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Innovation Project Allowance Report – Low Voltage Constraint Modelling

June 2025

1. Purpose

This is Wellington Electricity's close-out report for its LV Modelling project under the DPP3 innovation allowance. This project was completed on 31 March 2025 with the publication of findings in WELL's 2025 AMP, in line with the Project Plan submitted in Appendix 1 of Wellington Electricity's May 2024 Innovation Project Allowance application.[1]

Under the Default Price-Quality Path Determination, where an innovation project has been approved by the Commission, the EDB must submit a report to the Commission outlining the key findings of that project, within 50 working days of completing the innovation project.[2]

2. Introduction

Historically, LV capacity has been invisible to distribution network planners, preventing the planning and development of the capex required to support demand growth on the LV network. Networks have also not been funded to develop the tools and processes to provide visibility of the LV network, manage the connection of large new customer devices, and incorporate flexibility.

Given the expected demand growth in Wellington outlined in Section 4 of WELL's 2023 AMP, WELL commissioned ANSA[3] to provide a LV constraint risk tool which:

1. Established the hosting capacity of each LV asset on each residential LV network.
2. Modelled and forecasted when the LV assets will run out of capacity.
3. Applied a standard cost model to each asset that needed reinforcing with additional capacity.
4. Aggregated those costs to provide a capex forecast for the next 50 years.

Since this work was not funded by DPP3 allowances, WELL submitted an Innovation Project Allowance application in May 2024, which was approved by the Commission on 17 June 2024. As the DPP3 innovation allowance only provided for 50% of the innovation project costs, WELL funded the 50% share that was not covered by the innovation mechanism through savings from other parts of the business.

As outlined in the Innovation Project Allowance application, the project was to be delivered over two years. Initial work in the 2023/24 regulatory year to develop the tool and models would be summarised in the 2024 AMP. The findings of this initial work would then inform an update to the tool and underlying data, to be delivered during the 2024/25 regulatory year and summarised in the 2025 AMP. The timeline for the project is presented in Figure 1.

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[1] https://www.welectricity.co.nz/disclosures/regulatory-applications/document/341
[2] In accordance with Clause 5, Schedule 5.3 of the Electricity Distribution Services Default Price-Quality Path Determination 2020
[3] www.ansa.nz

Deliverable	Reg year ending 31 March 2024				Reg year ending 31 March 2025			
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Test LV gas study (10 networks) – concept model								
Select scope for full study – 2,000 residential networks								
Consumption data from retailers								
Develop ICP load curves								
Load GIS data into ANSA model – repair of errors								
Develop load curves and growth scenarios								
Develop constraint curves for every LV asset								
Develop standard cost model and capex								
Update AMP to include capex								
Update model with revised GIS data								
Enhance model to assess meshed LV networks								
Update constraint curves, capex model, and AMP								

Figure 1: Project Plan

A summary of the initial findings of this work was published in Section 9.7 of WELL's 2024 AMP, and presented to industry at the Electricity Engineers' Association Conference in September 2024.[4] The final results were summarised in Section 9.7 of WELL's 2025 AMP.

This report provides additional context and detail to the 2025 AMP, and details the key findings from the project:

- The use of the ANSA probabilistic model is enabling Wellington Electricity to target LV visibility enhancements in a targeted and cost-effective manner.
- The appropriate use of seasonal ratings for assets, reflecting the real impact of demand on their lifecycle, rather than planning based on nameplate ratings, can reduce the amount of capex forecast to support demand growth on winter peaking LV networks.
- An increase in the regulatory upper voltage limit and mandating Volt-Var control in PV inverters are both able reduce the cost of supporting PV uptake, however the upper voltage limit has the greatest impact on the ability of the existing network to host PV, with Volt-VAr control offering no additional reduction in cost.
- Actively managing EV charging away from the evening peak through demand flexibility would significantly increase the capacity of the existing LV network to host residential EV charging.
- The existing LV network is unable to support the widespread uptake of 7.4kW chargers even when their demand is being managed away from peak periods.
- A hybrid strategy that considers the use of HV extensions to split LV circuits can be more cost effective than pursuing a strategy of resolving constraints by only upgrading constrained LV assets.

3. WELL's LV Visibility Strategy

WELL's immediate focus for LV management is on developing LV visibility by combining GIS spatial data with ICP level consumption, voltage data, and transformer monitoring information. WELL's approach has been to develop key concepts into trials and pilot programmes as building blocks, that leverage previous work and build towards the goal of allowing the market to manage LV constraints in realtime.

[4] https://www.welectricity.co.nz/major-projects/innovation-projects/document/402

WELL's current view of the required LV visibility building blocks and their interrelationships are shown in Figure 2.

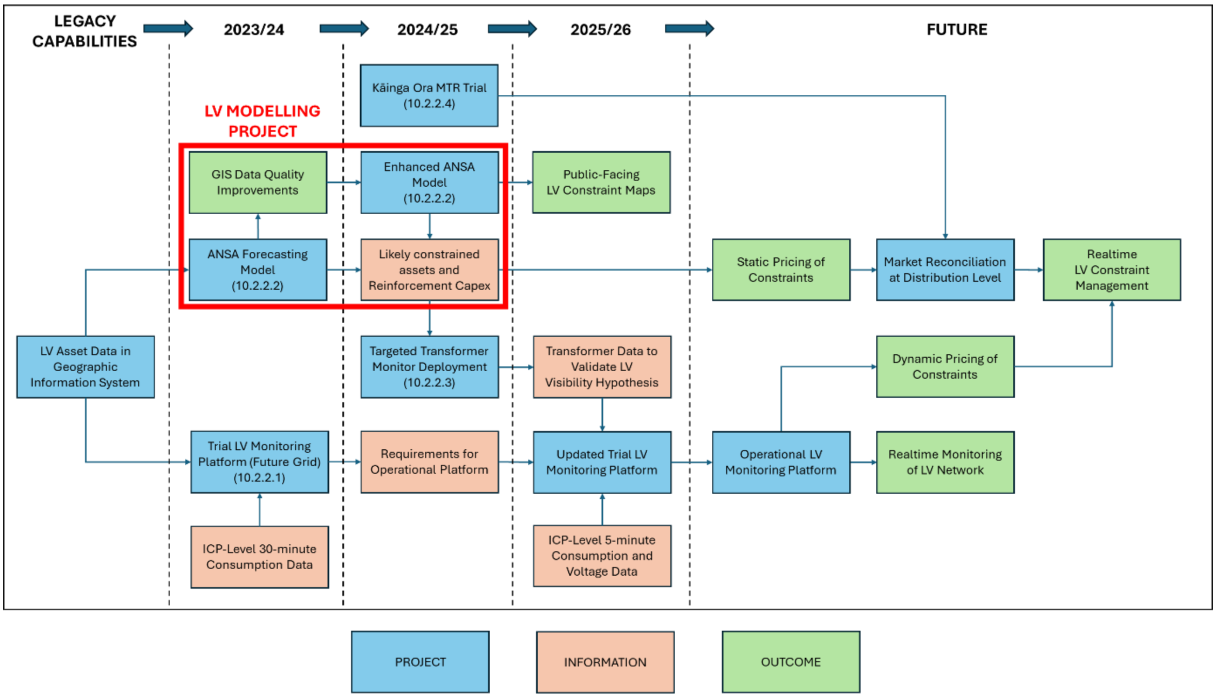

Figure 2: Key LV Visibility Building Blocks with 2025 AMP References, Highlighting LV Modelling Project

WELL is currently considering the most effective and efficient combination of data to provide visibility of the LV network. The currently hypothesis is that using the probabilistic ANSA model to identify LV network areas that are likely to be constrained, supplemented with 5-minute consumption and power quality data from those areas, is likely to be substantially a more efficient than either procuring of smart meter data or a large scale roll out of transformer monitoring equipment.

4. LV Modelling Study Scope

The Wellington network is a winter evening peaking network and residential customers drive peak demand. The study therefore focused on residential LV networks. The study assessed 1,860 residential urban LV networks, capturing the majority of residential customers.

Rural networks below 100kVA were excluded as they supply fewer customers, have lower diversity so are designed with a higher capacity headroom, and are also less likely to have reticulated gas connections.

Commercial and industrial networks were also excluded. These are being assessed through separate workstreams,[5] with increases in demand being more likely to require customers to upgrade their electricity connections, allowing constraints to be identified and resolved as they occur.

[5] Including analysis by DETA Consulting, discussed in Section 4.2.1.3 and Section 9.2.2.3 of Wellington Electricity's 2025 AMP.

5. Study Methodology

The ANSA tool builds a spatial model of LV assets, including customer ICPs, the transformers that supply those connections, and the connecting conductors. The model allows different power flows to be applied to the network models, testing whether each asset has the capacity to host changes in customer electricity demand at each ICP.

The ANSA model then applied various growth scenarios to the network models by using Monte Carlo simulation to calculate the impact on the capacity of the LV assets. The growth scenarios incorporated the follow factors:

- EV uptake rates;
- Gas to electricity transition rates;
- PV uptake rates;
- Average EV charger size (1.8 kW, 3.7 kW, 7.4kW), and
- EV charging patterns, defining the proportion of EVs charging at 6pm, 9pm, 12am, and 3am.

The simulation provides a probability of when each asset will exceed its capacity, then applies standardised costs for the reinforcement of each constrained asset. The aggregated reinforcement costs form the network growth capex.

6. Inputs and Assumptions

6.1. Assumptions and Limitations

The following assumptions and limitations apply:

1. There may be factors other than capacity constraints that trigger conductor and transformer replacement, such as age and condition. Only reinforcement due to load increases is considered in this study.
2. It is assumed that there are no mechanical constraints in upgrading conductors. These upgrades may be limited by wind and other structural loading.
3. The determination of customers with gas connections, assessment of gas consumers' demand, and the assignment of demand during modelling is limited due to imperfections in ascertaining gas consumers, the nature of their gas use (i.e. water heating, cooking, and space heating), and the technology that might replace that use (e.g. traditional electric hot water cylinders, heat pump cylinders, or electric continuous flow heating).
4. The customer demand profiles utilised by the model for customers transitioning from gas include the effect of Wellington Electricity's existing ripple control strategy.
5. The capex forecast is the expenditure required to address constraints that the model assesses as having a 50% likelihood of occurring, with the capex contribution of each constraint to the forecast being halved to reflect that on average only half of these constraints are expected to occur.

6.2. Decarbonisation Assumptions

Three transition scenarios were developed for each demand type, representing slow, moderate, and rapid decarbonisation of that demand.

6.2.1. Residential Gas-To-Electricity Transition

The Rapid and Moderate scenarios represent a policy-driven exit of residential gas, with the Rapid scenario seeing 33% of gas connections transitioning by 2030, and the remaining 67% transitioning by

2035. The Moderate scenario has this gas exit predominantly occurring between 2040 and 2050. In contrast, the Slow scenario is a customer-led exit at 1% per year. These scenarios are summarised in Table 1.

Table 1: Proportion of ICPs with Reticulated Gas Connections for Growth Scenarios

Growth Scenario	2025	2030	2035	2040	2045	2050
Slow	40%	38%	36%	34%	32%	30%
Moderate	40%	36%	32%	28%	20%	0%
Rapid	40%	27%	0%	0%	0%	0%

6.2.2. EV Uptake

For the 2025 update, starting from the December 2024 EV penetration for each of the four territorial authorities in WELL's network, assumed uptake rates for the three scenarios for were then applied to give EV penetration rates in average EVs per ICP as summarised in Table 2.

Table 2: Average EVs per ICP by City for Growth Scenarios

Scenario	City	2025	2030	2035	2040	2045	2050
Slow	Wellington	6.5%	11%	19%	31%	46%	65%
	Porirua	6.3%	11%	19%	30%	45%	63%
	Lower Hutt	5.0%	9%	15%	24%	36%	50%
	Upper Hutt	4.9%	9%	15%	23%	35%	49%
Moderate	Wellington	6.5%	18%	33%	51%	69%	82%
	Porirua	6.3%	17%	32%	49%	67%	81%
	Lower Hutt	5.0%	14%	26%	40%	56%	71%
	Upper Hutt	4.9%	13%	25%	39%	55%	69%
Rapid	Wellington	6.5%	24%	47%	71%	93%	100%
	Porirua	6.3%	23%	46%	69%	90%	99%
	Lower Hutt	5.0%	18%	37%	57%	76%	92%
	Upper Hutt	4.9%	18%	36%	55%	75%	90%

6.2.3. PV Uptake

The Slow PV uptake scenario representing a linear continuation of current trends of approximately 600 new PV connections per year, and Moderate and Rapid reflecting different rates of acceleration up to an assumed practical limit of 33% of residential properties being suitable for PV. These scenarios are summarised in Table 3.

Table 3: Average PV Installations per ICP for Growth Scenarios

Growth Scenario	2025	2030	2035	2040	2045	2050
Slow	2%	4%	6%	8%	10%	12%
Moderate	2%	5%	10%	17%	24%	28%
Rapid	2%	8%	17%	25%	30%	33%

7. Findings

The ANSA tool has allowed Wellington Electricity to explore the impact of a range of factors on future LV reinforcement capex requirements. The key findings are summarised below.

7.1.1. Decarbonisation impacts are expected to begin after 2030

The study tested a range of different combinations of uptake scenarios for the 2025 AMP, summarised in Table 4.

Table 4: Decarbonisation Scenarios Tested for 2025 AMP

Scenario	EV Uptake Rate	Gas Transition Rate	PV Uptake Rate
Slow Decarbonisation	Slow	None	Slow
Slow with Residential Gas Exit	Slow	Rapid	Slow
Moderate Growth	Moderate	Slow	Moderate
Rapid Decarbonisation	Rapid	Rapid	Rapid

The impact of these decarbonisation scenarios on LV reinforcement capex is shown in Figure 3.

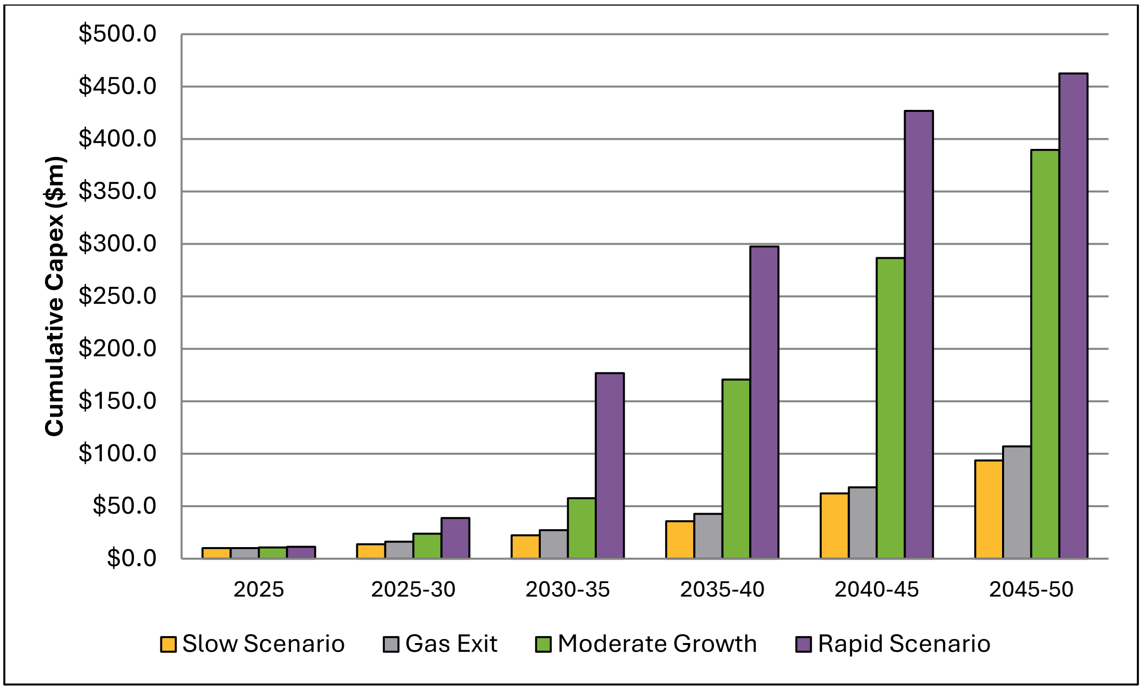

Figure 3: Cumulative Capex Forecasts by Decarbonisation Scenario

7.1.2. Probabilistic modelling can be used to cost-effectively target LV visibility projects

Wellington Electricity has approximately 177,000 customers and 4,500 distribution transformers. Implementing LV visibility via procurement of ICP-level data across the entire network, or installing monitoring equipment on every distribution transformer, would result in expenditure in locations where this is not needed. The use of the probabilistic ANSA model is allowing Wellington Electricity to target locations that are likely to be constrained, deploying additional monitoring in those locations where it will provide the greatest benefit. This is believed to be a cost-effective approach that manages the risk at the lowest practical cost to customers. This hypothesis is being tested through the other workstreams identified in Figure 2 that the ANSA model has enabled.

An example of how the ANSA tool allows locations to be targeted is shown in Figure 4, which presents a heat map of transformer constraint risk, identifying areas for additional investigation, marked by the red hexes.

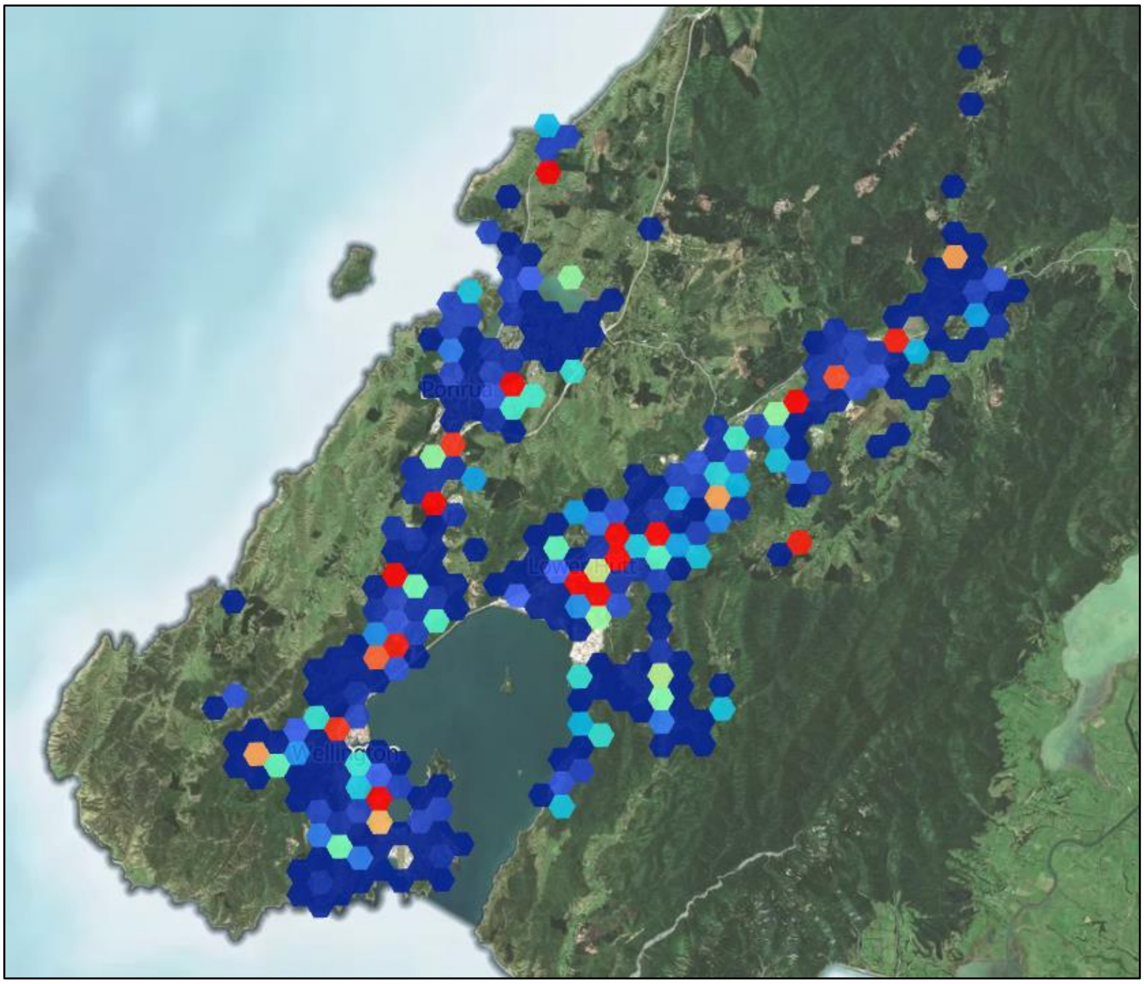

Figure 4: Transformer Constraint Risk Heat Map Generated by the ANSA LV Model
Image © ANSA® 2025

7.1.3. The use of seasonal asset ratings can reduce reinforcement capex requirements.

The LV capex model has also allowed WELL to test the impact of seasonal asset ratings on forecast LV capex. Wellington's residential demand peaks during winter evenings. Distribution transformer ratings are limited by their maximum operating temperate, with loading exceeding that rating leading to excess heating that will shorten the transformer's life. That rating assumes a fixed ambient temperature, which is typically significantly higher than the ambient temperate in Wellington during winter evenings. This colder ambient temperature improves the efficiency of transformer cooling, allowing the transformer to carry more load for a given operating temperature.

Wellington's network standards allow residential distribution transformers to operate to 120% of nameplate rating during winter, and 110% of nameplate rating during summer.

Figure 5 shows the impact of seasonal transformer ratings on the capex investment required to resolve transformer capacity constraints through to 2075 for the standard scenario. This shows the importance of having accurate assumptions about seasonal ratings.

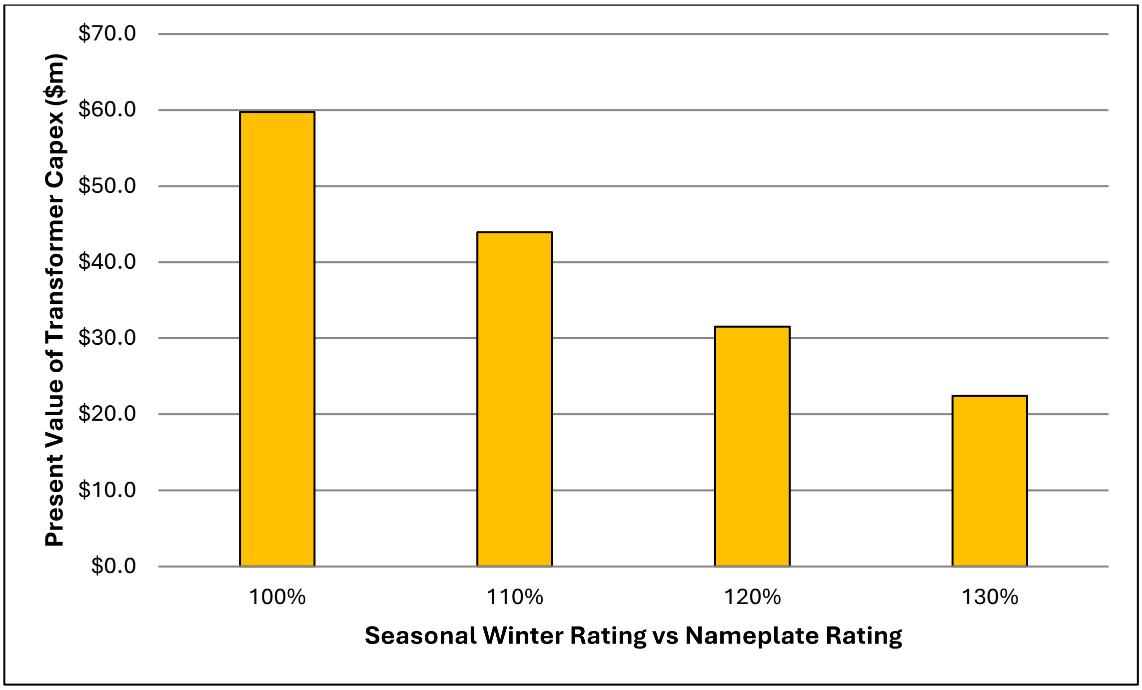

Figure 5: Impact of Seasonal Transformer Ratings on Distribution Transformer Capex to 2075

7.1.4. Increasing the upper voltage limit reduces the cost of supporting PV uptake, to a greater extent than mandating Volt-VAr control.

The Ministry of Business, Innovation, and Employment is proposing to change the standard voltage range defined in the Electricity (Safety) Regulations 2010 from 230V±6% to having an upper limit of +10%. A change to this regulation would affect the point at which assets become voltage constrained by PV export. We have tested the impact of these proposed changes using the ANSA model.

Figure 6 shows the impact of a 10% upper voltage limit on the capex forecast. This shows a significant reduction in the capex required to resolve voltage constraints on cable and lines.

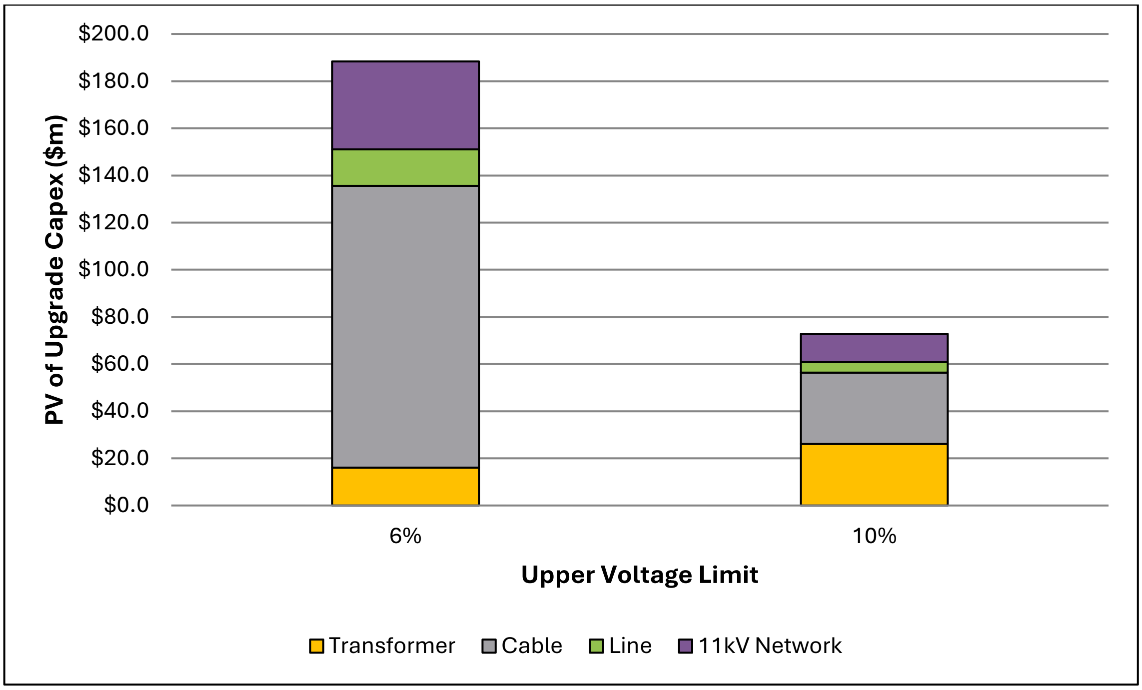

Figure 6: Impact of Upper Voltage Limit on Capex to 2075 by Component

Transformer capacity is not affected by the voltage limit, however, the model is forecasting an increase in transformer capex. This is due to a reduced amount of work required at the 11kV level: under the 6% limit it is more cost-effective to resolve both voltage and thermal constraints at the same time by undertaking 11kV extensions to split the LV networks. However, under the 10% limit there are fewer voltage constraints, leading the model to determine that it is more cost-effective to resolve many of the remaining thermal constraints by simply upgrading the existing transformers.

PV inverters can use Volt-VAr control to absorb or inject reactive power in order to manage local voltage levels, at the cost of reducing their active power output. Mandating Volt-VAr settings for inverters would reduce the requirement for LV reinforcement to resolve voltage constraints, as the inverters will be working to keep the voltage within the required limits. Figure 7 shows the LV reinforcement capex required for the base scenario at 0% and 60% Volt-VAr control, at both 6% and 10% upper voltage limits.

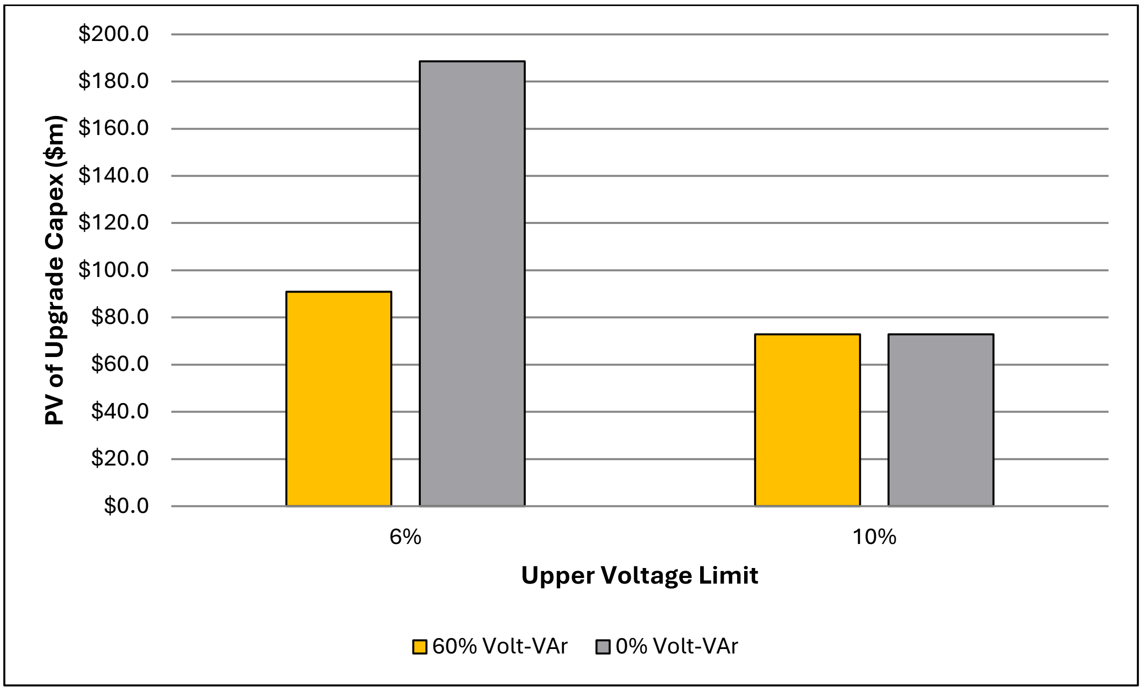

Figure 7: Impact of Volt-VAr Response on Capex to 2075

This shows that mandating Volt-VAr control reduces LV reinforcement capex at the current upper voltage limit of 6%, however Volt-VAr control does not offer any additional benefit if the upper voltage limit is increased to 10%.

7.1.5. Customers benefit from managing EV charging away from the network peak.

EV charging is one of the key discretionary demands that can be managed by flexibility services without impacting customers' quality of life. Figure 8 shows the impact of EV uptake rates, charger size, and charging schedule on LV reinforcement capex, excluding the impact of PV uptake and gas transition.

The figure compares an uncontrolled scenario where 50% of EVs are charging during the evening peak, and a flexibility scenario where this demand is moved away from the peak such that only 5% of EVs are charging during that time.

This shows the extent to which even rapid uptake with 3.7kW chargers can be supported by the existing network with a small level of reinforcement required, as long as the impact of charging during peak demand periods can be reflected in price signals, incentivising the management of charging to avoid these periods. It also shows the extent to which the existing network cannot support 7.4kW chargers, even when under active management.

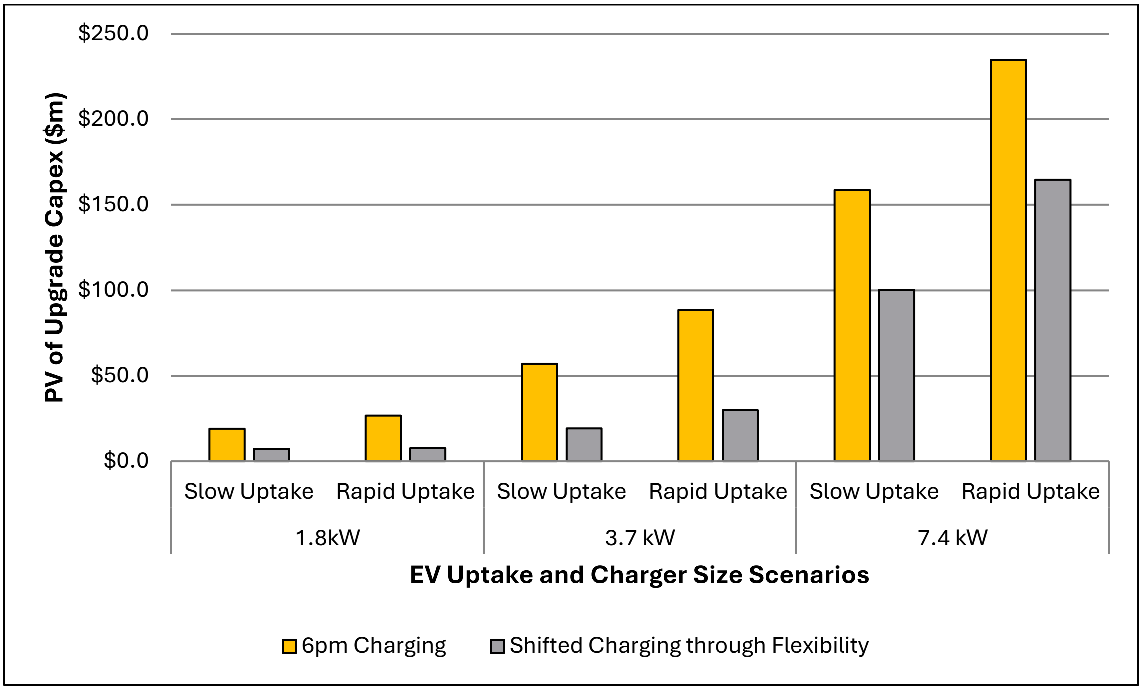

Figure 8: LV Reinforcement Capex to Support EV Uptake Rate, Charger Size, and Charging Schedule

7.1.6. 11kV extensions can be a cost-effective means of managing LV constraints.

Two options for resolving LV capacity constraints are to upgrade the existing LV assets, or to combine LV reinforcement with consideration of extending the 11kV network and installing new transformers to split the existing LV circuits.

As illustrated in Figure 9, the modelling showed that integrated planning between the LV and HV networks to consider HV solutions to resolve LV constraints can be more cost-effective than taking a pure LV reinforcement approach.

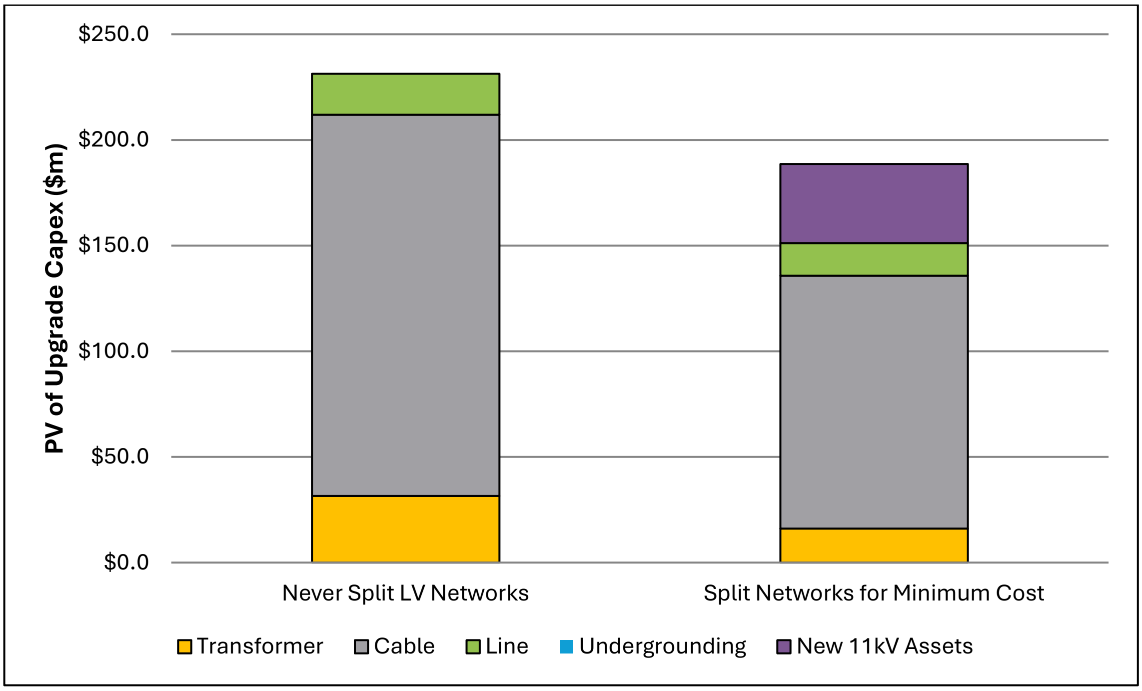

Figure 9: Comparison of Cost of LV Reinforcement vs Co-ordinated HV/LV Solutions

8. Next Steps

The ANSA LV modelling project has been a key stepping stone in Wellington Electricity's LV visibility strategy. Further work is currently being undertaken that leverages the results of the project.

- Wellington Electricity is currently deploying transformer monitoring in areas that have been identified by ANSA as being likely to be constrained. The results of that project will be used to inform future capital investment forecasts, which in turn will form the basis for valuing price signals for non-traditional solutions as an alternative to resolving those constraints through traditional network reinforcement.
- Wellington Electricity intends to use the ANSA results to increase visibility to its customers of PV hosting capacity, and to streamline DG connection applications.
- Wellington Electricity is reviewing how the DPP4 Innovation and Non-Traditional Solutions Allowance (INTSA) could be used to support further work.

An update on progress with the strategy will be published in Wellington Electricity's 2026 AMP.

9. Conclusion

Wellington Electricity's engagement of ANSA to develop an LV reinforcement capital forecasting tool through its DPP3 innovation project has resulted in a number of findings that are informing its approach to supporting residential decarbonisation. The results of the project will continue to give benefits through enabling the evaluation of non-traditional solutions against traditional LV network reinforcement, and the appropriate targeting and price signals for those solutions to ensure a balance between decarbonisation and customer affordability.