# Smart New Zealand Energy Futures: A Feasibility Study

*Summary Report*

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# SMART NEW ZEALAND ENERGY FUTURES – EXECUTIVE SUMMARY

## Abstract:

The aim of this study is to understand smart grid technology implications and opportunities from a New Zealand electricity system perspective. Meridian is releasing this report publicly to help inform New Zealand electricity industry stakeholders.

Meridian Energy commissioned this study by Professor Goran Strbac of Imperial College, London, in order to better assess the implications of smart grid technologies for New Zealand. Professor Strbac has previously completed work for Meridian to quantify the wider system implications and costs of integrating significant amounts of wind into the New Zealand power system.

The main subject of this feasibility study is the quantification of potential benefits of emerging new sources of flexible electricity demand response and control. This includes activities such as the flexible charging of electric vehicles (EVs) or control of Heat Pumps (HPs) to reduce and smooth periods of peak electricity demand. Flexible use of demand could potentially reduce the requirement for future electricity system investment and in turn reduce the cost of future electricity supply to consumers. Technologies often referred to as the ‘smart grid’ are expected to enable significant demand response.

This study finds that there are likely to be limited power system benefits from a smart grid implementation over this decade. However, future changes in electricity demand are expected to create a substantial economic case for the smart grid opportunity in New Zealand. The benefits available from using demand flexibly could reduce New Zealand’s required electricity system investment by up to $3.5 billion in 2030 and up to $10.6 billion in 2050. These benefits are significant and warrant further investigation. Accordingly, for New Zealand to deliver the best national benefits from a smarter energy future a number of factors are identified.

## Study methodology:

This study uses a scenarios based approach to examine New Zealand’s future electricity supply and demand in 2030 and 2050. In each scenario we assume that wind generation increases from 500MW in 2010 to approximately 3.5GW in 2030. Our core scenario includes high residential uptake levels of EVs and heat pumps. This core scenario has been constructed to test the bounds of New Zealand’s potential smart grid opportunity. Though plausible, it does not represent our forecast of the future.

We then explore two alternative electricity system control approaches ‘Uncontrolled’ and ‘Smart’. The smart approach seeks to optimise the use of flexible sources of demand, including EVs and heat pumps, to smooth and manage peak demand periods. For each approach we assess the required investment in generation, transmission and distribution network as well as the impact on system balancing costs. This analysis is not constrained by the present commercial and market arrangements and practices associated with the treatment of demand.

The sources of flexible demand investigated include the use of water heaters (ripple control) and (in the future) heat pumps, electric vehicles, and smart appliances. The difference in system costs under the two electricity system control approaches provides insights into the benefits associated with the smart grid concept.

This study has not explicitly considered a range of other potential benefits from applying smart grid concepts and technologies, including the value that consumers may place on smart grid enabled services. As New Zealand moves towards a smarter energy future, understanding these other benefits will also be important.

## Benefits of using flexible sources of demand:

Internationally, climate change challenges are strongly driving investigations into the benefits of a smarter grid. There are two main drivers: the need to integrate renewable generation into existing systems, and the need to meet energy requirements from electricity in preference to fossil fuels.

This analysis suggests that, over the next decade, smart grid deployment in New Zealand is likely to have limited effects in terms of deferring investment in electricity infrastructure. New Zealand's electricity system is hydro dominated and renewables based. This gives New Zealand greater flexibility to respond to the challenge of integrating intermittent generation. Furthermore, New Zealand has a significant load control resource already in place through hot water ripple heating control. These factors mean a smart grid implementation offers fewer benefits in the near term compared to the benefits expected to be available in thermally based power systems.

Future changes in electricity demand are expected to create a substantial economic case for the smart grid opportunity in New Zealand. The electrification of the transport sector and ongoing electrification of space heating in New Zealand will cause significant peak demand increases, requiring additional electricity system investment. However, deploying smart technologies to exploit flexibility in various forms of demand can significantly mitigate the additional amount of investment required.

New Zealand's distribution network is likely to benefit from smart grid implementation from 2020 if electrification of the transport sector and increased electrification of space heating occurs. Benefits would then appear from 2030 at a generation level. Transmission benefits are marginal in 2030 but are likely to be significant by 2050. There is also a role for smart use of flexible consumer demand to play in providing system balancing services. However, the benefits are limited due to the inherent flexibility of New Zealand's hydro-based power system.

This study finds that the benefits available from using demand flexibly could reduce New Zealand's required electricity system investment by up to $3.5 billion in 2030 and up to $10.6 billion in 2050. Smart EV charging is the most flexible of all the technologies we examined. Hot water heating load control will continue to be important in deferring the need for local network reinforcement, especially when penetration of EVs and heat pumps is relatively low.

Quantification and discussion of all the benefits identified is provided in the full overview of the report. This report does not consider the costs of implementing these smart grid technologies, but such costs are expected to be an order of magnitude lower than the benefits available.

## Delivering a smarter energy future for New Zealand:

- In order to achieve the full benefits of the smart grid concept and smart technologies a number of issues will need to be considered. New Zealand's market design and regulatory framework will need to evolve to provide the right investment signals to unlock flexible demand side participation. The following factors are important for New Zealand to deliver the best national benefits from a smarter energy future:
- **Ensure that New Zealand's existing load control resource is being fully utilised**. New Zealand's existing power system may be 'smarter' than most. This is in part due to New Zealand's existing hot water heating control resource, which

has been in place for over 50 years. Consumers currently choose if they wish to opt into hot water load control by selecting a controlled tariff. It is unclear if New Zealand's existing hot water heating control resource is declining over time, both in terms of the maintenance and installation of the hardware, and in terms of how much use is made of the resource to manage peak demand periods and distribution network congestion. In addition to maintaining the existing resource, there is an opportunity to enhance existing hot water heating control by making full use of consumption information from smart meters. This is particularly attractive as New Zealand's hot water heating control resource, augmented with smart metering information, is effectively a sunk cost, and could provide many of the benefits that a fully functional smart grid aims to provide.

- **Conduct focused trials.** In line with international initiatives, New Zealand could conduct focused trials to learn more about the benefits before wide spread roll out is considered. This is particularly relevant for New Zealand given the growing uptake of Heat Pump technology and the impact this uptake could have on distribution networks during unusually cold spells. It will be important to fully understand the usage patterns associated with different installations and explore the benefits and challenges associated with alternative demand control strategies. Trials with two way information flows to test customer engagement and tailor products to suit customer needs will be an important step to learn about the systemic value of a smarter grid. It is important to emphasise that the infrastructure for conducting such trials, smart metering with accompanied communication and control technologies, is already available which will make the trials very cost effective. Specific areas of investigation in the nearer term could also include:
    - trialling hot water heating control approaches augmented with smart metering information
    - monitoring of heat pump operation and investigating opportunities for control
    - using smart metering data to deepen the understanding of electricity consumption patterns across various consumer segments, augmented with appliance monitoring and consumer behavioural research.
- **Encourage demand participation.** The benefits of demand response (and other smart grid technologies, such as storage) may be shared among several industry participants along the energy value chain. Achieving active demand side participation is internationally considered to be a barrier to achieving the full economic benefits that a smarter grid could deliver. The industry has a key role to play to raise awareness, put appropriate systems and processes in place and create incentives for greater demand side participation in the energy market.
- **At the network level, New Zealand's regulatory framework may need to evolve to recognise investment in efficiency.** Network operators need to be able to make choices between investing in innovative demand response and investing in network assets. Incentives to adopt technically effective and cost efficient non-network solutions need to be considered as part of the regulatory design framework. Such incentives could be complemented with a review and update of network design standards in order to accommodate the contribution that flexible demand initiatives may be able to make as a substitution for building network infrastructure.

# 1. STUDY OVERVIEW AND SUMMARY OF FINDINGS

## Objectives and scope of work

1.1. The main subject of this feasibility study is the quantification of potential benefits of emerging new sources of electricity demand response and control. Technologies often referred to as the 'smart grid' are expected to enable significant demand response.

1.2. Our overall aim is to quantify the cost savings that can be achieved by integrating responsive flexible demand into New Zealand's future electricity system. Such savings would arise from applying smart grid concepts and technologies to optimise the operation of and investment in New Zealand's future generation, transmission and distribution infrastructure, as well as from the potential to provide system balancing services. This analysis is not constrained by the present commercial and market arrangements and practices associated with the treatment of demand.

1.3. The research and development for this report was carried out during 2011. With respect to this study any publications or new developments released later than July 2011 will not be included in this study.

## Context in New Zealand and the wider international environment

1.4. Internationally, climate change challenges are strongly driving investigations into the benefits of a smarter grid. There are two main drivers: the need to integrate renewable generation into existing systems, and the need to meet energy requirements from electricity in preference to fossil fuels.

1.5. Firstly, a growing interest in demand response initiatives arises from the search for a cost effective means for enabling the integration of renewable generation into thermal-based electricity systems. The New Zealand electricity system is already over 70 percent renewables-based, being hydro dominated. New Zealand therefore has greater flexibility to respond to the challenge of integrating intermittent generation. However, New Zealand has set a 90 percent target for renewable energy penetration.[1] There is potential for a smarter grid to assist in achieving this goal.

1.6. Secondly, the need to reduce $CO_2$ emissions has created a focus on transitioning the heat and transport sectors from fossil fuels to electricity. The continued uptake of efficient electrical heating appliances and the development of electric vehicles are likely to achieve this transition. Over time, such changes will mean that New Zealand is likely to progress towards a total energy system that has a greater reliance on electricity, with a resultant change in electricity demand.

1.7. Because of these factors, a status quo approach to electricity infrastructure planning is likely to lead to a greater increase in electricity demand in peak periods than in energy demand overall. Additional heating and electric vehicle charging demand is expected to occur at times of already high electricity demand, typically in the early evening. A future electricity system with greater peak energy demands will significantly impact on the utilisation of generation and network infrastructure.

[1] The New Zealand government has set a target for 90 percent of electricity to be generated from renewable sources by 2025 in the New Zealand Energy Strategy 2011-2021 report: Developing our energy potential.

1.8. An alternative approach offers significant opportunities and benefits. This approach requires a shift from today's sources of system control and flexibility, predominantly provided by physical generation assets, to a more sophisticated form of electricity system management. Duties and opportunities for providing grid control services would be reallocated to include the demand side. The opportunities for demand side participation may be significant, given that both the heat and transport sectors inherently include energy storage potential.

1.9. Incorporating the use of flexible demand into New Zealand's future electricity system operation and design would offer a number of benefits. These may include increased network asset utilisation, increased ability to accommodate intermittent generation, and enhanced network flexibility in the face of uncertain future development. Such changes would offer the opportunity to reduce the overall investment in generation and network assets, and improve network reliability and resilience at a lower cost than the status quo approach. These benefits should ultimately lead to a reduction in electricity costs to end consumers.

1.10. New Zealand has already made some significant advances in managing flexible demand. For example, Christchurch is among world leading cities in the application of various forms of advanced technology. Christchurch has considerable positive experience with ripple control of water heaters, and more recently a number of electricity retailers have rolled out smart meters. Implementing advanced distribution management systems with the functionality to provide customer connectivity is underway.

## New Zealand electricity system futures and analysis approach developed for this study

1.11. The analysis uses three main scenarios which all include a high level of wind generation installed capacity to supply future electricity demand. It looks at system wide integration issues under two of these scenarios which incorporate the additional electrification of transport and heating demand for 2030 and 2050.[2]

1.12. In each scenario we assume that wind generation increases from 500MW in 2010 to approximately 3.5GW in 2030. To support the level of wind generation capacity with the additional heat pump and EV load, while ensuring system reliability, we worked from the premise that additional thermal generation would be required to satisfy the incremental uncertainty driven by the EV and heat pump load. We assume in our model that the facilities to provide this extra generation capacity would be built in the Upper North Island in regions with a developed gas infrastructure, such as Auckland, Huntly, Hamilton, and Stratford. Quantifying the extent to which this investment in thermal generation can be deferred is one of the key sources of value of a smart grid.

1.13. The generation assumptions are not a forecast of New Zealand's future generation build mix. The purpose of the scenarios is to develop and test the bounds of the potential New Zealand smart grid opportunity, with high uptake of wind representing the most intermittency that can be added to the system from the competitive forms of generation being built in New Zealand (section 4 discusses the generation assumptions in further detail). We are not ruling out other possible future generation scenarios, such as a future with a greater uptake of distributed generation. We believe that such a scenario is accommodated within the modelled scenarios. A smart grid could help to support greater uptake of distributed

[2] We also considered a broader range of scenarios, including very high wind generation penetration (7.1GW) and different uptake levels of EVs and heat pumps. These are discussed in the main body of the report.

generation, although we have reservations about the overall contribution that distributed generation can make in the New Zealand energy system based on the significantly higher levelised costs of this technology.

1.14. The scenarios are described in the table below.

**Table 1. Table of key scenarios**

| Scenario full name | Description | Referred to in charts as |
|---|---|---|
| **Business as usual 2030** | Business as usual demand growth forecast based on Electricity Authority forecasts | **Business as usual** |
| **Uncontrolled high demand scenario with integrated EV & heat pumps, 2030 and 2050** | Business as usual demand growth, plus 50 % electrification of heating and transport by 2030, and 100% by 2050 – with uncontrolled demand | **Uncontrolled** |
| **Smart high demand scenario with integrated EV & heat pump control, 2030 and 2050** | Business as usual demand growth, plus 50 % electrification of heating and transport by 2030, 100% by 2050 - with smart use of flexible demand | **Smart** |

1.15. The uncontrolled and smart scenarios include high uptake of electric vehicles and heat pumps. These are possible, but not forecasted, futures. Making a forecast is not the purpose of the scenarios. Instead, the scenarios help us to understand the drivers of future system costs and to assess the order of magnitude of total possible savings that may be made by integrating flexible demand in system operation and development.

1.16. Figure 1 shows the analysis approach adopted. For each of the alternative electricity network control scenarios 'Uncontrolled' and 'Smart', we assess the required investment in generation, transmission and distribution network as well as the impact on system balancing costs. The smart scenario involves the use of flexible demand to manage and smooth peak demand periods.

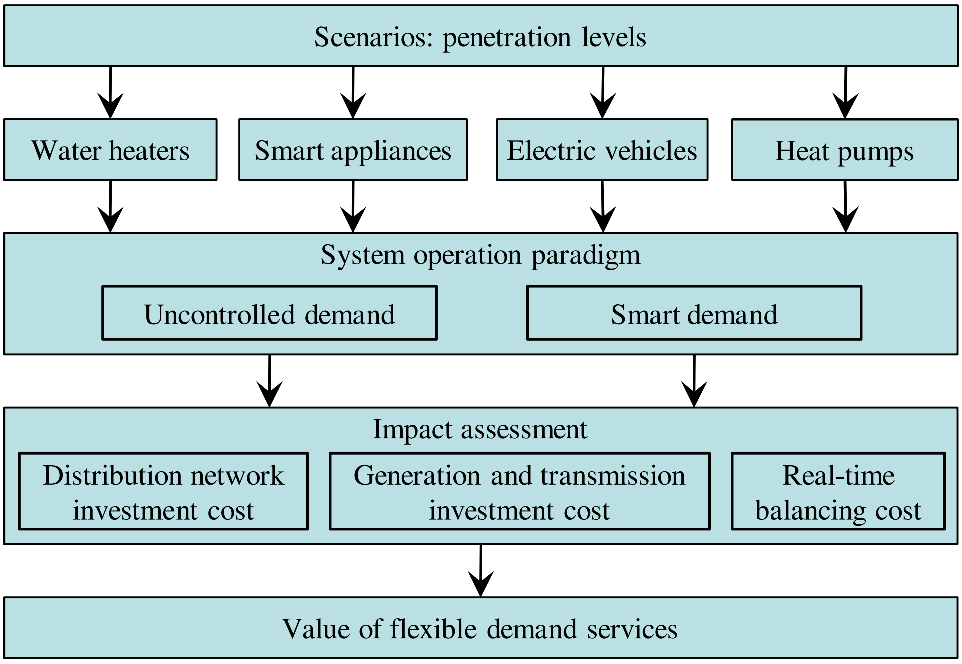



**Figure 1. Methodology block diagram**

1.17. The sources of flexible demand investigated includes the use of water heaters (ripple control) and (in the future) heat pumps, electric vehicles, and smart appliances. The difference in system costs under the two scenarios provides insights into the benefits associated with the smart grid concept.

1.18. This study focuses on the economic opportunity to use sources of flexible demand potentially available from New Zealand residential electricity consumers in the future. There will also be opportunities for a smart grid to facilitate greater demand response in the commercial load sector but that is not the purpose of this study. Commercial demand response is already more directly facilitated through the time of use electricity pricing signals that large commercial users face.

1.19. This study has not explicitly considered a range of other potential benefits from applying smart grid concepts and technologies, including the value that consumers may place on smart grid enabled services. As New Zealand moves towards a smarter energy future, understanding these other system benefits will become important. Such benefits may include the potential for improved outage management and system reliability performance, improved maintenance and asset replacement strategies, better investment optimisation, increased ability of the system to accommodate a wider range of future energy scenarios, and greater capacity to absorb various forms of distributed generation, such as solar PV. We have also not considered the power quality implications of EV charging.

## Reference demand data – business as usual scenario

1.20. The starting point for the analysis is a business as usual electricity demand growth scenario. The assumed energy and peak demand growth in this scenario is consistent with the energy growth assumed by the Electricity Authority. The growth in both energy and peak power is approximately linear at 720GWh and 108MW per annum respectively. Table 2 shows peak demand increasing from 7.2GW in 2010 to 9.4GW by 2030. There is corresponding energy growth per annum from 46TWh in 2010 to 60.4TWh in 2030.

**Table 2. Annual peak demand, energy consumption, and load factor for business as usual scenario**

| Description | Min demand (MW) | Peak demand (MW) | Annual electricity consumption (TWh)[3] | Load factor (%) |
|---|---|---|---|---|
| 2010 | 3,371 | 7,214 | 46.0 | 73% |
| 2030 | 4,417 | 9,366 | 60.4 | 74% |

1.21. As indicated in Table 3, we estimate that additional investment of around $14.7 billion in today's dollars will be needed by 2030 to support the "business as usual" scenario of electricity demand growth[4].

**Table 3. Investment cost ($bn) under business as usual scenario by 2030**

| Generation | | Transmission | Distribution | Total |
|---|---|---|---|---|
| Conventional | Wind | | | |
| 3.4 | 5.6 | 3.6 | 2.1 | **14.7** |

1.22. Under the business as usual scenario, few additional system benefits are likely from adding smart grid technologies. This is mostly due to the flexible nature of New Zealand's hydro-dominated power system to manage peak demand and integrate additional forms of renewable generation.[5] This includes the flexibility provided by New Zealand's existing water heating control resource.

## Electrification of heat and transport sectors

1.23. The uncontrolled scenario allows us to examine the impact of integrating two new demand sources into the existing New Zealand electricity system: the electrification of the transport sector and the ongoing electrification of space heating. Such electrification will require additional investment in electricity infrastructure capacity. The uncontrolled scenario builds onto the business as usual scenario described above. It is a high electricity demand growth scenario used later in this study to test the bounds of total cost savings available through the application of smart technologies.

1.24. In New Zealand, transport accounts for around 38 percent of primary observed energy demand. Almost all transport energy demand is supplied by oil [46]. Residential heating is supplied from a mixture of sources including electricity. BRANZ research found that solid fuel provides the dominant form of house heating, representing over 50 percent by gross space heating [47]. In recent years, heat pumps to provide space heating have increased penetration of the New Zealand market [49].

1.25. Projections for the uptake of heat pumps in the "uncontrolled" scenario are based on extrapolating current New Zealand residential heat pump penetration levels

[3] The modelling of demand includes transmission and distribution losses and non-metered demand from co-generation and distributed generation.

[4] This investment consists of 2.4GW of new gas fired plant at a cost at $1400 per kW and 2.8GW of additional wind generation at a cost at $2000 per kW. Transmission network costs include upgrading the capacity of New Zealand's main transmission corridors by around 1.2TW-km (in addition to presently planned transmission reinforcements). The cost of this reinforcement is estimated to be around $3.6bn. Distribution network investment between 2010 and 2030 is around $2.1bn. This is primarily driven by the connection of about 400,000 new houses.

[5] Thermal markets typically face issues around peak energy constraint, whereas New Zealand's electricity market faces the challenge of energy constraint during periods of low hydro inflows (where demand needs to be curtailed, rather than shifted).

established by BRANZ [25]. These projections transition from living area heating only, to whole house heating by 2050. Figure 2 shows heat pump penetration for the heating area parameters (living area heating and whole house heating). The penetration level of heat pumps in 2030 reaches approximately 50 percent.

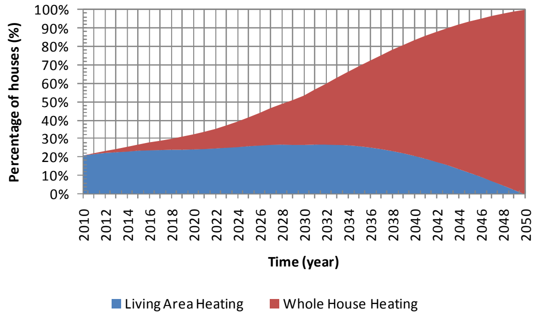



**Figure 2. Penetration of heat pumps for living area and whole of house heating**

1.26. We have used two scenarios for electric vehicle (EV) uptake in New Zealand, based on a spectrum of scenarios considered in a number of primarily European jurisdictions [43]. These are a high scenario (100 percent electrification of transportation by 2050), and a low scenario (just under 40 percent electrification of transportation by 2050). The number of EVs by 2050 is 2.8 million in the high scenario and 1 million in the low scenario. We have adopted a wide range of possible penetration levels of EVs (Figure 3) to capture the full range of possible future uptake in New Zealand.

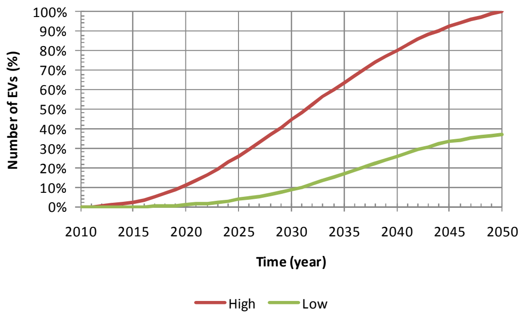



**Figure 3. Penetration of electric vehicles for high and low levels of uptake**

1.27. The uncontrolled scenario looks out to 2030 and 2050. It assumes by 2030 there is around 50 percent uptake of EVs and 50 percent uptake of heat pumps, with a mixture of single room heating only and whole house heating. By 2050 there is 100 percent uptake of EVs and 100 percent uptake of heat pumps, all with whole house heating.

1.28. We then consider the impact on peak electricity demand growth and system utilisation of integrating the heat and transport sectors into the electricity system. We need to understand this impact to assess what capacity is needed in the future for generation, transmission, and the distribution network. Figure 4 presents a load duration curve for the business as usual scenario in 2010, compared with load duration curves for the uncontrolled scenario in 2030 and 2050.

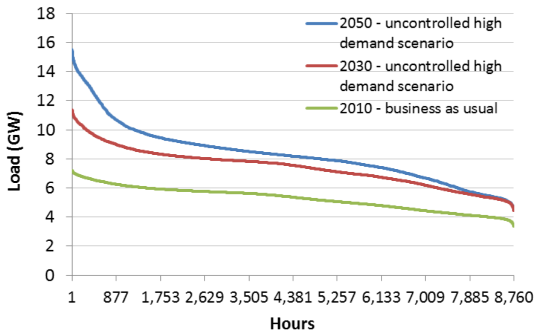



**Figure 4. Load duration curve of each scenario and corresponding peak demand**

1.29. Figure 4 shows that, compared to 2010, the increase in peak demand in 2030 and 2050 is disproportionately higher than the increase in total annual electricity consumption. The increase at peak demand is shown at 1 hour on the graph; the increase in total annual consumption at 8,760 hours. By 2030, peak demand has grown by nearly 60 percent from 7.2GW in 2010 to 11.3GW. (Compare this with peak demand of 9.3GW under the business as usual 2030 scenario shown in table 1.)

1.30. As table 4 shows, such a growth in peak demand reduces the electricity system's capacity utilisation (load factor) from 73 percent in 2010 to 65 percent in 2030 (compared with the 74 percent in 2030 business as usual shown in table 1) and to 53 percent in 2050. This indicates that the utilisation of generation, transmission and distribution assets will degrade significantly by 2030 in the uncontrolled scenario, compared to the business as usual scenario. Quantifying the extent to which using flexible sources of demand could reverse this trend is a key aspect of this study.

**Table 4. Annual peak demand, energy consumption, and load factor**

| Scenario | Peak demand (MW) | Annual electricity consumption (TWh) | Load factor (%)[6] |
|---|---|---|---|
| 2010[7] | 7,214 | 46 | 73% |
| 2030 | 11,386 | 65 | 65% |
| 2050 | 15,527 | 73 | 53% |

1.31. Figure 5 illustrates why system utilisation degrades. It examines the change in the shape of a daily load curve as a result of integrating the heat and transport sectors into the electricity system.

[6] Load factor is a measure of how many GWh of energy is produced annually divided by the total GWh it would be possible to produce if all generation was running at its maximum rated capacity.

[7] Source: *Transpower 2010 Annual Planning Report.*

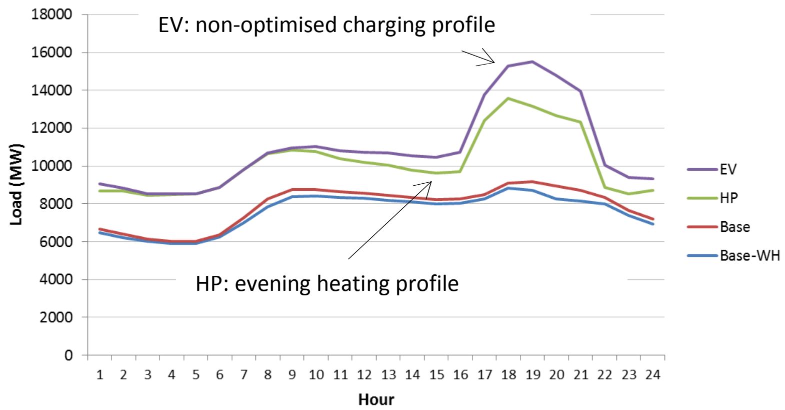



**Figure 5. Daily load curve for a 2050 winter day: Increase of peak demand driven by evening heating and EV charging loads**

1.32. Figure 5 shows the load composition for a cold winter's day in 2050 in New Zealand. Peak demand is typically highest in the late afternoon (red line). This is exacerbated with the addition of uncontrolled heat pump (green line) and EV charging (purple line) loads, leading to a considerable increase in national peak demand. The heat pump load has the highest impact on energy and peak demand increases, followed by the EV load. At a national level, using water heating load control to reduce peak demand has a relatively small impact (shown by the blue line, which represents the base daily load with the load of water heaters subtracted). We discuss later that the role of water heading load control will continue to be significant, especially at the distribution network level.

1.33. Table 4 shows a reduction in load factor for 2030 and 2050, which means that significant system capacity must be reserved to accommodate peak demand periods of relatively short durations. Consequently, the system capacity load factor will tend to reduce, and concerns about overall investment efficiency may arise.

## Key findings - use of flexible demand under a smart scenario to defer electricity infrastructure investment costs

1.34. Our third scenario, the smart scenario, looks at what savings can be achieved across the distribution, transmission and generation segments of the electricity industry by using smart control of flexible demand. It also examines the potential for flexible demand to provide system balancing services.

1.35. Under the smart scenario, we optimise the use of flexible demand to smooth and manage peak demand periods. The main sources of flexible demand investigated were hot water heating control, smart electric vehicle charging, smart heat pump control, and smart appliances (such as smart dishwashers).

1.36. The use of flexible demand differs from generation. Using demand flexibly redistributes demand in time, rather than stopping energy to cope with demand. So load recovery periods that follow load reduction periods will be characterised by increases in demand that generators will need to meet later. In this study we have sought to carefully optimise the use of flexible demand to manage the load recovery process. This also includes designing approaches that do not compromise consumer comfort levels. In the main body of the report (section 2), we further discuss the assumptions underpinning our modelling of flexible demand.

1.37. The reinforcement cost and savings that follow are based on present unit costs without inflation.[8]

### 1) Smart controls impact on distribution network investment

1.38. The study found significant potential for smart control to reduce the need for investment in distribution network infrastructure, compared to the uncontrolled scenario. To model the potential savings available across the distribution network sector, we created representative distribution networks to capture the range of network topologies present in New Zealand (these are discussed in detail in section 3).

1.39. Smart control benefits are quantified in terms of the costs associated with the reduced network reinforcement needed to accommodate future growth in electricity demand. We used the models developed for the uncontrolled and smart control scenarios to study distribution network planning. In the smart control scenario, we optimised an aggregate effect of various flexible sources of demand: controlling water heaters, smart appliances, EVs, and heat pumps. The savings allowed us to minimise the investment needed to accommodate load growth.[9]

1.40. Figure 6 shows the network reinforcement costs for the uncontrolled scenario (with the high EV uptake case in Figure 3) for 2030 and 2050, and the savings that could be made when flexible demand is controlled as in the "smart" scenario. By 2030, an additional $2.0 billion of distribution network reinforcement is required under the uncontrolled scenario (this is in addition to the $2.1 billion required under the business as usual scenario). Savings under the smart scenario reach about $1.6 billion in 2030 and about $3.3 billion in 2050. The savings are very significant compared to the uncontrolled case.

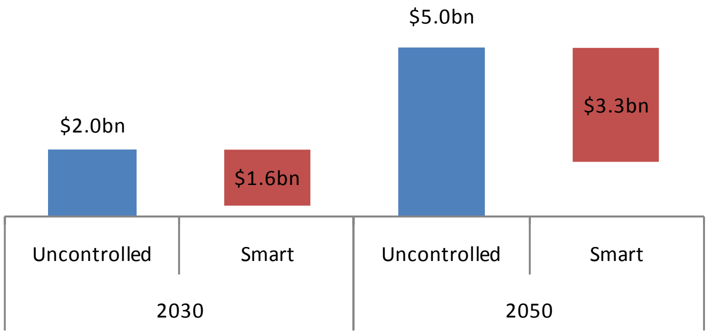



**Figure 6 New Zealand distribution reinforcement costs for the uncontrolled scenario and savings achieved from controlling flexible demand (Smart) in 2030 and 2050**

1.41. Table 5 summarises the costs for distribution network reinforcement costs when several flexible demand technologies are used simultaneously to mitigate the

[8] All $ costs quoted in this study are in today's $ and are a cumulative calculation of the level of additional capacity required for any given scenario and its associated capital cost (these are not NPV costs and do not take into account the cost of implementing the technologies under examination).

[9] In rural networks the use of in-line voltage regulators is also included.

increase in peak demand (through a coordinated control of flexible demand technologies).

**Table 5. Range of New Zealand distribution networks reinforcement costs ($m)**

| Controls | 2030 | 2050 |
|---|---|---|
| Uncontrolled | 1,972 | 4,951 |
| Water heaters (Smart 1) | 1,314 | 4,236 |
| Water heaters, Smart appliances (Smart 2) | 1,253 | 4,185 |
| Water heaters, Smart appliances, EVs (Smart 3) | 522 | 2,157 |
| Water heaters, Smart appliances, EVs, heat pumps (Smart 4) | 490 | 1,926 |
| Water heaters, smart appliances, EVs, heat pumps, voltage control in low voltage networks (Smart 5) | 359 | 1,626 |

1.42. Based on this analysis, we can evaluate the benefits associated with the individual flexible demand technologies. Figure 7 shows the cost reduction obtained by deferring network reinforcement.

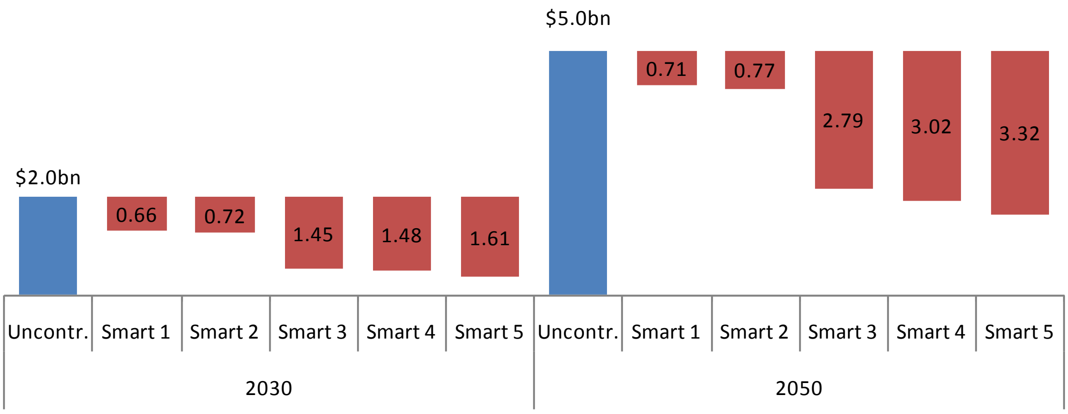



**Figure 7. New Zealand distribution reinforcement costs for uncontrolled scenario and savings from controlling various flexible demand technologies for 2030 and 2050**

1.43. Figure 7 shows that control of water heaters (smart 1) can provide $660 million of reduced investment by 2030 against the uncontrolled scenario. This analysis shows that water heating load control, by deferring the need for local network reinforcement investment, will continue to be important in the future. Water heating load control will be especially important if the penetration of EVs and heat pumps is relatively low.

1.44. Figure 7 shows that the value of controlling smart appliances is marginal. The Smart 1 example is water heaters and smart 2 is water heaters and smart appliances. By 2030 there is only a small amount of additional benefit from control of smart appliances, around $60 million. New Zealand's existing hot water heating control resource can already provide most of the flexibility that the addition of smart appliances can offer.

1.45. By far the biggest impact is associated with controlling charging of EVs (smart 3). The additional contribution of controlling heat pumps (smart 4) and controlling voltage in LV networks is lower (smart 5), but still important, particularly when penetration of EVs and heat pumps is high.

1.46. The above analysis is based on a scenario where the uptake levels of EVs and heat pumps are uniformly spread across New Zealand. However, the uptake of EVs and heat pumps is not likely to be geographically even. This means there will be a significant impact on distribution network reinforcement cost. For example, we considered EV and heat pump penetration of 17 percent at the national level (under the high EV uptake scenario this is reached after 2025) and then considered a uniform and a non-uniform distribution of these technologies as shown in Figure 8 (left). With non-uniform distribution, some areas have high levels of penetration (significantly above 17 percent) while uptake in other areas may be very low. The overall impact of the distribution of the uptake of EVs and heat pumps across the country on distribution network reinforcement costs is potentially very significant. Network reinforcements of $935 million are associated with uniform distribution. and costs of $1,589 million with non-uniform distribution, a 70 percent increase in investment cost. Given the expectation that the uptake of EVs and HPs will be uneven, it is likely there will be considerable impacts on the local distribution network long before any significant impact at the national level is observed.

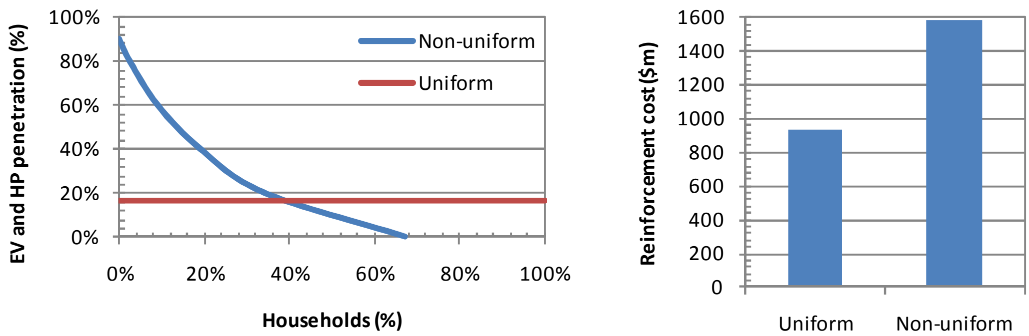



**Figure 8. Illustrative example of the impact of uneven penetration of EVs and Heat Pumps on distribution network reinforcement costs**

## 2) Smart controls impact on generation capacity investment

1.47. We have studied the use of smart EV charging and heat pump control for reducing the level of investment in national generation capacity required in the future compared to the uncontrolled high demand scenario. Other forms of flexible load control are included in this scenario, such as smart appliances; however, these make a minimal impact at a national level in terms of deferring the need for new generation investment, and so are not explicitly shown in the results.

1.48. Figure 9 shows that additional generation capacity investment can be reduced by over 50 percent by 2030 through smart control, compared to the uncontrolled scenario. Under the uncontrolled scenario, additional generation investment is needed to deal with the increase in electricity demand in 2030 and 2050. By 2030 an additional $2.5 billion of new generation investment is required over and above the $9 billion required in the business as usual scenario. Under the smart scenario the use of flexible EV smart charging and heat pump control offers savings of over 50 percent, through deferring the need for $1.4 billion of new generation investment by 2030. By 2050, $9 billion of new generation investment will be required under the uncontrolled scenario. The use of flexible demand saves about $4.5 billion. These results are discussed in detail in section 4.

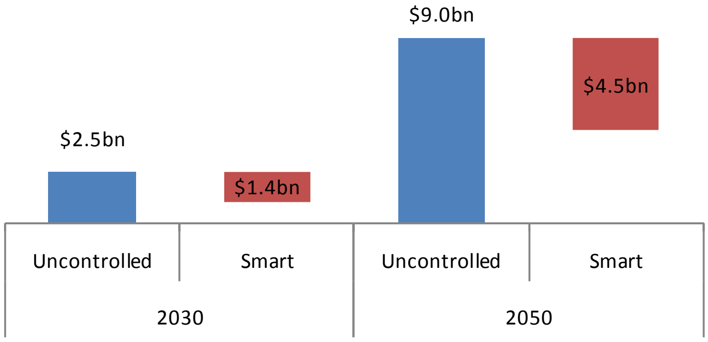



**Figure 9. Additional generating investment needed to accommodate electrification of transport and heat sectors in Uncontrolled and Smart futures**

## 3) Smart controls impact on transmission investment

1.49. We have studied the use of smart EV charging and heat pump control for reducing the level of investment in national transmission capacity required in the future compared to the uncontrolled scenario[10]. For this purpose we developed a simplified New Zealand Transmission network model that represents key network boundaries. The results are presented in Figure 10. The study found significant potential for smart control to reduce the need for transmission investment by 2050, compared to the uncontrolled scenario.

1.50. We do not expect the required level of transmission investment to be materially impacted by the electrification of the heat and transport sectors by 2030 (an additional $300 million of investment is required over and above the $3 billion required under the business as usual scenario). By 2050 the impact will be material, but can potentially be largely mitigated through the smart use of flexible demand. We observe that the application of smart control could save about $0.28 billion by 2030, and $2.6 billion by 2050. These results are discussed in further detail in section 4.

[10] Similar to the generation study, other forms of flexible load control are included in this scenario, such as smart appliances; however, these make a minimal impact at a national level in terms of deferring the need for new transmission investment, and so are not explicitly shown in the results.

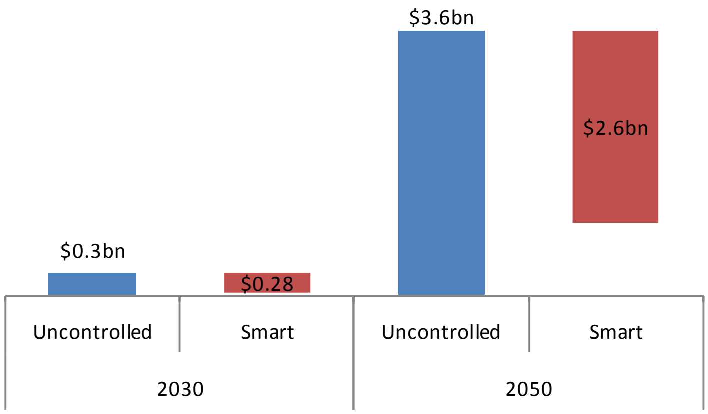



**Figure 10. Savings in transmission investment contributed by smart demand**

## 4) Smart controls impact on system balancing

1.51. This study also examines the potential for flexible demand to provide system balancing services. We quantify this potential in terms of the use of flexible demand to offset some of the additional generation system costs needed to balance system frequency. The overall benefits from the use of smart control to manage system balancing are relatively modest compared to the other benefits observed in this study. These benefits are discussed in fuller detail in section 4 and outlined briefly below.

1.52. We demonstrated in the New Zealand Wind Integration Study that hydro generation makes a significant contribution to balancing wind power fluctuations at a relatively low cost.[11] This means balancing services in a future New Zealand power system with 3.4GW of installed wind capacity are of only modest value (an order of magnitude lower than in thermally dominated generation systems, which have a significant contribution from inflexible nuclear generation).

1.53. Our analysis finds there are two main flexible demand technology candidates that are well placed to provide frequency response services: smart refrigerators (SF) and electric vehicles (EVs). These technologies could also be augmented in the future with frequency response provided by EVs injecting power to the grid to compensate for the loss of generation, which is known as the Vehicles-to-Grid (V2G) concept.[12]

1.54. Figure 11 shows the capitalised cost of frequency response services needed for system balancing in New Zealand with 3.4 GW of installed wind capacity. If there is no contribution from smart demand, the capitalised cost of this service could reach $300 million. The use of flexible EV charging and smart fridges could provide savings of around 50 percent (SF+EV:IC). The addition of vehicle-to-grid technology could provide almost all of the frequency response services required (SF+EV:V2G). Figure 13 also shows an extreme high wind future scenario, with 7.1 GW of installed wind capacity. Under this scenario the capitalised costs of balancing services could reach $800 million, but with a combination of flexible

[11] G. Strbac et al, *Wind Integration Costs: New Zealand (Phase II)*, a report to Meridian Energy Ltd, June 2008.

[12] There is, however, still considerable debate associated with the viability of the V2G concept, given the potential impact on battery life and technology requirements to deliver frequency regulation services.

demand applied, as in the 3.4 GW wind case, this can also theoretically offset most of the system balancing costs.

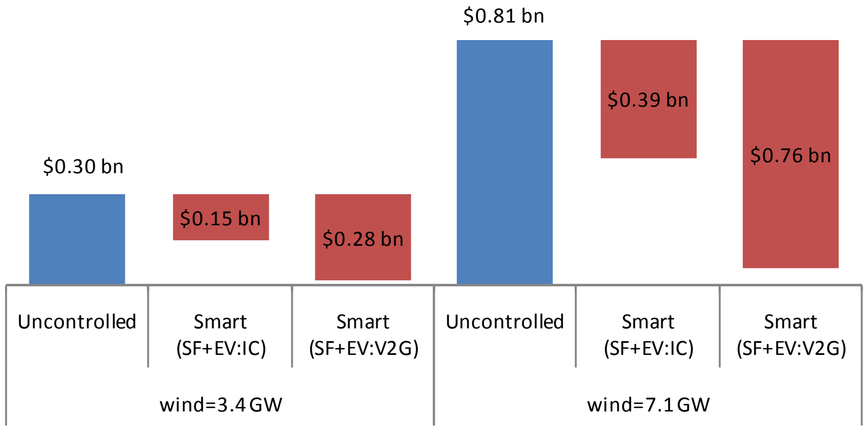



**Figure 11: Capitalised value of cost and savings in providing frequency response**

## Summary of all benefits quantified

1.55. The electrification of the heat and transport sectors included in the uncontrolled scenario will require an additional $4.8 billion of investment in transmission, distribution and generation by 2030 (in addition to the system investment already required under a business as usual scenario of demand growth). The deployment of smart grid technologies, the smart scenario, to manage demand can reduce this additional investment by $3.6 billion by 2030.

1.56. Figure 12 summarises all the benefits quantified in this study for the years 2030 and 2050, showing all the savings available under the smart scenario.

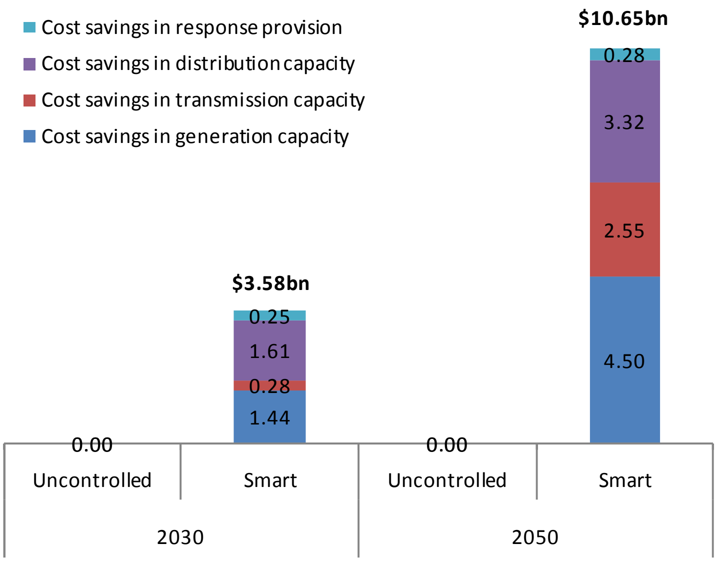



**Figure 12. Breakdown of estimated benefits of Flexible Demand in 2030 and 2050 ($bn)**

1.57. By 2030 the most significant benefits from using flexible demand will be through the reduced investment required in generation (saving $1.4 billion), and distribution network (saving $1.6 billion). More modest benefits are gained from demand participation in deferring transmission investment (saving $280 million), and response provision ($250 million saving).

1.58. In 2050, the volume of benefits increases significantly across most segments. In particular, the potential contribution of flexible demand to reduce investment in the transmission network significantly increases to a $2.5 billion saving. Given that New Zealand is a hydro dominated system, the value of flexible demand in providing balancing services will remain relatively modest, with a $280 million saving.

## Discussion of findings

1.59. This analysis suggests that, over the next decade, smart grid deployment is likely to have limited effects in terms of deferring investment in electricity infrastructure in New Zealand.

1.60. A number of countries with thermal-based power systems are investigating smart grid implementation. They seek to integrate renewable energy into their systems, and move energy consumption from fossil fuels to electricity. The cost of increasing peak demand in thermal systems is significant, as it requires investment in peak capacity in generation, transmission and distribution.

1.61. In contrast, New Zealand's electricity system is hydro dominated and renewables based. This gives New Zealand greater flexibility to respond to the challenge of integrating intermittent generation. Furthermore, New Zealand has a significant load control resource already in place through hot water ripple heating control. These factors mean a smart grid implementation offers fewer benefits in the near term compared to the benefits expected to be available in thermally based power systems.

1.62. Future changes in electricity demand are expected to create a substantial economic case for the smart grid opportunity in New Zealand.

1.63. The electrification of the heat and transport sectors in New Zealand will cause significant peak demand issues, requiring additional electricity system investment. However, deploying smart technologies to exploit flexibility in various forms of demand can significantly mitigate the additional amount of investment required.

1.64. New Zealand's existing hot water load control is a valuable strategic asset. Ripple control of water heaters will continue to be important in deferring the need for local network reinforcement, especially when penetration of EVs and heat pumps is relatively low. However, when there is high uptake of EVs and heat pumps, smart charging of EVs and control of heat pump demand will be of critical importance to smooth and manage peak demand periods. Smart EV charging is the most flexible of all the technologies we examined. On the other hand, the control of smart appliances makes only a modest contribution to smoothing peak demand.

1.65. The above analysis is based on the assumption that the uptake of EVs and heat pumps will be evenly distributed across the country. However, the uptake of EVs and heat pumps may not be uniformly spread. A high uptake in one area may mean a significant impact on the local distribution network long before any significant impact at the national level is observed. With uneven distribution, the smart grid concept could bring significant benefits at a distribution network level, perhaps from 2020 onwards, and benefits of similar magnitudes at the generation level may be obtained around 2030.

1.66. This report does not consider the costs of implementing these smart grid technologies, but such costs are expected to be an order of magnitude lower than the benefits available.

1.67. In order to achieve the full benefits of the smart grid concept and smart technologies a number of issues will need to be considered. New Zealand's market design and regulatory framework will need to evolve to provide the right investment signals to unlock flexible demand side participation. The following factors are important for New Zealand to deliver the best national benefits from a smarter energy future.

1.68. **Ensure that New Zealand's existing load control resource is being fully utilised**. New Zealand's existing power system may be 'smarter' than most. This is in part due to New Zealand's existing hot water heating control resource, which has been in place for over 50 years. Consumers currently choose if they wish to opt into hot water load control by selecting a controlled tariff. It is unclear if New Zealand's existing hot water heating control resource is declining over time, both in terms of the maintenance and installation of the hardware, and in terms of how much use is made of the resource to manage peak demand periods and distribution network congestion. In addition to maintaining the existing resource, there is an opportunity to enhance existing hot water heating control by making full use of consumption information from smart meters. This is particularly attractive as New Zealand's hot water heating control resource, augmented with smart metering information, is effectively a sunk cost, and could provide many of the benefits that a fully functional smart grid aims to provide.

1.69. **Conduct focused trials.** In line with international initiatives, New Zealand could conduct focused trials to learn more about the benefits before wide spread roll out is considered. This is particularly relevant for New Zealand given the growing uptake of Heat Pump technology and the impact this uptake could have on distribution networks during unusually cold spells. It will be important to fully understand the usage patterns associated with different installations and explore the benefits and challenges associated with alternative demand control strategies. Trials with two way information flows to test customer engagement and tailor products to suit customer needs will be an important step to learn about the systemic value of a smarter grid. It is important to emphasise that the infrastructure for conducting such trials, smart metering with accompanied communication and control technologies, is already available which will make the trials very cost effective. Specific areas of investigation in the nearer term could also include:

- trialling hot water heating control approaches augmented with smart metering information
- monitoring of heat pump operation and investigating opportunities for control
- using smart metering data to deepen the understanding of electricity consumption patterns across various consumer segments, augmented with appliance monitoring and consumer behavioural research.

1.70. **Encourage demand participation.** The benefits of demand response (and other smart grid technologies, such as storage) may be shared among several industry participants along the energy value chain. Achieving active demand side participation is internationally considered to be a barrier to achieving the full economic benefits that a smarter grid could deliver. The industry has a key role to play to raise awareness, put appropriate systems and processes in place and create incentives for greater demand side participation in the energy market.

1.71. **At the network level, New Zealand's regulatory framework may need to evolve to recognise investment in efficiency.** Network operators need to be able to make choices between investing in innovative demand response and investing in network assets. Incentives to adopt technically effective and cost efficient non-network solutions need to be considered as part of the regulatory design framework. Such incentives could be complemented with a review and update of network design standards in order to accommodate the contribution that flexible demand initiatives may be able to make as a substitution for building network infrastructure.

# 2. ROLE AND MODELLING OF FLEXIBLE DEMAND

2.1. As discussed above, incorporating flexible demand into New Zealand's electricity system can benefit its operation and design. These benefits include increased generation and network asset use, increased capacity to allow for low carbon generation and load growth, better network flexibility in an uncertain future, and better network reliability and resilience.

2.2. Understanding the characteristics of flexible demand is vital to establishing its economic value. For there to be regular flexible demand, controlled devices (or appliances) must have access to storage when rescheduling production or when needing to function during interruptions. The type of storage may be thermal, chemical or mechanical energy, or intermediate products. Flexible demand *redistributes* the load but may not lessen the total energy the device appliance uses. Load reduction periods are followed or preceded by load recovery. How long a load recovery lasts depends on the type of interrupted process and the type of storage. The amount of energy recovered may exceed the amount of load that is restricted due to losses in the storage or energy conversion process.

2.3. Achieving flexible demand means carefully managing this process of load reduction and load recovery. One key outcome of using demand control is the reduction in the range of appliances. For example, let us assume we have 1000 refrigerators and that each refrigerator, when operating (using electricity), has a load of 200W. Next assume a coincidence factor of 25 percent, as only a quarter of the devices will use electricity simultaneously. This means the diversified load of 1000 refrigerators is 50kW (1000 x 0.200 x 0.25). If all 1000 refrigerators are switched off, the expected load reduction will be only 50kW. If these are reconnected back to supply after one hour, the load is likely to be 200kW (1000 x 0.200). This is because the temperature in every refrigerator will be above the set levels and thermostat control is trying to reduce the temperature by having all refrigerators use electricity.

2.4. So, the total load of the group of controlled devices will increase during the load recovery period. To counteract this load increase, some other appliances must be switched off. This would reduce load control efficiency. A key technical challenge is to design ways to maximise both the efficiency and use of controlled loads, while at the same time not comprising consumers comfort levels.

2.5. This section describes the flexibility of various forms of demand. The modelling framework sets out to minimise the cost of system reinforcement and operation. To do so, it optimises the aggregate effect of various types of flexible demand technologies examined in this study, including water heaters, smart appliances, smart refrigerators, smart control of EVs, and smart control of heat pumps.

## Water heaters

2.6. The diversified water heater demand model used in this report is given in Figure 13. This diversified curve shows the average uncontrolled water heater use from a large sampling of water heaters [35]. The diagram shows use peaking at 7.30pm, with a smaller peak, at 7am. These two peaks are due to water heaters being used mostly in the morning and in the evening (shown by the blue line in Figure 13).

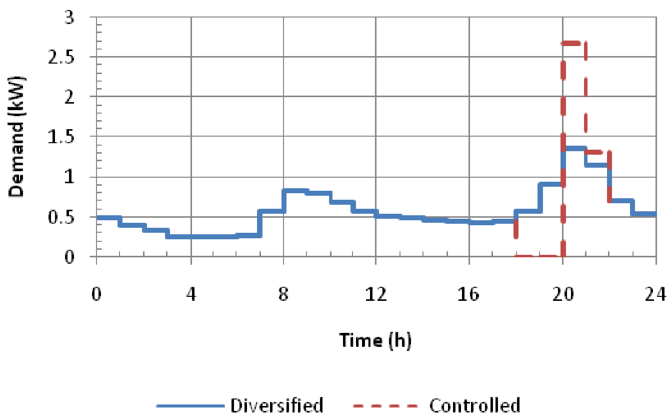



**Figure 13: Diversified water heater demand**

2.7. Reconnecting a group of water heaters to the system affects their performance, and we see a spike in demand (known as payback). This effect is shown in the red dashed line in Figure 13. For the controlled diversified curve of water heaters, during load reduction, the demand of controlled water heaters is zero. During payback, net restored demand is added to the uncontrolled diversified demand.

2.8. The developed models used in this study optimally schedule the control of groups of water heaters to minimise peak demand (or generation cost), while noting the load reduction and load recovery effect shown in Figure 13. The model has been calibrated using data gained from field applications.

2.9. Figure 14 shows controlled and uncontrolled load profiles for residential and mixed residential and commercial areas. We can see that peak demand reduces from 7MW to 5.5MW for the residential areas, and from 8.5MW to 7.5MW for the mixed residential and commercial areas.

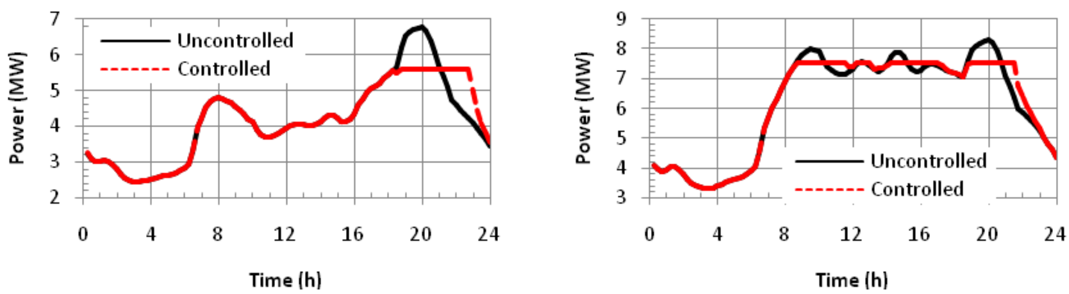



**Figure 14. Controlled and uncontrolled load profile for residential areas (left) and for mixed residential and commercial areas (right)**

2.10. Figure 15 and Figure 16 shows water heater control schemes for residential and mixed areas. In residential areas water heaters are controlled only in the evening, while in mixed areas they are controlled in the morning, at midday and in the evening. The horizontal bar shows the control period when water heaters are switched off. The number after that control scheme bar shows the number of controlled water heaters in the scheme. For example, 120 water heaters are switched off for two hours from 6.15pm to 8.15pm in residential areas. In this example, each water heater is controlled once at maximum, although split schemes with multi-day control periods is also modelled [35].

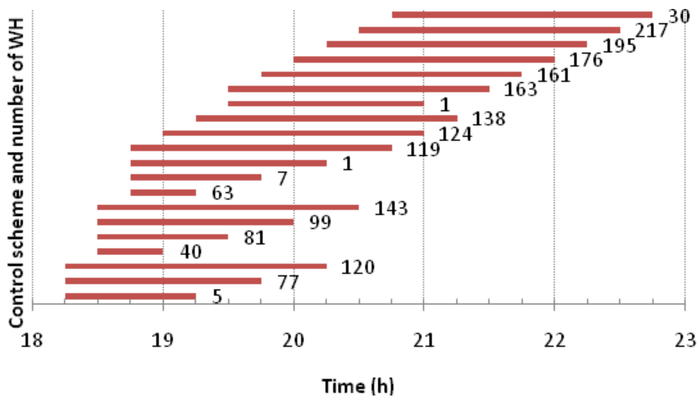



**Figure 15. Water heaters control schemes for residential areas for controlled profile shown in Figure 14 (left diagram)**

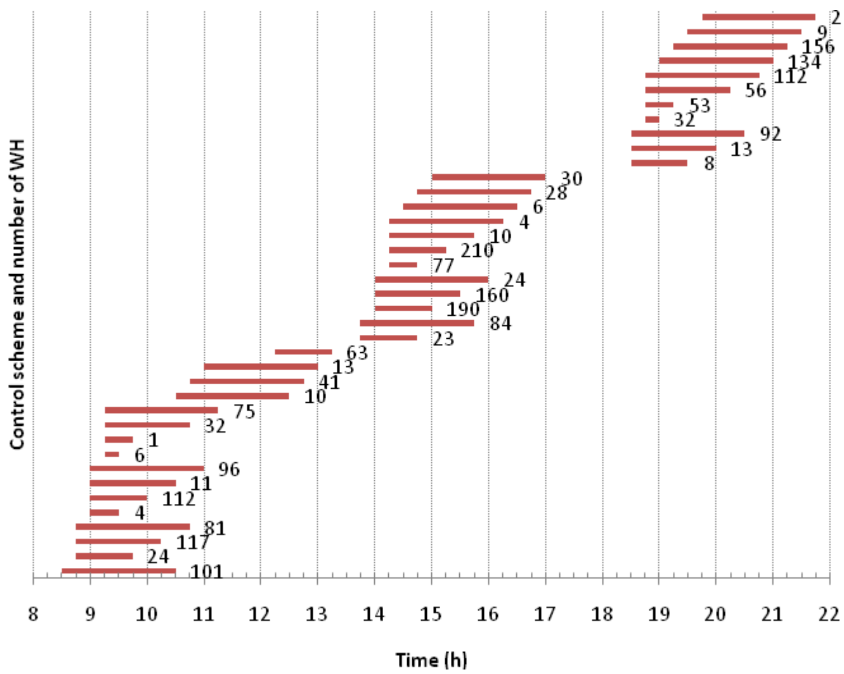


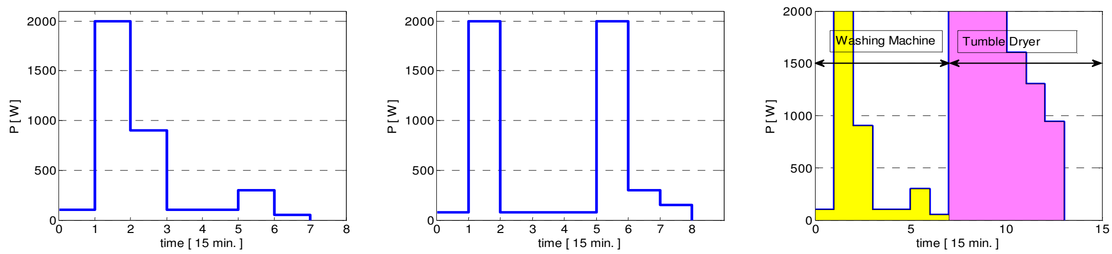

**Figure 16. Used water heaters control schemes for mixed residential and commercial areas for controlled profile shown in Figure 14 (right diagram)**

2.11. We see that the ability of water heating control to reduce peak demand is more effective when the demand profile has a prominent peak, as in the residential areas. A flatter demand profile, as in the mixed areas, limits the ability of water heating control to reduce peak.

## Smart Appliances

2.12. The aim of smart operation of appliances is to adapt appliance usage to electricity system conditions. Smart appliances (SAs) become a source of demand-side flexibility. They provide a range of services, such as generation/demand balancing, peak reduction, and network congestion management. Our analysis focuses on three types of appliances: washing machines (WM), dishwashers (DW), and washing machines equipped with tumble dryers (WM+TD). The data relevant for appliances use and optimisation is sourced from the Intelligent Energy Europe Smart-A project [8].

2.13. The operation cycle defines the duration and power consumption at each time instant when the appliance is in use. Figure 17 shows the typical operation cycle pattern for a WM, DW and WM+TD, in 15 minute resolutions.




WM DW WM+TD

**Figure 17. Operation cycles for WM, DW and WM+TD**

2.14. The WM demand per washing cycle shows that its demand is greater during the water heating phase at the start of the cycle, with a smaller demand rise visible in the spinning phase towards the end of the cycle. Since the tumble dryer cycle started straight after the washing cycle, we need to merge the cycles of both devices to get the WM+TD cycle as seen in Figure 17. The operation cycle data for each device type is taken from Synergy Potential of Smart Domestic Appliances in Renewable Energy Systems.[17]

2.15. The diversified profile is of the aggregated and normalised demand of an appliance. Figure 18 shows the diversified profiles for WM, DW and WM+TD in the United Kingdom. It suggests that most households use their WM early in the morning or in the evening.

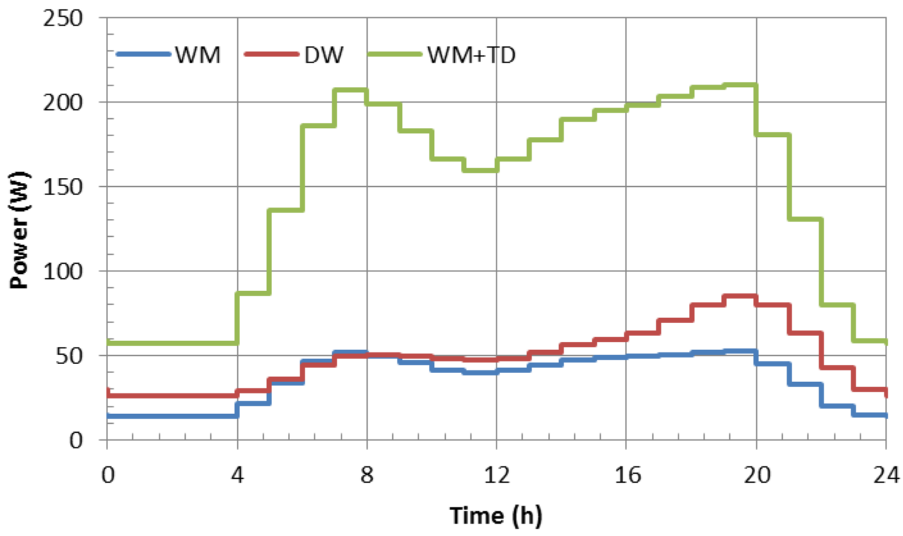



**Figure 18. Diversified profiles for WM, DW and WM+TD**

2.16. Distribution of the cycles during the day is important to determine when controllable demand is available [36]. Figure 19 shows typical estimated appliance usage patterns for New Zealand.

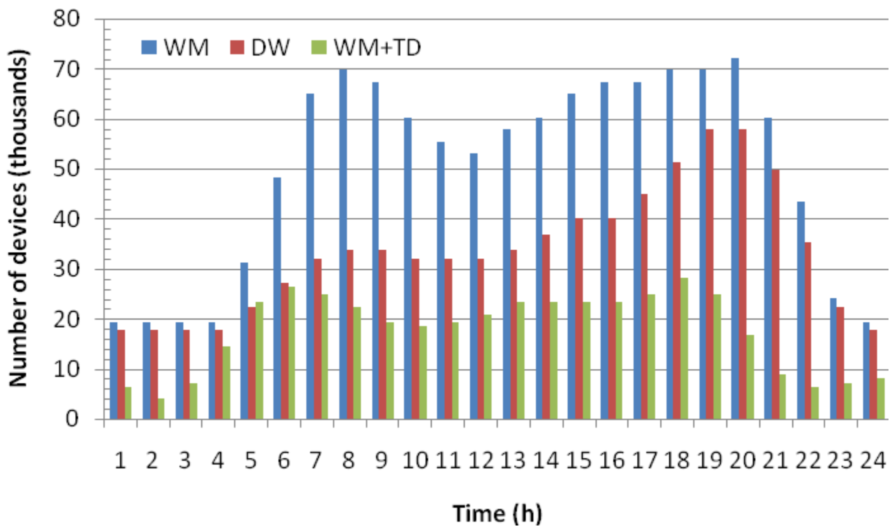


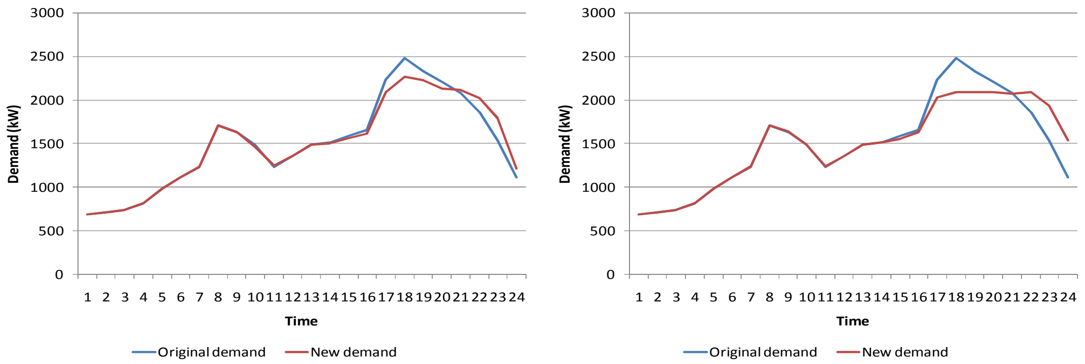

**Figure 19. Estimated number of appliances starting a cycle during a day**

2.17. Table 6 shows a summary of the operation cycle and allowed shifting times for the three appliances. The data is from EU customer acceptance surveys [39]. We assume the penetration rates reflect the current or near-future households that own a WM, DW or WM+TD and use it in a flexible way.

**Table 6. Operating parameters of Smart Appliances**

| Appliance type | Acceptable shifting levels (in hours) | Cycle duration (in hours) |
|---|---|---|
| WM | 1–3 | 2 |
| DW | 1–6 | 2 |
| WM+TD | 1–3 | 4 |

2.18. The role and value of using smart appliances to help system operation and investment is specific to each system. In most inflexible thermal generation dominated power systems, the key aim of smart appliances is to improve how the system absorbs increased amounts of intermittent renewables. It achieves this aim by balancing services. In contrast, in the hydro generation dominated system of New Zealand, smart appliances may have greater benefits by reducing peak demand of local distribution networks. Figure 20 shows two ways to reduce peak demand in residential areas. These are the existing level of penetration of smart appliances, with a peak reduction of 8.4 percent, and full penetration of smart appliances, with a peak reduction of 15.8 percent.




(present situation) (full penetration)

**Figure 20. How smart appliances can reduce the peak load of a distribution network**

## Smart Refrigeration

2.19. Automatic frequency regulation services keep the tight balance between generation and demand. Frequency needs to be managed after a sudden loss of generation. These services are usually provided by synchronised generators, running part loaded, and by frequency-sensitive load reductions from some industrial customers. Such instantaneous services keep the system frequency over time from seconds to several tens of minutes.

2.20. Smart Refrigeration (SR) could potentially contribute to frequency regulation. Reduced system operation cost and lower carbon emissions will drive the value of such a service, while increasing its ability to absorb intermittent generation.

2.21. Domestic refrigerators generally keep the refrigerator temperature between two set points. Once the internal temperature reaches the set point value of $T_{max}$, the compressor starts and the refrigerator starts to cool. Once the refrigerator's internal temperature reaches the minimum required temperature set point of $T_{min}$, the compressor stops. The cycle then repeats. Figure 21 shows this standard refrigeration cycle. The compressor has a duty cycle (that is, the time when the refrigerator uses energy) of 20 percent to 30 percent. When the compressor is on, the temperature reduces; when it is off, the refrigerator cabinet temperature rises.

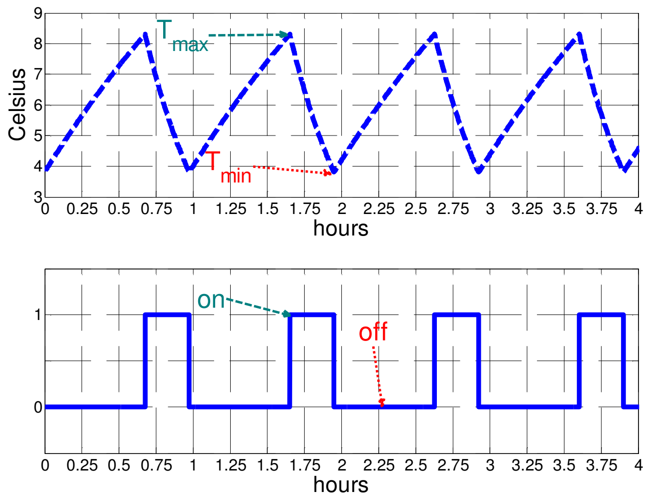



**Figure 21. Standard refrigerator cycles**

**(top diagram shows state representation,**
**bottom diagram shows refrigerator temperature and compressor state)**

2.22. Given a duty cycle of about 30 percent and a rating between 120W and 150W for individual appliances, the diversified load of an individual refrigerator is between 40W and 50W. This means that an estimated 2.5 million refrigerators in New Zealand will impose a load of 100MW to 125MW.

2.23. The inclusion of SR control in a domestic refrigerator changes the way it works by changing its duty cycle length as the frequency changes. The need for the refrigerator to continue to contribute system balancing means that average energy use for each appliance should reduce as the system frequency reduces.

2.24. Figure 22 shows how an SR changes after a system frequency change. At the 2-hour point, the grid frequency changes from 50Hz to 49.5Hz. We see that the refrigerator duty cycle decreases after a frequency drop due to loss of generation.

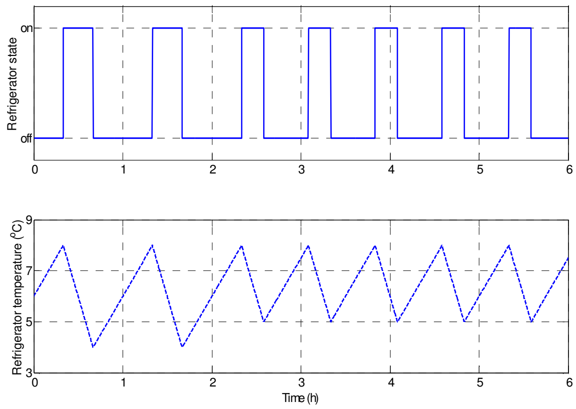



**Figure 22. SR behaviour with a step change of system frequency**

2.25. This reduction in turn means that the refrigerators contribute to frequency stabilisation by reducing their aggregate load as noted by the system. During that time, the refrigerators deliver some of their stored energy to support the system. This causes the average temperature to increase slightly. After some time, the temperature increase will cause the disconnected refrigerators to progressively reconnect to keep the temperature within prescribed limits. They will need energy to gradually restore their duty cycle length to the original, pre-disturbance, level. Figure 23 shows how the process of load reduction and load recovery can be optimised to match the range of the generation system.

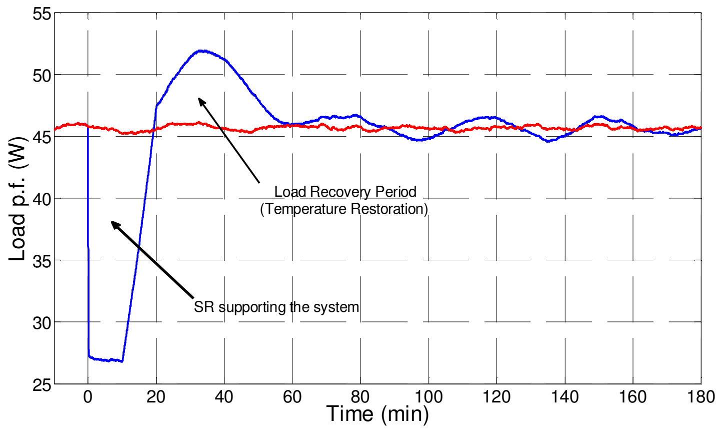



**Figure 23. SR supporting frequency regulation**

2.26. The analysis suggests that SR could provide the supply of Instantaneous Reserve to a maximum of 15W to 20W for each refrigerator. This will add between 37.5MW and 50MW to the Instantaneous Reserve services, which benefits the system by its aggregate of SR load. As Instantaneous Reserve requirements after 2030 are projected to increase to between 534 MW and 869MW, the contribution of SR will be marginal.

## Modelling of Plug-in Electric Vehicles

2.27. Plug-in Electric Vehicles[13] (EVs) are viewed as key to any policy seeking to hasten the decarbonisation of transport. Renewable and other low-carbon electricity generation technologies will have a major role in electrified transport.

2.28. We describe two possible EV usage rates: a high rate (100 percent electrification of transportation by 2050); and a low rate (just under 40 percent electrification of transportation by 2050). These rates are based on a range of scenarios, mainly focused on Europe. A high EV rate by 2050 means 2.8 million EVs, while a low rate means 1 million EVs. Figure 24 captures the extremes.

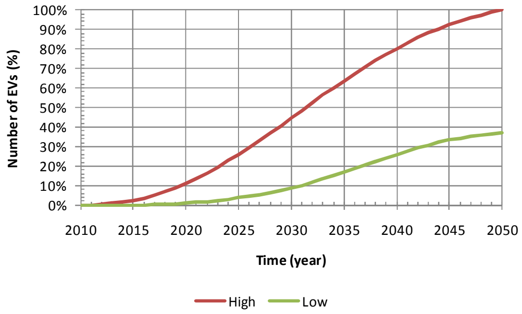



**Figure 24. Penetration of electric vehicles**

2.29. EVs have a significant storage capability. This provides opportunities to use more efficient charging strategies that will optimise electricity production capacity and make network and generation assets more effective. Yet Smart EV charging will require an active philosophy of demand control be included in electricity system operation and design practices. This report quantifies the value of these practices.

2.30. EV loads are particularly well placed to support network operation, given

- the modest amount of energy needed (typically less than 15 percent of the daily energy demand on a peak day for a residential area where everyone uses EVs)
- the generally short driving times of small passenger vehicles (Figure 25 shows over 90 percent of vehicles to be usually stationary)
- batteries are expected to have relatively high power ratings (as typical power ratings for home charging EV batteries would likely reach 3kW–6kW, the total installed battery power of 2.5 million vehicles would be between 7.5GW and 15GW).

2.31. The summary statistics of the fully electrified fleet of New Zealand light vehicles is estimated on the basis of MED data [44], [45] and the expected characteristics of EV batteries (Table 7).

[13] The term Plug-in Electric Vehicles (EV) includes plug-in hybrid vehicles and battery electric vehicles.

**Table 7. Key statistics of electrified fleet of light vehicles in New Zealand**

| | |
|---|---|
| Daily distance [million km] | 81.9 |
| Average daily distance [km/vehicle] | 29.5 |
| Daily energy demand (average) [GWh] | 12.3 |
| Average energy per vehicle [kWh/vehicle] | 4.4 |

2.32. A review of the literature on EV energy use shows a wide range of values (from 0.11kWh/km to 0.25kWh/km) and vehicles design and size. Typically, lesser values match smaller vehicles, while higher values match larger vehicles and hybrid vehicles. Recent studies show better energy efficiency in future. This may help reduce EV energy use. As this study focuses on the years 2030 and 2050, we believe an average value of 0.15kWh/km is reasonable. Sensitivity studies show that applying smart charging to EV peak demand will not significantly impact energy use. But smart charging will affect the peak if using uncontrolled charging. The relatively low value of EV energy use might underestimate the value of smart charging. This might result in conservative estimates for benefits of 'smart' as compared with the estimates for 'uncontrolled' regime.

2.33. The flexibility in when vehicles can be charged could benefit distribution and transmission networks operation.

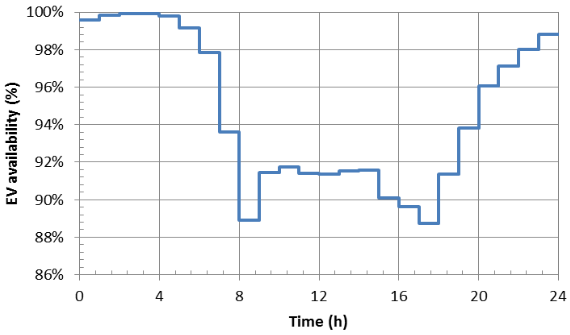



**Figure 25. Percentage of stationary vehicles during a typical day**

2.34. We have developed a suite of tools to assess the impact of coordinated charging of large numbers of EVs in New Zealand's future electricity systems. These tools can quantify how EVs might help to achieve a more efficient and cost-effective system.

2.35. Our modelling of EVs is based on statistics for light-vehicle driving patterns (we calibrated EU data and UK data [43] to match New Zealand driving patterns). We examined the start time and end time of single journeys grouped to distance travelled. Typically the data was sorted into distance bands (less than 1 mile, 1–2 miles, 2–3 miles, and so on). We used each group of journeys and the number of vehicles to determine the distance travelled and the start time and end time of each journey. Then we were able to evaluate the energy needed for each journey. Such data is needed to develop an effective analysis. The times the journey starts and ends lets us know when the vehicle is on-road. At all other times the vehicle is parked and (potentially) can be charged or give system support (assuming that a recharging infrastructure is available). The modelling can include efficiency losses during battery charging and other in-vehicle use (such as air conditioning). Table 8 shows a small sample of the total data set.

2.36. The journey data (prepared as set out above) means that we can simulate other charging strategies. We get energy use during the journey and the times when vehicles are stationary (and potentially available for charging). We have identified some 40,000 different types of journeys when charging is simulated or at its best. Our simulation and optimisation algorithms ensure that the charge state of batteries will not adversely affect how vehicles carry out their journeys.

**Table 8. Journey data table**

| 1st journey | | 2nd journey | | No. of EVs | E1 | E2 |
|---|---|---|---|---|---|---|
| start | end | start | end | (from 1st to 2nd) | kWh | kWh |
| 1 | 1 | 2 | 2 | 64.93 | 87.881 | 88.456 |
| – | – | – | – | – | – | – |
| 8 | 9 | 17 | 18 | 4900.83 | 6705.441 | 6880.413 |
| – | – | – | – | – | – | – |
| 22 | 23 | 23 | 24 | 8.24 | 11.156 | 11.321 |

2.37. The aim of the project means this report will contrast two approaches for charging EVs: uncontrolled and real-time optimisation.

- The first approach is ‘unconstrained’ operation (or uncontrolled) where EV charging is done on demand. Such a policy may increase peak demand significantly. This increase may result despite the extra energy needed being relatively small. For example, say commuters charge their EV batteries in the early evening. This extra load would coincide with peak demand and potentially cause overloads on the local distribution network and stress generation and transmission system (see the example in figure 26 below).
- The second approach is real-time optimisation of EV charging by making charging part of a communication infrastructure. The modelling framework allows various charging policies to be simulated and optimised. It assumes that EVs are (potentially) available for charging at the end of each journey. This approach optimises EV charging (while simultaneously optimising all other forms of flexible demand) at the local level. This approach is meant to manage constraints and avoid or postpone network and generation capacity reinforcements.

2.38. Figure 26 shows a semi-urban area where all light vehicles are electric. The original peak demand increases substantially from 6.8MW to 12MW (an increase of 76 percent), while, conversely, the load factor drops from 85 percent to 61 percent.

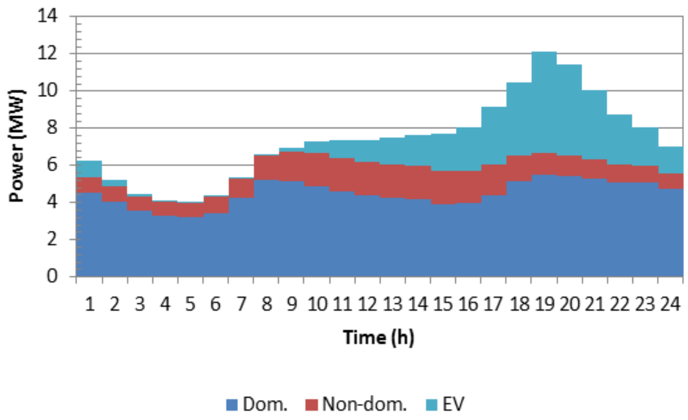



**Figure 26. Semi-urban area with all EVs**

2.39. If the charging of EVs is optimised, then peak demand increases from 6.8MW to 7.5MW and the load factor increases from 85 percent to 100 percent.

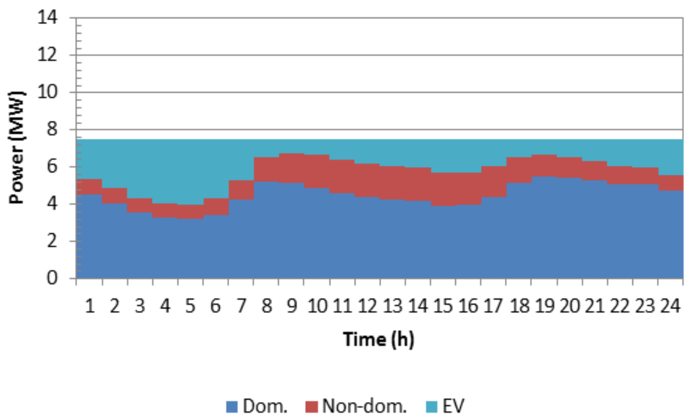



**Figure 27. Optimised profile for Figure 26 data**

2.40. Conceptually, this optimal EV charging process is simple: when a car ends its journey and is ready to be recharged, the driver would give information about when they will next need to drive the car. This information and information about the level of charge in the battery (taken after the previous journey) would be sent to the supplier, and system or network operator (as applicable). The charging would be optimised for all other loads while adhering to system conditions and network and generation constraints. This is a complementary approach to that noted in the recent report from the New Zealand Centre for Advanced Engineering that considered overnight charging.[48]

2.41. Smart charging of EVs can manage network and generation demand. EVs could also help to increase the efficiency of system operation. In particular, they would provide instantaneous reserve services when disconnected and charging. Figure 28 shows how we have optimised the charging of EVs to flatten out system peaks while providing Instantaneous Reserve. We can see that when EVs are not charging (to minimise system peak), they cannot provide Instantaneous Reserve.

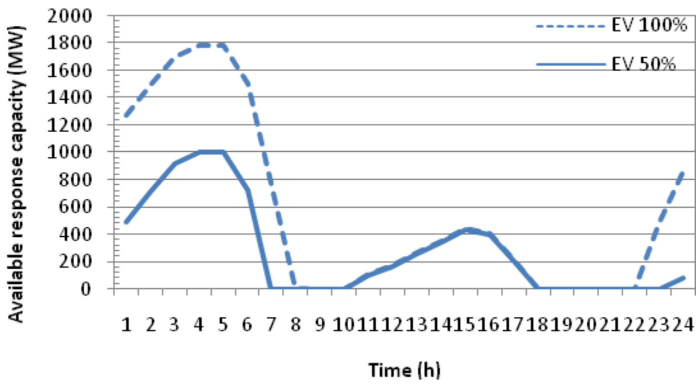



**Figure 28. Minimising peak and providing frequency regulation**

2.42. EVs could also discharge car batteries to support grid balancing or network congestion (so called vehicle-to-grid (or V2G) applications). Figure 29 shows how EVs might be able to provide Instantaneous Reserve through V2G.

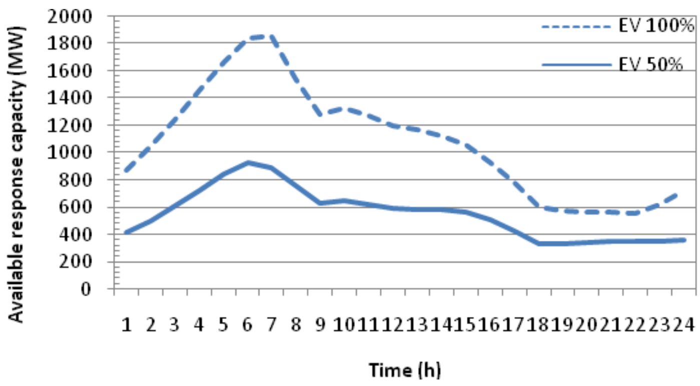



**Figure 29. V2G**

2.43. Debate still exists about how viable V2G technology is given the potential impact on battery life if discharged frequently to support system operation. We make a conservative assumption that the discharge level to support frequency regulation could not exceed 5 percent of the total charge available.

## Electrification of heat sector

2.44. The electrification of heat demand will significantly impact on how New Zealand's future electricity system operates and develops. Projections for the uptake of heat pumps (HP) are based on extrapolating current New Zealand residential heat pump penetration levels established by BRANZ [25] that consider living area heating only and transitioning to whole-of-house heating. Figure 30 shows heat pump use for living area only and whole-of-house heating. We see that the rate of heat pump use in 2030 is 50 percent.

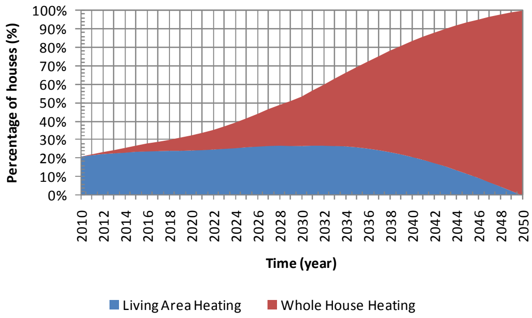



**Figure 30. Penetration of heat pumps**

2.45. The system level study started with extensive modelling. The modelling was done to identify the patterns and breadth of thermal load (cooling and heating) for a variety of building types and sizes, construction characteristics and insulation levels, size, occupancy patterns, indoor temperature settings, and outdoor temperatures. We were then able to identify the main factors that affect a building's energy needs and to develop heating and cooling load simulation methodologies. Energy Plus Energy Simulation Software[14] [28] (based on data reported by BRANZ [25]) helped us to develop the detailed models of residential space heating loads for existing and new built houses. Finally, we investigated building thermal responses under different control strategies. This gave us insights into the tradeoffs between reduced comfort level and power reduction when performing different Heating, Ventilation and Air Conditioning (HVAC) control strategies. Performance models of HVAC appliances means that we could see how thermal load is transferred to electrical load.

2.46. We used the Evening Heating scenario (denoted as Even22) for the heating load profile, and the Day Cooling scenario (denoted as Day20) for the cooling profile. The thermal load profiles we obtained for space heating and space cooling are comparable to the profiles in the BRANZ report. Figure 31 shows the profiles obtained from both models.

[14] EnergyPlus is an energy analysis and thermal load simulation program developed by the US Department of Energy (see http://apps1.eere.energy.gov/buildings/energyplus/energyplus_about.cfm) [Updated October 18 2010 and accessed 30 July 2011]

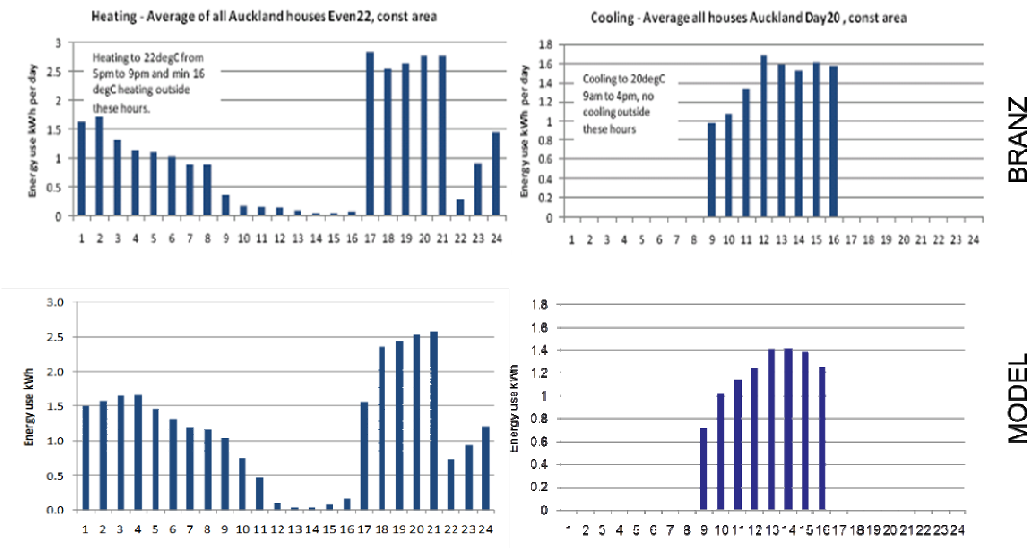



**Figure 31. Comparison between the thermal load profiles for heating and cooling obtained from the BRANZ report and developed models**

2.47. Table 9 summarises the space heating and space cooling electricity load obtained from our models and the results from BRANZ (if only the living area is conditioned). The model only approximates the BRANZ analysis, given the absence of detailed data (window size, detailed insulation characteristics, number of each house type, occupancy levels and so on). Further, for ease of reference, we use simplified weather data that shows the North Island and South Island separately (and with no local conditions for each region).

**Table 9. Comparison of HVAC electricity load for space heating and cooling**

| | Model | | BRANZ Report | |
|---|---|---|---|---|
| | Peak [MW] | Energy [GWh] | Peak [MW] | Energy [GWh] |
| Cooling (Day20) | 339 | 175 | 303 | 164 |
| Heating (Even22) | 1068 | 1804 | 934 | 1960 |

2.48. Table 10 shows the estimates of peak and annual energy consumption associated with heat demand in individual regions (as defined in the BRANZ report), with 50 percent of houses having HVAC systems conditioning the whole house.

**Table 10. Modelled heat peak and energy demand in individual regions**

| Region | Even22 | |
|---|---|---|
| | Peak [MW] | Energy [GWh] |
| Northland | 93.1 | 120.6 |
| Auckland | 893.7 | 1219.7 |
| Waikato | 232.1 | 294.2 |
| Bay of Plenty | 187.8 | 228.1 |
| Gisborne | 19.6 | 24.2 |
| Hawke's Bay | 95.2 | 116.8 |
| Taranaki | 54.8 | 69.3 |
| Manawatu–Wanganui | 116.3 | 145.2 |
| Wellington | 266.1 | 330.8 |
| Tasman | 38.2 | 85.4 |
| Nelson | 48.2 | 113.0 |

| Region | Even22 | |
|---|---|---|
| | Peak [MW] | Energy [GWh] |
| Marlborough | 45.2 | 99.5 |
| West Coast | 23.0 | 53.3 |
| Canterbury | 723.4 | 1623.5 |
| Otago | 238.2 | 534.0 |
| Southland | 92.6 | 205.5 |
| **New Zealand** | **3167.5** | **5263.2** |

2.49. We then aggregated the modelled heating and cooling demand for different types of houses at different locations, under two temperature profiles (South and North Island) to get the correct hourly heat loads for the generation, transmission and distribution networks that this report covers. Figure 32 shows the modelled evening heating hourly HVAC load profiles for a week of maximum load across different transmission regions.

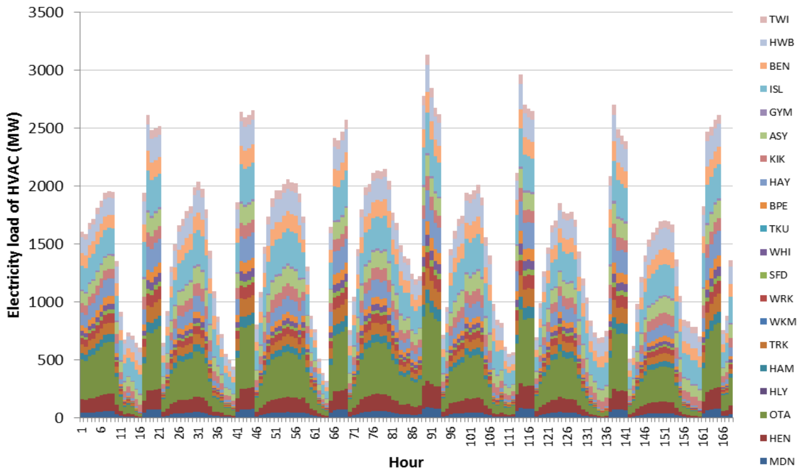



**Figure 32. Evening heating and hourly HVAC load profile in the week of maximum load**

2.50. Figure 33 provides profiles of New Zealand's total heat demand (heating and cooling) for this report, with minimum and maximum temperature profiles starting from 1 July.

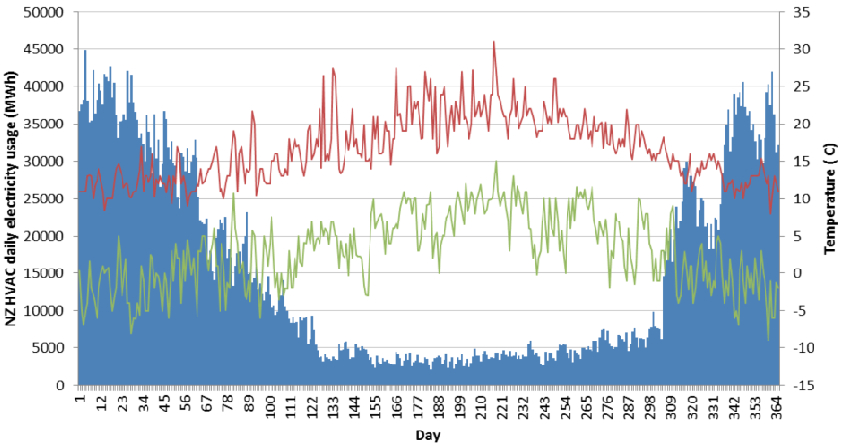



**Figure 33. Total heat demand (heating and cooling) with New Zealand minimum and maximum temperature profiles (starting from 1 July)**

2.51. Figure 34 shows a daily demand profile in a South Island semi-urban area where all the houses use a heat pump to get whole-of-house heating. The peak demand is 6.8MW in those houses without a heat pump and 14.6MW in those houses with a heat pump. This is an increase of 115 percent. Meanwhile the load factor dropped from 85 percent to 71 percent. This is simulated for the coldest day in the year, with temperatures in Christchurch reaching about -10°C. Such temperatures impose the largest aggregate heat pump load and are relevant for making the system have adequate capacity, including in its generation, transmission and distribution network infrastructure. Further study might examine alternative approaches to provide back up heating (electricity or solid fuel heat supply) in extremely cold weather to investigate the impact on peak demand and corresponding investment in generation, transmission and distribution infrastructure.

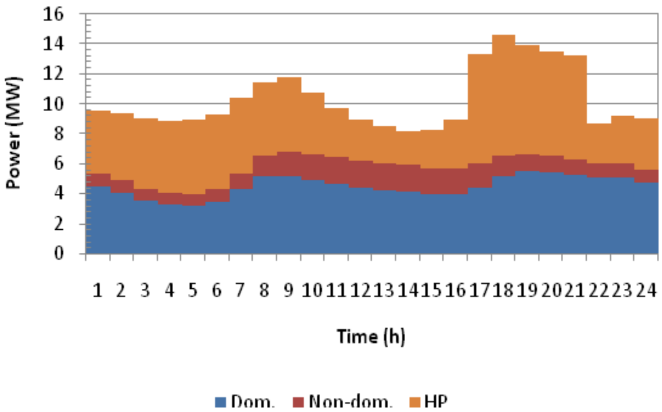



**Figure 34. South Island semi-urban area where HPs heat the whole of the house in all households**

2.52. In assessing the flexibility of heat pump use, we assume the houses included in this study are well insulated[15]. Effective insulation provides increased thermal

[15] New Zealand's current housing stock has mixed levels of insulation. Pre-heating is not a suitable strategy in poorly insulated houses.

inertia and the opportunity to manage heat pump demand efficiently (mainly as pre-heating and taking into account corresponding losses). Figure 34 highlights this opportunity.

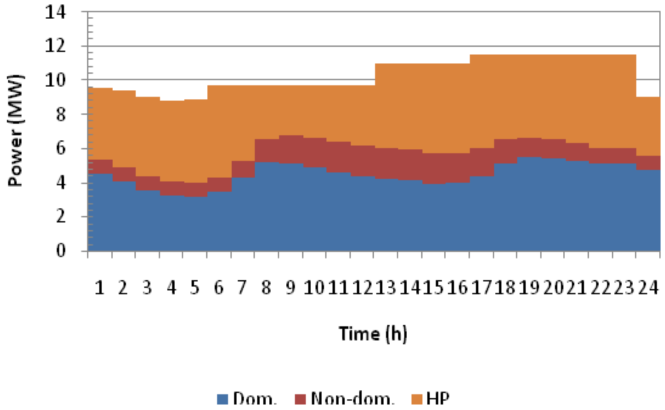



**Figure 35. Optimised profile of Figure 34 data**

# 3. EVALUATION OF THE BENEFITS OF FLEXIBLE DEMAND FOR DISTRIBUTION NETWORK INFRASTRUCTURE

## New Zealand distribution network modelling and Smart and Uncontrolled network operation strategies

3.1. This section discusses the impact of uncontrolled and smart distribution network controls on distribution network costs for future demand growth scenarios that involve electrifying the heat and transport sectors.

3.2. We have used Imperial College's distribution network design tools to create representative low-voltage (LV) and high-voltage (HV) distribution networks for New Zealand. Such networks capture the statistics of typical network topologies that range from high-load density city/town networks to low-density rural networks. The design parameters of the representative networks should closely match those of real distribution networks of similar topologies (especially consumer and load density, ratings of feeders and transformers used, and associated network lengths and costs).

3.3. Figure 36 shows the LV representative networks we developed for New Zealand. We created four representative networks: urban, semi-urban, semi-rural, and rural. Table 11 shows the different parameters for the representative networks (and note how the consumer density varies between 9 consumers per square km in rural areas to 2200 consumers per square km in urban systems).

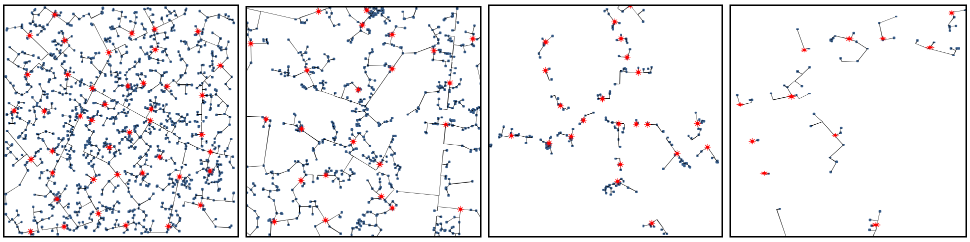


**Figure 36. Four LV-representative networks: urban, semi-urban, semi-rural, and rural (the blue dots are LV consumers and the red dots are distribution transformers)**

**Table 11. Representative networks parameters**

| Parameter | Urban | Semi-urban | Semi-rural | Rural |
|---|---|---|---|---|
| Consumer density (per km$^2$) | 2200 | 651 | 111 | 9 |
| LV substation density (per km$^2$) | 32 | 22 | 11 | 2 |
| LV length density (km per km$^2$) | 20.53 | 12.8 | 2.8 | 0.6 |

3.4. The representative networks were calibrated using consumer density and network data from Orion's supply areas. The composition chosen in the North and South Islands (Table 12) matches closely the actual number of connected consumers and LV overhead and underground lengths in the different regions.

**Table 12. Number of representative networks in each region**

| Region | Urban | Semi-urban | Semi-rural | Rural |
|---|---|---|---|---|
| North Island | 58.6 | 216 | 164 | 146 |
| South Island | 19.5 | 108 | 13.9 | 50.2 |
| New Zealand | 78.1 | 324 | 177.9 | 196.2 |

3.5. We developed four representative networks so that we could evaluate the impact from uptake of EVs and heat pumps on distribution network reinforcement. From this we were able to quantify the costs for the North Island, the South Island, and nationwide. Figure 37 shows this approach. We did network design studies for different levels of demand technologies. Peak load conditions are relevant for network design. As electricity systems meet a high proportion of the heat demand, we made sure our design was effective by examining low-temperature conditions.

3.6. We did distribution network planning studies for passive (or uncontrolled) and active, flexible demand (or smart grid) scenarios. With the smart grid scenario, we optimised flexible demand by controlling water heaters (WHs), smart appliances (SAs), EVs, and heat pumps to minimise how much of the network needed reinforcing. We also used in-line voltage regulators to avoid reinforcing the network when voltage overloads did not happen at the same time as network thermal overloads.

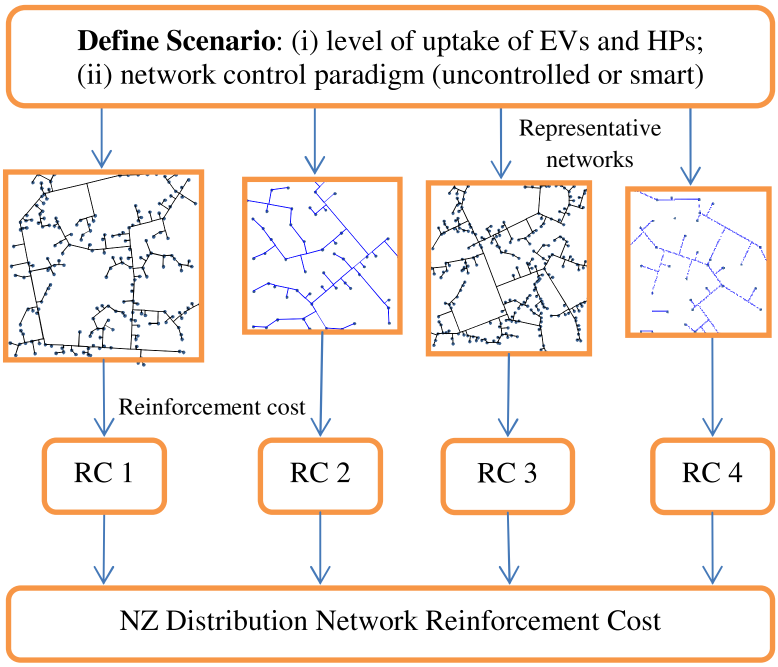



**Figure 37. Representative networks approach to estimate EV and HP driven NZ wide distribution reinforcement cost and the effectiveness of mitigation measures based on flexible demand**

3.7. The benefits of smart control are quantified in terms of the reduced costs of reinforcing the network to allow for future demand growth. The benefits of controlling WHs, SAs, EVs and heat pumps individually are quantified to assess the flexibility in value that they provide to those reduced costs.

3.8. The reduced cost need to reinforce the distribution network is achieved by using flexible demand to reduce peak load. Figure 38 shows the aggregate profile of a semi-urban network that uses EVs and heat pumps. We can see that the base load peak demand is 5.5MW for a combined domestic and non-domestic load, before EVs and heat pumps are added to the load. We can also see a significant increase in energy and network peak load when EVs are charging and heat pump heating load are added (the level of heating load matches a cold winter day). This increase reaches 14MW, if uncontrolled.

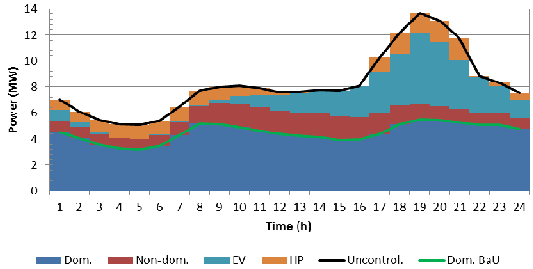



**Figure 38. Load profile in a section of semi-urban network with EV and HP with passive network control paradigm ('uncontrolled')**

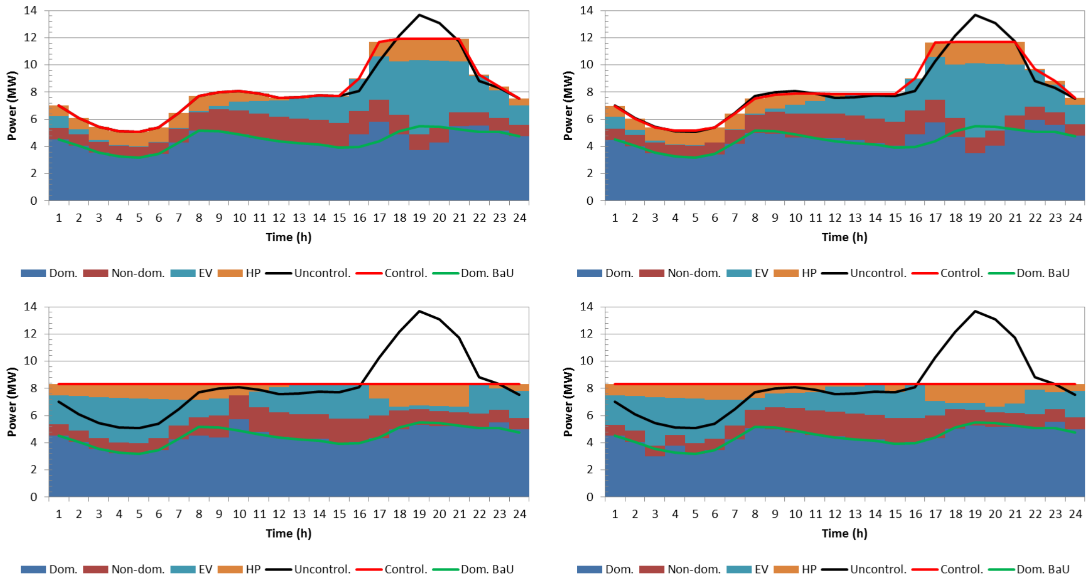



**Figure 39. Semi-urban network with WH control (top left),;WH, SA control (top right); WH, SA, EV control (bottom left); and WH, SA, EV, HP (bottom right); HP load is heated living areas in the North Island**

3.9. The chart on the top left in Figure 39 shows smart control of water heaters. The black line marks the load shape for the uncontrolled case, while the red line matches the load profile when water heaters are optimally controlled. As a result, peak demand reduces to 12MW. The green line marks the base-load domestic profile in the uncontrolled case, which means we can see the changes in the domestic load due to control of water heaters.

3.10. The chart on the bottom left in Figure 39 shows a demand profile with smart control of WHs, SAs and EVs. We see that the demand profile becomes flat at the level of 8MW and that there are no further benefits from controlling heat pumps (the chart on the bottom right). Also, we can see that the reduction of peak demand under smart control could be significant and, in turn, significantly reduce the need to reinforce the distribution network (and the cost of doing so). Although the flat demand profile is achieved, the demand level is above the base load peak and some network reinforcing is inevitable.

3.11. We did similar analyses on the other three representative networks relevant for New Zealand distribution networks. We examined the different levels of usage for heat pumps and EVs and used the data to establish the value of flexible demand for distribution networks.

3.12. We note that the benefits of flexibility of particular demand technologies (such as water heaters and EVs) are not an absolute characteristic. Figure 39 shows (and we conclude) that optimal control of water heaters would result in a clear reduction in peak load. However, if we first optimise EV charging, we get a practically flat diagram as shown in Figure 40 (left), and there is no further benefit from controlling water heaters (right). This also emphasises that EV charging is the most flexible of all the technologies we examined.

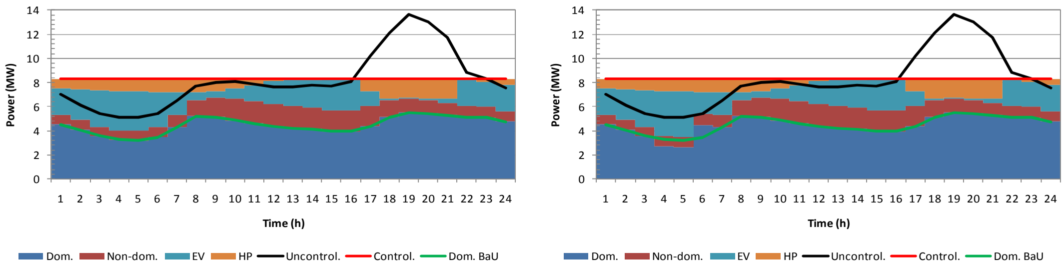



**Figure 40. Semi-urban network with high EV and HP penetration for smart EV charging (left) and smart EV charging and WH control (right); HP load is heated living areas in the North Island**

## Scenarios Analysis

3.13. As discussed in Section 2, the projected uptake of heat pumps is based on extrapolating BRANZ data, while we considered high and low outcomes for the uptake of EVs by 2050, with electrification of transport being 100 percent (high) and 40 percent (low). Figure 3 shows the projected uptake of both.

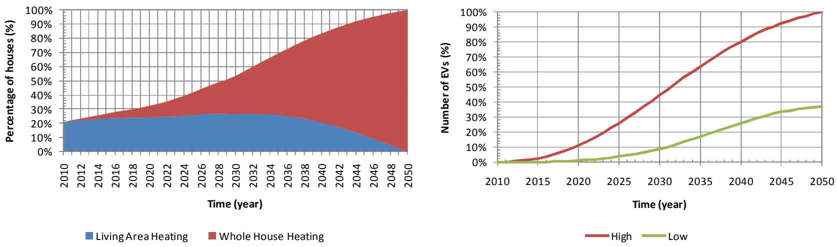



**Figure 41. Uptake profile of HPs (left) and EVs (right)**

3.14. Figure 42 shows the range of cumulative costs of reinforcing the New Zealand distribution network under the considered scenarios of uptake of heat and transport sector demand in the electricity system for the uncontrolled (left) and smart (right) network operations. The chart shows that controlling flexible demand (smart) would have a significant benefit in terms of avoided distribution network reinforcement. We also see that the reinforcement the network needs for Smart control is less sensitive to EV penetration than in an uncontrolled future.

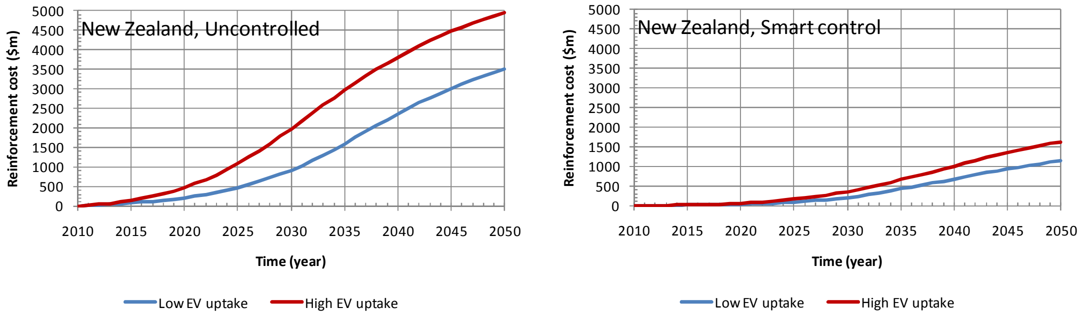



**Figure 42. NZ distribution networks reinforcement cost for business as usual (left) and smart (right)**

3.15. Table 13 shows the cumulative costs of reinforcing networks reinforcement for 2010—2050, in 10-year increments (the minimum and maximum figures correspond to the two levels of EV uptake). It can be seen that controlling flexible demand (Smart) would bring a very significant benefit. We can see that the cost of reinforcing the network under Smart is six times lower than for Uncontrolled in 2020 and three time lowers in 2050. The absolute value of savings could reach between $0.7 billion and $1.6 billion in 2030 and between 2.3 billion and $3.3 billion in 2050.

**Table 13. Range of NZ distribution networks reinforcement costs ($m)**

| Controls | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|
| Uncontrolled | 210–476 | 914–1,972 | 2,355–3,810 | 3,498–4,951 |
| Smart | 36–57 | 203–359 | 680–1,010 | 1,146–626 |

**Figure 43 and**

3.16. Table 14 show the costs of reinforcing the network for uncontrolled (left) and smart (right) in the North Island and the South Island. The trends may seem similar, but the network costs and savings are more significant in the North Island.

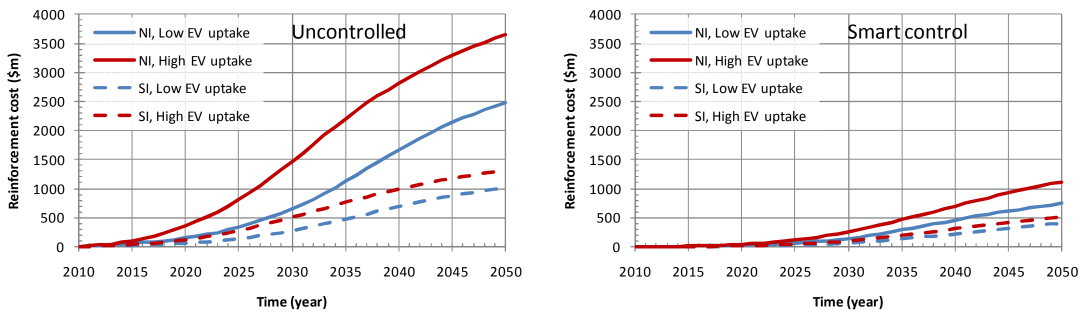
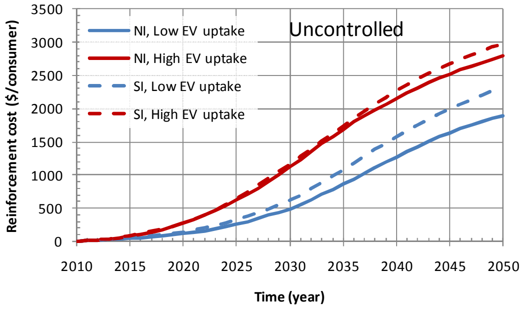



**Figure 43. Future costs of reinforcing distribution networks in the North Island and South Island (for uncontrolled (left) and smart control (right) future)**

**Table 14. Range of North Island and South Island distribution networks reinforcement costs ($m)**

| Island | Control | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|
| North Island | Uncontrolled | 147–356 | 644–1,462 | 1,664–2,814 | 2,480–3,646 |
| | Smart | 25–42 | 140–259 | 458–700 | 745–1,113 |
| South Island | Uncontrolled | 62–121 | 270–510 | 691–996 | 1,018–1,305 |
| | Smart | 11–15 | 63–100 | 223–310 | 400–513 |

3.17. Figure 44 shows the relative costs of reinforcing uncontrolled (left) and Smart (right) networks, focusing on individual network users in the North Island and the South Island. We can see that the network costs for each user are systematically higher in the South Island. This result is due to lower temperatures in the South Island and so higher heat demand in winter. This increases the cost of reinforcing networks.



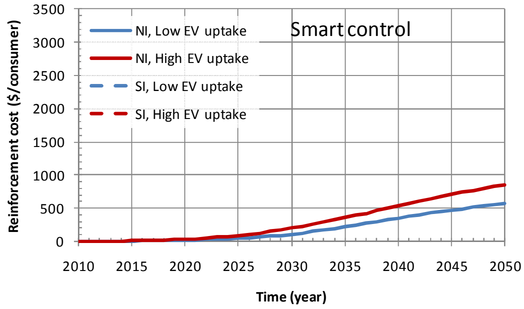




**Figure 44. Future costs of reinforcing North Island and South Island distribution networks (for each user of uncontrolled (left) and smart control (right))**

3.18. The above analysis is based on the uptake levels of EVs and heat pumps being consistent nationwide. However, the uptake of EVs and heat pumps is not likely to be geographically even. This means there is likely to be a significant impact of distribution network reinforcement costs. For example, we considered EV and heat pump penetration of 17 percent nationally (to be reached in 2025 under the high EV uptake scenario) and then considered a uniform and non-uniform distribution of these technologies. Figure 45 (left) shows these considerations. With non-uniform distribution, in some areas penetration may be above 17 percent; in other areas it may be low. The impact on network reinforcement costs caused by the uptake of EVs and heat pumps nationwide may be significant. The cost of reinforcing a network that has uniform distribution amounts to $935 million, while the cost of reinforcing a network with non-uniform distribution amounts to $1,589 million. The difference represents a 70 percent increase in investment cost. Given that we expect the uptake of EVs and heat pumps to be uneven, the local distribution network will feel considerable impacts long before we see any such impact nationally.

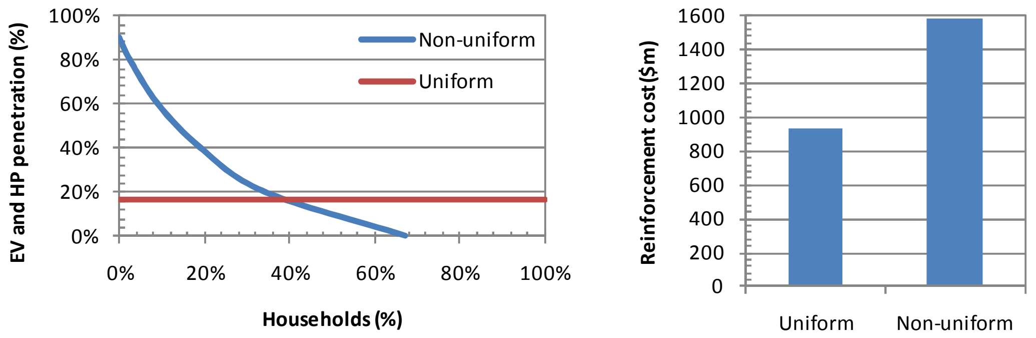



**Figure 45. The impact of uneven penetration of EVs and HPs on the costs of reinforcing the distribution network**

3.19. Figure 46 and Figure 47 show aggregate profiles for semi-urban networks in the South Island for high EV and heat pump penetration under various control strategies. In this case, heat pumps are used to heat the whole house (rather than just the living room, as in Figure 38 and Figure 39). In Figure 46 we can see that this growth in load increases peak demand from 5.5MW to 19MW in a passive, uncontrolled network.

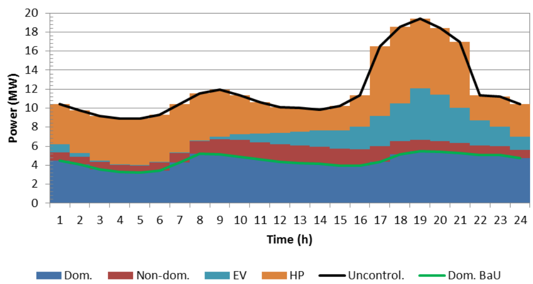



**Figure 46. Semi-urban network with high EV and HP penetration for uncontrolled; HP load is for whole-of-house heating in the South Island**

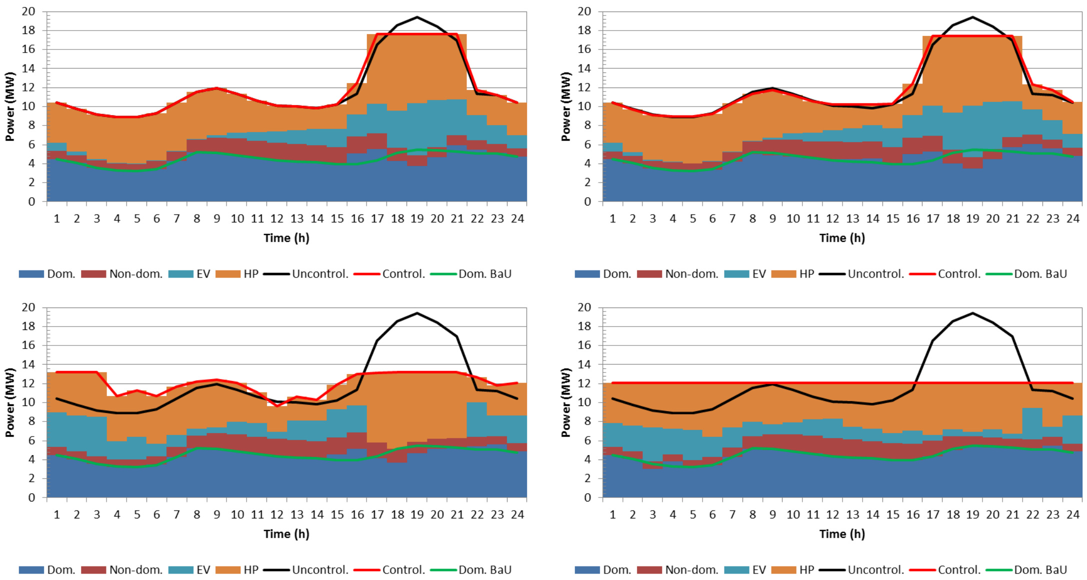



**Figure 47. Semi-urban network with high EV and HP penetration for WH control (top left); WH, SA control (top right); WH, SA, EV control (bottom left); and WH, SA, EV, HP (bottom right); HP load is for whole-of-house heating in the South Island**

3.20. The top left chart in Figure 47 shows how using water heater control reduces peak load in an uncontrolled scenario (from 19MW to 17MW). The bottom left chart shows the effect of controlling water heaters, SAs, and EVs. We see how demand reduces to 13MW in this scenario. Further control of heat pumps (the bottom right chart) would result in a marginal reduction of peak demand to about 12MW, which flattens the demand profile.

3.21. From this analysis, we can see that reducing peak demand is one benefit from controlling water heaters. However, introducing smart charging of EVs (supported by smart control of water heaters and other domestic appliances) has a significant impact on peak demand. This is because transport load is the most flexible. The EVs are stationary on average more than 90 percent of the time, and there is significant scope for smart charging. The scope to reduce peak demand further is limited, and controlling heat pumps brings only marginal benefits.

3.22. Figure 48 offers further insight into the impact from electrifying the heat and transport sectors on distribution networks of different characteristics. It shows the breakdown of reinforcement costs for urban (left) and rural (right) networks under the uncontrolled, high demand scenario.

3.23. The main factors driving reinforcement costs in an urban network (diagram on the left) are the violated thermal limits of LV circuits (LV-I), overloads of the secondary distribution substations (HV/LV), and primary substation including the extra-high voltage network (EHV/HV+). The cost of reinforcing the HV network is relatively small, while the cost of reinforcing the LV network (due to going beyond voltage limits) is negligible.

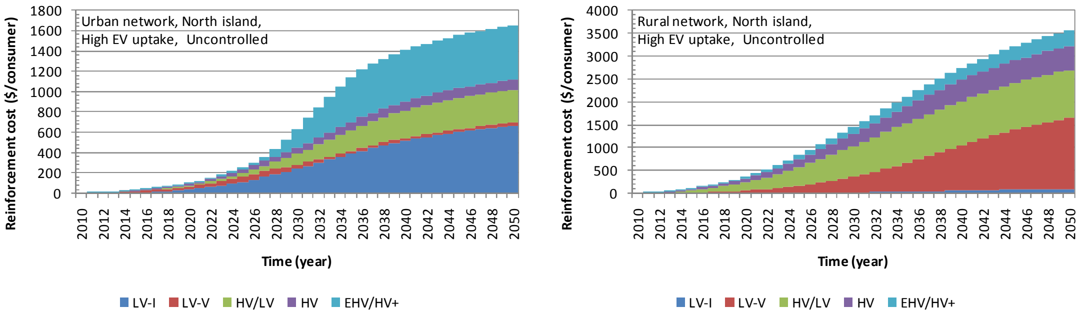



**Figure 48. Breakdown of cost to reinforce an urban network for the North Island (left) or South Island (right) for uncontrolled high demand scenario**

3.24. By contrast, as shown in Figure 48 (right diagram), the main factors driving reinforcement in a rural network are violated voltage limits in the LV system (LV-V) and the thermal limits of the secondary substations (HV/LV). The costs of reinforcing HV circuits are modest, with the costs of reinforcing primary substations and their supply network (EHV/HV+), and LV circuits due to thermal overloads (LV-I), being less significant. Given the significant amount of network reinforcement in rural systems being driven by the violations of voltage constraints, smart voltage control through in-line voltage regulators may be a suitable substitute to reinforcement.

3.25. The increase in losses in a low-voltage distribution network is estimated at between 10-20 percent for a smart operation. Although the increase in network losses does not impact the proposed change in the network control philosophy, it may be worth studying the consequences on distribution investment decisions (to balance the cost of losses versus the cost of capital associated with distribution networks).

# 4. FUTURE OPERATION AND INVESTMENT IN GENERATION AND TRANSMISSION INFRASTRUCTURE IN NEW ZEALAND: EVALUATION OF THE BENEFITS OF SMART PLUG-IN VEHICLE CHARGING AND HEAT PUMP LOAD CONTROL

## Scope and objectives

4.1. This section assesses the benefits that smart charging of EVs and using heat pump load control could make in the future towards reducing the need to invest in generation and transmission capacity.

4.2. For each level of penetration for 2030 and 2050, we examined the investment in generation and transmission assets for varying levels of demand side participation. In particular, we looked at two boundary operating scenarios: passive (uncontrolled) where there is no control on flexible demand; and active (smart) where there is both smart charging of EVs and heat pump load control.

4.3. We developed an integrated generation and transmission operation and investment model. This model quantifies the cumulative generation and network reinforcement needed to provide new generation and demand growth. It does so while creating an economic system that continues to offer constant supply. The Appendix has a detailed description of the model.

**Table 15. Baseline capacity of NZ main transmission boundaries**

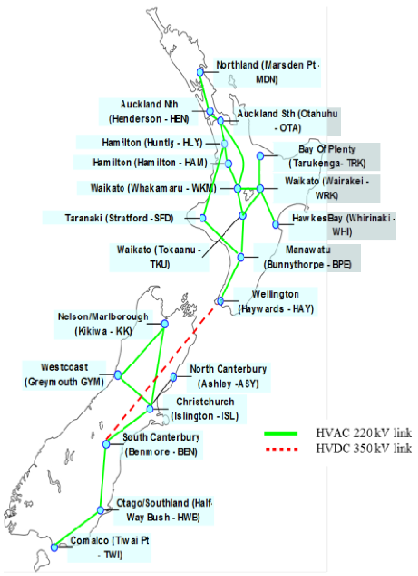



**Figure 49. NZ transmission network model**

| Interconnector | Transfer capacity (MW) Region I–Region J | Transfer capacity (MW) Region J–Region I |
|---|---|---|
| Manapouri to Tiwai Pt | 1384 | 1384 |
| Southland/Otago to Benmore | 1403 | 1403 |
| Benmore to Christchurch | 1330 | 1330 |
| Christchurch to West Coast | 57 | 57 |
| Christchurch to North Canterbury | 142 | 142 |
| Christchurch to Nelson/Marlborough | 592 | 592 |
| West Coast to Nelson/Marlborough | 138 | 138 |
| Benmore to Wellington | 1200 | 875 |
| Wellington to Manawatu | 2097 | 1047 |
| Manawatu to Taranaki | 790 | 790 |
| Manawatu to Tokaanu | 908 | 832 |
| Tokaanu to Whakamaru | 536 | 536 |
| Tokaanu to Wairakei | 381 | 381 |
| Intra Waikato (Wairakei to Whakamaru) | 1221 | 1221 |
| Taranaki to Hamilton (Huntly) | 550 | 550 |
| Waikato to Hawkes Bay | 989 | 989 |
| Waikato to Bay of Plenty | 471 | 471 |
| Waikato (Whakamaru) to Hamilton | 449 | 449 |
| Intra Hamilton (Hamilton to Huntly) | 449 | 449 |
| Waikato to South Auckland | 2410 | 2410 |
| Hamilton (Huntly) to South Auckland | 1451 | 1451 |
| South Auckland to North Auckland | 2745 | 2745 |
| North Auckland to Northland | 809 | 809 |

4.4. Figure 49 shows the 20 regions and 23 inter-regional connections of the simplified New Zealand transmission network model. Table 15 summarises the projected baseline installed capacity of the main transmission boundaries we used in this study. We decided on these boundaries after assessing the current installed capacity and the planned or ongoing transmission reinforcement projects due for completion by 2030.

4.5. Figure 50 shows the projected generation capacities needed for the system to operate securely at a regional level by 2030, given baseline demand growth. The total installed generation is 14.7GW, of which 3.4GW comes from wind power.

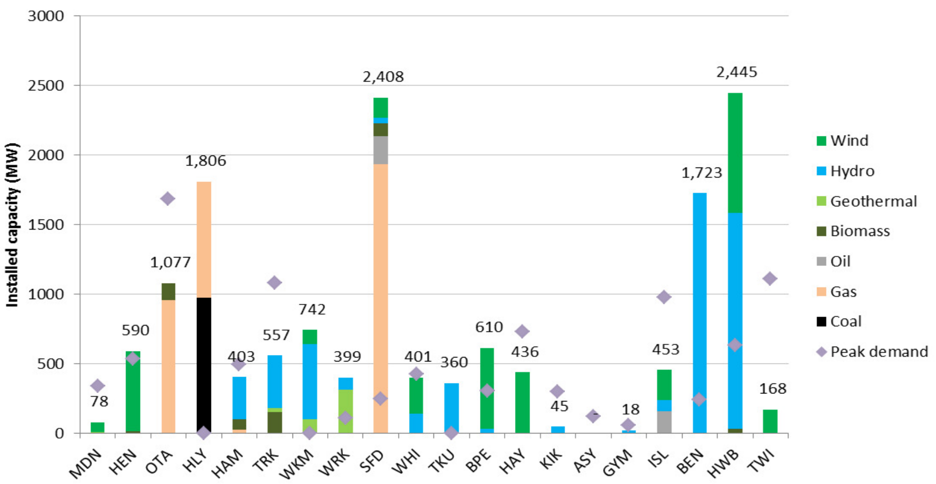



**Figure 50. Installed capacity of various generation technologies across New Zealand, where 3.4GW of capacity comes from wind power**

4.6. To support the level of wind generation capacity with the additional heat pump and EV load, while ensuring system reliability, we worked from the premise that additional thermal generation would be required. We assume in our model that the facilities to provide this extra generation capacity would be built in the Upper North Island in regions with a developed gas infrastructure, such as Auckland, Huntly, Hamilton, and Stratford. Quantifying the extent to which this investment in thermal generation can be deferred is one of the key sources of value of a smart grid. This scenario has been developed to help test the bounds of the value of a smart grid; it is not a forecast of New Zealand's future generation investment mix.

4.7. We are not ruling out other possible future generation scenarios, such as a future with a greater uptake of distributed generation. We believe that such a scenario is accommodated within the modelled scenarios. A smart grid could help to support greater uptake of distributed generation, although we have reservations about the overall contribution that distributed generation can make in the New Zealand energy system based on the significantly higher levelised costs of this technology.

4.8. There are a range of other future generation scenarios possible, including a large gas-find, possibly in the South Island, which could see a higher proportion of gas fired plant and/or gas fired plant located in the South Island being built in the future. We consider that such an outcome is unlikely, particularly in the short to medium term. Another possible future is one with higher relative shares of other forms of renewable generation, including hydro and geothermal. In such a future the value of the smart grid may be reduced, compared to the benefits found in this study, due to these technologies having relatively higher capacity factors. Notwithstanding this, there is a tranche of competitive geothermal projects being built in New Zealand and when this is exhausted wind is expected to be the most competitive generation technology option in the future. We also expect some hydro to proceed but the options for development are limited, tend to have long lead time and take some years to come to market. Therefore, we believe our framework for testing the bounds of the value of a smart grid is robust given the economics and available resource depth of New Zealand's future generation outlook.

## Benefits of smart EV and HP control in reducing the need for generation capacity investment

4.9. Figure 51 shows the extra generation capacity needed in the New Zealand system to handle the increase in electricity demand after adding EV and heat pump demand, and given the uncontrolled and flexible demand (smart) scenarios in 2030 and 2050. We quantified the contribution that EV smart charging can bring and also the benefits of controlling EV and heat pump loads.

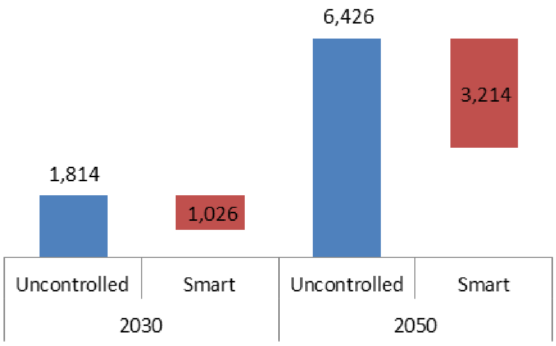



**Figure 51. Extra generating capacity needed to accommodate electrification of transport and heat sectors in uncontrolled and smart futures (MW)**

4.10. This analysis shows that controlling flexible load of EVs and heat pumps can reduce generation capacity by 1GW by 2030 and 3.2GW by 2050.

4.11. If we consider the reduced generation capacity of a gas-fired plant with a capital cost of $1.4m/MW, Figure 52 shows savings of $1.4 billion by 2030 and $4.5 billion by 2050.

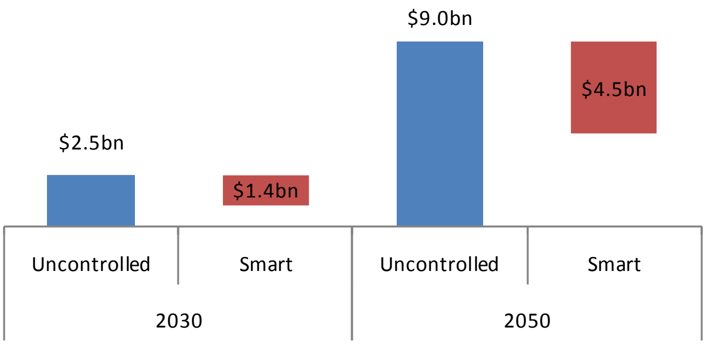



**Figure 52. Extra generating investment needed to accommodate electrification of transport and heat sectors in uncontrolled and smart futures**

4.12. Figure 53 shows how flexible demand affects daily demand (on a cold, winter day). We see how the need for peak generation capacity lessens as peak demand reduces. As EV charging is flexible, this load is shifted into the off-peak period.

As the houses lack thermal storage and have a relatively low thermal inertia, heat pump demand is much less flexible. But if a pre-heating control strategy is successfully applied, the peak continues to reduce.

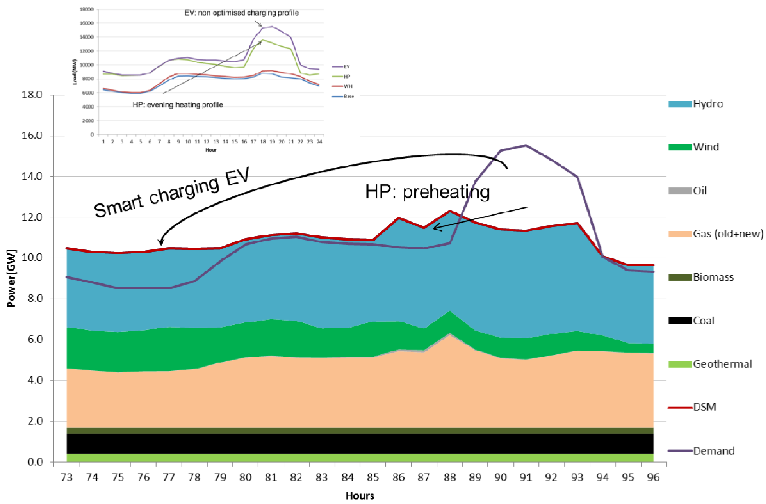



**Figure 53. Shifting electricity demand and reducing system peak electricity demand**

4.13. Figure 54 shows the changes in frequency distribution of various demand levels. We can see how controlling flexible demand helps to reduce peak demand. We also see that the minimum level of demand (between 4GW and 8GW) during summer is not affected by flexible demand. This is because the need for demand to be flexible is focused on winter peak load conditions when margins are tight.

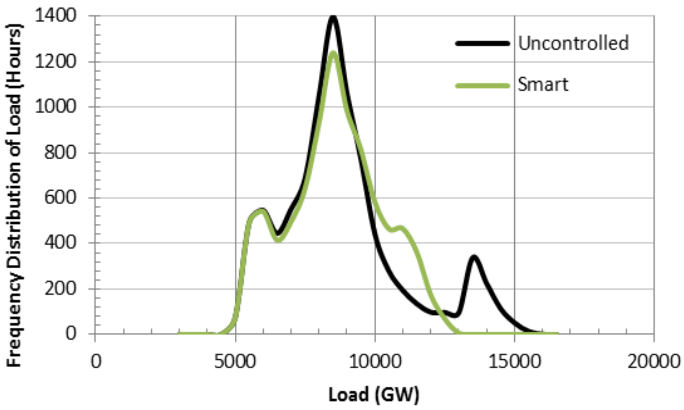



**Figure 54. Frequency distribution of electricity load with and without smart demand**

4.14. Figure 55 shows the correlation between flexible demand and wind generation output across a year. The horizontal axis represents daily demand, starting on 1 July and ending on 30 June. As expected, we see that flexible demand is used when the generation system is under stress. This stress occurs when high demand (in winter) coincides with low wind power outputs. By contrast, during summer (shown in the middle of the diagram) the smart demand activity is very modest.

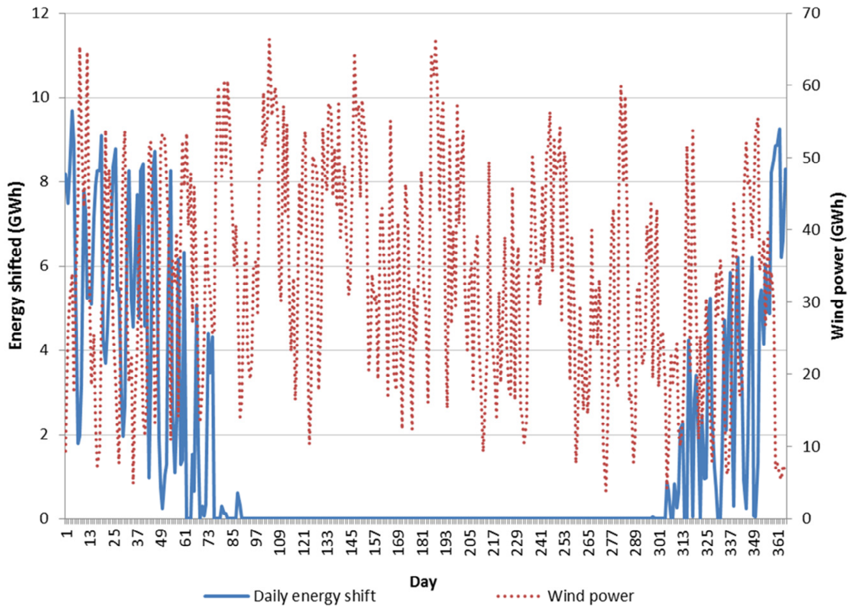



**Figure 55. Daily shift of electricity consumption caused by smart demand across a year (2050)**

4.15. Figure 56 shows smart demand use in two winter weeks that experience low and high wind conditions. As expected, we see an inverse correlation between wind output and how much flexible demand is used: low use corresponds to high wind conditions while high use corresponds to low wind conditions. Here flexible demand is similar to hydro generation in that it shows how wind capacity can improve.

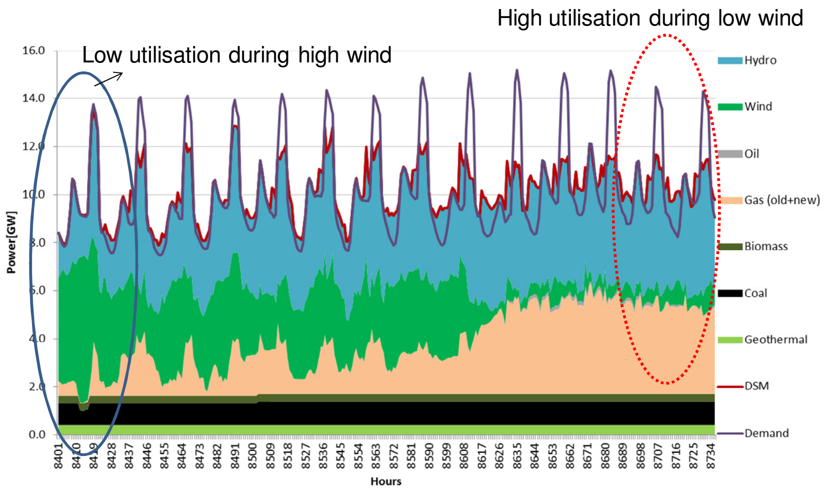



**Figure 56. The usage of smart demand in 14 winter days under low wind and high wind conditions**

4.16. Figure 57 is a duration curve showing flexible demand use. We see that, at maximum, only 5 percent (or 8.7GWh) of daily energy consumption is shifted to lessen generation and transmission capacities. This maximum available flexibility is used for only a few critical days when very low wind output coincides with high demand peaks on very cold winter days. There were less intensive energy shifts for a larger number of days, but, overall, smart demand was used for less than 100 days. The use of flexible demand with heat pump loads could potentially lead to mild reductions in the comfort levels of electricity users. Figure 57 shows that these instances will be infrequent and will have a modest impact. Further studies would be useful to understand users' opinions on the flexibility of smart demand.

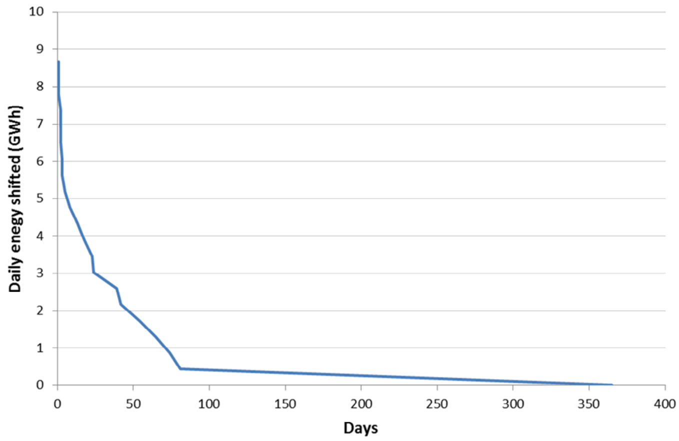



**Figure 57. Duration curves at various levels of shift in required daily energy**

## Applications of flexible demand to defer transmission reinforcement

4.17. Flexible demand could potentially reduce the level of transmission infrastructure reinforcement needed to cover future demand growth from the electrification of the transport and heat sectors. Figure 58 shows the savings that use of smart demand can make to transmission capacity investment by 2030 and 2050 expressed in GW.km.

4.18. The required level of transmission capacity build is not materially impacted by the electrification of the heat and transport sectors by 2030, with an extra 103 GW.km required. Use of flexible demand could substantially reduce this level of extra transmission reinforcement needed to cover load growth expected by 2030. Significant extra transmission reinforcement would not be required until 2050, with 1,312 GW.km of transmission capacity required. Smart EV charging could reduce up to 720 GW.km of transmission capacity investment. When you add this to savings from heat pump load control, we see a total reduction in transmission capacity investment needed of 956 GW.km.

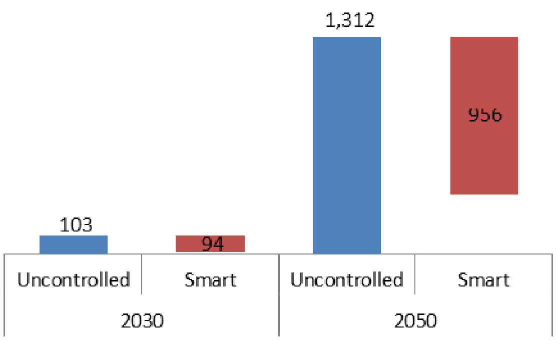



**Figure 58. How smart demand helps to achieve savings in transmission capacity (GW.km)**

4.19. The average capital cost for reinforcing transmission is $3000 for every MW/km. As Figure 59 shows, the savings from reducing transmission capacity would be $0.28 billion in 2030 and $2.6 billion in 2050.

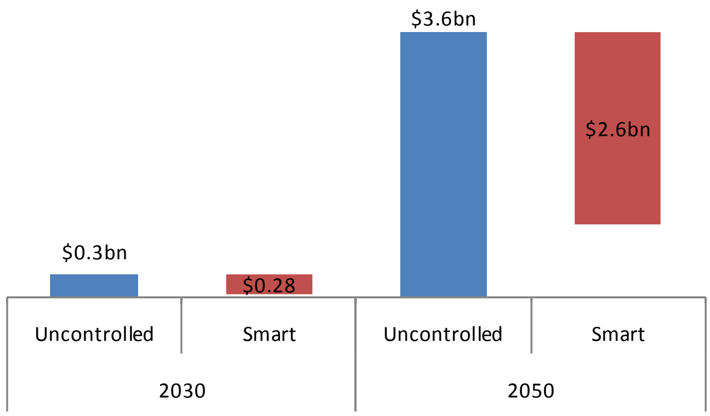
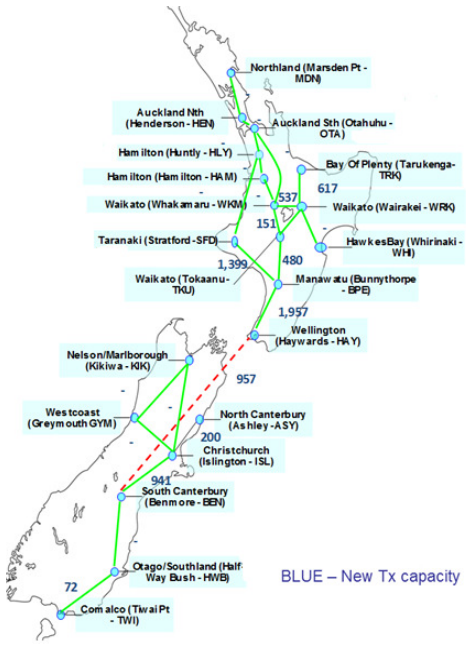



**Figure 59. How smart demand helps to achieve savings in transmission investment**

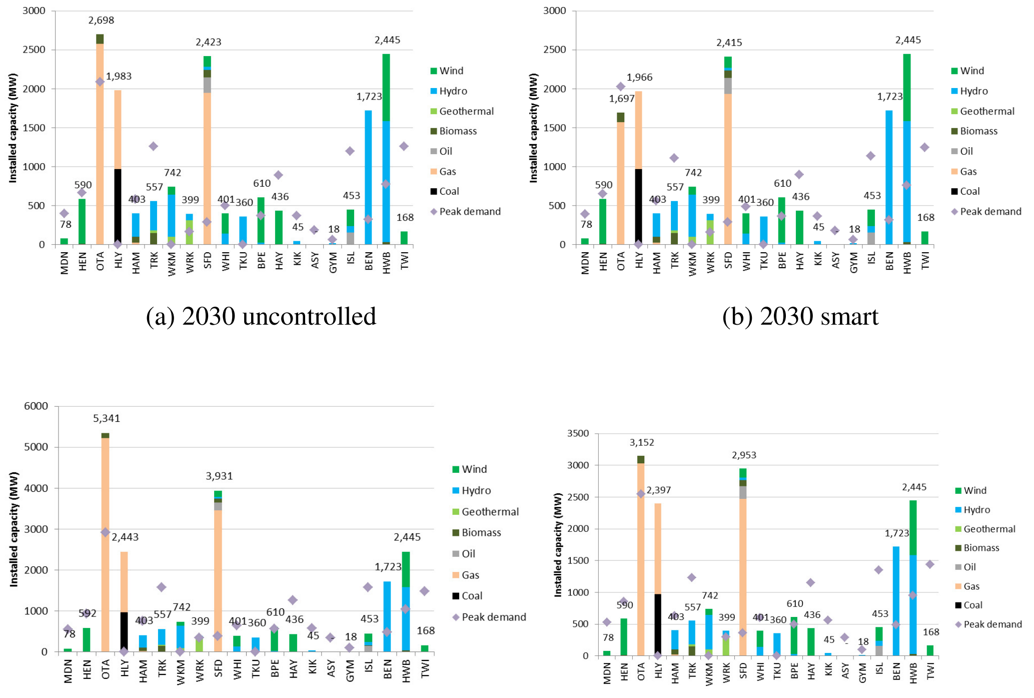
4.20. The table in Figure 60 shows key corridors in the New Zealand transmission system that would need reinforcing to match the projected demand growth.




| | 2030 | | 2050 | |
|---|---|---|---|---|
| | Business as usual | Smart | Business as usual | Smart |
| Manapouri to Tiwai Pt | - | - | 72 | - |
| Benmore to Christchurch | 208 | 48 | 941 | 491 |
| Christchurch to North Canterbury | 61 | 42 | 200 | 138 |
| Benmore to Wellington | - | - | 957 | 93 |
| Wellington to Manawatu | 296 | - | 1,957 | 754 |
| Manawatu to Taranaki | - | - | 1,399 | 488 |
| Manawatu to Tokaanu | 58 | - | 480 | 62 |
| Tokaanu to Whakamaru | - | - | 151 | - |
| Intra Waikato (Wairakei to Whakamaru) | - | - | 537 | - |
| Waikato to Bay of Plenty | 301 | 152 | 617 | 271 |

**Figure 60. Reinforcement of NZ transmission system (MW)**

4.21. As expected, where the generation facilities are located would impact greatly on transmission needs. Our assumption was that the new conventional generation could be built in the North Island, in the regions of Taranaki, Hamilton, and Auckland, as shown in Figure 61. We observe that flexible demand can offset the generation capacity needs, as shown Figure 61. Given that at present dominant power flows are from North to South, and that increase in demand is met but new thermal generation in the North, the need for transmission network reinforcement in 2030 is modest (as indicated in Figure 60).




(a) 2030 uncontrolled

(b) 2030 smart

(c) 2050 uncontrolled

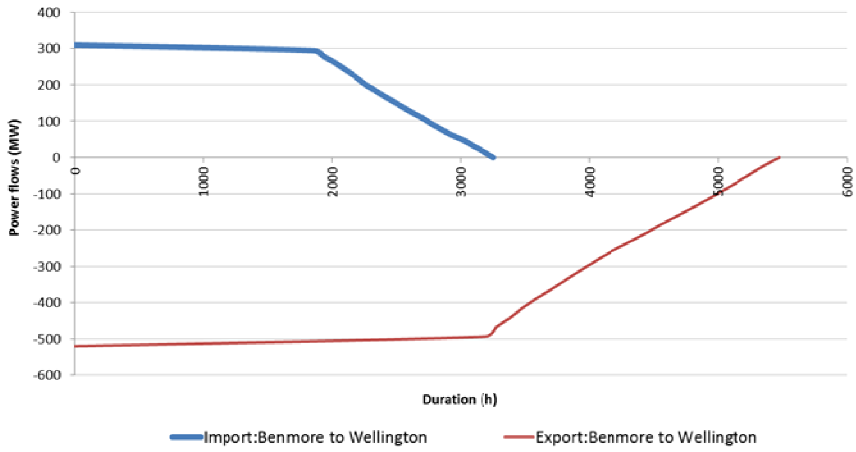
(d) 2050 smart

**Figure 61. Distribution of generation and peak demand in NZ under various scenarios**

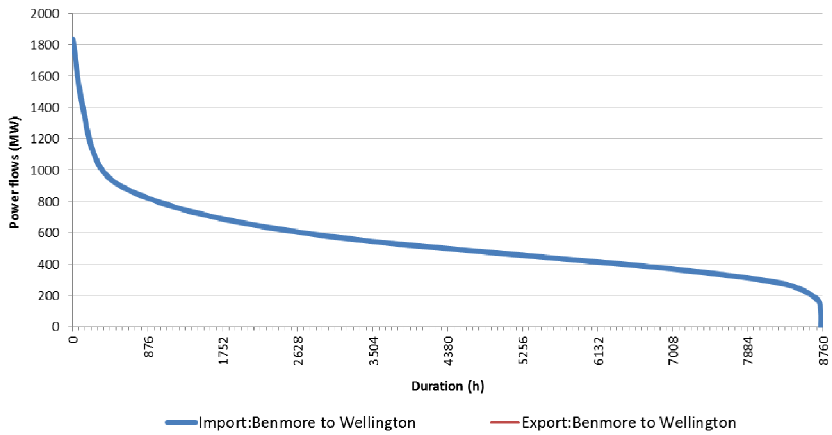
4.22. Transmission capacity for the Auckland area would not need reinforcing further, as the region's extra generation capacity would be more than adequate to supply its local demand growth and the neighbouring regions to the north. Significant increases in local generation in the North Island would reduce stress on the transmission capacity for the Auckland area. We also observe that the flexible demand can reduce the network investment significantly in the 2050 scenario.

4.23. The reinforcing of the North to South HVDC inter-connector would help to drive north to south power flow. We also saw the need for only modest reinforcing between the Otago region and the New Zealand Aluminium Smelters (NZAS) at Bluff, as the interconnector between NZAS and the Otago region is relatively strong already.

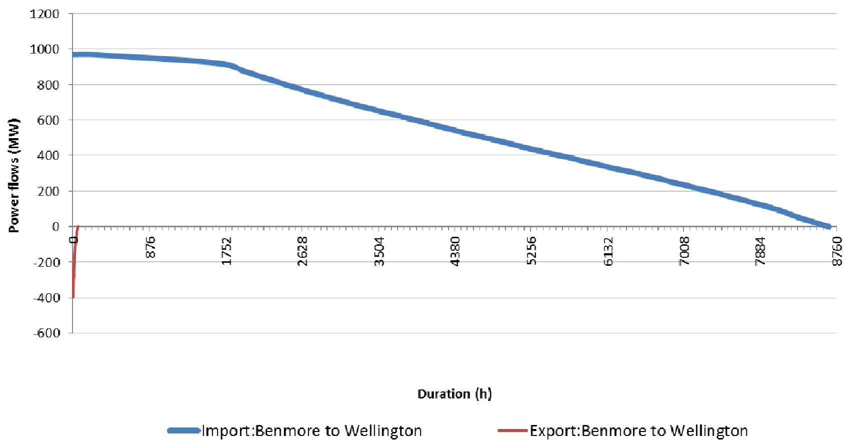
4.24. The flows through the DC link are in general bi-directional (energy is exchanged between the regions). The upper left diagram in Figure 62 shows this flow. The other three diagrams show future north–south flow as dominant. The location of generation needed to support demand growth drives this trend. We also see that the use of flexible demand could reduce the amount of HVDC link capacity required and increase its use.




2010 Business-as-Usual




2050 uncontrolled high demand scenario




2050 smart high demand scenario

**Figure 62. Flow duration curve of the North-South HVDC link**

## Benefits of smart demand response on managing intermittency

4.25. A key aspect of system security is its ability to closely balance demand and supply over different time horizons. A range of factors drive the need for operating reserves. They include the unplanned outage of a generating plant or important parts of transmission networks, errors in forecasting wind power output, unpredicted changes in user demand due to changes in weather conditions and other events, and imperfections in the dispatch process that lead to an imbalance between supply and demand. Traditionally, flexible generation plant provides operating reserves that constantly balance supply and demand.

4.26. There is uncertainty in achieving sustained output from wind power. This uncertainty increases with an increase in the number of wind power facilities. This means the penetration of wind power could have a significant impact when deciding on the level of reserves New Zealand needs. Extra part-loaded thermal generators, hydro plant and flexible loads will provide extra reserves, but some generating units operate less efficiently when part-loaded. This will lead to higher generation costs and thus higher system operating costs.

4.27. The system operator has two possible key categories of reserve: frequency response services and reserve services. Each has a different response time.

- *Frequency response services (from seconds to about half hour)*

  These are combined from Instantaneous Reserves and Frequency Keeping Reserves.

  Instantaneous Reserves manage the risk of the loss of infeed from the largest single plant. Fast instantaneous reserve (FIR) is available within 6 seconds and sustained for 1 minute, while sustained instantaneous reserve (SIR) is available within 60 seconds and sustained for 15 minutes. FIR aims to stop the decline in system frequency after a contingent event. SIR aims to then restore the frequency to within the normal band of 50 (+/- 0.2)Hz. Currently the largest generator outage experienced in the North Island is around 380MW (one combined cycle gas turbine (CCGT) unit). The outage is offset by a combination of generation from Huntly, hydro generation (mainly from the Waikato chain) and demand-side interruptible load. In the South Island the risk is typically between 60MW and 120MW (or one unit from Manapouri), which is offset by hydro generation.

  Frequency Keeping Reserve uses nominated frequency-keeping stations based in the North Island and the South Island in quantities of +/- 50MW (or a 100MW range). The Huntly coal station or Waikato hydro stations provide this service for the North Island, while hydro stations provide it for the South Island.

- *Reserve services (several hours)*

  Synchronised and Standing Reserves restore instantaneous and frequency-keeping reserve capabilities in case these are exercised. The time scale for this reserve is determined by the time needed to synchronise a generator that would replace a plant outage—typically 2 to 4 hours for a CCGT plant. A mix of synchronised and standing plant is used to provide such reserves. The allocation of reserves between synchronised and standing plant is a trade-off between the cost of efficiency losses of part-loaded synchronised plant (plant with relatively low marginal cost) and the cost of running standing plant with relatively high marginal cost. We optimised the balance between both reserves to get the minimum overall reserve cost of managing the system.

4.28. Usually, we get frequency response services from conventional generators (hydro and thermal plant) running part loaded and from the interruptible loads of large industrial users. Increasing wind power in New Zealand will see the need for these services to increase. This, in turn, will increase operating costs. The use of flexible demand can provide frequency regulation services and reduce operating costs. This means that we may need less conventional generation to provide such services. Figure 63 shows that the value of those services potentially accessible by to flexible demand.

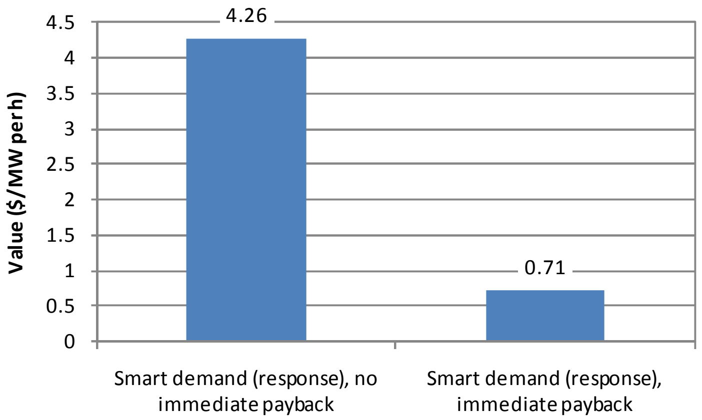



**Figure 63. Value of instantaneous reserve (response) services with and without immediate payback**

4.29. Yet we must stress that load reduction periods, when reserve services from flexible demand are used, may lead to load recovery periods, meaning an increase in load. This is because flexible demand differs from generation. Flexible demand can redistribute demand in time, rather than stopping energy to cope with demand. So load recovery periods that follow load reduction periods will be characterised by increases in demand that generators will need to meet later. This means that some generation will need to be kept in reserve to supply increases in load (payback). After that we will see flexible demand providing frequency regulation and reserve services.

4.30. We analysed two key factors of flexible demand and smart demand to quantify the benefit gained from having smart demand provide the operating reserves.

- *Flexible demand provides frequency response and does not have immediate payback*. This means that the stop in demand need not be recovered in short time scales, and there will be no need to impose extra reserve requirements (the value of the response service is $4.26/MWh)
- *Smart demand provides instantaneous reserve for frequency control that has to be restored in a short time scale.* Flexible demand used to provide response services will impose extra requirements for load following reserve (the value of the response service drops to $0.71/MWh).

4.31. Our analysis suggests that Smart Refrigerators (those equipped with a frequency-sensitive thermostat control) could supply frequency regulation services to a maximum of 50MW. We could also achieve significant frequency regulation services by controlling the charging of EVs (such as interruptible charging (IC) for short period of time) or through Vehicles to Grid (V2G) technology. V2G technology involves injecting power from batteries in case of a significant change in frequency (EV:V2G).[16] We analysed both options. As Figure 64 shows, the capitalised value benefit of flexible demand providing response services to a New Zealand system with 3.4GW of wind, vary widely ($42m–$250m in 2030, and $47m–$285m in 2050).

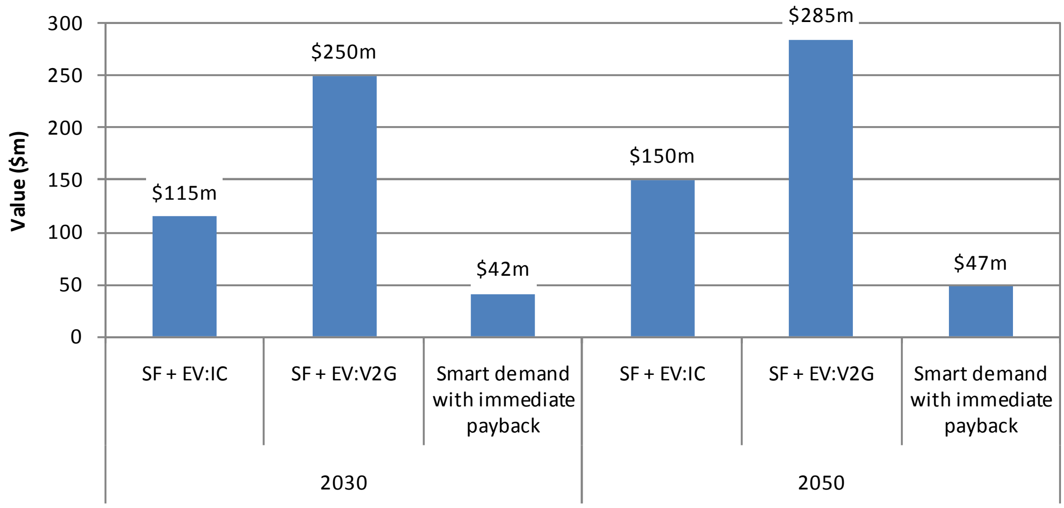



**Figure 64: Value of system balancing services for varying degrees of demand flexibility in 2030 and 2050 (for a system generating 3.4 GW of wind)**

4.32. The benefits of using flexible demand in 2050 are higher than in 2030. This is due to the higher level of EV penetration in 2050.

4.33. However, as the New Zealand Wind Integration Study showed, the cost of reserves from wind generation was modest when compared with a system dominated by thermal generation. This is because hydro generation helps to cancel out at relatively low-cost any fluctuations in wind power. So the value of balancing services in the New Zealand system is modest. It is significantly lower than in thermally generation dominated systems which have a strong contribution from inflexible nuclear generation. Nuclear generation needs to operate at a continuous output and cannot flex like hydro generation to accommodate intermittent forms of generation, such as wind. It is useful to observe that in some European jurisdictions a strong proportion of the benefits of the value of a smart grid (perhaps over half the benefits) is attributed to the value that may be available from system balancing services. The objective of achieving these benefits is strongly driving international smart grid research. Whereas, in the case of New Zealand, this value is found to be relatively modest and less than 10 percent of the total benefits available by 2030.

## High Wind Scenario

4.34. We examined increasing wind power generation in New Zealand from 3.4GW in our base-case scenario to 7.1GW in our high wind scenario and the impact of this on system operation cost. We also looked at the extra investment needed to back up generation and transmission system infrastructure. Table 16 lists the capacities

[16] There is continued debate about the viability of the V2G concept given the potential impact on battery life and technology requirements to deliver frequency regulation services

of wind power installed in different regions for the base-case and high wind scenarios.

4.35. We used the 2050 demand and extreme wind power scenarios, and did not change the capacity of other installed generation technologies. We used the planning model to calculate the extra gas-fired plant and transmission capacity needed for the uncontrolled and smart scenarios.

**Table 16. Wind power capacity for base case and extreme wind**

| **Region** | **Installed wind (MW)** | |
|---|---|---|
| | **Base case** | **Extreme wind** |
| Northland | 69 | 159 |
| Auckland North | 578 | 961 |
| Auckland South | - | - |
| Huntly | - | 425 |
| Hamilton | - | 420 |
| Bay of Plenty | - | - |
| Whakamaru | 100 | 458 |
| Wairakei | - | - |
| Stratford | 143 | 127 |
| Hawkes Bay | 261 | 261 |
| Tokaanu | - | - |
| Manawatu | 580 | 1253 |
| Wellington | 436 | 814 |
| Marlborough | - | 81 |
| North Canterbury | - | - |
| West Coast | - | - |
| Christchurch | 215 | 215 |
| South Canterbury | - | 231 |
| Otago/Southland | 861 | 1190 |
| Tiwai | 168 | 500 |
| **Total** | **3411** | **7095** |

4.36. Figure 65 shows how much extra thermal generation the New Zealand system needs to handle the upsurge in electricity demand from adding EV and heat pump demand. The data is for uncontrolled and flexible demand (smart) in 2050 for a base-case 3.4GW of wind and for 7.1GW of wind. We also quantified the benefits EV smart charging can bring and the benefits of controlling EV and heat pump loads.

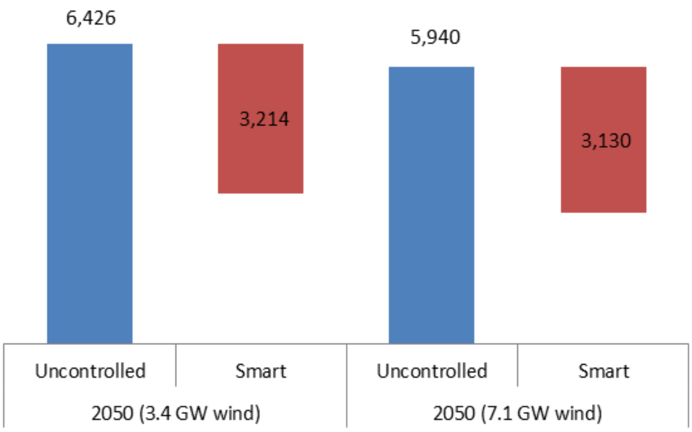



**Figure 65. Extra thermal generating capacity (in MW) needed to meet electrification of transport and heat sectors in business as usual and smart futures for 2050, with 3.4 GW and 7.1GW wind**

4.37. This analysis shows that adding an extra 3.6GW to 3.4GW of wind power capacity will not reduce greatly the extra generation capacity of thermal plant needed to meet demand. The required generation capacity reduces from 6.4 GW to 5.9 GW. This suggests that the capacity value of 3.6GW wind at this extreme level of wind is only 13.8 percent. This lower value is because the growth in wind capacity does not increase proportionally the diversity of the wind resource. Further, the capacity value of wind generally decreases with an increase in penetration level (even in cases where there is no match between existing and added wind power).

4.38. Our analysis also suggests that controlling the flexible load of EV and heat pumps can help to reduce the generation capacity needed in both cases. However at the higher level of wind penetration available demand response is essentially exhausted and cannot firm up further wind capacity and we therefore do not see a greater reduction of generation capacity in the high wind scenario.

4.39. Figure 66 shows a similar need for extra transmission capacity in uncontrolled (with 3.4GW and 7.1GW). This suggests that the increase in installed wind capacity across the system (as shown in Table 16) has no significant impact on the total transmission capacity needs of New Zealand. We note that these results are specific to this study.

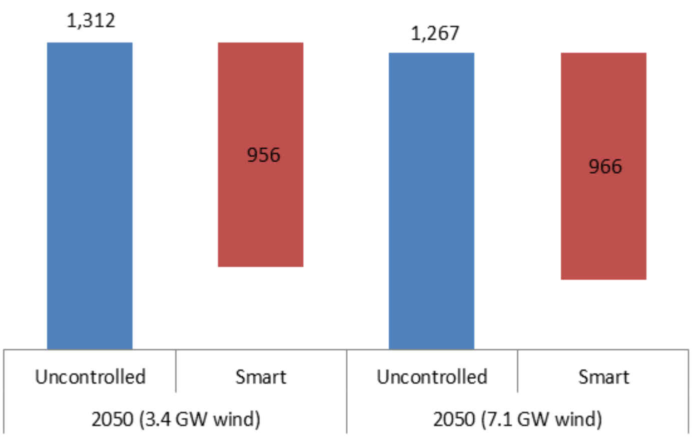



**Figure 66. Savings in transmission capacity (GW.km) from smart demand for 2050, with 3.4 GW and 7.1 GW of wind**

4.40. Our analysis further suggests that by controlling the flexible load of EVs and heat pumps the need for transmission capacity can be reduced in both cases at similar ranges (between 956MW and 966MW). This suggests that demand response at this level cannot improve the value of wind power for the network. From this study, with 7.1GW of wind capacity, we cannot see how transmission capacity can be further reduced.

4.41. Figure 67 shows that the value of the frequency response service will increase significantly for a high wind scenario when compared with the base case. This is because about 4 percent of all wind production cannot be absorbed. The loss happens when low demand conditions coincide with stronger winds. The loss can be prevented by changing the demand shape (such as increasing demand during off-peak periods). Such use of flexible demand would reduce the cost of frequency regulation services.

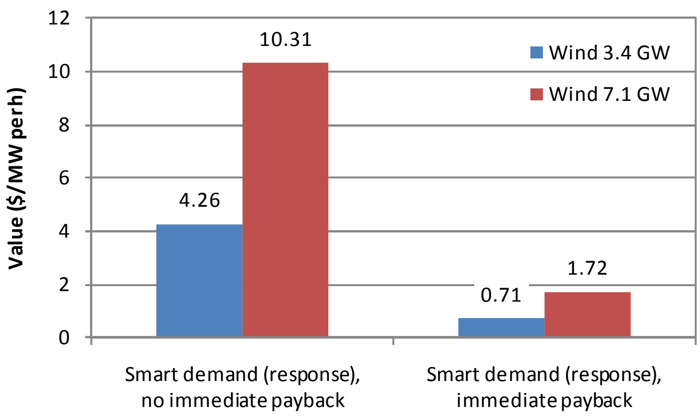



**Figure 67. Value from response services with and without immediate payback**

4.42. Figure 68 shows the benefit of system balancing for 3.4 GW and 7.1 GW of installed wind generation capacity. Our analysis suggested that two main flexible demand technologies are well placed to provide frequency response services: SF and EVs. As we noted in Section 2 of this report, SF could help to the provide frequency regulation services by adjusting the frequency deviation thermostat. We analysed both options in a New Zealand setting, for the 3.4GW and 7.1GW wind scenarios. For EVs, we considered two types of flexible demand operation: frequency response by interrupting charging of vehicles for short periods (IC); and frequency response provided by EVs injecting power to the grid to offset the loss of generation (the V2G concept).

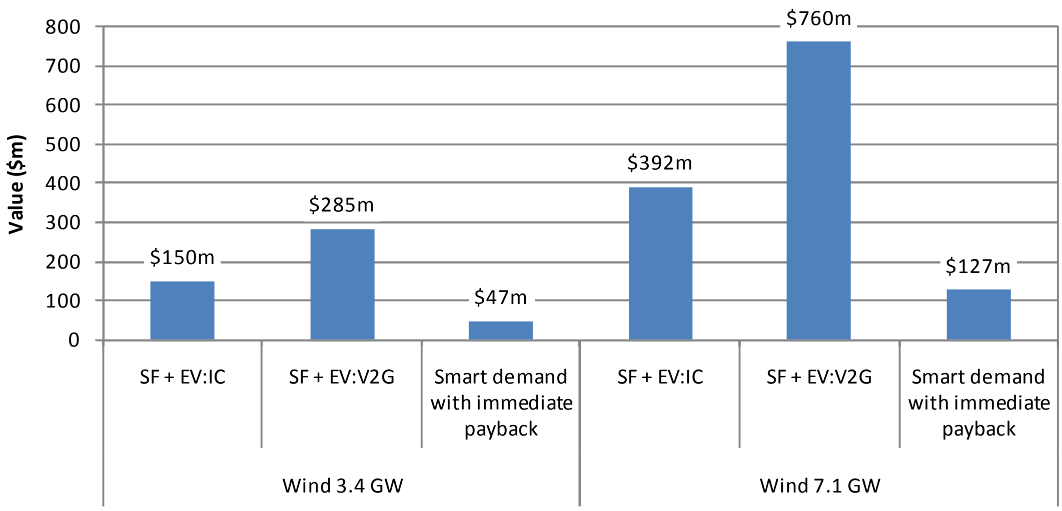



**Figure 68. Value of balancing services in a system, showing demand flexibility in 2050, for 3.4GW and 7.1GW of capacity for installed wind generation**

4.43. Figure 69 shows the wide range of benefit from a capitalised value of flexible demand.

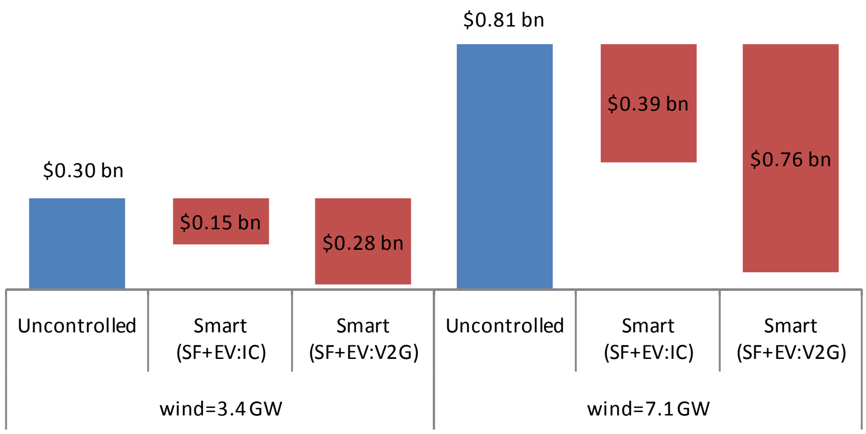



**Figure 69. Capitalised cost of the frequency response services**

4.44. We see that the cost of providing frequency response services could potentially be halved by using SF and through interrupting charging of EVs together for a short time after a loss of generating plant. If the V2G concept turns out to be technically viable, the possible reduction in cost available could potentially reduce greatly the cost of system balancing. However, the balancing cost of the New Zealand system is quite modest even with a significant increase in wind power generation.

# CONCLUSIONS

4.45. The analysis in this report focuses on New Zealand's future electricity system. In particular, it looks at the impacts of the electrification of the transport sector and the ongoing electrification of the heating sector. This could lead to a future electricity system characterised by lower generation and network asset use. This would be due to increased low-capacity wind generation and an increase in peak demand that is disproportionately higher than the increase in energy, driven by the electrification of heat and transport sectors. Yet, these new demands are characterised by a significant flexibility that may open up ways to optimise demand flexibility and improve the efficiency of the entire electricity supply chain, including electricity generation, transmission and distribution.

4.46. We used a range of future electricity system scenarios that, although plausible, do not necessarily represent a forecast of future electricity demand and supply. We developed the scenarios primarily to assess the range of possible values that may be given to flexible demand. In this context, this work has quantified how deep the effect will be from electrifying New Zealand's transport and heat sectors under an unconstrained (or uncontrolled) network control scenario and an active (smart) control scenario based on optimised demand side response. We have identified significant opportunities to optimise demand response within network constraints. Table 17 summarises all the benefits set out in this study for the year's 2030 and 2050.

**Table 17. Breakdown of estimated benefits of Flexible Demand in 2030 and 2050 ($bn)**

| ***Scenario*** <br> ***Cost savings ($bn)*** | 2030 | 2050 |
|---|---|---|
| Generation capacity | 1.44 | 4.50 |
| Transmission capacity | 0.28 | 2.55 |
| Distribution capacity | 1.61 | 3.32 |
| Response provision | 0.25 | 0.28 |
| **Total benefits of Smart** | **3.58** | **10.65** |

4.47. Table 17 shows that by 2030 the most significant benefit from using flexible demand will be the savings gained by reducing the investment needed for generation (a $1.4 billion saving) and the distribution network (a $1.6 billion saving). The benefits gained from demand participation in transmission investment deferral are more modest (a $280 million saving) and response provision (a $250 million saving). In 2050, we see that the volume of benefits increases significantly across most segments. In particular, if flexible demand helps to reduce investment in the transmission network, the savings increase to $2.5 billion. However, New Zealand's strong contribution from flexible hydro power means that the saving available from using flexible demand for balancing services will be modest (at $280 million).

4.48. We expect that the uptake of EVs and heat pumps to be unevenly distributed across New Zealand. This will impact heavily on local distribution networks long before we see any significant impact at a national level. This means that the smart grid concept could bring significant benefits at a distribution network level, perhaps from around 2020 onwards, with similar benefits available at a national generation level from around 2030.

4.49. In order to achieve the full benefits of the smart grid concept and smart technologies a number of issues will need to be considered. New Zealand's market design and regulatory framework will need to evolve to provide the right investment signals to unlock flexible demand side participation. The following factors are important for New Zealand to deliver the best national benefits from a smarter energy future.

4.50. **Ensure that New Zealand's existing load control resource is being fully utilised**. New Zealand's existing power system may be 'smarter' than most. This is in part due to New Zealand's existing hot water heating control resource, which has been in place for over 50 years. Consumers currently choose if they wish to opt into hot water load control by selecting a controlled tariff. It is unclear if New Zealand's existing hot water heating control resource is declining over time, both in terms of the maintenance and installation of the hardware, and in terms of how much use is made of the resource to manage peak demand periods and distribution network congestion. In addition to maintaining the existing resource, there is an opportunity to enhance existing hot water heating control by making full use of consumption information from smart meters. This is particularly attractive as New Zealand's hot water heating control resource, augmented with smart metering information, is effectively a sunk cost, and could provide many of the benefits that a fully functional smart grid aims to provide.

4.51. **Conduct focused trials:** In line with international initiatives, New Zealand could conduct focused trials to learn more about the benefits before wide spread roll out is considered. This is particularly relevant for New Zealand given the growing uptake of Heat Pump technology for space heating. The impact of Heat Pumps on distribution may be significant, particularly during unusually cold spells. It will be important to fully understand the usage patterns associated with different installations and explore the benefits and challenges associated with alternative mitigation measures, including the control of Heat Pumps (e.g. preheating strategies) and Water Heater control. Trials with two way information flows to test customer engagement and tailor products to suit customer needs will be an important step to learn about the value a smarter grid can bring to both consumers and the electricity industry. It is important to emphasise that the infrastructure for conducting such trials, smart metering with accompanied communication and control technologies, is already available which will make the trials very cost effective. To some extent this has begun already in New Zealand with retailers' trialling peak and off peak pricing signals and providing real time consumption information for customers with smart meters. Specific areas of investigation in the nearer term could also include:

- trialling hot water heating control approaches augmented with smart metering information
- monitoring of heat pump operation and investigating opportunities for control
- using smart metering data to deepen understanding of electricity consumption patterns across various consumer segments, potentially augmented with appliance monitoring and consumer behavioural research.

4.52. Trials will also help to inform the true potential for wide-spread roll out of smart technologies to support flexible demand use in New Zealand. A smart grid approach involves substituting the use of flexible demand for network investment. The potential to access significant flexible demand when it is needed, often at times of system stress, requires trials to understand the risks involved. This study shows smart appliances will be of limited benefit from an electricity system perspective so trials in this area are likely to offer less national benefit. We expect future opportunities for technology transfer around Electric Vehicles charging infrastructure and smart communication.

4.53. **Encourage demand participation.** The benefits of demand response (and other smart grid technologies, such as storage) may be shared among several industry participants along the energy value chain. Achieving active demand side participation is internationally considered to be a barrier to achieving the full economic benefits that a smarter grid could deliver. The industry has a key role to play to raise awareness, put appropriate systems and processes in place and create incentives for greater demand side participation in the energy market.

4.54. **At the network level, New Zealand's regulatory framework may need to evolve to recognise investment in efficiency.** Network operators need to be able to make choices between investing in innovative demand response and investing in network assets. Incentives to adopt technically effective and cost efficient non-network solutions need to be considered as part of the regulatory design framework. Such incentives could be complemented with a review and update of network design standards in order to accommodate the contribution that flexible demand initiatives may be able to make as a substitution for building network infrastructure.

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# 6. APPENDIX A

## Generation and transmission system investment optimisation model

6.1. We developed an investment modelling framework to determine the optimal capacity needed for New Zealand's generation and transmission system under various development scenarios. The framework optimises the extra generation and transmission investment, recognising the needs of an hourly operation over one year. The model seeks to minimise the total system costs made up of:

- extra generation capacity
- extra inter-regional transmission network capacity
- annual electricity production cost, recognising the cost of constraining merit generators or renewables for network congestion management.

6.2. We created the model to assess all key cost components while keeping the required level of system reliability and being mindful of operating constraints. Figure 70 shows the model's structure.

6.3. The infrastructure (generation and transmission) evaluation models capture the effects of sharing generation capacity between the North Island and the South Islands. The sharing of such inter-regional transmission lessens the costs for the extra generation and transmission capacity needed to deliver the necessary level of reliability.

6.4. Loss of load expectation (LOLE[17]) is used to measure how effectively the system performs (a maximum of 8 hours per year). The integrated reliability assessment calculates the LOLE by assessing how likely it is that there will be insufficient local generation and remote generation capacity (while optimising transmission network capacity) available to meet demand for every hour in a year. Insufficient local generation might come from forced outages of generating plant, an optimised production schedule of the available conventional generation technologies, seasonal availability of hydro power (and the variability of 'run of river' and hydro with reservoir), and the probable contribution of renewable generation and short and long-term correlation with demand. Demand response and energy storage facilities can be explicitly modelled (as can the effects from loss of efficiency). Such modelling can assess how effective these measures are in reducing extra generating capacity and transmission investment while keeping the required level of system reliability.

[17] Loss of Load Expectation (LOLE) is an internationally accepted statistical measure for assessing the reliability of supply and showing the total duration (within a year) when demand exceeds the available generating capacity and leads to stops in demand.

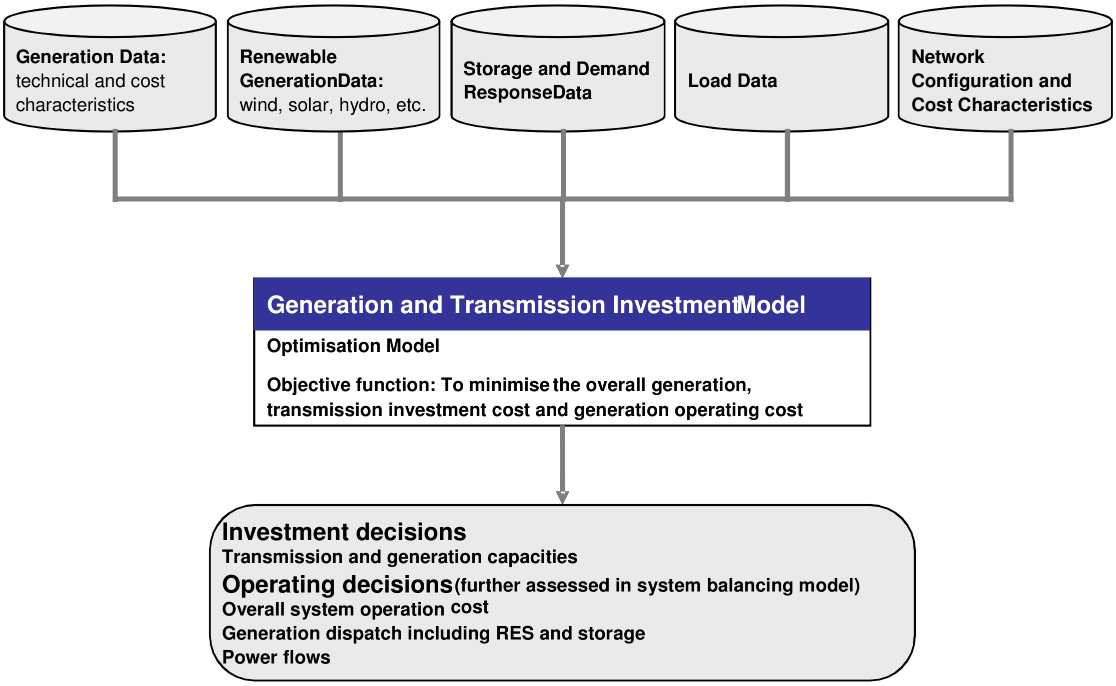


**Figure 70. Structure of the power system optimisation planning model**[18]

6.5. We give a list of key assumptions used in this study below.

a) Maximum LOLE is limited to 8 hours/year.
b) The generation units operate independently (for example, an outage of one generator will not directly affect the operation of the other units in the system).
c) The generating units are either fully available or out of service, in line with their long-term plant availability statistics.
d) Hydro generators are constrained by their rated capacity and available hydro energy, when considering reservoir and run-of-river schemes.
e) To meet the reliability criterion (point a), the regions with current gas infrastructure (Auckland, Huntly, Hamilton, and Stratford) will get any extra gas-fired plant.
f) The cost of extra generation capacity from a gas-fired plant is $140,000 for every MW in a year. This does not include the cost of reinforcing the gas infrastructure.
g) Transmission capacity across transmission links and corridors is secure (the network design and capacity has met current security criteria). The unit cost of reinforcing transmission is $300 for every MW/km in a year.
h) Baseline demand does not include electricity demand from EV and HPs.

6.6. Key inputs into the investment model include a time series of hourly electricity demand profiles and hourly profiles for the available renewable energy sources; seasonal hydro energy for both 'run of river' and hydro with reservoir; installed capacity, dynamic characteristics and operating costs of generation; investment cost of extra generating capacity in each region; network topology; and the costs of reinforcing the network.

6.7. Key outputs of the investment model include the extra generation capacity and secured transmission capacity; information about demand side management; generation dispatches; flows; and investment and operating costs.

[18] The investment model improves on the model used to assess the adequacy and optimal capacity of generation and transmission system in Europe in the Roadmap 2050 project [42].

## Model for optimising the way the system operates

6.8. The capacity proposed in the planning model is passed as an input to the system operation optimisation model. The model optimises generation to meet demand and operating reserve needs while recognising the dynamic parameters of a generation system. The aim of the model is to show how we can best minimise the overall annual generation costs of providing energy and types of reserve.

6.9. The need to provide reserve increases generation costs as some generators need to be part loaded. This will cause them to run at sub-optimal levels, leading to less efficient operation. The optimisation recognises the cost of part loading generation by considering the no-load cost of generation, start-up costs, and possible commitment of costlier generators. The cost of reserve purchased from interruptible loads is modelled explicitly in the optimisation problem.

6.10. An increase in wind generation increases the depth of operating reserve needed. This leads to extra system costs. We computed the overall production costs with and without the impact of wind for 2030 and 2050. The difference between the two time horizons is the extra operating reserve needed to offset wind generation.

6.11. Our evaluation of the extra reserve cost is cost-based rather than market-based (yet we recognise that the current market co-optimises energy and reserve). Clearly, the cost of reserve must be included in any overall generation cost.

6.12. We used a technique that statistically assesses the variable behaviour of wind output to assess the level of operating reserve needed across different locations. We also assessed the impacts on instantaneous reserves and frequency keeping under various levels of wind output.

6.13. We based our assessment of the breadth of operating reserve needed to handle plant rescheduling on two distinct time horizons: Instantaneous Reserve and Frequency Keeping; and Synchronised and Standing Reserves. We discovered a sub-minute to several tens of minute's time horizon for the former, and up to a few hours time horizon for the latter. We determined the forecast errors in demand and conventional generation separately from historical data, while we based the wind power variations over corresponding time scales on the standard deviations of wind power variations of annual (prepared) wind generation profiles. We used the wind output variations to compute the standard deviations of changes in wind power output for projected wind.

6.14. We then combined these computations (for the North Island and the South Island), with the standard deviations of the demand forecast errors and changes in conventional-generation to determine the level of overall uncertainty to be managed. We used the standard statistical approach of combining the independent (uncorrelated) errors (the mean square error root of the combination of the mean square errors) to make the calculation.

6.15. We modelled the contribution of demand response in providing operating reserves in three different ways.

a) Flexible demand provides instantaneous reserve for frequency control (response), but without immediate payback. This means that the lost demand does not need to be recovered in a short time. There will be no increase in the need for extra reserves.
b) Smart demand provides instantaneous reserve for frequency control and has to be restored in a short time. The extra demand for load will mean use of reserves.
c) Smart demand provides load after reserve services. The load loss will not need to be recovered in a short time. There will be no increase in the need for extra reserves.

6.16. Figure 71 shows key features of the model, including its input and output data. Most of the input data is the same as that used by the planning model, but showing detailed dynamic generation parameters and operating reserve needs.

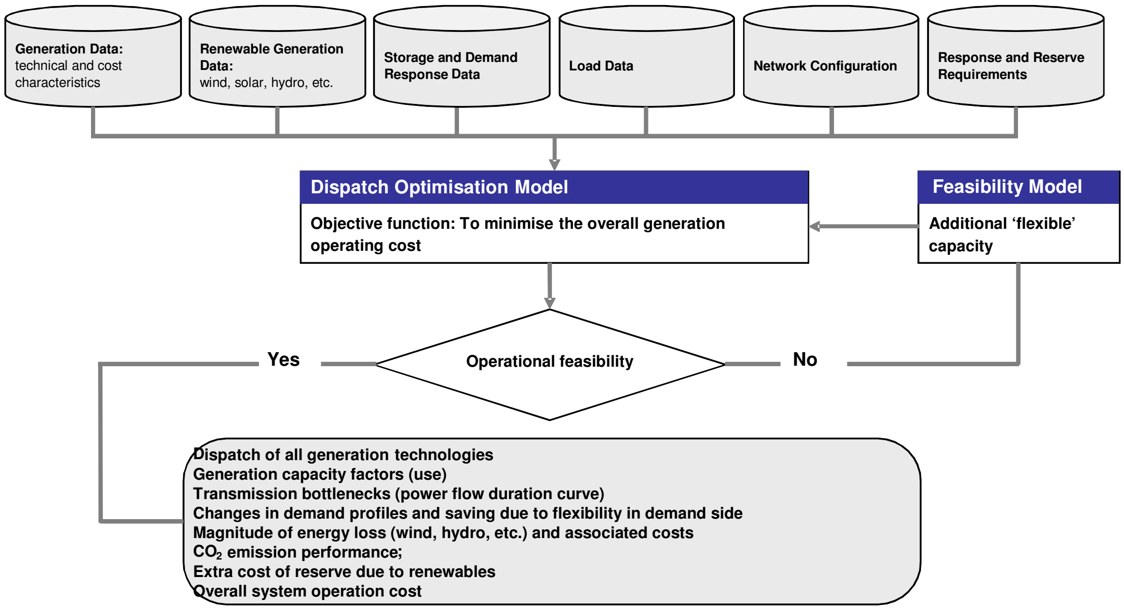


**Figure 71. Structure of the model showing how to optimise the way the power system operates**

# 7. ABBREVIATIONS

| | |
|---|---|
| CCGT | combined cycle gas turbine |
| DW | dishwasher |
| EV | plug-in Electric Vehicles (include plug-in hybrid vehicles, range extended electric vehicles, and battery electric vehicles) |
| HP | (electric) heat pump |
| HV | high voltage |
| HVAC | heating, ventilation and air conditioning |
| IC | interruptible charging |
| LV | low voltage |
| MW | megwatt |
| SA | Smart appliances |
| SR | Smart Refrigeration |
| TD | tumble dryer |
| V2G | vehicles to grid |
| WH | water heater |
| WM | washing machine |