Dynamic Analysis

Australia's National Science Agency

Consumer impacts of the energy transition: modelling report

Report for Energy Consumers Australia

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Important disclaimer

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Acknowledgments

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Executive summary

Background

Energy Consumers Australia (ECA) commissioned CSIRO and Dynamic Analysis to determine the economic impacts and available benefits of the energy transition on energy consumers. The analysis is undertaken in the context of the existing *Step change* scenario developed by the Australian Energy Market Operator (AEMO) for the 2022 Integrated System Plan (ISP). The ISP provides a projection of the generation and transmission investment and planning needs of the National Electricity Market (NEM) (which excludes Western Australia and Northern Territory).

The *Step change* scenario was developed through AEMO's stakeholder engagement process and has emerged as the most likely scenario for planning purposes. It incorporates Australia's net zero emissions goals, strong energy efficiency, high uptake of grid level renewables and storage as well as high adoption of electric vehicles, rooftop solar, home batteries and electrification of gas appliances.

This report extends the publicly available ISP analysis to calculate the impact of the transition on residential customer bills. The generation and transmission sectors are modelled (using CSIRO models) to extract electricity price outcomes which are not reported in the ISP. The modelling scope is extended to the distribution sector (by Dynamic Analysis) including distribution sector price outcomes. Together, the generation, transmission and distribution sector price outcomes can be summed to calculate the retail price outcomes and average electricity bills for each NEM state.

Gas and road transport costs are also included given they are also important household energy costs. By adding these separate component costs, the report projects future outcomes and opportunities for the total household energy bill, and allows for the analysis of the impacts on future energy bills from electrifying various parts of the energy sector.

Findings

The report finds that the transition presented by AEMO's *Step change* scenario provides ongoing shared system benefits to all customers. Electrification of vehicles and of gas appliances adds more to the volume of electricity sold than it does to peak demand growth. This leads to higher utilisation of existing electricity infrastructure, particularly of the distribution network sector, which means that distribution networks can reduce the price per unit of energy delivered through their grid. This higher volume effect was strongest under vehicle electrification with shared household benefits of up to $500 a year. Shared benefits from gas electrification were significant (up to $90 a year) but smaller. Those benefits reduce over time as growth in winter electric heating contributes more to peak demand growth (and higher peak demand requires more infrastructure).

The modelling also investigated whether peak demand growth could be further curtailed by more flexible and dynamic operation of customer energy resources (CER) such as electric vehicles and batteries. Shared benefits of up to $50 were found from improved CER flexibility.

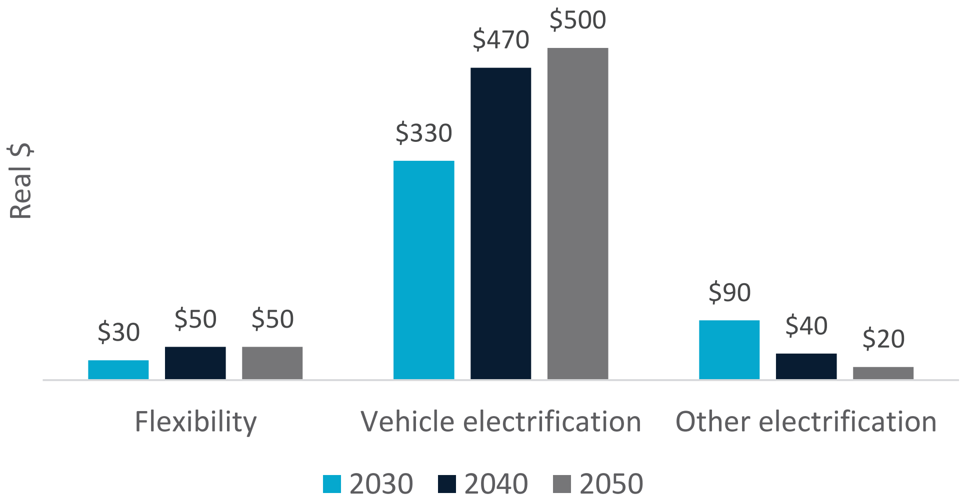

Figure 0-1 Projected shared bill savings available to all customers, NEM average

Benefits to individual customers from adoption of various savings measures were found to be very significant. These benefits tend to only be available if the household is a separate dwelling and owned or mortgaged by the occupier. Renters and apartment dwellers tend to face more obstacles in accessing the saving measures. Also, the measures are only available if not already taken up by the household. Electric vehicle ownership is expected to be the largest cost saving from 2030 at around $1400 a year. Solar PV and battery ownership have slightly lower benefits at around $1250 a year.

Addressing energy efficiency could save around $500 a year, on average. Electrifying gas appliances is another source of savings which begins modestly but has a higher benefit over time, particularly in those states with currently high use of gas such as Victoria.

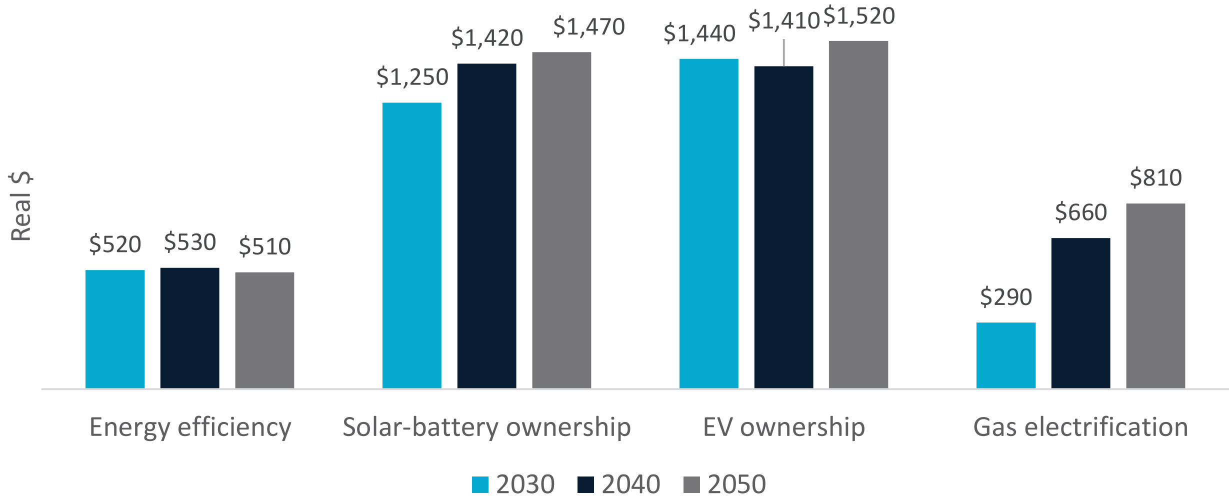

Figure 0-2 Projected individual household savings available to some customers, NEM average

1 Introduction

Energy Consumers Australia (ECA) commissioned CSIRO and Dynamic Analysis to conduct modelling which extended Integrated System Plan (ISP) modelling by the Australian Electricity Market Operator (2022) to consider how customers are economically impacted by the energy transition. The ISP provides scenario modelling of the future capacity required for the least cost operation of the generation and transmission systems.

Customers are primarily impacted by their energy bills which are a function of the price outcomes of the generation, transmission, distribution and retail sectors as well as other energy costs such as natural gas use and transport. They are also impacted by their choices around adoption of customer energy resources (CER) such as rooftop solar, batteries and adoption of energy efficiency. The ISP does not report on generation prices or on the distribution and retail sectors. The ISP does include projections of the uptake of CER. However, it uses this information to determine the impact of CER on generation and transmission systems, not on customer outcomes.

The modelling here extends the ISP analysis by:

- Calculating the price outcomes from the ISP on the generation and transmission sector
- Including modelling by Dynamic Analysis of the distribution sector and its price outcomes
- Including natural gas and road transport costs in overall energy bills
- Including the customer impacts of energy efficiency and electrification of gas appliances
- Including the customer impacts of both the ownership and operation of customer energy resources

Dynamic Analysis collaborated with CSIRO in designing the complete modelling package to deliver the required outputs. They applied their expertise in modelling the distribution network regulated revenue recovery process and resulting distribution price outcomes for distribution networks.

The impacts on customers are included from two perspectives:

- **System or shared impacts**: benefits or costs that all customers receive as a result of changes to costs that are passed through to all customers
- **Individual impacts**: Benefits or costs that are available to individual customers who choose to take certain actions such as ownership of CER or electrifying their gas appliances.

Consistent with the ISP, the analysis only covers the National Electricity Market (NEM) which excludes Western Australia and Northern Territory. This report is set out in two parts. The first section describes the modelling method and the scenarios which were implemented in order to understand the various system impacts on customers. The second section describes the modelling results.

2 Scenarios and method

To calculate the customer impacts of the ISP scenarios and assumptions with respect to energy efficiency, building electrification, transport electrification and adoption of solar PV and batteries, it is important to separate system impacts from individual customer impacts (these definitions are provided in the introduction). We specifically implement the *Step change* scenario which has emerged as the most likely scenario in the various scenario stakeholder consultation that AEMO has undertaken[1].

Calculating system impacts requires system level modelling of the electricity sector in all its parts: generation, transmission and distribution. Calculating individual impacts requires simulating the energy needs and operations of customer owned appliances and resources. In this respect the focus is on residential households rather than commercial or industrial customers. An overview of the modelling process incorporating the two different types of quantitative analysis is shown in Figure 2-1.

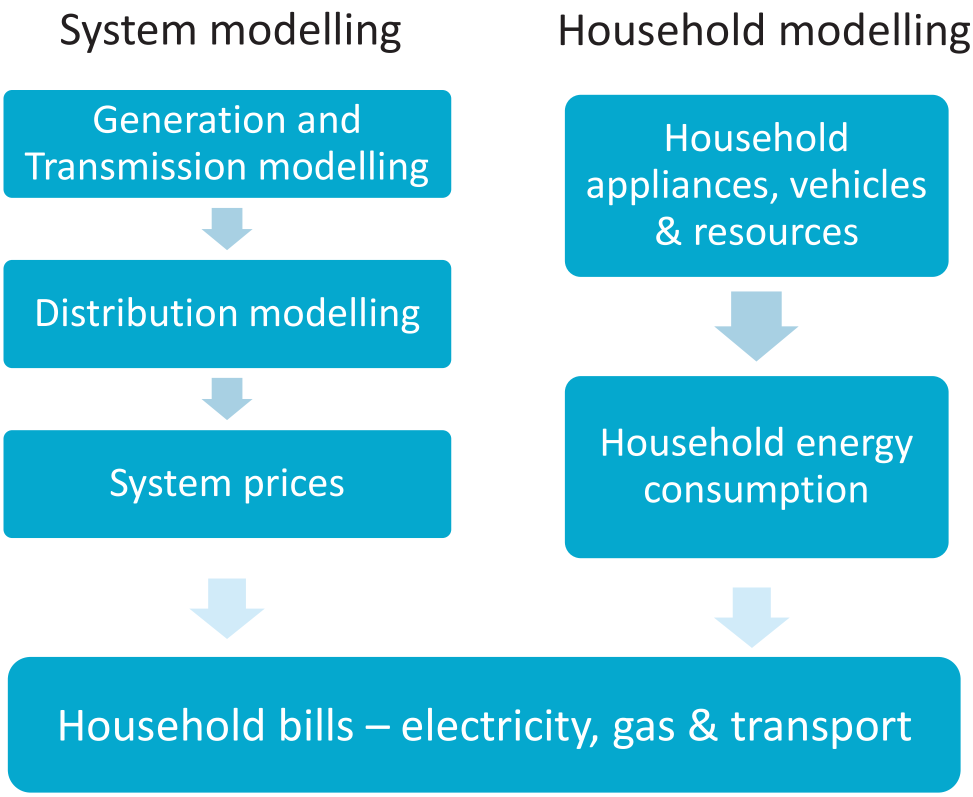

Figure 2-1 Overview of customer impact analysis framework

The electricity system and each of the key retail electricity price components are modelled in detail. However, simpler methods and assumptions are used to calculate household gas and

[1] This analysis is based on the ISP 2022 version of *Step change*. In AEMO's 2023 inputs, assumptions and scenarios consultation, AEMO has proposed using two versions of *Step change* going forward.

transport costs. The gas network component of the retail gas price is calculated based on the projected change in volume of gas consumption under the ISP Step Change scenario. Residential and commercial gas consumption is projected to fall by 78% by 2050 reflecting electrification of gas appliances. Consequently, we assume the network price for gas will need to increase in order to recover more revenue per unit of energy sold.

The analysis includes the NEM states only. It would be possible to include Western Australia under the same methodology, but it was excluded because it has some significant data shortages and inconsistencies with NEM scenarios and data. The main public scenario data is the Western Australian Whole of System Plan (WOSP) from 2020[2]. The WOSP is considered out of date because it precedes the current national consensus on a net zero emission target for 2050. Data on Western Australian distribution network electricity loads, investments and revenue recovery are also less routinely published than for east coast distribution networks. The Northern Territory also has similar data limitations and is less advanced in net zero emission planning.

2.1 System models and data

2.1.1 Electricity demand model

The process followed by AEMO for the ISP and replicated here is to estimate half hourly electricity demand at the state level for every year until 2050 by summing or subtracting (as appropriate) from the underlying demand:

- Rooftop solar generation and all other solar less than 30MW
- Storage charge and discharge for batteries located in residential and commercial buildings
- Charging of the whole electric vehicle fleet (motor cycles, cars, trucks and buses)
- Energy efficiency
- Electrification of gas appliances in residential and commercial buildings
- Changes in the operation of appliances such as hot water heating, pool pumps and air-conditioners

For most of these categories the number of devices and the depth of changes in operation is increasing over time. The changes in energy efficiency and the number of CER deployed over time has been sourced from the ISP 2022 assumptions for the *Step Change* scenario. The number of electric vehicles[3] by state in the *Step change* scenario is shown in Figure 2-2. At the national level, these numbers result in an electric vehicle fleet share of 0.3% in 2022, 15% in 2030, 61% in 2040 and 99% in 2050. Electric vehicle sales are 50% by 2030 and close to 100% from 2040.

[2] A new WOSP is due at the end of 2023

[3] This includes all electric, plug-in hybrid electric and fuel cell electric. However, fuel cell vehicles only make up a significant share in the heavy truck (also called articulated truck) segment of road transport

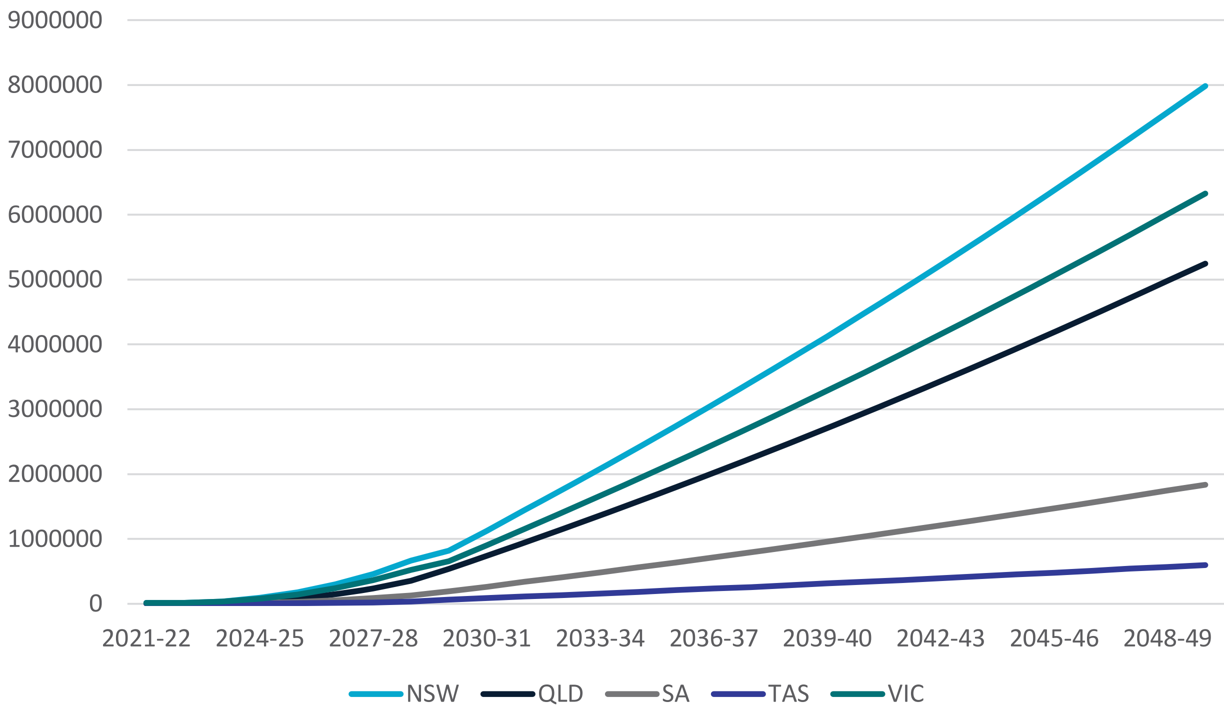

Figure 2-2 Projected electric vehicle numbers by NEM state under *Step change*

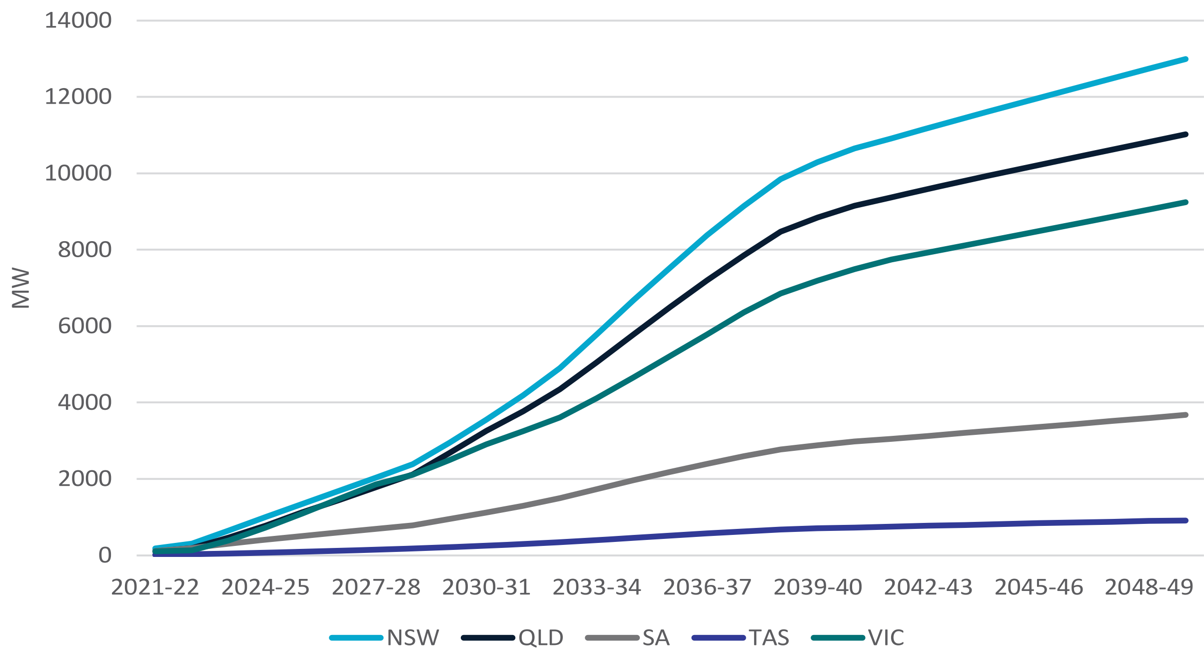

Figure 2-3 Projected battery capacity by NEM state under *Step change*

The capacity of residential and commercial batteries by state under *Step change* in shown in Figure 2-3. Batteries are present in 1 to 2% of households in 2022 (depending on the state) and this increase to between 28% and 40% of households in 2050. The *Step change* battery adoption projections are developed based on an assumption of residential or commercial business uptake of batteries, typically paired with a solar installation. From a modelling perspective, the impacts on the electricity sector would be broadly similar whether the batteries were privately owned or community batteries. The major difference would be in the operational profiles of these batteries, described in more detail below. The total capacity is just over 9GW in the NEM by 2030 and just under 38GW in the NEM by 2050 with a duration of around 2 hours.

The projected capacity of rooftop solar PV in the NEM under *Step change* is shown in Figure 2-4. In total there is around 30GW of customer owned solar PV in the NEM by 2030 and 53GW by 2050. The 2022 share of households with rooftop solar was between 17 and 40% depending on the state[4]. That range increases to 45% and 57% by 2050.

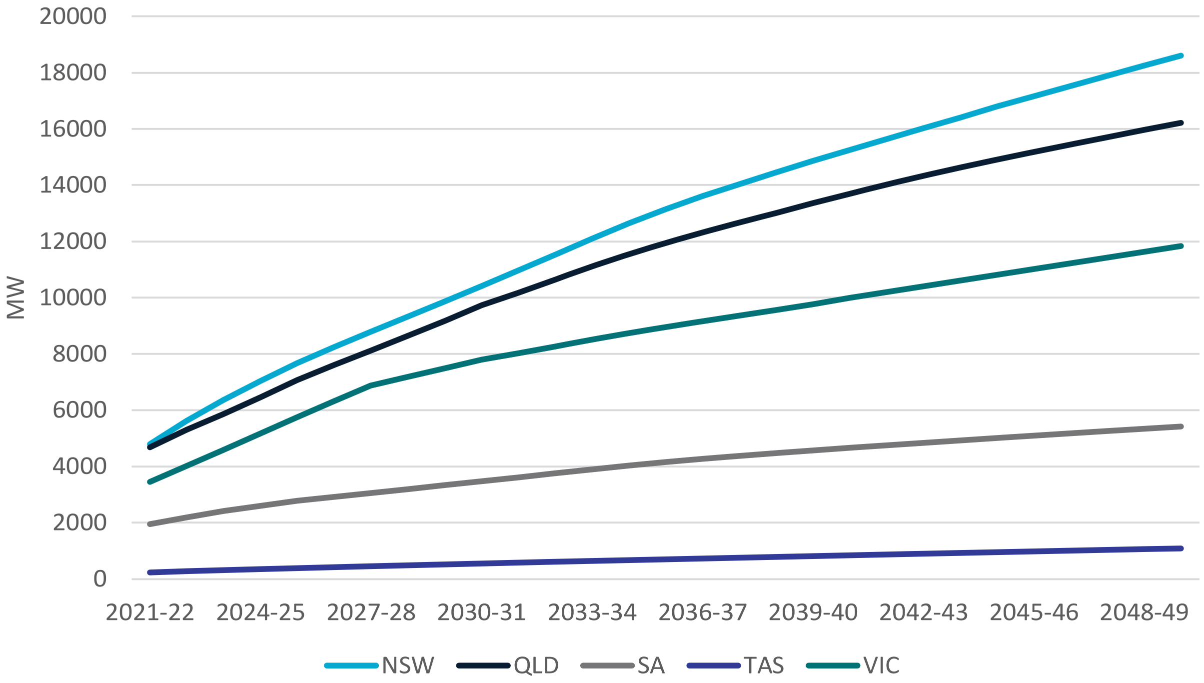

Figure 2-4 Projected rooftop solar PV capacity by NEM state under *Step change*

2.1.2 Update of electric vehicle charging profiles

While we have sought to remain consistent with most assumptions in the ISP 2022 *Step change* scenario, we did choose to use a more updated source of electric vehicle charging profiles. The ISP 2022 electric vehicle charging profiles was based on research from 2021 (Graham and Havas, 2021) which did not have access to the most recent data from Australian electric vehicle trials. This new data became available during 2022 and has been subsequently published[5]. An explanation of the new sources of data are provided in the published report (Graham, 2022). The changes are significant, and subsequently it was decided to include this update rather than continue using the older 2021 data. The differences in the two data sets are demonstrated in Figure 2-5. The new data has less charging during the evening peak period in most profiles. There is also a generally stronger alignment with solar production.

[4] CSIRO estimate. These estimates will vary between source as the Clean Energy Regulator does not specify which installations are residential.

[5] The report is available at Microsoft Word - CSIROEVreport_20221124.docx (aemo.com.au) and the data from https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aemo-detailed-electric-vehicle-workbook---draft-2023-iasr.xlsx?la=en

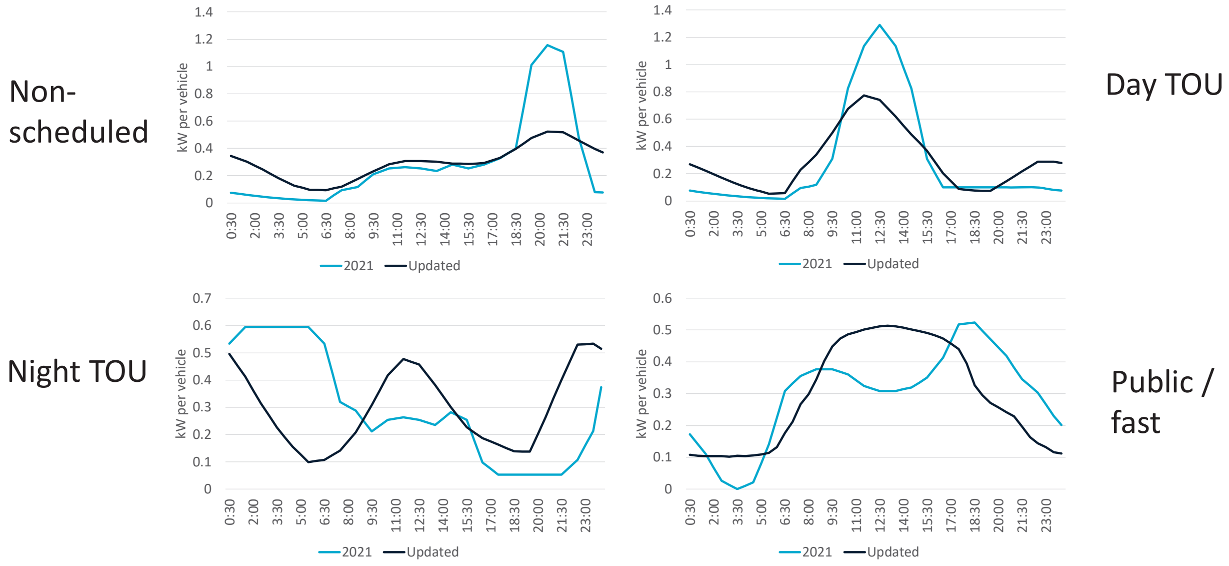

Figure 2-5 Comparison of the 2021 and updated electric vehicle charging profiles

2.1.3 Generation and transmission models

CSIRO uses two models of the electricity system which work together and perform slightly different tasks. The following table describes their key inputs, outputs and dependencies

Table 2-1 Generation and transmission models applied

Model	Market segment	Key function	Key inputs and outputs
Aus-TIMES	Energy consumption and conversion economy wide (residential, commercial and industrial) including all energy carriers (e.g., electricity, gas, LPG, liquid petroleum fuels, biomass and hydrogen)	Project annual energy end-use across the economy, hydrogen supply (where relevant) and electricity generation investment and retirement	Input from electricity demand model on the shape of electricity load Output to the demand model on the growth in electricity consumption Retirement schedule of electricity generators is the main input to STABLE
STABLE	Generation and transmission	Co-optimise generation and transmission investment and hourly operation of those assets to meet demand. Project the hourly operation of hydrogen electrolysers where relevant	Input from demand model on half-hourly load Input from Aus-TIMES on electricity generator retirement schedule Provide generation and transmission prices to customer bills analysis

2.1.4 Update of fossil fuel prices

For the generation and transmission modelled we again diverged from the ISP 2022 modelling assumption by updating gas and coal prices. At the time of modelling, gas and coal prices were peaking and strongly influencing wholesale electricity market outcomes. These impacts were too strong to ignore. It was important that the modelling have a view on when prices would return to normal. The modelling adopted the assumption that fossil prices would peak in 2022-23 and fall reasonably rapidly over the following year, with prices returning fully back to their longer-term trend by 2027. This timing reflected discussions and information presented at the 26th October 2022 AEMO Forecasting Reference Group on the outlook for fuel prices.

Oil prices, and subsequent calculation of Australian petrol prices for internal combustion vehicles, are based on IEA (2021). Like gas, petrol prices have been adjusted to take account of the recent fossil fuel price cycle.

2.1.5 Distribution model

Dynamic Analysis undertook modelling of distribution network prices for each state based on energy, peak demand and customer growth data provided by CSIRO. The modelling was performed on one distribution network in each state including Ausgrid (NSW), Energex (Qld), Powercor (Vic), SAPN (SA) and TasNetworks (Tas).

The model sought to forecast the annual change in fixed and energy consumption tariffs in each network based on forecast revenue requirements and changes in energy consumption. The model predicted an increase in network tariff rates if revenue growth exceeded energy consumption, and vice versa.

Revenue requirements

The revenue requirements utilised the calculation steps in the Australian Energy Regulator's (AER) Post Tax Revenue Model (PTRM)[6]. The PTRM calculates the financing, operating, tax and incentive payments based on expenditure profiles, and previous financing data such as existing value of asset base and depreciation. In an innovative approach, the AER's PTRM model was extended to a 30-year outlook and expressed in FY2022 dollars. The starting point was to identify the existing revenue components in the AER's final determination for each network.

Dynamic Analysis capital expenditure and operating expenditure forecast by asset class based on the following drivers and assumptions.

- Growth capex – The growth capex model used existing zone substation capacity data as a proxy to identify augmentation needs arising from peak demand growth. The level of growth capex was a function of peak demand growth, spare capacity at each zone, and the relative cost of infrastructure in each zone.
- Replacement capex – It was assumed that 40 per cent of a network's system assets would need to be replaced over the 28-year period to 2050. The value of replacement capex was based on the reconstruction value of a network's assets which in turn relied on data published by the AER's website relating to population of assets and costs of replacing assets.
- Other capex – It was assumed that other system capex and non-network capex would continue at levels currently being experienced by the relevant network.

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[6] The current version of the PTRM can be downloaded from the AER: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-post-tax-revenue-models-transmission-and-distribution-april-2019-amendment

- Operating expenditure – Operating expenditure forecasts utilised the AER's existing trend calculations which include an adjustment for increased network size and customer numbers, together with a productivity factor of 0.5 per cent.

The capital expenditure forecast was allocated to the relevant system asset class in the network's Regulated Asset Base (RAB). From here, the return on capital was calculated in line with the AER's PTRM which uses the nominal weighted average cost of capital (WACC). The cost of capital forecast reflected an uplift from network's current WACC based primarily on a forecast increase in cost of equity and debt.

The depreciation element of revenues was based on the application of the AER's approach to apply straight line depreciation minus inflation. We utilised the existing year on year tracking depreciation schedules and applied the forecast capital expenditure profile by asset class.

The final step was to add the forecast operating expenditure and tax forecast to derive the annual revenue requirement by year for each network.

Energy consumption

Dynamic Analysis utilised the energy consumption forecast produced by CSIRO for each state. The methodology ensured that large loads that connect at the transmission level are excluded from the energy consumption forecast. Further information on the methodology is discussed in section 2.1.1 of this report.

Calculation of tariffs

Dynamic Analysis derived a forecast of network tariff rates for fixed and energy parameters for each of the networks. The underlying logic of the model was that network tariffs would increase if revenue grew faster than energy delivered by the grid, and vice versa.

The first step was to identify the current fixed and energy rates for residential customers in the approved pricing proposals for FY23. The next step was to identify the relevant annual growth rates for revenue and energy consumption forecasts from FY24 to FY50. The last step was to identify the change in network tariff required to ensure that revenue could be collected from residential customers.

2.2 System modelling scenarios

There are three questions that the system modelling has been designed to answer:

- What is the system impact of greater CER flexibility through more dynamic coordination?
- What is the system impact of electric vehicle uptake?
- What is the system impact of electrification of gas in buildings?

A summary of the scenarios is provided in Table 2-2, however, the following sections provide more detail on each of the three areas of focus.

Table 2-2 Summary of scenarios

Question to be answered	Scenario	Counterfactual scenario (against which to measure any system savings)
What is the system impact of electric vehicle uptake?	*Step change* level of EV uptake	*No EV uptake*
What is the system impact of electrification of gas in buildings?	*Step change* level of residential and business electrification of gas appliances	*No electrification* of gas appliances
What is the system impact of CER flexibility through better coordination?	*Well-coordinated*: Better than *Step change* CER coordination	*Sub-optimal*: Worse than *Step change* CER coordination

2.2.1 Electric vehicles

While still relatively small, electric vehicle uptake is growing fast and under *Step change* is projected to almost completely replace the internal combustion engine fleet by 2050. Electric vehicles could add to peak demand if not well controlled. This issue of the optimality of control is addressed in the CER flexibility scenarios. The second significant impact of electric vehicles is that they significantly add to electricity consumption volumes. For the generation and transmission sectors, we found that moderate changes in the volume of electricity generated does not significantly impact average annual wholesales market prices. However, by improving network utilisation, the volume of energy delivered does significantly reduce the energy unit-based prices used to recover distribution costs under current distribution network regulations. Californian data indicates this can already be observed (Fitch el al., 2022).

To explore this topic, we modelled the distribution sector without any electric vehicle uptake in order to project NEM distribution prices under lower electricity consumption. The purpose is to quantify the benefit to electricity bills that is associated with the extra electricity consumption from electric vehicle charging.

2.2.2 Electrifying gas consumption in buildings

As part of the greenhouse gas abatement efforts in the *Step change* scenario, gas consumption from the residential and commercial (which mostly occurs in buildings) reduces over time. The energy for those existing gas consuming processes is met by electricity through replacing gas-based equipment to the equivalent electricity-based device.

There are two impacts from this substitution of electricity for gas:

- The volume of electricity consumer by the residential and commercial sectors is higher than it otherwise would have been
- There are new loads that could potentially impact growth in peak demand if they are used during peak times

AEMO publish data on both the volume and peak demand impacts of residential and commercial electrification in *Step change*. To determine what their impact is, the distribution modelling is run without the electrification included in *Step change*. Our expectation is that, like electric vehicles, electrification can be beneficial for distribution sector energy unit prices. However, like electric vehicles, the use of electric appliance during peak times can impact peak demand, moderating potential benefits. Of most concern is states such as Victoria where gas uptake is very high for winter heating which occurs during the peak. As this load is electrified it will add significantly to winter peak demand.

The *Well-coordinated* CER operation assumptions are applied in all the modelling which explores the impact of electric vehicles and building gas electrification.

2.2.3 CER flexibility

For the question of CER flexibility we designed two scenarios. The *Well-coordinated* scenario was developed and has all the same assumptions as *Step change* except that CERs are highly coordinated to reduced system impacts by flattening demand. The assumptions go beyond those that already exist in *Step Change* which includes a reasonably high degree of coordination already. To compare the impact of this scenario against a counterfactual where the degree of coordination is more modest a scenario called *Sub-optimal* was developed.

The two CER coordination scenarios primarily differ in how the various CER are operated. Operation of the devices might be through flat tariffs, price invectives such as time-of-use (TOU) tariffs (which set several daily price steps updated once a year by retailers) or through more dynamic and direct control of devices such as in virtual power plant (VPP) type arrangements which may be reacting directly to real time wholesale and network market prices[7]. The assumptions for the two scenarios vary the degree to which these types of controls are taken up over time by customers. The number and capacity of CER is the same in both scenarios[8].

Table 2-3 provides an overview of the key scenario assumptions and the CER devices which have been the focus of coordinated operation. Additional details on the operation assumptions for electric vehicles and batteries are provided in Table 2-4 and

Table 2-5. Addressing building comfort and insulation was also originally considered in scenario design. However, their inclusion would have mixed demand (load) and energy efficiency impacts

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[7] While wholesale price exposure is the most feasible route at present, there are trials (such as Project Edith) which are seeking to also make real time distribution prices available to CER operators as well. Project Edith - Ausgrid. In the modelling, the wholesale market price is the key driver.

[8] In particular we considered that *Step change* CER uptake might not be achieved or that CER availability for coordination might be impacted by issues with communication infrastructure. However, mixing different levels of the usable scale of CER with differences in its operation would have made the interpretation of scenario results more difficult.

making it more difficult to interpret scenario results. However, the important topic of energy efficiency is addressed further in the household level modelling.

This CER flexibility topic is not included in the ECA summary report which focuses on the implications of the first two questions.

Table 2-3 CER flexibility scenario descriptions

	Suboptimal	Well-coordinated
Grid visibility and price signals	Existing TOU rates prevail for much of the market. Low network visibility and no dynamic network price	Real-time Network and Wholesale Integrated Energy Prices (NEWIE prices) available to all consumers/devices with modified price constructs available to suit other consumer/device types
EVs	Higher share of convenience and TOU charging. Less coordinated V2G	Higher share of coordinated V2G, less of other strategies
Batteries	Higher share of TOU, less VPP	Higher share of VPP, less TOU
Hot water	More linked to home solar systems	Increased relevance of system coordination
Pool pumps	No significant change to current management	Greater application of peak avoiding coordination

Table 2-4 Electric vehicle operation assumptions for *Well-coordinated* and *Sub-optimal*

	Sub-optimal			Well-coordinated		
	2030	2040	2050	2030	2040	2050
Convenience	69%	57%	44%	63%	38%	14%
TOU – night & day	13%	17%	20%	14%	15%	15%
TOU - solar sponge	8%	14%	21%	8%	5%	1%
Public	10%	10%	10%	10%	10%	10%
V2H	0%	2%	3%	1%	3%	6%
V2G	0%	2%	3%	5%	30%	54%

Table 2-5 Battery operation assumptions for *Well-coordinated* and *Sub-optimal*

	Sub-optimal			Well-coordinated		
	2030	2040	2050	2030	2040	2050
VPP share	21%	26%	31%	41%	51%	62%
Residential flat	44%	38%	32%	44%	38%	32%
Residential TOU	35%	36%	37%	15%	11%	6%

2.3 Household bill modelling and data

Every customer has a unique set of circumstances in terms of their type of housing, household appliances and CER ownership and operation. Rather than select individual households, the household bill analysis focuses on the average customer in each NEM state. The analysis includes each customers electricity, gas and vehicle costs. To define the average customer the analysis makes use of the *2021 Baseline study for Australia and New Zealand 2000-2040*[9] and additional AEMO data such as the number of residential connections[10]. To understand the impact of ownership of solar PV and batteries we model the operation of those devices against half hourly electricity consumption data using a CSIRO data set that includes representative customers for each state[11] (Graham and Mediwaththe, 2022).

When solar PV ownership is included in energy bills, increasing export revenue losses from solar PV curtailment are also included in the assumptions. The losses to export revenue are assumed to grow to roughly 20% of revenue by 2050 for a solar PV system without batteries. This assumption is based on unpublished CSIRO analysis of future prices at solar generation hours as a proxy for the impacts of distribution system congestion.

For battery owners, the potential sources of revenue are at an early stage with their full opportunities not expected to be clear until they are a large collective scale in the market and the variable renewable energy (VRE) share of NEM generation exceeds 50%. To approximate this unknown future value, it is assumed additional revenue of $250 p.a. for grid support will be available.

CSIRO calculated that the average annual benefit available now for participation in TOU is $100 based on simulation of all TOU tariffs in each distribution network zone. However, it is very dependent on individual circumstances (particularly load shape) with the benefits ranging from $0 to $950 across customers simulated. This analysis suggests there is a $150 gap between current average annual TOU benefits and a potential future revenue of $250 under virtual power plant (VPP) participation in generation markets.

[9] Report: 2021 Residential Baseline Study for Australia and New Zealand for 2000 — 2040 | Energy Rating

[10] NATIONAL ELECTRICITY FORECASTING (aemo.com.au)

[11] This data set has been described in Microsoft Word - CSIROSolBatReport_20221209.docx (aemo.com.au)

For vehicles it is assumed that each household has an average 1.7 vehicles (cars only). This is based on ABS (2022) Census 2021 household numbers and BITRE (2022) 2021 vehicle fleet data.

2.3.1 Treatment of capital items

The presence of capital items such as solar PV and vehicles means that the analysis needs to consider the best way to incorporate these upfront costs without misrepresenting energy costs. If the capital costs are not included, then energy bill results might over-estimate the benefits of ownership of capital-intensive options. When capital costs are included, the analysis needs to make assumptions about how many years to spread the capital costs over as it would be misleading to assign them to a single year since they would always appear to be unattractive financially on this approach. Spreading costs over the asset lives is likely the most reasonable for self-funded household investments.

Overall, our approach is that, when capital items are not involved, energy bills are presented on a single year basis. Where capital is involved, energy costs inclusive of capital are averaged over 20 years. The averaging over this time frame is also useful in avoiding single year retail price events dominating the household bill analysis[12]. The capital costs included are solar PV, batteries and vehicles because these include extra capital costs which discretionary[13]. We do not include the costs of general appliances that are included in most households because these are not considered additional expenses if replaced at normal retirement rates. We do not include the cost of any additional wiring to accommodate greater use of electricity because it is very location specific. It is interesting to note some initial trials have indicated most customers using standard power points for electric vehicle charging (Origin Energy, 2021).

[12] Some approaches to calculating bills involve in taking the retail energy price in a single year and repeating that energy price over the life of the capital assets

[13] Solar PV and batteries are not essential household times. We also include vehicle costs because while petrol or diesel vehicles are essential and common, electric vehicles are not.

3 Modelling results

3.1 Electricity demand

As discussed in the previous section, across all scenarios modelled, the amount of CER is the same as the *Step change* scenario. The *Sub-optimal* and *Well-coordinated* scenarios vary the way in which CER is operated with the latter scenario designed to have greater efficacy in reducing peak demand. Figure 3-1 shows the average summer load across all NEM states in 2050 (when we have maximum deployment of CER). It shows that *Well-coordinated* has regularly lower demand in the peak time of the early evening.

It is important to note that major benefits of the operational assumptions of the *Well-coordinated* scenario are not able to be shown in the daily electricity load profile because the impact of any dynamically controlled batteries that have been designated as VPP do not appear in the demand profile. Instead, they are assigned as additional battery storage capacity that is available to the generation side of the modelling. Consequently, there is greater ability to address peak demand in *Well-coordinated* than appears in the demand profile alone.

Peak demand is, of course, an event that occurs only once per year and not necessarily on the same day or season in each state of the NEM. When we look at the peak demand events across all states, reduction in peak demand in *Well-coordinated* relative to *Sub-optimal* builds to 4.3% by 2050 or around 3.3GW (again, not including the benefits of dynamically controlled batteries).

In fine tuning the assumptions of these two scenarios we found that both TOU tariffs and more direct control schemes were both fairly effective at avoiding evening peaks. As electric vehicle numbers become large towards the end of the projection period, a different challenge emerges which is finding the ideal time to charge the electric vehicle fleet on low solar output days. TOU tariffs in *Sub-optimal* continued to direct consumers to charge during the day when solar is normally available. However, in some cases we saw mid-morning emerge as new state peak events in the 2040s on low solar PV production days. With more vehicles under direct control in the *Well-coordinated* scenario, they can be redirected to charge away from daytime hours when solar PV output is low.

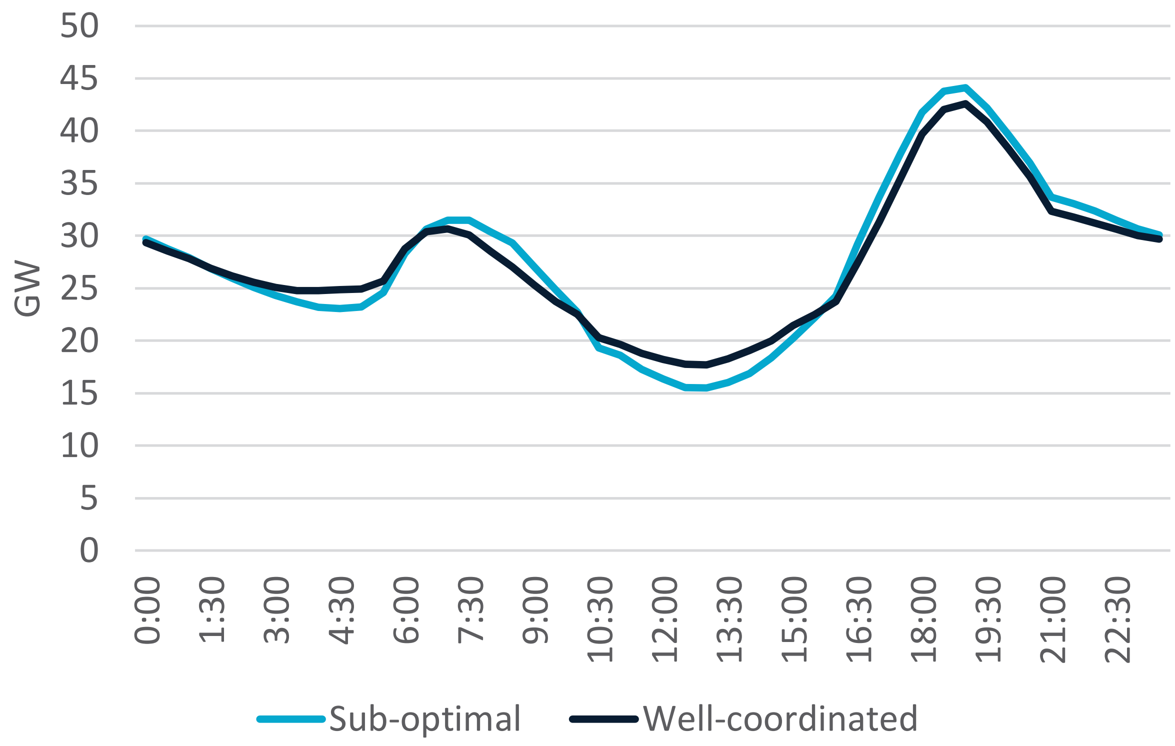

Figure 3-1 NEM average summer load in 2050

3.2 Generation and transmission sectors

Our overall finding is that the cost of generation and transmission is only moderately sensitive to changes in the volume and peakiness of electricity demand – at least in the medium to long term and with reasonable market foreknowledge. On any moderate to high demand day, with fixed generation capacity, higher demand will lead to higher prices as the dispatch system works through higher and higher bids to access the required level of supply. However, in a planning sense, over the medium to longer term, capacity is not fixed and the only limit in meeting a wide range of future levels of electricity demand is the cost of technology and fuel.

The generation and transmission modelling includes the transmission and regional cost assumptions incorporated in the AEMO input and assumptions workbook for the 2022 ISP, which includes, for example, differences in costs in accessing generation from various renewable energy zones. However, accessing more renewable energy zones does not lead to a large increase in costs when supplying different volumes of demand, and we do not include any additional assumptions around supply chain constraints for faster deployment of projects. Furthermore, peak demand is often met by technologies such as storage and gas peaking plant. These can often be located in places that do not require long distance transmission connection to renewable energy zones.

The historical and projected wholesale electricity price for *Well-coordinated* and *Sub-optimal* is shown in Figure 3-2. The projected prices are based on the long run marginal cost of generation and transmission modelling. In theory the wholesale market must converge to the long run marginal cost of generation technology[14]. However, market prices will be more volatile in reality than projected here because market foreknowledge will not be perfect. The market is currently at a high price point owing to high fossil fuel prices in 2022 and 2023. As discussed in the section 2, we assume fossil fuel prices fall significantly in 2023 and are back to pre-2022 levels by 2027. This is the low point before 2030 as indicated in Figure 3-2. This is also a period of high variable renewable investment due to state renewable policies which also serves to bring down prices. In the early 2030s, wholesale prices are rising reflecting the long run marginal cost of installing sufficient supporting technologies together with variable renewables to meet future electricity demand. Projected long run marginal costs level out at around $70-80/MWh which is consistent with projected long run marginal costs for high variable renewable electricity systems (Graham et al., 2022).

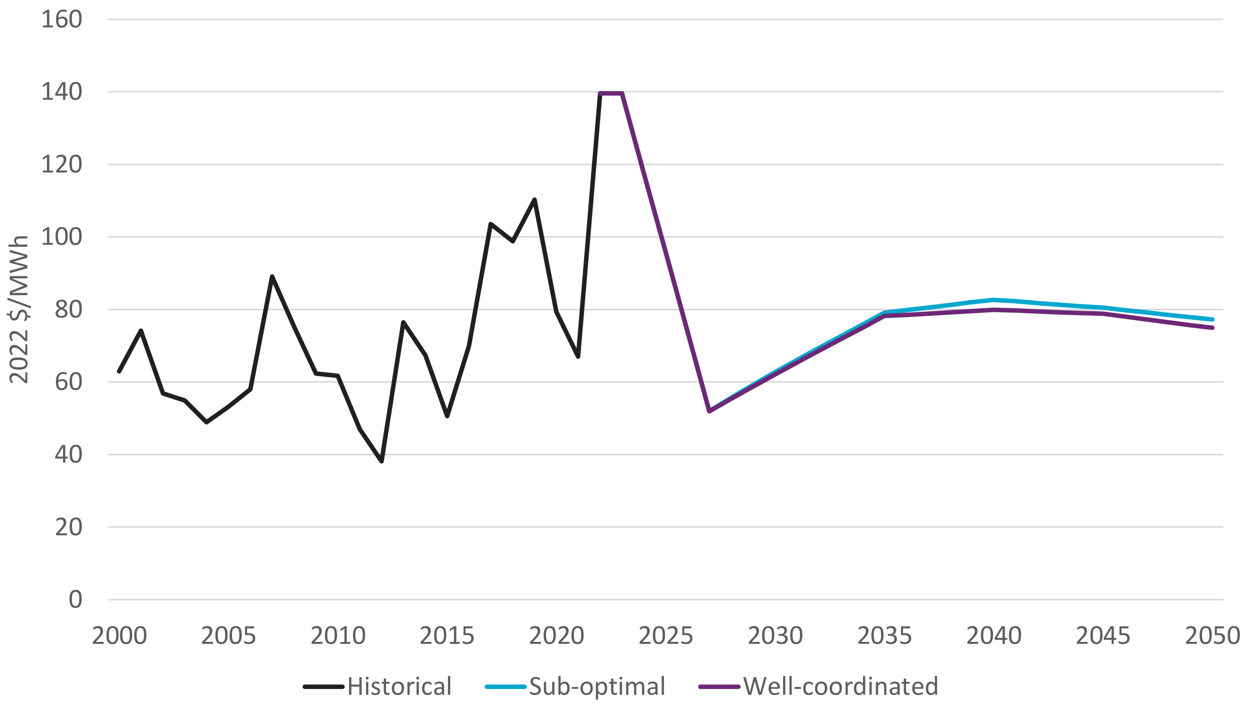

Figure 3-2 Projected NEM wholesale electricity generation prices for the Well-coordinated and Sub-optimal scenarios

The difference in wholesale prices between *Well-coordinated* and *Sub-optima*l is minimal in Figure 3-2, reflecting that the main driver of costs is the long run marginal cost of generation. However, the outcome is reasonably proportional when considered against the scale of demand reduction as shown in Figure 3-3.

[14] If the price is lower than the long run marginal cost for too long, then investment will stall leading to under-capacity which forces the price back up. If the price is higher then the long run marginal cost for too long, then a period of high investment will occur eventually dampening down the price with more capacity.

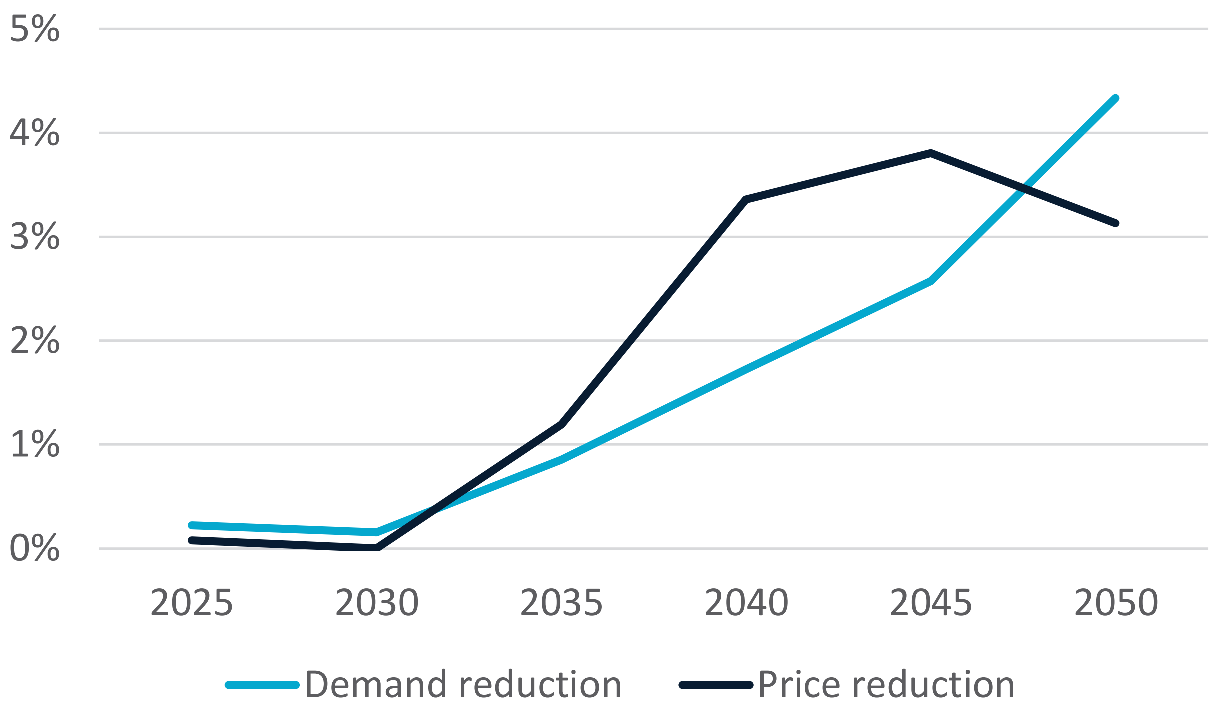

Figure 3-3 Generation price reduction achieved due to peak demand reduction

The total cumulative expenditure on generation and transmission investment in *Well-coordinated* is around $500 billion[15]. Relative to *Sub-optimal*, improved CER coordination results in around $700 million in savings per year from the mid-2030s. These lead to cumulative savings of $13.7 billion or $4.6 billion on a net present value basis.

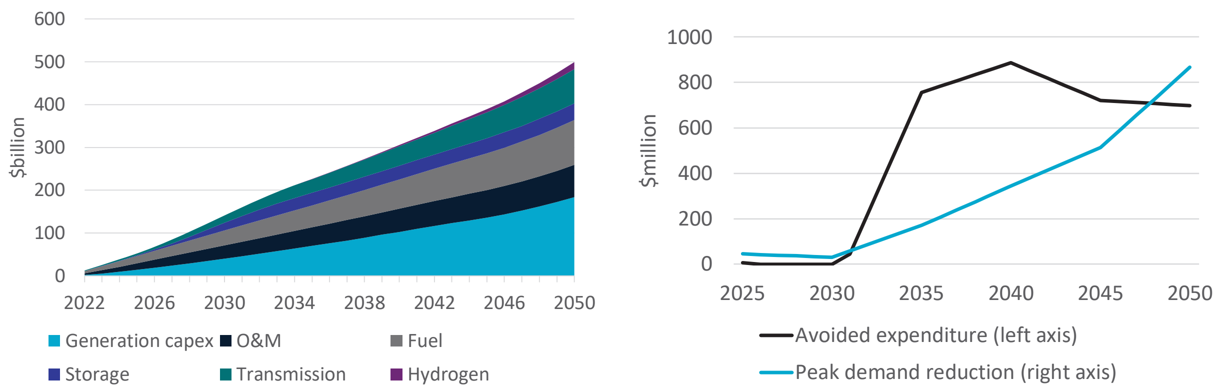

Figure 3-4 *Well-coordinated* total cumulative generation and transmission investment (right) and avoided expenditure (left)

Given the limited sensitivity of generation prices to demand changes, the generation model was not re-run for the *No EV uptake* and *No electrification* scenarios. The *Well-coordinated* generation prices were used for any bill calculations associated with those two scenarios.

[15] We also include the cost of hydrogen infrastructure since the flexibility of hydrogen electrolysers tends to significantly reduce the storage needs of the system, therefore making it an integrated part of the electricity system.

3.3 Distribution sector

The modelling shows that distribution network tariffs would initially rise in the period to 2030, but would then fall significantly below today's price by 2050. This can be seen in the weighted average of energy tariff rates across the five networks (Figure 3-5).

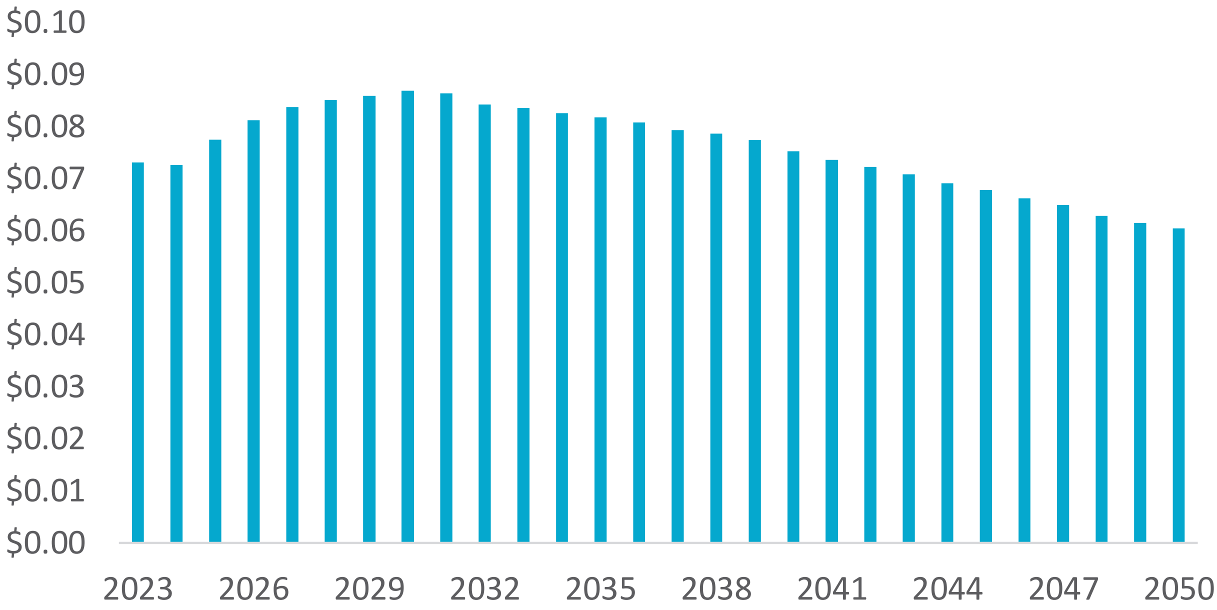

Figure 3-5 Distribution sector energy tariff rate in *Well-coordinated* (weighted across five networks)

In the period to 2030, revenue requirements are forecast to increase primarily due to higher rates of return. The equity component of the rate of return was 'locked in' by the AER in the current distribution determination of most networks. The rate was significantly below historical levels due to unprecedented low interest rates. However, recent financial data indicates that the equity component will be significantly higher in the upcoming determinations of distribution networks. We also expect a moderate increase in replacement capex due to ageing of network assets.

At the same time, energy consumed from the grid is forecast to be relatively flat in the period to 2030 due to increasing volumes of self- consumption from new and updated solar panels. The combination of higher revenues from increasing rate of return and relatively flat energy sales results in a forecast of higher network tariffs for residential customers.

From 2030 onwards, network tariffs start to decline as energy consumption exceeds the growth rate in revenue. Energy consumption grows significantly in most states due to an acceleration in forecast electric vehicles and increasing electrification. Revenue is also forecast to increase over this period due to increasing replacement and the need to augment the network to meet growing demand at peak times. However, the growth in replacement is much lower than energy consumption, leading to lower network prices.

The results emphasise that networks have high fixed costs and therefore have significant economies of scale. For this reason, growing energy sales from electric vehicles has a significant impact on reducing network tariffs. Figure 3-6 shows how revenue does not increase in line with energy consumption growth from 2030 onwards, leading to a forecast decline in network tariffs.

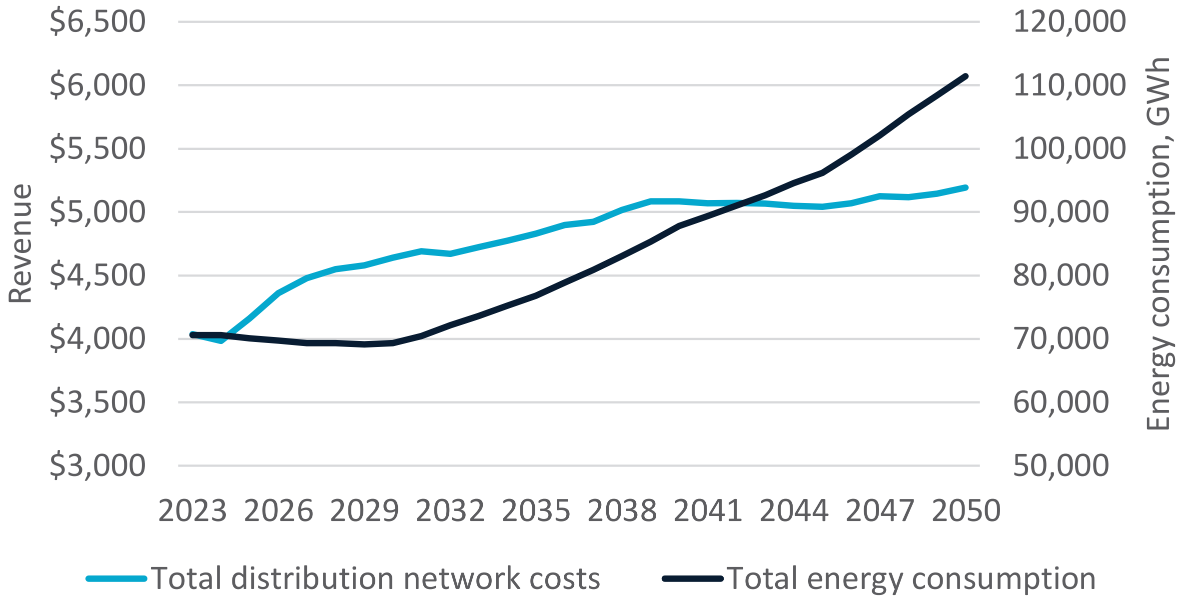

Figure 3-6 Distribution network consumption and costs in *Well-coordinated*

3.4 Household bills

The following analysis steps through each component of household energy costs – electricity, gas, road transport. It also explains how electrification of buildings and road transport impact customers, in terms of their direct impact as an individual adopter and in terms of the shared system-wide impacts of mass adoption.

3.4.1 Electricity bill trends

The projected generation, transmission and distribution costs have been applied to calculate household electricity bills. The projected annual average household bill for the NEM is shown in Figure 3-7. Owing to current high fossil fuel prices, the main change from 2023 to 2030 is a reduction in wholesale costs by $700 a year. Network costs increase slightly during this period but fall for the remainder of the projection period as the electrification of the road vehicle fleet improves the utilisation of the distribution network. Electric vehicle charging costs not included in the bill at this stage but are added further below. Improved energy efficiency of around 0.5% per annum (based on the 2022 AEMO ISP) also contributes to overall household electricity bill cost reductions.

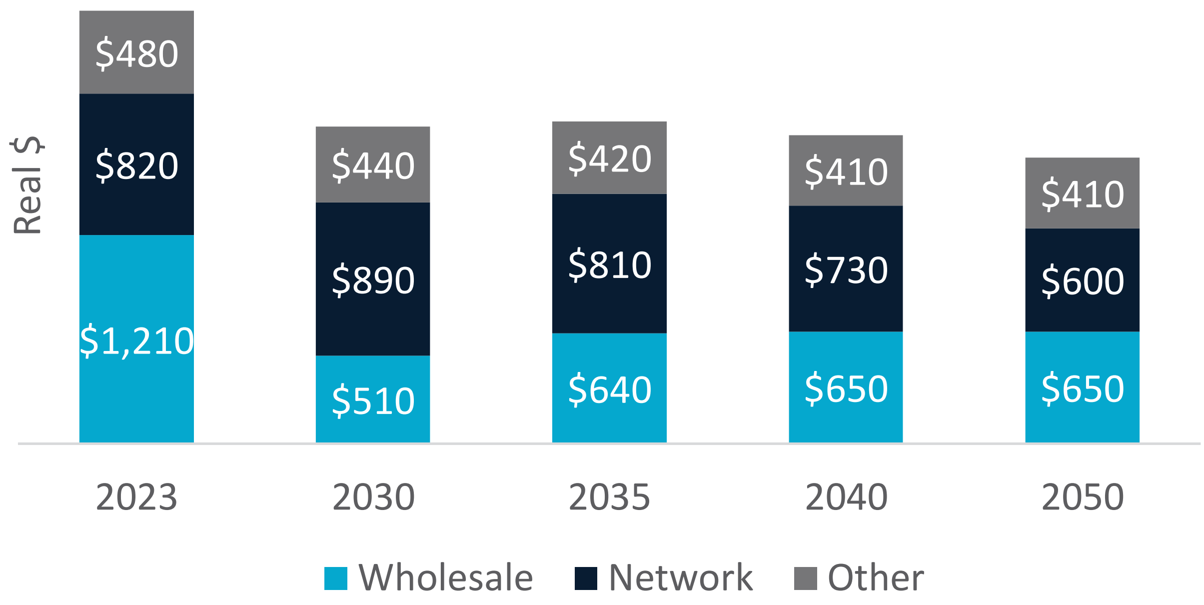

Figure 3-7 Annual average NEM electricity bill for selected years

State electricity bill components are shown in Figure 3-8. New South Wales, South Australia and Tasmania have tended to have higher bills because their retail prices are higher. This is projected to continue to be the case under the scenario modelling results (Figure 3-9). South Australia tends to have the highest retail electricity price, but this is moderated by lower electricity consumption in favour of gas (Figure 3-11). The highest average household gas consumer, Victoria, has the lowest electricity bill owing to fewer electric appliances on average. Queensland does not have high gas consumption but it has had historically lower retail prices and the modelling projects this to continue to be the case after the current high prices period has ended.

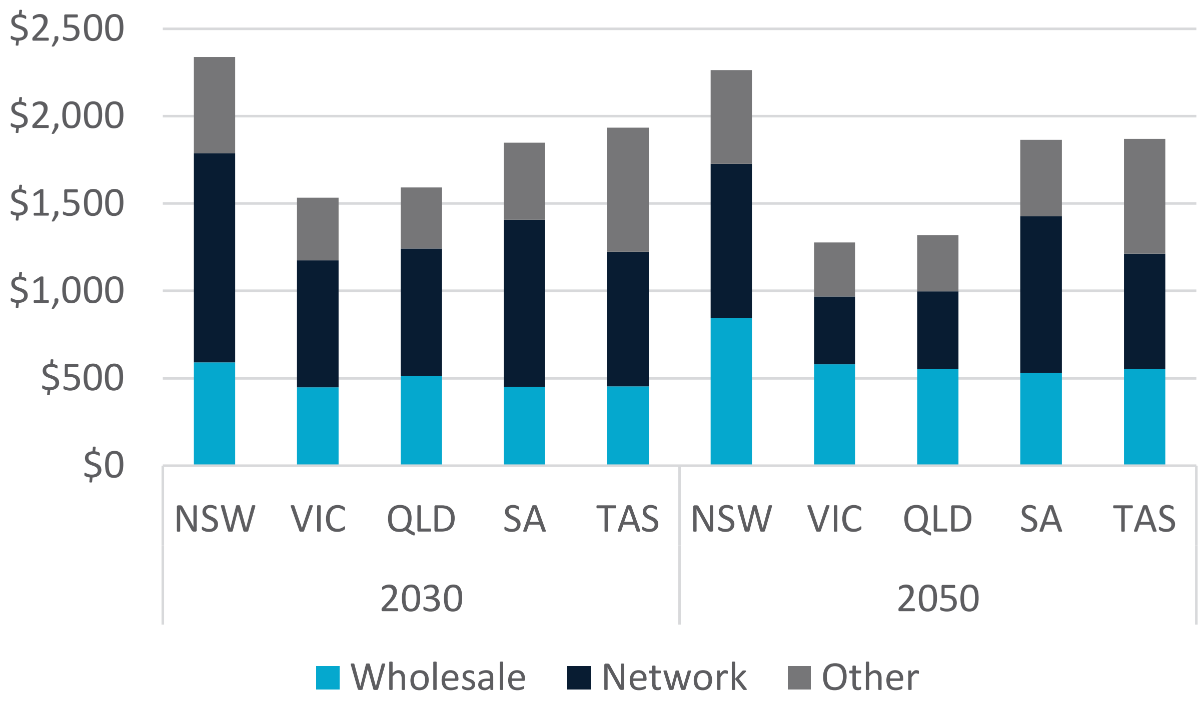

Figure 3-8 Annual average state electricity bill for selected years

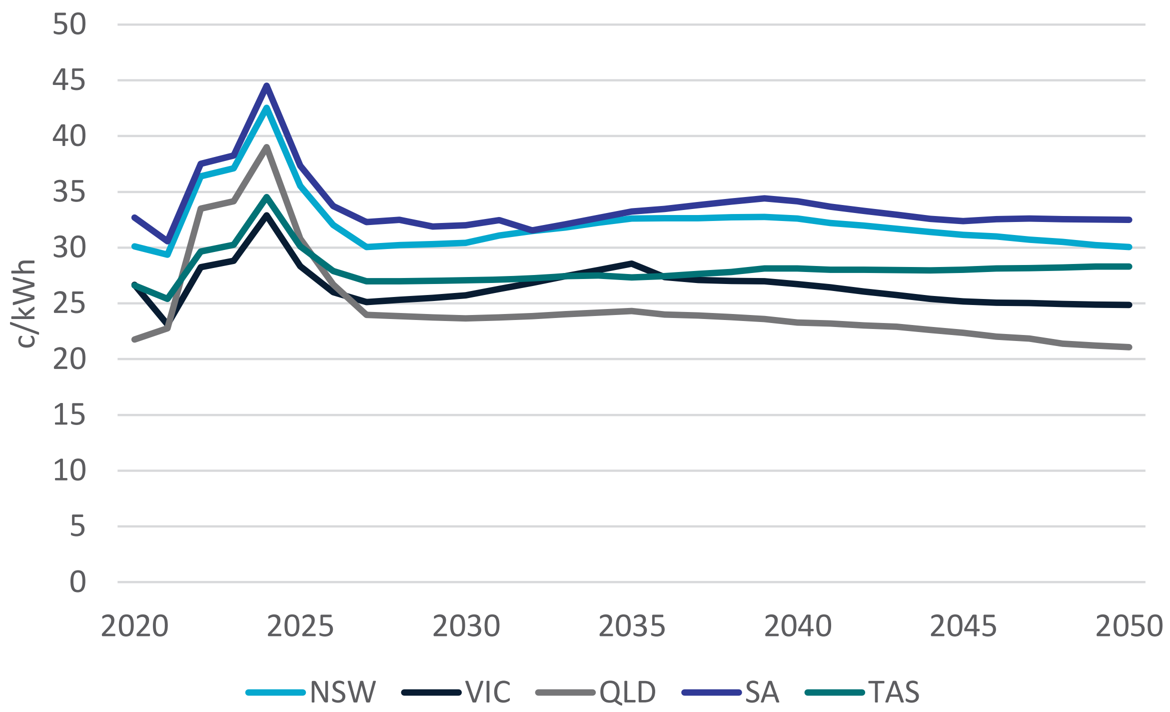

Figure 3-9 Projected average retail prices by state, *Well-coordinated*

3.4.2 Gas bill trends

The projected average gas bill for the NEM is shown in Figure 3-10. In alignment with the electricity bill analysis, there is an improvement in wholesale gas costs by 2030 due to the assumptions that gas prices will be restored to normal levels by 2027. However, network costs rise throughout the projection. This follows from the projected 78% reduction in residential and commercial gas consumption (AEMO 2022 ISP). The gas bill projections assume that the gas networks will have to charge the remaining customer proportionally more to make up for this loss of sales volume (Figure 3-10). This approach is by no means the only way in which networks and regulators may seek to deal with financial arrangements of lower gas demand. However, it is the most straightforward way of projecting network costs without an agreed alternative. This topic is an acknowledged long-term issue for the gas distribution sector[16].

Gas bills are small relative to electricity bills in most states. However, the impacts of rising gas costs are potentially very significant in states such as Victoria where natural gas is a greater share of household energy consumption. A moderating factor in the impact on Victorian households of rising gas network costs is that the network component is a relatively lower share of their retail gas costs (Figure 3-11). The lower the share of the network component, the lower the total increase in retail gas prices (Figure 3-12).

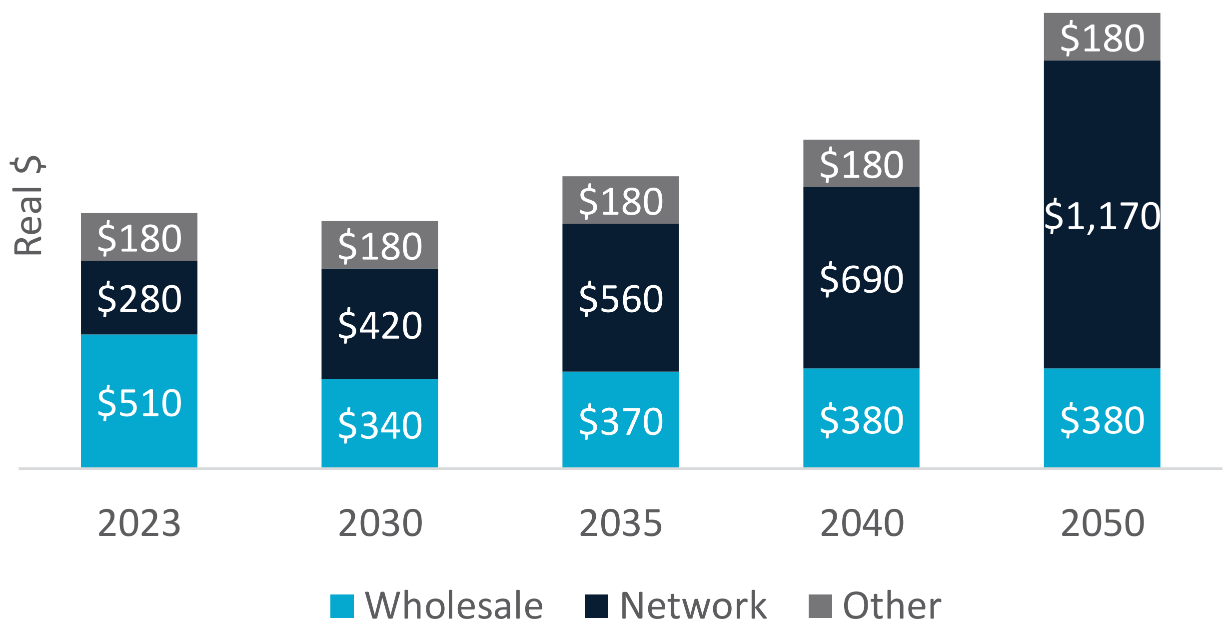

Figure 3-10 Projected annual average NEM gas bill

There is no assumed improvement in the efficiency of gas use in households. In the AEMO GSOO 2022, the *Step change* scenario shows gas consumption and gas connections falling by similar amounts indicating that there is no projected change in average gas consumption per household. Gas consumption should fall in new housing stock due to better design and higher energy efficiency standards. However, it may be that under Step Change, new houses are more likely to be electrified.

[16] See this Australian Energy Regulator information paper: Regulating gas pipelines under uncertainty - Information paper | Australian Energy Regulator (aer.gov.au)

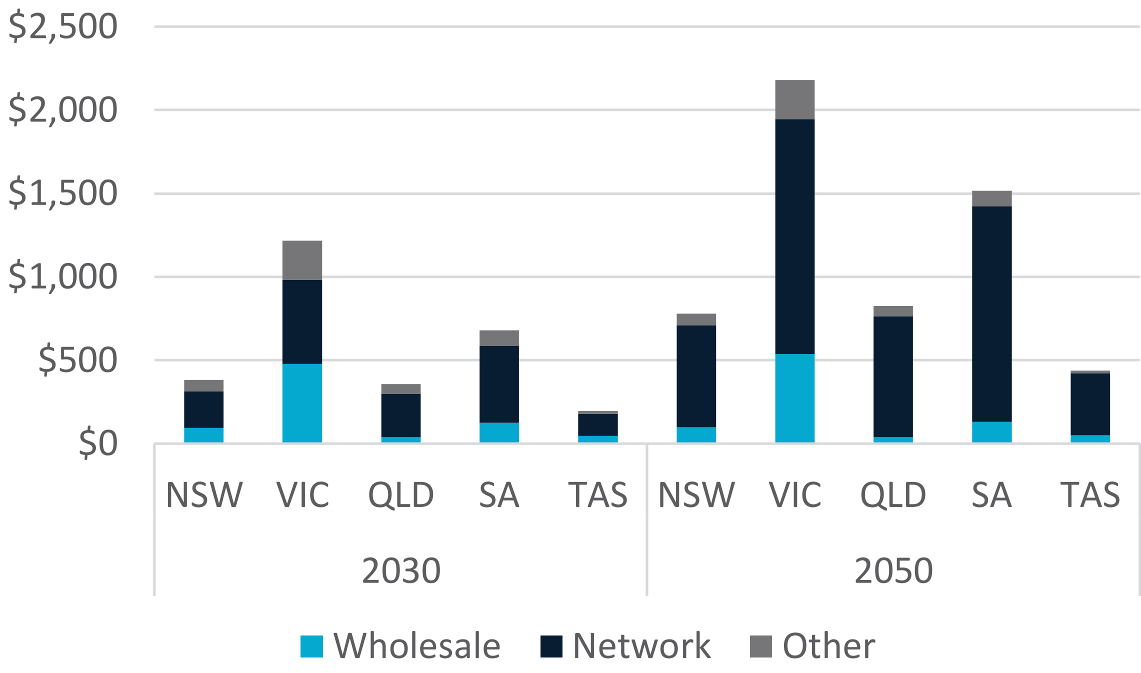

Figure 3-11 Projected annual state gas bills for 2030 and 2050

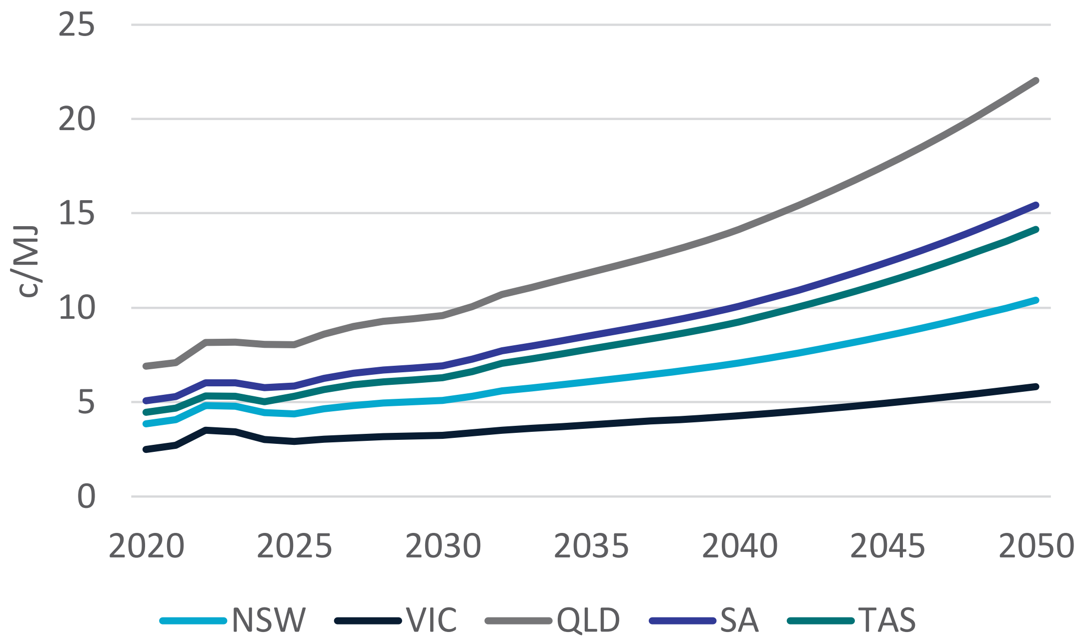

Figure 3-12 Indicative retail gas prices by state, *Well-coordinated*

3.4.3 Transport bill trends

Unless purchasing a significantly older second-hand vehicle, the car is the most expensive part of overall road transport costs. Among current models available for sale in Australia, petrol or diesel internal combustion engine (ICE) vehicles are significantly lower cost than electric vehicles (by around $20,000 depending significantly on the model). On the other hand, electric vehicle annual fuel savings can be around $2000 (varying significantly depending on how far you drive each year and where you charge – at home or from public charging stations). Electric vehicles are also expected to have lower maintenance costs owing to many fewer parts.

To navigate this uncertainty in costs we use the average number of vehicles per household (1.7), a medium vehicle size with equal driving range under liquid fuel or electric and historical average annual driving distances per state. Most underlying data is sourced from Graham (2022). The calculations also include planned state road user charges on electric vehicles[17]. The capital and running costs are calculated over 20 years of ownership and averaged over the NEM resulting in the projected road vehicle transport costs in Figure 3-13.

On the average 20-year bill basis, electric vehicles are already similar in costs to ICE vehicles today. That is, 20 years is long enough that the extra upfront costs of an electric vehicle have been paid back by lower running costs relative to ICE vehicles. However, it is expected that over time the costs of electric vehicles will converge towards that of ICE vehicles by 2030. Consequently, the running costs savings delivered by electric vehicles result in a longer-term reduction in road transport costs of around $1500 per annum (averaged over 20 years of ownership).

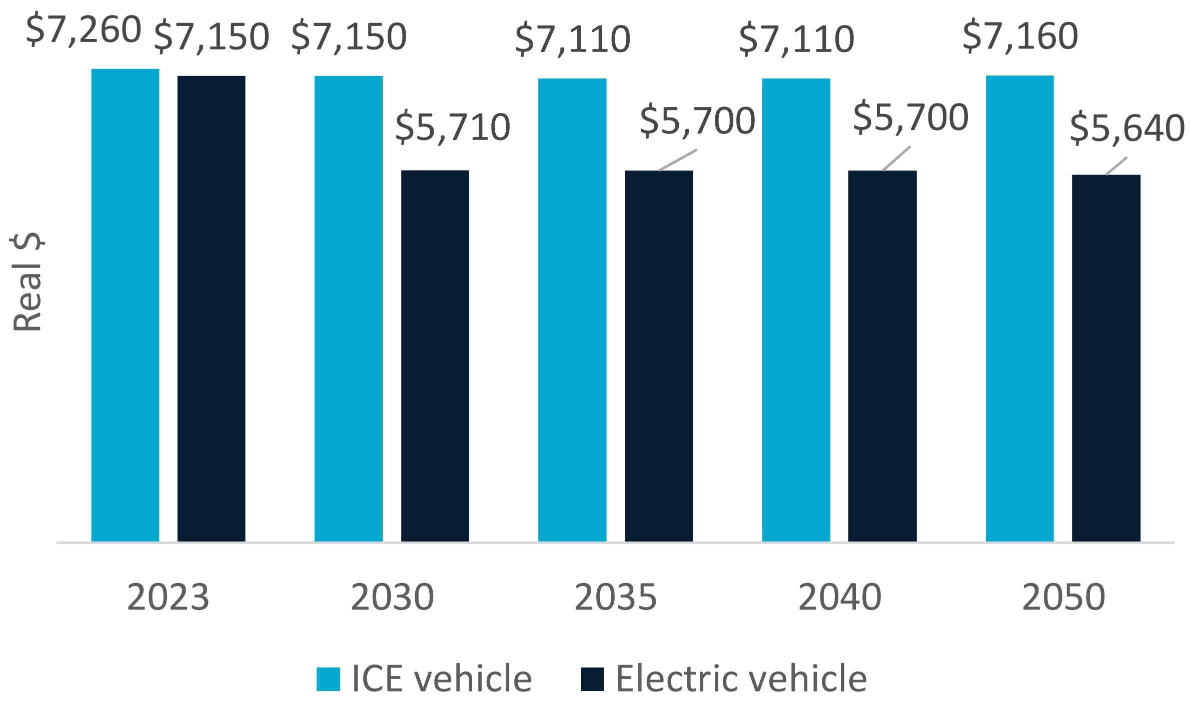

Figure 3-13 Annual average 20-year ICE and electric vehicle costs, NEM average

The state results for 20-year average ICE and electric vehicle running costs vary mostly by driving distance since vehicles are assumed to be available for the same costs in all states (Figure 3-14). There are some differences in electricity prices by state, but this is not as significant an issue as average driving distance. Victoria and Queensland passenger vehicles have historically higher average kilometres travelled per year than the other NEM states.

[17] We do not include the range of subsidies available to electric vehicles because of uncertainty as to how long they will remain available over our whole projection period

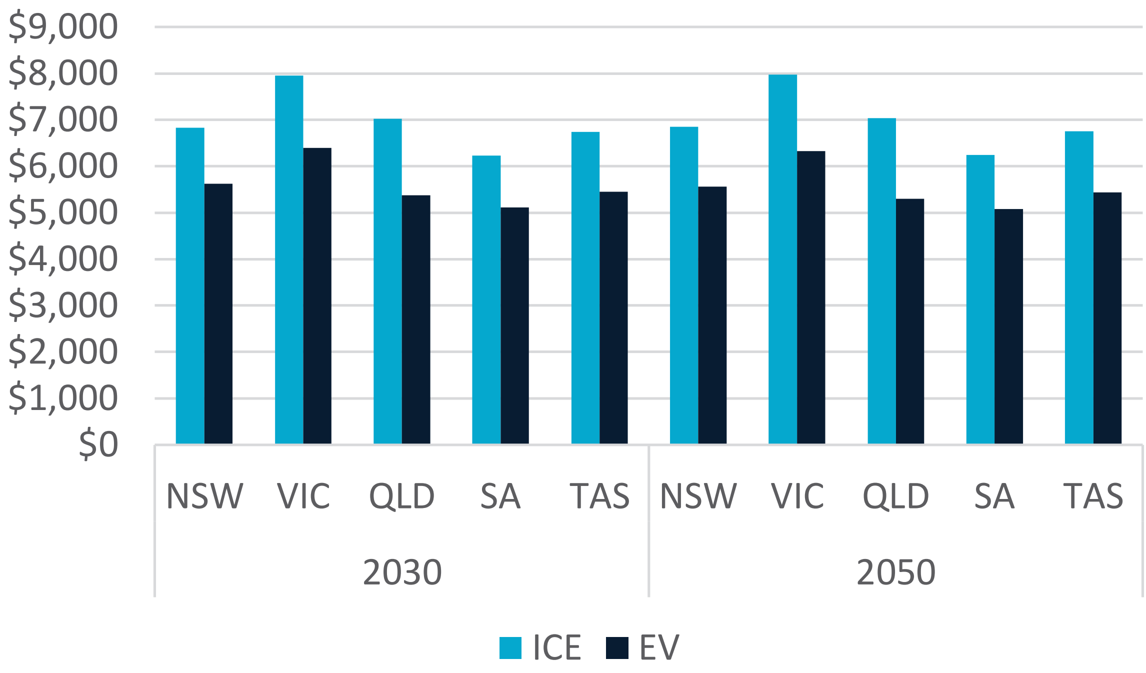

Figure 3-14 Annual average 20-year ICE and electric vehicle costs by state

3.4.4 System or shared savings

The generation, transmission and distribution network components of electricity supply costs can be sensitive to the scale of electricity consumption and its peak demand. As discussed in the generation sector results, generation is only moderately sensitive to changes in demand in the long run because most technology and fuel supplied can be scaled up at similar costs if investors have some foreknowledge.

For distribution and transmission networks to maintain reliability, they are generally required to invest in more capacity proportional to growth in peak demand. If the volume of electricity hasn't changed then this investment must be recovered from the same volume of electricity and the network unit price increases. If peak demand stays the same but network volume decreases, this can also result in an energy unit price increase. The reverse is also true. An increase in energy volume with no increase in peak demand can result in network energy unit cost decreases.

In the *Well-coordinated* scenario, the operation of customer energy resources (CER) was improved to determine its impact on peak demand and compared with a less improved scenario, *Sub-optimal*. In the household bill analysis, it is calculated that every customer (whether they own CER or not) benefits from the improved flexibility of CER by around $30 to $50 per annum (Figure 3-15).

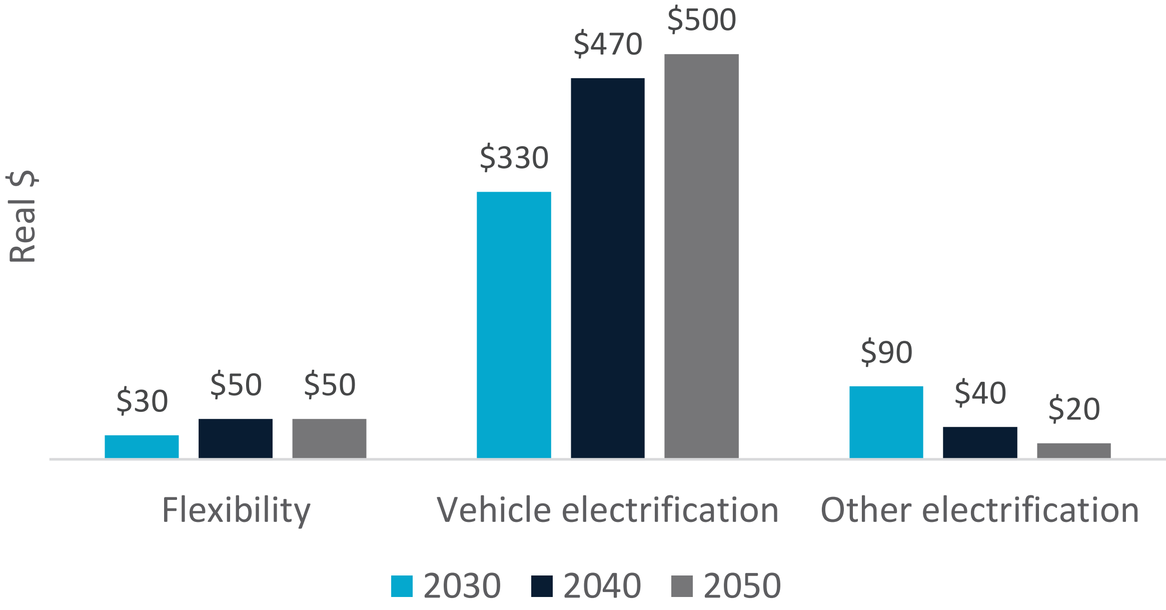

Figure 3-15 Projected system savings for selected years, NEM average

Vehicle electrification and other household electrification from gas appliances are two other potential sources of shared savings. The widespread adoption of electric vehicles creates a new source of electricity consumption which can be managed to largely avoid adding to peak demand. Under these circumstances networks can reduce the energy unit costs they need to recover from each customer, resulting in shared annual savings of $330 to $500 in the period 2030 to 2050, regardless of whether a customer owns an electric vehicle or not.

Other electrification which refers to the electrification of building gas appliances results in shared savings of $90 per customer by 2030. This is the same effect as the vehicle electrification with the extra volume reducing the energy unit price needed for network revenue recovery. However, these savings tend to be reduced over time due to the impact of electrified household heating on winter peak demand. Most mid to northerly Australia states are summer peaking due to summer cooling needs. However, as more electric appliances are used for winter heating, some states become winter peaking and the further growth of electric heating contributes to peak demand growth. The network investment costs that come with this peak demand growth erodes some of the network energy unit costs savings from the additional electricity consumption. As a result, shared system savings reduce to $20 per annum per customer by 2050.

3.4.5 Individual household savings

Separate from any changes in grid energy supply costs, there are a number of savings that households can potentially access individually. Costs savings at a household level related to electrification have been studied elsewhere, most notably by Rewiring Australia (Griffith at al., 2021).

The ability to access household savings depends on the amount of control a customer has over their housing. Installing solar PV and batteries requires significant upfront costs which are only worth undertaking if you can recoup the ongoing savings from long term ownership. For this reason, they are generally not suited to rental housing unless there is a cost sharing arrangement in place[18]. They are also rare in apartment buildings where the roof space is shared. Electric vehicle ownership might not be constrained by housing ownership as renters may be able to use an existing power outlet in their current parking space. However, some buildings will not have an existing power outlet and being a homeowner in a separate dwelling with off-road parking space gives you the best control over installing one. Home ownership (whether apartment or separate dwelling) also makes it more straightforward to access energy efficiency and electrify appliances.

Assuming a customer can access the cost savings methods, Figure 3-16 shows the projected savings over time that are available. Taking up energy efficiency measures assumed to be available under the *Step change* scenario provides $500 in savings per year. This amount will vary for individual households depending on their unique circumstances including how efficient the individual house and appliances are relative to the average home.

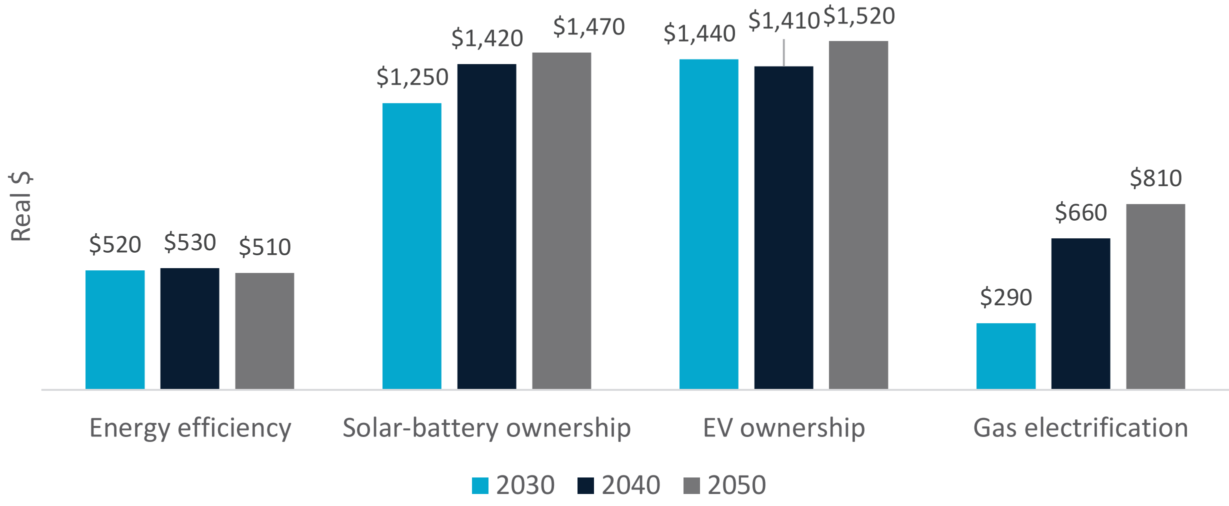

Figure 3-16 Projected savings available for household level action, NEM average

Solar-PV-battery systems and electric vehicle ownership provide the highest savings at around $1400 to $1500 per year relative to a customer without these technologies. The savings available from solar PV systems have been well known for some time and are reflected in the high adoption rates in Australia. Battery systems are less common due to currently high costs, but are expected to become more affordable over time. Electric vehicles are also an option that is high upfront cost at present, but are also expected to become more attractive to a wider range of customers over time (both in a financial sense and in terms of product range available).

Gas electrification is initially modest measure. However, as the costs of the gas network increases due to a loss of market volume in the later part of the projection period, the benefits of electrification of gas appliances increase more rapidly.

[18] There are some government programs which seek to encourage more renter-landlord agreements: Information for rental providers | Solar Victoria

Summary of total bill and individual savings

The individual household savings span across the electricity, gas and road transport bills of customers (i.e., the total energy bill). We can therefore calculate their total energy bill and measure all the savings against it. The savings over time are set out in Figure 3-17. These data use the 20-year average method of bill calculation as previously discussed in Section 2.3.1.

In 2023, the total average 20-year NEM energy bill which uses the average amount of electricity and gas, 1.7 ICE vehicles for road transport and no changes in energy efficiency is $11,060. This increases marginally to $11,110 by 2030 reflecting the reduction in fossil fuel prices by 2027 offset by increases in gas and electricity network costs. However, if a customer implements the various individual savings available, they could reduce their bill by 31% to $7,620. If we extend this further into the projection period, the energy bill savings available for a customer who has not previously taken up these measures is 34% in 2035, 36% in 2040 and 38% in 2050. These savings are annual so that, depending on which options and when they are taken up, the cumulative savings over 20 years are in the order of several multiples of $10,000.

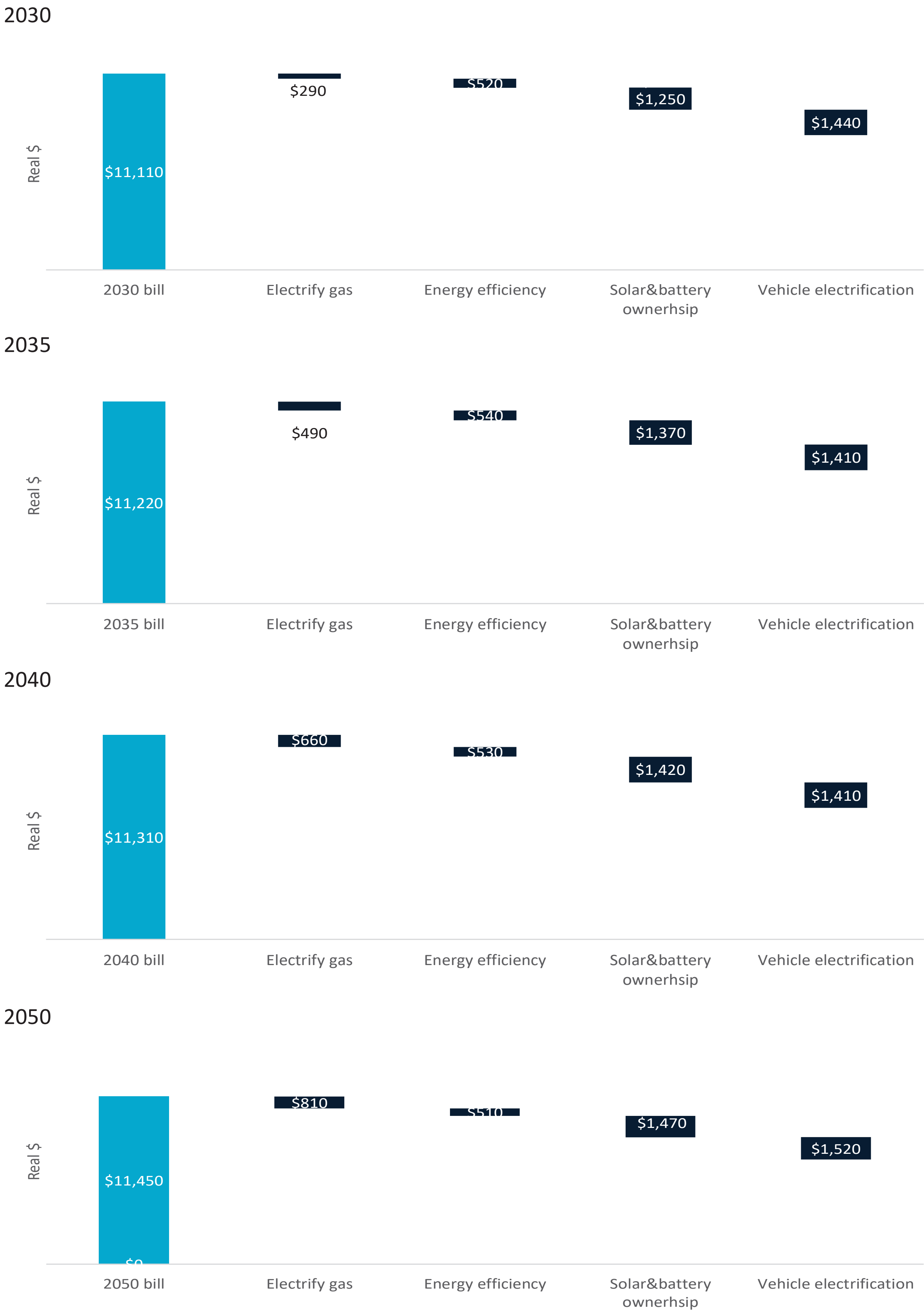

Figure 3-17 Total potential reductions in electricity bills from household level actions

Shortened forms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CER	Customer energy resources
ECA	Energy Consumers Australia
EV	Electric Vehicle
ICE	Internal Combustion Engine
ISP	Integrated System Plan
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
PTRM	Post Tax Revenue Model
TOU	Time-of-use
V2G	Vehicle to Grid
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital

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