, Motor Industry Association of New Zealand, Orion, Powerco, Transpower, Trustpower, Unison Networks, Wellington Electricity

We would like to thank the many individuals who have provided valuable input into our work. However, this report represents our analysis and views (and any errors within it are our own) and should not be construed as representing the views of any of the supporting organisations.

About Concept Consulting Group Ltd (www.concept.co.nz)

We have been providing useful, high-quality advice and analysis for more than 20 years. Our roots are in the electricity sector and our practice has grown from there. We have developed deep expertise across the wider energy sector, and in environmental and resource economics. We have also translated our skills to assignments in telecommunications and water infrastructure.

Our directors have all held senior executive roles in the energy sector, and our team has a breadth of policy, regulatory, economic analysis, strategy, modelling, forecasting, and reporting expertise. Our clients include large users, suppliers, regulators, and governments. Our practical experience and range of skills means we can tackle difficult problems and provide advice you can use.

About Retyna (www.retyna.co.nz)

Retyna is a specialist consultancy focusing on electric vehicles and renewable energy for transport. Retyna's Managing Director, Elizabeth Yeoman, was previously the General Manager Transport at EECA and led the set up and delivery of EECA's EV programme. She has worked in the renewable energy and transport fields for over 25 years in both the private and public sectors.

Disclaimer

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Executive Summary

Mass uptake of EVs will lead to almost unprecedented levels of electricity demand growth. With this growth comes both challenge and opportunity.

The challenge relates to the potential for peak demand growth to cause significant network and generation investment pressures. Our analysis suggests that poorly managed growth could lead to the average household paying $220 (incl. GST) more per year by 2050 – a present value cost of $1.7bn (excl. GST) to 2050.

The good news is that, even with such costs, the economic benefit of switching to EVs from ICE vehicles still massively outweighs this cost.

The even better news is that this cost can be avoided using arrangements that incentivise 'smart' EV charging that removes any additional stress on network or generation capacity. Plus, the ability for EVs to inject power back into the grid – so-called 'vehicle-to-grid' or 'V2G' – creates an opportunity for EVs to offset some of the $440 per year households currently pay towards the costs of meeting peak demand.

Various network companies and retailers are starting to trial means of delivering smart charging and V2G benefits. However, like the rest of the world, these are at a relatively early stage of development, with no clear consensus as to which option(s) will be best.

Our report:

- analyses the overall market need for flexibility, and how EVs are likely to fit into this
- uses this analysis to identify which consumer tariffs and associated market arrangements will likely be best at maximising the flexibility potential from EVs (and other appliances).

Lastly, our report addresses the other problem with current consumer tariffs – consumers are generally being charged more for re-charging their vehicles than the underlying electricity supply costs, thereby making EVs appear relatively less cost-effective for consumers than petrol and diesel vehicles.

With the right settings, New Zealand can transition to EVs:

- *without* needing to reinforce network capacity
- with a positive impact on the cost per unit of electricity
- with an even more positive impact on overall energy bills.

We will need to generate more electricity, but EVs don't have to contribute to peak demand. In fact, they can help make demand *less* peaky than today and therefore less expensive to produce and distribute.

What is the overall market need for flexibility, and how do EVs fit into this?

Our analysis reveals that EVs offer flexibility potential that far exceeds all other appliances put together, with hot water cylinder control offering the next biggest source of flexibility. Together, we think EVs and hot water will provide almost 90% of the potential for flexibility from consumer appliances. What's more, this significantly exceeds the need for flexible response to manage network peaks – in other words, these two appliances alone could meet all our network flexibility requirements and some proportion of our generation flexibility requirements[1].

EVs and hot water dominate the market for flexibility because of their scale of energy use, and because they are both *storage* technologies. They are both capable of re-charging outside of peak periods without compromising the quality of service they deliver – ie, consumers can still have hot water when they need it and can drive their car when they want to.

Other technologies, such as space heating or fridges, are much more limited in their ability to reduce demand without impacting service quality – especially for the extended control hours needed to manage peak demand on the very coldest days.

Our report also analyses the scale of demand for flexibility, and the extent to which it is predictable and evenly spread or volatile and geographically varied in terms of when and where it is required. We find that:

- access to flexibility for relatively small amounts of time (typically less than 1% of the year) can deliver significant cost savings, with rapidly diminishing returns from further access
- most of the benefit is from avoided network costs (mostly distribution), with avoided generation costs accounting for just over one-third of the benefit
- although there are some periods of the year when flexibility is generally more important (ie, predominantly in winter, and never overnight) there is significant randomness as to which days require flexibility, and how much flexibility for how long is required on different days, and
- there is significant geographical variation as to when and where flexibility is required to avoid distribution network costs. Also, the location will change over time as network investments are made to address capacity shortages. In contrast, there is little geographic variation as to where flexibility is required to avoid peak generation costs.

Which tariffs and market arrangements will best meet the need for flexibility?

Directly signalling the value of flexibility through dynamic and highly-locational tariffs would produce highly volatile and consumer-unfriendly tariffs that very few users would be able to monitor and respond to effectively. The experience of The Lines Company's past implementation of such tariffs suggests that vulnerable customers would find such tariffs particularly difficult to manage.

Simpler time-of-use (TOU) structures with broad geographic coverage and stable peak vs. off-peak structures are more promising as an interim step for encouraging night-time EV charging while uptake is low. However, TOU is unlikely to deliver optimal outcomes *on its own* as EV demand grows because EV charging and hot water heating are large and flexible enough to cause a spike in demand at the end of the peak period. TOU is also poorly suited to dealing with geographically-varying distribution network stress, or to coordinate a renewable-firming response as we move to a system with higher intermittent wind and solar generation.

Our evaluation is that by far the best long-term option for delivering flexibility from EVs and hot water are managed appliance tariffs. These grant the supplier the right to control an appliance to deliver flexibility – subject to meeting minimum service levels – in return for the consumer receiving a discount reflecting the value of such flexibility.

That said, we do not regard the choice between TOU and managed appliance options as being completely binary. We think it is possible, likely even, that some consumers may elect to charge

[1] EVs and hot water can't contribute to providing dry-year flexibility. However, neither can any of the other consumer flexibility resources such as other smart appliances and batteries. All such resources could contribute to meeting the increasing need for short-term wind and solar balancing.

their vehicle on TOU tariffs, while others take up managed appliance options due to the higher value such options can deliver. To the extent that well-designed TOU tariffs deliver much of the benefit from smart charging, the need for managed charging options will be reduced but not eliminated – particularly as managed charging options are the only feasible way of unlocking the significant potential benefits of V2G.

Hot water ripple control is currently widely used within New Zealand, with consumers enjoying a lower price which is intended to reflect the avoided peak network costs associated with networks being able to manage these appliances.

However, ripple technology cannot provide the highly granular control that would be most useful for managing large-scale EV charging. In contrast, internet-based communications can deliver appliance-specific control, with a growing number of trials in New Zealand and overseas successfully demonstrating the potential for this technology. Such appliance-specific control can also readily enable flexibility to be provided for network *and* generation purposes – something that is not feasible at scale with ripple technology.

Whereas ripple control requires a single control infrastructure across each network, internet-based control does not need all appliances in a network to be using the same system – it is entirely feasible to have adjacent households whose appliances are controlled by two different systems.

However, what is necessary to ensure good outcomes is:

- common communication protocols between systems so that a party seeking flexibility services (eg, a network company or retailer) can easily procure and call-upon such services, irrespective of which control systems individual consumers' appliances may be connected to, and
- third-party access requirements that enable any party to use the services of an appliance control system without being excluded or subject to significantly adverse terms of access.

These aspects will require some degree of regulatory prescription.

Ideally, appliance-specific tariffs would work in tandem with appliance-specific metering. This enables the level of reward to match the level of flexibility provided – for example, consumers with the highest EV charging demand (who also have the highest economic and environmental benefit from going electric) would receive the biggest discount. However, adding an extra 'revenue grade' meter may cost several hundred dollars per household, which would materially reduce (although still not eliminate) the benefit of EV control.

Longer-term, the best solution would be to allow on-board EV meters to be used. Their accuracy does not have revenue-grade assurance but should be suitable for 'differencing' arrangements beneath a revenue grade gateway meter. They should also be adequate for multiple-trader arrangements where, say, one retailer supplies EV energy and another supplies the balance of the property, and should be adequate to support use of EV flexibility across network and generation.

Given the scale of potential benefit from EV management, we think regulatory work on enabling the use of EV meters should be a high priority.

In the interim, we think 'inclusive' tariffs provide an acceptable way of implementing managed EV tariffs while EV numbers are low. Inclusive tariffs are widely used to support discounts for hot water control. They tend to over- and under-reward between individuals, but the degree of mismatch shouldn't be higher for EVs than for hot water and should be tolerable in the wider context of the inevitable imperfections involved in matching discounts to volatile avoided costs.

Lastly, we note there is some debate as to whether distribution companies should be allowed to own the type of distributed energy resource that appliance-specific control infrastructure represents. Provided the regulatory safeguards regarding third-party access and common communication protocols are in place, we do not believe there would be significant adverse outcomes if distributors are allowed to make such investments. Informing this decision are the following observations:

- our analysis shows that the greatest value from flexibility is from avoiding distribution network costs, and that avoiding distribution costs will also require much more locationally-specific control than avoiding transmission or generation costs. This points to a risk of poor outcomes if barriers to distributor involvement are too high
- to-date, some of the most innovative trials of dynamic EV management in New Zealand appear to being driven by distributors (eg, Wellington Electricity and Vectors' trials)
- internet-based appliance control systems are highly specialised systems that also benefit from economies of scale. As such, we think it most likely that a handful of service providers will emerge, potentially with one or two such service providers having investment from network companies. We do not think it likely that a constellation of 29 different systems will be developed by the 29 different distribution companies.

That said, we are also cognisant of the risk that the monopoly position of networks could extend into the market for flexibility services and crowd out other potential suppliers, or other uses for flexibility. Accordingly, we would encourage regulatory arrangements that

- facilitate open access to information about network needs (ie, where capacity constraints are likely to emerge and create a potential value stream for flexibility services)
- require networks to operate their flexibility services on an arms' length basis with suitable cost allocation rules so that other flexibility providers can compete on their merits
- require networks to provide open access to flexibility services under their control, such that other parties can access resources on suitable commercial terms.

These requirements may be less critical in the early phases of EV uptake, where easy access to pilots and trials takes priority, but will become increasingly important as the scale of the EV flexibility resources (and the intensity of potential capacity investment pressure) grows.

What other tariff reforms are necessary to maximise the potential benefit of EVs?

We have analysed the cost drivers for each component of a typical household electricity bill – generation, transmission, distribution, retail, and metering and found that:

- around 50% of costs are sensitive to demand (either annual kWh or peak kW)
- the other half is not.

To be cost-reflective, consumer tariffs should reflect this mix – at least on average over a long timeframe. In practice, only 15% of the cost of supplying residential consumers is currently recovered though fixed tariff components. This means that variable portion of a typical residential consumer's bill is around 80% higher than it should be.

A key consequence of this over-variablisation is that it makes the incremental cost to consumers of switching from fossil to electric options for transport and heating much higher than the incremental cost of supply – in other words, it deters efficient electrification. This has significant environmental and economic costs. For transport alone, we estimated in our first report that delaying EV uptake by just one year has a carbon cost of $0.5bn[2] and other costs of $0.8bn.

Rebalancing tariffs is technically not difficult for distributors, and the Electricity Authority is working with the sector to advance a programme of transmission and distribution price reform. Until very recently, the low-user low-fixed charge regulations were a major impediment to such reform. We

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[2] Based on a carbon value of NZ$200/t$CO_2$.

therefore welcome the government's decision to phase out the Low-Fixed Charge regulations and allow networks and retailers to rebalance their tariffs over the next five years.

Rebalanced tariffs will also deliver better outcomes for those households with the most severe energy hardship challenges – ie, those with the combination of low income and high energy demand due to factors such as poor insulation, large families or (in future) high transportation needs. However, other households with low incomes (albeit those facing lesser energy hardship as their energy demands are not as great) may find the increase in fixed daily charges difficult to afford.

Although not the focus of this study, the EPR also recommended rebalancing cost allocation of shared network costs away from residential consumers. Our own work in other areas has reinforced this view, which presents the prospect that combining both sets of rebalancing (reduced variablisation and lower allocation of shared network costs to residential consumers) could significantly improve outcomes on several fronts – supporting efficient electrification, while reducing household energy hardship.

1 Introduction

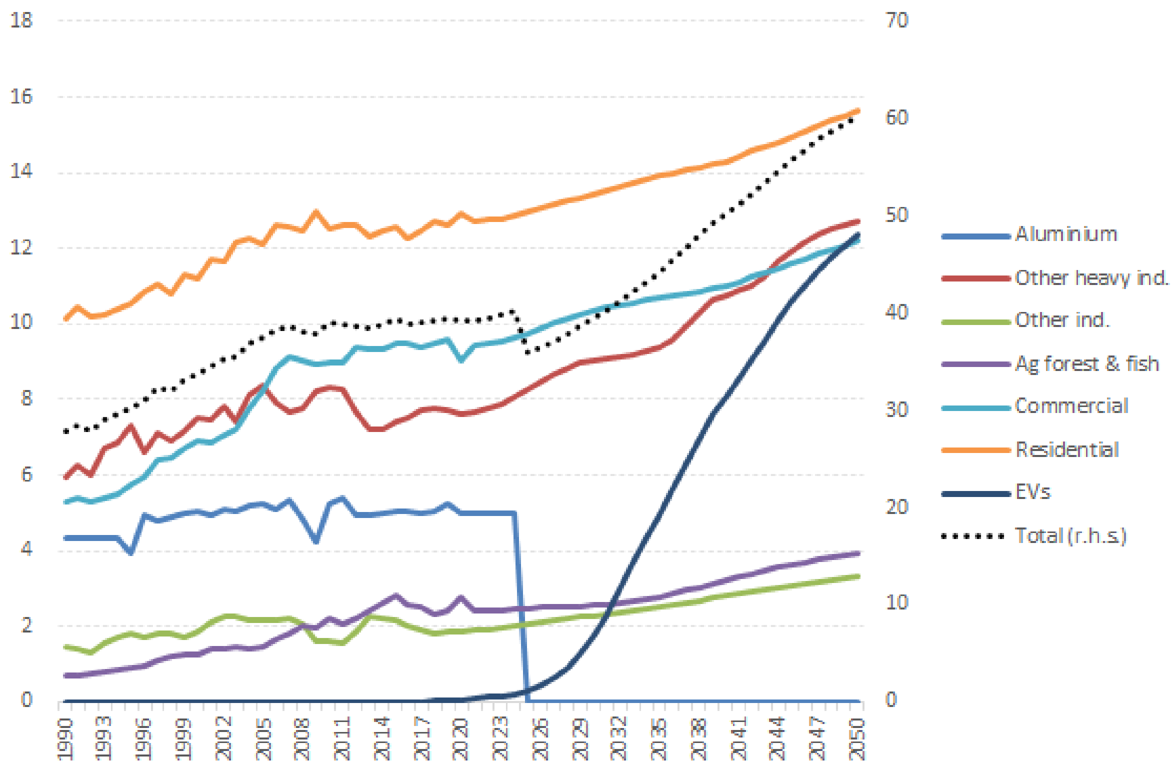
This is the second of three reports into policies for accelerating uptake of low emission vehicles.

Our first report focussed on policies to support electric vehicle (EV) purchases – we estimated that our core recommendations for fleet emission standards, a feebate scheme, and several complementary policies, would generate around $15 billion of benefits to 2050. Our EV uptake assumptions were consistent with the Climate Change Commission's 2021 draft and final advice, and our policy recommendations built on policies already adopted by government. Our key policy recommendation for light vehicles – for a feebate scheme to operate in conjunction with fleet emissions standards – has since been implemented.

This second report focuses on the arrangements for supplying electricity to re-charge EVs at the vehicle owners' homes and business premises.

As Figure 1 below shows, New Zealand is likely to face almost unprecedented levels of electricity demand growth associated with EV uptake.

Figure 1: Climate Change Commission electricity demand projection for its 'Demonstration Path' (TWh)



The vast majority of this EV demand – likely of the order of 85% – will be from 'at-base' charging at vehicle owners' homes and business premises.

However, New Zealand's current electricity supply arrangements at consumers' premises are generally not fit-for-purpose, and will need to evolve to maximise the significant economic and environmental benefits that the electrification of our transport fleet could achieve:

- Most consumers have little or no financial incentive to charge their vehicles in a 'smart' fashion that minimises network and generation stress. This will result in unnecessary electricity network and generation investment, which will flow to higher prices in the longer term. Some networks and retailers have started to develop more cost-reflective pricing to try and incentivise smart charging from EVs (and flexibility response from other appliances). However, there are a variety of different approaches being pursued, all of which are at the early stages of development, with some considerable debate as to which approaches are likely to deliver the best outcomes.

- Consumers are generally being charged more for re-charging their vehicles than the underlying electricity supply costs, thereby making EVs appear relatively less cost-effective for consumers than petrol and diesel vehicles. All things being equal, this will slow the shift away from petroleum vehicles to electric vehicles, resulting in poor economic and environmental outcomes.

This report addresses both such factors:

- Sections 2 through to 6 assess which of the different possible tariff approaches are likely to maximise the potential benefits from smart EV charging, and what associated electricity market arrangements are likely to be required.
  - Section 2 quantifies the potential scale of cost impact if EV charging isn't smart.
  - Section 3 introduces the main tariff options that could potentially incentivise smart charging.
  - Section 4 presents analysis on:
    - how EV demand and flexibility potential compares with other types of demand and DER flexibility providers, and
    - how demand for flexibility response varies both over time and by location.
  - Section 5 uses the results from section 4 to identify which of the tariff options in section 3 are likely to be best.
  - Section 6 identifies what market arrangements are likely to need to be developed to support the best tariff option.
- Section 7 addresses what other tariff changes may be required to enable an optimal level of EV uptake for New Zealand.

The purpose of this analysis is to contribute to the current policy debate around electricity tariff reform, and the development of associated market rules and regulations. As such, much of the analysis is aimed at individuals who already have a reasonable understanding of electricity supply arrangements.

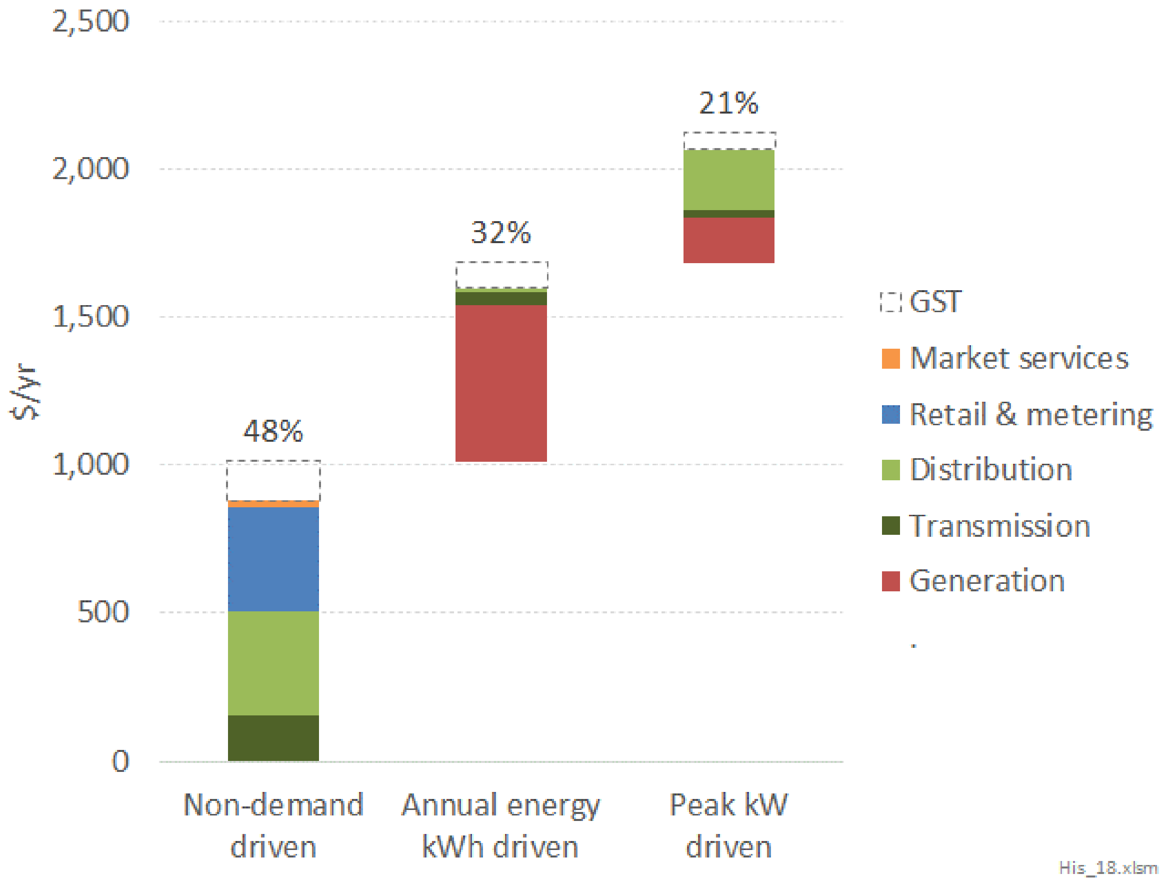
2 What is the scale of potential cost impacts from uncoordinated charging?

If consumers face no incentive to manage the charging of their EVs at particular times, they will tend to start charging when they arrive back at their 'base'. A significant proportion of this will be early evenings when people arrive back from work in their cars, and when business vehicles have finished their days' work. Unfortunately, this early evening period is also the time of peak electricity demand as many other household activities are concentrated at such times.

Increasing peak demand significantly increases the costs of providing infrequently-used generation and network assets.

To help estimate the potential nature and scale of such cost increases Figure 2 below shows a breakdown of the average residential electricity bill as reported by MBIE for the year ending March 2021. This came to $2,120 which, on a fully-variablised basis equates to a cost of $294/MWh (29.4 c/kWh).

Figure 2: Breakdown of average residential electricity bill for YE Mar '21



Source: Concept analysis based on data from MBIE, the Electricity Authority, Orion, and Transpower. Note the % values don't sum to 100% due to rounding.

As can be seen, not all costs are driven by demand:

- Approximately 48% of the costs are independent of demand. For example, for retail & metering there are fixed costs of providing such services per customer, and for transmission & distribution the costs are driven by geographic coverage plus some element of fixed costs.
- 32% of the costs are driven by the kWh of energy consumed. For generation this requires building more power stations to meet demand growth. For transmission this is largely due to the costs associated with building assets to connect new power stations to meet demand growth plus some element of individual consumers' anytime maximum demands – which are assumed to be broadly correlated with energy.
- The remaining 21% of costs ($439/yr) are driven by the need to build extra generation and network capacity to meet the infrequent periods of peak demand.

Using the projections of EV uptake produced by the Climate Change Commission, our modelling indicates that by 2050 uncontrolled EV charging could increase average household peak demand by 40%.[3] This peak-driven aspect would increase the average cost of supplying households by approximately $220/yr (incl. GST).[4] Multiplied by the projected 2.2m households in 2050, this gives

[3] This calculation takes account of current numbers of light passenger (cars and SUVs) and light commercial (utes and vans) owned by households (as opposed to being used for commercial purposes) and assumes a 30% mode shift away from light vehicle travel to public transport and active modes by 2050.

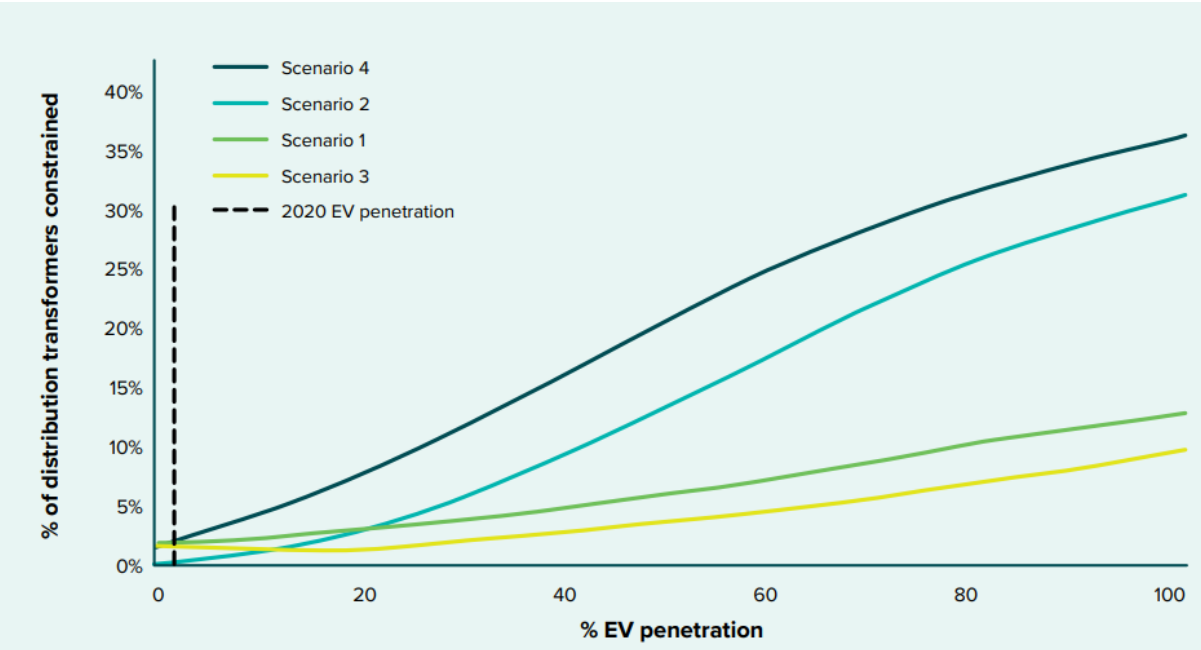
[4] This calculation takes into account the projected increases in network costs due to the significant programme of asset replacement and renewal that will be required over the next couple of decades.

a cost of approximately $430m per year (excl. GST). On a present value basis, given the pattern of EV uptake, this equates to $1.7bn of additional cost (excl. GST).

At this point, it is important to highlight that even with this extra system peak cost, New Zealand would still be significantly better off from a transition from petrol and diesel vehicles to EVs. As was detailed in the Climate Change Commission's analysis[5], the avoided petroleum and emissions costs from ICEs, coupled with the lower maintenance costs of EVs and (from the latter half of this decade) lower capital costs, more than outweighs the higher electricity supply costs – even without smart charging. Further, the Climate Change Commission's analysis didn't account for the additional human health benefits of switching away from petrol and diesel vehicles – estimated to account for hundreds of millions of dollars per year.

Large-scale uptake of EVs also won't "blow-up" our networks as some parties have suggested. For example, Figure 3 shows an extract from Orion's asset management plan which indicates that, while poorly-managed charging occurring at peak will give rise to some need for investments in upgrading its Christchurch network capacity, the majority of the network won't require capacity upgrades even at 100% EV penetration.

Figure 3: Projected residential distribution transformer constraints on the Christchurch network[6]



However, because EVs have batteries, EV-charging doesn't need to occur at peak times. Smart charging would avoid peak periods, with re-charging predominantly occurring during the night-time period. Given typical distances travelled by vehicles, the night hours will provide more than enough

[5] Section 8.2 of *"Ināia tonu nei: a low emissions future of Aotearoa"*, Climate Change Commission, May 2021

[6] Source: https://www.oriongroup.co.nz/assets/Company/Corporate-publications/Orion-AMP-2021.pdf. Note, Scenario 4 is a very pessimistic projection of undiversified EV load at peak (3kW per EV). Our past analysis, and other real-world studies indicate that there is a significant amount of diversity as to when EVs charge, resulting in a 1 kW contribution to peak per EV, on average, from non-smart charging.

time to recharge vehicles to meet the next days' travel requirements for more than 95% of daily journeys.[7]

Smart charging can enable EV uptake to occur with little or no increase in peak demand: A $1.7bn additional prize on top of the CCC's estimated $18bn economic benefits from transitioning from ICE vehicles to EVs.[8] Further, with the potential for EVs to inject power back into the grid (so-called 'vehicle-to-grid' or 'V2G') there is even the opportunity for EVs to offset some of the peak demands of other appliances that are currently driving the $439/yr of peak-driven electricity supply costs for households.

3 What are the tariff options to incentivise smart EV charging?

For EVs to be charged in a smart fashion, consumers need to have an incentive to do so. But most consumers currently face no such incentive - the predominant 'flat' tariff structure (ie, a tariff whose price doesn't vary between peak and off-peak periods) provides no incentive for consumers to avoid charging at peak periods.

There are three main types of alternative tariff structures that can be introduced to provide an incentive to deliver smarter charging outcomes:

- ***Time of use (TOU)***

  This involves defining peak and off-peak periods in advance and setting different $ per kWh price levels for each. For example, a TOU arrangement may specify peak as 7-11am and 5-9pm on weekdays, and set a (high) cost-reflective price for those periods and a very low or zero rate for off-peak periods. Variations can include setting different rates for summer vs. winter, or adding a 'shoulder' period with intermediate price levels (for example, the shoulder could be non-peak hours between 6am and 11pm). Some networks and some retailers have started to implement TOU pricing.

- ***Coincident peak demand (CPD)***

  This involves applying a $/kW rate for consumption during actual periods of system peak demand, whenever they may be. Typically, the CPD rate would be applied during the top 50 or so hours of system peak in the year, although a much tighter period can be used (e.g. the top three half-hours). This compares with 'peak' periods in the TOU tariff example above covering 2,080 hours. CPD pricing can only really be applied to the network component of tariffs. Because peak costs are being spread over such a small number of time periods, the effective $/kWh cost of consumption during these peak periods is significantly higher than the $/kWh charge for a typical peak period under a TOU pricing approach. For example, a cost-reflective peak-period TOU price could be of the order of 8 cents/kWh, whereas an equivalent coincident peak charge applied over the top 50 hours of the year would be $1.75/kWh – twenty-two times as much.[9] The Lines Company (the network company serving the King Country) introduced CPD

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[7] MoT stats indicate that the median distance travelled by a light passenger vehicle in a day is 25 km, and the 95th percentile distance travelled is 80 km. Using a standard 3-pin plug which allows 2.3 kW of demand, and assuming an EV fuel efficiency of 0.2 kWh/km, the time to recharge these daily journeys is one-and-three-quarter and seven-and-a-half hours, respectively. A higher-rated charger of 3.9 kW would reduced these re-charge times to one hour and four hours, respectively, and a domestic 7.9 kW fast-charger would reduce them to half-an-hour and two hours, respectively.

[8] Concept analysis of Figure 8.2 in of *"Ināia tonu nei: a low emissions future of Aotearoa"*, Climate Change Commission, May 2021

[9] The increase in effective $/kWh price is not simply based on the ratio of the number of hours over which peak is defined for each approach, but must also take account of the typical profile of demand during these peak periods. This example was calculated using actual half-hourly consumption data for a network.

pricing in 2007. However, following significant public and political disquiet with its consequences, it dropped the approach in 2018. No network company or retailer currently implements CPD pricing in a form that results in mass-market consumers facing such price signals.

- ***Managed appliance tariffs***

  Whereas TOU and CPD tariff approaches apply to all demand for the property, managed appliance tariffs allow for specific tariffs for appliances that an electricity supply company can control at times of stress on the network.

  In return for granting the electricity company the rights to control the appliance, consumers are typically offered a discounted price, reflecting that such appliances make a much smaller contribution to capacity investment pressure. Managed appliance discounts are common in New Zealand for hot water heating but could also work for electric vehicles.

  The rest of the property's consumption would be charged via another tariff – e.g. TOU, CPD or flat tariffs.

There are some key differences between the above tariffs that help inform which option is likely to be best at incentivising flexibility from EVs and other consumer appliances. Two differences are particularly significant:

- Firstly, TOU and CPD tariffs apply to the whole property, whereas managed appliance tariffs apply to specific appliances.

  This is an important consideration because:

  - If the characteristics of EV consumption and controllability are similar to most other household appliances, then a whole-of-property tariff solution may be most appropriate; however
  - If EVs have distinct characteristics and their potential contribution to flexibility is large relative to other electricity demands, then more appliance-specific options may be most appropriate.

- Secondly, TOU and CPD tariffs place the onus on individual consumers to respond to the price signals and provide the flexibility response at the times and locations required, whereas managed appliance tariffs allow the supplier to call upon flexibility from the appliances when and where it is required.

  This is an important consideration generally (ie, not just for EVs) regarding which approach is likely to be most effective at bringing forward flexibility response.

  - If reasonably consistent amounts of flexibility response are required at reasonably consistent times of the day and year at reasonably consistent levels across the network, it is reasonable to expect consumers to be able to meaningfully respond and 'self-dispatch' their distributed energy resources to meet this requirement.
  - However, if there is significant variability as to when, where, and how much flexibility response is required, it is less feasible that consumers will undertake the time and effort required to monitor system conditions to determine when to turn their appliances on or off, or when to inject power back into the grid from their EVs (or home batteries).

Section 4 presents analysis to help inform both such considerations:

- To help inform the first consideration, sub-section 4.1 details how EV demand and flexibility potential compares with other types of demand and DER flexibility providers

- To help inform the second consideration, sub-section 4.2 details how demand for flexibility response varies both over time and by location.

4 What is the technical context of potential EV flexibility in the broader context of the total supply and demand for flexibility?

4.1 How does EV demand and flexibility potential compare with other types of demand and DER flexibility providers?

To consider this, we have analysed two points in time:

- 'Today', being a breakdown of electricity consumption between end-uses as per EECA's Energy End-Use Database[10]
- 'Electric 2050', being our modelling of the increase in average per household electricity consumption by 2050 assuming the broad degree of electrification proposed by the Climate Change Commission.

Key assumptions for the Electric 2050 are:

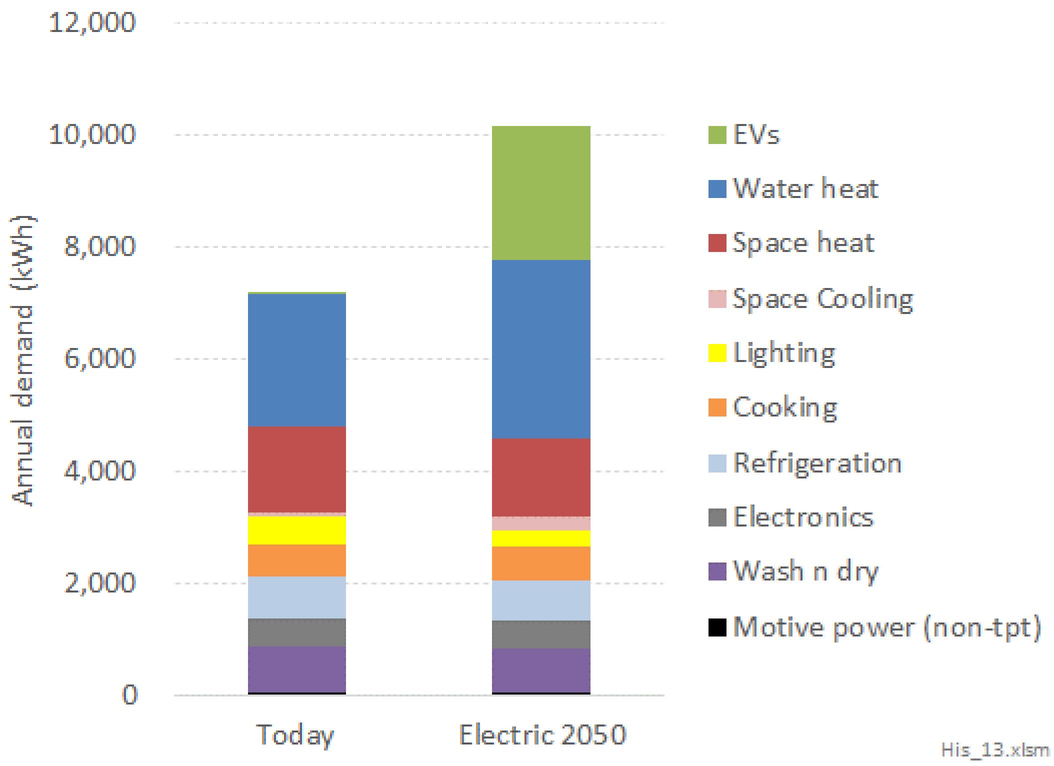
- Household vehicles are all fully electric, and 30% of today's travel kms undertaken by private vehicles shift to active or public transport.
- 90% of natural gas and LPG space heating load switches to heat pump electric, with the remaining 10% switching to resistance electric.
- Water heating all switches to electric, with 15% using heat pump cylinders (and the balance using resistive heating).
- Gas and LPG cooking is all switched to electric; and
- There are energy efficiency improvements across lighting (25%), space heating (15%), water heating (5%) and appliances (2.5%).[11]

Figure 4 shows the breakdown of average annual electricity consumption.

[10] https://tools.eeca.govt.nz/energy-end-use-database/

[11] The space and water heating efficiency improvements are due to a combination of: improved insulation; heat pump efficiency improvements; and some switching from resistance electric to heat pump electric heating. These are likely to improve significantly faster for space heating than for water heating, in large part due to the significantly greater potential for insulation improvements. We have assumed an average annual rate of improvement in energy efficiency for space heating of just under 0.6%, and just under 0.2% for water heating. We understand these are consistent with the assumptions used by the Climate Change Commission for its projections.

Figure 4: Breakdown of average household annual electricity consumption



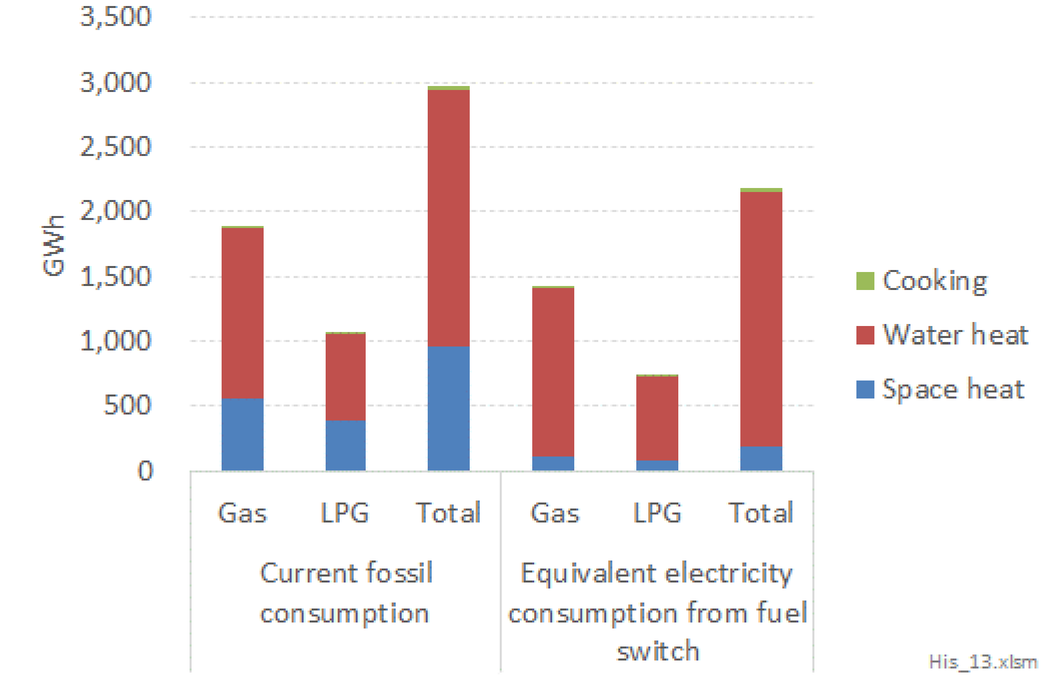
Note: 'Motive power (non-tpt)' covers appliances such as lawn-mowers, and other power tools.

This shows that by 2050, average per household annual electricity consumption could increase by 42% - from 7,170 kWh per household today to 10,160 kWh in 2050. The main contributors are from households switching from ICEs to EVs, and the switch from gas and LPG to electric water heating.

Box 1: Why is there no increase in space heating consumption?

Unlike the fuel switch for water heating, the switch from gas and LPG space heating does not cause a material increase in electricity consumption because, as shown in Figure 5 below, there is currently much less fossil-supplied space heating than water heating, and space heating heat pumps have very high efficiencies.[12] In addition, as detailed in footnote 11, it is assumed that efficiency improvements are likely to be much more significant for space heating efficiency than for water heating.

Figure 5: Current residential fossil gas consumption and electricity equivalent if fuel-switched by 2050



While the increased annual consumption shown in Figure 4 will certainly drive a need for more *energy* generation production, just as significant a cost driver is whether it also drives a need for more network and generation *capacity*. This depends entirely on whether the increased consumption contributes to peak demand because, as illustrated previously in Figure 2, a significant proportion of network and generation costs are driven by peak demand.

Figure 6 shows our estimated breakdown of average per household contribution to peak demand *without* any demand management – ie, prior to any appliance control or action by consumers to shift when they use an appliance.[13]

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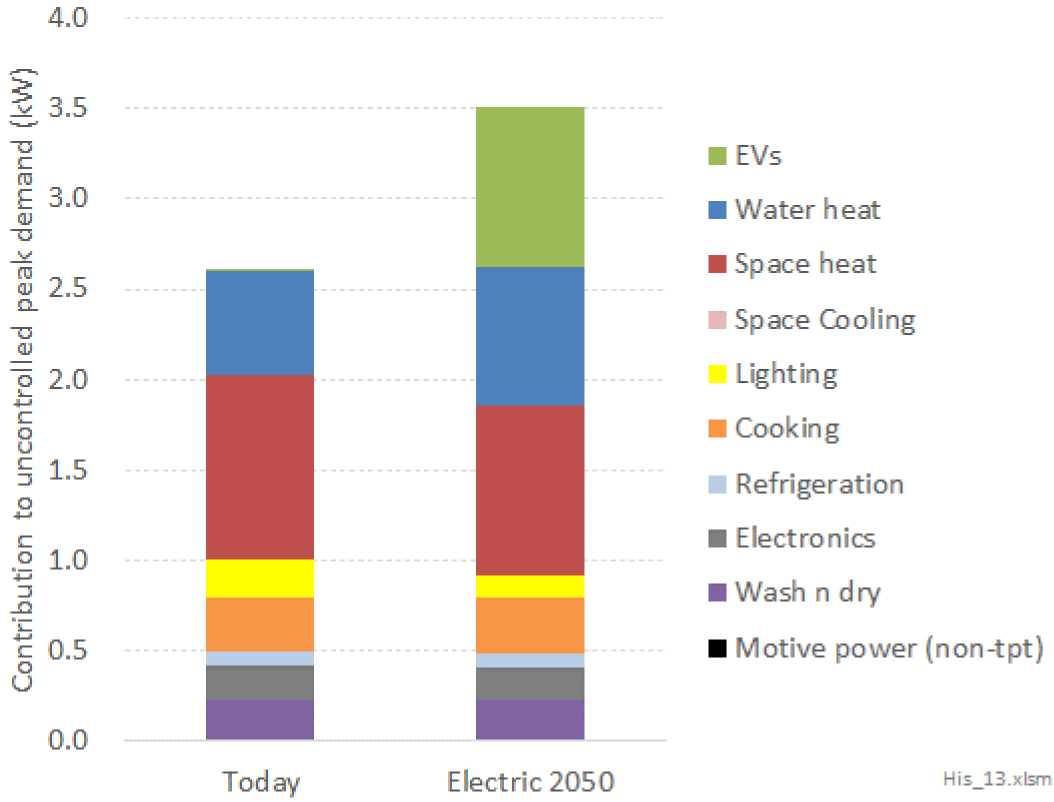
[12] EECA's EEUD analysis assume space heating heat pumps have a coefficient of performance (COP) of 380% (i.e. for every 1 kWh of electricity they consume, they deliver 3.8 kWh of useful heat), compared with 78% for gas heaters. For our analysis, we have used a heat pump COP of 350%.

[13] The estimates have been derived from within-year patterns of consumption from the BRANZ Household Energy End-use Project (HEEP) (https://www.branz.co.nz/environment-zero-carbon-research/heep/), combined with Concept estimates of within-day patterns of consumption informed by, amongst other things, an EECA-funded University of Otago hourly appliance monitoring study (https://cfsotago.github.io/GREENGridEECA/)

Figure 6: Breakdown of average per household contribution to peak demand prior to any appliance demand management



As can be seen, prior to any demand management, the biggest driver of today's average uncontrolled household contribution to system peak is space heating, followed by water heating, then cooking, with other appliances driving the remaining 30% of peak demand.

By 2050 we estimate that, if households have no incentive to manage when they charge their EVs, un-managed peak per household demand will increase by 37% - largely from EVs, with some increased contribution from water heating and small offsets from other uses. In total, EVs would represent 26% of un-managed peak per household demand.

Our estimate of EV-driven peak demand is based on modelling we undertook for a 2018 study on electric vehicle uptake.[14] We developed this from observed household within-day travel patterns and the distribution of journey distances. The 2018 report goes into the detail of the analysis, but the key take-away is that, despite people generally arriving home in the evening, there is significant diversity in:

- when they come home – this is typically spread over a period of many hours from the early afternoon to late evening; and
- how far their vehicle travelled during the day.

These sources of diversity mean that, despite EVs being charged at home at rates of between 2.3 and 7.9 kW[15], unmanaged EV charging will 'only' increase average the after-diversity household contribution to system peak demand in 2050 by about 0.9 kW. This theoretical modelling has been

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[14] *"Driving change" – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand*, Concept Consulting, March 2018. Available for download here: https://www.concept.co.nz/updates.html

[15] 2.3 kW charging can be done via a standard 3-pin plug. 7.9 kW charging would require the installation of a fast-charging connection.

borne out in practice from studies of actual home-charging behaviour by the likes of Vector and Wellington Electricity.

As set out on page 8, an increase in peak demand of the scale indicated by Figure 6 would cost New Zealand approximately $1.7bn in increased network and generation costs.

But if consumers can be incentivised to charge their vehicle in a 'smart' fashion that largely avoids charging during system peak periods, this increase in peak demand and associated costs need not occur.

However, the potential to manage demand isn't limited to electric vehicles. In theory, consumers could potentially also manage when they use other end-use appliances. If the potential for demand management is widely spread across all end-uses, it would suggest that whole-of-property tariff approaches (TOU or CPD) could be most appropriate for incentivising consumer demand management. However, if the potential for demand management is concentrated in just one or two end uses, it would suggest that managed appliance tariffs could be most appropriate.

The extent to which different end-use appliances can contribute to peak demand management depends on:

- the size of the end-use's unmanaged contribution to peak demand – as set out in Figure 6 above; and
- the extent to which the demand is time critical.

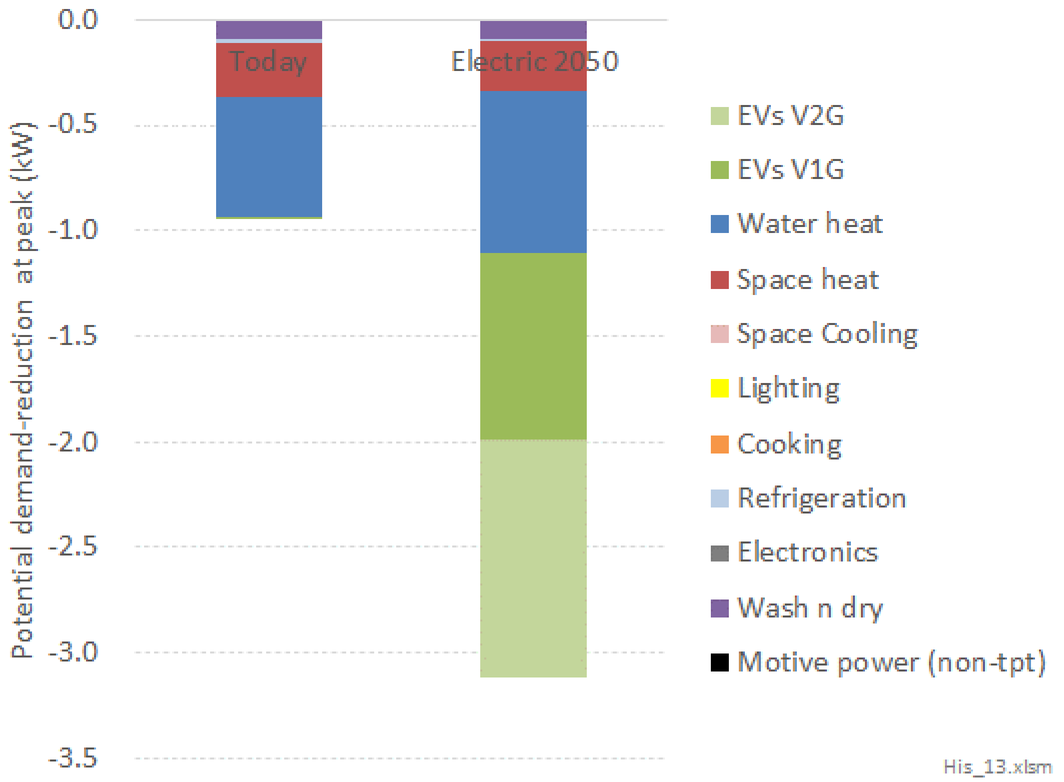
With regards to this latter point (ie, how easily the demand can be time-shifted away from peak periods):

- Storage technologies (ie, hot water and EVs) have significant potential for demand to be reduced during peak periods, without materially affecting the energy service.
- Space heating & refrigeration have some limited potential, using the thermal mass of the house or fridge as the 'storage' mechanism. However, there are limits to the duration of such a reduction before the quality of service starts to be severely degraded – ie, the house starts to get too cold or the fridge too warm. Poorly insulated houses and fridges are particularly ill-suited to such load management.
- Wash 'n dry technologies (laundry and dishwashers) can be postponed to after peak periods to a certain extent
- Other uses have very limited ability to interrupt / postpone without severely degrading the service (lighting, cooking, electronics)

In addition, EVs also offer the potential for the energy stored in the battery to be injected back *into* the grid. This grid injection is known as vehicle-to-grid, or 'V2G', with smart charging (ie, avoiding charging during peak periods) known as 'V1G'.

Figure 7 shows an estimated breakdown of the potential for demand management, taking all these factors into account.

Figure 7: Breakdown of average household potential for appliance demand management during peak demand



The key takeaway is that EVs offer by far the greatest potential for load management, followed by water heating:

- both technologies are large loads and are storage technologies, thereby offering significant potential for peak demand management simply by avoiding charging during peak periods – with this aspect for EVs being classed as V1G in Figure 7.
- EVs also have the potential to inject power back into the grid – V2G in Figure 7. Crucially, because this can be called upon by electricity supply companies at times of system scarcity, the kW capacity for delivering V2G isn't affected by the diversity effects that drive the peak demand outcomes. The main limiting factor is whether a vehicle will be plugged-in at the time.[16] For the analysis in Figure 7 we have conservatively assumed that only 25% of vehicles will be at their base (and thus technically able to offer V2G) during winter evening peaks. We have also assumed that the average vehicle injection capability is 2.5 kW. We suspect this could also be conservative as it is likely that many V2G installs will have 7 kW charger capacities.

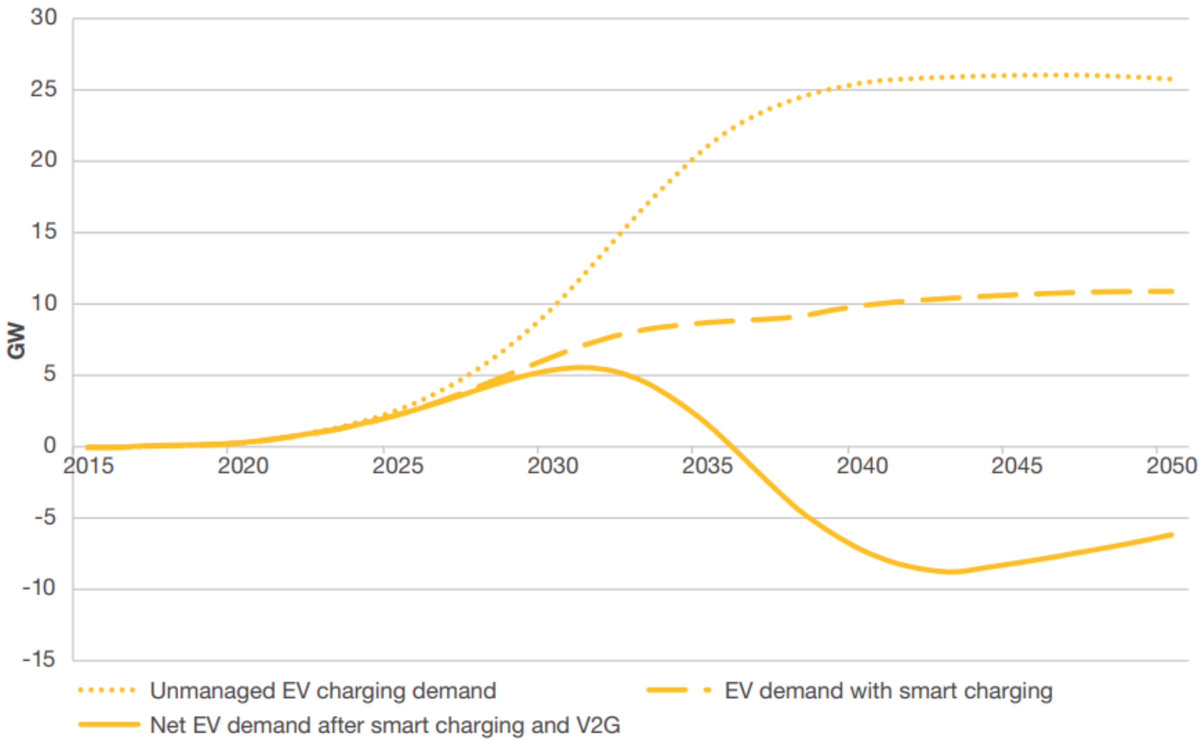
Together, EVs and hot water account for almost 90% of our assessed potential for flexibility from consumer appliances.

As a cross-check, the values we have used for Figure 7 for the potential relative contribution of EV smart charging and V2G appear to align reasonably closely with those assumed by the UK's National

[16] It should also be noted that charger costs are also a limiting factor for V2G at the present time. Thus, for V2G to be enabled, an EV will currently need to be connected to a specific charger (as opposed to simply being plugged into a standard domestic socket), and the costs of such chargers currently outweigh the benefit of V2G. However, charger costs, like EVs, are significantly declining in price as uptake grows. Thus, by 2050, our provisional assessment is that charger costs will no-longer be the impediment to V2G uptake that they currently are.

Grid for their 'Consumer Transformation' scenario in their latest "Future Energy Scenarios" publication, as shown in Figure 8 below.

Figure 8: National Grid UK projection of electric vehicle charging behaviour at winter peak system demand for their 'Consumer Transformation' scenario



Space heating has much less potential due to constraints on the ability to turn off, or even turn down, the appliance without starting to materially affect the heating service. These constraints are particularly for periods longer than an hour yet, as we set out later on page 26, such sustained load management is required for the coldest days that drive network capacity requirements. For the analysis shown in Figure 7 we have assumed that dynamic demand management could result in a 25% reduction in space heating's contribution to system peak demand. We suspect this could be optimistic.

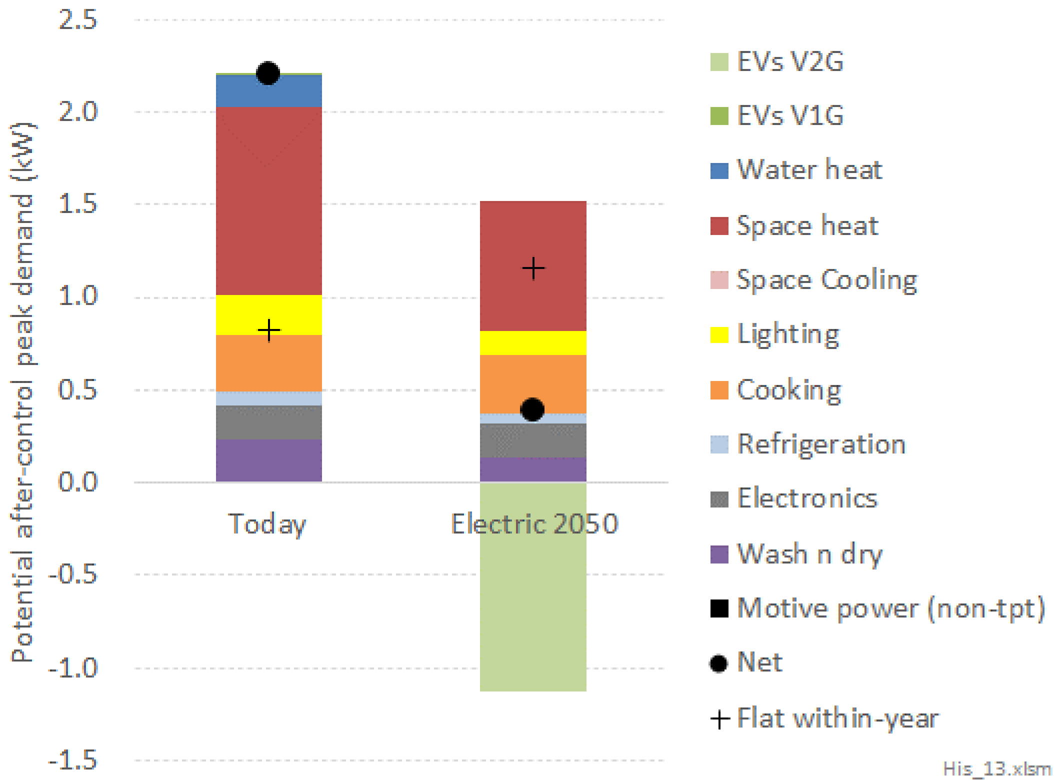
Refrigeration's potential is very small. In large part this is because, as shown in Figure 6 previously, it is not a big driver of peak demand. Thus, although refrigeration's annual consumption is roughly half that of space heating, its contribution to peak demand is only 8% that of space heating. This is because space heating demand is heavily concentrated in peak periods, whereas refrigeration demand is basically 'flat' throughout the year. Further, like space heating, refrigeration is likely to suffer constraints on the ability to control load for a sustained period on the coldest days that drive network capacity requirements.

A significant proportion of washing and drying peak demand could potentially be avoided by delaying turning on such appliances until after peak demand periods – we have assumed 40% reduction for Figure 7. However, their absolute contribution to demand reduction is relatively limited because the appliances are not large contributors to uncontrolled peak demand.

There is little or no ability to control lighting, cooking, and home electronics without causing significant disruption and inconvenience to households.

In Figure 9, we combine our analysis and demand growth and controllability to show a breakdown of peak demand with the maximum potential for load management utilised.

Figure 9: Breakdown of average per household after-demand management contribution to peak demand



On a simple analysis, it may appear that using the full potential of demand management and V2G could reduce the average household contribution to peak demand from around 2.2kW to 0.4kW. However, this is less than the 1.2kW demand that would occur if household energy use were completely flat across the year. This apparent disparity is because we are dealing with load shifting rather than outright demand control. The challenges of this are explored in more detail in Appendix A.

Nonetheless, this analysis does clearly highlight that the potential for demand management is dominated by just two technologies: EVs and hot water control. Taken together, these would more than satisfy the need for peak demand management, without needing to call on other technologies.

Box 2: What about household solar and batteries?

The analysis above doesn't consider the potential contribution from household solar and batteries.

In theory, these could make significant contributions to altered household demand and provision of flexibility. However, we note the following points:

- residential rooftop solar can reduce average annual net consumption, but makes no contribution to flexibility because system demand peaks occur on the coldest winter evenings when solar output is effectively zero
- our evaluation is that residential rooftop solar is fundamentally uneconomic because it is significantly more expensive than utility-scale solar, which benefits from:
  – significant economies of scale, and
  – a far superior ability to use axis tracking or optimised angles of inclination to optimise scheme output.
- also, solar (whether residential or utility) has the potential to become a cost *driver* independent of the traditional demand drivers if penetration becomes high enough to reverse flows
- our evaluation is that household-scale static batteries are also significantly less economic than utility-scale batteries, which benefit from:
  – significant economies of scale; and
  – the ability to locate (and relocate) relative small quantities of utility batteries in locations that optimise network investment deferral benefits
- also, well-managed EVs and hot water can deliver the same benefit as static batteries (whether household or utility-scale) at much lower incremental cost.

Taken together, it is difficult to estimate the potential from technologies that are uneconomic relative to alternatives.

That said, the uptake of these technologies is indicative of the need for tariff reform, as the predominant current tariff structures are incentivising households investing in uneconomic solar plus (in some cases) batteries.

This is not a good outcome from both an economic and environmental perspective, as the type of non-cost-reflective tariffs which incentivise household solar uptake will *dis*-incentivise EV uptake.

4.2 How does the demand for flexibility response vary both over time and by location?

As set out on page 11, another important consideration regarding the appropriateness of different tariff approaches for incentivising flexibility is how variable the need for flexibility is:

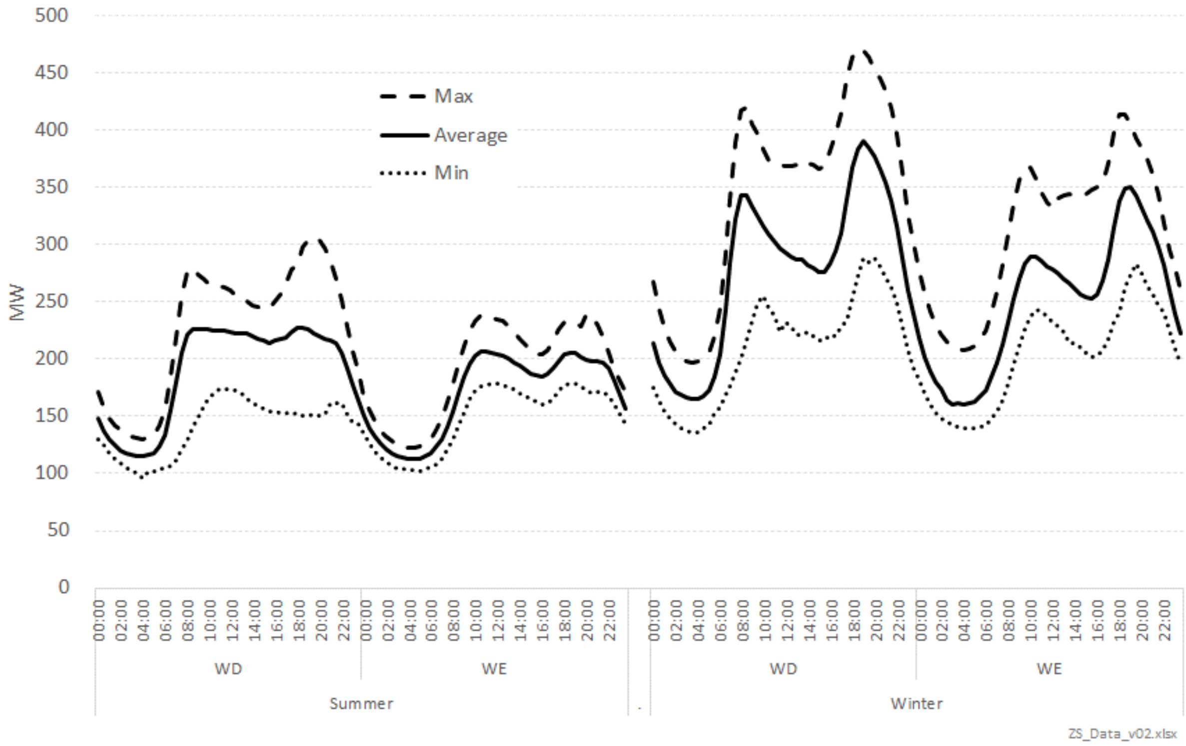
- If the need for flexibility is reasonably consistent and predictable in timing and location, then it is more reasonable to expect consumers to 'self-dispatch' their distributed energy resources to meet this requirement.
- However, if there is significant variability as to when, where, and how much flexibility response is required, it is less feasible that consumers will undertake the time and effort required to monitor system conditions to determine when to turn their appliances on or off.

To help consider this, we have analysed a year's worth of half-hourly data from Wellington Electricity's zone substations[17] from 2018 to get some insights into:

- How much flexibility response might be required to deliver material cost savings?
- When and where might such response be required?

Figure 10 below shows that there is a general pattern of demand, with: winter being higher than summer; weekdays being higher than weekends; and morning and evenings being the highest periods during the day and nights the lowest. However, the max and min lines show that on any given day there can be considerable variation as to the demand levels.

Figure 10: General pattern of demand summed across all zone-substations[18]



However, despite there being this general pattern of demand across the network, Figure 11 shows that there can be significant variation between zone subs based on the type of consumers located beneath them. Thus, the CBD zone-sub shows a very different pattern of demand: the peak demand

[17] Many thanks to Wellington Electricity for generously making such data available for this study.
[18] Winter is defined as the four months from June to September, and Summer being the four months from December to March.

is during summer due to air-conditioning load; there is much greater weekday vs weekend variation; and a much flatter within-day shape.

Figure 11: Patterns of demand for two individual zone subs

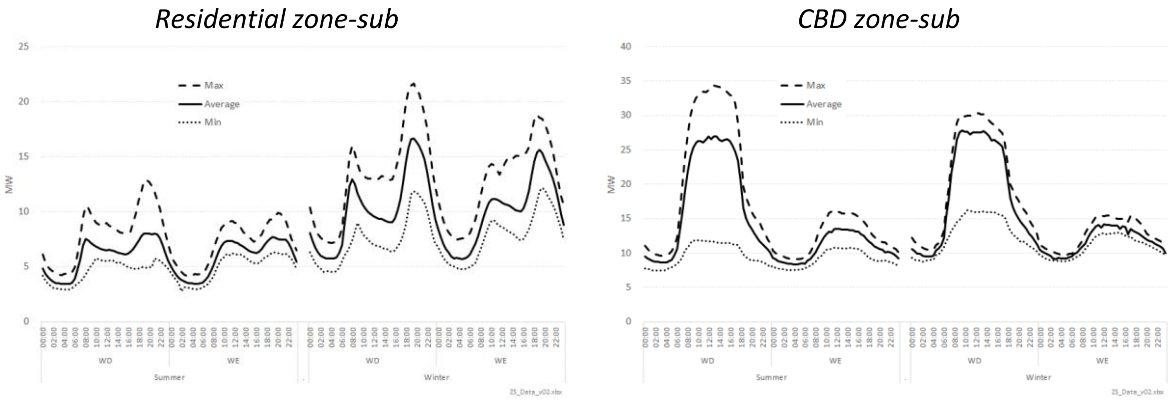


Figure 12 below represents the half-hourly demand across the year for each Wellington Electricity zone sub as a duration curve. It shows that there is a huge variation between high and low demand periods. It also shows that the top few percent of peak demand hours are responsible for a disproportionate amount of peak capacity requirements. Thus, looking at the 'ZS_Avg' line (being the average of all the individual zone sub duration curves), the top 10% of hours are responsible for 35% of the capacity requirements on the network during 2018.

Figure 12: Zone sub load duration curves for 2018

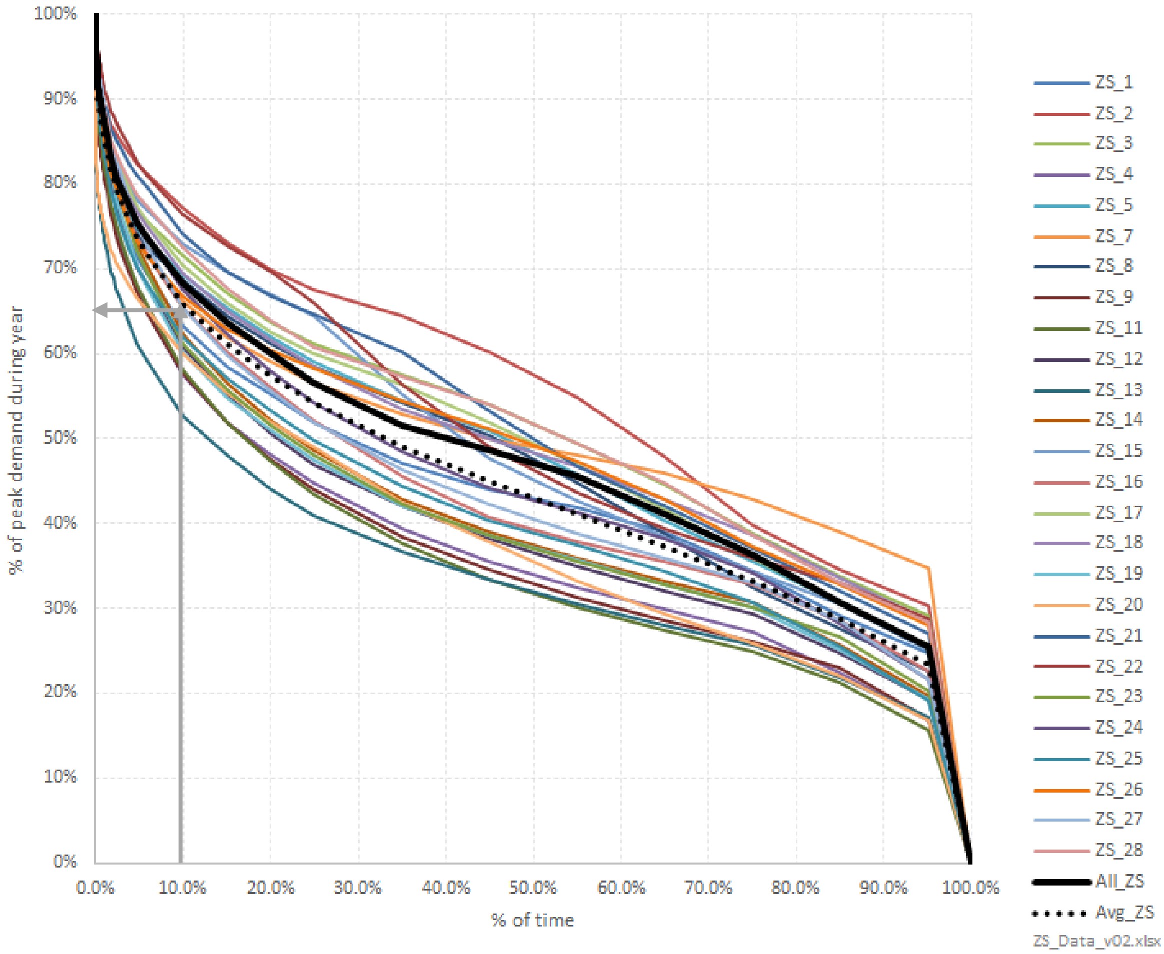
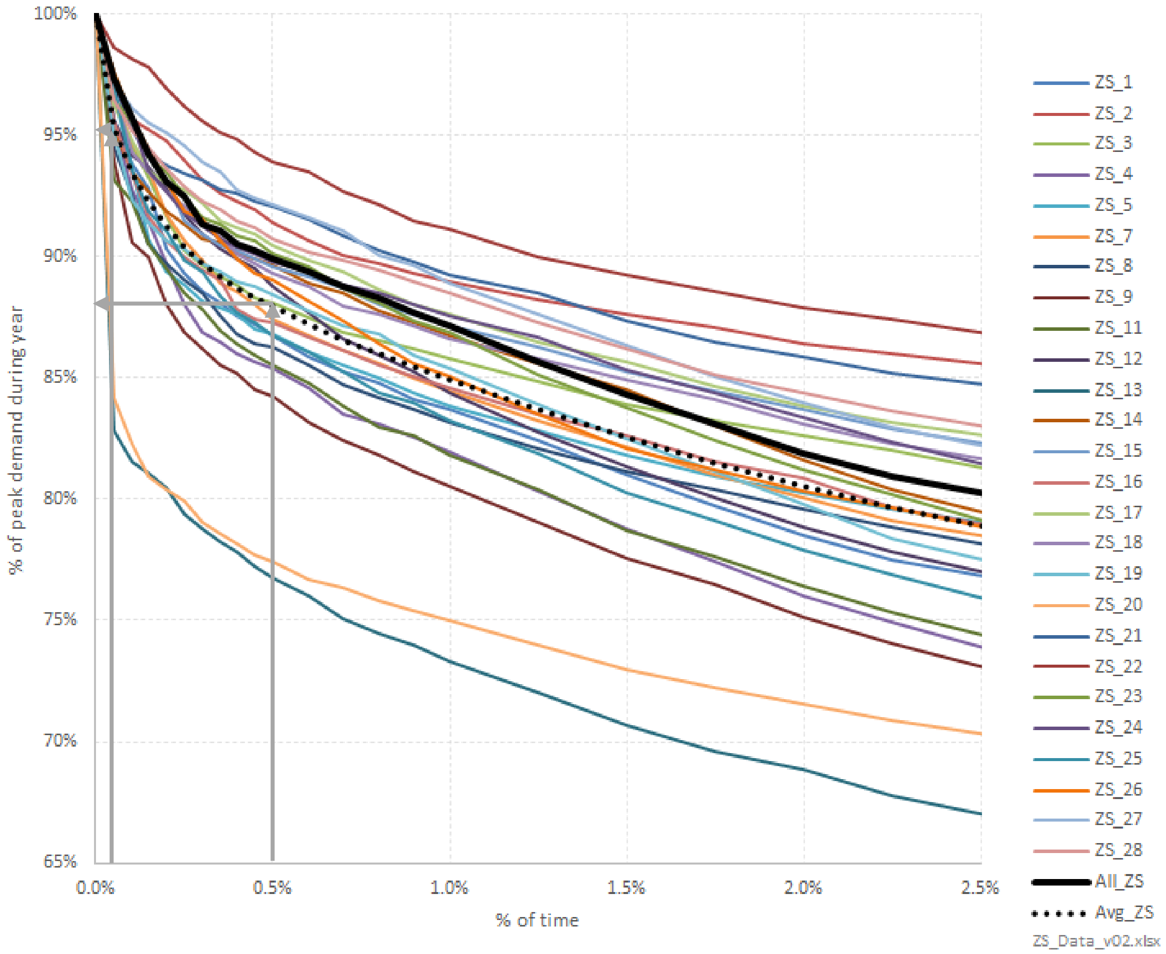


Figure 13 further illustrates this point of the top few hours being responsible for a disproportionate amount of peak capacity requirements. This shows that the top 0.5% of hours (approximately 43 hours) are responsible for 12% of peak capacity requirements, and that 0.05% of hours (approximately 4.5 hours) are responsible for almost 5% of the peak capacity requirements.

Figure 13: Duration curve covering top 2.5% of hours during 2018

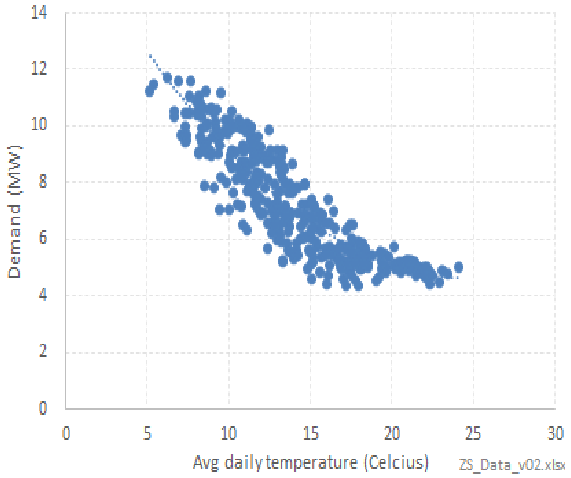


The above analysis likely under-estimates the extent to which a few extreme periods of demand drive the capacity requirement because 2018 was a relatively mild year without extreme cold periods. If the same analysis were extended across multiple years, it would show a more extreme result.

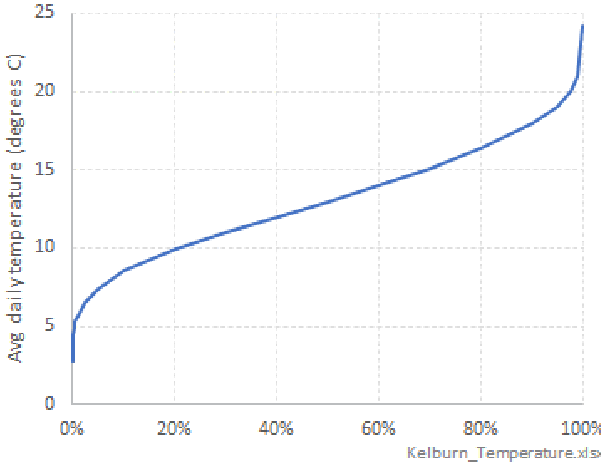
To illustrate this, the graph on the left in Figure 14 below shows how demand for a residential-heavy central Wellington zone-sub increases as temperature falls (with temperature being taken from the Kelburn weather station). It also shows that the lowest average daily temperature was 5˚C for 2018. However, the graph on the right shows a duration curve of average daily temperatures for the Kelburn weather station for the period April 2004 (the earliest date data was available) to August 2021. It shows that there can be days when average daily temperature drops a couple of degrees below 5˚C, but these are very rare events.

Figure 14: Temperature influence on demand in Wellington

Demand / temperature relationship for 2018



Temperature duration curve for 2004 to 2021



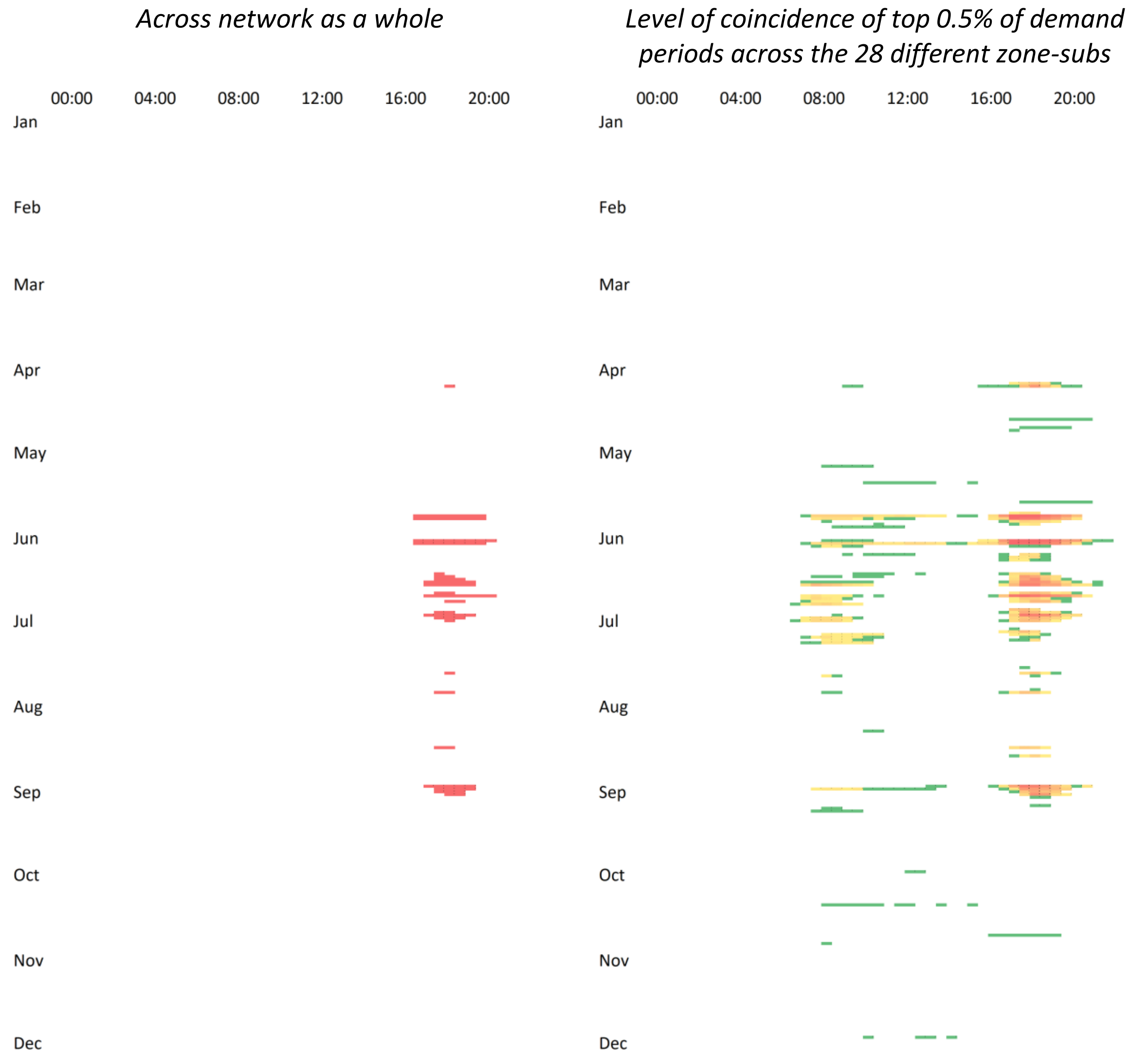
Combined, the above temperature analysis indicates that the load duration curves shown in Figure 12 and Figure 13 would be materially peakier when measured over a timescale of many years.

Figure 15 below shows when during 2018 the top 0.5% of demand periods occurred. The left-hand chart shows the incidence of the top 0.5% of demand across the network as a whole. It shows that they were all in the evening periods and predominantly in months classed as winter. However, some occur in late May and a couple even occur in April.

It also shows there is randomness as to when they occur. While none occur in weekends, there can be several weeks in winter that don't have any peak demand periods, while in some weeks there can be several consecutive days with several hours that are in the top 0.5% of demand periods.

The right-hand column shows the coincidence across the different zone subs for top 0.5% demand periods. A dark green colouring for a half-hour indicates that only one zone sub had a top 0.5% demand period in that half hour. The deeper the red colour for a half-hour period, the greater the number of zone subs for whom the half hour was one of their top 0.5%. It shows that there can be variation as to when peak demand periods occur for different zone subs. Thus, some have peak demand periods in the morning peaks, and a few even have peak demand periods in summer days. The highest peak demand period only coincided with a top 0.5% demand period for 22 out of the 28 zone subs.

Figure 15: Heat maps of incidence of top 0.5% of Wellington Electricity demand periods in 2018



The last key take-away from all the above analysis is that controlling to eliminate the top x% of demands, will require sustained flexibility response over many hours for some days. In other words, peak demand periods are heavily concentrated in a few days of extreme weather, with demand being extremely high for a large proportion of such days.

Analysis of the total network demand indicates that if flexibility response is required for the top 0.25% of hours in the year (22 hours in total) – ie, limiting demand so it doesn't go above the 99.75th percentile of uncontrolled demand – this will require 3.5 hours of sustained response for the highest demand day. Providing flexibility response for the top 2% of hours in the year will require seven hours of sustained response for the highest demand day.

Further, based on the type of analysis shown in Figure 14, if the above analysis incorporated many years' worth of temperature data instead of the single 2018 year of data, we suspect that the level of flexibility response required to manage demand so that it doesn't exceed the 'Xth' percentile of demand will require significantly longer periods of sustained response for the highest demand day than the values set out above.

This dynamic of sustained response being needed for a large number of hours on the peak demand day is important because some of the technologies detailed in section 4 previously are better suited to providing sustained response than others:

- storage technologies such as hot water and EVs are relatively well suited to providing sustained response
- space heating is relatively poorly suited to providing sustained response over many hours, particularly as such response is required on the very coldest days.

Appendix A provides further detail of the challenge of providing ever-increasing quantities of sustained response in the few days of highest demand in order to reduce peak demand below a given capacity target.

5 Which tariff option is likely to be best at delivering NZ's overall DER flexibility potential?

The analysis set out in the previous sections demonstrates flexibility response can be enormously valuable, and EVs and hot water can deliver the vast majority (if not all) of such benefit. Thus:

- Flexibility response is only required for relatively small periods of time in order to deliver significant capacity savings;
- The scale of response from EVs and hot water dwarfs the potential response from other appliances. The response from these two appliances would more than satisfy the overall need for flexibility response.

However, the analysis also highlights the challenges with accessing this response:

- A lot of sophistication and effort is required to coordinate when and where to call upon response:
  - There is significant randomness as to when flexibility response is required
  - There can be significant variation between sub-locations within a network as to when peak demand periods occur. There is also likely to be significant variation as to the margin between the local network capacity and the local peak demand – ie, how much spare capacity there is on the network to accommodate demand growth before investment in additional capacity is required.
  - There can also be variation between when stress periods occur for network capacity management, and when they occur for generation capacity management
  - There is weather-driven variation in the amount of response required from year-to-year and within-year, with the top few peak days in the 1-in-10-year-type weather events that drive system capacity needs requiring sustained flexibility response for many hours
- We consider it unlikely that most individual consumers will be sufficiently incentivised by the potential savings from flexibility response to undertake the level of active engagement necessary to achieve the level of coordination required.
  - The average per household avoided supply costs from flexibility response are 'only' a couple of hundred dollars a year. While this amounts to billions of dollars of benefit when multiplied across all consumers, the level of individual saving seems unlikely to be of a level necessary to persuade many customers to actively monitor and respond to electricity supply situations on a day-by-day (even hour-by-hour) basis.

With reference to the tariff options set out in section 3, all the above suggests the optimal consumer supply arrangements are:

- Managed appliance tariffs for those appliances that are suitable for control (of which EVs and hot water cylinders are the primary candidates).
- Simple 'peak/off-peak' TOU tariffs for the rest of the household load.

This evaluation is based on the following reasons:

- There will be an ever-increasing need for more locationally granular and temporally dynamic flexibility response. This is poorly suited to the 'consumer-delivered' flexibility response from TOU and CPD pricing, but ideally suited to supplier-managed appliance options
- Time-of-use pricing has the potential to create new peaks in demand if applied to EVs and hot water
- Coincident peak demand (CPD) pricing is very consumer unfriendly, materially impeding its effectiveness
- Utilising the potential from vehicle-to-grid technology will inevitably require some central coordination

Before elaborating on each of these points below, it is worth pointing out that while managed appliance tariffs are likely to be the best options for EVs and water heating in the long-term, TOU options are likely to be a good interim option for EVs in the short term – particularly while managed options are being developed.

It is possible that some consumers may continue to elect for TOU options for their EVs, even when managed options are well developed. Further, it is possible that TOU options may deliver much of the benefit for EVs, reducing the need to get additional value from managed appliance options.

As such, while we think managed appliance options are likely to deliver the greatest long-term benefit compared to TOU options, we do not regard managed vs TOU as a binary choice.

5.1 There will be an ever-increasing need for more locationally granular and temporally dynamic flexibility response

This increasing need for more locationally granular and temporally dynamic flexibility response is because:

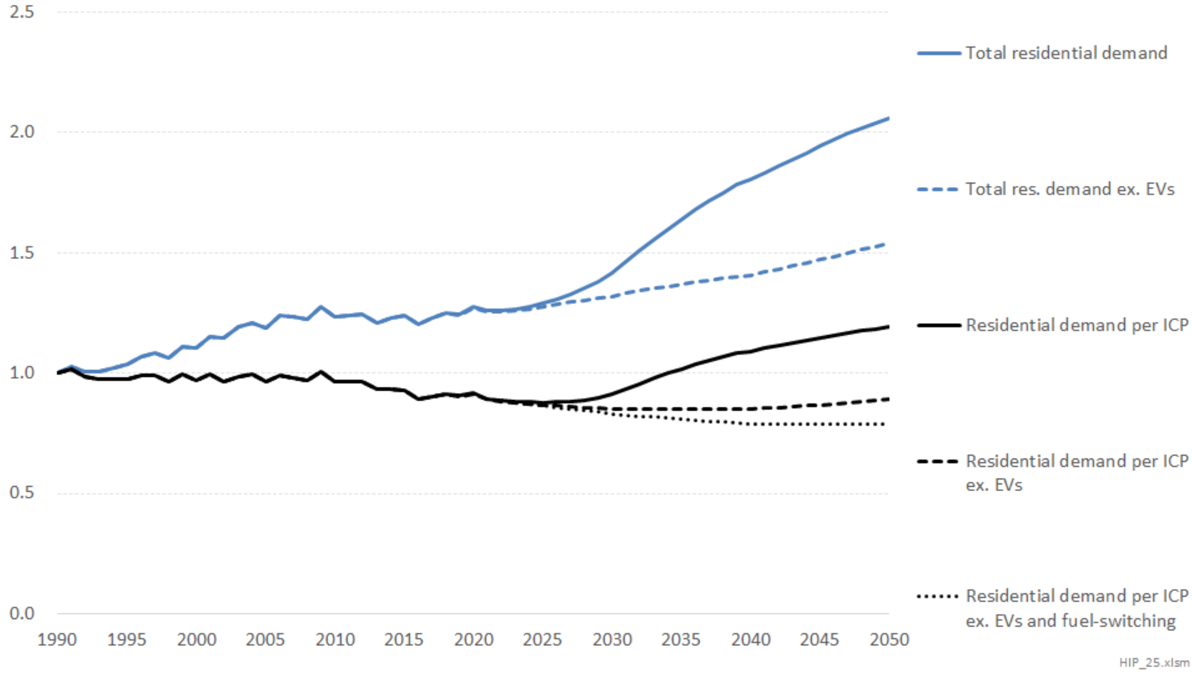
- Decarbonisation-driven growth in per consumer demand is likely to increase the value of more locationally-granular demand management
- The growth of wind and solar will require more dynamic temporal demand management to address generation scarcity situations

We elaborate on each of these points below.

5.1.1 Decarbonisation-driven growth in per consumer demand is likely to require more locationally-granular demand management

Figure 16 below shows how average residential electricity demand has changed relative to 1990, and how it is projected to change in the future under the Climate Change Commission's 'Demonstration Path' scenario.

Figure 16: Relative growth in different measures of distribution-connected annual electricity demand for CCC Demonstration Path scenario



For the historical period 1990 to 2020, total residential demand has grown by approximately 25%, while average per ICP demand (i.e. per household demand) has fallen by about 10%. In other words, the growth in total residential electricity demand has been entirely due to population growth, which in aggregate has more than counter-acted the reduction in per household demand caused by a combination of energy efficiency and some fuel-switching away from electric heating.

Going forward, however, this trend of falling per household demand is projected to reverse due to the uptake of EVs combined with some fuel-switching away from fossil gas more than counter-acting the projected ongoing improvements in energy efficiency.

If per household contribution to peak demand increases in line with this increase in per household annual demand, this is going to put pressure on LV networks which typically service around 60-100 properties. While these have generally been built with some degree of 'over-sized' capacity to accommodate potential growth due to housing in-fill or 'densification', some are likely to breach their capacity limits from the degree of demand increase indicated by Figure 16.

Further, there is likely to be variation in the extent to which different LV networks experience EV-driven peak demand growth. For example, those in relatively distant satellite suburbs whose households drive relatively longer commuting distances to work each day are likely to experience materially higher increases in demand compared to inner-city suburbs where households drive shorter distances and are more likely to use public or active transport. Coupled with likely different rates of EV uptake in different suburbs, and likely significant variation in the extent of densification in different suburbs, this is likely to result in significant variation in peak demand growth across different LV networks and their parent HV networks.

In this respect, managed appliance tariffs are inherently much better suited to delivering the kind of highly locationally granular DER response required to manage this variation in local peak demand growth.

In theory, TOU and CPD options could potentially deliver a more locational level of response if networks started to apply highly locationally granular distribution pricing zones – including down to the LV level. However, this is likely to introduce significant overhead on consumers and retailers to manage (increasing costs and consumer stress) and is extremely unlikely to deliver as effective a level of response when required as managed appliance options.

5.1.2 The growth of wind and solar will require more dynamic temporal demand management to address generation scarcity situations

As Figure 2 highlighted, generation accounts for a significant proportion of the costs of meeting any increase in peak demand. To-date, there has been a strong timing overlap between periods of peak demand on distribution networks, and periods when infrequently-required peaking generation is required. This overlap has meant that providing flexibility response to manage network stress has also generally contributed to managing generation scarcity.

However, as the proportion of wind and solar on our system grows, there is likely to be increasing periods of time when infrequently-used peaking generation is needed outside of the times when peak demand is occurring. i.e. there will be times when demand is not particularly high, but wind and solar output is very low.

Both TOU and CPD pricing approaches will inherently be unable to contribute to generation scarcity at such times.

However, managed appliance options naturally enable supplier-led coordination of flexibility response from DER to meet both network and generation scarcity situations – subject to appropriate contractual arrangements between consumers, network companies, and retailers. This latter aspect is addressed further in section 6 below.

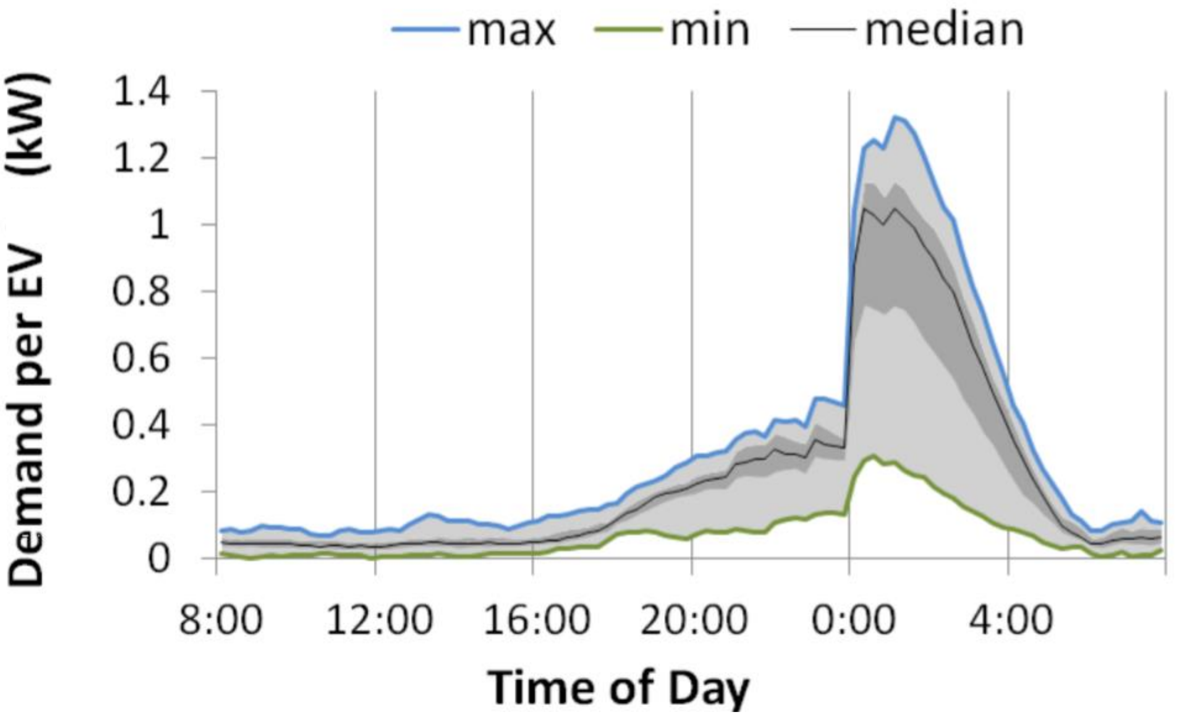
5.2 Time-of-use (TOU) has the potential to create new peaks in demand from EVs and hot water

Ironically, it is the very controllability of storage technologies such as EVs and hot-water cylinders that means TOU is unlikely to be the best long-term solution for these technologies. There is a very real risk of consumers responding to the price signal of a TOU tariff and using timers (built within the control functionality of every EV, or simple add-ons for hot-water cylinders) to start charging at the start of the off-peak period. In doing so, all the natural diversity of households charging needs occurring at broadly different times would be lost, and a significant new peak could develop.

Experience with TOU tariffs illustrates such outcomes are likely. This has occurred in New Zealand historically with networks applying TOU pricing for hot water control.[19] It also illustrated in this example shown in Figure 17 below for San Francisco, where Pacific Gas & Electric offered EV-owning customers a time-of-use price with an off-peak period starting at midnight.

[19] For example Orion had TOU rates in the late '90s and early 2000's and experienced localised peaks as hot water cylinders all came on at once.

Figure 17: Weekday EV charging demand for San Francisco



Note: The x-axis starts at 8am

This was analysed further in our 2018 "Driving Change report,[20] with quantitative analysis demonstrating that large-scale EV uptake with simple TOU pricing applying to EVs would likely result in higher peaks than if consumers just faced a flat price and increased peak demand consistent with that shown in Figure 6.

That said, as a temporary measure while managed appliance tariff options are developed, simple TOU approaches are likely to be preferable for EVs than continuing with flat tariffs.

Further, as previously set-out, it is likely that a well-designed TOU tariff may be a sufficient option for many EV owners, and thus sit alongside managed charging options being taken-up by other EV owners. However, we don't think only relying on TOU will be adequate to realise the benefit (and avoid the potential costs) from EV charging.

5.3 Coincident Peak Demand (CPD) pricing is very consumer unfriendly, materially impeding its effectiveness

As discussed earlier on page 10, by focussing peak-driven-cost recovery over a very small number of periods, the $/kWh cost of consumption during such periods is orders-of-magnitude higher than the $/kWh cost of consumption during periods classed as peak for a TOU approach.

The experience from The Lines Company's implementation of CPD pricing highlights consumers find it harder to understand than TOU pricing. This difficulty in understanding, coupled with the extreme prices during CPD periods and not knowing in advance which of the 50 or so hours in the year are going to be classed as system peak, can create significant uncertainty and fear among many consumers – as was the experience with The Lines Company.

[20] *"Driving change – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand"*, Prepared for Orion, Unison, and Powerco, 7 March 2018. Available for download at https://www.concept.co.nz/updates.html

A pricing approach that is hard to understand is less likely to deliver good consumer decisions – as was evidenced by the Electricity Authority's review of The Lines Company's pricing. And a pricing approach that is mis-trusted or feared by consumers is unlikely to be politically durable – as was evidenced by The Lines Company eventually moving away from CPD pricing.

Further, in terms of trying to positively influence consumer decisions, our past analysis[21] demonstrates that there is little to no difference between CPD and TOU pricing options in terms of the economic price signal regarding:

- what appliances to buy (eg, whether to convert to LED lighting, from gas to electric heating, or from a fossil to electric vehicle)
- what regular patterns of use to encourage.

Options are equivalent for sending a price signal for consumer appliance purchases – but CPD may be practically worse

The price signal for consumers deciding on appliances is equivalent between CPD and TOU pricing. This is because the relative proportions of demand from the different appliances during periods classed as peak in a simple TOU structure are very close to the relative proportions of demand from the different appliances during the periods of absolute peak network demand. This is a key insight and is crucial to appreciating the effectiveness of different options for delivering appliance investment signals.

The only appliance where CPD is almost always going to send a stronger signal than a TOU structure is space heating. This is because space heating is the activity that is most strongly associated with extreme peak demands. However, this difference in signal between CPD and a 'reasonably' structured TOU is one of degree, rather than being fundamentally different. Further, we consider there are adverse social consequences (including to human health) of having a tariff that gives rise to some consumers (generally the most vulnerable) being afraid to turn their heating on. Additionally, the Electricity Authority's review of The Lines Company's experience with CPD pricing found that many consumers found it confusing resulting in them making the wrong appliance choice.

As for managed appliance tariffs, these can send an equivalent price signal to TOU or CPD by suppliers setting an appropriate discount for consumption from the managed appliance.

Options are equivalent for encouraging regular patterns of consumption – but CPD may be practically worse

A simple, understandable TOU structure is easy for consumers to develop regular patterns of use around – eg, postponing running the dishwasher till later at night.

And under a managed appliance option, there is no need to encourage patterns of consumption, as the supplier will manage that aspect.

Again, CPD pricing could theoretically encourage regular patterns of consumption. However, if consumers find the pricing hard to understand, they may also be less efficient at developing the best consumption patterns.

For incentivising dynamic response when and where it is required, CPD is theoretically better than TOU, but worse than managed appliance tariffs

The only area where CPD is theoretically better than TOU is in encouraging dynamic load shifting during the few periods of actual peak demand.

[21] "*Issues and options for moving towards more cost-reflective network tariffs*", available on request.

However, this requires significant management overhead by consumers to respond to, significantly degrading their effectiveness (while also increasing consumer stress).

Further, managed appliance options will inherently be far superior to CPD at delivering high levels of appliance response during periods of system stress as electricity suppliers will be much better able to coordinate the level of response required at different times and locations rather than rely on individual consumers responding.

In summary, CPD pricing may be theoretically 'right', but practically very 'wrong'

All in all, while CPD pricing may be appropriate for a handful of large industrial consumers who have the resources and expertise to meaningfully respond to such signals, we believe it is completely inappropriate for the vast majority of consumers.

5.4 Utilising the potential from vehicle-to-grid technology will require some third-party coordination

As Figure 7 highlighted, V2G has the potential to offer significant amounts of very valuable flexibility response.

However, injecting power into the grid – particularly in significant quantities – requires significantly more coordination than managing when consumption occurs.

This is clearly apparent at the national level, with significant systems and processes to enable the operation of the power system in a stable and efficient manner. It is equally true at the distribution level, particularly as such grids have been designed for uni-directional power flows and face equipment and local power quality challenges if reverse flows become significant. Safety also becomes a much more significant factor if appliances start injecting power back into the grid.

In our view, TOU and CPD tariffs are very poorly suited to delivering the level of coordination necessary to enable the potential benefits of V2G to be realised. In contrast, managed appliance approaches are inherently well suited to delivering coordinated flexibility response.

5.5 Summary evaluation of merits of options

Table 1 below applies some simple scoring out of 10 to the different pricing options, drawing upon the qualitative evaluations above, and distinguishing between pricing for storage devices (including EVs and hot water cylinders) and non-storage devices.

The evaluation starts by considering the merits of the options for influencing consumers' decisions in three respects:

- What appliance to buy. These are typically infrequent decisions such as what car to buy (eg, EV or ICE), what space or water heating appliance to buy (eg, gas or electric) or whether to buy more or less efficient electric appliances. Over the long-term these appliance choices will have the greatest effect on the system which is why we have weighted this category's importance as two-thirds
- When to use the appliance, split between
  - Incentivising regular usage patterns (eg, regularly operating in a way which avoids peaks)
  - Incentivising dynamically calling upon flexibility for the infrequent periods of scarcity

The evaluation then factors the theoretical price signal by practicality considerations. It then also considers other factors that may be different between the pricing options including:

- The ability of the pricing option to allocate flexibility resources to both network and generation uses

- The ability to deliver location-specific response
- The ability to deliver V2G, and
- The costs associated with any control infrastructure

Table 1: Ranking of pricing options

Consumer decision value drivers		Weight	Storage devices TOU	Storage devices CPD	Storage devices Ctrl	Non-storage TOU	Non-storage CPD	Non-storage Ctrl	**Notes**
Theoretical price signal	Appliance choice	67%	10	10	10	8	10	10	Simple TOU gives same appliance investment price signal as other options for almost all appliances. Only for space heating is it slightly less strong
	Regular usage patterns	17%	10	10	10	10	10	10	TOU & CPD should both incentivise usage patterns which avoid peaks. Ctrl scores as high as rest, because no need for consumers to develop regular usage patterns
	Dynamic response when required	17%	0	10	10	0	10	10	TOU can't deliver dynamic response only in specific peak periods or extra in such periods
	Weighted average	0%	8.333	10	10	7	10	10	
Practical price signal	Practicality factor	0	100%	10%	100%	100%	10%	100%	CPD hard for consumers to understand and requires significant effort to meaningfully respond
	Suitability factor	0	60%	100%	100%	100%	100%	10%	TOU can cause new peaks for storage devices. Ctrl unsuitable for non-storage devices
	Revised score	0	5.0	1.0	10.0	7.0	1.0	1.0	

Other value drivers (applies to storage & non-storage)		TOU	CPD	Ctrl	Notes
Ability to value-stack Nwk and Gen flexibility benefits		1	3	10	Ctrl options for Nwks will have control infrastructure avail for generation purposes. Less likely that separate control infrastructure developed for other options
Ability to deliver location-specific response		1	2	10	Ctrl tariffs don't require location-specific tariffs, and with modern control infrastructure can deliver LV-nwk specific control. Zone-sub-specific tariffs for TOU or CPD introduce significant overhead, and can't deliver LV-nwk specific control
Ability to deliver V2G	Now	0	0	0.1	EV control infrastructure for managed demand can also deliver V2G
	Future	0	2	10	
Low control infrastructure costs	Now	10	8	2	EV control infrastructure currently relatively high (but falling) cost
	Future	10	8	6	

Overall weighted score	Storage devices TOU	Storage devices CPD	Storage devices Ctrl	Non-storage TOU	Non-storage CPD	Non-storage Ctrl
Now	5.6	3.4	7.5	6.7	3.4	3.1
Future	4.6	3.1	9.0	6.7	3.4	4.3

Pricing_Illustrations_01.xlsm

For storage devices such as EVs and hot water, our analysis is that managed appliance options are going to deliver the greatest value followed by time-of-use options.

For other appliances, simple time-of-use pricing options are likely to deliver the greatest value.

That said, as we set out further below, we do not see the choice between managed appliance options and TOU options for storage devices as being completely binary. We can envisage a mix of managed appliance and TOU options emerging for EVs, with the proportions of consumers choosing each option being driven by the relative value to be delivered from each option.

6 Implications for market arrangements

Section 5 concludes that the consumer tariff arrangements that will deliver the greatest value are:

- Managed appliance tariffs for those appliances that are suitable for control (of which EVs and hot water cylinders are the primary candidates).

- Simple TOU tariffs for the rest of the household load, and potentially some proportion of EV load.

However, while managed hot water tariffs are well-established in New Zealand, and TOU tariffs are becoming increasingly common in New Zealand, the development of managed appliance tariffs for EVs is still in its infancy. In particular, some of the key questions to be answered are:

- Should managed appliance options be mandated?
- What type of control systems are required? Can we simply use the systems for controlled hot water?
- What type of metering systems are required?
- Who should own such systems and/or determine to what extent the flexibility provided by managed appliances is used for different purposes?
- Might generic managed appliance tariffs be appropriate, or might technology-specific tariffs be required?

We address each of these points in this section.

6.1 Should managed appliance options be mandated?

While our analysis suggests managed appliance options will deliver the greatest flexibility value for EVs and hot-water control, we don't believe these should be mandated options.

As well as raising questions about individual consumers' property rights, we don't even regard it as being feasible to mandate management of an appliance such as an EV that can be plugged into any three-pin socket in any property.

Managed tariffs should be an option, with the incentive for consumers being the lower prices they would enjoy from being on a managed option rather than charging their vehicle under the standard TOU arrangements. This superior electricity value will come from:

- V2G benefits
- The value from not causing local peaks at the start of off-peak TOU periods

Some managed charging service providers may also offer battery optimisation services – ie, charging the vehicles in such a way that maximises the lifetime of the battery.

Going forward, we are therefore likely to see a mix of TOU and managed appliance offerings. If TOU can deliver most of the benefit without causing local peaks, there may be relatively little need to develop managed service offerings. However, if, as we suspect, there could be material additional value from offering managed service options, it is likely that these will be increasingly developed and offered as options to consumers.

6.2 What type of control systems are required?

New Zealand currently has a significant quantity of managed appliances in the form of hot water cylinders that can be turned on and off via ripple control. However, we consider that this type of control, while it was world-leading when it was introduced many decades ago, is not going to be suitable for providing managed EV charging.

This is because ripple control is a relatively 'crude' on/off signalling mechanism that controls large numbers of appliances all at once. Thus, typically, a network company will assign consumers to one of a dozen-or-so control 'channels', and the network can then only turn on or off appliances to a granularity of, for example, one-twelfth of its customer base.

Managed EV control is likely to require more sophisticated control that can distinguish between individual EVs based on factors such as the state of charge (eg, distinguishing between batteries that are relatively full or empty) and potentially also the LV-specific location within the network. This would require individual appliance-specific control signals. Such granularity of control is well-beyond ripple control capabilities but is perfectly suitable for internet-based signalling given the ubiquity of home internet and wireless communications.

Such appliance specific control is being trialled overseas and in New Zealand, with trials from companies such as Wellington Electricity and Vector. These systems involve signals being sent over the internet to a fixed EV charging point installed at a consumer's premises. This allows for relatively sophisticated control beyond simple on/off commands, and (in some overseas trials) can coordinate vehicle-to-grid injection.

6.3 What type of metering systems are required?

For managed appliance options to work:

- suppliers need to have reasonable assurance that the control they are paying for is being delivered; and
- consumers need to be appropriately rewarded for providing such control.

A key issue is how exact this assurance and compensation process needs to be? For example, some suppliers have raised concerns that some EV owners may sign-up for a managed EV tariff but then on the day of a peak event happen to have decided to plug their EV into a standard uncontrolled plug because they have a particular need for a fully-charged battery later that day.

In this, we believe there are trade-offs between theoretical perfection and practicality, and that an approach that takes account of consumer diversity will maximise the overall benefit.

6.3.1 Measurement of flexibility delivered for supplier assurance purposes

We think suppliers should get high levels of assurance because, unlike hot water control, which is currently only a one-way signal, EV appliance management will need to have some form of two-way communication to provide maximum benefit to EV owners that have opted-in for such management. Thus, the systems will need to be able to interrogate the EVs to determine the battery charge levels to:

- enable prioritisation of control during system peak between batteries at different charge levels;
- smooth the charging over different vehicles within the night-time period in a way that maximises the long-term health of the batteries.

This two-way communication will enable suppliers to determine that EVs were connected to control infrastructure for a sufficient proportion of the year to qualify for the control discount – even if they are not connected to the control infrastructure during every flexibility event that requires control.

We cannot see any reason why there should be a systematic bias such that EV owners opt to plug their EVs into uncontrolled circuits during days that require peak control. There will inevitably be some consumers who do that on any given day due to their personal circumstances (e.g. having driven a lot during the day, and needing to go out later in the evening) but that can readily be accounted for by networks assuming a given % of EVs will not be able to be controlled, and incorporating this value into their network design and operation standards.

Some overseas managed EV charging options inform consumers via a mobile phone app that their vehicle is about to have its charging managed-down during a peak scarcity period and giving them the opportunity to opt-out if they have a particular need to use the vehicle later that day. If the consumer opts out for more than a certain number of times during a given period, they lose the discount for being on a managed charging tariff.

6.3.2 Metering systems

With regards to metering, the ideal would be to have a separate meter which measured the consumption and/or output from the managed appliance. This would allow for a more exact setting of a tariff.

However, there could be material costs involved in changing existing meter set-ups to provide for an extra meter. At the very least it would require an electrician to connect the circuit with the EV charger to the correct advanced meter register and, in most cases, we understand the advanced meters would need to be upgraded to enable an extra register. This process could involve a one-off cost of several hundred dollars per household.

There are, however, two alternative approaches:

- using 'inclusive' tariffs, or
- making use of in-vehicle meters

Inclusive tariffs

An interim approach is to use the co-called 'inclusive' tariff approach that is taken for hot water control. This is used by those New Zealand networks that have hot water control, but don't have a separate meter for the hot water cylinder. Instead, they set a discount for the single meter that reflects the average proportion of household demand from a hot water cylinder. For example,

- if:
  - the average consumption from hot water cylinders represents 25% of the average household's consumption; and
  - the tariff for a separately metered controlled hot water cylinder is 1 c/kWh and the tariff for separately metered uncontrolled load is 5 c/kWh[22]
- then, the inclusive tariff for the combination of controlled hot water and uncontrolled load would be 25% x 1 c/kWh + 75% x 5 c/kWh = 4 c/kWh

This approach could equally apply to rewarding consumers for signing up to a managed EV tariff. In setting the level of tariff to apply, a network company would need to estimate the average household consumption from an EV as well as from a controlled hot water cylinder and from uncontrolled. They would then have four tariff options:

Tariff	Managed appliances
Uncontrolled	None
Inclusive HW	Hot water
Inclusive EV	EV
Inclusive HW + EV	Hot water + EV

[22] The size of discount (relative to uncontrolled consumption) for a controlled appliance is based on the average kW level of control from the appliance multiplied by the $/kW/yr level of peak demand costs, and then spread over the average kWh consumption from the controlled appliance.

This approach can work equally well with TOU tariffs, with the tariffs in the peak and off-peak periods reflecting the proportions of the different loads in each of those periods.

This inclusive approach inevitably doesn't reflect the exact level of discount that should apply to individual households given that there will be variations between households as to the proportion of their consumption from the different uncontrolled and controlled loads. However, this is a dynamic that exists at the moment with inclusive hot water tariffs, with households that proportionately consume a lot of hot water being under-rewarded, and vice-versa for those who consume relatively little hot water.

It is possible, indeed likely, that there is greater variation in demand per EV than demand per hot-water cylinder, as there is likely greater variation in how much different households drive their vehicles (or how many vehicles they have) than there is variation in how much hot water they use.

However, on the flip side, it is likely that a significant proportion of households on Inclusive Hot Water tariffs

- have hot water cylinders whose relays have faulted-on, or
- no longer have an electric hot water cylinder, having switched to gas or LPG water heating.

In contrast, the ability for managed EV control systems to communicate with the vehicle and the associated assurance processes to determine that EVs are connected to control systems should eliminate such unjustified rewarding of discounts.

On balance, therefore, it is not clear that an inclusive metering approach for managed EV charging would result in grossly inequitable results – particularly as an interim step to enable managed charging options to be offered before more sophisticated metering options are developed.

Inclusive metering approaches could even be applied to V2G approaches. Thus, if a consumer signs up to a managed EV tariff that also grants the supplier the right to inject power back into the grid at certain times – subject to specific service levels[23] – they would have an even greater discount (or a credit). This would result in even greater variations in inclusive EV tariffs – at the very least a V1G version (for vehicles with managed charging only) and a V2G version (for vehicles that also inject power to the grid) – potentially with variants for the injection capacity of the vehicle (and charger).

Using the meter within the vehicle

EVs have a lot of sophisticated computing and measurement functionality within them. This includes a meter that records charging.

There is therefore the potential for this meter to be used for the purposes of supplying an EV under an EV-specific tariff. This would deliver advantages over relying on inclusive tariffs as it would better achieve a consistent price signal across customers with different charging loads – including better-rewarding those consumers who drive longer distances (and thus who will have greatest charging demands) and who are the highest priority for switching from petrol to electric.

We understand the accuracy of some EV meters is not within the same tolerances as the 'revenue-grade' meters installed for the purposes of charging consumers for electricity. We do not believe this is an issue, as the most likely (and in our view, appropriate) scenario is to use a gateway metering arrangement where:

- purchase of wholesale electricity remains based on the main revenue-grade 'gateway' meter to the ICP.

[23] Service levels would typically specify the maximum number of hours in a year a supplier could call upon V2G

If the retailer were offering an additional EV control tariff based on wholesale prices, it would be up to the retailer as to whether they split this consumption using the on-board EV meter readings for billing the consumer[24].

- network billing is based on the combination of the gateway meter and the EV meter.

  Essentially, the EV consumption would be billed based on the EV meter, with the rest of the property's consumption billed based on the difference between the gateway meter and the EV meter. Even if the EV meter has slightly wider accuracy tolerances as the gateway meter, the accuracy would still be significantly greater than relying on an inclusive tariff metering approach.

Further, we think use of the EV's on-board meter would also be suitable for multi-retailer arrangements, or for V2G:

- multiple-retailer arrangements - this is where different retailers supply electricity for the EV and the rest of the property.

  We think this arrangement can work satisfactorily provided:

  - there is a revenue-grade meter at the ICP gateway
  - both retailers are aware of the tolerances of the EV meter, and
  - there is no systematic bias for EV meters to over- or under-record.

  With these provisos, there doesn't appear to be a fundamental reason why retailers can't adequately trade using a gateway meter arrangement.

- vehicle to grid (V2G)

  Fundamentally, recording injection of electricity is no different to recording consumption of electricity. As such, we see no reason why the arrangements described above for purchasing wholesale electricity and network services couldn't equally apply to suppliers effectively purchasing wholesale electricity or network offsets from the consumer's appliance.

  Further, this could equally apply to multiple-trader arrangements as detailed above.

In summary, we believe using the on-board EV meter could offer significant benefits:

- It would allow for EV-specific measurement and tariffs that would better achieve a consistent price signal across customers with different charging loads. In doing so, this would better-reward those EVs that tend to be driven the most. These higher-use vehicles are those where the economic and environmental benefits from switching from petrol to electric are greatest; and
- It would enable such EV-specific measurement without incurring the cost of upgrading existing advance meters to have a second register.

To enable this would require market arrangements that:

- certifies individual EV models as having a suitably compliant meter; and
- registers a particular EV and associated meter within a property as a meter for inclusion within the electricity trading arrangements.

Developing the market arrangements to enable this could take some time. However, we understand that there is currently no specific Electricity Authority workstream being pursued on this issue.

[24] This ability for the retailer to offer EV control for wholesale market benefits *in addition to* the network company controlling to deliver network benefits is developed further in section 6.4 below.

Given the importance of EVs, we think such a workstream should be created and elevated in importance.

6.4 Might generic managed appliance tariffs be appropriate, or might technology-specific tariffs be required?

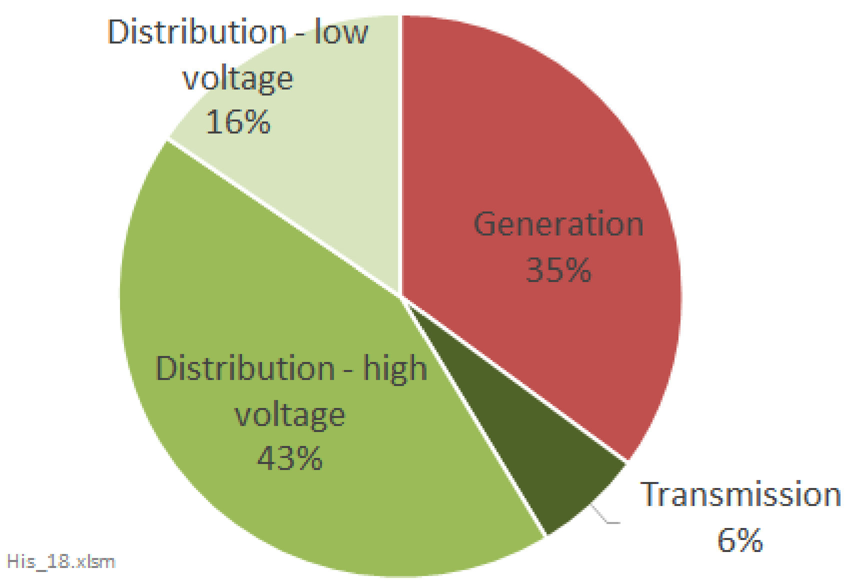
In principle having technology-agnostic tariffs are preferable to having technology-specific tariffs. However, for managed appliance tariffs there are a couple of factors that mean that technology-specific tariffs will most-likely be required:

- Firstly, service level agreements will likely need to be technology specific. Thus, the type and duration of control that is suitable for hot water cylinders is likely to be different to that for electric vehicles.
- Secondly, in the case of inclusive tariffs, it is necessary to base the level of discount on estimates of the proportion of demand from the managed appliance relative to the rest of the ICP's load. This will necessarily be appliance specific.

6.5 Who should own EV control systems and determine what EV flexibility is used for?

Much of the focus on the benefits of demand management have related to avoided network costs. However, as Figure 2 previously highlighted, there are considerable generation-related costs associated with the need to provide infrequently required capacity to provide peaking energy and reserves. To highlight this, Figure 18 below splits out the peak-MW driven cost component from Figure 2 into its sub-components.[25]

Figure 18: Split of long-term peak-driven supply costs for residential consumers



This chart shows that:

- the biggest benefit of peak management comes from avoiding distribution network costs, especially within the high voltage (including sub-transmission) part of those networks

[25] This long-term analysis also takes account of the extent to which the significant programme of asset replacement and renewal for networks over the next couple of decades will increase the relative proportion network costs beyond the levels seen in today's bills.

- avoiding peak-driven generation costs is the next biggest benefit, and is material overall.

There may be times when providing peak flexibility for distribution network services will also deliver transmission or generation peak benefits given the timing overlap of when peaks occur. However, as the analysis on pages 26 detailed, there is significant variation within different parts of a network as to when control is required, plus, as the analysis on page 30 detailed, there is even greater non-coincidence of timing between generation requirements and network requirements and the extent of this non-coincidence is likely to grow as the proportion of wind and solar on the system grows.

This raises the question as to whether flexibility response from EVs (or indeed any other controllable appliance) can be used to contribute to all the different peak-driven parts of the electricity supply value-stack and, if not, what arrangements can be put in place to allow the flexibility to be allocated to the highest value use.

Currently, hot water control is largely limited to providing support for the network parts of the supply chain. The fact it is not additionally used for generation peak avoidance is not due to the predominant network ownership of the ripple-signalling infrastructure, but rather due to technical limitations with the ripple control infrastructure. Thus, in simple terms, the ripple signal is sent as a network-wide broadcast that cannot distinguish between ICPs. Therefore, it is not possible for retailers to offer a hot water control tariff that provides an additional discount if their cylinder is also controlled during times of generation scarcity (as well as during network peak periods). This is because it will not be possible to distinguish between consumers who choose this tariff and those who don't for the purposes of control.

However, systems that allow for appliance-specific control open up this possibility. Thus, consumers could elect to have

- a discounted network tariff that grants the network the rights to manage their appliance for network peak management purposes; *and*
- a discounted wholesale tariff that grants their retailer the rights to manage their appliance for wholesale peak management purposes. Potentially, different tariff options could be offered relating to the threshold wholesale price at which the appliance will be controlled. (e.g. a bigger discount for a tariff that grants the retailer the right to control when wholesale prices rise above $200/MWh compared to one where the threshold price rises above $500/MWh).

In most cases there should not be mutual exclusivity between providing control for network purposes versus generation purposes. However, there could be occasions where flexibility can't be delivered for both.

The most likely situation relates to the service level agreements between the consumer and the electricity suppliers. It is likely that most consumers will want to have a single bundled electricity supply contract. In the case of managed appliance tariffs, this will provide consumers with a composite discounted rate (capturing both network and generation benefits), with associated minimum service level agreements.

A key service level agreement would be one that specified the maximum level of control the supplier could exercise in a given day. For example, in the case of hot water, the maximum number of hours the appliance could be controlled off. It is possible that on some days with significant non-coincidence of stress periods for generation and network, the combined number of hours that would be desired to control for network and generation purposes exceeds this service level agreement. In this situation there would need to be some coordination to determine whether controlling for generation or network purposes is of the highest value.

In general, our analysis (such as that shown in Figure 18) suggests that controlling for distribution peak management is likely to deliver the greatest value. We think there is nothing to stop the contracts between network companies and retailers reflecting this relative hierarchy. Thus, if retailers wished to offer consumers a tariff that included network control, the agreement between the network and the retailer would specify the priority for calling control on days where there is likely to be non-coincidence of requirements. Knowing this priority, retailers would be able to evaluate the extent to which this would be likely to reduce the value of control for generation purposes and adjust the wholesale discount they offered to consumers accordingly.

We also think that these outcomes can be achieved irrespective of which party owns the infrastructure used to communicate with the EVs to exercise control. What is required, however, is market arrangements that enable third parties to use the signalling infrastructure.

- Thus, if a network owns the signalling infrastructure, they should make it available for retailers to use for the purposes of generation peak management.
- Likewise, if a retailer or other third party owned the signalling equipment, they would need to enable the network company to use it for the purpose of network management.

Such arrangements would also be consistent with having multiple traders operating at a property. For example, one retailer supplying electricity to the EV, while another retailer supplying electricity to the rest of the property.

However, to enable these outcomes will likely require some degree of regulatory-prescribed coordination and mandate:

- the development of common communication protocols for requesting and confirming load control from the operator of the control system;
- the implementation of rules that prevent third parties from being excluded from accessing the use of control infrastructure.

While we note that theoretically the best outcomes can be achieved independently of which party owns the signalling infrastructure, we note that arrangements that maximise the ability of networks to use the signalling infrastructure are likely to deliver the greatest benefit. This is because:

- A significantly greater proportion of the benefits are likely to be from managing distribution capacity issues (as shown in Figure 18)
- There will need to be much more geographically granular control to realise these distribution benefits (as demonstrated in section 4.2), whereas most benefits from generation control can be achieved from sending signals on a whole-of-island basis.

Lastly, we note there is some debate as to whether distribution companies should be allowed to own the type of distributed energy resource that appliance-specific control infrastructure represents. Provided the regulatory safeguards regarding third-party access and common communication protocols are in place, we do not believe there would be significant adverse outcomes if distributors are allowed to make such investments. Informing this decision are the following observations:

- The greatest value from flexibility is from avoiding distribution network costs (as shown in Figure 18);
- There will need to be much more geographically granular control to realise these distribution benefits (as demonstrated in section 4.2), whereas most benefits from generation control can be achieved from sending signals on a whole-of-island basis.
- Together, this points to a risk of poor outcomes if barriers to distributor involvement are too high

- To-date, some of the most innovative trials of dynamic EV management in New Zealand appear to being driven by distributors (eg, Wellington Electricity and Vector's trials), alongside other trials by retailers;
- Internet-based appliance control systems are highly specialised systems that also benefit from economies of scale. As such, after a period of trial-and-error from multiple different parties exploring EV management, we think it most likely that a handful of service providers will emerge, potentially with one or two such service providers having investment from network companies. We do not think it likely that a constellation of 29 different systems will be developed by the 29 different distribution companies.

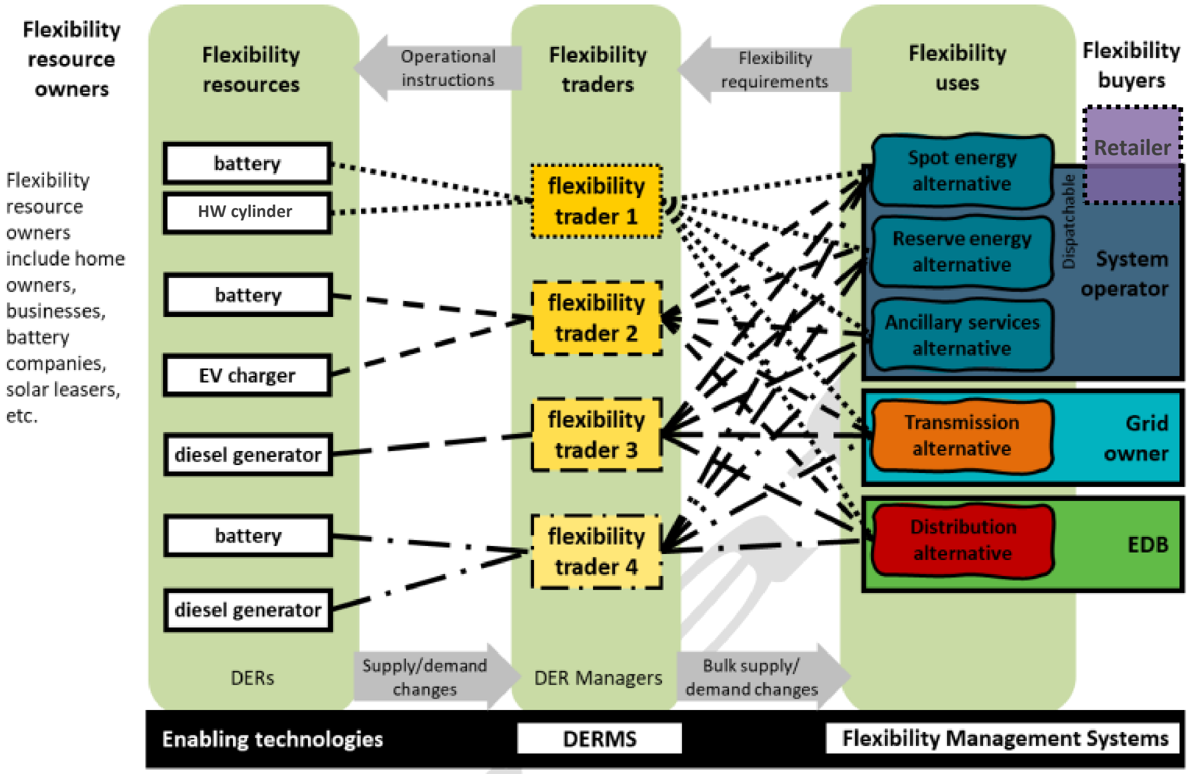
That said, we are also cognisant of the risk that the monopoly position of networks could extend into the market for flexibility services and crowd out other potential suppliers, or other uses for flexibility. Accordingly, we would encourage regulatory arrangements that

- facilitate open access to information about network needs (ie, where capacity constraints are likely to emerge and create a potential value stream for flexibility services)
- require networks to operate their flexibility services on an arms' length basis with suitable cost allocation rules so that other flexibility providers can compete on their merits
- require networks to provide open access to flexibility services under their control, such that other parties can access resources on suitable commercial terms.

These requirements may be less critical in the early phases of EV uptake, where easy access to pilots and trials takes priority, but will become increasingly important as the scale of the EV flexibility resources (and the intensity of potential capacity investment pressure) grows.

We think the above outcomes are consistent with the framework developed by the Innovation and Participation Advisory Group (IPAG) in its recent review of the Transpower Demand Response Programme.[26] This review also considered the wider arrangements for procuring flexibility from distributed energy resources (DER). Figure 19 below is taken from Figure 1 of the IPAG report.

Figure 19: IPAG representation of flexibility markets[27]



The left-hand part of this framework sets out that there can be multiple different flexibility resources, including EV chargers, batteries, hot-water cylinders, and diesel generators. These may be owned by different parties, including homeowners, businesses, solar leasers, and the like.

The right-hand part of this framework shows that flexibility can provide value across the electricity supply chain including

- avoiding distribution and transmission investments needed to meet peak. To achieve this, the flexibility services are effectively purchased by EDBs and the transmission grid owner (Transpower), respectively.
- avoiding calling upon expensive generation investments to meet situations of wholesale market scarcity (split between “spot energy”, “reserve energy” and “ancillary services” alternatives in this illustration). To achieve this, the flexibility services are purchased either by the system operator or individual retailers (who may want to manage their exposure to spot prices).

In the middle are flexibility traders. These procure the rights to access flexibility from the owners of the individual flexibility resources. They can then on-sell the flexibility to the different flexibility buyers. The arrangements of such transactions should enable flexibility to be used for the highest value use – enabling a given resource to be used for different purposes at different times.

[26] https://www.ea.govt.nz/assets/dms-assets/28/Transpower-DR-programme-review-draft-memo.pdf
[27] We have amended this figure slightly, to change one of the “battery” resources to be a “HW cylinder”, and to include “Retailer” as one of the buyers of flexibility services to manage their spot energy exposure.

These flexibility traders use their DER Management Systems (DERMS) to call upon the different flexibility resources and dispatch them for their different uses as required.

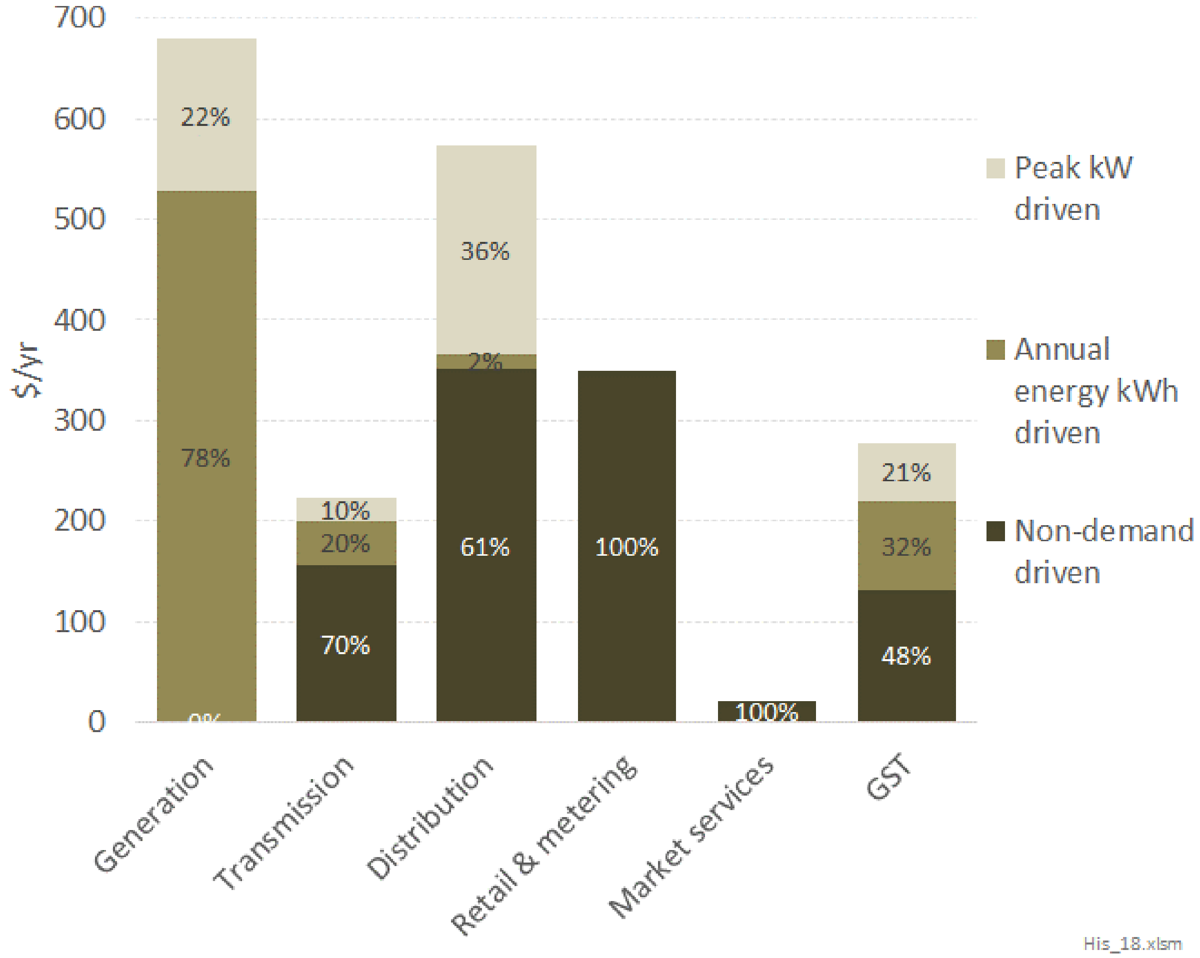
Within this framework DERMS that managed EV charging could be owned by an EDB, Transpower, a retailer, or a specialist load management company, each of whom would be acting in the role of a flexibility trader.

In each case, provided there was sufficient regulatory oversight to ensure open access to such systems, there is nothing to stop any of the other parties procuring the EV management services.

7 Other tariff reforms to deliver good EV uptake outcomes

Figure 20 below presents the same data on the breakdown of the average electricity bill as in Figure 2 on page 8 previously, but 'pivots' the x- and y-axis categories.

Figure 20: Breakdown of average residential electricity bill for YE Mar '21[28]



Source: Concept analysis based on data from MBIE, the Electricity Authority, Orion, and Transpower

The chart shows that each element of the supply chain has a different sensitivity to demand growth:

- Generation costs are entirely demand driven, but only 22% of generation costs are driven by providing capacity to meet peak demand growth.
- The majority of transmission and distribution network costs are <u>not</u> driven by demand. Instead, coverage is the biggest long-term driver of network costs: There are significant fixed costs of building the towers, poles, trenches etc. to reticulate electricity to communities, plus there are significant economies of scale associated with cables and transformers. Given this dynamic, the incremental cost of having a higher capacity cable or transformer to meet higher levels of demand for a given community are relatively small.
- None of the costs of retail & metering or running the market are driven by the kWh of demand. Retail & metering costs are driven by the number of customers (not how much each customer consumes), and the costs of running the market are independent of how many kWh passes through the market.

[28] Note: The % split values don't sum to 100% due to rounding.

Overall, Figure 20 shows that approximately half of the costs of providing electricity to households are driven by demand (either annual kWh of energy, or peak kW), and half of the costs are not driven by demand.

As a consequence, on average and over time, around half of the costs of supply should be recovered via charges that aren't based on usage – eg, $/day fixed charges. Recovering such costs via demand-based charges (e.g. a c/kWh tariff) makes using electricity appear more expensive to consumers than it actually is. This matters, because switching from fossil to electric options for transport and heating has been identified as one of the key planks in New Zealand meeting its net-zero-by-50 goal. Making electric vehicles and electric heating options appear more expensive than they actually are will frustrate this switch causing environmental and economic harm.

However, a high proportion of costs that aren't driven by demand are currently being recovered by demand-based charges:

- Commerce Commission disclosures indicated that only 20% of distribution network revenues in 2019 were recovered via charges that weren't based on demand – despite our analysis indicating over 60% of distribution costs are not driven by demand.[29]
- Only 15% of Transpower's revenues are from non-demand based charges – despite our analysis indicating that approximately 70% of their costs are not driven by demand.
- It is apparent that retailers are recovering a significant proportion of the costs of retail & metering via demand-varying charges, even for consumers who aren't on the low-fixed charge tariffs: A simple analysis of tariffs advertised in Powerswitch indicates that on average only 65% of the approximately $400/customer (incl. GST) for retail and metering costs is recovered via fixed charges for consumers on 'Standard' tariffs (approximately 72 cents/day, incl. GST), with the remainder recovered by $/kWh charges – even though the costs of providing retail and metering services do not vary with a consumer's level of demand.

On average, we estimate that the variable charge for residential tariffs is approximately 80% higher than it should be if tariffs were cost-reflective. For consumers on low-fixed charge tariffs, their usage charges are on average twice as high as the cost of supply and for consumers on standard tariffs their charges are on average just over 50% higher than underlying costs.

It is our evaluation that making the cost of using electricity much more expensive than the actual cost of supplying electricity will have a material impact on the rate of switching from fossil to electric for transport and space & water heating. This will have material economic and environmental costs:

The modelling we undertook for the first report in this three-part study indicated that if the rate of EV uptake is delayed by just one year, it would result in $0.8bn in non-emissions costs plus $0.5bn in carbon costs (valued at NZ$200/t$CO_2$).

Correcting the over-variablisation of tariffs is technically very simple for networks and retailers to achieve: Increase the proportion of cost-recovery from fixed charges and decrease the proportion from consumption-based charges. The programme of reform for distribution and transmission pricing methodologies should help facilitate this.

Until very recently, the low-user low-fixed charge regulations were a major impediment to such reform. We therefore welcome the government's decision to phase out the Low-Fixed Charge regulations and allow networks and retailers to rebalance their tariffs over the next five years.

[29] https://comcom.govt.nz/__data/assets/pdf_file/0023/203774/Total-electricity-distribution-2019-December-2019.pdf

Although it is not the focus of this study, removing this distortion will not only deliver significant economic and environmental benefits, but it will also improve social welfare outcomes. This is because the low-fixed charge regulations are:

- currently harming those who face the greatest energy hardship: Those having the unfortunate combination of low incomes but living in housing situations that give rise to high electricity consumption needs (eg, large households living in poorly insulated homes with individuals at home during the day).
- giving rise to situations where low-income consumers are under-heating their homes because the variable cost of consuming electricity is so high.

That said, we acknowledge that removing the regulations will result in residential consumers who are currently low users facing bill increases, with some of those also being low-income consumers. The politics of this are inherently tricky. However, we think that implementing another of the Electricity Price Review's recommendations – changing the approach for allocating residual (non-demand driven) network costs – would significantly address this. Again, although this is not the subject of this study, the Electricity Price Review analysis (and our own subsequent analysis for other pieces of work) indicates that network costs are generally being over-allocated to residential consumers. Correcting this would not only significantly address the bill shock faced by low-user residential consumers from removal of the low-fixed charge but could deliver wider economic and social benefits as it would go some way to address the significant foregone consumption (of electricity and other goods) by low-income residential consumers.

Appendix A. Understanding the diminishing returns from peak demand management

One perspective for thinking about how best to maximise the potential for demand management from EVs and from other end-uses, is considering *how much* demand management is required and when does this occur?

We use a worked example to illustrate the nature of the challenge.

Figure 21 below shows a typical within-day winter demand profile for a residential-heavy network, on both a chronological basis, and as a duration curve (where the demands for each half-hour in the day are sorted from high to low).

***Figure 21: Demand profile for a residential-heavy network in winter*[30]**

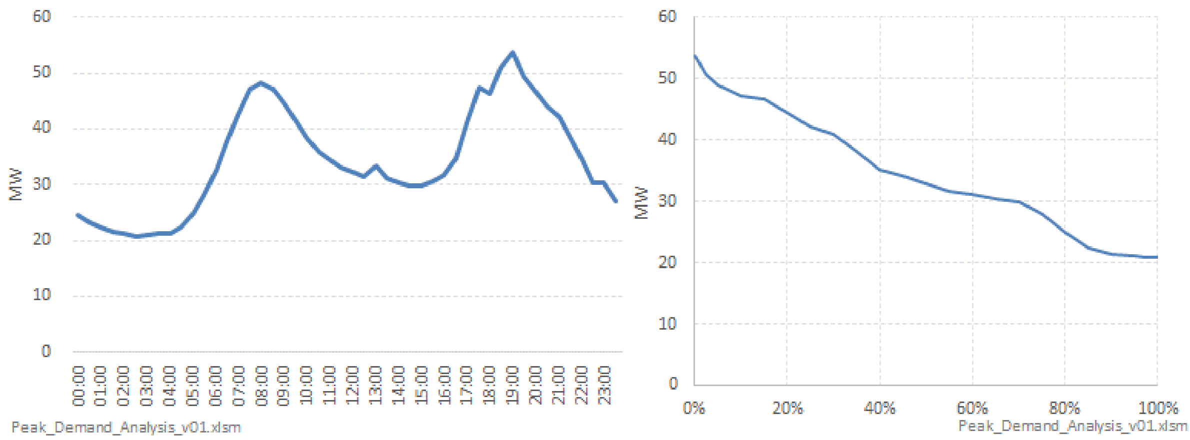
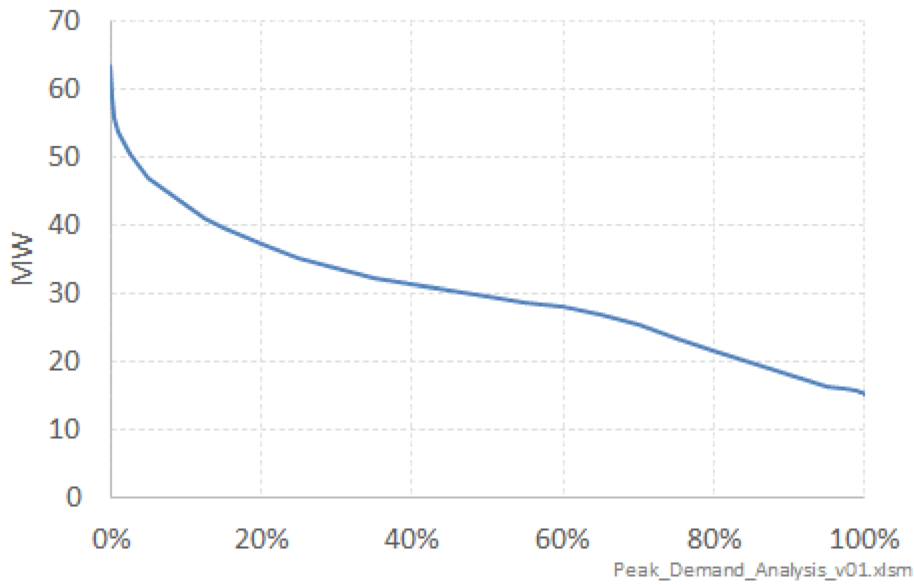


Figure 22 shows the load duration curve for the same network for the full calendar year of 2019.

Figure 22: Full year load-duration curve for a residential-heavy network



[30] This is the demand for the Paraparaumu GXP (which has a relatively high proportion of residential load) for Monday 29 July 2019.

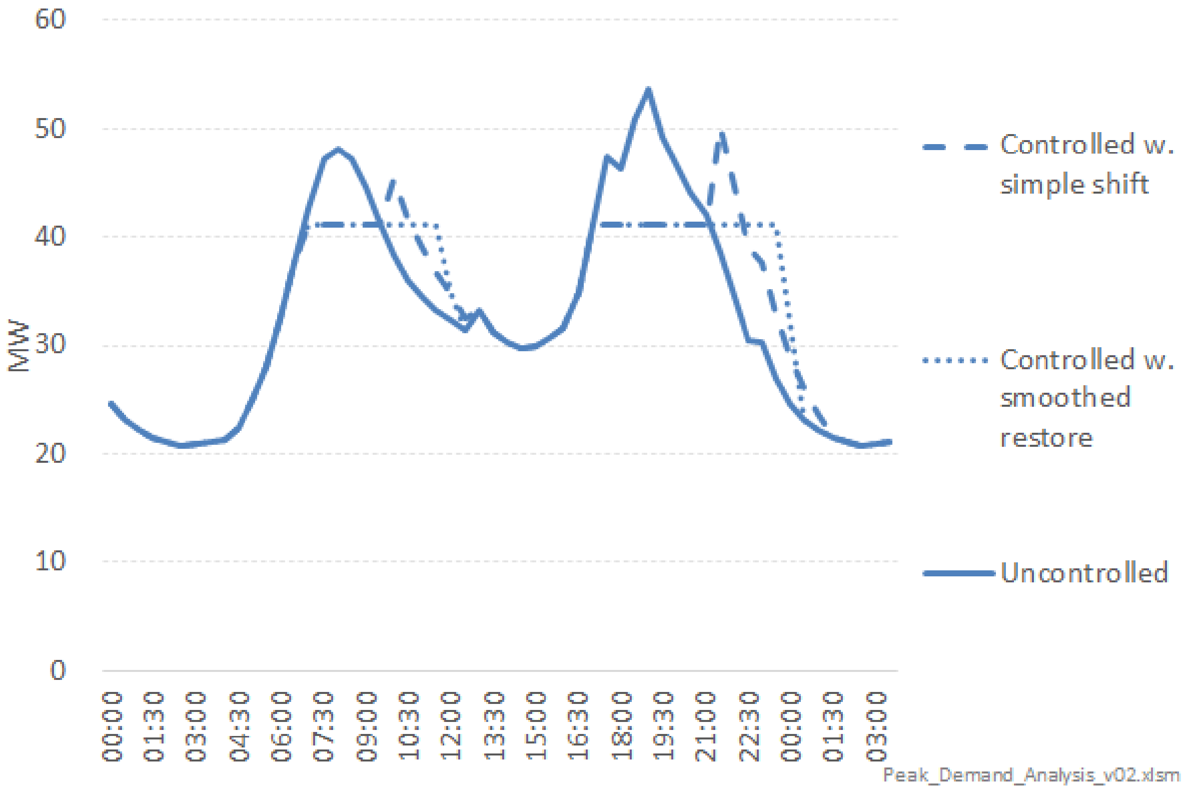
This shows that a lot of network capacity needs to be built that will only be required for a very short amount of time. Thus, approximately 15% of network capacity is only required for 1% of the time, and roughly 35% of network capacity is only required for 12.5% of the time.

If the demand that occurs in the peak periods can be 'shifted' to other times, there is the potential to save a lot of money that would otherwise need to be spent on providing this infrequently-used capacity.

Generally, there is little ability to shift demand over periods much longer than five to twelve hours. Therefore, in considering the potential for demand management it is important to consider what can be achieved within those days when peak demand periods occur.

Figure 11 shows a simple worked example of the load management that would need to occur if the network demand was not going to go above 41 MW – which, if it were to consistently occur, and with reference to Figure 22, would reduce the network capacity requirement by 35%.

Figure 23: Example of demand management for the residential-heavy network for the example winter day



The solid blue line shows the uncontrolled load – i.e. the same as in Figure 21.

The dashed blue line shows the likely outcome if loads were controlled for those periods when demand would otherwise be above 41 MW, but then when control stops the shifted demand is spread over the subsequent hours in a fashion where the shifted demand is greatest at the start of the period, but then gradually decays.

This is what is observed when hot water cylinders that have been controlled are then restored. The moment that they are switched back on, almost every cylinder goes to full power to restore the temperature back to the desired setting – i.e. there is none of the normal diversity associated with people using devices at different times. After this initial burst of all cylinders being on, those cylinders for whom the water temperature is still quite hot (i.e. because hadn't been used much during the control period) will soon reach the desired temperature and switch off, whereas those cylinders that had a lot of use during the control period would take a lot longer to get back to the desired temperature and stay on for longer.

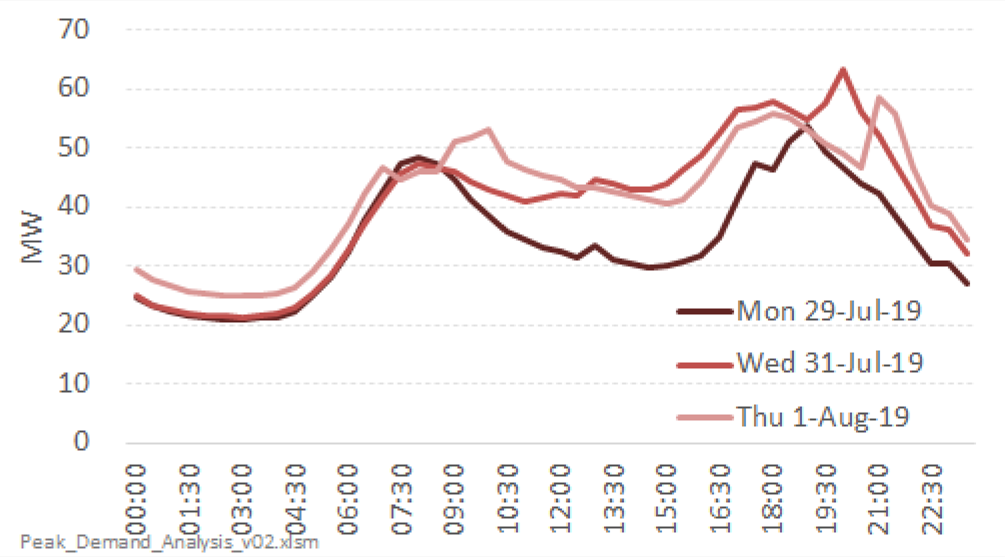
As can be seen, this surge in power from controlled devices switching back on can result in a peak in demand that is almost as high as would otherwise have occurred. This can be seen from actual GXP demand for the week in question in Box 3 below.

The dotted blue line shows the outcome that would occur if the restoration of controlled load was managed in such a way that a secondary peak doesn't occur above the 41 MW threshold. As can be seen, load management needs to continue beyond the hours when demand would otherwise be above a threshold. Indeed, for the day in question, while demand would have been above the 41 MW threshold for 29% of the time, load needed to be managed for 48% of the time.

Box 3: Example of a shifted-peak due to controlled load being restored without much diversity

The data in Figure 24 is for the same GXP as shown in Figure 21 for the same day (Monday), plus the Wednesday and Thursday later in the week. These two additional days were much colder than the Monday requiring the network company to control hot water during the morning and evening peaks. However, once demand was restored for these cylinders, it created a new peak later in the evening. Presumably this new peak is lower than the peak would have been earlier in the evening if hot water hadn't been controlled.

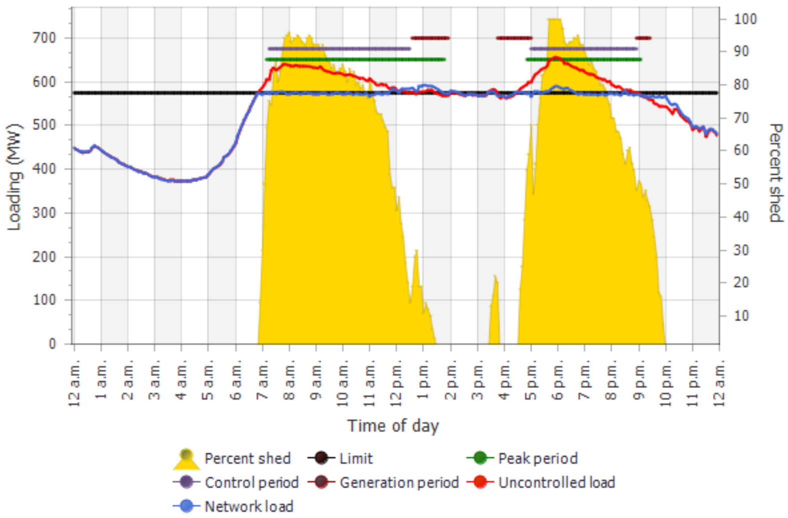
Figure 24: Demand profile of PRM0331 for three winter days



The key take away from this example is that it gets progressively harder to control load to reduce peak network capacity requirements as it requires sustained control over long periods during the coldest winter days.

That is not to say it is impossible. Indeed, as the following example from the Christchurch electricity network company, Orion, shows, they have managed to use sustained hot water load management (including with smoothed restoration) to flatten their load below thresholds on cold days.

Figure 25: Orion network load on 8 August 2016[31]



Source: https://online.oriongroup.co.nz/LoadManagement/Default.aspx?autorefresh=false&reportdate=2016-08-08

This analysis also points to the relative suitability of different types of load management to deliver savings. With reference to Figure 6 previously, the end-uses that are the biggest contributors to peak demand are water heating, space heating, EVs (in the future) and (a distant fourth) cooking.

While the two storage technologies (water heating and EVs) can deliver the type of sustained control required, other forms of load control are less well-suited. For example, controlling space heating over long periods of time on the coldest winter days would start to materially impact the quality of the service (ie, keeping your house warm). And there would be a significant amount of inconvenience if people could not cook in the early evenings on a cold winter day.

[31] The 'percentage shed' refers to the proportion of hot water load that is controlled.