



Automated and Zero
Emission Vehicle
Infrastructure Advice
Energy Impacts Modelling

Infrastructure Victoria

Final Report

9 July 2018



Contents

1	Executive Summary	4
2	Introduction	22
2.1	Background	22
2.2	Current Situation	24
2.3	Energy market overview	32
3	Modelling Approach	38
3.1	Overview of modelling approach	38
3.2	Interpretation of MABM results	41
3.3	Contribution to peak demand profiles	54
3.4	Generation model	66
3.5	Network model	83
3.6	Spatial analysis	88
3.7	Modelling of Hydrogen scenario	96
4	Modelling results	103
4.1	Interpreting the results	103
4.2	Overview of modelling results	107
4.3	Scenario: Dead End	114
4.4	Scenario: Electric Avenue	118
4.5	Scenario: Private Drive	129
4.6	Scenario: Fleet Street	142
4.7	Scenario: High Speed	148
4.8	Scenario: Slow Lane	153
4.9	Scenario: Hydrogen Highway	160
4.10	Sensitivity analysis	169
5	Infrastructure responses	173
5.1	Introduction	173
5.2	Charging infrastructure	174
5.3	Capturing benefits	199
5.4	Generation and transmission infrastructure	224
5.5	Distribution network infrastructure	234
5.6	Hydrogen Highway	246
	Appendix A: Impact on System Peak timing under scenarios	266



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Inherent limitations

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Model outputs are always an approximation of what can be expected in the real environment. The KPMG Electricity Market Impact Model is a strategic high level model that is best at representing generation entry and exit and network demands and patterns at the system level. Notwithstanding this, there will usually be differences between forecasts or projected and actual results, because events and circumstances frequently do not occur as expected or predicted, and those differences may be material

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Glossary

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AV	Automated Vehicle
AZEVIA	Automated and Zero Emission Vehicle Infrastructure Advice
DER	Distributed Energy Resource
DNSP	Distribution network service provider
FCV	Fuel Cell Vehicle
GWh	Gigawatt per hour
KWh	Kilowatt per hour
ICE	Internal Combustion Engine
IV	Infrastructure Victoria
MABM	Melbourne Activity and Agent Based Model
GST	Good and Service Tax
MW	Megawatt
PHEV	Plug in hybrid electric vehicle
TJ	Terajoule
VITM	Victorian Integrated Transport Model
VOC	Vehicle Operating Costs
VHT	Vehicle Hours Travelled
VKT	Vehicle Kilometres Travelled
V2I	Vehicle to infrastructure (refers to communication technology)
V2G	Vehicle to Grid
ZEV	Zero Emission Vehicles



1 Executive Summary

This report considers the impacts to the Victorian electricity system resulting from adoption of emerging transport technologies, such as zero emission vehicles (ZEVs) and automated vehicles (AVs). For this report, electric vehicles powered by batteries (BEVs) or hydrogen fuel-cells (FCVs) are considered to be zero emissions.

The purpose of this report is to provide insights and evidence as part of Infrastructure Victoria's Automated and Zero Emission Vehicle Infrastructure Advice (AZEVI). KPMG has been asked to consider:

- the impacts on both the electricity generation and network sectors;
- potential changes in emissions in the electricity generation sector;
- potential infrastructure responses to market impacts, and
- evaluate the factors and policy arrangements which will determine the effectiveness of those responses.

Scenarios modelled

The introduction of autonomous and zero emissions vehicles is fraught with uncertainty. Accordingly, Infrastructure Victoria (IV) have crafted seven separate scenarios as part of framing their advice to the Victorian Government. Each scenario is a deep dive into the effect of one particular way that transport technology could unfold. These scenarios are designed to challenge thinking and answer the many "what if" questions that exist for the implementation of autonomous and zero-emissions vehicles.

The table below summarises the scenarios modelled for this report. The Dead End scenario assumes no new vehicle technology is introduced between 2015 and 2046 (a 'business as usual' scenario). The other scenarios explore how different technologies may impact the state in 2046. There is one scenario which assumes a faster uptake of BEVs by 2031.

Three of the seven scenarios are based on a shared fleet operator model where the vehicles on are demand and customer can request a ride when it wants transport and use it to access destinations. The other scenarios assumed that vehicles remain in private ownership.




It should be noted that in reality, Melbourne's future is more likely to be a combination of these scenarios and technologies, rather than any one extreme. The purpose of the scenarios is to explore and clearly demonstrate the disparate impacts of different transport futures, not to accurately represent a likely future state.

For the scenarios, we have used data from the Melbourne Activity and Agent Based Model (MABM) employed by IV for the AZEVI project. The MABM has been developed by KPMG Transport practice in separate advice to IV and informs on a number of transport metrics including vehicle numbers, trip frequency, and vehicle kilometres driven under each scenario.¹

In order to understand and model the impacts on the Victorian energy sector, we have converted the MABM outputs into maximum demand and consumption estimates under the relevant scenarios.

¹ For this engagement, we have taken the MABM outputs has being verified and approved by Infrastructure Victoria.



Scenario	Description	Automated Vehicles 	Vehicles on demand 	Zero emission vehicles 
Dead End	This is the no change, 'business as usual' scenario. None of the technologies are taken up by 2046. The fleet is entirely composed of traditional CDVs which are privately owned. This forms a reference scenario in that it is similar to existing fleet composition and ownership models.	✗	✗	✗
Private Drive	All vehicles are automated, but are privately owned (i.e. no vehicles on demand). The AVs are zero emission – they are powered by electricity, not fossil fuels.	✓	✗	✓
Fleet Street	All vehicles are automated, and operate as on-demand vehicles. This means that all car travel is undertaken via a fleet of shared, on-demand automated taxis. All vehicles are automated and are powered by electricity, not fossil fuels.	✓	✓	✓
High Speed	This scenario is the same as the Fleet Street scenario described above, but a full shift to automated, electric vehicles as an on-demand service occurs by 2031 instead of 2046.	✓	✓	✓
Slow Lane	Half of the population uses a vehicle on demand model (like the Fleet street scenario), and the other half of the population use privately owned CDVs (like the Dead end scenario).	✓ ✗	✓ ✗	✓ ✗
Hydrogen Highway	All vehicles are privately owned and automated. The cars are powered by hydrogen fuel cell vehicles rather than fossil fuels.	✓	✗	✓
Electric Avenue	The fleet is entirely composed of electric vehicles (but vehicles are not automated) and are privately owned.	✗	✗	✓

Source: Infrastructure Victoria

In addition to the scenarios modelled, KPMG has also conducted a number of supporting permutations with respect to:

- whether the vehicle owner faces price incentives that influence their vehicle charging behaviour to shift charging away from peak periods. We apply this permutation for both the Private Drive and Electric Avenue scenarios; and
- the impact of potential technological advancements for FCVs and hydrogen production technologies under the Hydrogen Highway scenario.



Our approach to modelling the energy market impacts

The impacts on the generation market will depend on both the demand at system peak times and the electricity consumption associated with BEVs charging or for producing hydrogen for FCVs.

The draw on the electricity system from charging a BEV will be driven by a number of factors. We use the following variables for the estimate of demand at peak times under the various scenarios:

- Type of vehicle use – residential, commercial or freight.
- The way or node of charging vehicle across the scenarios. Our model has four different charging nodes – residential, commercial and out-of-home for private fleets, and then a separate node for shared fleet charging.
- The charging rate which will depend on charging infrastructure technology, which determines the length of time needed to charge the vehicle. Our model distinguishes between three different charging levels ranging between 3 kW, 9.5 kW and 240 kW.
- Regarding the time-segment profile of charging over the day, for relevant scenarios, our model either has an incentivised profile where the BEV owner has an incentive to alter the time of their charging, or a non-incentivised profile where there is no incentive to charge at different times.

How the population will use and charge their ZEV will vary significantly and it is impossible to model all possibilities of charging behaviour for BEVs. For the model, we have employed a number of representative charging patterns which differ by type of vehicle use, the rate of charging and the load profile.

KPMG's Electricity Market Model is comprised of the following components:

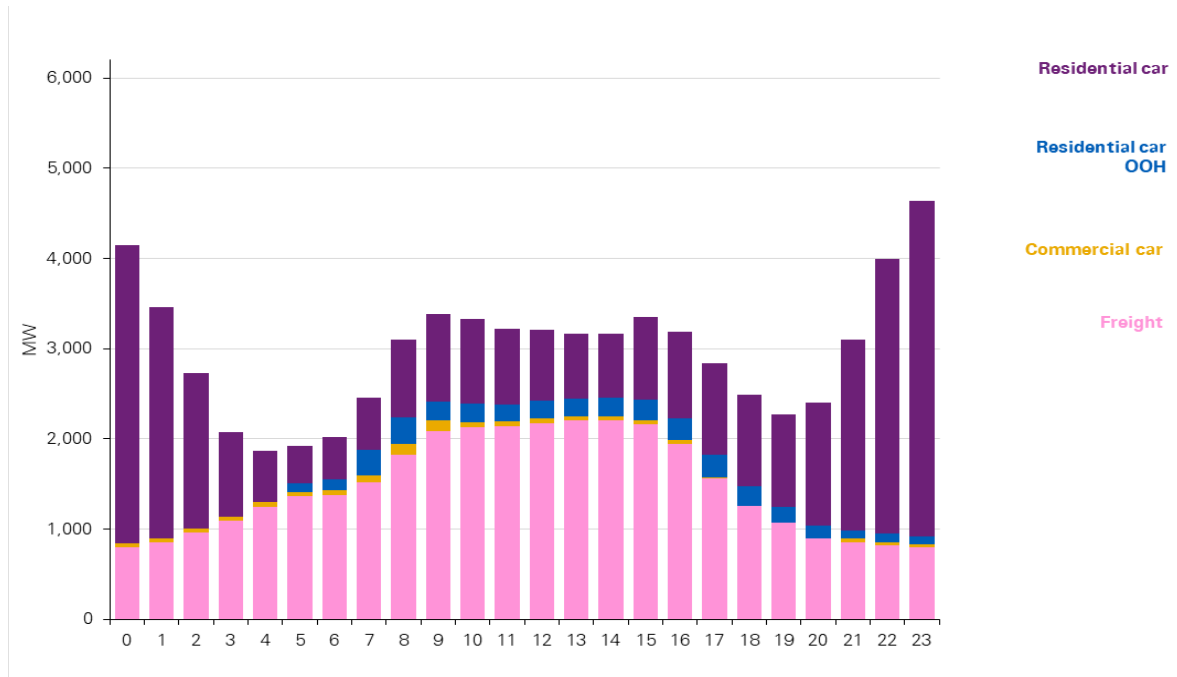
1. Conversion of transport data inputs from MABM to electrical consumption and demand. In some cases, we have also used the transport data to inform the timing of BEV charging.
2. A calculation of the contribution to peak electricity demand from BEVs. This is based on the vehicles' electricity consumption while driving, as well as the profile of BEV charging over a given day.
3. A generation model to model the impacts of ZEVs on generation capacity, cost, and emissions. This determines the magnitude of new generation required.
4. Modelling of the average network costs for each of the five distribution networks to serve the additional demand. This is based on published long term marginal cost figures.
5. Network spatial analysis to assess potential localised impacts on the distribution network from BEV demand at the zone substation level.

An important aspect of KPMG's Electricity Market Impact Model is the development of a representative contribution to the peak demand profile over a 24 hour period. Peak demand is the highest amount of demand for electricity over a defined period of time that in turn drives the level of generation and network capacity needed. For each scenario, the model generates a range of daily demand profiles for different customers and vehicle types covering assumptions about the rate of charging and customer preferences. For each scenario, we sum the relevant charging patterns for the different customer types to calculate an aggregate peak demand profile.

An example of this is shown below in figure A for the Electric Avenue Scenario with incentivised charging which has four separate charging patterns.



Figure A: Example of modelled contribution to peak demand profile



For the Hydrogen Highway scenario, we have separately modelled the hydrogen requirements to support the road network, and then utilised this within the generation component of our model to estimate the electricity generation required to produce this required level of hydrogen.

Limitations

The NEM is a highly complex market system with generators bidding into the market on a five minute basis. A complete simulation of the operation of the NEM involves predicting economically driven new entry and retirements of generation capacity on a half hour basis.² Further, to fully understanding the network impacts would require very detail and granularly load studies of flows and existing network capabilities across the networks.

These types of detailed market and networks simulations to estimate the impacts under BEV are outside the scope of this engagement. Instead we have developed a simple representation of the Victorian energy system to help better understand the relationships between BEV uptake and the extent of network and generation responses required under the scenarios. Further our models helps to identify the main factors which determine the extent of investment needed. The outputs from Electricity Market Impact Model need to be interpreted with an understanding of the above general limitations as well as the specific strengths and weaknesses of the methodology as described in the report.

What are the potential impacts?

The modelling shows that under scenarios where ZEVs replace conventional vehicles, there will be substantial impacts for both the Victorian generation and network sectors. The extra

² This would need to reflect for example forecast demand, solar PV uptake, government policy (e.g. carbon pricing, renewable energy targets), generator fuel prices, operational and technical performance of individual power stations, generator bidding strategies, the way electricity flows through the grid and of course economic inputs such as capital costs and capacity factors of new builds and interest rates.



demand from BEV charging would result in a doubling of the existing capacity of Victorian generation sector to over 20,000 MW³ and potentially add an extra 20% to the existing regulatory asset base (RAB) valuations in order to augment the respective networks.

Generation capacity will be driven both by the need to serve additional peak demand and the need to provide capacity to serve consumption during the off-peak period. The distinction between peak capacity and non-peak capacity is important as peak capacity must be dispatchable, that is, to be able to run when required. Table A summarises the estimates for the level of dispatchable generation and non-dispatchable generation installed.

For the modelling, we assume that all new generation entry triggered by BEVs will be from renewable sources. This is consistent with the objective that electric vehicles are zero emissions along the supply chain. Accordingly, our model assumes that additional peak demand over the period to 2046 will be served through a mixture of pumped hydro and batteries, while any non-dispatchable capacity can be addressed through increased wind and solar generation.

For the Private Drive scenario, up to 14,000 MW of new generation and storage capacity will need to be installed compared to 17,000 MW under the non-incentivised profile. 14,000 MW of new capacity would more than double the amount of generation (and storage) capacity in Victoria. Even where charging of BEVs can be managed to occur outside peak periods, substantial investment in generation and networks would still be required to serve the additional demand.

These estimates are based on the respective assumed capacity factors (30% for wind and 21% for solar PV). It is possible that capacity factors of wind and solar increase or average size of plant increase which would decrease the number of new generation installations needed.

Table A: Required investment in generation investment per Scenario

	Dispatchable generation installed (MW)	Non-dispatchable generation installed (MW – 50% wind and 50% solar)	Total capacity (MW)
Dead End	800	-	800
Electric Avenue (Incentivised)	3,361	9,308	12,669
Electric Avenue (Non-incentivised)	6,205	9,308	15,513
Private Drive (Incentivised)	3,519	10,279	13,798
Private Drive (Non-incentivised)	6,719	10,279	16,998
Fleet Street	1,451	9,198	10,649
High Speed	0	1,636	1,636
Slow Lane	1,121	3,808	4,929
Hydrogen Highway - Electrolysis base case	0	18,313	18,313

³ Victoria currently has 10,190 MW of installed generation capacity, out of which 5,140 MW is fuelled by brown coal



In a number of scenarios, the estimate cost of the additional investment in the electricity sector will be substantial, with our modelling indicating potential investment between \$1.5 billion and \$14.5 billion. As shown in the Table B, costs are highest where vehicles remain in private ownership and there is no incentive to charge at off-peak times. For private ownership scenarios, the use of incentivised charging profile reduces total costs by around \$2.5 billion, as charging is less concentrated in the system peak hours of 5 – 7 pm.

Table B: Estimated total cost in generation and network investment under the scenarios (NPV terms, additional to Dead End Scenario)⁴

	Installed generation	Network requirement	Total
	\$ m	\$ m	\$ m
Electric Avenue (Incentivised)	\$4,599	\$1,759	\$6,358
Electric Avenue (Non-incentivised)	\$5,992	\$2,832	\$8,824
Private Drive (Incentivised)	\$5,080	\$1,860	\$6,940
Private Drive (Non-incentivised)	\$6,644	\$3,084	\$9,728
Fleet Street	\$3,840	\$1,395	\$5,235
High Speed ⁵	\$1,108	\$995	\$2,103
Slow Lane	\$1,550	\$654	\$2,204
Hydrogen Highway - Electrolysis base case	\$14,524	\$0	\$14,524
Hydrogen Highway - Electrolysis strong shift	\$8,053	\$0	\$8,053

Generation Impacts

Generation capacity will be driven both by the need to serve additional peak demand and the need to provide capacity to serve consumption during the off-peak period. The distinction between peak capacity and non-peak capacity is important as peak capacity must be dispatchable, that is, to be able to run when required.

For the modelling, we assume that all new generation entry triggered by BEVs will be from renewable sources. This is consistent with the objective that electric vehicles are zero emissions along the supply chain. Accordingly, our model assumes that additional peak demand over the period to 2046 will be served through a mixture of pumped hydro and batteries, while any non-dispatchable capacity can be addressed through increased wind and solar generation.

⁴ Total cost estimates are on an NPV basis, meaning that requirements further into the future add less to the total costs in NPV terms than requirements in the near term.

⁵ Please note that the High Speed scenario considers an outcome as at 2031, whereas the Dead End scenario considers an outcome as at 2046. For this reason the two outcomes are not directly comparable, especially in light of the assumed Yallourn retirement in 2032 in the Dead End scenario (which results in new capacity being installed). Under the Dead End, all new capacity is installed after 2031. Therefore for the purpose of presenting the results we have assumed that all of the costs estimated for the High Speed Scenario is incremental to Dead End as at 2031.



The total consumption of electricity is between 37% and 56% higher in all permutations and scenarios which involve complete uptake of BEVs relative to the Dead End scenario which has no uptake. The exception to this is the Slow Lane scenario, which involves a shared fleet for half the population only (and ICE for the other half of the population), where total consumption only increases by 23%.

Table C below provides estimates the number of wind and solar farms and storage installations associated with this total capacity, given the average size of existing plants.

Table C shows that potentially up to 250 new generation installations would need to enter the market to serve the demand from BEVs (in Private Drive, non-incentivised scenario). While the number would fall to below 200 if the charging was incentivised to charge at off-peak periods, there would still need to substantial investment in renewable installations to serve the extra demand. These estimates are based on the respective assumed capacity factors (30% for wind and 21% for solar PV). It is possible that capacity factors of wind and solar increase or average size of plant increase which would decrease the number of new generation installations needed.

The Hydrogen Highway scenario would consume a significant amount of electricity to produce hydrogen for FCVs through electrolysis. While we assume that hydrogen production would not occur at the system peak times and hence would not trigger additional dispatchable generation, there could still be over 300 new solar and wind farms required. Our modelling also considered the utilisation of natural gas or brown coal to produce hydrogen. While natural gas is the predominant method to produce hydrogen presently, both this and coal-based production introduces an emissions component that would need to include carbon capture and storage (or a similar solution) to neutralise the process.

Given such large number of new generation installations required, there could be insufficient availability of suitable locations in Victoria for such investment to occur. Our modelling does not assume any constraints on the supply of renewable generation. In reality, Victoria is part of the interconnected National Electricity Market and therefore additional generation could be sourced from other regions through increased interconnection.

Our analysis is complicated by the possibility that the size of the BEV load will influence the timing of the peak periods. Our report conducted a sensitivity analysis and found that in a number of scenarios, the peak shifts to earlier in the afternoon, as there is more limited charging happening in the 5 – 7 pm window. In the earlier afternoon it is possible that the contribution of solar PV in particular is higher than it is for the early evening, meaning that less dispatchable generation may be required than the modelled estimates.



Table C: Renewable Generation to be installed under each scenario

Assumed size	# pumped hydro plants required	# large scale battery installation required	# Wind farms required	# Solar farms required	Total number of new generation installations
	~30 MW	~100 MW	~140 MW	~75 MW	
Dead End	13	4	0	0	17
Electric Avenue (Inc)	56	17	27	73	173
Electric Avenue (Non-inc)	103	31			234
Private Drive (Inc)	59	18	30	81	188
Private Drive (Non-inc)	112	34			257
Fleet Street	24	7	27	72	133
High Speed ⁶	0	0	5	13	18
Slow Lane	19	6	11	30	66
Hydrogen Highway – Electrolysis Base Case	0	0	84	225	309
Hydrogen Highway – Electrolysis Strong Shift	3	1	54	144	202

Network impacts

The network costs are similarly influenced by the extent to which BEV charging contributes to maximum demand in the respective peak period. Our modelling approach uses current estimates of network costs (represented as long run marginal costs) as a proxy of the costs associated with serving additional demand. We supplement this analysis by also conducting spatial analysis at the zone substation level to estimate whether the additional demand from BEVs would trigger the need for the capacity at the substation to be upgraded. Our modelling results are summarised in Table D.

The impacts vary across the five distribution networks due to the outputs under the MABM on number of vehicles in each of the network zones and the relative size of the existing RABs. In all scenarios, there is a likely need to upgrade a substantial number of the current 228 zone-

⁶ Please note that for high speed the results are for 2031 and therefore our model does not output any need such infrastructure as this is before any assumed retirements of coal fired generation. Given Yallourn is expected to retire in 2032, new investment post 2031 would be needed under this scenario. The amount would be similar to the Fleet Street estimates.



substations compared to the base case where maximum demand in Victorian is expected to remain relatively flat over the period to 2046.⁷

These estimates of network impacts are likely to under-forecast the full impact on transmission and distribution networks under a situation of high penetration of BEVs due to limitations in the modelling methodology.

Firstly, the model only attempts to estimate costs associated with augmenting the network to provide more capacity to serve the extra demand. Distribution networks could be required to invest in the additional assets under these scenarios. This could include the costs associated with managing the network security impacts, or communication and associated trading technology which help support the capture of potential market benefits from BEVs.

Further, as distribution capabilities and assets vary geographically, it is important to note the localised impacts of BEV charging, where size, timing, and particular location of isolated loads can have significant effects on network reliability as a whole. The impact on the distribution network are likely to vary significantly at the local "street-level". BEV uptake will in many cases lead to distribution transformers failing (or generally needing to be replaced) much earlier than zone substations. It is also possible that the additional demand placed on the distribution network will require replacement of local assets below the sub-station zone level such as cables, or subdivision of the distribution network via installation of additional distribution transformers.

Table D: Summary of network impact modelling estimates

	Value of transmission investment as % of existing RAB	Range of distribution investment as % of existing RAB	Number of zone substations estimated to be upgraded
Electric Avenue (incentivised)	18.2%	4% to 14%	41
Electric Avenue (non-incentivised)	28%	6.5% to 22%	104
Private Drive (incentivised)	19%	5% to 15%	89
Private Drive (non-incentivised)	30%	8% to 24%	120
Fleet Street	15%	3% to 11.5%	76
High Speed	9%	2% to 7%	42
Slow Lane	8.3%	2% to 6.5%	51

⁷ This is based on forecasts produced by the Australian Energy Market Operator in its 2018 Integrated Systems Plan Report. This is discussed in section 3.4.2 of this report.



Another limitation is that the flows across networks under BEV scenarios could be substantially different which would undermine the use of the current LRMC estimates as a proxy of the costs of serving additional demand.

While recognising these limitations, we would expect that the impacts of high penetration would be greater in the generation sector than the network sector. While both the network and generation sector need to respond to provide more infrastructure to meet the impact on peak demand, the generation sector also has to respond further to provide generation capacity to serve the additional electricity consumption from BEVs. As shown in Table A, we have found that the level of non-dispatchable generation installed under the scenarios is substantially more than the dispatchable capacity needed to serve peak demand.

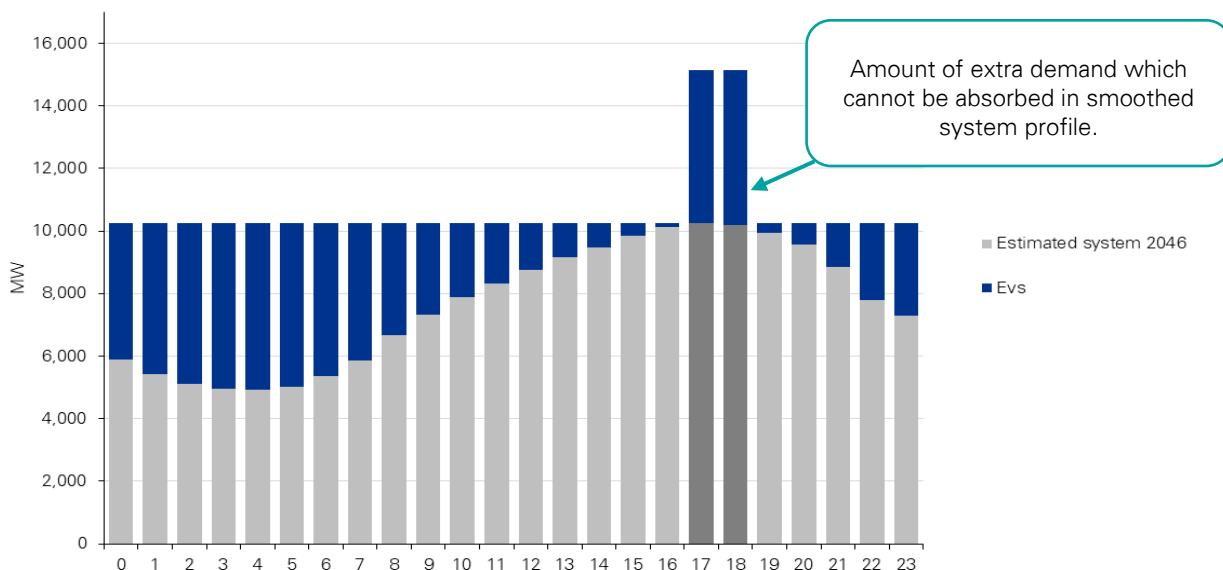
Impact on Victorian system peak demand profile

We also conducted sensitivities as to whether the profile of BEV charging could be managed throughout the day to avoid any increase in system peak (based on current demand profiles). However, due to the material change in consumption under all scenarios, (with the exception of Slow Lane) there is likely to be an increase in the system peak. This is shown in the Figure A below.

Private ownership versus shared fleet

The estimated investment is higher under the private ownerships scenarios for BEVs compared to the shared fleet scenarios. In the Fleet Street scenario, total incremental cost is over \$5 billion, compared to \$6.3 billion under the Electric Avenue scenario. This is driven mainly by the difference in the assumed peak demand under either scenario with the expectation that the shared fleet operator will be able to manage charging in order to avoid peak periods.

Figure B – Not possible to avoid impact on system peak through managed charging



Private ownership versus shared fleet

The estimated investment is higher under the private ownerships scenarios for BEVs compared to the shared fleet scenarios. In the Fleet Street scenario, total incremental cost is over \$5 billion, compared to \$6.3 billion under the Electric Avenue scenario. This is driven mainly by the difference in the assumed peak demand under either scenario with the expectation that the shared fleet operator will be able to manage charging in order to avoid peak periods.



While in the Fleet Street Scenario, the MABM model provides a substantially lower number of vehicles (only 256,490 vehicles which is only 7% of the vehicles needed for the Electric Avenue scenario) the total consumption of electricity is similar. There are fewer cars in Fleet Street, but they drive further. The difference in cost impact is instead driven by the additional flexibility of fleet-based charging. A shared fleet operator would have the ability to coordinate charging times, and a strong commercial incentive to keep electricity costs low.

However, the impacts on the distribution networks could be higher than modelled through the choice of charging infrastructure and location of the shared fleet operator. While the number of vehicles will be substantially lower (MABM estimates that only 7% of the total vehicles under the Private Drive scenario will be required for the Fleet Street scenario), the fleet will be clustered in a number of common depots. Each depot would represent a significant large load, with a material number of BEVs charging simultaneously. The distribution network impacts will be affected further if the shared fleet operator installs Type 3 fast chargers (i.e. 240 kV).

This report did not attempt to estimate the impact of this, given the level of uncertainty regarding the shared fleet operation. There are a range of diverse variables which a shared fleet operator will consider in deciding upon the number and location of depots. In deciding its strategy, an operator will have to weigh up customer demand characteristics and locations, access to customers, cost of electricity, network charges, and fleet size. The operator may decide to have a higher number of vehicles in order to have some redundancy in their fleet and hence flexibility on when the fleet will be charged. Alternatively, the operator could invest in on-site battery storage to help manage electricity costs.

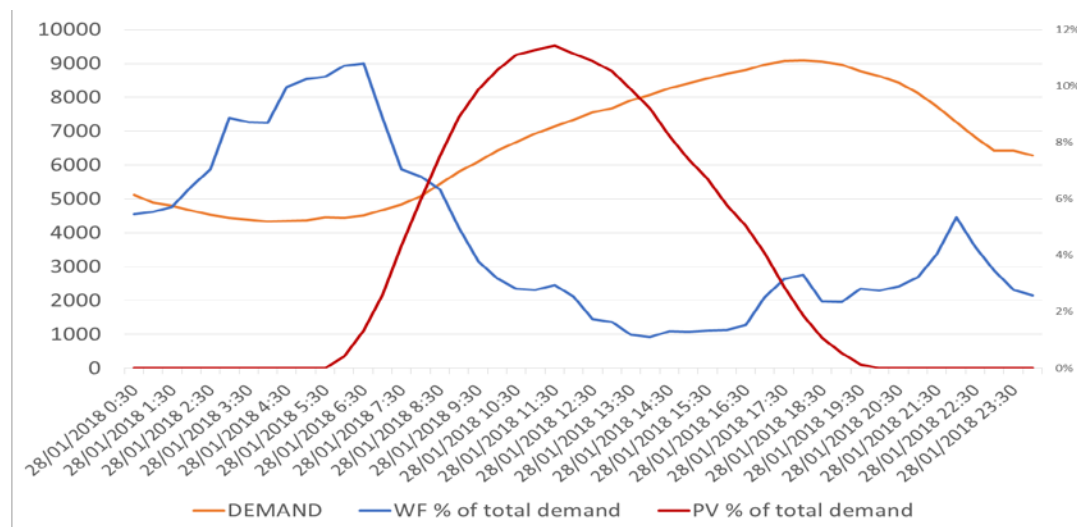
The price signals which the energy market provides to the shared fleet operator will be key in promoting efficient integration of the shared fleet into the market.

Value of day-time charging

Our modelling found that there are benefits from also encouraging charging through the morning to mid-afternoon period in addition to over-night charging. This is because this helps to match BEV consumption with renewable generation output and also for the shared fleet scenarios lessens, the amount of charging infrastructure needed to support overnight.

Figure C highlights that the bulk of renewable production occurred at times when system demand was low. The uptake of BEVs can aid in addressing this mismatch through encouraging the charging of BEVs during periods of high renewable generation.

Figure C– Victorian wind and rooftop solar production against system demand





The trade-off between “targeting” charging away from the system peak or when there is ample renewable generation to reduce the requirement to invest in storage technologies, and the economic costs associated with potentially limiting or discouraging travelling at these same times (as vehicles need to be charging and/or renewable energy may be limited at certain times) could merit further investigation.

Hydrogen Highway

The Hydrogen Highway scenario would consume a significant amount of electricity to produce hydrogen for FCVs through electrolysis. Hence the costs under this scenario are substantially higher compared to BEVs with over \$14 billion of incremental investment – solely in the generation sector needed as we assume that there will no network impacts under this Scenario. This difference reflects the relative efficiencies of FCVs versus BEVs. This amount decreases to \$8 billion if electrolysis technology improves markedly in conjunction with increased efficiency of FCVs.

While our modelling has indicated a significant requirement for electricity where electrolysis is the preferred method to produce hydrogen, fossil fuels could also be explored as an alternative. We have modelled the potential of steam methane reforming (using natural gas) and coal gasification (of brown coal) in conjunction with electrolysis. The use of these methods will significantly reduce impacts on the electricity network but would instead create the requirement for the respective fossil fuels. Given the abundance of brown coal in Victoria, this could represent a cheap resource for hydrogen production. However, the emissions component of fossil fuel based methods would need to be considered in their suitability within a zero-emissions future.

A significant component of the modelled hydrogen requirement (more than half) came from freight vehicles. Despite only covering 12% of overall vehicle kilometres travelled, freight vehicles contributed to 59% of the hydrogen required. We stress that the likely consumption of freight vehicles may differ in reality as we have had to use a rough guess of vehicle efficiency as freight-based FCVs are not yet in mass production.

This scenario would have a fundamental change to the energy markets and would also necessitate the requirement for a new hydrogen supply chain to be established that would require significant production and distribution infrastructure responses. As noted above, we have considered three different production methodologies to consider likely resource requirements if they were solely used to produce hydrogen. Within the use of electrolysis technology, thought would need to be given on whether to implement centralised facilities or instead install distributed electrolysis throughout Victoria.

The potential network for distribution of hydrogen also presents a number of infrastructure options for the transport of hydrogen to the end-user. Where on-site, distributed electrolysis is employed, there would be no need for distribution infrastructure. However, where large-scale, centralised facilities are constructed, pipelines or trucking are likely to be the preferred methods of distribution. Liquefaction of hydrogen could also be explored to increase the efficiency of transport.

The change from petrol and diesel fuels to hydrogen under the Hydrogen Highway scenario may also present opportunities for filling stations to repurpose and retrofit their sites to support hydrogen fuel as ICE vehicles are phased out. Given that there are likely to be significant capital costs to deploy hydrogen filling stations across Victoria, the re-use of existing sites may be a viable alternative to minimise this cost and support uptake of FCVs between 2018 and 2046.

Emissions

We have also considered the impact on emissions of ZEVs.

We have assumed all new capacity to be zero emissions (pumped hydro, batteries, solar, and wind), consistent with the Victorian Government target of a net zero emissions grid by 2050.



The average emissions per GWh consumed and MW of capacity installed falls significantly as more renewables are introduced into the system to address the extra consumption from BEVs. For example, in 2046, renewables (hydro, wind and solar) make up 56.3% of total generation in the Electric Avenue scenario (with the Incentivised permutation), and 77.9% of total installed capacity (hydro, wind, solar, batteries and pumped hydro). This compares to 11.2% and 31.2% respectively in 2018.

Across the scenarios, the average emission per kWh reduces by more than 50%, while the emission intensity of the capacity falls by over 70%.

A key uncertainty is the extent and pace of the market transitioning towards 100% renewable generation. While our modelling assumes that there will be some coal and gas generation remaining in 2046, this could change under policy reforms. For example, the Victorian Government has announced a net zero emissions target by 2050, the detailed design of which remains to be confirmed. Further the Federal Government emissions target may also change over time which will have further impacts on the relative costs of fossil fuel generation.

The role of alternative zero emissions technologies like solar thermal and biomass also needs to be considered in more detail. In a zero emissions situation, BEVs, both as a source of demand for electricity and a potential source of electricity storage, have an even greater potential to play a key role in the optimisation between demand (charging patterns) and supply (as a (potentially virtual) battery) both on a system wide basis and on a localised basis. That said, our analysis shows that high uptake of BEVs creates a significant increase in electricity consumption. This may create an incentive for existing coal fired (and gas fired) generation to remain operational for a longer period than it would in the absence of this consumption increase. This would be further the case if the charging of BEVs occurred at peak times and gas peaking plants were called on to service demand.

In summary, the potential for fossil fuel generation to continue to operate in 2046 under these scenarios will depend on the commercial viability and reliability of renewable sources as “base load” dispatchable plants (i.e. via the use of batteries and/or pumped hydro), how well the market integrates BEV charging with renewable generation, and the impact of government emissions policies on the costs of fossil fuel generation.

Under the Hydrogen Highway scenario, if fossil fuel methods are used to produce hydrogen, these will introduce a significant emissions component in the absence of carbon capture and storage. For this advice, we have made the simple assumption that in theory carbon capture and storage technology has been perfected and all emissions could be sequestered. In practice, this may not turn out to be case.

What influences the impacts?

The key influences for the energy market impacts are either due to:

- The stress placed on the system at peak times due to BEV charging; or
- How the energy market responds to the additional demand from BEV charging.

The contribution to peak demand impacts will depend on the number of vehicles, their charging times, and the rate of charging.⁸ We have modelled in total nine separate charging patterns which differ by these factors. This analysis is based on a number of evidence based load profiles which differ by whether:

- the vehicle is for residential or commercial use.
- the fleet is private or shared.

⁸ For network impacts, it will also depend on the location of the charging.



- there are incentives to influence the charging profile.

A key factor will be the use of rapid charging stations which provide the flexibility to charge at high voltages in short time periods. We have assumed that 10% of private residential cars would charge at rapid charging states (i.e. out of home, at 240 kW) using data from MABM on timing of trips over the course of the day.

While we found that charging times would be around 10 mins for the average trip, the impact on the electricity market will be highly dependent on the extent to which cars simultaneously use rapid charging, and the extent to which vehicle charging at public stations can be staggered. This will determine the number of rapid charging stations required. For example, in the Electric Avenue scenario, 341,491 cars are assumed to be charged out of home (10% of all residential cars). 28,344 of these cars are assumed to charge between 7 and 8 am and 8 and 9 am in the morning (peak). If these cars all arrive sequentially to one another (and there is no time lost between cars, likely only a theoretical possibility), then 1,092 Type 3 chargers would be required. If these cars all arrive at the start of the hour however, then a full 28,344 Type 3 chargers would be needed. Clearly the impact on the market would be substantially different under these two extremes. Our modelling results are based on the assumption that rapid charging can be co-ordinated.

Impacts will depend on the driving patterns and charging decisions of BEV owners and the choices offered to them by the market. As demonstrated in the modelling results, incentivised charging can lower the total costs to the market. There are a wide range of different structures and designs to electricity prices which could provide an effective incentive to charge BEVs at optimal times. Effectively, there needs to be a substantial difference between the rate for charging in peak times and the rate applicable at other times. Costs could be further reduced under the private ownership scenarios if BEV owners opt for controlled charging options.⁹ Such options would need to provide sufficient compensation and certainty to BEV owners plus recognise the different rate of charging available to the owners.

BEV owners may desire flexibility in when their vehicle can be charged which in turn will depend on the charging infrastructure (i.e. rate of charging available to them). Faster charging units would provide more flexibility but will incur additional costs. BEV owners may also need to cover other costs relating to the metering technology, communication systems, and potentially any costs associated with controlling charging patterns. Further, if a customer solely wants their BEV load to act as a flexibility demand which can be shifted across the day, they may need to incur the costs of an additional smart meter to isolate the BEV demand from the rest of the household.

Therefore, to be convinced to participate in any energy market flexibility scheme, the market needs to provide sufficient compensation to offset such costs. This will depend on the policy and regulatory frameworks in place as these will determine how market benefits (discussed below) are priced and treated. It will also depend on whether the market supports the co-optimisation of benefits from BEVs across the various sections of the electricity market.¹⁰ However, there are currently a range of potential regulatory or market barriers limiting the ability of resources to capture all the value across multiple revenue streams (i.e. a lack of co-ordination between market participants, the ability of networks to control operations for technical reasons, and established contractual terms for the customer).

⁹ Controlled charging is where the management of the BEV charging load is assigned to another party (network, retailer or a third party DSP provider, such as an aggregator) in accordance with an agreed contract with the consumer

¹⁰ When BEV batteries act as a source of energy storage which can be injected back into the grid, they take the same features as other types of Distributed Energy Resources such as solar PV, and other battery technologies. A critical feature of any type of DER is their potential to be used in multiple market applications and hence their ability to deliver both network and energy related benefits to the systems.



Sensitivity Analysis Results

Regarding the factors which influence the market response, we conducted a range of sensitivity analyses for the Electric Avenue incentivised permutation. This is to provide an indication of the potential change in impact under different assumptions.

There are a number of potential factors that could reduce the impacts on the electricity market under the scenarios modelled. If maximum demand or total consumption is reduced elsewhere through demand-side participation or increased uptake of rooftop PV and storage, or existing generation may be able to ramp up, then new capacity may not be required. Further, a higher contribution factor for solar PV and wind to meet the maximum demand will mean less dispatchable generation is required. However, other factors, such as constraining flows into Victoria, or if all fossil fuel generation was removed, would add to the investment needs under these scenarios.

Table D - Sensitivity Analysis Summary

Electric Avenue (Incentivised)	Dispatchable capacity installed	Non- dispatchable capacity installed	NPV of generation requirement	NPV of network requirement
	MW	MW	\$ m	\$ m
Default settings	3,331	9,308	4,918	2,028
Absence of Out of home rapid charging	-133	0	-57	-66
Increased demand side participation	-1,024	0	-478	-27
Constrained Interconnector availability	+1,555	0	+834	0
No fossil fuels generation in 2045	+4,855	+12,846	+3,084	0
Ramp up of existing generation	+31	-931	-355	0

Benefits to the energy system from BEVs

While high penetration of BEVs will lead to substantial investment needs, there will also be potential benefits to the electricity system. The types of benefits that the penetration of BEVs may provide include:



1. improving the load factor of the system (that is, enhanced asset utilisation) which could lead to lower average prices. This is more likely to occur if increased demand occurs in substations where the transformer load is under-utilised;
2. harnessing the flexibility benefits of BEVs in terms of managing costs and risks across the system such as network limitations or wholesale prices;
3. supporting efficient integration of renewable/intermittent generation into the market; and
4. providing specialised, technical ancillary services which could be of high value in certain situations. Energy markets require reserves of various forms, collectively called ancillary services, to balance supply and demand in every second and satisfy all constraints.

The flexibility of BEV loads refers to the ability to respond to changes in the electricity system. BEVs create flexibility through two ways:

- As a discretionary load where the charging is not time crucial and can occur at various times during the day.
- Through storage of electricity in the vehicle's batteries which could be transported back into the grid during system stress (i.e. vehicle-to-grid).

The potential benefits with BEVs could lead to substantial value across all sectors of the electricity supply chain – generation, network and retail. However, the mobility requirements, load unpredictability of driving patterns and charging behaviour, plus challenges in coordination will all set challenges in capturing such benefits. Location will also be important as some of the benefits from V2G such as ancillary services and grid support will only be material in certain parts of the network.

The recent increased uptake of renewable generation has occurred due to subsidies available under the Federal Government LRET scheme and the corresponding retirement of conventional thermal generation. This changing mix has caused disruption to the power system given the renewable generation is less reliable and creates separate security issues. BEVs could assist in integrating a penetration of renewable generation and resolve these issues where:

1. BEVs are used to recharge during periods of high levels of renewable generation, this can help to manage disruptive impacts of renewable generation on the market.
2. The BEV fleet is used as a source of short term and distributive storage of excess electricity generated by renewable sources which can be re-supplied during peak times.
3. BEVs acting as a source of ancillary technical services through vehicle-to-grid solutions.

Importantly, it is necessary that there be a certain level of certainty or firmness to the timing and flexibility of the BEV load so that it can better integrate with renewable generation.

When BEV batteries act as a source of energy storage which can be injected back into the grid, they take the same features as other types of distributed energy resource such as solar PV, and other battery technologies. A critical feature of any type of such resource is their potential to be used in multiple applications and hence their ability to deliver both network and energy related benefits to the systems.

Therefore, a single installation of energy storage has the potential to provide multiple services to several entities with compensation provided through different revenue streams. The ability to "stack" the incremental values a may provide across these multiple uses – i.e. the wholesale market, distribution networks, retailers and customers – may be necessary to make solutions such as Vehicle to Grid economically viable.

This report explores the range of policy and regulatory challenges which need to be resolved in order to capture the benefits identified. These issues are not unique to BEVs and apply to all forms of distributed generation and storage. However, such issues need to be resolved in a



predictable and robust manner to facilitate the investment and business models needed to achieve appropriate infrastructure responses.

How will the market respond?

The magnitude of response by the generation sector over the next 25 to 30 years will need to be substantial if there is a high uptake of ZEVs in Victoria. The nature of the response will be influenced by government policy and market design arrangements. This report explores a range of issues and policy arrangements which will influence the ability of the market to respond effectively and timely to the uptake in ZEVs.

A potential supply constraint to generation entry is the availability of transmission capacity to transport energy from new renewable generation to customers and businesses. We understand that this maybe an issue today with renewable projects being affected by the limitations in the existing Victorian transmission grid.

Historically, large coal-fired generation plants have been located near their fuel source and transmission has been built to transport power to load centres. However, renewable generation has different characteristics from coal-fired generation. First, the best locations for renewable generation are typically not located close to existing transmission networks. Second, renewable generation tends to be smaller in scale than the relatively large coal-fired plants. It is not possible to scale down transmission investment to match smaller scale generation.

These issues mean there are challenges in coordinating renewable generation and transmission investment. Significant investment may be required to connect new large-scale renewable energy generation in areas where there is currently limited or no transmission network.

For distribution network businesses, BEVs present both opportunities and challenges which will compound as increased penetration of BEVs occurs across the Victorian networks. For the effective integration of BEVs into the electricity networks, it is important to recognise that distribution networks will have three roles to play:

1. they will facilitate the choice to purchase BEVs by ensuring that there is sufficient network capacity and connections to serve the additional demand;
2. distribution networks will also act as an enabler for capturing the market benefits through facilitating transactions between customers and participants; plus
3. distribution networks may also support integration through purchasing the services such as demand response and ancillary services available from BEVs.

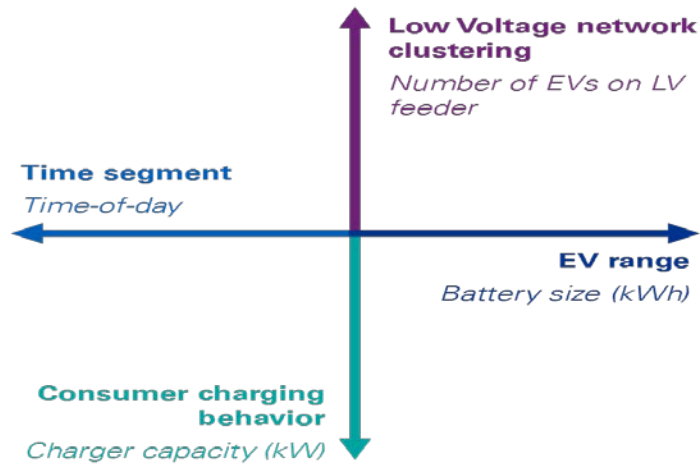
Therefore, the effectiveness of this framework will depend on sufficient expenditure being allowed to enable DNSPs to increase the level of capacity needed to serve the expanding BEV fleet as well as managing all impacts from BEV network integration within their network. Further the regulatory framework needs to provide the right incentives on network businesses to support and enable the efficient integration of BEVs through a range of issues such as design of tariff structures, rewarding BEVs the value of any network savings, and connection standards.

However, a key problem is how the regulatory framework will manage uncertainty arising from BEVs, especially in the early years of adoption. Factors such as location, charging behaviour, and BEV range will make it extremely hard for network businesses, and also for the regulator, to reliably predict the extent of the impacts on the grid from BEV charging.

However, the current regulatory framework is based on the principle that the regulator will only allow network expenditure when there is sufficient robust evidence that justifies customers paying for that expenditure. This could be difficult, especially in the initial period of BEV uptake, to accurately forecast the uptake of BEVs to satisfy this requirement.



Figure D: Factors impacting on network response to BEV charging which need to be forecasted



Therefore, a key risk is the pressure placed on the role of regulatory frameworks and the regulator to ensure that the BEV integration and regulatory treatment occurs in a manner which best promote customer interests.

Different providers are developing different business models to serve customer needs. As the volume of BEVs on the roads grows, the market for charging services will no doubt evolve and providers will adapt and refine their product offerings as competition grows. The regulation of BEV charging services needs to reflect the early-stage nature of the market and encourage innovation and competition among business models and providers. Governments will have an important role in this transformation.

Ensuring an adequate level of charging infrastructure is available will require ongoing work as BEV uptake grows between now and 2046 to ensure a suitable supply by the time a 100% BEV scenario occurs. A number of parties in the public, private and not-for-profit sectors may emerge as providers of charging infrastructure. Careful consideration will need to be given to constructing the correct mix of charging infrastructure that minimises charging times for consumers without overloading the energy network. As noted, a shared fleet scenario will alter the requirements in comparison to private ownership. The design of the price signals provided by the energy system to charging infrastructure operators will determined the economic impacts.

Charging at home will also need to be considered for private ownership scenarios. Particularly for households that house multiple vehicles, a DNSP will need to be wary of excessive charging infrastructure installations at a home that may overload the network at the “street-level”. As there is currently no way for a DNSP to pinpoint the installation of charging infrastructure (beyond identify large increases in consumption), there may be a future requirement for BEV owners to identify their vehicle and charging equipment to allow DNSPs to better plan their network augmentation.

Going forward government is likely to have a role in the provision of charging infrastructure. This may take the form of subsidising charging infrastructure, providing education programs, constructing infrastructure in areas the private sector neglects, supporting interoperability, and potentially in standards development. The role may also need to consider the effectiveness of integrating BEV charging with the electricity sectors in ensure that the market provides the right signals.



2 Introduction

2.1 Background

2.1.1 Project briefing and objectives

In October 2017, the Special Minister of State in Victoria requested that Infrastructure Victoria prepare advice with respect to the implementation of autonomous vehicles (AV) and zero-emissions vehicles (ZEV) in Victoria. Specifically, Infrastructure Victoria are focused on providing advice on the infrastructure required:

- To enable the operation of autonomous vehicles on Victorian roads;
- To support a high proportion of the Victorian fleet being composed of zero-emissions vehicles; and
- To respond to new ownership and market models for autonomous vehicles.

For the purposes of this analysis, the following definitions are used by Infrastructure Victoria:

- Autonomous vehicles are SAE levels 4 and 5, do not require a driver and are likely to be able to cooperate with each other; and
- Zero emissions vehicles emit no (or minimal) emissions and do not generate any indirect, whole of life emissions in their manufacturing, charging, and disposal. Currently, vehicles powered by electric batteries or hydrogen fuel-cells have the potential to be considered zero emission.

The Victorian Government is aiming to ensure that the introduction of AVs and ZEVs, along with any required infrastructure, is handled in an informed and considered manner for safe, efficient and accessible transport in Victoria.

In doing this, Infrastructure Victoria are commissioning a number of technical studies. KPMG have been engaged to provide advice on the energy market impacts resulting from the implementation of AVs and ZEVs in Victoria. This includes consideration of the impacts on both the generation and network sectors plus potential changes in emissions from energy sources. KPMG has also been asked to consider the potential infrastructure responses to these energy market impacts and evaluate the factors and policy arrangements which will determine the extent of those responses.

We have considered a base-case model reflecting the energy network in 2046 which has been overlaid with transport inputs from a number of scenarios to determine the overall energy impacts. Our analysis will include a discussion of potential infrastructure responses that may be required to meet and support ongoing energy requirements from AVs and ZEVs.

Infrastructure Victoria have defined seven scenarios as an analytical tool to develop this advice. For energy impacts, there will be a particular focus on the type of technology used and the distance travelled by vehicles on the road. Discussion of these scenarios will be outlined in Section 2.1.2. The final advice, which will be a compilation of the work completed across all work streams, will be presented to the Special Minister of State in October 2018.



2.1.2 Future scenarios

The introduction of autonomous and zero emissions vehicles are fraught with uncertainty. Within a 2018 context, many questions lie ahead that would need to be responded to in shifting the make-up of vehicles on Victorian roads. Currently, electric vehicles are a seldom-seen sight, there are no hydrogen fuelling stations in Victoria and driverless cars are but a future fantasy.

Accordingly, Infrastructure Victoria have crafted seven separate scenarios as part of framing their advice to the Victorian Government. These scenarios are designed to challenge thinking and answer the many “what if” questions that exist for the implementation of autonomous and zero-emissions vehicles. Within the bounds of KPMG’s work, these scenarios provide an opportunity to demonstrate the potential impacts on the energy network, and the resulting infrastructure responses required.

Table 1 below sets out the seven scenarios defined by Infrastructure Victoria. Specifics of these scenarios, and how they have been applied to the work carried out, will be detailed in Section 3 where we discuss the results of the modelling undertaken.

Table 1 – The seven scenarios for this advice

Scenario	Description
Electric Avenue	The fleet is entirely composed of electric vehicles (which are not automated) and are privately owned.
Private Drive	The fleet is entirely composed of automated and electric vehicles which are privately owned.
Fleet Street	The fleet is composed of electric and automated vehicles with a shared ownership model. A fleet of electric and automated taxis (robotaxis) service the needs of Victoria’s travellers in the place of privately owned vehicles.
Hydrogen Highway	The fleet is entirely composed of automated hydrogen vehicles which are privately owned. The cars are powered by hydrogen fuel cell vehicles rather than fossil fuels.
Slow Lane	Half of the driving population uses a shared, electric, automated fleet, while the other half continue to use traditional internal combustion, privately owned vehicles.
High Speed	This scenario is equivalent to Fleet street, except the change happens more rapidly, and a full shift to automated, electric vehicles as an on-demand service occurs by 2031.
Dead End	The shift to autonomous and zero emissions vehicles did not occur, with internal-combustion engines remaining the norm.



2.1.3 Purpose of this report

KPMG’s advice will be provided in a number of chapters for this Report as follows:

1. Introduction to the analysis and a review of the current markets for electricity, and autonomous and zero emissions vehicles.
2. Discussion of the methodology applied to the construction of KPMG’s electricity market modelling.
3. Presentation of the results of our modelling for each of the seven scenarios, including a discussion of particular sensitivities.
4. Consideration of a range of issues and infrastructure responses that may be required to support autonomous and zero emissions vehicles in 2046 from an energy impacts perspective.

The focus of this report is on the impacts to the electricity markets, which includes a number of key components. In understanding these impacts, KPMG have sought to model both generation and network considerations, which are discussed further in their relevant sections.

The remainder of this chapter will serve as an overview of the electricity market, and the current situation for automated and zero emissions vehicles.

2.2 Current Situation

This section provides some background on the current situation and expected trends on zero emission vehicles.

Zero emissions vehicles currently focus on two differing types of vehicle: battery electric vehicles (BEV) and fuel-cell vehicles (FCEV or FCV). Throughout this report, references to ZEV will together refer to battery electric vehicles and fuel-cell vehicles. A brief definition of each type of vehicle is provided below.

Definition of electric vehicles

Taken in their whole definition, electric vehicles refer to any vehicle that use electric motors for their propulsion¹¹, which includes plug-in hybrid electric vehicles, battery electric vehicles and fuel cell vehicles. We will not consider every type of electric vehicle within our analysis and we have defined the common types of electric vehicles in Table 2 below.

Table 2 – Electric vehicle classifications

Type of electric vehicle	Description
Plug-in hybrid electric vehicle (PHEV)	These vehicles contain both an internal-combustion engine and an electric motor so are not zero emissions. The electric motor can be charged via an electrical plug, while the internal-combustion engine requires conventional fuel. The Chevrolet Volt is the leading seller in this category. Our analysis will not consider PHEVs. As these vehicles are not zero emission, we have assumed a full uptake of battery electric vehicles within relevant scenarios.

¹¹ <https://www.collinsdictionary.com/dictionary/english/electric-vehicle>



Battery electric vehicle (BEV)

Battery electric vehicles rely solely on battery packs for the electric motors and have no internal-combustion engine. Therefore, these require no conventional fuel and are charged with electricity from a charging point. The Nissan Leaf is the most widely sold BEV at present, followed by Tesla's Model S.

Fuel-cell vehicle (FCEV or FCV)

As the name suggests, a fuel-cell vehicle relies on a fuel-cell rather than a battery pack to drive its electric motors. Typically the fuel cells require hydrogen (in addition to oxygen from the atmosphere) to drive a chemical reaction that generates energy for the motors. The Toyota Mirai is the top-selling passenger FCEV.

To date, the uptake of BEVs has outstripped FCVs globally. At this time, it is not possible to determine whether one technology will prevail over the other, or if the two technologies will co-exist in particular niches. The sections that follow will provide the broad, current 'state-of-play' for BEV and FCV technology.

2.2.1 Battery electric vehicles

Globally, sales of BEVs and PHEVs have been slowly growing yet remain a niche market. Statistics from Macquarie Research indicate that PHEV and BEV sales in China, US, Europe, Japan and Canada in 2017 represented 1.7% of all new car sales¹². The driving force in this growth has been the Chinese market, where the Chinese Government have implemented measures on both the supply and demand side with an aim of improving air quality¹³. Such measures implemented include legislated production targets for PHEVs/BEVs and offering tax subsidies to alleviate the higher purchase price of these vehicles.

Australia has lagged behind the rest of the world when it comes to the adoption of electric vehicles. In 2016, electric vehicle sales in Australia totalled 1,369 and represented just 0.1% of the total market for new vehicle sales¹⁴. On a pure sales basis, Victoria currently leads Australia in EV sales. Forecasting by the Australian Energy Market Operator estimates that by 2036, 36.5% of new vehicle sales in the National Electricity Market in Australia could comprise electric vehicles, with this figure progressing to 90.0% by 2050¹⁵.

Range anxiety has been particularly pronounced in Australia. Due to a distributed population and greater travel distances, consumers are concerned as to whether a vehicle relying solely on batteries would be able to meet their driving needs without running out of charge.

The other issue in an Australian context is the cost of new BEVs, which are currently significantly higher than comparable petrol or diesel cars. There are no subsidies offered to

¹² Global electric vehicle sales are booming, Business Insider Australia, 22 January 2018, <https://www.businessinsider.com.au/the-rapid-growth-in-global-electric-vehicle-sales-in-4-charts-2018-1>

¹³ Electric cars still stuck in first gear in Australia, The Australian, 27 January 2018, <https://www.theaustralian.com.au/news/inquirer/electric-cars-still-stuck-in-first-gear-in-australia/news-story/d3c825447b9ea75a0342dd2c9dd54386>

¹⁴ ClimateWorks Australia 2017, The state of electric vehicles in Australia, https://climateworksaustralia.org/sites/default/files/documents/publications/state_of_evs_final.pdf

¹⁵ Energeia 2017, Electric Vehicles Insights prepared by Energeia for the Australian Energy Market Operator's 2017 Electricity Forecast Insights, http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2018/FINAL---AEMO-EV-Insights---September-2017.pdf



Australian consumers at present to reduce the purchase price of a PHEV or BEV. The Renault ZOE, a small hatchback BEV, is expected to be available for sale by the end of 2018 at a price tag of \$42,470. By comparison, a base model petrol-fuelled Toyota Corolla retails in Australia for approximately \$24,000.

It has been suggested that policy can aid the uptake of PHEVs and BEVs in Australia¹⁴ and globally, particularly to address cost issues. While a number of countries have made commitments to phase out the sale of new petrol and diesel cars, no such policy response has yet been made in Australia.

In April 2018, the ACT Government released their action plan to support a transition to zero-emissions vehicles. This plan includes a commitment for 50% ZEVs in newly leased ACT Government fleet passenger vehicles in 2019-20, expanding to 100% by 2020-21¹⁶.

Data released by ClimateWorks Australia in 2017¹⁴ indicates that Victoria is slightly behind other State Governments in supporting PHEVs and BEVs at a policy level. Victoria currently offers just one incentive to electric vehicle owners, a \$100 discount on vehicle registration. The Parliament of Victoria has recently released its findings on an inquiry into electric vehicles to gain a better understanding of the future market, with a large number of submissions made by parties small and large.¹⁷ A finding from this report was that a Victorian electric vehicles target, when aligned to Victoria's Renewable Energy Targets, may support Victoria to achieve net zero emissions by 2050. The report also acknowledged that Victoria may be falling behind in terms of regulations, incentives and initiatives for PHEVs and BEVs.

2.2.2 Hydrogen and fuel-cell vehicles

Global

The principle problem for hydrogen and FCV propagation can be described as a "chicken-and-egg" dilemma. Carmakers have not moved to mass production of FCVs due a lack of supporting hydrogen infrastructure to refuel FCVs and keep them on the road. Meanwhile, infrastructure providers are not pushing the building of capital-intensive hydrogen fuel stations as there are simply not enough FCVs on the road to justify the cost.

Japan are seen as one of the sector leaders in accelerating development of a hydrogen industry and attempting to solve the "chicken-and-egg" dilemma. The Government of Japan released their Basic Hydrogen Strategy in December 2017¹⁸ which has targeted 40,000 FCVs and 160 fuelling stations in Japan by 2020. In support of this strategy, 11 companies in Japan formed Japan H₂ Mobility¹⁹ which have targeted the building of 80 hydrogen fuelling stations by 2021. The companies in this consortium comprise automakers, infrastructure developers and financiers.

In comparison to EV uptake globally, FCVs have seen significantly slower propagation. Table 3 below demonstrates the gulf between global sales in 2017 of the Toyota Mirai, a leading FCV, and all Toyota electrified vehicles. Table 4 meanwhile highlights the current fuelling infrastructure in place to support FCVs.

¹⁶ The ACT's Transition to Zero Emissions Vehicles Action Plan 2018-21, ACT Government, Canberra.

¹⁷ <https://www.parliament.vic.gov.au/eic/article/3507>

¹⁸ Basic Hydrogen Strategy Determined, Ministry of Economy, Trade and Industry, Japan, http://www.meti.go.jp/english/press/2017/1226_003.html

¹⁹ Japan H₂ Mobility, LLC established by eleven companies to accelerate deployment of hydrogen stations in Japan, Nissan Motor Corporation Global Newsroom, 5 May 2018, <https://newsroom.nissan-global.com/releases/release-ea95927c382ada6ea8c100576a03104c-180305-01-e>



Table 3 – FCV statistics in 2017²⁰

Item	Number
Toyota Mirai sales in 2017 – global	c. 2,700
Toyota electrified vehicle sales in 2017 – global	c. 1,520,000
FCVs in Australia ²¹	6

Table 4 – Hydrogen refuelling stations

Item	Number
Japan ²²	101
Europe ²³	82
United States ²⁴	65
Australia	1

Australia

The hydrogen industry in Australia is still in a state of development and production of hydrogen at large-scale is not currently undertaken. In response to global signals such as Japan’s Basic Hydrogen Strategy, there is beginning to be an uptick of activity in developing a hydrogen industry for export. In 2018 there have been the announcement of a number of projects or developments, including:

- The public launch of the Hydrogen Energy Supply Chain project which will aim to produce hydrogen from brown coal in the Latrobe Valley.
- An announcement of a ‘Hydrogen Hub’ in South Australia with a 50MW electrolyser capable of producing 20 tonnes of hydrogen each day.

²⁰ Toyota sells 1.52 million electrified vehicles in 2017, three years ahead of 2020 target, Toyota Global Newsroom, 2 February 2018,

https://newsroom.toyota.co.jp/en/corporate/20966057.html?adid=aq478_mail&padid=aq478_mail

²¹ Hyundai Nexo hydrogen car coming to Australia this year, petrol-free driving range 800km, News.com.au, 10 January 2018,

<http://www.news.com.au/technology/innovation/motoring/hitech/hyundai-nexo-hydrogen-car-coming-to-australia-this-year/news-story/70718407b2b6a78020d054febd9a5f57>

²² Auto giants, energy firms team up for expansion of hydrogen fuelling stations, The Mainichi, 6 March 2018, <https://mainichi.jp/english/articles/20180306/p2a/00m/0na/018000c>

²³ Total number of hydrogen filling stations, European Alternative Fuels Observatory, <http://www.eafo.eu/infrastructure-statistics/hydrogen-filling-stations>

²⁴ Hydrogen fueling station locations, Alternative Fuels Data Center, U.S. Department of Energy, https://www.afdc.energy.gov/fuels/hydrogen_locations.html#/analyze?fuel=HY&hy_nonretail=true&show_private=true



- Funding for a 'green hydrogen' plant in South Australia that will house a 10MW hydrogen-fired gas turbine and a 5MW hydrogen fuel-cell.
- A power-to-gas demonstration plant in South Australia which will generate hydrogen through an electrolyser and inject it into the existing natural gas pipeline system.
- Visits by delegations to Gladstone who are exploring the development of hydrogen production facilities for export.

Alongside this, the CSIRO are currently developing a National Hydrogen Roadmap that will identify investment priorities and key areas for the development of a hydrogen value chain in Australia.

However, while these announcements are exciting for the development of a hydrogen production industry, there has not yet been a push for FCVs. As was shown in Table 3, the uptake of fuel-cell vehicles in Australia to date has not made significant progress. Only 6 FCVs are on the road, which represent demonstration models that are not available to the general public.

Hyundai are looking to launch their second generation FCV, the Nexo, in late-2018, which is purported to offer a driving range akin to a conventional internal combustion engine. The ACT Government has partnered with Hyundai to take delivery of 20 of these vehicles by the end of 2018, which will include the construction of one refuelling station in Canberra and ongoing maintenance for the vehicles²⁵.

Presently, there is currently one hydrogen refuelling station in Australia, located at Hyundai Australia in Sydney²⁶. Toyota Australia also has a portable refuelling station mounted on a truck²⁷ for refuelling their demonstration Mirai vehicles.

In a Victorian context, there is currently no hydrogen fuelling infrastructure in the state. The Moreland City Council announced a \$9 million project in 2017²⁸ to build Australia's first commercial hydrogen refuelling station and convert a number of municipal waste collection vehicles to hydrogen fuel.

2.2.3 Autonomous vehicles

What are autonomous vehicles?

Broadly, an autonomous vehicle is able to respond to its environment and function without a driver intervening. There are currently no fully autonomous vehicles in production and the technology is still in a research and development phase.

To assist in understand differing levels of autonomy, SAE International developed a standard with 6 levels of autonomy. The lower levels rely on a human to monitor the environment and control the vehicle while higher autonomy levels see a vehicle able to monitor their own environment with the driver largely relegated to a secondary role.

²⁵ Next generation renewables auction: Local investment outcomes, ACT Government, https://www.environment.act.gov.au/_data/assets/pdf_file/0009/988965/Next-Generation-Renewables-Local-Investment-ACCESS.pdf

²⁶ 2018 Hyundai Nexo first drive review, Drive, 23 February 2018, <https://www.drive.com.au/new-car-reviews/2018-hyundai-nexo-first-drive-review-117330>

²⁷ Hydrogen cars: what are they and when will we drive them?, ABC News, 14 September 2017, <http://www.abc.net.au/news/2017-09-14/hydrogen-car-explainer-what-are-they-and-when-will-we-drive-them/8946184>

²⁸ Melbourne council to build emissions-free rubbish trucks by 2020, ABC News, 5 August 2017, <http://www.abc.net.au/news/2017-08-05/zero-emissions-garbage-trucks-moreland-city-council/8777900>



Figure 1 below presents the definitions of autonomous vehicles as per the J3016 standard from SAE International. As noted, levels 4 and 5 of this standard are considered *autonomous vehicles* in this advice.

Figure 1 – SAE J3016 autonomous vehicle definitions²⁹

SAE level	Name	Narrative Definition	Execution of Steering and Acceleration/Deceleration	Monitoring of Driving Environment	Fallback Performance of Dynamic Driving Task	System Capability (Driving Modes)
Human driver monitors the driving environment						
0	No Automation	the full-time performance by the <i>human driver</i> of all aspects of the <i>dynamic driving task</i> , even when enhanced by warning or intervention systems	Human driver	Human driver	Human driver	n/a
1	Driver Assistance	the <i>driving mode</i> -specific execution by a driver assistance system of either steering or acceleration/deceleration using information about the driving environment and with the expectation that the <i>human driver</i> perform all remaining aspects of the <i>dynamic driving task</i>	Human driver and system	Human driver	Human driver	Some driving modes
2	Partial Automation	the <i>driving mode</i> -specific execution by one or more driver assistance systems of both steering and acceleration/deceleration using information about the driving environment and with the expectation that the <i>human driver</i> perform all remaining aspects of the <i>dynamic driving task</i>	System	Human driver	Human driver	Some driving modes
Automated driving system ("system") monitors the driving environment						
3	Conditional Automation	the <i>driving mode</i> -specific performance by an <i>automated driving system</i> of all aspects of the <i>dynamic driving task</i> with the expectation that the <i>human driver</i> will respond appropriately to a <i>request to intervene</i>	System	System	Human driver	Some driving modes
4	High Automation	the <i>driving mode</i> -specific performance by an automated driving system of all aspects of the <i>dynamic driving task</i> , even if a <i>human driver</i> does not respond appropriately to a <i>request to intervene</i>	System	System	System	Some driving modes
5	Full Automation	the full-time performance by an <i>automated driving system</i> of all aspects of the <i>dynamic driving task</i> under all roadway and environmental conditions that can be managed by a <i>human driver</i>	System	System	System	All driving modes

From an energy impacts perspective, we do not consider that there will be a large difference in the drivetrains of an autonomous vehicle compared to a conventional vehicle. However, autonomous vehicles, particular in shared fleets, are likely to have different usage behaviours that may necessitate a varied charging approach. This is considered in our modelling and use of load profiles, which will be discussed in Chapter 3.

Global examples of autonomous vehicles

As noted, there are currently no autonomous vehicles in production that are able to drive themselves with no driver intervention. However, there are a number of manufacturers exploring the implementation of autonomy in their vehicles:

- The Audi A8 is the first production vehicle developed to allow level 3 automated driving³⁰ per Figure 1. With this system, the car is able to undertake all driving tasks in slow moving traffic under particular conditions.

²⁹ SAE International 2014, Automated Driving – Levels of driving automation are defined in new SAE International standard J3016.

³⁰ The new Audi A8: future of the luxury class, Audi MediaCenter, 7 November 2017, <https://www.audi-mediacycenter.com/en/press-releases/the-new-audi-a8-future-of-the-luxury-class-9124>



- Tesla has developed its 'Autopilot' system that is currently considered to fit within the level 2 definition of autonomy³¹, with an expectation that this will be capable of progressing to level 5.
- Mercedes-Benz, Volvo, and Cadillac have all released systems incorporated into particular models that are capable of level 2 autonomy³².

As of 2017, 33 states in the United States have enacted some form of legislation concerning autonomous vehicles³³. A number of states allow autonomous vehicles to be tested on public roads alongside driver-controlled vehicles. Notably, Waymo (subsidiary of Google's parent company) has been developing autonomous vehicle technology since 2009 and have announced plans to launch a self-driving car service by the end of 2018 in Phoenix, Arizona³⁴.

Australian context

In an Australian context, autonomous vehicles are not currently on public roads. The Australia and New Zealand Driverless Vehicle Initiative (ADVI) is the peak industry body for autonomous vehicles in Australia and New Zealand. ADVI have adopted and support SAE International's definitions on autonomous vehicles³⁵.

Current Australian road legislation lacks adequate definitions for the use of autonomous vehicles, particularly concerning how responsibility is assigned³⁶. In May 2018, the National Transport Commission released a policy paper on required legislation changes required to support autonomous vehicles on the road. As well as this, Australia's transport ministers have agreed that Australia should have regulation in place by 2020 to support autonomous driving on Australian roads³⁷.

2.2.4 Zero emissions vehicles and the energy market

The uptake of AVs and ZEVs to Victorian roads presents a number of opportunities and challenges to the energy market, which would necessitate a number of responses, both in terms of investment to provide the required infrastructure; and policy arrangements to support efficient outcomes, to ensure that the energy markets have the required capacity and resilience to manage the energy draw from AVs and ZEVs.

The key issues that we will be considering in the report will be centred on the following:

1. **Generation capacity** – the introduction of AVs and ZEVs will increase overall grid requirements under both an EV and FCV scenario, which will require increased generation

³¹ The basics of Tesla Autopilot – what is it, and how legal is Autopilot in Australia?, Drive Zero, 13 May 2018, <https://www.drivezero.com.au/tesla-autopilot-guide/>

³² Car Autonomy Levels Explained, The Drive, 3 November 2017, <http://www.thedrive.com/sheetmetal/15724/what-are-these-levels-of-autonomy-anyway>

³³ Autonomous vehicles | Self-driving vehicles enacted legislation, National Conference of State Legislatures, 21 May 2018, <http://www.ncsl.org/research/transportation/autonomous-vehicles-self-driving-vehicles-enacted-legislation.aspx>

³⁴ Waymo's self-driving car service is launching in Phoenix later this year, VentureBeat, 8 May 2018, <https://venturebeat.com/2018/05/08/waymos-self-driving-car-service-is-launching-in-phoenix-later-this-year/>

³⁵ Australian Driverless Vehicle Initiative 2017, Regulatory barriers to more automated road and rail vehicles, <http://advi.org.au/wp-content/uploads/2017/06/NTC-Regulatory-barriers-to-more-automated-road-and-rail-vehicles.pdf>

³⁶ Australia is getting new driving laws for autonomous vehicles, Gizmodo Australia, 30 May 2018, <https://www.gizmodo.com.au/2018/05/australia-drafts-new-driving-laws-for-autonomous-vehicles/>

³⁷ Changing driving laws to support automated vehicles – Policy paper May 2018, National Transport Commission Australia, Melbourne, Australia.



capacity. Proliferation of charging points for BEVs will have an impact on the grid, as would the deployment of hydrogen production infrastructure that requires significant energy to produce hydrogen on the scale required for full uptake.

2. **Network response** – while grid factors will provide a whole-of-network lens, energy networks will be affected by varying degrees depending on population distribution, increased electricity demand and current infrastructure capacity. The impacts will differ between transmission and distribution networks.
3. **Emissions** – the increased consumption of electricity for ZEV charging or hydrogen production will impact on the emissions intensity and CO₂ emissions levels of the energy sector. This will be influenced by the type of generation technology (and fuel) that is used in generating the required electricity to meet this demand.
4. **Charging infrastructure** – From a BEV perspective, the charging infrastructure utilised will impact the size of peak demand based on time of charge and the type of charger. The time of charging will influence when loads are placed on the grid while the type of charging infrastructure will impact the size of load peaks, with fast-charging infrastructure drawing a greater degree of power over a shorter time period.
5. **Capturing benefits to the energy system (i.e. Vehicle-to-Grid)** - Vehicle-to-Grid (V2G) technology serves as the enabler to use car batteries as short-term storage and supports an intelligent integration of BEVs into the grid. Under V2G, the battery within ZEVs will effectively have a second purpose – that is, to act as a store of surplus energy produced by renewable power. Commercialising the bidirectional charging solution creates synergies between the energy and transport sectors and has the potential to be a low cost way to provide electricity storage, thus helping to support the reliability of increased renewable energy more practical on a large scale.



2.3 Energy market overview

This section provides a summary description of the Victorian electricity sector to provide background to the modelling methodology and results.

2.3.1 Wholesale and retail electricity market

The National Electricity Market (NEM) commenced operation as a wholesale electricity spot market in December 1998, and connects five regional markets which also act as price regions: Victoria, South Australia, Tasmania, New South Wales (including the ACT) and Queensland. Electricity generators sell electricity they produce, and retailers buy electricity which they then on-sell to consumers. Distribution and transmission networks transport electricity between generators and consumers.

Moving electricity between generators and consumers is facilitated through a spot market, or a 'pool'. That is, the power supply is matched to the power demand instantaneously in real time through a centrally coordinated dispatch process, managed by the Australian Energy Market Operator (AEMO). Generators make offers to supply the market with a certain amount of electricity at certain times for certain time periods (and can re-submit the offered amounts at any time). AEMO decides which generators should generate electricity on the basis of these bids, with the cheapest generator being deployed first (typically a factor of the fuel and operating cost, meaning renewables are used before for example high-cost peak gas turbines). This way, demand is satisfied in the most cost efficient way. AEMO also takes into account the need for spare generation capacity, in case it is required, and any limitations on the transmission network.

Some types of generation have so called "intermittent output", including wind and solar farms. Such generators also participate in the central dispatch process, to the extent that they have to control their output in response to network constraints. At other time these generators can supply up to their maximum registered capacity. AEMO refers to this type of generation as "semi-scheduled" (as opposed to "scheduled" generation, which is fully dispatchable in terms of the centrally coordinated dispatch process).

The electricity "spot price" is determined every 30 minutes for each of the NEM price regions. The spot price is the average of six five-minute dispatch prices. The spot price is the price that is used to settle all transactions for electricity traded in the NEM. The last generator used in each five minute interval to meet demand sets the price.

There is both a cap and a floor for the spot price, known as the "market price cap" and the "market floor price" respectively. On July 2017, the cap was set at \$14,200/MWh and the floor was set at -\$1,000/MWh. The cap and floor are adjusted annually for inflation. Many NEM participants manage price volatility by way of hedging contracts, which allow them to fix the future price of electricity. The spot price (and future price) provides market signals for investment in generation and competitive responses in the retail market.

Victoria currently has 10,190 MW of installed generation capacity, made up of 5,140 MW of steam sub critical (primarily brown coal), 1,872 MW of open-cycle gas turbines (OCGT), 2,213 MW of hydro and 965 MW of on-shore wind. There are three large brown-coal fired generators, Loy Yang A (owned by AGL), Loy Yang B (owned by Alinta Energy) and Yallourn (owned by EnergyAustralia) which have a combined capacity of 4,630 MW, just under half the total installed generation capacity for Victoria. A major coal-fired generator, Hazelwood, was retired in 2017 by ENGIE, removing 1,700 MW of generation capacity in Victoria.



The Victorian Government is targeting that 25% of electricity in Victoria be generated by renewables by 2020, and 40% by 2025. Furthermore, the Victorian Government committed in 2016 to achieving a net zero emissions target by 2050, with emissions to be reduced as low as possible with the balance of remaining emissions set off through methods such as planting trees or capturing carbon³⁸.

As noted above, all five regional markets of the NEM are connected through interconnectors. Interconnectors allow for electricity to be imported and exported between NEM regions, and play an important role in balancing supply and demand in the NEM. At times of constraint, imported energy from an interconnector can be an important supply of power when local generation is insufficient to meet demand. Victoria is connected directly to Tasmania via the Basslink interconnector, South Australia via the Heywood interconnector and the Murraylink interconnector, and New South Wales via the Victoria to New South Wales interconnector.

The price that final consumers pay for electricity is a function of the following:

- The wholesale market cost described above.
- A network cost comprising the regulated cost to transport electricity over the transmission and distribution networks.
- An environmental policy cost.
- A residual component.

The AEMC reported that, in 2016/17, the residential electricity market offer price in Victoria was approximately \$1,105 for a representative customer. This was made up of 34.2% wholesale market costs, 45.1% network costs, 5.9% environmental policy costs and 14.8% residual costs.³⁹

In December 2016, there were 22 electricity retail businesses in Victoria (25 brands). According to the AEMC, competition is and continues to be effective in the retail electricity market. Victoria has the lowest level of market concentration in the NEM, and the highest share of so called "second tier" (i.e. not AGL, Origin or EnergyAustralia) retailers.⁴⁰

Structural separation occurred in the 1990s in the electricity sector, with the break-up of vertically integrated businesses into generation, transmission, distribution, and retail businesses. However, there has since been a trend for vertical integration with generation businesses seeking to acquire retailers and vice versa. Vertical integration is a means for retailers and generators to internally manage the risk associated with the volatility of the spot price, without having to enter into hedging contracts. For example, the three owners of major coal-fired generation in Victoria (AGL, Alinta Energy and EnergyAustralia) are all retailers in the Victorian market (commonly referred to as 'gentailers').

³⁸ Victoria's Net Zero by 2050 Emissions Reduction Target, Department of Environment, Land, Water and Planning Victoria, <https://www.climatechange.vic.gov.au/media-releases/victorias-net-zero-by-2050-emissions-reduction-target>

³⁹ Final Report – 2017 Residential Electricity Price Trends, Australian Energy Market Commission, 18 December 2017, New South Wales, Australia <https://www.aemc.gov.au/sites/default/files/content/bf56a5d5-e2b2-4c21-90ed-79dda97eb8a4/2017-Residential-Electricity-Price-Trends.pdf>, p. 118

⁴⁰ Final 2017 AEMC Retail Energy Competition Review, Australian Energy Market Commission, 25 July 2017, New South Wales, Australia, <https://www.aemc.gov.au/sites/default/files/content/006ad951-7c42-4058-9724-51fe114cabb6/2017-AEMC-Retail-Energy-Competition-Review-FINAL.pdf>, p. 266



2.3.2 Electricity transmission and distribution in Victoria

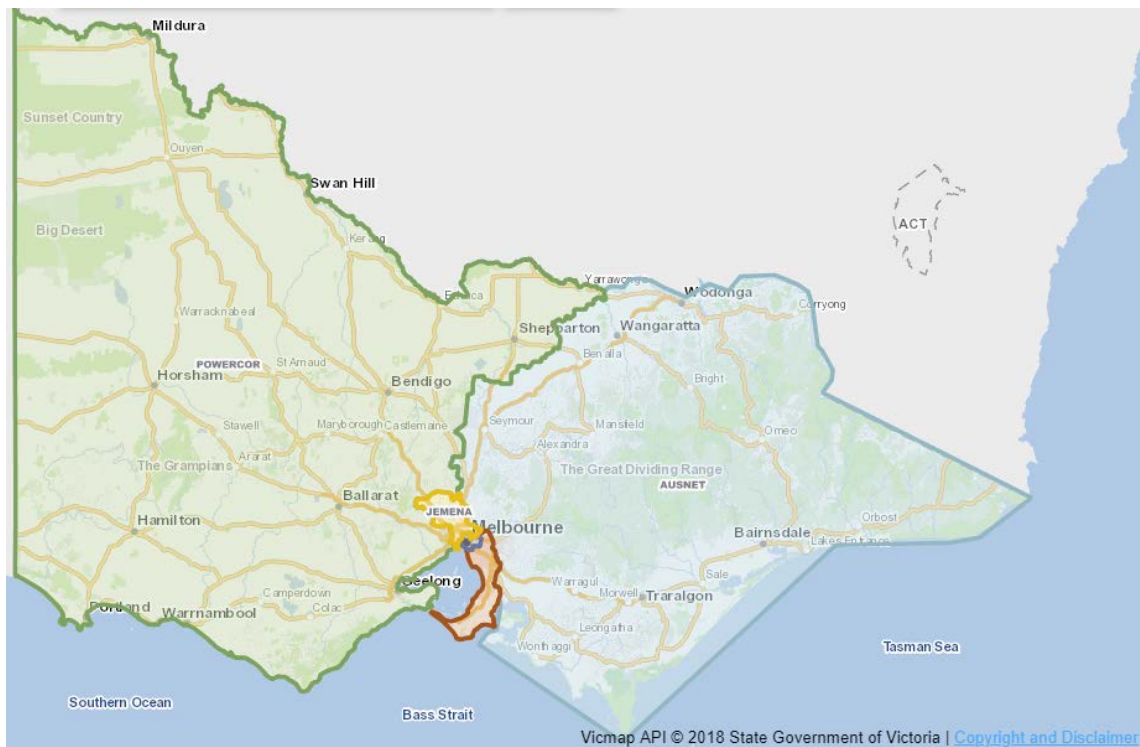
The transmission and distribution networks in Victoria are responsible for taking electricity from its generation point and delivering this to end-users across the state. These networks are separate to each other such that electricity will travel on the transmission network before it is “handed over” to the distribution network for the final stages of transport.

In Victoria, the transmission and distribution networks consist of the following:

- one transmission network service provider: AusNet Services; and
- five distribution network service providers (DNSP): AusNet Services, CitiPower, Jemena, Powercor, and United Energy.

AusNet’s transmission network services the whole of Victoria. Each distribution network is defined by a specific geographic area – see Figure 2 for a state-wide illustration and Figure 3 for the Greater Melbourne distribution network.

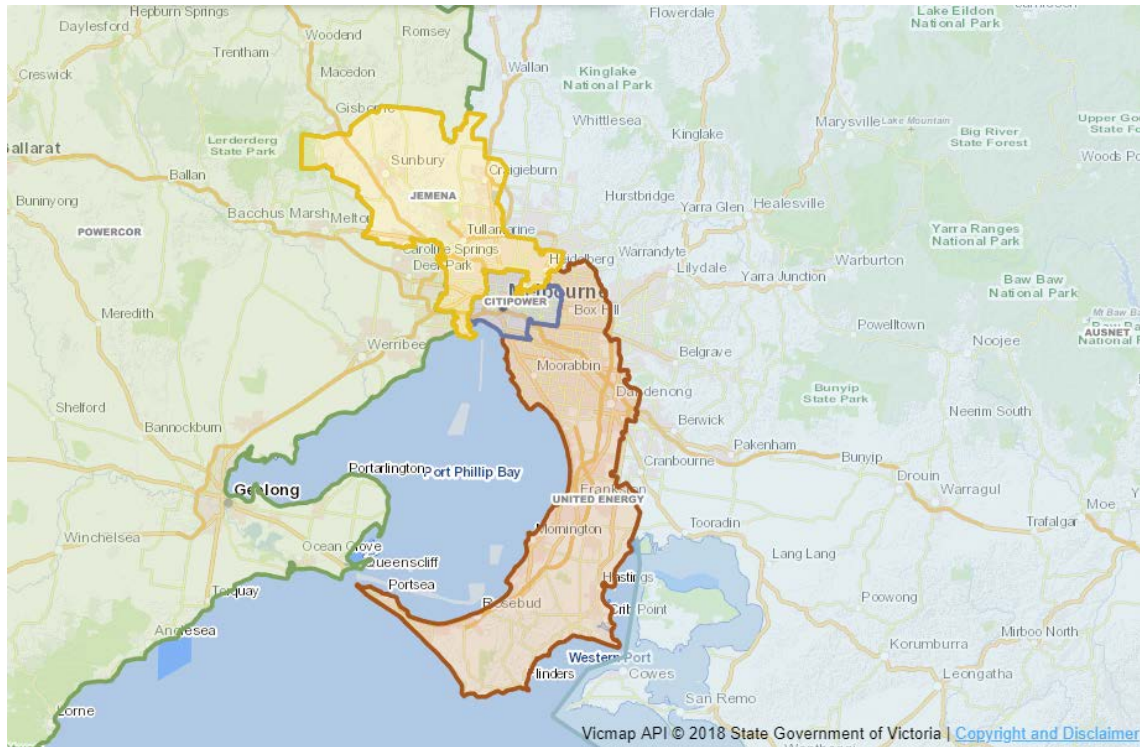
Figure 2 – Distribution networks in Victoria



Powercor’s network spans the western half of Victoria, and AusNet’s distribution network spans the eastern half. The other three networks span the area surrounding Greater Melbourne and are presented in Figure 3.



Figure 3 – Distribution networks in Greater Melbourne



CitiPower’s network covers the CBD, Jemena’s network is located north of the CBD, and United Energy, is located to the south and includes the Mornington Peninsula.

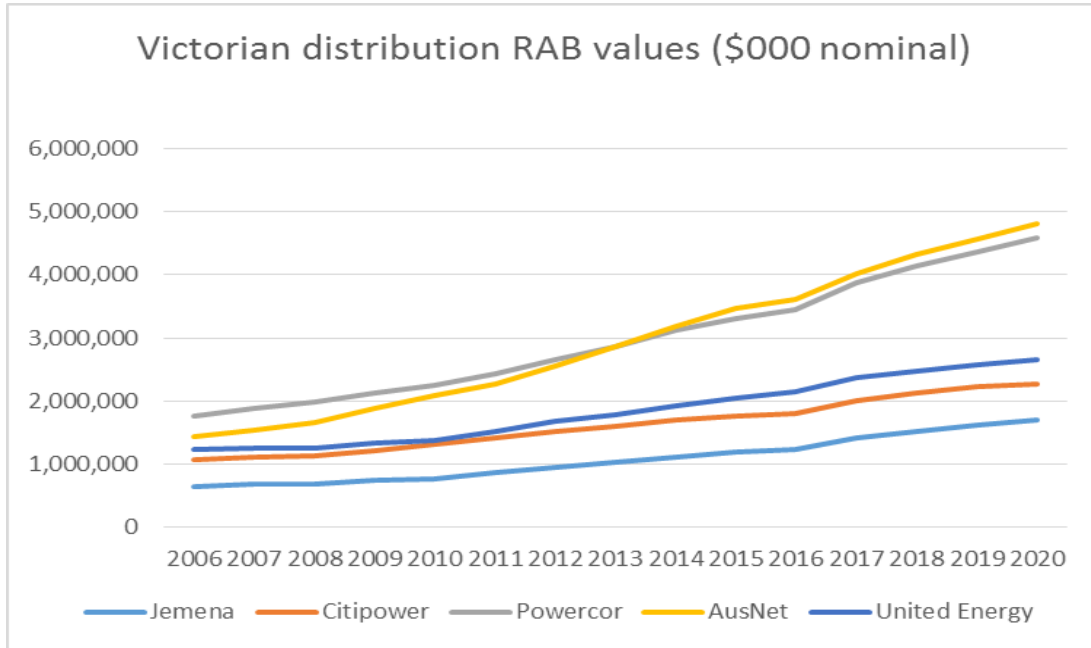
Drivers of investment

Investment drivers vary across electricity networks and depend on a network’s age and technology, load characteristics, the demand for new connections, licensing, reliability, and safety requirements. An electricity network periodically requires new investment to replace ageing equipment and other assets. If energy demand is rising, then augmentation (expansion) of parts of a network may also be considered.

Figure 4 shows the current Regulatory Asset Base (RAB) values for each of the Victorian distribution networks which represents the current depreciated value of all existing capital assets owned by the networks. This shows that there has been substantial capacity investment in network capacity in recent years. This has been driven by high network utilisation along with continued maximum demand growth (albeit less than previous). It also reflects that the current distribution networks are aged having been installed prior to the early 1960s with evidence of increasing asset failures that necessitate replacements.



Figure 4 – Regulatory Asset Base values for Victorian networks



Source: AER distribution determinations

The Australian Energy Regulator has allowed Victorian distribution businesses to increase their capital expenditure over the current regulatory period of 2015 to 2020. While flat demand and a reduction in Victorian customers’ valuation of supply reliability has eased investment requirements in 2016–21, this outcome is more than offset by a rise in replacement expenditure (partly to meet regulatory obligations arising from the 2009 Victorian Bushfire Royal Commission).

For distribution networks, investment is driven by demand conditions at the local level. Hence, despite the general slowing in demand growth at the network level, there are areas within the Victorian network where maximum demand is forecast to grow well beyond the network average level. This is mainly due to urban development and increase in population density. Such factors can lead to a need to augment the capacity at a zone substation level.

The situation differs for the transmission network where generation entry and flows can influence network investment. An increase in new generation in different locations compared to traditional plant will require the transmission network to be augmented to manage this flow. This has been seen in certain areas of Victoria that are seeing investment into wind and solar assets where typically there had been little prior energy investment.

Going forward over the modelled period, it is expected that replacements will be the key driver of investment for both distribution and transmission networks given the age of existing assets. Replacement expenditure is needed to ensure reliability and public safety. Under the scenarios of ZEV uptake, a potential challenge will be ensuring optimal timing co-ordination between the triggers for replacement and the need to augment the network to potentially service the extra demand due to BEV consumption.



Methodology and approach



3 Modelling Approach

3.1 Overview of modelling approach

KPMG has been engaged to model the impact on energy system costs as a result of 100% ZEV uptake under the seven scenarios defined by Infrastructure Victoria. This required an approach to estimate both the increase in generation and network capacity to provide and transport the electricity to charge BEVs. The impacts on the generation market will depend on both the demand at system peak times and the electricity consumption associated with the BEVs. While the impact on network capacity will be dependent on the demand during the peak periods for the network.

For the hydrogen FCV scenario, we have modelled the hydrogen requirements to support the road network, and then the electricity generation required to produce this required level.

The draw on the electricity system from charging a BEV will be driven by a number of factors. Our model incorporates the following variables into the estimate of the demand at peak times under the various scenarios:

- Type of vehicle use – residential, commercial or freight.
- The way or node of charging vehicle across the scenarios. Our model has four different charging nodes – residential, commercial and out-of-home for private fleets, and then a separate node for shared fleet charging.
- The charging rate which will depend on charging infrastructure technology, which determines the length of time needed to charge the vehicle. Our model distinguishes between three different charging levels ranging between 3 kW, 9.5 kW and 240 kW.
- Regarding the time-segment profile of charging over the day, for relevant scenarios, our model either has an incentivised profile where the BEV owner has an incentive to alter the time of their charging, or a non-incentivised profile where there is no incentive to charge at different times.

KPMG's Electricity Market Impact Model is comprised of the following components:

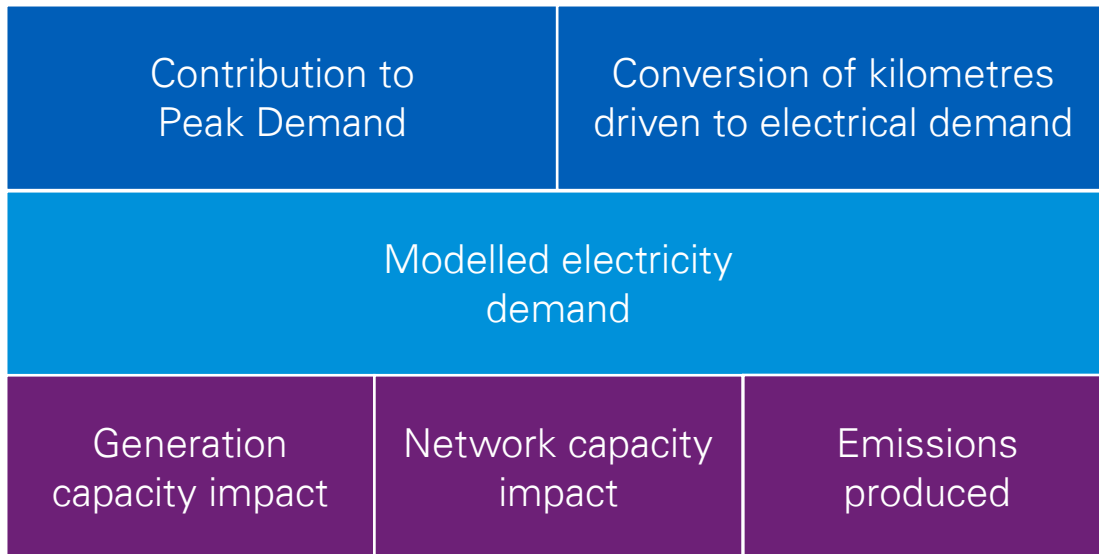
1. Conversion of transport data inputs from the Melbourne Activity Based Model to electrical consumption and demand. In some cases, we have also used the transport data to inform the timing of when a BEV charges.
2. A calculation of the contribution to peak electricity demand from BEVs. This is based on the vehicles electricity consumption while driving, as well as the profile of BEV charging over a given day.
3. A generation model to model the impacts of ZEVs on generation capacity, cost, and emissions. This determines the magnitude of new generation required.
4. Modelling of the average network costs for each of the five distribution networks to serve the additional demand. This is based on published long term marginal cost figures.
5. Network spatial analysis to assess potential localised impacts on the distribution network from BEV demand at the zone substation level.

For the Hydrogen Highway scenario, a separate calculation has been utilised that is unique to this scenario. Our approach to this will be discussed in detail in Section 3.7.

Our approach in creating our Electricity Market Model and the function of this model is shown in Figure 5 as follows:



Figure 5 – KPMG Electricity Market Modelling approach



A brief overview of each main component of the KPMG Electricity Market Model is provided below. A detailed discussion of our modelling approach will follow that sets out the rationale for the assumptions and methodology applied.

Conversion of transport distance driven to electricity demand

The primary inputs which our modelling is based upon is vehicle kilometres driven and vehicle numbers across Victoria from the Melbourne Activity Based Model. In order to understand and model the impacts on the electricity network, we have converted the distances driven and numbers under the relevant scenarios modelled into a maximum demand and consumptions estimates, which are utilised in both the generation and network components of the KPMG Electricity Market Model that were outlined above.

In performing this conversion, we have considered a number of factors including:

- Average energy consumption of BEVs.
- Energy loss factor on charging.
- Charging rates and preferences.

Calculation of the contribution to the peak demand

Peak demand from BEVs will be common across both the generation and network sectors. Our model estimates the contribution to peak demand based on the typical day used by MABM. The contribution to peak demand across the day from BEV will effectively be equal to the total number of BEVs charging in the hour multiplied by the charging rate⁴¹ for each vehicle. The charging rate will differ by the type of customer and the customer preference for charging (i.e. whether it is out of home or at home).

The load profile used determines the behaviour and timing of charging. While driving, BEVs are not drawing power from the electricity network and thus have no impact. However, once a BEV is plugged into a charging outlet, it begins to draw electricity from the network. Accordingly, the use of load profiles dictates when the network is likely to be put under stress at times of peak demand.

⁴¹ In addition there will be an adjustment for the power factor correction to account for the difference between kVA and kW.



In our Electricity Market Model, we have considered six different situations with their own load profiles to represent the different use-cases for which BEVs may impact the electricity network (see Table 5). This also recognises that the nature and timing of charging will differ across the private fleet and shared fleet scenarios.

Table 5 – Selected load profiles

Residential	Commercial	Out-of-home (OOH)	Shared
Non-incentivised	Non-incentivised	Non-incentivised	Shared fleet profile
Incentivised	Incentivised		

Based on these profiles and assumptions on the type of charging rate applicable to each profile, our model calculates separate contribution to the peak profile for a number of individual charging types. We then aggregate the individual profiles relevant to that scenario to estimate the total contribution to the peak.

This is explained further in Section 3.3.

Generation impacts modelling

Our model estimates the level of generation and associated capital costs needed to meet maximum and total consumption of electricity demand in Victoria with the uptake of BEVs through the defined timeline. We first calculate the capacity needed to meet the additional system peak and then estimate the further generation is needed to serve any electricity consumption that cannot be met from the peak demand capacity.

The costs of generation will depend on the type of generation plant assumed that will enter the market to serve additional demand and consumption. Following discussions with Infrastructure Victoria, we have assumed that all new generation to serve BEVs are renewable sources with no emissions. This is consistent with the objective of BEV impacts being zero emissions and complements the Victorian government policy objective of a zero net emission system by 2050.

Generation types for meeting peak demand must be dispatchable (i.e. available to run when required) and therefore we have limited the choice to either batteries or pumped hydro. For generation to meet excess consumption, we have based the choice on a mixture of solar and wind.

The generation model is also used to estimate the electricity costs associated with hydrogen production for the Hydrogen Highway scenario.

Our generation model assumption and methodology is explained in detail in Section 3.4.

Network impacts modelling

The network component of our model has been utilised to calculate the likely network costs for each of the five distribution networks in Victoria following the introduction of electric vehicles to the road network under each scenario.

To do so, we have utilised the long run marginal cost to calculate the impact of BEVs on the network. This has then been scaled up to determine a whole-of-network impact, for which we have calculated the incremental network costs for each of the five distribution networks in Victoria.

The network model approach is discussed in Section 3.5.



Spatial network analysis

Within our analysis of network impacts, we have also considered a separate spatial analysis at the zone substation level to determine particular areas within each DNSP's network that may require upgrading to cope with the additional demand caused by BEVs. This analysis is provided for 228 zone substations (ZSS) across the Victorian network.

This is based on current capacity of existing ZSS, estimated number of vehicles in each ZSS area which determines the estimated BEV demand in each ZSS. This analysis is quite simple as we don't attempt to model population or demand growth at the ZSS level. To undertake our analysis, we have estimated the number of BEVs using data from the transport model on number of trips by SA2 area.

This is discussed in Section 3.6 of the report.

Discount rate

As a component of our modelling considers the net present value impact of BEV investment, a real discount rate has been adopted to calculate this. Given the long-term time horizon to 2046, the choice of discount rate will impact the final values expressed. Where a higher discount rate is utilised, the net present value will be a lower figure, with the inverse being true if a lower discount rate is selected.

Following discussions with Infrastructure Victoria, we have adopted a real discount rate of 7.00% for the purposes of our modelling. This is consistent with commentary from the Victorian Department of Treasury and Finance who recommend this rate for easily monetised benefits (i.e. public transport, roads and housing)⁴², and Infrastructure Australia who recommend this rate for appraisal summary results⁴³.

3.2 Interpretation of MABM results

3.2.1 The Melbourne Activity Based Model

The Melbourne Activity Based Model (MABM) was developed by KPMG for use by Infrastructure Victoria in response to a need for a strategic transport model for Melbourne. A strategic transport model tests the impacts of infrastructure and policy scenarios on transport network performance, including the fairness and equity impacts from these scenarios. The MABM is intended to form part of the evidence base to inform public debate on transport policy and investment in Victoria.

The MABM builds on a theoretical framework and open-source platform known as the "Multi-Agent Transport Simulation" (MATSim). The MATSim theoretical framework represents leading

⁴² Economic Evaluation for Business Cases - Technical guidelines, Victorian Department of Treasury and Finance, August 2013.

⁴³ Assessment Framework, Infrastructure Australia, March 2018, http://infrastructureaustralia.gov.au/policy-publications/publications/files/IFA_Infrastructure_Australia_Assessment_Framework_Refresh_v26_lowres.pdf



practice in strategic transport modelling. The MABM is an agent and activity-based modelling tool with the MATSim framework modified to suit local conditions in Melbourne.

The original MABM provided a strong framework for the modelling of AV and ZEV scenarios for the purposes of this advice as the MATSim base has already been used to undertake AV and ZEV scenario modelling for other projects. The baseline MABM is a simulation of a typical day of the week, specifically, a Tuesday in August during the school term with no public holidays.

For the whole piece of advice, of which this work forms part, KPMG have developed a new reference scenario for the year 2046 and developed additional functionality in MABM to test the impacts of AV and ZEV technologies, along with associated ownership models.

For the purposes of our work in modelling the impacts on the energy network, we rely on a number of outputs from the MABM to shape our analysis. While we have not modified the functionality of the model in any way, we have adjusted particular outputs or applied assumptions to them, for which our discussion below will cover each of these.

Furthermore, MABM considers a number of permutations to the seven scenarios (such as empty running or changes to traffic flow). Our modelling has utilised the 'base case' of each scenario, with the exception of Private Drive, where we have modelled impacts of the 'empty running' permutation in line with advice from Infrastructure Victoria.

3.2.2 Key assumptions

Annualisation of daily VKT data

As was noted in Section 3.2.1 above, the MABM provides data for a typical day in a typical week. For the purposes of our analysis of the impacts on the electricity network, we have opted to annualise this output to provide a typical year of vehicle travel in Victoria.

To convert the typical workday provided by the MABM to an annual figure, we have utilised data provided publically by VicRoads⁴⁴ on the traffic volumes by day of week in Victoria. This data compares the traffic volume on a given day to an average weekday. As would be expected, the traffic volumes on a weekend will be a lower share as a percentage of an average weekday. Figure 6 below sets out the latest data published by VicRoads.

⁴⁴ Traffic Monitor, 17 February 2017, VicRoads, https://public.tableau.com/views/TM-Volumes2014-15/TrafficVolumes?:embed=y&:showTabs=y&:showVizHome=no#1&:display_count=yes&:atoolbar=no



Figure 6 – Victorian traffic volumes by day of week

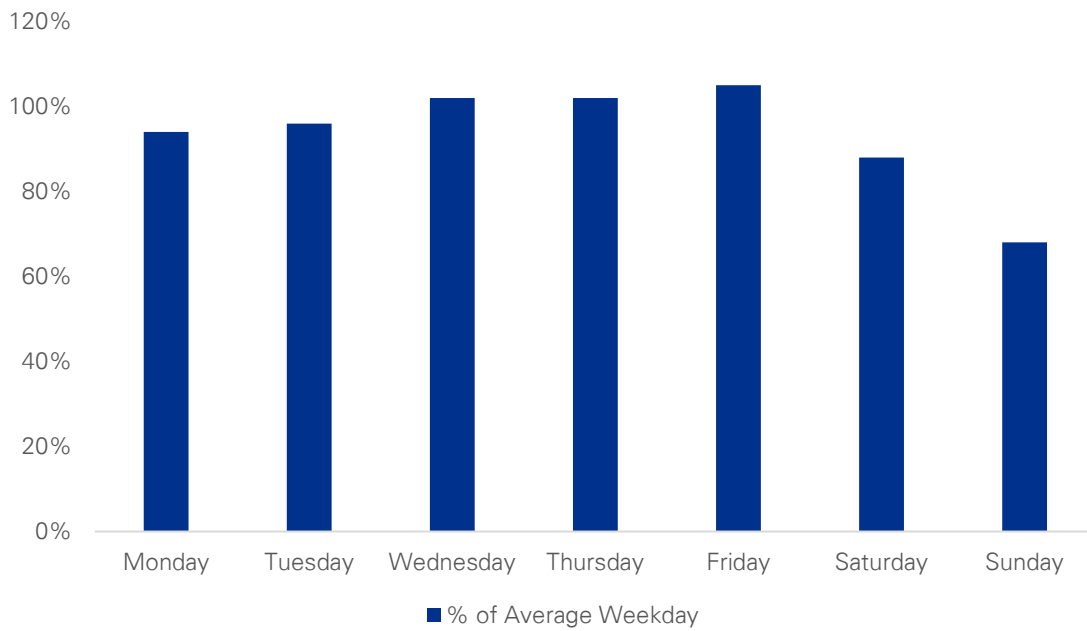


Table 6 – Derivation of annualisation factor

Day	Number of days	% of average weekday	Weighted average number of days
Monday	52	94%	48.88
Tuesday	52	96%	49.92
Wednesday	52	102%	53.04
Thursday	52	102%	53.04
Friday	52	105%	54.60
Saturday	52	88%	45.76
Sunday	52	68%	35.36
Additional day	1	100%	1
Total Days	365	Annualisation factor	341.6

We have calculated an annualisation factor in Table 6 based on the data shown in Figure 6. We have assumed a standard year (i.e. not a leap year) with an equal distribution of weekdays and weekends. By nature, this leaves 1 additional day, which we have assumed for ease will represent one perfectly average weekday.

This annualisation factor will be applied to the VKT figure of a typical work day provided by the MABM to provide an annualised VKT.



Uptake of ZEVs

The MABM provides outputs for 2031 and 2046, which provides point-in-time results. For the purposes of KPMG’s Electricity Market Modelling, we have modelled impacts annually to determine supply and demand factors as it is necessary to understand how generation requirements are met over time given the time required to finance, construct, and commission new assets.

For particular extrapolation calculations, these will be discussed in their relevant sections below based on how they affect relevant calculations within the generation and network demand modelling. For these, we have typically relied upon published data to guide the assumptions utilised.

For the purposes of modelling ZEV uptake in Victoria between the present day and 2046, we have assumed a consistent linear uptake curve. This is in line with advice provided by Infrastructure Victoria and allows for infrastructure responses that are able to respond to a gradual uptake of vehicles.

Fleet size and distance travelled

The MABM provides the total fleet size as an output, thus this will be used where required. We note that the fleet size is not classified by vehicle type and we have had to make some assumptions in particular circumstances. This will be expanded on further below for our utilisation of residential, commercial, and fleet vehicle classifications.

Presented in Table 7 are the outputs from the MABM for fleet size and total VKT, with the resulting average VKT per vehicle shown.

Table 7 – ZEV fleet size and VKT outputs from MABM

	Private CDVs	Private AVs	Shared vehicles	Total ZEVs	Total VKT	Avg VKT / vehicle
Electric Avenue	3,910,885	-	-	3,910,885	168,810,742	43.16
Private Drive, Empty Running	-	4,137,808	-	4,137,808	197,558,007	47.74
Fleet Street	-	-	638,622	638,622	167,627,616	262.48
Hydrogen Highway	-	4,131,391	-	4,131,391	184,405,555	44.64
Slow Lane*	192,291	-	122,741	315,032	73,084,274	231.99
High Speed	-	-	415,674	415,674	146,848,688	353.28
Dead End	3,888,201	-	-	3,888,201	166,948,417	42.94

Apportionment for Slow Lane scenario

Unlike the other scenarios considered, the Slow Lane scenario is unique in that it considers a future where ICE and ZEV vehicles coexist on the road network. As our modelling is concerned with the energy impacts from the introduction of ZEVs (and that our Dead End scenario



considers an energy network base case), we have only taken the relevant data of ZEVs under the Slow Lane scenario.

Table 8 below sets out our approach for apportioning the various vehicle types under the Slow Lane scenario.

Table 8 – Fleet apportionment for Slow Lane scenario

	Number of vehicles	VKT
Cars		
Private ICE	1,868,412	86,683,154
Shared BEV	122,741	62,103,057
Freight		
ICE	192,291	10,981,217
BEV	192,291	10,981,217
<i>ICE total</i>	<i>2,060,703</i>	<i>97,664,371</i>
<i>BEV total</i>	<i>315,032</i>	<i>73,084,274</i>
Grand total	2,375,735	170,748,645

Classification of vehicles

An important consideration within our modelling of the electricity market are the load profiles selected to reflect driver behaviour and charging times. As these load profiles dictate when vehicles are charged, they will directly influence the contribution to peak demand.

In selecting these load profiles, KPMG has aligned these profiles to expected driver and vehicle behaviours (i.e. families would return home from work at night to charge their vehicle, depot-based vehicles would see more charging during the working day). A detailed discussion of load profiles is contained in Section 3.3.

Based on the dashboard outputs of MABM, there are issues identified that need to be addressed:

- While the dashboard separates passenger vehicle VKT from freight VKT, it does not provide a split between passenger vehicle VKT for residential purposes and commercial purposes.
- The energy consumption of a passenger vehicle used for commercial trips will differ greatly from freight vehicles as the definition of freight vehicles in MABM consists of rigid and articulated trucks.
- The load profiles used in KPMG’s modelling of electricity impacts require fleet sizes classified by vehicle, which will need to be assumed as MABM only provides an aggregated passenger vehicle fleet.

Accordingly, we sought additional data from the KPMG team that developed MABM to source outputs that may assist in classifying vehicles in a manner that suited the modelling of electricity impacts.

In doing so, we have classified vehicles into the following broad categories:



- **Residential:** All passenger vehicle VKT that is not considered to be a commercial trip. Understanding that not all residential charging would be undertaken at home, a separate “out-of-home” load profile was derived to address this. A detailed discussion of load profiles used within KPMG’s modelling can be found in Section 2.3.2.
- **Commercial:** The portion of passenger vehicle VKT that is defined as a commercial trip.
- **Freight:** Following the definitions in MABM, these are rigid or articulated heavy vehicles. Due to MABM’s functionality, it does not report the size of the freight fleet thus we have determined the fleet size based on a ratio of freight VKT to the 2015 base case.

The derivation of the commercial and freight fleet figures are provided in further detail below.

Commercial

Utilising separate VKT data provided by the KPMG team that developed MABM, we have been able to split car VKT between commercial and non-commercial trips, with these ratios presented in Table 9.

Table 9 – Split of car VKT between residential and commercial

	Residential split	Commercial split
Electric Avenue	96.94%	3.06%
Private Drive, Empty Running	97.03%	2.97%
Fleet Street	96.09%	3.91%
Hydrogen Highway	96.70%	3.30%
Slow Lane	96.49%	3.51%
High Speed	97.33%	2.67%
Dead End	96.92%	3.08%

The ratios above have been applied to the passenger vehicle fleet size output from MABM to determine the number of cars that are considered to be commercial passenger vehicles.

Freight

As noted above, MABM does not output a freight fleet size for the scenarios modelled. However, MABM does provide a separate freight VKT for each scenario. Therefore, an assumption has been made in order to calculate an indicative freight fleet based upon the freight VKT travelled for each of the seven scenarios.

Infrastructure Victoria provided KPMG with a ratio calculation that utilised the 2015 base case freight fleet and the relevant VKT for the 2046 scenario being considered. These were applied to determine the freight fleet size for our modelling and is shown in Table 10 below.



Table 10 – Freight fleet size per scenario

	Freight VKT	Ratio of freight VKT to 2015 base case	Freight fleet size
Electric Avenue	22,176,627	2.86	388,333
Private Drive, Empty Running	21,980,797	2.84	384,904
Fleet Street	21,822,519	2.82	382,132
Hydrogen Highway	21,594,481	2.79	378,139
Slow Lane	21,962,434	2.83	384,582
High Speed	11,684,426	1.51	204,605
Dead End	21,952,769	2.83	384,413

Additional points to note for Table 10 are:

- The Dead End scenario has no ZEVs thus none of these vehicles will be considered in our modelling.
- The freight fleet size shown is the total freight fleet for the Slow Lane scenario. It has been assumed that 50% of the total Slow Lane freight fleet will comprise BEVs while the balance remain ICE vehicles. This is reflected in Table 11 below.

Total fleet size

On this assumption, as well as the freight VKT contained within MABM, we have used this data to provide an assumed fleet breakdown based on the total fleet size. While this is not a perfect representation, it does allow for a split of vehicles into our relevant load profiles. This data is also used separately in the Hydrogen Highway modelling; the application to this scenario is noted in Section 3.7.2 of this Report.

Table 11 provides this fleet breakdown by relevant scenario, noting that the Dead End scenario has zero ZEVs.

Table 11 – Assumed fleet breakdown of ZEVs

	Residential ZEVs	Commercial ZEVs	Freight	Total ZEVs
Electric Avenue	3,414,910	107,642	388,333	3,910,885
Private Drive, Empty Running	3,641,430	111,474	384,904	4,137,808
Fleet Street	246,462	10,028	382,132	638,622
Hydrogen Highway	3,629,516	123,736	378,139	4,131,391
Slow Lane	118,435	4,306	192,291	315,032

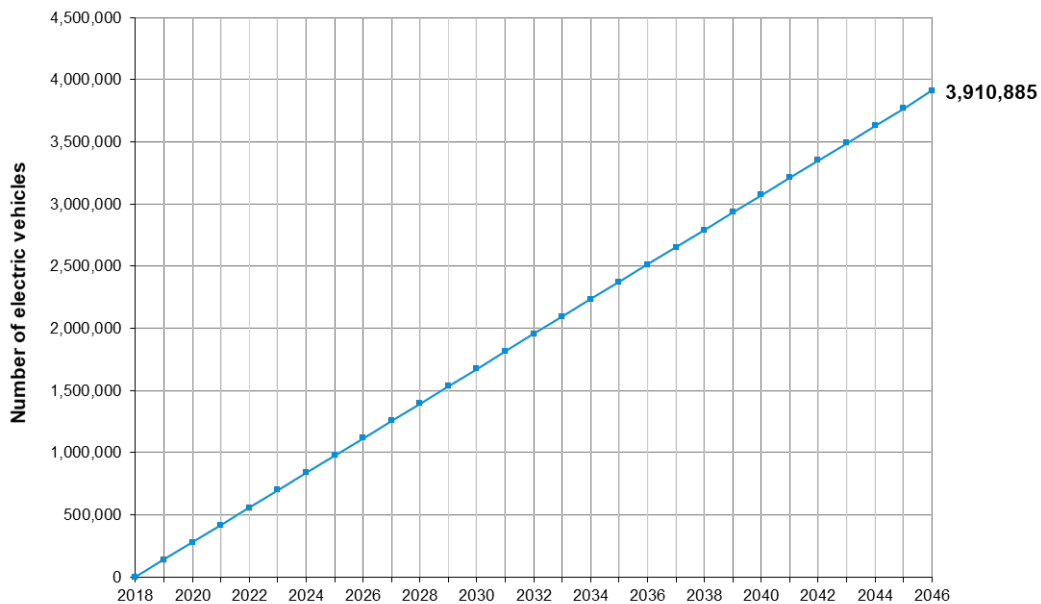


High Speed	205,435	5,634	204,605	415,674
Dead End	-	-	-	-

While MABM estimates activity for a typical day in the reference year (i.e., either 2046 or 2031), our energy market model estimates generation and network impacts on annual basis. This is because the timing of the gap between demand and existing capacity will influence the cost and type of investment responding to address that gap. This is especially the case for generation investment as the price of batteries is expected to fall substantially over the modelled period. For example, if the gap occurs before batteries are commercially competitive with other forms of generation, then the likely response will be a gas-fired plant.

To generate annual estimate of peak demand from BEVs we simply extrapolate the trend in BEV numbers over the period as shown in Figure 7 below.

Figure 7 – Annual number of vehicles for Electric Avenue Scenario



Trip matrices

Data provided from the MABM includes trip matrices for ZEVs with a range of statistics. This includes an origin point and a destination point for each trip, along with trip times and trip distances across four different time slices during a day. We note that the origin and destination points are based on SA2 regions.

As an example, this data may indicate that in a day, a ZEV undertakes the following trip:

- A vehicle commences its day in Albert Park (origin point = ‘Albert Park’ SA2 region);
- This vehicle travels to the city (destination point = ‘Melbourne’ SA2 region) during the morning peak time (time slice = AM); and
- At the conclusion of a working day (time slice = PM), the vehicle leaves the city (origin point = ‘Melbourne’ SA2 region) and returns to its original starting point at the beginning of the day (destination point = ‘Albert Park’ SA2 region).

Based on this trip data, we can assume the total number of vehicles on the road network with the notion that every ZEV will return to its origin point at the end of each day. Each such unique



value represents one ZEV. The number of total vehicles will be used within our modelling for overall network impacts. The transport model also assigns vehicles by SA2 region which we then used to inform the network spatial analysis by the zone sub-station level. This is explained further in Section 3.6.

3.2.3 Key definitions from MABM

A number of definitions have been provided in the work completed in developing MABM and framing the overall automated and zero emissions vehicle advice for Infrastructure Victoria. Therefore, to ensure consistency across the project, we are utilising a number of common, key definitions.

These are included in Table 12 below. Not all definitions have been included; those that are relevant to KPMG’s work, and are referenced in this Report, have been noted below for reference.

Table 12 – Terms derived from MABM

Term	Definition
Autonomous vehicle (AV)	Vehicles capable of self-driving that meet Level 4 or 5 automation per the Society of Automotive Engineers. Level 4 vehicles represent “high automation” which requires some human input while Level 5 vehicles represent “full automation” and can drive anywhere unassisted.
Conventionally driven vehicle (CDV)	Represents vehicles as we know them in 2018 that requires a driver to operate.
Empty running	A trip made by an AV that does not include passengers. A common example of empty running would be a privately-owned AV returning to their owner’s residence after dropping them off at a destination.
‘Robotaxi’	Through the concept of vehicles-on-demand where a consumer requests a ride at a given time to a particular destination, a robotaxi is an autonomous vehicle used for taxi and ridesharing purposes.
VKT	Vehicle kilometres travelled.
Zero emission vehicle (ZEV)	A vehicle that does not emit any tailpipe or source emissions as they are driven. For the purposes of KPMG analysis in this report, this includes both battery electric vehicles and fuel cell vehicles.

3.2.4 Key energy terms used in this report

Basic terminology

A watt is a standard unit of measurement that describes the level of energy either generated or consumed. A number of different multiples are commonly used given the large scale of energy generation or consumption. Table 13 provides a number of multiples that are used throughout our report.

Table 13 – Electricity measurements used in this report

Item	Equivalent amount
------	-------------------



1 terawatt (TW)	1,000 gigawatts (GW)
1 gigawatt (GW)	1,000 megawatts (MW)
1 megawatt (MW)	1,000 kilowatts (KW)
1 kilowatt (KW)	1,000 watts

We make numerous references between watts and watt hours (across various denominations) in our analysis. While watts is used to determine the rate of electricity consumption, watt hours are used to determine the level of power generation or consumption over an hour.

Total consumption and maximum demand

Our modelling considers consumption and demand throughout. From an energy perspective, these two terms, despite sounding quite similar, refer to different concepts. These are linked to the prior discussion on watts and watt hours.

- **Demand** – when referring to electrical demand, this represents the rate at which electricity is consumed. Reference to electricity demand will be measured in watts or another denomination (such as MW or TW).
- **Consumption** – consumption is linked to demand but represents a slightly different concept. Consumption refers to the amount of electricity that is consumed over a given time period. This is measured in watt hours or a denomination thereof (such as MWh or TWh).

A consideration of the above in the context of our modelling results is discussed in Section 0, prior to the presentation of these results. This will discuss how the concepts of consumption and demand are applied within our modelling, particularly between dispatchable and non-dispatchable generation.

3.2.5 Conversion of distance to electricity demand

Overview

Key outputs taken from MABM include the total VKT for all vehicles on the road as well as the overall fleet size. This allows us to determine an average mileage per vehicle which will inform energy consumption of these vehicles.

The KPMG Energy Market Model will convert total daily kilometres into:

- total daily electricity consumption.
- estimated annual electricity consumption.
- peak demand under a range of different situations and charging preferences

These measures will be used to analyse the impacts on the Victorian electricity sector under the range of scenarios.

Energy consumption conversion

In order to undertake this conversion, the following two assumptions are required:

- Conversion of distance to energy consumption; and
- Energy loss factor.

The following will explain our approaches in developing these assumptions.



Conversion of distance to energy consumption

The electricity consumption of vehicles is a critical component of KPMG's modelling. By using distances travelled and an average efficiency of vehicles, we have been able to determine the amount of electricity consumed by a vehicle.

For these calculations, we have had to make assumptions regarding vehicle efficiency. For conversion of kilometres to kilowatt hours, KPMG have proposed to use differing efficiency figures for passenger vehicles and freight vehicles. To align with MABM, our passenger vehicle consumption figure will be identical to MABM. As we understand that MABM doesn't consider vehicle efficiency for freight, KPMG undertook a literature review to arrive at an assumed efficiency figure.

We have also made the assumption that the electrical energy requirements of BEVs remain constant over the period to 2046. This factor will be sensitive to the nature, design and weight of any BEV manufactured in the future.

Residential

Pursuant to the discussion on vehicle classification in Section 3.2.2, residential vehicles were determined based on the split of passenger vehicle VKT between commercial and non-commercial activities. As was noted in Table 9, the vast majority of VKT constituted non-commercial travel and thus residential passenger vehicles represent a sizable portion of Victoria's vehicle fleet.

For residential vehicles, our assumption for electricity consumption while driving is based on the same assumption built into the MABM for BEVs and uses the Tesla Model S consumption as a proxy figure, which equates to 20 kWh per 100km.

The KPMG Energy Market Model assumes that all ZEVs are battery electric vehicles in 2031 and 2046 (for all scenarios except Hydrogen Highway), and that there are no plug-in hybrid electric vehicles. We have made this assumption in line with a zero emissions future as plug-in hybrid electric vehicles rely on ICE and produce tailpipe emissions, which does not fit the definition of a ZEV.

Commercial

As was detailed earlier in Section 3.2.2, for the purposes of KPMG's modelling, a commercial vehicle consists of passenger vehicles used for commercial trips.

For cars undertaking commercial trips, we understand that MABM considers these to be a standard car (i.e. it does not consider vans or light commercial vehicles). Therefore, for consistency with MABM, we have used the same energy consumption figure (20 kWh per 100km) for commercial passenger vehicles.

Freight

We understand that MABM does not consider the electricity consumption of a freight vehicle separately. Our discussions with the KPMG team that developed MABM indicated that "freight" is defined as articulated or rigid trucks pursuant to the National Heavy Vehicle Regulator in Australia. Based on ICE consumption, these vehicles consume significantly more fuel than a passenger vehicle. Accordingly, we have sought to derive a proxy efficiency figure for freight to avoid understating energy requirements.

The difficulty is that there are no articulated or rigid BEVs currently in mass production. Accordingly, we undertook a literature review to develop an average efficiency figure based on a number of trials or prototypes, which is demonstrated in Table 14.

In being consistent with the definition of "freight" in MABM, we have not sought to include light or medium-duty trucks within our chosen figures, instead focusing on vehicles of at least 15 tonne.



Table 14 – Derivation of average freight efficiency

Vehicle	Indicative kWh / 100km
Theoretical optimal case for a 36 tonne truck ⁴⁵	117.38
Port of Los Angeles – 27 tonne demonstration ⁴⁶	124.27
UC Riverside Class 8 truck (>15 tonne) – cruise speed simulation ⁴⁷	124.27
UC Riverside Class 8 truck (>15 tonne) – city simulation ⁴⁷	130.49
UC Riverside Class 8 truck (>15 tonne) – regional simulation ⁴⁷	149.13
Average vehicle efficiency	129.11

Given that we have based this figure on trials or prototypes, the actual efficiency of such vehicles in 2046 may differ. However, based on the information selected, this will allow us to present an idea of how freight consumption from BEVs may impact the electricity network.

Energy loss factor

For the model, the level of electricity required for charging BEVs needs to be uplifted to account for energy losses. Such losses will occur both during the flow of electricity through the transmission and distribution networks and at the charging infrastructure due to the inability to achieve full efficiency when charging the battery. Currently the network losses are equivalent to approximately 10% of the total electricity transported between power stations and market customers. The energy loss incurred for charging batteries will depend on the technology and the technical design of the charger. Accordingly, the extent of the loss factor will depend on the make and model of a given vehicle.

For the model we have assumed a combined 10% loss factor for both these impacts. While our initial research points to a wide range between of estimate losses at charging infrastructure site of between 15% to 35% it is expected that the technology would have improved by 2046. Further it is hard to estimate the extent the network losses which are due to electrical resistance and the heating of conductors. Network losses are also location specific and will vary annually based on flows across the network and could be less if the source of generation is closer to the BEV charging points. A 10% combined energy loss factor is considered reasonable given the extent of uncertainty about future technology developments.

⁴⁵ Sripad, S & Venkatasubramanian, V 2017, Performance Metrics Required of Next-Generation Batteries to Make a Practical Electric Semi Truck, ACS Energy Letters.

⁴⁶ Electric Truck Demonstration Project Fact Sheet, The Port of Los Angeles.

⁴⁷ California Air Resources Board 2018, Battery Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicles, pp. 18.



Estimated annual consumption

Estimated annual electricity consumption from ZEV charging will be used to estimate the emissions generated from the ZEV under the range of scenarios. It will also inform the improved load factor benefit for the market.

Within the Model, KPMG have considered a conversion of the total typical daily energy consumption to an annual consumption amount. We have used an annualisation factor of 341.6 based on VicRoads traffic data, as discussed earlier.

Daily travel distance

The derivation of average VKT has been based on outputs from MABM, as discussed in prior sections. These are based upon VKT and fleet size data to provide the average VKT of all vehicles. Table 15 summarises the core vehicle data that is being used within KPMG's modelling of the seven scenarios.

Table 15 – Summary of vehicle data used in modelling

	Freight fleet	Freight VKT	Avg VKT / fleet vehicle	Passenger vehicle fleet	Passenger vehicle VKT	Avg VKT / passenger vehicle
Electric Avenue	388,333	22,176,627	57.11	3,522,552	146,634,116	41.63
Private Drive, Empty Running	384,904	21,980,797	57.11	3,752,904	175,577,210	46.78
Fleet Street	382,132	21,822,519	57.11	256,490	145,805,098	568.46
Hydrogen Highway	378,139	21,594,481	57.11	3,753,252	162,811,074	43.38
Slow Lane	192,291	10,981,217	57.11	122,741	62,103,057	505.97
High Speed	204,605	11,684,426	57.11	211,069	135,164,262	640.38
Dead End	-	-	-	-	-	-



3.3 Contribution to peak demand profiles

3.3.1 Introduction

An important aspect of KPMG's Electricity Market Model is the development of the typical contribution to peak demand profile over a 24 hour period. Load profiles allow for modelling of the impacts of ZEVs on the broader energy market, including analysis of the potential impact of demand from ZEVs on other energy users.

Load profiles will also allow for the identification of potential infrastructure needs in the future as the market responds to the ongoing penetration of ZEVs in the conventional vehicle market.

Based on the factors discussed above, the model generates a daily demand profile for a range of situations and assumptions about charging infrastructure and preferences.

This daily demand profile will then be mapped to current Victorian daily operational demand profile to identify the coincident contribution to the system peak generated by ZEV charging. The impact on system peak will not be the maximum demand generated by ZEV over the course of the day but the demand from the EV charging at the time of day when the system demand is highest.

We also assume that the typical day modelled by MABM will be typical of the system peak demand on the Victorian market.

The shape of the charging profile will determine the degree which ZEV charging coincides with system peak demand.

3.3.2 Potential Charging Profiles

The contribution to peak demand across the day from BEV will effectively be equal to the total number of BEVs charging in the hour multiplied by the charging rate for each vehicle. The charging rate will differ by the type of customer and the customer preference for charging (i.e., whether it is out of home or at home).

In estimating the impact of BEV model, the model distinguishes between four factors:

- 1 Type of vehicle use – residential, commercial or freight, and the efficiency of different vehicles.
- 2 Node of vehicle charging – residential, out of home residential, commercial and shared.
- 3 Charging rate – Type 1 (3 kV), Type 2 (9.5 kV) and Type 3 fast (240 kV).
- 4 Charging profile – incentivised or non-incentivised. This choice is only applied to either residential or commercial vehicle charging.

3.3.3 Calculation of contribution to peak demand profile

In summary, the model calculates a contribution to peak demand for each of the nine patterns (see table 17) through the following steps:

1. Calculate average kWh consumption per vehicle over a 24 hour period.
2. Based on results in step 1, calculate the average time to recharge the BEV battery. This is done per vehicle type per charging rate.
3. Use the assumed load profile to generate number of vehicles by hour. These load profiles are used to indicate the time when the vehicle starts to charge. This is slightly different from charging profiles which show the volume of demand by hour and we have adapted



our profiles accordingly. Where possible, we have used data from MABM (and associated outputs) for considering time to initiate charging

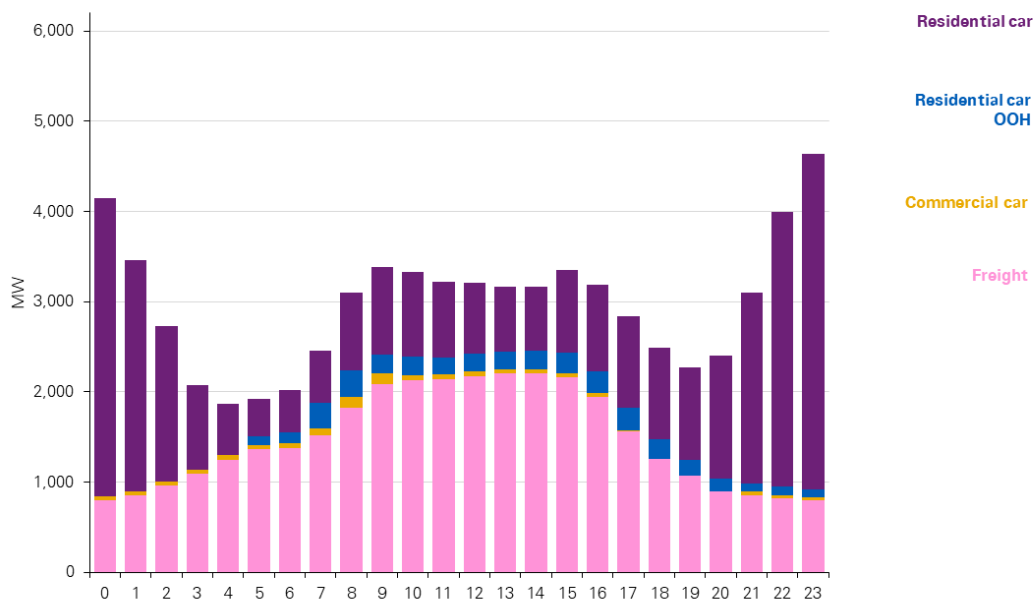
4. For each hour of the day, calculate hourly kW by charging time and by average time to charge. Our assumption is that there is equal distribution of the vehicles charging over the hour. Hence if the average charge time is 3.5 hours – half the scenario vehicle numbers will be charging at the deemed charging rate in the fourth hour.
5. Sum hourly kW demand in each hour to calculate aggregated kW demand in each hour.
6. Uplift for network and charging loss factor to calculate for kW profile over the 24 hours.

For each scenario, we sum the relevant charging patterns (out of the nine possible patterns). For example, the results for the incentivised permutation of the Electric Avenue scenario will be the sum of the following three patterns:

- a) Residential (incentivised).
- b) Commercial (incentivised).
- c) Out of home charging.

This is shown in Figure 8 below.

Figure 8 – Aggregated Contribution to the MW demand profile for Electric Avenue scenario and incentivised charging.



3.3.4 Input assumptions and approach

Ownership of BEV

The ownership nature of a ZEV fleet will impact on demand loading. There are three different ownership models to consider:

- Private fleet ownership – residential use;



- Private fleet ownership – commercial use (and assumed to be charged at their respectively depots/offices); and
- Shared fleet ownership.

Charging infrastructure

The type of charging infrastructure used to charge a BEV will be a key consideration in the peak demand given the differing levels of load drawn by respective technologies. KPMG have identified the following types of charging infrastructure to consider within the Electricity Market Model:

- **Type 1** - Charging at home or work is possible via a standard electrical power point (240 volt AC / 15 amp electricity supply). The rate of charge will depend on the EV’s on-board charger and 3 – 4 KW is commonly assumed.
- **Type 2** - The vehicle is connected directly to the electrical network via specific socket and plug and a dedicated circuit. This may become the most common home and public charging level. Level 2 allows for a wide range of charging speeds, all the way up to 19.2 kilowatts (KM), or about 85 km of range per hour of charging. Level 2 charging is much quicker because it is done at higher voltage and at higher amperage. However, it requires more robust, three-phase wiring to handle the extra electrons and the heat they generate.⁴⁸
- **Type 3 - DC Fast Charging (DCFC)** - this is a dedicated infrastructure to provide rapid charging. DC Level 3 for residential requires significant panel and service upgrades and consequently is the most expensive to deploy. These are likely to be publicly accessible ‘fast charger’ or ‘super charger’ outlets to provide power to the battery at a faster rate. The rate of charge can vary, with potential for charging up to or in excess of 1 megawatt being plausible in the future.

There is also the possibility of super-fast chargers whereby charging commences immediately on arrival at a charging facility and is completed within 5 minutes. It is still unclear how home-based charging will evolve. Type 2 charging may require strengthening of the household connection and possibly the distribution network in the street and as such is likely to be limited especially in the short-term, but could become the dominant technology over the modelling period.

To keep the model simple and practical, we made the following assumptions about the proportion of node of vehicle charging by the type of charging infrastructure. In reality, the charging of BEV may be quite different.

Table 16 – Charging levels per vehicle classification

Charging level	Charging rate	Residential	OOH	Commercial car and freight	Shared
Type 1	3 kW	50%	-	-	-
Type 2	9.5 kW	50%	-	100%	cars
Type 3	240 kW	-	100%	-	freight

⁴⁸ We understand that very few households have three phase supply, which is generally required to provide Level 2 charging.



We note for the purposes of our modelling that we have selected a 240 kV charging rate for Type 3 DC Fast Charging. As will be discussed in Section 5.5, developments in charging infrastructure may see a higher rate of charging in the future, particularly to support heavy vehicles.

Node of vehicle charging

We expect that there will be a wide range of charging options available to BEV owners both in private areas and also public stations. For the model, the node charging will be based on the ownership of the BEVs. We have also made a number of simplifying assumptions in order to keep the number of permutations from the model manageable.

For example, we have assumed that only residential vehicles will exercise the choice to charge either at home or out of home. Further we have assumed that all commercial vehicles will be charged in level 2 charging rates.

Charging scenarios

The Model sets out the following two charge management scenarios which are used in the analysis:

1. **Non-incentivised charging:** charging occurs as soon as a BEV is plugged in and hence may coincide with the pre-existing peak demand period; and
2. **Incentivised charging:** an incentive (such as a time-based tariff) is applied to encourage drivers to alter their behaviour and charge during off-peak periods, such as late in the evening.

In order to understand the potential range of impact of BEVs on an energy system we have considered the use of incentivised load profiles to shift demand out of undesirable peak times.

The design of an incentive will influence the likelihood of adoption. An aggressive incentive, such as significant rate decreases, will act as a stronger signal for more actors to consider changing their behaviour. Conversely, a conservative reduction will provide less incentive to alter behaviours. The design of an appropriate tariff is complex and requires trade-offs when considering its calculation.

Therefore the charge management scenarios represent a spectrum of possible situations from non-incentivised charging, to incentives designed to encourage off-peak charging, to mandating that charging occurs in off-peak periods. The disadvantage of shifting charging to the off-peak period is that users forgo the option of having a fully charged vehicle later in the evening. Even if users do not plan on using their vehicles, they are likely to value having a fully charged car and worry about the possibility of running out of charge (range anxiety).

In addition, there could be options where there is greater controlled charging or super smart charging where the responsibility for charging is assigned to a third party. Under these solutions, vehicles have smart chargers implemented that allow drivers to respond to signals such as real-time pricing which provides better incentives than time-of-use pricing for off-peak charging. The technology will determine the optimal time to charge to minimise system costs and therefore charging profile could differ day-by-day.

Under a controlled charging approach users would be required to install a switch that allows their EV charging to be turned off during periods when the network is experiencing high demand. This could be controlled by a distribution company, a retailer or an aggregator. Consequently, all charging under this scenario will occur during off-peak periods.

The impacts of controlled charging solutions are explored further as an infrastructure response in Section 5.2. It is likely to be more effective to minimise the system impacts of BEVs compared to pricing incentives because the market has total control over when BEVs are



charged. Whilst controlled charging ensures off-peak charging of BEVs, it may impact on driver range anxiety and deter people from purchasing BEVs.

3.3.5 Load charging profiles

In our model, load profiles are used to determine the distribution of number of vehicles charging over the 24 hour period. They map the percent of the total daily charging occurring in each hour period.

Based on the assumptions discussed in the sections above, there will be the following nine separate charging patterns considered within KPMG modelling:

Table 17 – Charging patterns used within KPMG modelling

Charging patterns	Type of vehicle use	Type of charging rate	Charging profile
1	Residential	Type 1	Incentivised
2	Residential	Type 2	Non-incentivised
3	Residential	Type 1	Non-incentivised
4	Residential	Type 2	Incentivised
5	Out of home	Type 3	Out of home profile
6	Commercial	Type 2	Incentivised
7	Commercial	Type 2	Non-incentivised
8	Shared	Type 2	Shared profile
9	Shared	Type 3	Commercial incentivised

The shape and function of these load profiles will be discussed in detail below.

Data sources

In order to identify appropriate load profiles KPMG undertook a literature review of relevant research and studies into electric vehicles.

The primary sources of data considered were:

- Previous Australian pilot studies including:
 - Smart Grids Smart City study.
 - Victorian Electric Vehicle Trial.
 - Western Australian Electric Vehicle and Charging Station Trials.
- US Plug-in Electric Vehicle and Infrastructure Analysis (Idaho National Laboratory, US Department of Energy).
- Joint IOU Electric Vehicle Load Research Reports (Public Utilities Commission of the State of California).

Selection criteria of load profiles

The criteria adopted in reviewing the data were threefold:



- **Robust data.** Given the dynamic nature of the associated technology and the speed of its development, KPMG sought to develop load profiles based on the most current data available.
- **Applicability.** KPMG sought to identify data that was applicable to the Australian context. That is, data was sourced from countries with broadly similar patterns of urban development and were therefore likely to experience similar patterns of ZEV use. In this case it meant we gave preference to jurisdictions such as California that had similarly dispersed urban profiles as opposed to some European or Asian countries that experience higher levels of population density in their urban areas.
- **Reliability.** Ideally the data is sourced from a reputable body and is subject to a rigorous peer review process. Ideally the data should also be sourced from a relatively large sample as they are more likely to provide for robust statistical outcomes.

Each of the load profiles used within our modelling will be discussed in turn below.

Commercial charging

Non-incentivised

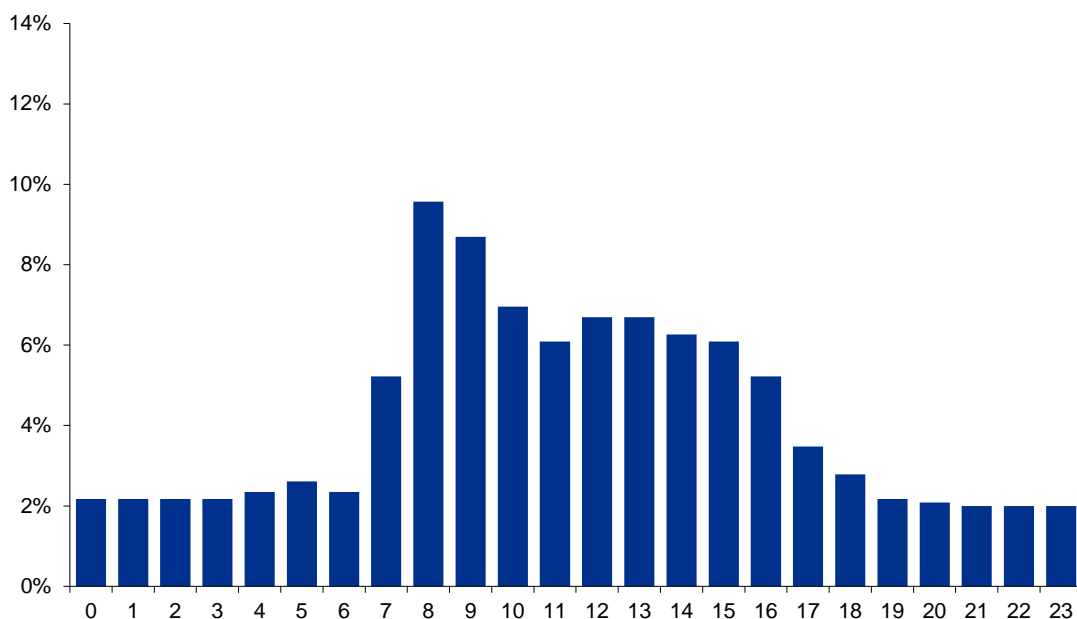
A non-incentivised commercial profile has been designed on the basis that commercial passenger vehicles and freight vehicles are more likely to be charged during the day in the absence of price incentives. While a residential driver would be expected to plug-in an EV when they return home, fleet vehicles are stored at depots or dedicated on site charging stations when not in use, leading to their day-time charging pattern.

Figure 9 below demonstrates the commercial load profile used for the model. This reflects a diversified electrical load profile for charging of fleet vehicles on an average weekday. We have developed a non-incentivised load profile based on the results of two Australian trials - Smart Grid Smart City study and WA Electric Vehicle and Charging Station Trials – for the situation where a commercial organisation provides a range of BEVs to a selection of its work-force. These trials demonstrated that charging is likely to occur early in the morning when the fleet arrives for work and then constantly over the day as vehicle travel to and from the depot. We have also sense-checked this profile with the results from the MABM model which found that that a large proportion of commercial trips will occur early in the morning.

As with all the load profiles used in the modelling, they are an attempt to provide a reasonably approximation of the charging behaviour for that scenario based on available evidence. The actual behaviour of the fleet could substantially differ in the 2046.



Figure 9 - Load profile (% per hour) for non-incentivised commercial charging over a typical day



(0 = 0.00am and 23 = 11pm)

This load profile indicates that vehicles are likely to be charged between 8:00AM and 10:00AM upon returning from early morning trips in preparation for the bulk of trips between midday and the afternoon.

Note that the behaviour of fleet managed vehicles charging may differ from that of privately owned vehicles that are charged at work, as such vehicles would not be expected to undertake trips during the course of the day but would be primarily garaged from arrival at work until the afternoon commute.

Incentivised

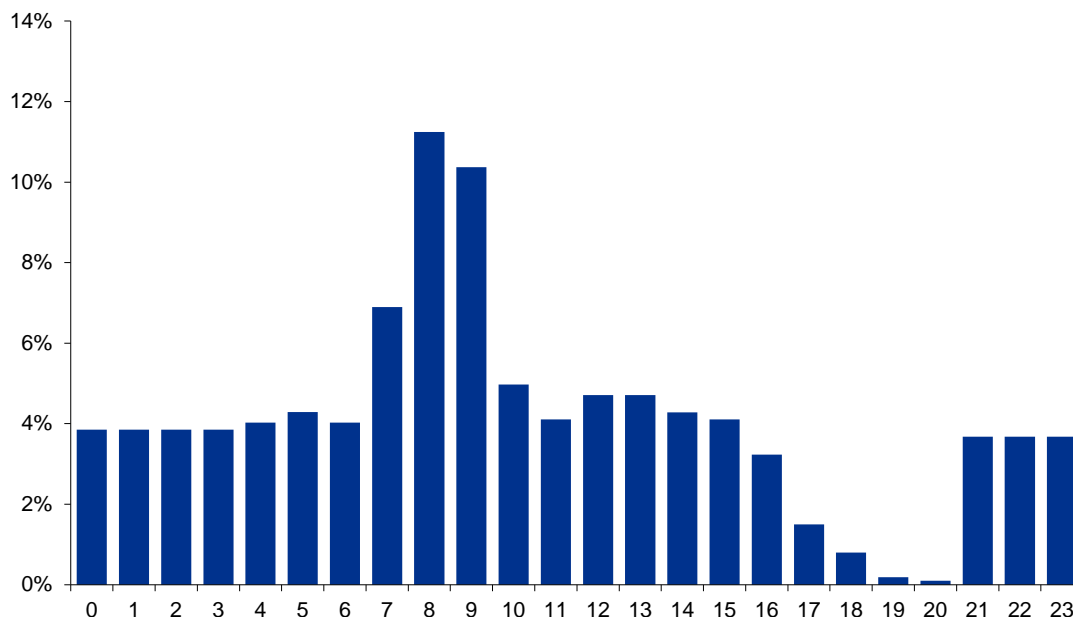
As was noted for the non-incentivised profile, commercial vehicles are more likely to charge during the day given the depot-based nature of commercial vehicles. This therefore means that the loads from commercial ZEV charging for our selected non-incentivised load profile peaked at 9:00AM, remain relatively high through to 5:00PM and then fell after this time.

Therefore, a price based incentive for a commercial vehicle would aim to shift peak loading away from the middle of the day to lessen the impact of commercial charging. For the purposes of our modelling, we have shifted 40% of the demand between 10:00AM and 9:00PM into other hours of the day, which smooths the demand. This is based on a conservative estimate of the potential load which the operators has flexibility to charge at off-peak times.

Figure 10 presents the 24 hour load profile under the incentivised commercial charging situation. A by-product of this shift is that loads at typical peak times (between 6:00PM and 9:00PM) have been reduced to avoid commercial charging being shifted into the typical peak demand period for the rest of the electricity network.



Figure 10 - Load profile for incentivised commercial charging over a typical day



(0 = 0.00am and 23 = 11pm)

Residential charging

Non-incentivised

A non-incentivised residential load profile essentially reflect that there are no factors applied to incentivise or otherwise change an EV owner choices.

In formulating a non-incentivised residential load profile, it broadly follows the typical working pattern of an adult. That is, loads are initially higher at the commencement of a day due to overnight charging, and gradually falls as load reaches its minimum at approximately 5:00AM. Throughout the commuting pattern of a standard working day (6:00AM through 4:00PM), loads are relatively stable as a majority of commuters are at work and thus BEVs are not being charged at a household.

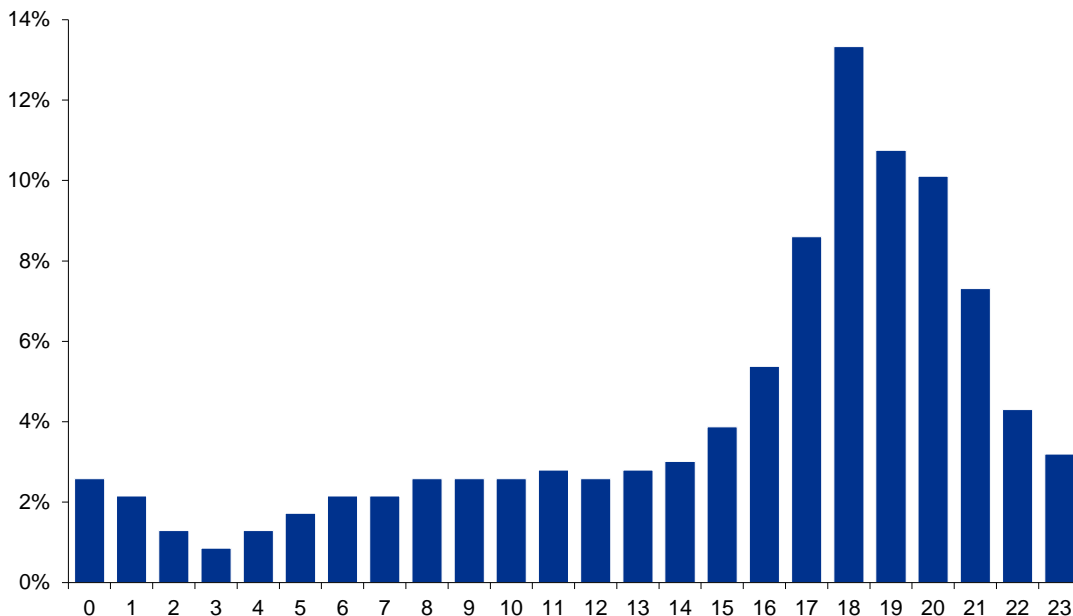
As workers begin their commute home, the draw on the electricity network begins to rise from 5:00PM, peaking at 8:00PM. This reflects two factors. Firstly, an increasing amount of people are commuting home, which eventually reaches a peak point that then tapers. Secondly, there is a lag factor at play. As ZEVs, particularly those being charged through slower charging points, take many hours to reach a full charge, drivers that arrive home earlier will still have their vehicles connected to a charger when those arriving home later place theirs on to charge.

Accordingly, for a 'dumb' profile, the load profile will follow the commuting pattern of the majority as there are no incentives to charge a vehicle to a different pattern. Without any incentives, a driver will simply plug in their ZEV to charge as soon as they arrive home.

Shown at Figure 11 below is KPMG's selected load profile for non-incentivised residential charging over a typical day which reflects the relationships discussed above.



Figure 11 - Load profile for non-incentivised residential charging



(0 = 0.00am and 23 = 11pm)

Incentivised

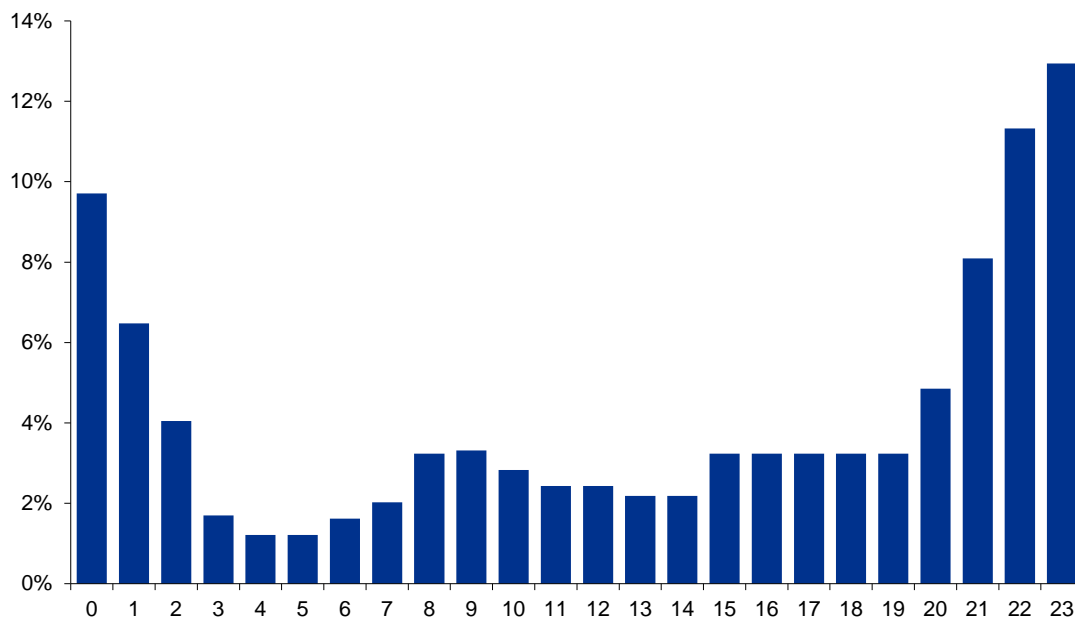
For an incentivised residential charging profile, we have based the profile of studies and trials where EV owners are exposed to a tariff which varies by time of day and had a material ratio between peak prices to off-peak prices.

Under such a profile, it would be expected that vehicles are more likely to be charged late at night or early in the morning when the effect of a price tariff would decrease the cost of charging at this time. Further, the use of a shoulder and off-peak rate will assist in smoothing demand. There is a risk with a single price tariff (particularly a very attractive rate) that peak demand will be shifted by residents commencing charging once the rate drops without also being smoothed.

Figure 12 demonstrates the pattern of the incentivised residential load profile, which aims to smooth the peak load somewhat and the majority of charging moves towards late night periods when overall network demand tends to be lower. This can be contrasted against Figure 11 above to show the difference in peak load.



Figure 12 - Load profile for incentivised residential charging



(0 = 0.00am and 23 = 11pm)

The effect of the price incentive is evident with increased charging commencing from 8:00PM as the shoulder rate commenced and then at a higher rate from 10:00PM when the off-peak period commenced.

Out-of-home (OOH) charging

While the residential profiles above consider the load profile of agents that primarily charge their vehicles upon returning home, consideration also has to be given to the possibility that drivers may also charge at fast charging stations akin to petrol stations where charging only takes up to 20-30 minutes.

We reference this profile as out of home (OOH) as limited this choice to residential vehicles.

Our methodology to calculate the residential OOH profile is based upon outputs of the MABM for privately-owned vehicles. The VKT for the various times of the day, is used to determine the likely load profile for each hour of the day. With these percentages, a 24 hour load profile can be constructed, on the assumption that OOH charging patterns follow VKT ratios. Table 18 demonstrates the calculation of this load profile.

Table 18 – Calculation of residential OOH load profile

MABM Timeslice	Number of hours	Proportion of daily VKT in timeslice	Hourly proportion of daily VKT
AM Period (7AM – 9AM)	2	14.7%	7.3%
IP Period (9AM – 3PM)	6	29.4%	4.9%
PM Period (3PM – 6PM)	3	22.5%	7.5%

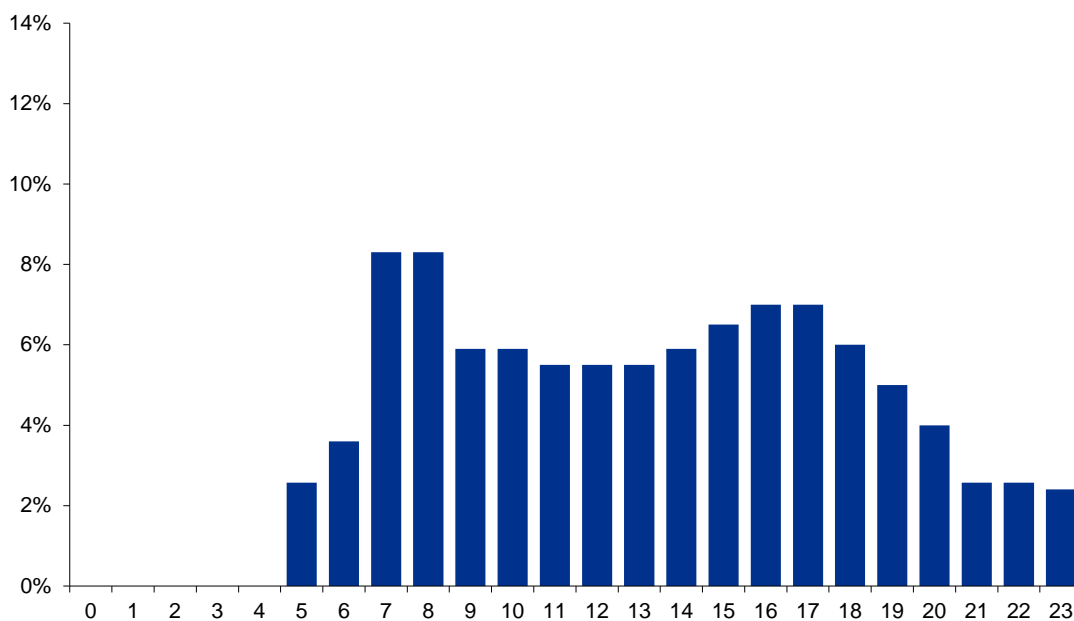


OP Period (6PM – 7AM)	13	33.4%	2.6%
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As we expect most trips to be relatively short in nature, high volumes of hourly VKT would therefore correlate to increases in load with vehicles being connected to a charger at the conclusion of their trip.

Figure 13 plots our selected load profile for OOH charging based on the calculation shown above. As is expected, the majority of the demand occurs during the day with residential vehicles being charged at a workplace or similar location, away from the home.

Figure 13 – Residential OOH load profile



(0 = 0.00am and 23 = 11pm)

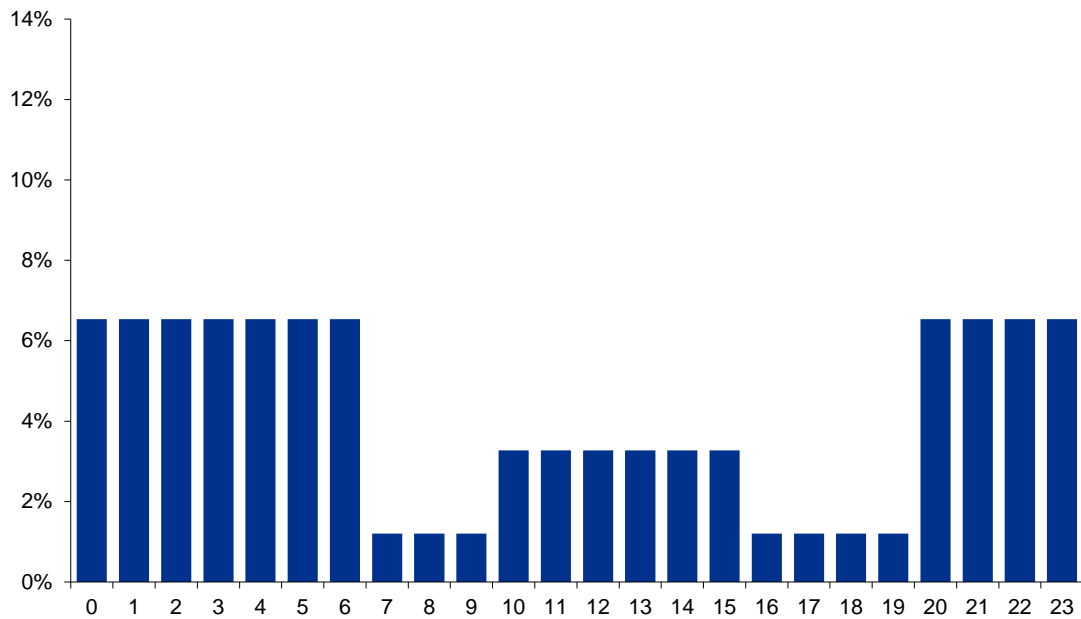
Shared fleet charging

For the shared fleet scenarios we apply two profiles:

- For shared cars (i.e. robotaxis) we have generated a shared profile which reflects the timing of trips from the transport model balanced with the assumption that shared cars will be charged with a level 2 charging. Hence we have adapted the profile to enable sufficient charging to occur over the day in order meet km demand
- For freight vehicles, it would not be possible for these to be charged using Type 2 charging given the higher energy consumption of such vehicles. Therefore these vehicles must use the level 3 fast charging option. Hence their option will be different from the shared car profile. For simplicity, we have assumed that shared freight are charged with the commercial incentivised profile.



Figure 14 - Shared fleet load profile



(0 = 0.00am and 23 = 11pm)

This profile recognises that given the charging times under type 2 some of the vehicles will still have to be charged at peak times, although a very low proportion. In practice, the shared fleet operator will have to balance a number of factors, including fleet size, batteries and electricity charging costs.



3.4 Generation model

3.4.1 Overview

The purpose of this report is to unpack the impact of different ZEV uptake scenarios on the Victorian electricity market in 2046, including the impact on generation. Of course, the state of play of the electricity markets, in particular with regards to policy and technology, is highly uncertain almost 30 years into the future (and indeed in the much shorter term as well).

Further, the NEM is a highly complex market system with generators bidding into the market on a five minute basis. A complete simulation of the operation of the NEM involves predicting economically driven new entry and retirements of generation capacity on a half hour basis, reflecting for example forecast demand, solar PV uptake, government policy (e.g. carbon pricing, renewable energy targets), generator fuel prices, operational and technical performance of individual power stations, generator bidding strategies, the way electricity flows through the grid and of course economic inputs such as capital costs and capacity factors of new builds and interest rates. This type of detailed market simulation is outside the scope of this report.

KPMG's generation model methodology assesses the extent to which BEVs add to maximum demand for, and total consumption of, electricity in each year until 2046 (2031 in the High Speed scenario). In the context of our modelling, the following key terms are used:

- Demand describes the electricity used at a particular time (MW). Maximum or peak demand refers to the highest amount of demand for electricity over a defined period of time.
- Capacity refers to an amount of continuous output (MW).
- Total consumption refers to the electricity used over a period of time (MWh). Total generation refers to the electricity generated over a period of time (MWh).
- "Dispatchable" refers to the ability of a generation plant to be dispatched when it is required (also called scheduled generation). "Non-dispatchable" refers to generation plant which cannot be relied upon to be available when required (e.g. wind and solar PV generation) (also called semi-scheduled generation).

Our generation modelling estimates, in a simplified way and on an annual basis, the new capacity that could be required under different EV uptake scenarios, focusing on the Victorian electricity market. Our methodology also estimates the cost of any additional capacity based on current forecasts of capacity, connection and fuel costs, as well as the resulting impact on overall and average emissions.

If there is significant demand for electricity from BEVs during peak times, this may require additional dispatchable capacity, and investments in networks. If this same level of demand occurs outside of peak hours, and especially when a surplus of renewable generation is available, new dispatchable capacity may not be required, or additional renewable generation may be sufficient.

A high level summary of KPMG's methodology for the generation component of our modelling is summarised below:

- **Step 1:** Forecast maximum demand and total consumption until 2046
- **Step 2:** Determine existing and committed capacity and generation available to meet maximum demand and total consumption
- **Step 3:** Calculate the gap between maximum demand and generation capacity available to meet that maximum demand, and between total consumption and the total generation available



- **Step 4:** Determine the likely technology of additional generation capacity
- **Step 5:** Determine the total cost of additional generation capacity
- **Step 6:** Determine the incremental emissions associated with BEVs

3.4.2 Generation model methodology

Step 1: Forecast maximum demand and total consumption until 2046

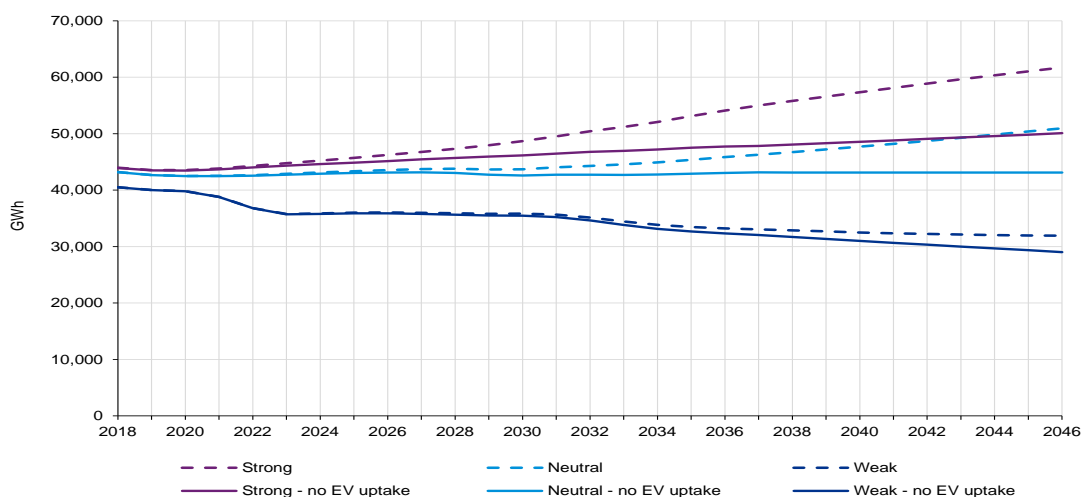
We have relied on AEMO’s 2018 Integrated Systems Plan Assumptions workbook for the forecast of annual operational⁴⁹ consumption and maximum demand in Victoria until 2046. AEMO’s makes a range of assumptions in determining its demand forecasts, and forecasts several scenarios that represent a probable range of futures for Australia. This includes a weak, neutral and strong outlook.

We have used the neutral maximum demand forecast for Victoria at a 10% probability of exceedence (POE). This is the probability, as a percentage, that the maximum demand level will be met or exceeded in a particular period of time. A 10% POE means that the forecast level will be met or exceeded on average in one year out of ten.

For the purpose of our analysis, we have made a number of adjustments to the annual operational consumption and maximum demand forecasts.

First, we have subtracted from the annual operational consumption forecast the amount attributed to electric vehicles, to derive the Dead End case which does not reflect any uptake of BEVs. As the AEMO’s BEV forecast only goes until 2037, we have extrapolated the forecast to 2046 using the implied growth rate from 2027 to 2037. Figure 15 shows the operational consumption forecast in all three of AEMO’s scenarios (weak, neutral and strong), both with and without the EV component. Our analysis relies on the neutral – no EV uptake forecast (solid light blue line), which is relatively flat from 2018 until 2046.

Figure 15 - Operational consumption forecast

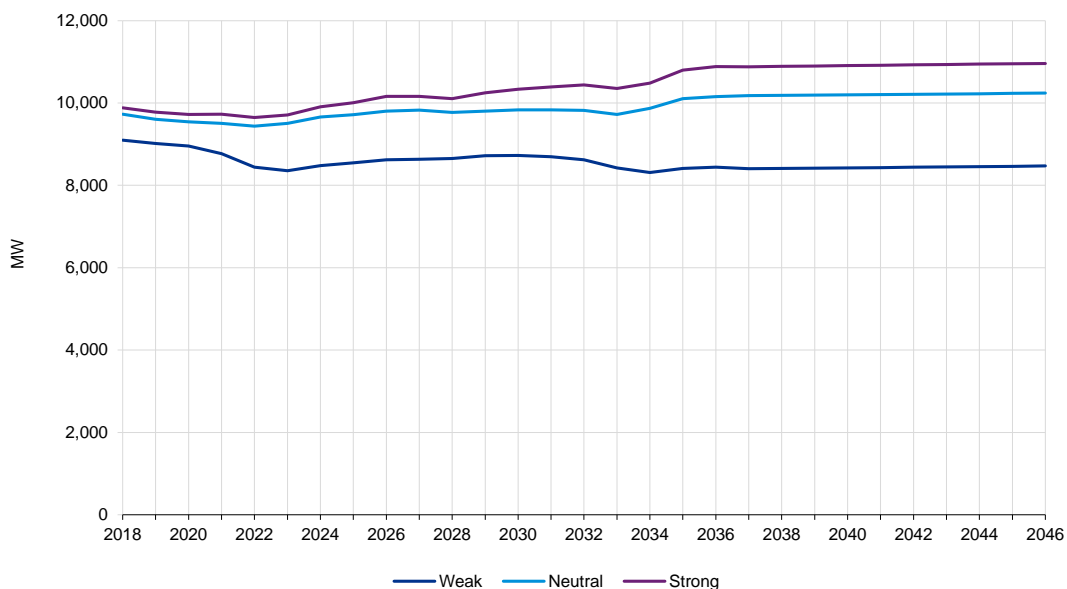


⁴⁹ AEMO uses the term operational to refer to the electricity that is used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generation units. It does not include electricity used by scheduled loads. It does include both distribution and transmission losses at regional resolution, but only distribution losses when measured at connection point resolution. It does not include demand met by rooftop solar PV (i.e. Operational consumption decreases as rooftop PV generation increases). For more please see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2018/Operational-Consumption-definition--2018-update.pdf



We have not subtracted any amount from the maximum demand forecast, as AEMO does not attribute any portion of its maximum demand forecast to BEVs. Figure 16 shows the forecast weak, neutral and strong maximum demand in Victoria until 2046. Our analysis relies on the neutral scenario (light blue line), which is increasing marginally over time.

Figure 16 - Maximum demand forecast



Second, we have added to maximum operational demand the Victorian minimum reserve level (MRL) of 498 MW from AEMO’s 2018 Integrated System Plan workbook (version 21), which notes that each region must have these firm capacity reserves in excess of maximum demand. We have assumed that this MRL remains constant throughout the forecast period.

Finally, we have subtracted from the maximum demand the demand side participation (DSP) forecast from AEMO’s 2018 Integrated System Plan workbook (version 21), which it notes will be removed from the market when modelled prices reach specified price limits. The DSP at above \$300/MWh starts at 31 MW in 2018 and increases to 187 MW in 2046. DSP activities could include for example generating electricity on-site or curtailing demand during maximum demand periods.

BEV contribution to maximum demand

All charging of BEVs will add to total consumption of electricity, but not necessarily to maximum demand.

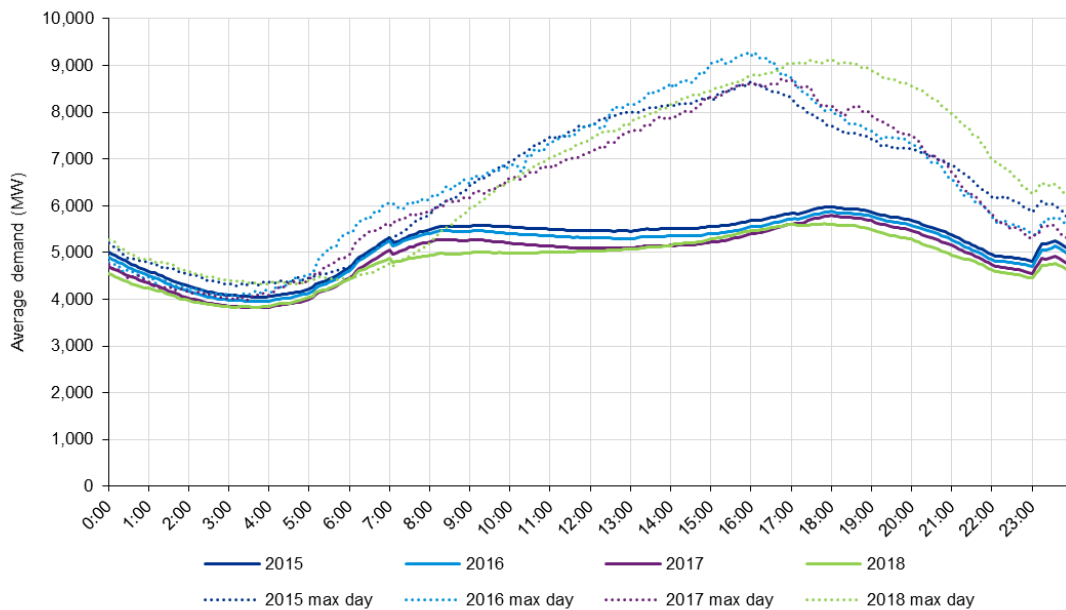
Since 2015, Victorian demand has peaked between 5 and 7 pm in the evening on average, as per Figure 17. The maximum demand days in these years have peaked at approximately 4PM in the afternoon. For 2018 to date, the maximum demand day peak has been at approximately 6 pm in the evening.

We note that an increased uptake of solar PV in the future should have the effect of pushing peak demand outside of sunlight hours as solar PV will contribute to reducing reliance on the electricity network while the sun is shining. AEMO’s forecasts incorporate a view that rooftop solar PV in Victoria will increase from 4% of total generation in 2018 to 12% by 2046.

Based on the above, we assume that charging done in the 5 pm to 7 pm time period will contribute to maximum demand.



Figure 17 – Average Victorian demand between 2015 and 2018



Step 2: Determine existing and committed capacity and generation available to meet maximum demand and total consumption

We have relied primarily on AEMO’s most recently available generation information⁵⁰ from 16 March 2018 for data relating to existing and committed generation in Victoria⁵¹. This information is prepared by AEMO for the purpose of providing information on existing, committed and proposed generation as advised by registered participants in the NEM.

AEMO distinguishes between scheduled (dispatchable) and semi-scheduled (non-dispatchable) generation. Semi-scheduled generation refers to a generating system with intermittent output, for example a wind or solar farm. AEMO can limit generation output from a semi-scheduled generating system if it exceeds network capabilities.

The installed capacity of existing (scheduled or semi-scheduled) generation in Victoria in March 2018 amounts to 10,190 MW, of which 965 MW is semi-scheduled. All of the currently installed semi-scheduled generation is wind generation.

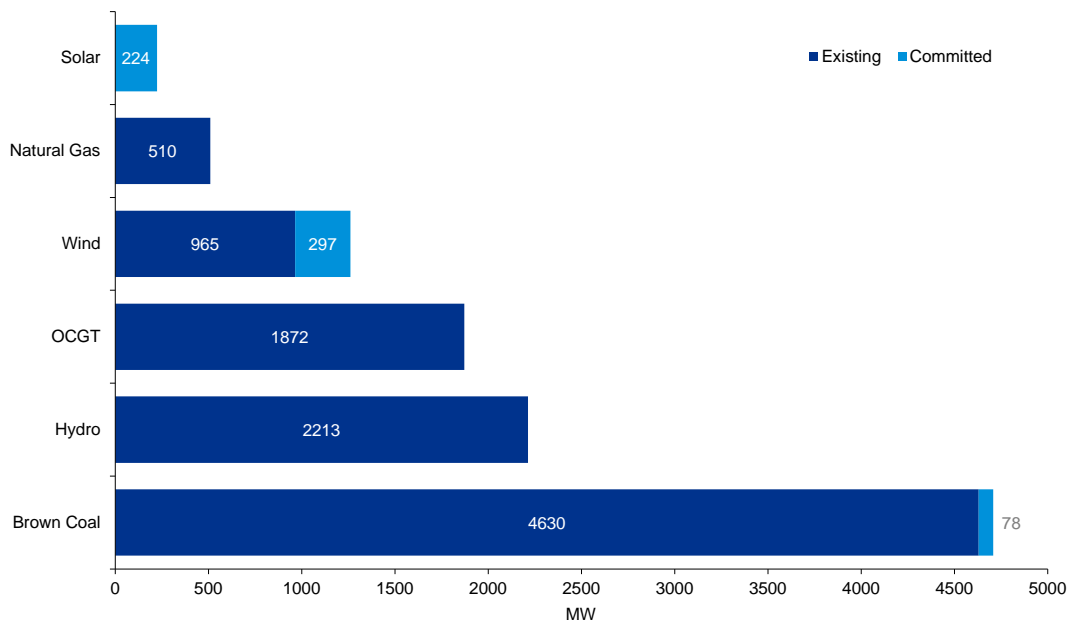
The capacity of “committed” generation (scheduled or semi-scheduled) amounts to 599 MW, out of which 521 MW is semi-scheduled. This is comprised of eight projects: Four wind farms, three solar farms and a 78 MW upgrade to Loy Yang B. AEMO categorises projects as committed if they meet all five of their commitment criteria, including site acquisition, contracts for major components, planning approval, financing and the date set for construction. Note that the Victorian Government’s Energy Storage projects have also been included, and that this is discussed later in this section. The split of existing and committed capacity by technology is illustrated in Figure 18

⁵⁰ We note that AEMO’s 2018 Integrated System Plan workbook relies on a previous version from December 2017. We have however used the wind and solar peak contribution factors from the 2018 Integrated System Plan workbook, as more detailed information is available in regards to solar contribution, which has not been specifically calculated for Victoria in the March 2018 version. The de-rating factor for wind in Victoria is 8.1% in this workbook, compared to 7.7% in the March 2018 generation information spreadsheet.

⁵¹ AEMO (2018), Generation information workbook.



Figure 18 – Existing and committed installed / nameplate capacity by technology



In relation to meeting maximum demand, we have relied on AEMO’s estimates for summer capacities for Victorian generation until 2027 (as opposed to installed capacity), as summer conditions relate to statistically predicted contribution under 10% POE maximum demand conditions. As previously noted, a 10% POE forecast is expected to be met, or exceeded, one year out of 10 on average.

We have assumed the available capacities remain constant from 2027 until the 2046 reference year. We discuss our approach for replacement generation technologies later in this section.

We have assumed that the total generation from existing generation capacity will remain constant at their 2017 levels. We have also assumed that committed renewable generation will generate at the average capacity factor of the technology type (30% for wind and 21% for solar PV, discussed in more detail in Step 4). In reality, existing generation might ramp up to serve additional consumption of electricity.

Intermittency of wind and solar generation

Consistent with AEMO’s assumptions, wind and solar generation capacities are de-rated in our modelling to account for the output that is most likely to be available during times of maximum demand, otherwise known as “firm contribution”.

We have used AEMO’s estimate of 8.1% of the wind capacity during summer in Victoria, and AEMO’s estimates of 25%, 11%, 5.5% and 0% respectively for existing and committed solar, new solar PV in 2017/18 to 2020/21, new solar PV in 2020/21 to 2025/26 and new solar PV post 2025/26. We note that the solar PV de-rating estimates are not specific to Victoria in AEMO’s 2018 Integrated System Plan assumptions workbook (version 21).

Issues relating to the intermittent nature of renewable generation are being raised and managed across the world as wind and solar generation accounts for an increasing share of the generation system. There are a number of initiatives looking at improving the dispatchable nature of these technologies. The potential for renewable generation contribution to peak demand to become more certain and reliable in the future will be discussed further in Section 5.3 of this Report.



Table 19 summarises the scheduled generation assumed to be available to meet maximum demand while Table 20 summarises the firm semi-scheduled generation assumed to be available to meet maximum demand.

Table 19 – Committed and existing summer scheduled generation

Power Station	Tech	Capacity	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27
Bairnsdale	OCGT	94	78	78	78	78	78	78	78	78	78	78
Mackay	Hydro	302	300	300	300	300	300	300	300	300	300	300
Dartmouth	Hydro	185	170	170	170	170	170	170	170	170	170	170
Eildon	Hydro	135	113	113	113	113	113	113	113	113	113	113
Hume VIC	Hydro	29	29	29	29	29	29	29	29	29	29	29
Jeeralang A	OCGT	212	189	189	189	192	192	192	192	192	192	192
Jeeralang B	OCGT	228	216	216	216	216	216	216	216	216	216	216
Laverton Nth	OCGT	312	300	300	300	300	300	300	300	300	300	300
Loy Yang A	Coal	2,180	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121	2,121
Loy Yang B	Coal	1,000	980	980	980	980	980	980	980	980	980	980
Upgrade LYB	Coal	78	0	0	0	78	78	78	78	78	78	78
Mortlake	OCGT	566	518	518	518	518	518	518	518	518	518	518
Murray 1	Hydro	950	950	950	950	855	855	855	855	855	855	950
Murray 2	Hydro	552	560	560	560	560	560	560	560	560	560	560
Newport	N. Gas	510	475	475	475	475	475	475	475	475	475	475
Somerton	OCGT	160	134	134	134	134	134	134	134	134	134	134
Valley Power	OCGT	300	270	270	270	270	270	270	270	270	270	270
West Kiewa	Hydro	60	68	68	68	68	68	68	68	68	68	68
Yallourn W	Hydro	1,450	1,420	1,420	1,420	1,420	1,420	1,420	1,420	1,420	1,420	1,420
Total		9,225	8,891	8,891	8,891	8,877	8,877	8,877	8,877	8,877	8,877	8,972

Table 20 – Committed and existing summer semi-scheduled generation

Power Station	Tech	Capacity	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27
Ararat	Wind	240	16	16	16	16	16	16	16	16	16	16
Bald Hills p1	Wind	107	9	9	9	9	9	9	9	9	9	9
Bannerton	Solar PV	88	0	22	22	22	22	22	22	22	22	22
Crowlands	Wind	80	0	0	6	6	6	6	6	6	6	6
Gannawarra	Solar PV	55	0	13	13	13	13	13	13	13	13	13
Kiata	Wind	31	3	3	3	3	3	3	3	3	3	3
Macarthur	Wind	420	34	34	34	34	34	34	34	34	34	34
Mt Gellibrand	Wind	132	0	11	11	11	11	11	11	11	11	11
Mt Mercer	Wind	131	11	11	11	11	11	11	11	11	11	11
Oaklands Hill	Wind	67	5	5	5	5	5	5	5	5	5	5
Salt Creek	Wind	54	0	4	4	4	4	4	4	4	4	4
Yatpool	Solar PV	81	0	20	20	20	20	20	20	20	20	20
Total		1,486	77	147	153	153	153	153	153	153	153	153

Future of coal fired generation

We have assumed that Yallourn coal fired power station will be withdrawn in 2032 on the basis that its coal stockpile is expected to last until this time⁵². Yallourn has 1,450 MW of installed

⁵² EnergyAustralia website, Yallourn Power Station, <https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station>



capacity, or 14% of the currently installed capacity for Victoria. This retirement is also consistent with AEMO's 2018 Integrated Systems Plan assumptions workbook (version 21).

We have not assumed any further withdrawals of generation by 2046 on the basis that none has been advised to AEMO. We note that the owners of Loy Yang A and Loy Yang B have expressed the view that they will continue operation beyond the 2046 reference year, and that their technical lives end in 2048 and 2056 respectively.

We note that our assumptions in regards to coal-fired generation are not necessarily in line with the Victorian Government announcement of a zero net emission target by 2050. The details of how this target will be achieved are yet to be released and legislated thus it is uncertain how this target would affect the generation market in the modelled years of 2031 and 2046. For example, it is unclear whether some gas generation could continue to operate through purchasing offsets.

We have considered a sensitivity which includes the retirement of all coal and gas fired generation in our modelling.

The impact of the retirement of coal fired generation is likely to increase the generation costs and infrastructure needed to service BEV charging as it will place more pressure on renewables and demand side participation.

Approach for replacement generation technologies

We note that although the financial life of for example wind farms is often estimated as 20 years, their life can be extended beyond this, and if they are decommissioned they will likely be replaced with new renewable energy. Broadly, we assume that retirement of technology due to age is replaced by the same technology – like for like, with the exception of coal-fired generation.

This may not turn out to be correct. It could be contemplated that wind is replaced by solar or OCGT may be replaced by batteries by retiring existing generation and replacing it with the cheapest alternative.

Further, we have not costed any new capacity required to replace retiring capacity, beyond that which is explicitly assumed. This is the case regardless of the age of new and existing capacity.

Entry of renewable generation and storage

We have added additional generation capacity to reflect the impact of the federal Large Scale Renewable Energy Target (LRET) and the Victorian Renewable Energy Target (VRET). The LRET mandates that 33,000 GWh be derived from eligible renewable energy sources by 2020 while the VRET aims to achieve 40% renewable energy in Victoria by 2025.

For this purpose we have relied on AEMO's "concentrated renewables pathway" modelled in its 2017 Electricity Statement of Opportunities (ESOO)^{53, 54}, as seen in Figure 19 alongside the "dispersed renewables pathways". Within the ESOO, AEMO defined three possible scenarios for future renewable generation:

- Committed and existing generation. This scenario only considers new generation that meets AEMO's commitment criteria.
- Concentrated renewables. This scenario assumes renewable generation after 2020 is concentrated primarily within Victoria as a result of the VRET.

⁵³ AEMO (2017), Electricity Statement of Opportunities, p. 37.

⁵⁴ We note that AEMO's 2018 Integrated Systems Plan specifies the new entry renewable capacity (MW) in Victoria for the VRET only, and not the LRET.

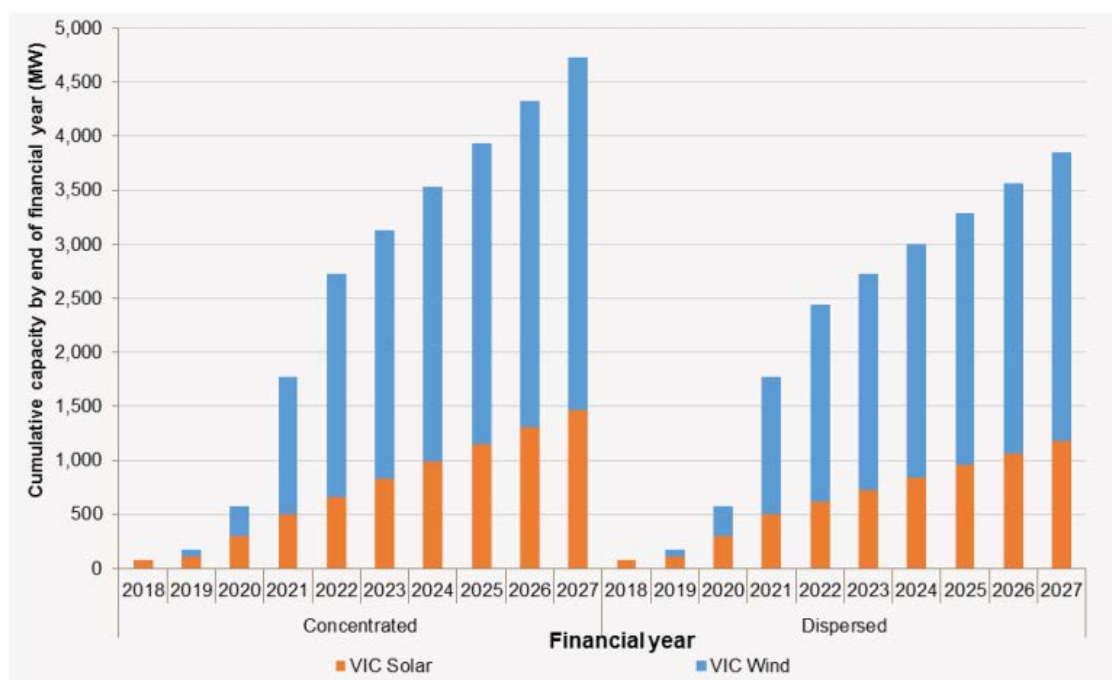


- Dispersed renewables. This scenario instead derives renewable development by national targets that would deliver a more geographically spread of renewable generation within the NEM.

We have opted to utilise the “concentrated renewables pathway” for our analysis as this is based on currently legislated initiatives (the LRET and VRET) which have mandated explicit targets. The “dispersed renewables pathway” instead uses assumptions of national targets to incentivise renewable capacity beyond 2021.

As noted, we have de-rated wind to 8.1% of its summer capacity, and solar to between zero and 25% depending on when it enters the market, for the purpose of meeting maximum demand, consistent with the approach to existing and committed generation discussed above.

Figure 19 - Additional cumulative build under the concentrated renewables and dispersed renewables pathways - Victoria⁵⁵



We have added the battery storage recently announced by the Victorian Government as part of its Energy Storage Initiative. On 22 March 2018, the Victorian Government announced that two projects would be provided as part of this initiative⁵⁶:

- Tesla 25 MW/50MWh battery to be integrated with Gannawarra Solar Farm which will store renewable energy on site; and
- 30MW/30MWh system connected directly to a vital grid intersection at a substation at Warrenheip near Ballarat.

We have assumed that these batteries will have an asset life of 15 years, consistent with AEMO’s 2018 Integrated System Plan workbook (version 21). However, as discussed above, we have assumed that the retirement of existing technology due to age is replaced by the same technology.

⁵⁵ AEMO (2017), Electricity Statement of Opportunities, p. 37.

⁵⁶ Delivering more large-scale battery storage for Victoria, Minister for Energy, Environment & Climate Change Victoria, 22 March 2018, <https://www.premier.vic.gov.au/delivering-more-large-scale-battery-storage-for-victoria/>



We have not included Snowy Hydro 2.0 in scenario analysis as it not a committed project under AEMO assumptions, but note that it could potentially add up to 1,000 MW of renewable scheduled (dispatchable) generation in Victoria.

Interconnection

We have made assumptions concerning the availability of capacity through interconnection. Interconnectors allow for electricity to be imported and exported between regions, and play an important part in balancing demand and supply in the NEM. At a time of high demand, imported energy from an interconnector can be an important supply of power when local generation is insufficient. This is especially the case with a changing generation mix towards higher levels of intermittent renewable generation. Increased use of interconnectors during maximum demand would help to reduce the investment impact related to EV charging.

Victoria is the most interconnected state in the NEM, with connections to Tasmania, South Australia and New South Wales. AEMO's 2018 Integrated System Plan workbook (version 21) assumes the following capacity is available:⁵⁷

- Tasmania to Victoria: 478 MW through Basslink.
- South Australia to Victoria: 650 MW through Heywood and 200 MW through Murraylink.
- New South Wales to Victoria: 400 MW through VIC1-NSW1.

For the model, we have assumed that 100% of the following capabilities are available to Victoria during maximum demand periods. It is impossible to estimate how interconnectors will be flowing in the typical day in 2046. We note that, in reality, it is likely that limited surplus generation will be available in neighbouring regions to service Victoria during times of peak demand. We therefore also consider a 10% sensitivity.

Table 21 - Interconnection

	Nominal capacity	Transfer capability during peak demand	10% of transfer capability during peak demand
NSW-VIC	400 – 1350 MW	400 MW	40 MW
VIC-SA (Heywood)	650 MW	650 MW	65 MW
VIC-SA (Murraylink)	220 MW	200 MW	20 MW
VIC-TAS (Basslink)	478 MW	478 MW	47.8 MW

Step 3: Calculate the gap between maximum demand and generation capacity available to meet that maximum demand, and between total consumption and total generation available

We have calculated the gap between maximum demand and total generation capacity available to meet maximum demand in each year from 2018 to 2046 as follows, with negative values representing a shortfall:

$$\begin{aligned}
 & \text{Required capacity (MW)} \\
 & = (\text{Firm existing and committed supply} + \text{firm LRET and VRET supply} \\
 & + \text{Interconnector transfer capability} - \text{Withdrawals}) - (\text{Maximum demand} \\
 & + \text{MRL} - \text{Committed DSP})
 \end{aligned}$$

⁵⁷ NTNDP Database, Australian Energy Market Operator, <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>



We have calculated the gap between total consumption and total generation available in each year from 2018 to 2046 as follows, where a negative value means a shortfall:

$$\begin{aligned} \text{Required generation (GWh)} &= (\text{Existing, committed and known generation} - \text{Known retirements} \\ &+ \text{Generation from capacity installed to meet maximum demand}) \\ &- \text{Total consumption} \end{aligned}$$

As noted in the previous section, we have assumed that existing, committed and known generation (MWh) remains constant over time, less assumed retirements. In reality, some existing generation could be able to ramp up its production to meet an increase in consumption before new capacity is installed.

We assume that storage generation installed to meet maximum demand (batteries, pumped hydro), will not add to total generation as they are effectively time-shifting generation.

Finally, we ensure that any additional generation added to meet total consumption also adds the “firm” proportion of its capacity to maximum demand, effectively reducing the capacity installed to meet maximum demand by an amount corresponding to the “firm” contribution of this capacity.

Step 4: Determine the likely technology of additional generation capacity

There is significant uncertainty in regards to the type of technology that will be developed to meet additional demand from BEVs (and to replace retiring coal fired generation). AEMO, in its 2018 Integrated System Plan assumptions workbook (version 21), has considered costs associated with eight types of technologies, including:

- Open cycle gas turbines (OCGT).
- Combined cycle gas turbines (CCGT).
- Wind farms.
- Large scale solar PV.
- Pumped hydro storage generation.
- Large scale batteries.
- Solar thermal generation.
- Biomass.

Notably AEMO does not include coal in its 2018 Integrated System Plan workbook (version 21). AEMO also did not include coal fired generation (nor nuclear generation or carbon capture and storage) as a new entrant candidate in its 2016 NTNDP Methodology and Input Assumptions⁵⁸. We have also assumed that no new coal fired generation will be constructed, on the basis of the significant revenue risk associated with a price on carbon⁵⁹, and that carbon capture storage and storage technologies are currently relatively unproven. We also do not contemplate nuclear power, solar thermal or biomass as part of our analysis.

The mix of generation capacity in the future, and the total cost associated with any additional capacity, will depend on a number of factors, including for example:

- when the capacity is required, as for example the cost of newer technologies like battery storage is expected to fall over time;

⁵⁸ AEMO (2016), 2016 NTNDP Methodology and Input Assumptions, p. 14

⁵⁹ We note that the Finkel Review reported a pre-tax WACC of 14.9% for coal in the BAU case, relative to 8.1% for gas CCGT and 7.1% for renewables, reflecting the uncertainty that investors and plant owners face regarding emissions reduction policy, and that “the uncertainty arises because there is the view that a carbon mitigation policy may be introduced in the future, but the timing and extent of any policy are uncertain”. (<https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-emissions-mitigation-policies-2017.pdf>, p. 22)



- the cost of fuel for non-renewable technologies, in particular the cost of gas, which is uncertain and potentially constrained in supply due to high export volumes and exploration moratoria;
- the ability of existing generation capacity to ramp up;
- the timing of retirement of coal-fired generation;
- the ability of certain technologies to capture revenue through providing additional services to the grid;
- the cost associated with a potential price on carbon or other government policy like the National Energy Guarantee (NEG) or the development of Snowy Hydro 2.0; and
- uptake of demand side participation or rooftop PV, which will have the net effect of lowering the total operational demand, i.e. requiring less additional generation capacity overall.

We also note that any additional generation capacity does not necessarily have to be developed in Victoria. Additional generation capacity in neighbouring states together with sufficient interconnection capability could also serve additional maximum demand or consumption in Victoria. Our modelling determines the capacity needed to service the additional maximum demand and consumption, but there is no guarantee that all the capacity will be located in Victoria.

Box 1: National Energy Guarantee

The integration of climate change policy and energy policy has been an ongoing issue for politicians and the energy industry for over a decade. The National Energy Guarantee (NEG), proposed by the newly formed Energy Security Board, is seeking to ensure a reliable and secure system at an affordable price while allowing Australia to meet its COP21 emission reduction targets.

The NEG comprises two components: an emissions requirement and a reliability requirement.

The emissions requirement requires retailers to identify, within a central registry, a total amount of historical generated energy equivalent to their historical retail sales. Retailers must then have an average emissions intensity below a set target, measured in tonnes CO₂ (equivalent) per MWh. Retailers can choose the way they obtain access to the necessary generation to meet their obligations, which are checked for compliance.

The reliability requirement requires AEMO to forecast peak electricity supply and demand in each of the NEM's regions. If there are persistent shortfalls in supply, certain retailers are allocated an obligation to alleviate the shortfall in supply by making investments or entering into contracts that encourage additional generation or encourage demand side participation (Reliability Obligations). If retailers do not adequately respond, AEMO is responsible for procuring generation resources as a 'procurer of last resort' and the AER may penalise retailers for non-compliance.

The objectives of the NEG is to ensure that there is an adequate level of dispatchable generation resources (i.e. available with a high level of certainty when required) to ensure that there is sufficient supply at times of maximum demand plus that the average emissions level of electricity generation supports Australian international commitments. By placing more value on generation technologies which are both clean and dispatchable will change the economics of entry into the market.

While the key aspects of the NEG are yet to be designed, importantly the emissions target, reliability assessments and also whether there will be exemptions granted, our modelling methodology attempts to be consistent with the objectives of the NEG through:



- only allowing dispatchable generation sources to enter the market in response to address an increase in maximum demand
- inclusion of a carbon price on generation emissions from 2021

The Energy Security Board is to continue to work on the design of the NEG and will present the final design to the COAG Energy Council for approval in August 2018. It is currently envisaged that the reliability requirement will start from 2020 while the emissions requirement takes effect from 2021.

Levelised cost of energy

For the purposes of comparing technologies, we have considered their respective levelised cost of energy (LCOE). This is a simplified method, and it does not capture the complex dynamics which drive capacity expansion, including demand correlation, intermittent resource diversity or transmission constraints.

The LCOE is a commonly used metric for comparing the relative cost competitiveness of different electricity generating technologies, taking into account the upfront capital cost, the fixed and variable operating and maintenance costs, the fuel costs, the project lifetime, and the capacity factor of the project.

Generally, the outlook for LCOEs varies between mature and renewables generation. The cost of mature technologies is expected to remain fairly constant in real terms, whereas the cost of renewable technologies are expected to fall as capital costs decline.

We have calculated the LCOE using the following formula⁶⁰:

$$LCOE = \frac{Capital\ cost \times CRF}{8760 \times Capacity\ factor} + \frac{Fixed\ O\&M}{8760 \times Capacity\ factor} + Variable\ O\&M + (Fuel\ price \times Heat\ rate)$$

Where:

$$CRF\ (capital\ recovery\ factor) = \frac{WACC \times (1 + WACC)^{lifetime\ of\ investment}}{(1 + WACC)^{lifetime\ of\ investment} - 1}$$

The following sub-sections detail our approach to each of the LCOE constituent components: Capital costs, fixed and variable operating and maintenance costs, fuel costs and heat rate, capacity factors, technical lifetime and WACC. Please note that the LCOE projections are highly uncertain and highly sensitive to assumptions made in regards to their component parts, and that they need to be viewed and considered with this mind.

Capital costs

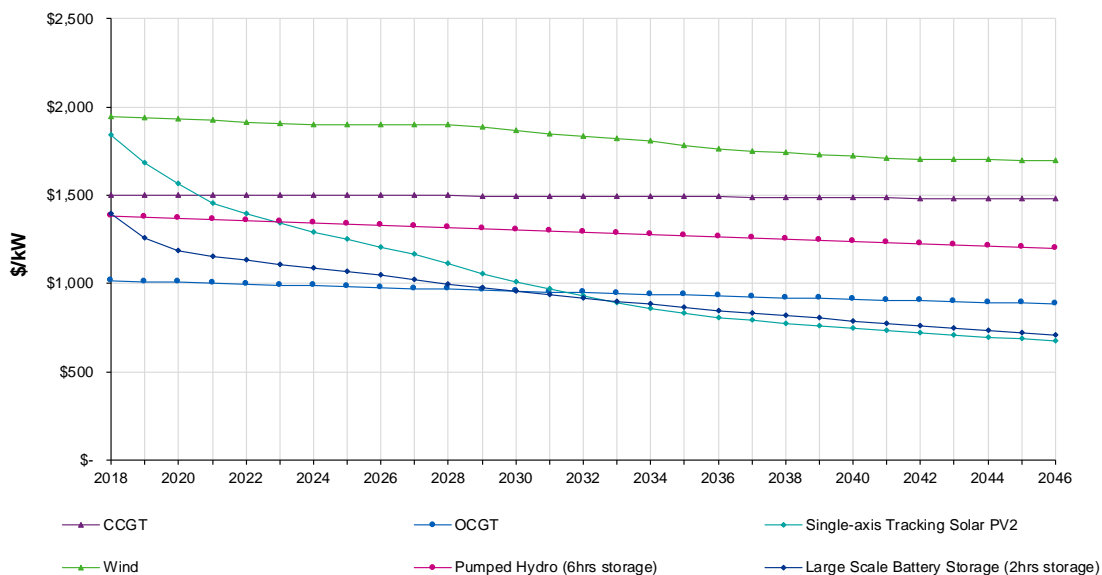
We have sourced the capital and connection cost projections from AEMO's 2018 Integrated System Plan assumptions workbook (version 21).

The capital cost projections are summarised in Figure 20 below.

⁶⁰ Foster, J, Wagner, L & Bratanova, A 2014, LCOE models: A comparison of the theoretical frameworks and key assumptions, <https://eemg.uq.edu.au/filething/get/137/2014-4.pdf>, p. 3



Figure 20 - Capital cost projections by technology (real 2017 \$/kw)



Fixed and variable operating and maintenance cost

We have sourced both the fixed and variable operating costs from AEMO’s 2018 Integrated System Plan assumptions workbook (version 21).

The estimates from AEMO are only available as a single year estimate, and therefore we have assumed that these costs remain constant over the modelling period.

The respective fixed (FOM) and variable (VOM) operating and maintenance cost estimates are summarised by technology in Table 22 below.

Table 22 - Fixed and variable costs (real 2017 prices)

	Solar PV	Wind	OCGT	CCGT	Pumped hydro	Batteries
VOM (\$/MWh)	0	15.73	10.15	7.10	5	0
FOM (\$/kW/yr)	30.44	45.67	4.06	10.15	5	0

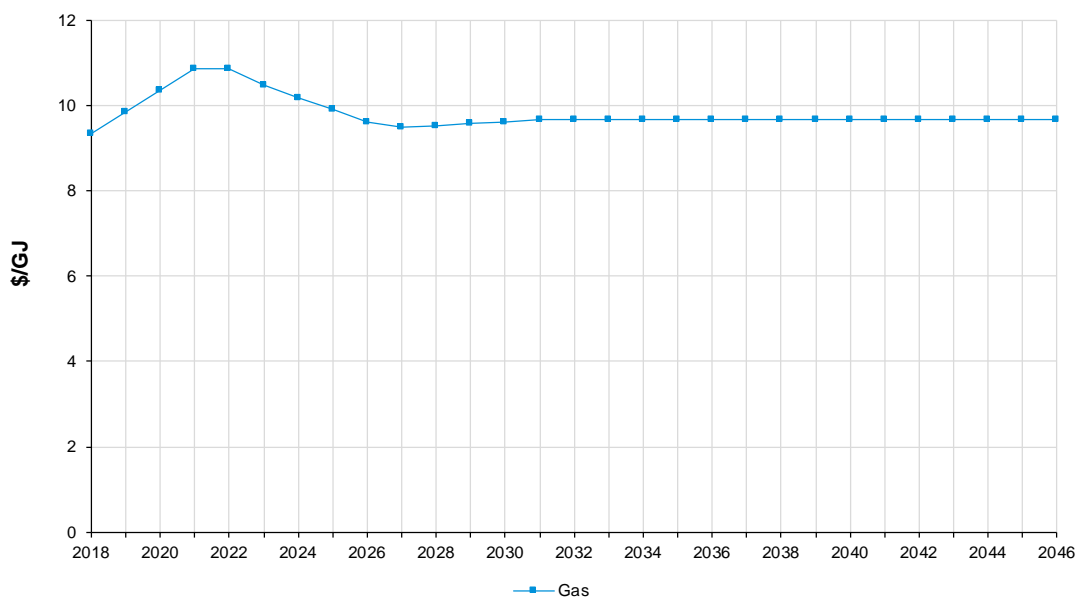
Fuel cost and heat rate

The fuel cost in this context relates to the cost of gas as we do not expect coal-powered generation to be developed going forward. As noted above, the cost of gas is uncertain and potentially constrained in supply due to high export volumes and exploration moratoria. The cost of gas going forward will be a key driver in regards to which type of peaking generation is developed to meet maximum demand.

We have sourced fuel cost forecasts on a \$/GJ basis from AEMO’s 2018 Integrated System Plan assumptions workbook (version 21).



Figure 21 - Fuel costs (real 2017 prices \$/GJ)



Capacity factors

We have sourced capacity factors from AEMO’s 2018 Integrated Systems Plan workbook for all technologies except wind and solar PV (which are not specific to Victoria).

For wind, we have assumed that the capacity factor reflects the average load factor for wind generation in Victoria across 2017 and 2018 (part of), which is 30%.

For solar PV, we have assumed an average capacity factor based on the EOI application data from the ARENA large-scale solar PV competitive round of 21%, as there is no existing solar PV capacity in Victoria.⁶¹

The capacity factors are summarised in Table 23.

Table 23 – Capacity factors by technology type

OCGT	CCGT	Wind	Solar PV	Battery	Pumped hydro
10%	50%	30%	21%	8%	25%

Project lifetime

For project lifetimes, or the economic life of a project, we have relied on estimates from AEMO’s 2018 Integrated Systems Plan workbook. These estimates are summarised below in Table 24.

⁶¹ ARENA (2016) ARENA large-scale solar PV competitive round – EOI application data, p. 3, https://arena.gov.au/assets/2017/02/ARENA-Large-scale-Solar-PV-Competitive-Round_EOI-Data-Output_March-2016.pdf



Table 24 – Project lifetime (years) by technology type

OCGT	CCGT	Wind	Solar	Battery	Pumped hydro
30	30	20	30	15	50

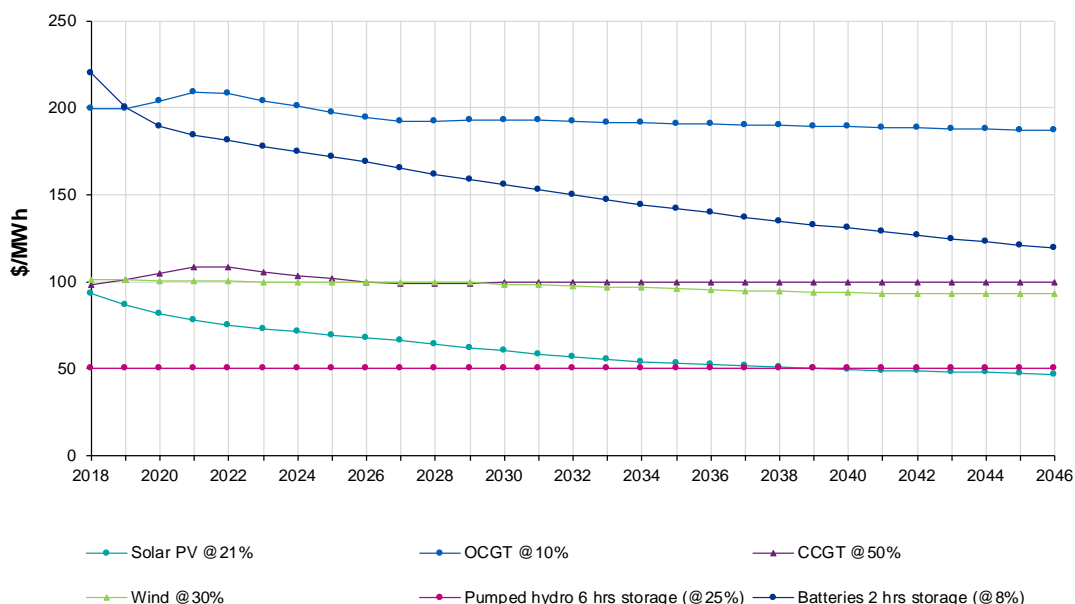
Weighted Average Cost of Capital

We have sourced the 6% WACC estimate from AEMO’s 2018 Integrated System Plan assumptions workbook (version 21).⁶²

LCOE projections

The following chart summarises the resulting LCOE projections.

Figure 22 - LCOE projections



Supply capacity constraints

The type of generation which is required will depend on the characteristics of demand, in particular, if the generation is required to help meet maximum demand. We assume that EV uptake scenarios which add to maximum demand will require scheduled (dispatchable) generation capacity. We contemplate in our analysis that increases in maximum demand will be met by storage (batteries and/or pumped hydro)⁶³. This is broadly consistent with AEMO’s approach of ascribing very little “firm” capacity to renewable energy during periods of peak demand based on its historical analysis of its contribution, as discussed previously.

In the absence of any specific supply capacity constraints on certain types of technology in Victoria, and the high uncertainty relating to the LCOE estimates, we conduct our modelling

⁶² Note that this rate is different to the 7% rate used in the NPV estimates.

⁶³ We have not contemplated biomass or solar thermal as part of the generation mix, but recognise that these technologies may form part of the generation mix in the future, as may other types of generation which have not yet been developed on a commercial scale yet.



using an equal share of batteries and pumped hydro to meet forecast maximum demand, to ensure that all new capacity is zero emissions.

If additional generation is required to meet increased total consumption, beyond the additional capacity required to meet maximum demand, we assume that this will be met by a combination of solar and wind generation⁶⁴, given their zero emissions status and relatively low LCOE.

Step 5: Determine the total cost of additional generation capacity

The total cost is calculated as the net present value of the total capital, connection and fuel cost of new generation capacity required in each year until 2046 to meet maximum demand and total consumption. It does not reflect ongoing operating expenses.

As all new entry is assumed to be zero emissions, and there is no specific fuel cost associated with renewable generation in AEMO's underlying fuel cost assumptions⁶⁵, there is no fuel cost component reflected in the results.

We present the estimates in net present terms using discount factor of 7% real.

Step 6: Determine the incremental emissions associated with BEV consumption

The total emissions associated with electricity generation in each year has been calculated as the total emissions from existing and committed plants (less assumed withdrawals), plus emissions associated with any new entrant gas-fired generation OCGT and CCGT.

Any new entrant renewable generation or storage technology are assumed to generate no additional emissions.

The emissions in year 2018 have been calculated for each plant as the installed capacity, multiplied by its 2017 average load factor, multiplied by 8760 hours, multiplied by its emissions intensity. The actual 2017 load factor is calculated as the average cleared MW divided by the maximum cleared MW. We have used emissions intensity assumptions data from AEMO's 2018 Integrated System Plan workbook (version 21). The emissions intensity and load factor of the committed Loy Yang B upgrade is assumed to be the same as for Loy Yang B, for simplicity. This information is summarised in Table 25.

The total emissions from existing generation is assumed to remain constant over time (as their generation is expected to remain constant, reflecting a flat consumption forecast base case without any EV uptake), less any assumed retirements and additions (Loy Yang B upgrade).

⁶⁴ We assume a 50/50 split between wind and solar generation, as these two technologies do not necessarily operate at the same time of the day. That is, 50% of the total required generation is assumed to come from wind (at 30% capacity factor) and 50% of the required generation is assumed to come from solar PV (at 21% capacity factor).

⁶⁵ Storage based generation will require electricity to charge, which in reality will be associated with a cost.



Table 25 - Emissions by power station

Name	Technology	2017 load factor	Comb Co2 (kg/MWh)	Fugi Co2 (kg/MWh)	Total emissions (kg/MWh)
Bairnsdale	OCGT	35.46%	529.57	41.29	570.86
Jeeralang A	OCGT	5.45%	844.53	61.25	905.78
Jeeralang B	OCGT	0.69%	844.53	61.25	905.78
Laverton North	OCGT	3.93%	767.74	46.14	813.88
Loy Yang A	Coal	7.04%	1253.50	5.25	1258.75
Loy Yang B	Coal	93.82%	1226.92	5.38	1232.3
Mortlake	OCGT	82.28%	535.30	43.87	579.17
Newport	Gas	33.01%	556.50	42.06	598.56
Somerton	OCGT	20.78%	767.60	58.49	826.09
Valley Power	OCGT	0.50%	821.77	58.49	880.26
Yallourn W	Coal	80.27%	1441.00	6.07	1447.07
Loy Yang B upgrade	Coal	93.82%	1226.92	5.38	1232.3



3.5 Network model

3.5.1 Overview of network model

KPMG's approach to modelling the impact on electricity networks in Victoria considers two areas:

- Determining network costs across the five distribution networks and transmission network in Victoria.
- Undertaking a spatial analysis to determine particular areas across Victoria that may be susceptible to demand issues based on network capacity, and the increased load from the introduction of BEVs.

Similar to the generation model, the determination of network costs will be based on the contribution to the peak demand profiles calculated for each scenario. The approach to this calculation is described earlier in Section 3.3. Long run marginal cost has been utilised to estimate the cost of additional demand, which can then be overlaid with the introduction of BEVs to determine incremental network costs.

KPMG's spatial analysis will consider the percentage utilisation of various zone substations by year (either in 2031 or 2046) to determine localised 'hotspots' for which network upgrades may be required in order to meet the extra demand from BEV charging.

3.5.2 Long run marginal cost (LRMC)

Our methodology for determining network costs examines the effect of electric vehicles on network costs in each of the five distribution networks in Victoria. There are four key steps, or elements, to our methodology:

- Step 1: Use of LRMC to estimate the cost of additional demand;
- Step 2: Calculation of EV contribution to the network peak; and
- Step 3: Calculation of incremental network costs for each network.

We note that there will be other impacts to the networks caused by BEV load in terms of network support and ancillary services. Therefore these estimates of network costs are likely to under-estimate the full impact on transmission and distribution networks under the high penetration of BEVs. There are a number of reasons for this. The model only attempts to estimate costs associated with augmenting the network to provide more capacity to serve the extra demand. Distribution networks could be required to invest in the following additional infrastructure:

- to manage the network security impacts associated with BEVs
- communication and associated transactive technology to help support capturing the market benefits from BEVs
- at the connection points to support fast charging of BEVs.

Certain parts of the network will need to be reinforced to deal with the potential DC Fast charging infrastructure. Customers may also be required to pay additional costs to strengthen the local connection to reduce the risk of overloading plus further metering equipment for separate meters. We will explore these further in chapter 5 in the infrastructure responses assessment.



Step 1: Use of LRMC to estimate the cost of additional demand

We have used estimates of long run marginal cost (LRMC) to calculate the effect of a single electric vehicle on network costs. In the context of electricity networks, LRMC is the cost of supplying an additional kW (or kVA) of demand allowing all factors of production (i.e. network capacity) to vary – see Box 2.

Box 2 – Long run marginal cost and its estimation

Marginal cost refers to the additional expense incurred to produce one extra unit of output. Marginal cost is a critical concept in microeconomics and economic regulation. It is an inherently forward-looking concept. In the words of Kahn:

Marginal costs look to the future, not to the past: it is only future costs for which additional production can be causally responsible; it is only future costs that can be saved if that production is not undertaken⁶⁶.

We highlight Kahn’s use of the phrase ‘causally’ responsible. Marginal cost is a causal concept – the cost that is caused by, or that arises from, the production of the additional unit.

There are both short run and long run notions of marginal cost. The distinction is whether all factors of production are fixed or can be varied, i.e.:

- the short run marginal cost is the cost incurred to produce one extra unit of output, holding at least one factor of production constant; and
- the long run marginal cost is the cost to produce one extra unit of output assuming all factors of production can be varied.

We will focus on long run marginal cost.

How do Victorian DNSPs estimate LRMC?

Victorian DNSPs estimate LRMC using an average incremental cost approach. This approach estimates LRMC as the average change in projected operating expenditure and capacity expenditure that can be attributed to projected increases in demand. In practice, it involves three steps:

Step 1: Forecast future load growth for the network;

Step 2: Project future operating and capital expenditure that arise from expected increases in demand; and

Step 3: Divide the present value of projected costs by the present value of expected load growth.

The formula for estimating LRMC using an average incremental cost approach is therefore:

$$LRMC = \frac{\text{Present Value (Expenditure attributable to load growth)}[\$]}{\text{Present Value (Increase in demand)}[kVA]}$$

Applying this formula yields an estimate of LRMC, expressed in dollars per kVA-year. These estimates typically use a forward-looking time horizon of between 20 and 30 years.

Table 26 reflects the estimates of LRMC for each Victorian DNSP. DNSPs estimate LRMC as part of their pricing process for their five-year determination in accordance with National Electricity Rules requirements to set tariffs based on LRMC. It follows that these estimates of LRMC provide sensible, ready-made values for the distribution network cost of an additional kW of demand.

⁶⁶ (Kahn, 1988)



Table 26 – Estimates of LRMC for each Victorian DNSP

Victorian DNSP	LRMC \$(/kVa year)	Source
AusNet Services	88.70	Annual tariff proposal 2018.
CitiPower	94.20	CitiPower 2018 Annual Pricing Proposal Attachment A.
Jemena	62.20	Jemena 2018 pricing proposal LRMC in \$/kW.year converted to kVA assuming power factor of 0.95.
Powercor	96.60	Powercor 2018 annual pricing proposal attachment A.
United Energy	85.425	LRMC not published. Assume average of other Vic DNSPs.

We have also used LRMC to estimate the cost of additional demand for transmission services. As there is no data published for the LRMC of transmission, we consider it necessary to utilise an assumed figure.

Power factor is the measure of how effectively a customer uses its electricity supply and is the ratio of real power (kW) to apparent power (kVA). A site with low power factor draws more apparent power than real power. As the LRMC estimates are expressed in kVa figures, we have to convert these to kW to calculate the demand impacts from BEV charging. We have assumed a power factor correction of 95% which means that the kVA figures are reduced by 5% to estimate the LRMC associated with serving addition kW capacity for the network

We have examined AusNet’s expenditure and non-coincident maximum demand data as published in the AER’s 2017 benchmarking report to estimate the cost per kVA·year of AusNet’s transmission services. Our calculation is set out in Table 27. We have calculated an annualised RAB payment assuming an interest rate of 8.00% and an average asset life of 30 years.

Table 27 - Calculation of transmission LRMC for AusNet's network

	Revenue from residential customers	Annualised value (\$ million)	Non-coincident maximum demand (MVA)	Cost per kVA:year (\$)
2016 Opex	91.046	91.046	9,678	9.41
2016 RAB value	258.489	26.71	9,678	26.71
Total cost per kVA:year				36.12

We have therefore assumed a single transmission LRMC of \$36.12 per kVA.year.

We have assumed that our estimates of LRMC are constant over the course of the modelling period. The rationale for this assumption is that estimates of LRMC already use a long modelling horizon (20 to 30 years). Moreover, there is no sensible reason to expect a change in



network costs – whether it be an increase or decrease – over the modelling horizon out to 2046. In our opinion, the current estimates of LRMC therefore represent the best available estimate over the modelling horizon.

However we do note that the flows across networks under BEVs scenarios could be substantial different which could undermine the use of the current LRMC estimates as a proxy of the costs of serving additional demand. It is possible that the additional demand from BEV and the nature of charging will place extra stresses on the distribution network requiring replacement of overhead cables, or subdivision of the distribution network via installation of additional distribution transformers

Step 2: Calculation of EV contribution to network peak

LRMC provides an estimate of the per-unit cost of demand. The next step is to determine how many units (kW) of extra network peak demand are caused by the BEV fleet under each scenario. We used the contribution to the peak demand profile and the existing peak period definitions used by the 5 DNSPs to do this.

As our contribution to peak demand profile is calculated at the Victorian system level we have to assign the proportions of the extra peak demand across the five distribution network. For these proportions we have used proxies based on the estimate of the location of vehicle trips in each the DNSPs areas under the transport model results. This is a simple approximation and likely to be mistaken. The proportions used for each scenario is set out below.

Table 28 – Proportion of BEV peak demand for each Victorian DNSP by scenario

	Electric Avenue	Private Drive	Slow Lane	Fleet Street	High Speed
AusNet	26.6%	26.2%	26.9%	27.5%	27.5%
CitiPower	5.8%	6.8%	6.0%	5.4%	5.4%
Jemena	14.0%	14.3%	13.8%	13.6%	13.6%
Powercor	34.1%	33.1%	34.0%	34.4%	34.4%
United Energy	19.5%	19.7%	19.4%	19.1%	19.1%

Electricity network costs are primarily driven by maximum demand across the network. There are 'peak' periods (e.g. late afternoon to early evening on weekdays) when demand may reach its maximum. It is this maximum level that determines need for capacity, and so drives network costs. Consumption outside of this peak period does not create a need for new capacity, and so has little or no effect on network costs. A simplistic approach would be to assume that the demand created by an EV is its maximum draw from the grid. But this approach does not consider the impacts of timing for EV charging.

An important assumption is the choice of peak period. We have chosen to use peak periods as defined for each of the DNSP's cost-reflective tariffs. These tariffs have the narrowest definition of the peak – in our experience, the definitions of peak periods are the best indicators of the times when networks experience their maximum demand, and so the periods when additional demand will give rise to additional network costs. The assumed peak periods are set out in 29, below.

Table 28 - Peak period definition for each Victorian DNSP

Victorian DNSP	Peak Period Definition	Source
----------------	------------------------	--------



AusNet Services	2:00PM to 6:00PM Working days	AusNet 2017-20 Tariff Structure Statement
CitiPower	10:00AM to 6:00PM Working days from December to March	CitiPower 2017-20 Tariff Structure Statement
Jemena	3:00PM to 9:00PM Working days from December to March	Jemena 2017-20 Tariff Structure Statement
Powercor	3:00PM to 9:00PM Working days from December to March	Powercor 2017-20 Tariff Structure Statement
United Energy	3:00PM to 9:00PM Working days	United Energy 2017-20 Tariff Structure Statement

We have assumed that the transmission peak aligns with the DNSP’s peak period in each of the 5 distribution networks.

We have also used the commercial peak period definition for Citipower – an assumption that reflects that Citipower’s network spans the Melbourne CBD. We therefore assume that electric vehicles will typically be charging at commercial sites, rather than residential sites. We note that we also assume BEVs will exhibit a different load profile in this network – one that sees them typically charging during the middle of the day.

An important question is whether these peak periods change over the course of the modelling period. There is an inherent interrelationship between the uptake of BEVs and the definition of the peak period. If enough BEVs enter the power system, there is potential for the peak to change. In turn, a change in the peak period has the potential to affect the charging profile, and even the uptake, of BEVs.

For the purposes of this exercise, we assume that the peak period definition remains constant.

The output of this step is an estimate of the network cost (i.e. transmission plus distribution) arising from a single EV in each of the 5 Victorian distribution networks.

Step 3: Calculation of incremental network costs for each distribution network

The final step is to multiply the estimates of network cost by the contribution to the peak times the proportion assigned to the DNSP zone

For example, for in Electric Avenue – incentivised, the contribution to the peak of EVs in the network peak times is 3,861 MW x 26.6% (AusNet) is 1,029 MW in 2046. 1,029 MW x the LRMC of \$84,265 per MW per annum gives \$86,679,512 in 2046. The model then calculates the NPV of the annual LRMC amounts over the modelling period.

The output is a projection of the total cost of BEVs in each distribution network over the modelling time horizon. There is a different projection for each scenario and permutations.



3.6 Spatial analysis

While the above analysis has considered the introduction of ZEVs and their effect on peak loads, it provides this analysis at a high level, forgoing a granular assessment of the Victorian electricity network. Further, this modelling has primarily been focused from a cost lens.

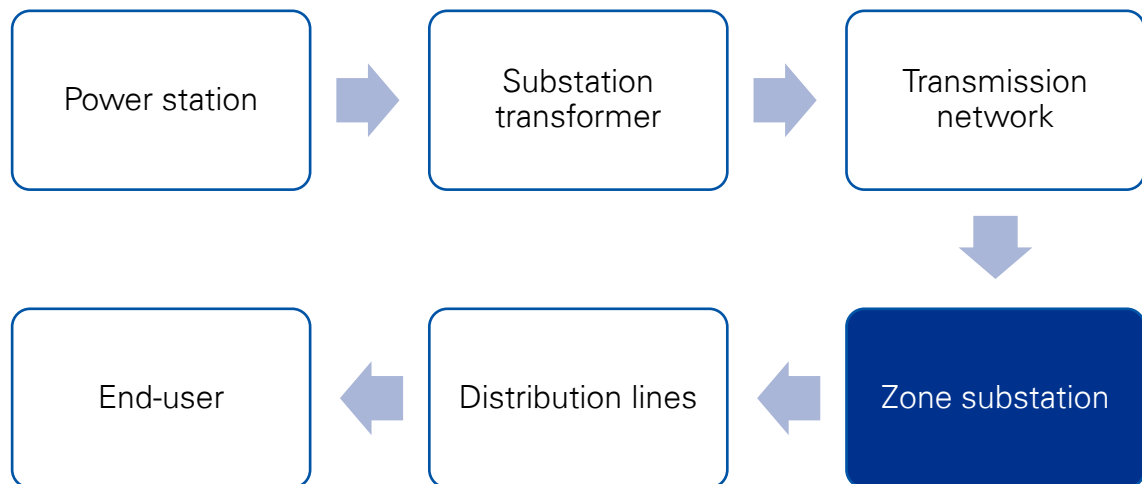
Accordingly, KPMG have also undertaken a spatial analysis exercise to assess localised impacts on the distribution network from at a zone substation level. From a planning perspective, it is important to understand areas of a distribution network that may already be at, or near, their distribution capacity.

The introduction of ZEVs, and their associated charging infrastructure, may impact some of these localised areas to the point that they are no longer able to reliably serve their demand. Such a spatial analysis therefore allows the identification of ‘pinch points’ within a network that may require upgrades.

3.6.1 Overview of electricity network

To understand where our spatial analysis fits into the electricity network, it is useful to first understand how the typical electricity grid operates within Australia. Figure 23 below presents this diagrammatically and we will briefly explain each element. It is noted that this reflects a traditional ‘grid’ network approach; distributed electricity networks may take a different form.

Figure 23– Overview of traditional electricity network



Power station

The electricity network commences at a power station where electricity is generated, which may come from a number of fuel sources. Once generated, the electricity is transmitted along large transmission equipment and through a substation transformer.

Substation transformer

The substation transformer modifies the voltage of the electricity generated from a power station so it can be delivered over transmission networks safely and efficiently.



Transmission network

The purpose of the transmission network is to bridge the electricity generated by power stations to the individual DNSPs in Victoria. Electricity is carried at a high voltage across the transmission network until it arrives at a terminal station, where the voltage is stepped down to be suitable to enter the distribution network. In Victoria there are over 40 terminal stations.

From these terminal stations, the sub-transmission system carries the electricity through to the respective zone substation. At this point, the electricity network is now in the hands of each respective DNSP.

Zone substation

This is the focus of KPMG's spatial analysis. Victoria contains over 225 zone substations which service the 5 DNSPs referred to throughout this report. The locale of these zone substations aligns to the various areas that the DNSPs serve.

The purpose of the zone substation is to again modify the voltage of the electricity to be safe and suitable for end-users. Once passed through a zone substation, electricity is transmitted along distribution lines.

Distribution lines

These distribution lines are the typical 'poles-and-wires' seen on household streets, although they may also be buried. They serve to bring electricity to an end-user, with transformers located at the end of the distribution lines to modify voltage a final time before being delivered to the end-user.

End-user

Electricity is delivered to homes and businesses for use in appliances, lighting, heating etc. Buildings are metered so electricity consumption can be measured to determine charges for end-users.

3.6.2 Zone substations in Victoria

As noted above, there are over 225 zone substations in Victoria which are managed in the relevant networks of each of the 5 DNSPs. Each zone substation is tailored for the area that it serves i.e. there may be a differing transformer capacity at each zone substation.

Upgrades or works to zone substations are managed by the relevant DNSP⁶⁷ and do not typically involve another party such as AEMO, unless transmission infrastructure is also impacted.

The National Electricity Rules require each DNSP to undertake an annual planning review that considers forecasts for each DNSP's network, including zone substations, for a minimum period of 5 years into the future⁶⁸. Accordingly, for the uptake of ZEVs, it is likely that a DNSP would be forecasting what they believe to be the uptake rate of ZEVs to determine how this would affect their overall network, and whether particular areas within a distribution network require upgrades.

As each DNSP considers their future network upgrades as part of this planning process, the purpose of our spatial analysis is not to recommend zone substations that should be upgraded.

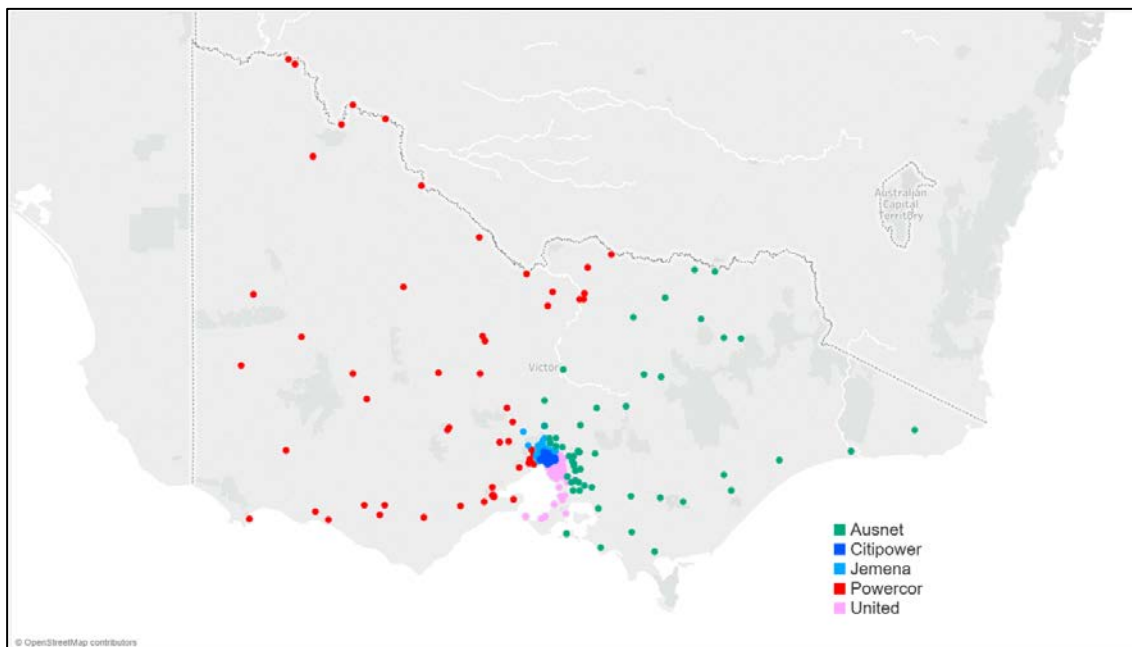
⁶⁷ Energy infrastructure in your community, Australian Energy Market Operator, May 2012, https://www.aemo.com.au/-/media/Files/PDF/ENERGY_INFRASTRUCTURE_IN_YOUR_COMMUNITY.pdf

⁶⁸ National Electricity Rules Version 107, Australian Energy Market Commission, <https://www.aemc.gov.au/sites/default/files/2018-04/National%20Electricity%20Rules%20version%20107.pdf>



Ultimately, it is up to a DNSP to decide upon distribution network upgrades and a number of factors are considered in this decision. Rather, we will seek to highlight the 'pinch points' in the Victorian electricity network for which loads may approach the capacity of a zone substation.

Figure 24 - Spatial location of distribution zone substations by DNSP



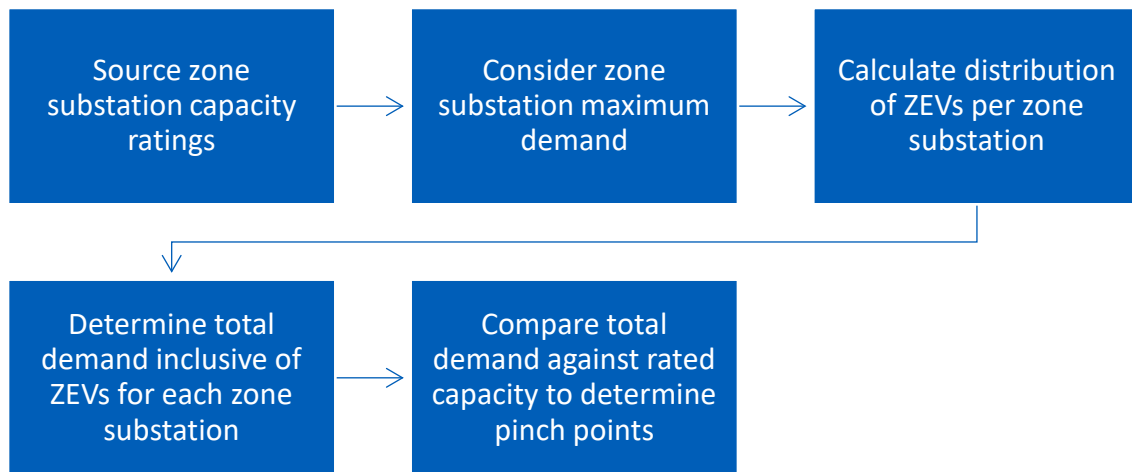
3.6.3 KPMG approach to spatial analysis

KPMG's approach to our spatial analysis is to review each zone substation in Victoria to determine which of these may be operating in excess of their rated capacity with the introduction of ZEVs. To do so, we have compared the rated capacity of each zone substation against a forecast maximum demand, inclusive of ZEVs. Should this demand exceed a rated capacity, it indicates a zone substation that may require future upgrading.

The process of our methodology is represented in Figure 25 below, with each step of this process being expanded upon in the following section.



Figure 25 - Spatial analysis methodology



Zone substation ratings

Pursuant to the National Electricity Rules, each DNSP is required to make data available for their zone substations. In our spatial analysis, we have utilised the provided 2016 capacity rating for each zone substation in Victoria as a basis for comparing total demand.

Each zone substation will have a capacity rating based on its size and equipment contained, which in itself will be determined based on the demand on that zone substation. In a high demand area, one would expect a zone substation with a higher capacity rating and the inverse in low demand areas.

Zone substation maximum demand

Weather corrected maximum demand

At a high level, the maximum zone substation demand (MD_{zs}) is simply the expected maximum electricity demand for a given zone substation. If this is higher than the zone substation rating, it may indicate that an upgrade is required or that the zone substation is at risk of not being able to adequately service its demand.

However, when considering MD_{zs} , a correction is applied to normalise this demand, with the key driver being weather. The purpose of this is to consider representative energy consumption over a long time horizon⁶⁹. Historical weather data is gathered and modelled to produce a typical weather condition that would be expected to occur.

This normalisation is tied to the concept of Probability of Exceedence (POE), which is the probability of maximum demand being exceeded over a given time period⁷⁰.

A 10% POE is utilised within the spatial analysis for the purpose of determining a normalised MD_{zs} . In simple terms, the 10% POE MD_{zs} is the level of demand that would be exceeded, on

⁶⁹ Lundstrom, L 2017, Adaptive Weather Correction of Energy Consumption Data, Energy Procedia, vol 105, https://ac.els-cdn.com/S1876610217308469/1-s2.0-S1876610217308469-main.pdf?_tid=06f5d459-5405-4468-b63d-84ae2815c6db&acdnat=1525248243_bc84b2c3a7d92ae4c7e672cd89cadab0

⁷⁰ Acil Allen Consulting, Connection Point Forecasting, 26 June 2013, <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting//media/Files/PDF/ConnectionPointForecastingANationallyConsistentMethodologyforForecastingMaximumElectricityDemandpdf.pdf>



average, once every ten years. The calculation and modelling of POE is complex and we have utilised the figures provided by DNSPs for their relevant zone substations.

Calculation of annual maximum demand to 2046

With the weather corrected maximum demand, this provides a baseline demand for 2016 at the zone substation. It is then necessary to apply system wide network growth to reflect increases in demand over time.

In our spatial analysis, we have utilised three scenarios to model annual changes in weather corrected maximum demand: weak, neutral and strong. As the names suggest, these will reflect different rates of demand growth over time.

The system wide network growth is considered on an annual basis so maximum demand can be calculated through to 2046. The use of a system wide network growth rate means that localised factors such as differences in suburb population growth are not captured.

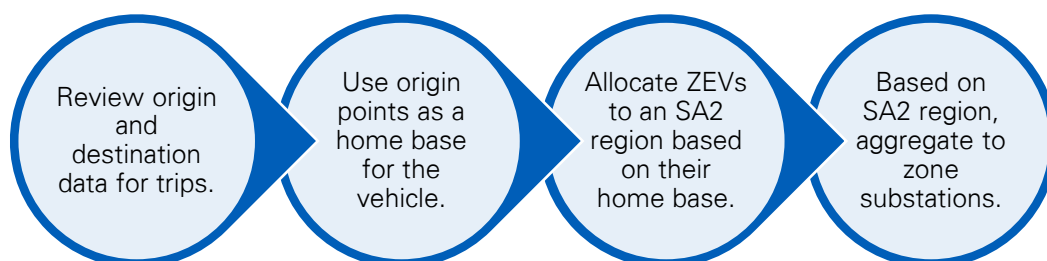
Distribution of ZEVs across Victoria

In order to determine the impact at a zone substation level, we need to understand the number of ZEVs that are distributed across Victoria as a method of determining where charging may occur, as well as how many vehicles are being charged in a given area. The more ZEVs that reside within that area, the greater the impact on that local zone substation.

As was discussed in Section 3.2.2, MABM provides an output of total fleet size under each scenario. Accordingly, we have used this figure as a basis in allocating vehicles across the road network.

Our process to allocate the number of ZEVs to each zone substation is set out in Figure 26.

Figure 26 - Allocation of ZEVs to zone substation



Allocation of ZEVs to SA2 region

As the trip matrices described in Section 3.2.2 provide the origin and destination of a trip at an SA2 level, this can be used to determine the 'home base' of a ZEV. As was discussed, we have assumed for residential vehicles that the origin of a trip slice represents a vehicle departing a residential home on its way to a given destination point. At some stage during the day (likely at the end of a working day), the ZEV will then return to this origin point to mimic the agent returning to their home.

As the data is provided at an SA2 level, the home base determined informs where in Victoria that particular ZEV 'lives'. With an understanding of the number of vehicles in each SA2 region, this can be matched to the relevant zone substation that the ZEVs would likely be charging from, which will provide the estimated energy demand at that zone substation from ZEVs.



Matching of SA2 regions to zone substations

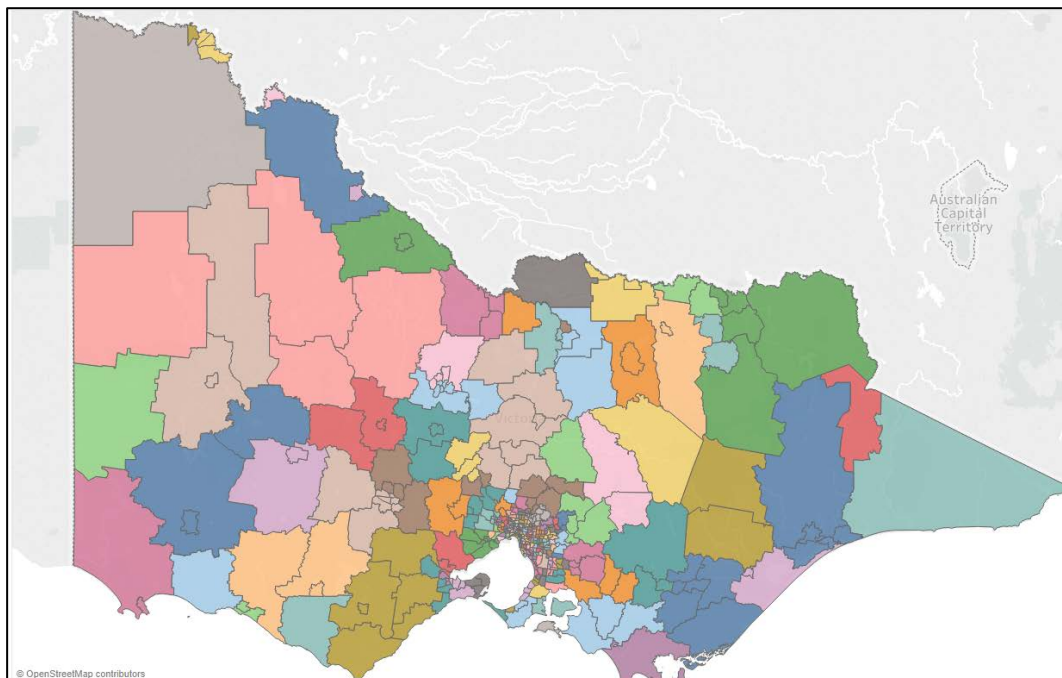
The final step in this process is the matching of SA2 regions to the relevant zone substation. We note that the resulting mapping is not 100% accurate however it allows for an understanding and appreciation of potential zone substation impacts.

Zone substations of each DNSP are named by a given suburb in Victoria which allows for an estimation on a map as to their actual location. For the purposes of our analysis, we have therefore plotted each zone substation into the suburb it is named from. We note that this will not provide the precise location of the actual zone substation but rather will place it in the centre of the relevant suburb.

From this, each plotted zone substation can then be allocated to the relevant SA2 region that corresponds to this mapping. Again, we stress that this does not provide exact locations however it does allow a spatial analysis of charging across Victoria from which we can illustrate the potential impacts at the zone substation level.

A presentation of this mapping is shown below in Figure 27.

Figure 27 - Matching of SA2 regions to zone substations



Determination of total demand

The calculation of total demand for each zone substation is simply the addition of the two aforementioned factors:

$$\text{Total demand}_{ZS} = 10\% \text{ POE MD}_{ZS} + \text{ZEV demand contribution}$$

ZEV Demand Contribution

The contribution of demand by ZEVs at each zone substation is calculated using the vehicle contribution at network peak as discussed in Section 3.5.2 of this Report. This allows for the determination of the contribution to network peak, in kVa, by an individual ZEV, which can then be grossed up for total demand contributions.

After ZEVs have been allocated to representative zone substations, the number of ZEVs is multiplied by the peak contribution factor to determine the ZEV demand contribution at that zone substation, which is then added to the 10% POE MD_{ZS} for that year. This figure now



represents an indicative total demand for a given year, inclusive of the impacts from ZEV charging.

With the total demand calculated for each zone substation, this can then be carried through to an analysis of the network ‘pinch points’.

Comparison of total demand to rated capacity

As noted above, once the total demand (inclusive of BEVs) of a zone substation has been determined, this can be contrasted against the rated capacity of that zone substation to ascertain the ‘pinch points’ within a network.

Within our spatial analysis, we have represented this as percentage utilisation of a given zone substation. Where this result exceeds 100%, this indicates that the zone substation may be operating beyond its rated capacity which may trigger the need for a DNSP to consider an upgrade.

Spatial analysis worked example

To bring the above concepts together, we present a worked example of two random, indicative zone substations in Victoria below that demonstrates how our analysis has been undertaken.

Table 29 below represents the two random zone substation chosen: Yarraville and Werribee. As can be seen from this data, the Yarraville zone substation has a MD_{ZS} below its rated capacity; the inverse is true for the Werribee substation.

Table 29 – Sample zone substations

DNSP	Zone Substation	2016 Rating (MVA)	2016 10% POE MD (MVA)
Jemena	Yarraville	49.50	29.84
Powercor	Werribee	99.00	130.60

Table 30 details a sample calculation of total demand (inclusive of ZEVs) which is compared against the zone substation’s rated capacity to provide a percentage utilisation. The contribution from ZEVs is 1.01 MVA higher at the Werribee substation, indicating a greater number of ZEVs in this region.

As can be seen in Table 30, the Yarraville zone substation is still well within its rated capacity and it is therefore unlikely on the basis of our analysis that an upgrade to the zone substation would be required. However, the Werribee zone substation, which appears to already have MD_{ZS} in excess of its 2016 capacity rating, is further worsened by the introduction of ZEVs and may indicate a zone substation in need of upgrades.

Table 30 – Indicative zone substation utilisation

Zone Substation	2046 10% POE MD (MVA)	ZEV demand contribution (MVA)	Total demand (MVA)	Rated capacity (MVA)	% utilisation
Yarraville	31.52	0.35	31.87	49.50	64.38
Werribee	137.93	1.36	139.29	99.00	140.69

3.6.4 Limitations of KPMG spatial analysis approach

There are a number of limitations to this approach when are summarised as follows:



- Demand growth has been assumed to be system wide across the Victorian electricity network. This does not reflect population shifts towards certain suburbs or areas. For example, a relatively undeveloped suburb today may experience significant growth and development which would have a marked difference on MD as compared to a gentrified, inner-city Melbourne suburb.
- The spatial analysis has been undertaken at the zone substation level, which does not consider the suitability of 'street-level' distribution equipment. There may be situations whereby one street has adequate infrastructure while a street located a few blocks away may be near its capacity, despite both being served by the same zone substation.
- Assumptions have been made on mapping BEVs to zone substations, as it is not possible to entirely localise EV charging to an individual charger against a relevant zone substation. Further, mapping of detailed zone substation coverage is not available to the household level. It is possible that two houses situated quite close together may be served by different zone substations.
- The actual basis of zone substation upgrades are subject to complex modelling by DNSPs that considers factors beyond a simple trigger whereby MD exceeds a capacity rating. As was noted, our analysis identifies gaps and provides an indication of particular areas in Victoria where upgrades may be required in the future.



3.7 Modelling of Hydrogen scenario

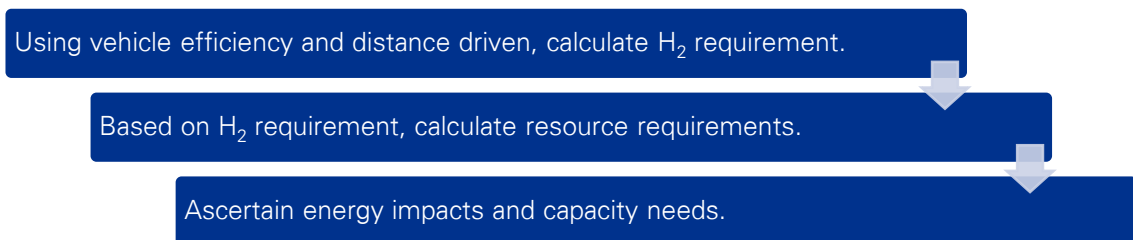
3.7.1 Modelling approach

The Hydrogen Highway scenario necessitates a different modelling approach to determine the impacts on the Victorian energy network. Given the nature of BEVs, in order to model their impacts on an energy network, it is necessary to consider load profiles, timing of charging, draw of charging infrastructure, where BEVs are charged and so on.

However, for FCVs, these are refuelled in a similar manner to current ICE vehicles. A driver would take their vehicle to a hydrogen refuelling station and the hydrogen tanks are replenished in approximately 5 minutes before a driver is back on the road. Accordingly, the energy impacts for FCVs result from the production of hydrogen, with kilometres driven influencing the level of hydrogen required. As fuelling is not dependent on a factor such as charging time, the production industry are able to make decisions around how to best supply the market to meet demand.

As a result, KPMG have undertaken a relatively basic modelling approach to consider the energy and resource impacts of a Hydrogen Highway scenario. Figure 28 below sets out the high level approach to KPMG’s modelling. The assumptions made, their rationale, and calculation steps, will be discussed in the sections that follow.

Figure 28 - Hydrogen modelling approach



3.7.2 Calculation of hydrogen requirement

KPMG have utilised a simple efficiency calculation to determine the amount of hydrogen that would be required in 2046 to support a road network of FCVs. As the production requirement is to be determined, we have used distance travelled and FCV vehicle efficiency to determine an annual hydrogen requirement, which is represented in the equation below. This output can then be utilised to determine resource requirements, and associated energy impacts.

$$H_2 \text{ required (kg)} = \frac{\sum \text{Vehicle kilometres travelled}}{\text{Assumed vehicle efficiency}}$$

Each component of this equation will be considered below. While the kilometres travelled will be a direct output of the MABM, the vehicle efficiency selected is based on assumptions given the infancy of FCVs.

Vehicle efficiency assumptions

A key input in determining energy impacts of the Hydrogen Highway scenario is to determine the level of hydrogen consumed by vehicles over a given distance. The efficiency assumption chosen will convert the kilometres travelled by FCVs in 2046 into a hydrogen requirement, for which production requirements can be calculated.



For consistency, we have split this between residential and commercial vehicles. Our methodology to classifying vehicles was discussed in Section 3.2.2 of this Report and the approach in deriving efficiency figures for these vehicle classes are discussed below.

Residential

At the current point in time, there are relatively few passenger FCVs available on the market, or historical data trends, for which efficiency assumptions could be based on. The main passenger vehicles available include the Honda Clarity FCV, the Toyota Mirai, and the Hyundai Tucson ix35 FCEV. The Hyundai Nexa will be available in late 2018 however is not yet for sale.

In determining a vehicle efficiency assumption, we have chosen to utilise the Toyota Mirai for this purpose as it currently represents the highest selling FCV on the market and has been formally rated for efficiency by the U.S. Environmental Protection Agency.

The officially quoted efficiency of the Toyota Mirai is 67 miles per gallon equivalent (MPGe)⁷¹. MPGe is a measure used in the United States that allows for the comparison of driving economy across a number of vehicle types (petrol, electric, hydrogen etc.) by converting these technologies to an equivalent petroleum economy figure. Usefully, the energy content of 1 gallon of petrol is equal to 1 kilogram of hydrogen⁷², so a quoted miles per gallon equivalent figure translates into a kilograms of hydrogen requirement.

Therefore, our vehicle efficiency assumption has been calculated pursuant to Table 31.

Table 31 – Car FCV efficiency assumption in KPMG modelling

Vehicle	MPGe	Quoted MPGe	Vehicle efficiency
2018 Toyota Mirai	1 gal petrol = 1 kg H ₂	67 mi / 107.83 km	107.83 km/kg H ₂

Commercial

As was discussed in Section 3.2.2, passenger vehicles used for commercial trips are treated the same as passenger vehicles used for residential trips. Thus, any commercial trips undertaken by passenger vehicles will use the same efficiency figure defined in Table 31.

Freight

For freight-based vehicles, there are limited examples available (and no officially assessed vehicles) to determine efficiency data from. Accordingly, we have turned to literature and research projects to determine an applicable figure. The MABM models both articulated and rigid trucks however there have been limited trials of FCV trucks in these classes. In lieu of other information, we have therefore used the range of various FCV trucks and their fuel tank size (for hydrogen) to determine an indicative average efficiency number, as set out in Table 32.

Table 32 – Freight FCV efficiency assumption in KPMG modelling

Vehicle	Range (km)	Fuel tank (kg H ₂)	Efficiency (km/kg H ₂)
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⁷¹ Toyota Motor Corporation, 2018 Mirai, https://ssl.toyota.com/mirai/assets/modules/carpageworks/Docs/MY18_Mirai_eBrochure_FuelCellTech.pdf

⁷² Kountz, E 2016, Understanding MPG and MPGe, Stanford University, <http://large.stanford.edu/courses/2016/ph240/kountz2/>



Kenworth T680 FCV ⁷³	241	30	8.05
Toyota 'Project Portal' ⁷⁴	241	40	6.04
US Hybrid FCV truck ⁷⁵	322	25	12.87
Moreland City Council FCV garbage truck ⁷⁶	275	22	12.50
Average efficiency			9.86

Distance driven

The second half of the hydrogen requirement calculation is to consider the VKT of FCVs on Victorian roads in 2046. While the vehicle efficiency factor considered above requires assumptions to be made, the VKT figure is far more straightforward.

The modelling for the Hydrogen Highway scenario will use the VKT from the MABM to determine the hydrogen requirement. The annualised VKT will be divided by the assumed vehicle efficiency to provide the total hydrogen requirement in 2046.

The VKT output from the MABM provides a typical day in a typical year, which is annualised for the purposes of our modelling. As with other aspects of the KPMG Electricity Market Model, the VKT is grossed up by an annualisation factor, which was discussed in Section 3.2.2.

3.7.3 Resource requirements

Once a hydrogen requirement has been determined, the resource usage for various technologies can be calculated and contrasted. We have chosen three different technologies for our analysis, which is consistent with our analysis of infrastructure responses:

- Electrolysis utilising electricity.
- Gasification of brown coal. We have utilised an energy efficiency conversion from black coal to provide an indicative consumption of brown coal.
- Steam methane of natural gas.

To determine the resource requirements for each technology, we have utilised models developed by the U.S. Department of Energy Hydrogen and Fuel Cells Program. These models include future projected requirements for technologies in 2020-2030, which we have used to provide a more indicative view of potential future improvements over current methods. Table 33 below sets out the chosen assumptions from these models.

Table 33 – Energy inputs for hydrogen production

Technology	Resource	Resource to produce 1kg H ₂
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⁷³ Zero-Emission Kenworth T680 Equipped with Hydrogen Fuel Cell on Display at Consumer Electronics Show, Kenworth News Releases, 9 January 2018, <https://www.kenworth.com/news/news-releases/2018/january/t680-zevt/>

⁷⁴ Secret 'Project Portal' Toyota Venture Launches Hydrogen Fuel Cell Heavy-Duty Truck, Trucks, 19 April 2017, <https://www.trucks.com/2017/04/19/toyota-project-portal-fuel-cell-truck/>

⁷⁵ US Hybrid Jumps into Hydrogen Fuel Cell Truck Arena, Trucks, 4 May 2017, <https://www.trucks.com/2017/05/04/us-hybrid-hydrogen-fuel-cell-truck/>

⁷⁶ Data provided by Stuart Nesbitt, Climate Change Technical Officer, Moreland City Council.



Electrolysis⁷⁷	Electricity, water	Electricity: 50.33 kWh Water: 15.07 L
Coal gasification⁷⁸	Coal, electricity, water	Brown coal: 11.35 kg Electricity: 2.15 kWh Water: 11.28 L
Steam methane reforming⁷⁹	Natural gas, electricity, water	Natural gas: 164.38 MJ Electricity: 1.41 kWh Water: 18.36 L

Conversion for coal gasification

The production model utilised by the U.S. Department of Energy for coal gasification is based on black coal whereas Victoria has abundant resources of brown coal. Accordingly, we have sought to model the potential resource requirements from brown coal using a conversion calculation based on respective higher heating values (HHV). The HHV that we have used for brown coal is based on information provided by the Victorian Government and reflects average properties of Victorian brown coal. This will produce a result that is more indicative of a Victorian context as it considers local resource consumption.

Our calculation to determine the production of hydrogen from brown coal is detailed in Table 34. We have used the HHVs of both black coal and brown hydrogen to calculate an efficiency adjustment based on the respective heating values of the two materials. Accordingly, our brown coal production figure reflects the increased requirement for brown coal as it is a less efficient production source.

Table 34 – Brown coal conversion

Item	Figure
Black coal HHV (taken from U.S. DoE model) (MJ/kg)	30.80
Average dried brown coal HHV ⁸⁰ (MJ/kg)	26.60
Hydrogen gravimetric HHV ⁸¹ (MJ/kg)	142.00
Black coal efficiency factor (%) (Black coal HHV ÷ H ₂ HHV)	21.69%

⁷⁷ Saur, G, Ramsden, T, James, B & Colella, W 2013, Future (2025) Hydrogen Production from Central Grid PEM Electrolysis, https://www.hydrogen.energy.gov/h2a_prod_studies.html

⁷⁸ Rutkowski, M 2008, Longer-Term (2020-2030) Hydrogen from Coal with CO₂ Capture, https://www.hydrogen.energy.gov/h2a_prod_studies.html

⁷⁹ Rutkowski, M 2012, Longer-Term (2020-2030) Hydrogen from Natural Gas with CO₂ Capture and Sequestration, https://www.hydrogen.energy.gov/h2a_prod_studies.html

⁸⁰ Coal | Earth resources, Department of Economic Development, Jobs, Transport and Resources Victoria, <http://earthresources.vic.gov.au/earth-resources/victorias-earth-resources/coal>.

⁸¹ Bossel, U & Eliasson B, Energy and the Hydrogen Economy, https://www.afdc.energy.gov/pdfs/hyd_economy_bossel_eliasson.pdf



Brown coal efficiency factor (%)	18.73%
Black coal production (kg/kg H ₂)	9.79
Efficiency adjustment	1.16
Brown coal production (kg/kg H₂)	11.35

Brown coal has a significantly higher moisture content than black coal, which requires it to be dried before use in coal gasification. For the purposes of our modelling, we have assumed that brown coal provided to a production facility has arrived dry and is ready for production. In a real-world context, consideration would need to be given to the drying process required.

Calculation of resource usage

With the various resource requirements from Table 33, the calculation of relevant resource usage is shown below:

$$\text{Resource usage} = \text{H}_2 \text{ required (kg)} \times \text{resource input} \left(\frac{x}{\text{kg}} \right)$$

To consider impacts of future technology, we will also employ a number of sensitivities to resource requirements as shown in Table 35 below. These sensitivities are based on the following:

- **Electrolysis:** The ‘weak shift’ is based upon meeting the U.S. Department of Energy’s 2020 production target for distributed electrolysis⁸² and the ‘strong shift’ is based upon achieving the theoretical electrical input minimum for electrolysis⁸³.
- **Coal gasification and steam methane reforming:** The ‘weak shift’ assumes a 10% reduction in resource requirements and the ‘strong shift’ assumes a 20% reduction in resource requirements.

Table 35 – Sensitivities within hydrogen modelling

Technology	Weak shift	Strong shift
Electrolysis	44 kWh / kg H ₂	39.4 kWh / kg H ₂
Coal gasification	10.22 kg / kg H ₂	9.08 kg / kg H ₂
Steam methane reforming	147.94 MJ / kg H ₂	131.50 MJ / kg H ₂

The requirements for coal, water and natural gas will be expressed in their respective units to provide a feel for the levels of resource that would need to be provided in a future scenario. For energy impacts, a further calculation is performed to determine the level of capacity required to support the various plant facilities.

⁸² DOE Technical Targets for Hydrogen Production from Electrolysis, Office of Energy Efficiency & Renewable Energy, United States Department of Energy, <https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-production-electrolysis>

⁸³ Bertuccioli et al 2014, Development of Water Electrolysis in the European Union Final Report, Fuel Cells and Hydrogen Joint Undertaking, Brussels.



3.7.4 Energy capacity requirements

To determine the likely required generation to meet hydrogen production requirements, we have used the same methodology as the other six scenarios. Our approach to modelling generation requirements was discussed in detail in Section 3.4.

While the other scenarios contemplate a mix of dispatchable and non-dispatchable generation required to meet BEV charging needs, for hydrogen FCVs we have assumed the required capacity could be met by non-dispatchable generation (such as wind or solar) as hydrogen can be stored after production.

3.7.5 Emissions

An important consideration in a zero emissions transport future for hydrogen is the emissions from the chosen production method. As previously discussed, FCVs produce no emissions in their running other than water, so there is no greenhouse gas issue in consumption.

However, hydrogen production methods that rely on fossil fuels produce emissions. The case studies being utilised to calculate hydrogen requirements also provide data on production emissions, which are reflected in Table 36.

For the purposes of our modelling, we have assumed that CCS technology would be mature in 2046 and thus any emissions produced have been sequestered. However, to understand the impacts, our results will still consider the emissions that were produced by the particular production method.

Table 36 – Process emissions per kilogram of hydrogen

Electrolysis	Coal gasification	Steam methane reforming
0.00 kg CO ₂ / kg H ₂	28.23 kg CO ₂ / kg H ₂	9.26 kg CO ₂ / kg H ₂

Emissions for brown coal gasification

As per Section 3.7.3, we have had to make an adjustment to consider the specific context for brown coal. To do so, we have sourced the brown coal emissions factor from the Australian Department of Environment and applied this to the HHV of Victorian brown coal to determine the kilograms of CO₂ produced for each kilogram of brown coal. We have then multiplied this by the amount of brown coal consumed in producing hydrogen to therefore arrive at the emissions produced.

Table 37 – Calculation of brown coal emissions per kilogram of hydrogen

Resource	Emission factor	Higher heating value	Coal consumed	Emissions produced
Brown coal	93.50 kg CO ₂ -e/GJ ⁸⁴	0.0266GJ/kg	11.35kg/kg H ₂	28.23kg CO₂/kg H₂

⁸⁴ National Greenhouse Accounts Factors 2015, Department of the Environment, Australian Government, Canberra, <https://www.environment.gov.au/system/files/resources/3ef30d52-d447-4911-b85c-1ad53e55dc39/files/national-greenhouse-accounts-factors-august-2015.pdf> .



Scenario modelling



4 Modelling results

This chapter discusses our results into the impacts to the energy market under the seven specified scenarios. For each scenario, we present:

- Contribution to maximum demand for a range of charging situations (i.e., incentivised or non-incentivised)
- Generation Investment requirements, both in capacity required and costs
- Impact on average emissions
- Network investment requirements, both in LRMC analysis and also spatial analysis at the impact on capacity at zone substations on the distribution network.

Given the uncertain nature of developments over the period to 2046, we also conducted a number of sensitivities to the results. These are discussed at the end of the chapter in Section 4.10.

4.1 Interpreting the results

It is important to view our results in the context of both the challenges of making of long term forecasts of energy markets over the next 30 years and also the limitations of our modelling methodology. We have approach this task as not trying to accurately predict what could happen in the future but more from understanding the impacts under the range of scenarios and what factors will drive what outcomes for the market.

The National Electricity Market (NEM) is in a state of change. The level of renewable generation is increasing, demand patterns are changing, and there is significant uncertainty about Government policy in regards to both energy and emissions. This has impacted the investment environment, as well as the ability of the electricity system to provide reliable and secure supply. There are currently a wide range of policy initiatives which seek to provide a more robust framework for the generation markets going forward.

There are also many state based policies and targets which will affect the electricity markets, including by encouraging the uptake of renewable energy over emissions intensive generation sources. At the same time, technology as it pertains to the electricity markets is developing quickly, and costs of for example renewable energy generation and energy storage is falling.

The purpose of this report is to unpack the impact of different ZEV uptake scenarios on the Victorian electricity market in 2046, including the impact on both generation and networks. state of play of the electricity markets, in particular with regards to policy and technology, is highly uncertain almost 30 years into the future (and indeed in the much shorter term as well). The results of our modelling exercise therefore need to be considered with this uncertainty in mind.

Approach to fossil fuel generation

A main uncertainty is the extent and timing of when coal fired generation exits the market and is replaced by renewable generation. There are a number of factors which will impact on this transition. The Energy Security Board has commented that based on existing plant lives, the



majority of the coal fired plants would have been retired by 2050. This aligns also with the Victorian Government announced policy of achieving a net zero emissions market by 2050.

Our approach has been to:

- In all scenarios, assume that any new generation entering the market to serve the demand will be a renewable source (i.e., battery, pumped hydro, wind or solar). This would be consistent with the objective of EV being 100% zero emissions along the supply chain and has been agreed to with Infrastructure Victoria
- Exit of fossil fuel generation based on publicly announced decommissioning date (i.e., retirement of Yallourn in 2032).⁸⁵

This means that there will be some coal and gas generation remaining in 2046 under our modelling results. As the design details of the Victorian Government 2050 zero emissions target have yet to be consulted on, it is impossible to model how this target would impact remaining fossil fuel generation over the period to 2046. It also possible that the Federal Government emissions target could change over time which will have further impacts on the relative costs of fossil fuel generation. Our modelling results is based on the assumption that capacity factors of the existing fleet of generations will remain the same over the period which in turn determines the extent of coal and gas generation output in the model.

Whilst our primary results do not reflect a significant retirement of coal fired generation in Victoria by 2046, this is a real possibility, depending on for example policy and the development of technology. We note that if and when Victoria (and the NEM) moves towards mostly – or only – zero emissions technologies, detailed analysis will be required to optimise the ratio between, and location of, intermittent renewable energy and energy storage, as well as the ratio between, and location of, wind and solar whilst maintaining the reliability of the system.

The role of alternative zero emissions technologies like solar thermal and biomass also needs to be considered in more detail. In a zero emissions situation, BEVs, both as a source of demand for electricity and a potential source of electricity storage, have an even greater potential to play a key role in the optimisation between demand (charging patterns) and supply (as a (potentially virtual) battery) both on a system wide basis and on a localised basis.

That said, our analysis shows that high uptake of BEVs creates a significant increase in electricity consumption. This may create an incentive for existing coal fired (and gas fired) generation to remain open longer than it would absent this significant consumption increase, especially in a situation where this is not a material price on carbon emissions. This would especially be the case if the charging of BEVs occurred at peak times and gas peaking plants where called on to service the demand.

In summary, the potential for fossil fuel generation to continue to operate in 2046 under these scenarios in will depend on the commercial viability and reliability of renewable sources being base load dispatchable plants (i.e. via the use of batteries and/or pumped hydro), how well the market integrate EV charging with renewable generation and the impact of government emissions policies on the costs of fossil fuel generation.

Limitations in the generation model

Further, as noted earlier in this report, the NEM is a highly complex market system with generators bidding into the market on a five minute basis. A complete simulation of the operation of the NEM involves predicting economically driven new entry and retirements of generation capacity on a half hour basis, reflecting for example forecast demand, solar PV

⁸⁵This is based on when the reserves available to power the station run out <https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station> and is consistent with AEMO approach.



uptake, government policy (e.g. carbon pricing, renewable energy targets), generator fuel prices, operational and technical performance of individual power stations, generator bidding strategies, the way electricity flows through the grid and of course economic inputs such as capital costs and capacity factors of new builds and interest rates. This type of detailed market simulation is outside the scope of this report, and the results of our modelling exercise need to be considered with this in mind as well.

Limitations in the network model

Our estimates of network costs are likely to under-estimate the full impact on transmission and distribution networks under the high penetration of BEVs. There are a number of reasons for this. The model only attempts to estimate costs associated with augmenting the network to provide more capacity to serve the extra demand. Distribution networks could be required to invest in the following additional infrastructure:

- to manage the network security impacts associated with BEVs
- communication and associated transaction based technology to help support capturing the market benefits from BEVs
- at the connection points to support fast charging of BEVs.

Further the flows across networks under BEVs scenarios could be substantially different which would undermine the use of the current LRMC estimates as a proxy of the costs of serving additional demand. It is possible that the additional demand from BEV and the nature of charging will place extra stresses on the distribution network requiring replacement of overhead cables, or subdivision of the distribution network via installation of additional distribution transformers.

Assessing impacts both in MW and MWh terms

KPMG's methodology assesses the extent to which BEVs add to maximum demand for, and total consumption of, electricity in each year until 2046 (2031 in the High Speed scenario). In the context of our modelling, the following key terms are used:

- Demand describes the electricity used at a particular time (MW). Maximum or peak demand refers to the highest amount of demand for electricity over a defined period of time.
- Capacity refers to an amount of continuous output (MW).
- Total consumption refers to the electricity used over a period of time (MWh). Total generation refers to the electricity generated over a period of time (MWh).
- "Dispatchable" refers to the ability of a generation plant to be dispatched when it is required (also called scheduled generation). "Non-dispatchable" refers to generation plant which cannot be relied upon to be available when required (e.g. wind and solar PV generation) (also called semi-scheduled generation).

In evaluating the impacts to the energy markets from BEVs, our report distinguishes between the MW effects and MWh effects. MW is effectively the measure of electricity demand on the system at any one point in time, while MWh measures the level of consumption of electricity over a defined period. The levels of the MW demand and kWh consumption will have different implications for generation and network sectors.

Both the generation and network sectors need to have sufficient capacity to serve the maximum (or peak) demand on the system – i.e. the time when demand for electricity is highest over the year. This is measured by the MW level. If there is insufficient capacity at either the network or generation levels, then a proportion of customers will not be served. Therefore the level of peak demand for each scenario will determine the level of new generation capacity and network capacity needed. Our model estimates a Contribution to Peak Demand level under the range of scenarios which then feeds into estimating the levels and costs of additional generation and network capacity required.



The MWh consumption effects will reflect the impact on the utilisation of the generation and network assets across the system i.e. how often the generation plants need to run to serve electricity consumption. It will also determine the emissions associated with total consumption.

For our generation impact estimates we present both a MW amount and MWh amount.

Our generation modelling estimates, in a simplified way and on an annual basis, the new capacity that could be required under different EV uptake scenarios, focusing on the Victorian electricity market. Our methodology also estimates the cost of any additional capacity based on current forecasts of capacity, connection and fuel costs, as well as the resulting impact on overall and average emissions. Our network modelling estimates cost associated with serving demand under those same scenarios.

If there is significant demand for electricity from BEVs during peak times, this may require additional dispatchable capacity, and investments in networks. If this same level of demand occurs outside of peak hours, and especially when a surplus of renewable generation is available, new dispatchable capacity may not be required, or additional renewable generation may be sufficient. Less network investment may also be required.

Our generation model solves firstly for the amount of dispatchable capacity that is required to meet overall peak demand in each year until the reference year. This includes dispatchable capacity to serve the contribution to peak demand of BEVs under a given scenario (zero in the Dead End scenario), as well as peak demand from other sources (as forecast by AEMO). It also reflects any shortfalls in dispatchable capacity created by the assumed retirement of existing dispatchable capacity. We refer to this amount as the “required” dispatchable capacity (MW).

Second, our model solves for any “shortfall” between total consumption and total generation of electricity (in GWh) in each year until the reference year. That is, the shortfall between the total consumption of BEVs under a given scenario (zero in the Dead End scenario), as well as any other consumption (as forecast by AEMO) and the total amount of electricity assumed to be generated⁸⁶. It also reflects any shortfall in generation created by the assumed retirement of existing generation sources. We refer to this as the “required” generation.

As detailed in chapter 3, we make a simple assumption that dispatchable capacity is met by storage (50% batteries and 50% pumped hydro), as well as any firm contribution from wind and solar PV, which are the technologies we assume are installed to meet the required generation. We refer to the actual dispatchable capacity installed – which is less than the “required” dispatchable capacity by an amount equal to the firm contribution of any new wind and solar PV – as the “installed” dispatchable capacity. We assume that 50% of the required generation is met by wind capacity at a 30% capacity factor, and that the other 50% is met by solar PV capacity at a 21% capacity factor.

⁸⁶ The amount of electricity generated by existing capacity is assumed to remain constant until 2046, less any assumed retirements.

That is, existing capacity does not ramp up or down in over the modelled period. New capacity assumed to be installed as part of the LRET and VRET schemes is assumed to be generating at the respective capacity factors of the relevant technology.



4.2 Overview of modelling results

4.2.1 Presentation of results and key findings

We have modelled a total of seven scenarios, including two permutations of Electric Avenue and Private Drive (incentivised and non-incentivised). We also present two versions of the hydrogen highway scenario – the base case, and another scenario (strong shift) where technology improvement result in FCVs becoming more efficient with hydrogen consumption decreasing by 20%.

Table 38 shows:

- total consumption of electricity by ZEVs in each scenario (in GWh⁸⁷) in 2046 (2031 for the High Speed scenario), as well as the increase on the underlying forecast electricity consumption in 2046.⁸⁸
- total dispatchable capacity installed to meet the overall maximum demand and the total non-dispatchable capacity installed to meet the total consumption of electricity.
- total cost of the installed generation capacity⁸⁹
- total cost for the distribution and transmission networks to meet increases in peak demand

The modelling estimates suggest that:

- Transition to BEVs by all vehicles will have substantial impacts on the energy markets with total costs of serving the additional demand will be substantial ranging up to \$10 bn (incremental to the dead end scenario), with the majority of cost estimated to be in the generation sector compared to the network sector.
- The need for dispatchable capacity to meet peak demand varies substantially between scenarios, and is much less in incentivised and fleet based scenarios than non-incentivised scenarios. For private ownership scenarios, the use of incentivised charging profile reduces total costs by around \$2.5bn, as charging is less concentrated in the system peak hours of 5 – 7 pm and the network peak periods.

This suggests that concentrating the significant amounts of charging required with the high levels of BEV uptakes into limited time frames – especially time frames which already experience significant electricity demand such as the early evening – requires significantly more generation capacity than when charging is spread across the day and night but outside peak hours.

- However even if charging of BEVs can be managed to occur outside peak periods, substantial investment in generation and networks will still be required to serve the additional demand. For the private drive scenario, up to 14,000 MW of new generation and storage capacity will need to be installed compared to 17,000 MW under the non-incentivised profile. 14,000 MW would more than double the amount of generation (and storage) capacity in Victoria currently existing.

⁸⁷ 1 GWh is equal to 1000 MWh

⁸⁸ AEMO's forecast consumption of electricity without BEVs.

⁸⁹ Cost estimate are presented in net present value terms at 7% real rate of return as explained in section 3.1



This is complicated by the possibility that the size of the BEV load can influence the timing of the peak periods. This issue is discussed in Section 4.2.3. In four out of seven permutations (the incentivised permutations and fleet scenarios) our modelling finds that the peak shifts to earlier in the afternoon, as there is more limited charging happening in the 5 – 7 pm window. In the earlier afternoon it is possible that the contribution of solar PV in particular is higher than it is for the early evening, meaning that less dispatchable generation may be required than our estimates.

- The costs are higher under the private ownerships scenarios for BEVs compared to the shared fleet scenarios. In the Fleet Street Scenario, total incremental cost is over \$5 bn compared to \$6.3bn under the Electric Avenue Scenario. This is driven mainly by the difference in the assumed peak demand under either scenario with the expectation that the shared fleet operator will be able to manage charging in order to avoid peak periods.

While in the Fleet Street Scenario, there is a substantial lower number of vehicles (only 256,490 vehicles which is only 7% of the vehicles needed for the Electric Avenue scenario) the total consumption of electricity is similar.⁹⁰ There are fewer cars in Fleet Street, but they drive further.

- The total consumption of electricity is between 37 and 56% higher in all permutations and scenarios which involve complete uptake of BEVs relative to the Dead End scenario (no BEVs). The total consumption in the Slow Lane scenario, which we assume involved a shared fleet for half the population only (and ICE for the other half of the population) only increases by 23%.
- In addition to conducting the permutations for incentivised charging, we also conducted sensitivities as to whether the profile of BEV charging could be sculptured in matter over the day to avoid any increase in system peak. However due to the material change in consumption under all scenarios, with the exception of Slow Lane, there is likely to be an increase in the system peak. This is discussed further in section 4.10.
- The Hydrogen Highway scenario would consume a significant amount of electricity to produce hydrogen for FCVs through electrolysis. Hence the costs under this scenario are substantially higher compared to the BEVs with over \$14bn of incremental investment – mainly in the generation sector needed. This amount decreases to \$8bn if technology advances improve the efficiency of hydrogen vehicle to reduce their consumption needs by 20%

This scenario would have a fundamental change to the energy markets and would also be a requirement for a new hydrogen supply chain to be established that would necessitate significant production and distribution infrastructure responses.

- We have also considered the impact on emissions of ZEVs. We have deliberately modelled all new capacity to be zero emissions (pumped hydro, batteries, solar and wind), consistent with the Victorian Government target of a net zero emissions grid by 2050. The average emissions per GWh consumed and MW of capacity installed falls as coal fired generation retires and more renewables are introduced into the system. For example, in 2046, renewables (hydro, wind and solar) make up 57.3% of total generation in the Electric Avenue (Incentivised) scenario, and 78.9% of total installed capacity (hydro, wind, solar, batteries and pumped hydro). This compares to 11.2% (assumed) and 31.2% respectively in 2018.
- The network costs are similarly influenced by the extent to which BEVs add to maximum demand in the DNSPs respective peak hours, and our modelling shows that the impacts to distribution networks could be up to 25% of existing RAB values under a non-incentivised

⁹⁰ 21,999 GWh in Electric Avenue (incentivised) vs 21,762 GWh in Fleet Street.



charging profile. The impacts for networks are less than generation for two primary reasons:

- a) While both the network and generation sector need to respond to provide more infrastructure to meet the impact on peak demand, the generation sector also has to respond further to provide generation capacity to serve the additional electricity consumption from BEVs. As shown in Table 40, the resulting non-dispatchable generation installed under the scenarios is substantially more than the dispatchable capacity needed to serve peak demand
- b) The relative costs impacts to the network and generation sector will depend on the extent to which there is spare capacity in the sector that can help to absorb the demand for BEV charging. As explained in chapter 3, the Victorian generation sector has currently a tight demand and supply balance.

Please note that the High Speed scenario considers an outcome as at 2031, whereas the Dead End scenario considers an outcome as at 2046. For this reason the two outcomes are not directly comparable, especially in light of the assumed Yallourn retirement in 2032 in the Dead End scenario (which results in new capacity being installed). Under the Dead End, all new capacity is installed after 2031. Therefore for the purpose of presenting the results we have assumed that all of the costs estimated for the High Speed Scenario is incremental to Dead End as at 2031.

Impact of charging infrastructure

The charging infrastructure will have a key impact on the network. An average home has a load impact of around 3 kW which means that even a level 1 charger effectively adds another home to the network when a BEV is being charged.

For our modelling, we made a highly simple assumption that residential charging is proportioned equally between Type 1 and Type 2 charging. It is highly uncertain what the proportion will be in 2046 and the impacts will be exacerbated if more customers opt for higher capacity chargers. It could reasonably be expected that given the long charging times associated with Type 1 charging, customers will opt for a faster option of Type 2 charging and absorb the extra costs. Adding a 9.5 kW charger equates to the equivalent of over 3 new homes being connected to the local network. For a superfast charger of 240 kW, this would equal to approximately 80 new homes being connected.

A UK study estimates that 32% of the low voltage feeders will require reinforcement by 2050 to cope with clustered BEV uptake. This would cost approximately £2.2 billion by 2015 based on the assumption that approximately 50% of customers have a Type 1 charger.⁹¹ These findings are supported by a recent report from the Sacramento Municipal Utility District which forecasted that BEV related overloads could necessitate replacing 17% of its transformers by 2030 at an estimated cost of USD \$89 million.⁹²

⁹¹ Electric Avenue (<http://myelectricavenue.info>) and ICF (2016): Overview of the Electric Vehicle Market and the potential of charge points for demand response.

⁹² SEPA and Black & Veatch (2017), Planning for the distributed energy future Vol II: A case study by Sacramento Municipal Utility District






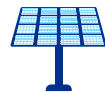
Table 38 - Summary of modelling results

	# ZEV cars in 2046	# ZEV freight in 2046	Average VKT per day per vehicle in 2046 (cars / freight)	Electricity required per day per vehicle in 2046 (cars / freight)	Total annual cons. of ZEVs in 2046	% increase from forecast without ZEVs for 2046	Dispatchable generation installed	Non-dispatchable generation installed (solar/wind)	NPV of total generation installed	NPV of distribution requirement	NPV of transmission requirement	Total NPV of generation, distribution and transmission	Incremental to Dead End case
	#	#	VKT	kWh	GWh	%	MW	MW	\$ m	\$ m	\$ m	\$ m	\$ m
Dead End	0	0	0	0	0	0%	800	0	\$319	\$190	\$79	\$588	-
Electric Avenue (Incentivised)	3,522,552	388,333	41.63 / 57.11	9.25 / 81.92	21,999	51%	3,331	9,308	\$4,918	\$1,435	\$593	\$6,946	\$6,358
Electric Avenue (Non-incentivised)							6,205		\$6,311	\$2,193	\$908	\$9,412	\$8,824
Private Drive (Incentivised)	3,752,904	384,904	46.78 / 57.11	10.4 / 81.92	24,100	56%	3,519	10,279	\$5,399	\$1,506	\$623	\$7,528	\$6,940
Private Drive (Non-incentivised)							6,719		\$6,963	\$2,370	\$983	\$10,316	\$9,728
Fleet Street	256,490	382,132	568.46 / 57.11	126.33 / 81.92	21,762	50%	1,451	9,198	\$4,159	\$1,178	\$486	\$5,823	\$5,235
High Speed	211,069	204,605	640.38 / 57.11	142.31 / 81.92	15,986	37%	0	1,636	\$1,108	\$704	\$291	\$2,103	\$2,103
Slow Lane	122,741	192,291	505.97 / 57.11	112.44 / 81.92	10,096	23%	1,121	3,808	\$1,869	\$653	\$270	\$2,792	\$2,204
Hydrogen Highway - Electrolysis base case	3,753,252	378,139	43.38 / 57.11	51.97 / 6.26	0	147%	0	28,529	\$14,843	\$190	\$79	\$15,112	\$14,524
Hydrogen Highway - Electrolysis strong shift	3,753,252	378,139	43.38 / 57.11	51.97 / 6.26	0	96%	166	18,313	\$8,372	\$190	\$79	\$8,641	\$8,053



Table 39 provides a summary of the wind and solar PV capacity installed under each scenario to meet the total consumption of electricity, given their respective assumed capacity factors (30% for wind and 21% for solar PV). The table also estimates the number of wind and solar farms associated with this total capacity, given the average size of existing and proposed wind and solar farms in Victoria. It is possible that capacity factors of wind and solar increase which would decrease the number of new plants needed.

Table 39 – Wind and solar PV capacity installed by scenario

	Wind capacity required	# Wind farms required	Solar PV capacity required	# Solar farms required
				
Dead End	0 MW	0	0 MW	0
Electric Avenue	3,833 MW	27	5,475 MW	73
Private Drive	4,232 MW	30	6,046 MW	81
Fleet Street	3,788 MW	27	5,411 MW	72
High Speed	674 MW	5	963 MW	13
Slow Lane	1,568 MW	11	2,240 MW	30
Hydrogen Highway – Electrolysis Base Case	11,747 MW	84	16,782 MW	225
Hydrogen Highway – Electrolysis Strong Shift	7,541 MW	54	10,773 MW	144

Note: Assumed average size of wind farm and solar PV farm is 140 MW and 75 MW based on existing and committed wind and solar farms in Victoria, as reported by AEMO (March 2018).

Table 41b provides a summary of the augmentation impacts for the networks sector.

Table 41b: Summary of network impact modelling estimates

	Value of transmission investment as % of existing RAB	Range of distribution investment as % of existing RAB	Number of zone substations estimated to be upgraded
Electric Avenue incentivised	18.2%	4% to 14%	41
Electric Avenue –non-incentivised	28%	6.5% to 22%	104
Private Drive incentivised	19%	5% to 15%	89
Private Drive non-incentivised	30%	8% to 24%	120
Fleet Street	15%	3% to 11.5%	76
High Speed	9%	2% to 7%	42
Slow Lane	8.3%	2% to 6.5%	51



For transmission we have modelled the average impact of having to provide additional capacity to serve the demand from BEV charging. There is likely to be other impacts for transmission through having to respond to the location choices of the new renewable generation entering the market.

Historically, large coal-fired generation plants have located near their fuel source and transmission has been built to transport power to load centres. However, renewable generation has different characteristics from coal-fired generation. First, the best locations for renewable generation are typically not located close to existing transmission networks. Second, renewable generation tends to be smaller in scale than the relatively large coal-fired plants. It is not possible to scale down transmission investment to match smaller scale generation. Attempting to model the need for changing transmission network capacity in response to potential locations of renewables generation is very complicated and outside the scope of this engagement.

Table 41b demonstrates that the impact for distribution networks will vary across DNSP area and will depend greatly on whether a) there is an incentivised charging profile and b) if the BEV fleet is privately owned or shared. As explained earlier, these figures are likely to underestimate the impacts on distribution networks as they only cover the impact on augmenting the network to meet the additional demand based on current LRMC estimates and there will be other costs impacts to distribution networks which are captured in the modelling.

4.2.2 Key influences on the modelling results

The modelling results are influenced by a range of factors, including but not limited to:

- A key assumption is that the model assumes that every vehicle is charged every day. It may be possible that some vehicles may be charged on an infrequent basis if they are not used regularly.
- New capacity may not be required if maximum demand or total consumption is reduced elsewhere in response to increasing prices, e.g. through demand-side participation (which may come at a relatively lower cost) or increased uptake of rooftop PV and storage.
- New capacity may not be located in Victoria, but in neighboring states, together with increased interconnection.
- Existing generation may be able to ramp up. Estimated generation in 2017 is expected to remain constant until 2046 in the analysis, plus new known additions (at average capacity factors) less assumed retirements. In reality, existing generation is likely to ramp up to meet increases in demand before new capacity is installed.
- A higher contribution factor for solar PV and wind to meet the maximum demand will mean less dispatchable generation is required.
- An increase in capacity factors for renewables will reduce the generation capacity that needs to be installed. Capacity factors of renewable energy are likely to increase as technology improves (but could also decrease as good resource sites are used). Capacity factors are assumed constant in the analysis.
- The system peak might shift later into the evening as rooftop solar PV take-up increases, e.g. to the hours after sunset which may coincide more with the evening charging of BEVs.
- Total cost estimates are on an NPV basis, meaning that requirements further into the future add less to the total costs in NPV terms than requirements in the near term.

Given the scope of this engagement we have not incorporated these factors into the modelling approach. However instead we consider some key sensitivities to the results in Section 4.10.



4.2.3 Potential implications for the peak under different scenarios

The overall system peak may change under certain uptake levels and charging profiles of EVs. The average maximum demand in 2018 to date (until end of April), and the maximum demand on the highest demand day of 2018, suggested a current peak of around 5 to 7 pm in the evening. Thus, our analysis has analysed the extent to which EVs under different scenarios add to demand in the window of 5 to 7 pm. Of course, it is not possible to know exactly how this profile will change between 2018 and 2046 (or 2031). It is possible that the peak will shift later into the evening with additional uptake of rooftop solar, when the contribution from rooftop solar falls but temperatures are still high.

Figure 29 and Figure 30 below illustrate if and how the overall system peak changes using a 2046 (2031) load profile estimated based on AEMO’s maximum demand estimate for 2046 (10,240 MW in the neutral scenario) and the shape of the load profile on the maximum day in 2018 (until end of April).

In four out of seven permutations (the incentivised permutations and fleet scenarios) the peak shifts to earlier in the afternoon, as there is more limited charging happening in the 5 – 7 pm window. In the earlier afternoon it is possible that the contribution of solar PV in particular is higher than it is for the early evening, meaning that less dispatchable generation may be required than if the peak occurred when the contribution of solar was more limited. In two scenarios (the non-incentivised scenarios), the peak remains in the 5 – 7 pm window. In the High Speed scenario the peak shifts until later in the evening.

Further information and graphs for the remaining scenarios not covered in Figure 29 and Figure 30 are provided in Appendix A.

Figure 29 - Electric Avenue (Incentivised) (Darker columns represent current peak period)

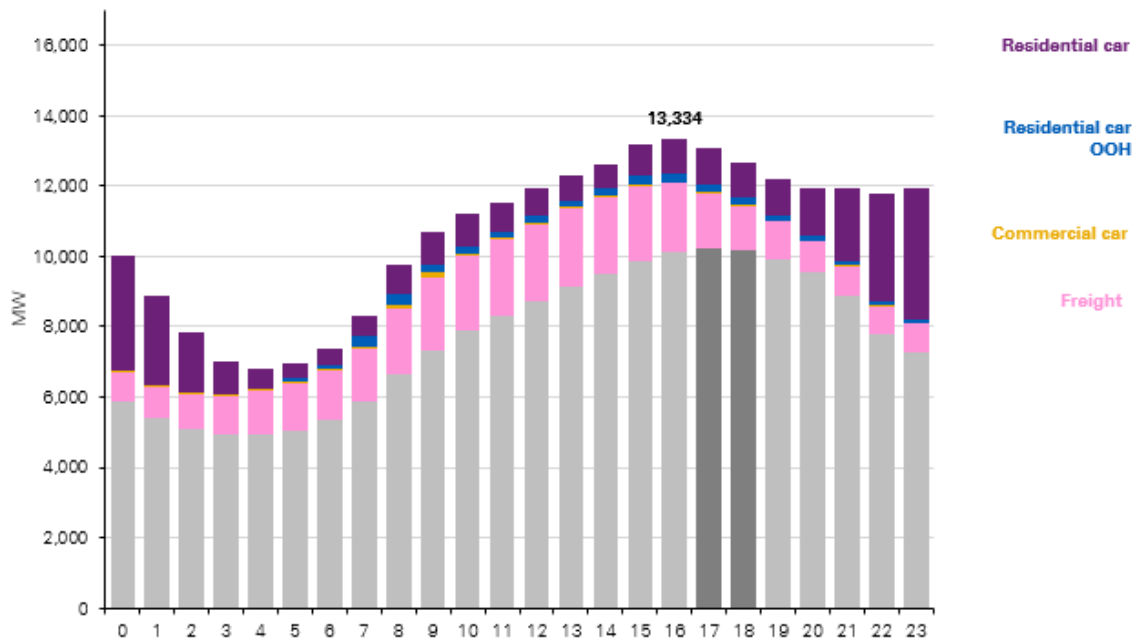
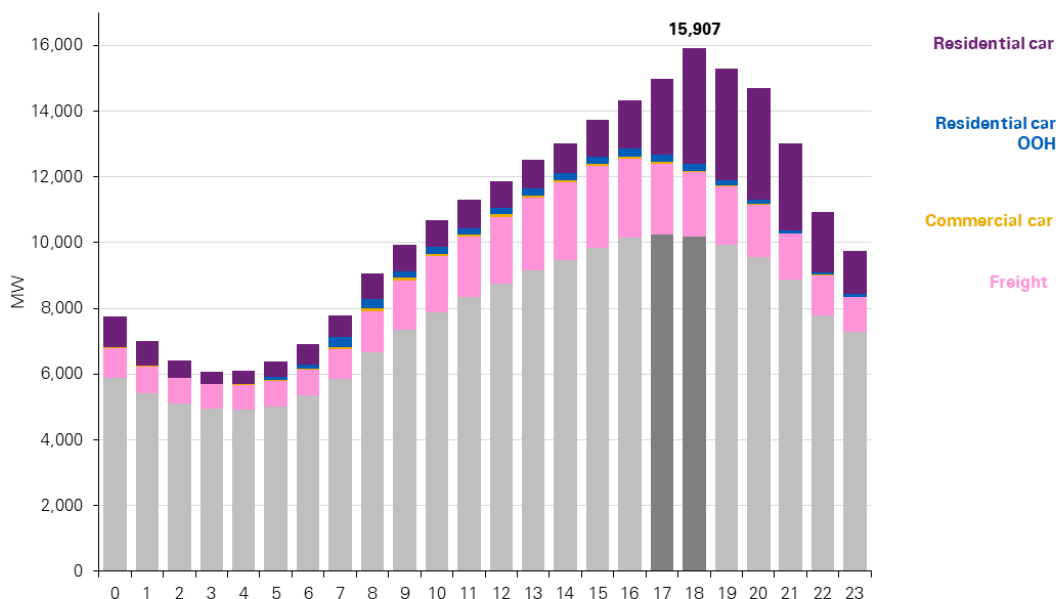




Figure 30 - Electric Avenue (Non-incentivised)



4.3 Scenario: Dead End

4.3.1 Scenario description

In the Dead End scenario, the entire fleet consists of traditional vehicles which are privately owned. That is, none of the vehicles are electric vehicles.

4.3.2 Energy consumption requirements

In the Dead End scenario, in 2046, there are no BEVs adding to total electricity consumption or to the maximum demand. However, additional generation and network investments are still required to meet the total consumption and maximum demand from sources other than BEVs, and to accommodate the assumed retirement of Yallourn in 2032.

4.3.3 Generation investment requirements

In the Dead End scenario BEVs do not add to maximum demand (as there are no BEVs), however a total of 800 MW of dispatchable capacity is required to accommodate the assumed retirement of Yallourn in 2032 as well as increases in maximum demand due to other sources. We assume that this increase in maximum demand will be met by a combination of batteries and pumped hydro (zero emissions technologies), as well as by any “firm” capacity contributed by wind and solar PV installed to meet the total consumption of electricity.

As the total annual consumption of electricity is expected to remain flat without BEVs, and the total generation added by committed projects and the assumed LRET and VRET capacity outweighs the reduction in generation due to the retirement of Yallourn, there is no generation shortfall in the Dead End scenario. The dispatchable and non-dispatchable generation capacity required in the Dead End scenario is illustrated in Figure 31.



Figure 31 - Dead End, generation investment requirements

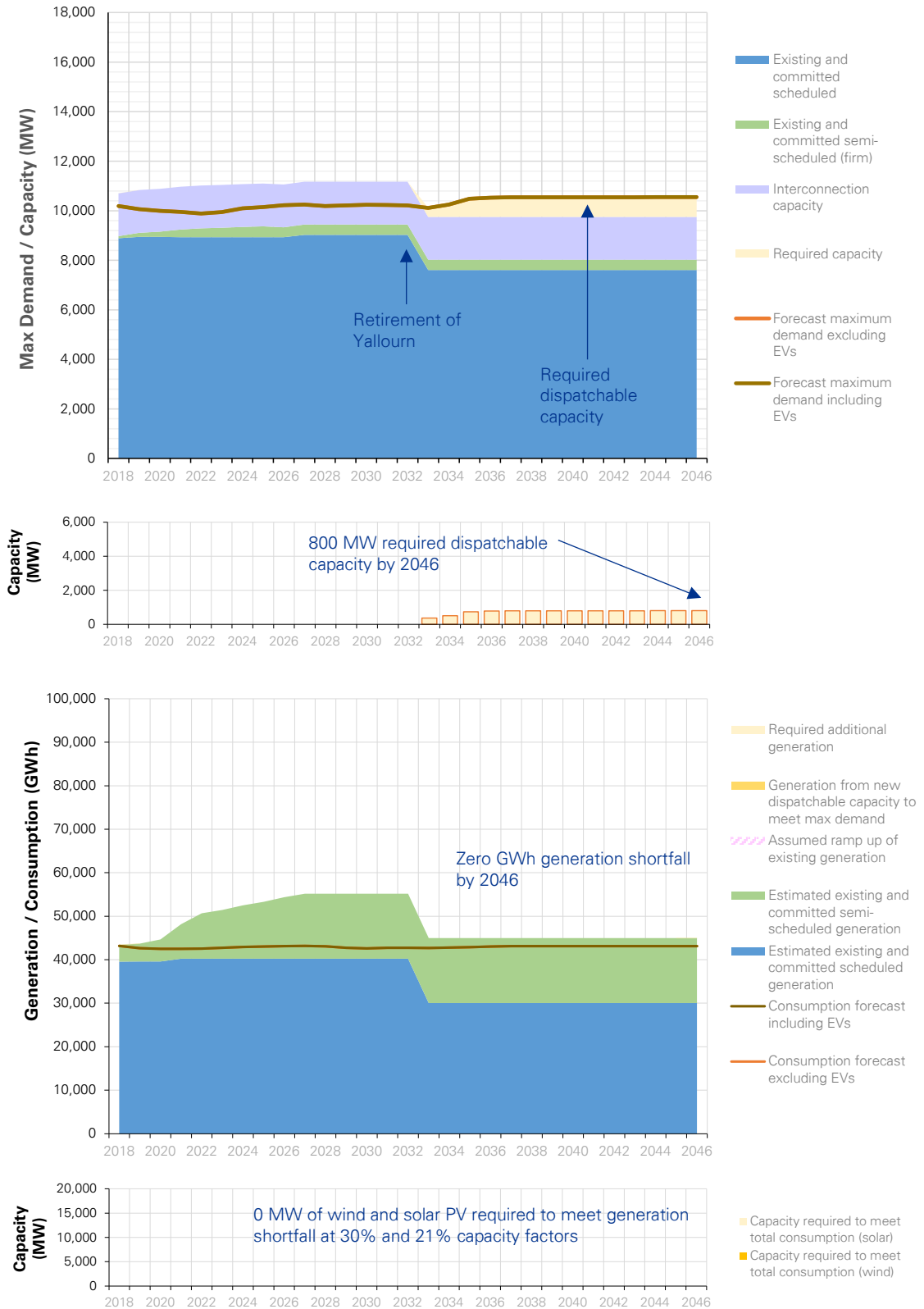




Table 40 summarises the total cost in net present value terms (at 7% real weighted average cost of capital) of new capacity (capital and connection costs only, not ongoing operating expenses) installed when required.

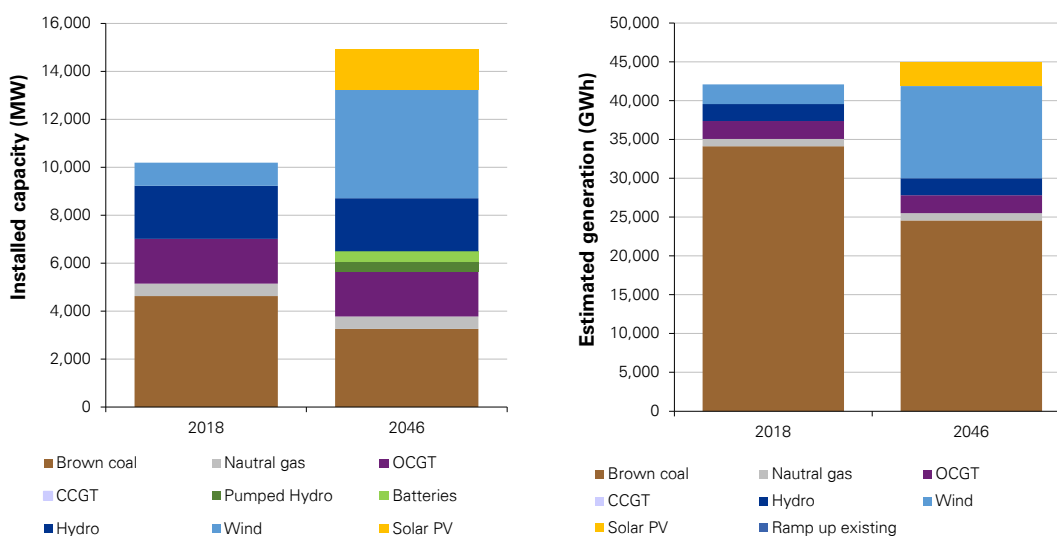
These results assume no further retirements are made beyond Yallourn in 2032 (irrespective of the age of existing generation sources). Further, it reflects no reduction in maximum demand (through for example increased demand side participation) in response to a constrained capacity situation, which may occur before the instalment of new capacity. We consider some sensitivities to these assumptions in Section 4.10, specific to the Electric Avenue scenario.

Table 40 - Dead End, total cost of installed capacity

	Dispatchable capacity installed	Total cost (NPV): Dispatchable capacity	Non-dispatchable capacity installed	Total cost (NPV): Non-dispatchable capacity	Total cost (NPV): All capacity	Total cost (NPV): Incremental to dead end scenario
Dead End	800 MW	319 m	0 MW	0 m	319 m	-

The installed capacity and generation mix resulting in the Dead End scenario is illustrated in Figure 32. The additional wind and solar PV capacity in 2046 is due to committed projects and the capacity associated with the LRET and VRET schemes. The additional storage capacity (light and dark green) is to serve the 800 MW of additional maximum demand under the Dead End Scenario.

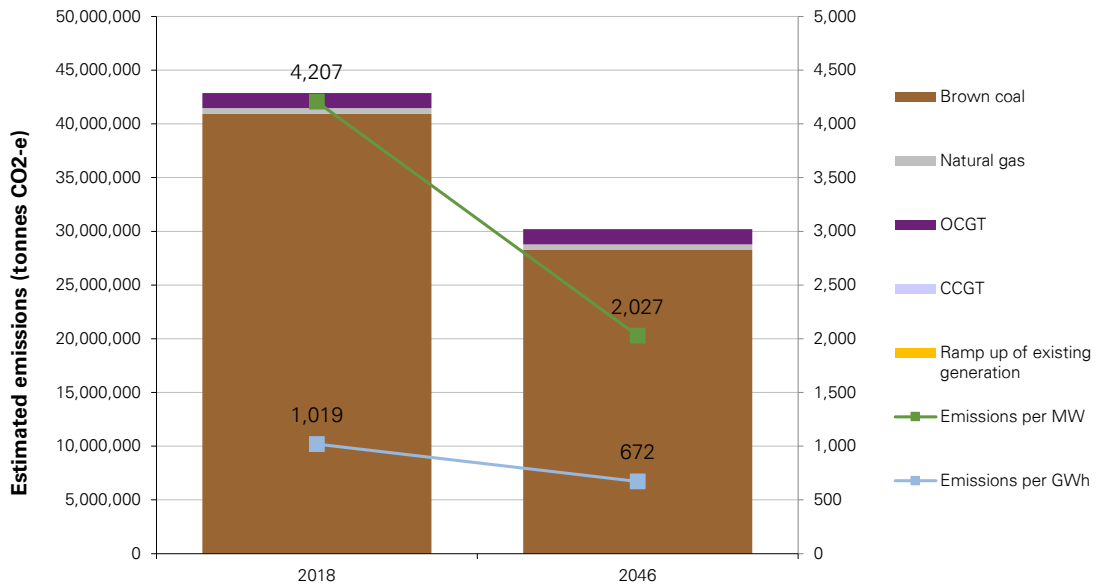
Figure 32 - Dead End, capacity and generation mix



The new capacity and generation mix in 2046 is associated with no more emissions than in 2018, as all new capacity is assumed to be zero emissions (pumped hydro, batteries, wind and solar PV). However, the average emissions (tonnes CO₂-e) per MW and GWh falls as maximum demand increases and as coal fired generation (Yallourn) retires. This is illustrated in Figure 33.



Figure 33 - Dead End, average emissions



4.3.4 Network investment requirements

AEMO’s maximum demand forecast excluding BEVs increases by 512 MW between 2018 and 2046 (see Figure 16). We have assumed that this will affect all five distribution networks, in proportion to the number of cars in each network area. Table 41 summarises the total MW required to meet the increase in MW by distribution network. As there are no EVs in this scenario, the requirement to service EVs is zero.

As can be seen in Table 41 below, CitiPower is expected to experience the lowest network investment requirement at 30 MW. This is followed by Jemena with 72 MW, United Energy with 100 MW, AusNet with 137 MW and Powercor with 175 MW.

At the LRMC per MW per year for distribution and transmission for each network the total cost in net present value terms (at 7% real weighted average cost of capital) to accommodate this increase by 2046 is \$190 million and \$79 million respectively.

Table 41 - Dead End, impact on network demand

	Dead End (MW)	BEV (MW)	Total (MW)	Share	Total (MW)
AusNet	512	0	512	26.7%	137
CitiPower	512	0	512	5.8%	30
Jemena	512	0	512	14.0%	72
Powercor	512	0	512	34.1%	175
United Energy	512	0	512	19.5%	100



4.4 Scenario: Electric Avenue

4.4.1 Scenario description

In the Electric Avenue scenario, in 2046, the fleet is entirely composed of privately owned, not automated, electric vehicles. Table 42 provides a summary of the key assumptions in the Electric Avenue scenario.

Table 42 - Electric Avenue Assumptions Summary

Description		Assumption
Number of vehicles	#	3,910,885
Total annual BEV consumption	GWh	21,999
Number of cars	#	3,522,552
Average VKT per day	km	41.63
Efficiency per 100 km	kWh	20
Network and charging losses	%	10%
Required electricity per day	kWh	9.25
Annual consumption of cars (factor 341.6)	GWh	11,131
% cars charged at home	%	10%
Chargers at home		50/50 Type 1 (3 kW) and 2 (9.5 kW)
Chargers out of home		Type 3 (240 kW)
Number of freight vehicles	#	388,333
Average VKT per day	km	57.11
Efficiency per 100 km	kWh	129.11
Network and charging losses	%	10%
Required electricity per day	kWh	81.92
Annual consumption of freight	GWh	10,867
Freight vehicle charger		Type 2 (9.5 kW)

4.4.2 Contribution to maximum demand

We have considered two permutations under the Electric Avenue scenario, reflecting an “incentivised” and a “non-incentivised” charging profile. The incentivised profile is illustrated in Figure 34. The non-incentivised load profile is illustrated in Figure 35. The non-incentivised profile concentrates demand (electricity used at a particular time) to the evening peak in Victoria, which is around 5 to 7 pm. The incentivised profile has more limited demand in this same window of time.



Figure 34 – Electric Avenue load profile (incentivised)

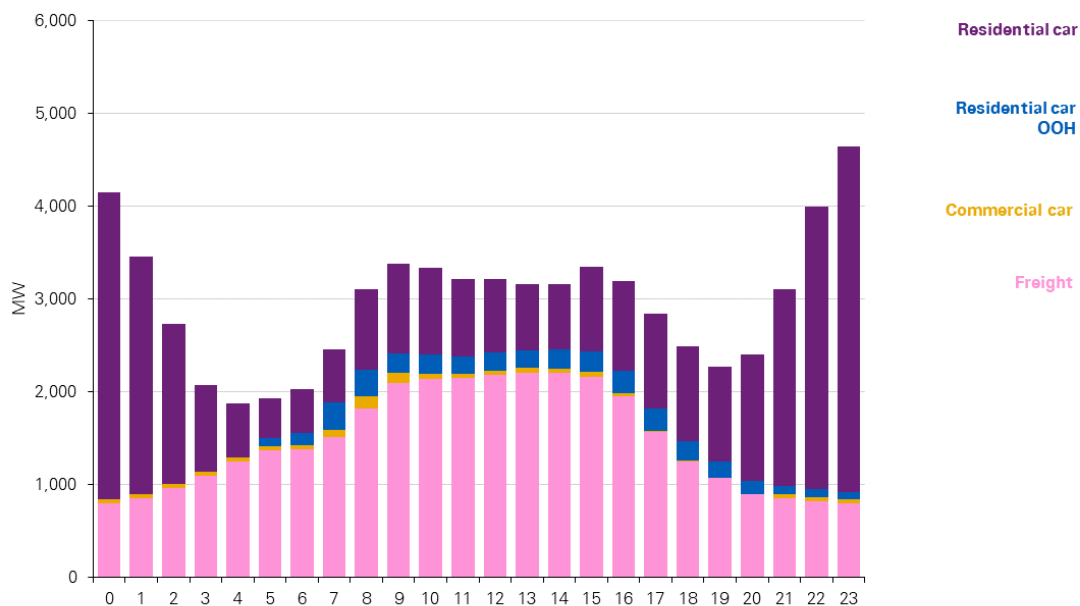
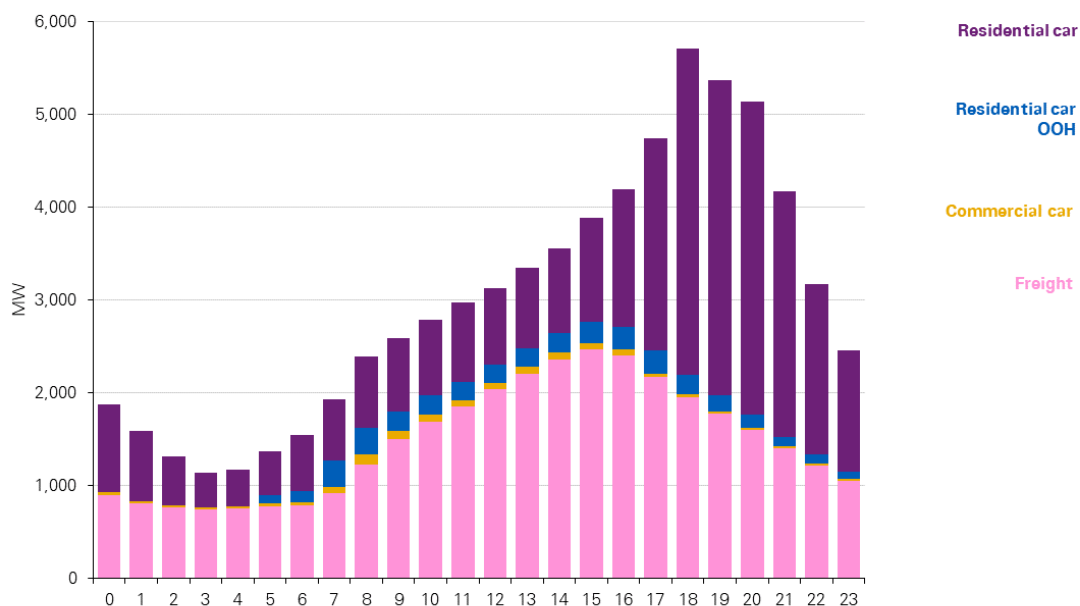


Figure 35 - Electric Avenue load profile (non-incentivised)



4.4.3 Generation investment requirements

In the Electric Avenue – Incentivised scenario, BEVs add a total of 2,841 MW to maximum demand during peak hours. In the Electric Avenue – Non-Incentivised scenario, EVs add a total of 5,716 MW to maximum demand during peak hours.

In the incentivised scenario, a total of 3,641 MW of dispatchable capacity is required to meet both the demand from BEVs and other sources (that is, 2,841 MW from BEVs and 800 MW



from other sources, as discussed in the Dead End scenario). In the non-incentivised scenario, a total of 6,516 MW of additional dispatchable capacity is required to meet all demand. We assume that this is met by a combination of batteries and pumped hydro (zero emissions technologies), as well as by any firm capacity from wind and solar PV installed to meet the total consumption of electricity.

As noted in Table 42, the total consumption of electricity by BEVs in 2046 is estimated as 21,999 GWh. This total consumption requirement is the same regardless of the charging profile. If we assume that the total generation (GWh) of electricity remains constant from its 2017 levels, plus committed capacity and assumed LRET and VRET capacity at average capacity factors, less the assumed retirement of Yallourn in 2032, then there is an 20,144 GWh shortfall of generation in 2046 (noting that storage technologies to meet maximum demand do not in and of themselves add to total generation). This equates to 3,833 MW of wind capacity and 5,475 MW of solar PV capacity at 30% and 21% capacity factors respectively. This is approximately 27 wind farms at the current average size of existing and committed wind farms in Victoria (140 MW), and 73 solar farms at the average size of committed solar PV farms in Victoria (75 MW).

The dispatchable and non-dispatchable capacity required is illustrated in Figure 36 and Figure 37 for the incentivised and non-incentivised scenarios respectively.



Figure 36 – Electric Avenue – Incentivised, generation investment requirements

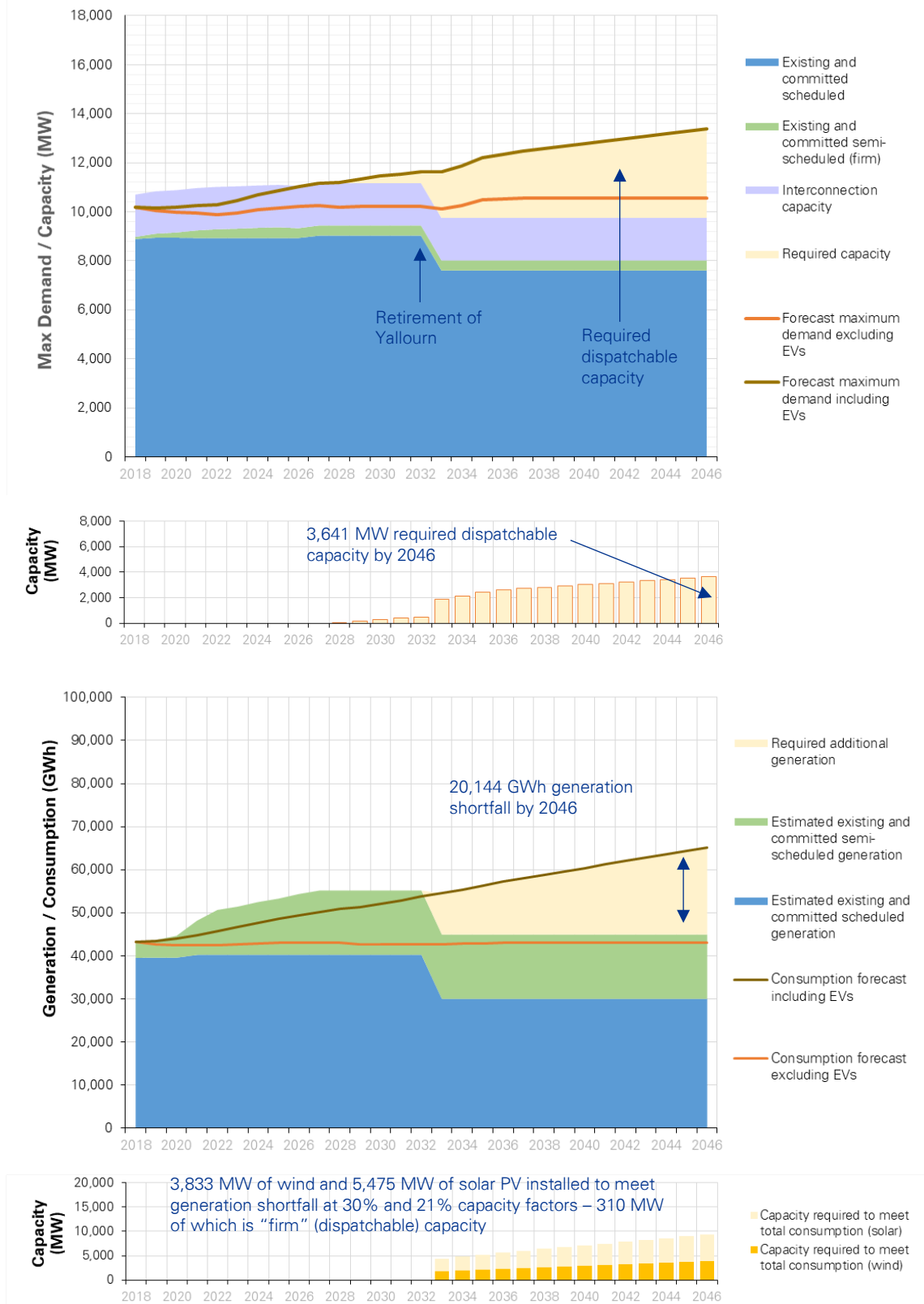




Figure 37 – Electric Avenue – Non-incentivised, generation investment requirements

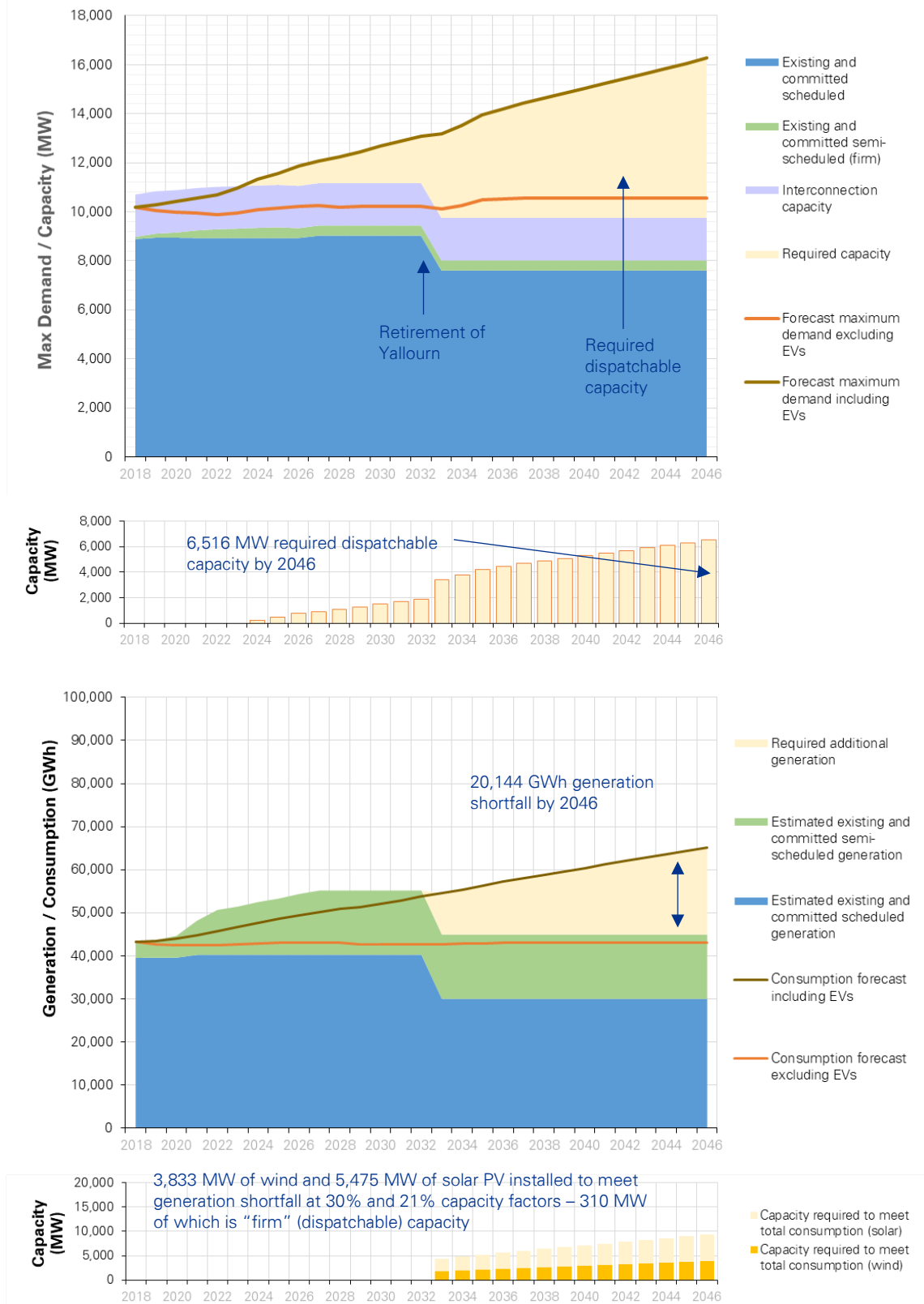




Table 43 summarises the total cost in net present value terms (at 7% real weighted average cost of capital) of new capacity (capital and connection costs only, not ongoing operating expenses) installed when required, as illustrated in Figure 36 and Figure 37 respectively. Note that the dispatchable capacity installed of 3,331 MW (incentivised permutation) reflects the dispatchable capacity “required” (i.e. 2,841 MW from BEVs and 800 MW from the Dead End scenario), less the “firm” peak contribution of the new non-dispatchable capacity installed (310 MW⁹³).

These results assume that no existing capacity ramps up generation to meet the additional consumption of electricity, and that no further retirements are made beyond Yallourn in 2032 (irrespective of the age of existing generation sources). Further, it reflects no reduction in either maximum demand (through for example increased demand side participation) or total consumption (through for example investments in energy efficiency) in response to a constrained supply situation, either or both of which may occur before the instalment of new capacity. We consider some sensitivities to these assumptions in Section 4.10.

Table 43 - Electric Avenue, total cost of installed capacity

	Dispatchable capacity installed	Total cost (NPV): Dispatchable capacity	Non-dispatchable capacity installed	Total cost (NPV): Non-dispatchable capacity	Total cost (NPV): All capacity	Total cost (NPV): Incremental to dead end scenario
Dead End	800 MW	319 m	0 MW	0 m	319 m	
Electric Avenue - Incentivised	3,331 MW	1,257 m	9,308 MW	3,660 m	4,918 m	4,598 m
Electric Avenue - Non-Incentivised	6,205 MW	2,650 m			6,311 m	5,991 m

The installed capacity and generation mix resulting in the Electric Avenue – Incentivised scenario is illustrated in Figure 38. The installed capacity and generation mix resulting in the Electric Avenue – Non-Incentivised scenario is illustrated in Figure 39. A comparison of the two figures reveals that the non-incentivised scenario involves additional storage capacity (light and dark green) to accommodate the additional maximum demand resulting from demand being concentrated in peak hours.

⁹³ Calculated as 3,833 MW of wind multiplied by the “firm” contribution factor of 8.1%, please see chapter 3 for more detail.



Figure 38 – Electric Avenue – Incentivised, capacity and generation mix

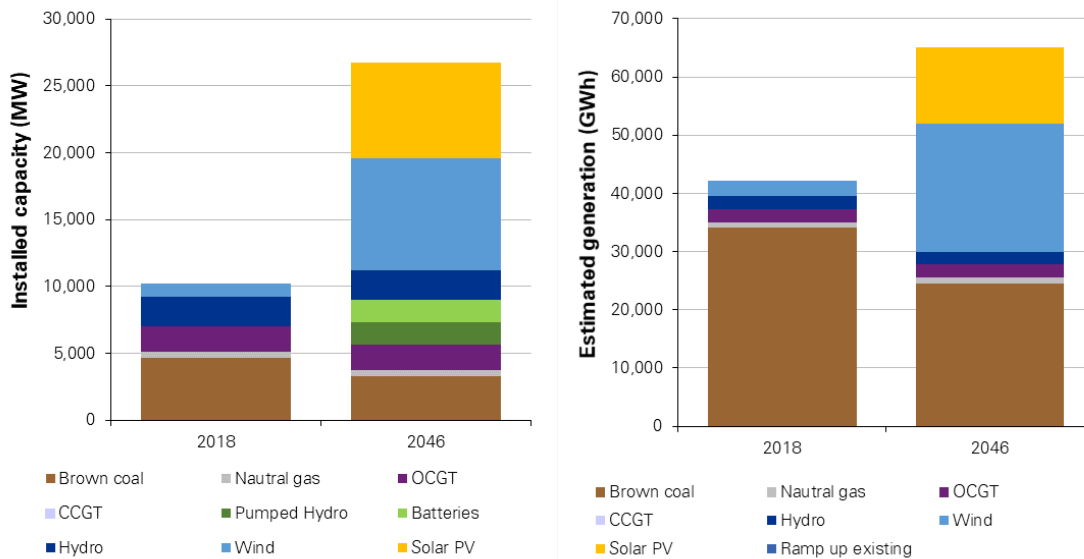
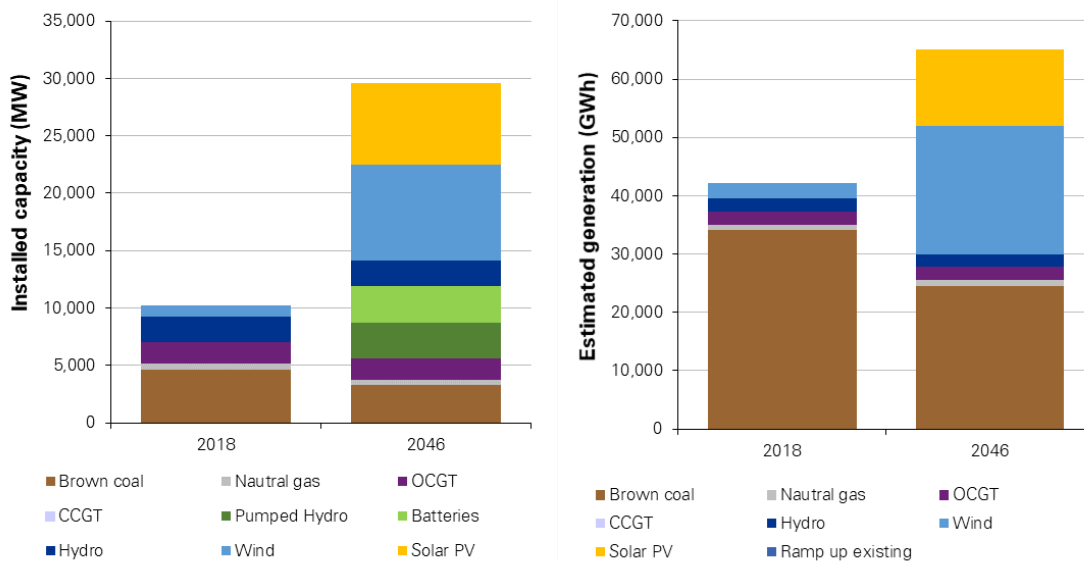


Figure 39 – Electric Avenue, non-incentivised, capacity and generation mix



The new capacity and generation mix in 2046 is associated with no more emissions than in 2018, as all new capacity is assumed to be zero emissions (pumped hydro, batteries, wind and solar PV). However, the average emissions (tonnes CO₂-e) per MW and GWh respectively fall as demand and consumption of electricity increases. This is illustrated for the incentivised and non-incentivised scenario in Figure 40 and Figure 41 respectively. The average emissions per MW is slightly lower in the non-incentivised case as a result of additional capacity being installed to meet a higher maximum demand than in the incentivised scenario.



Figure 40 – Electric Avenue, incentivised, average emissions

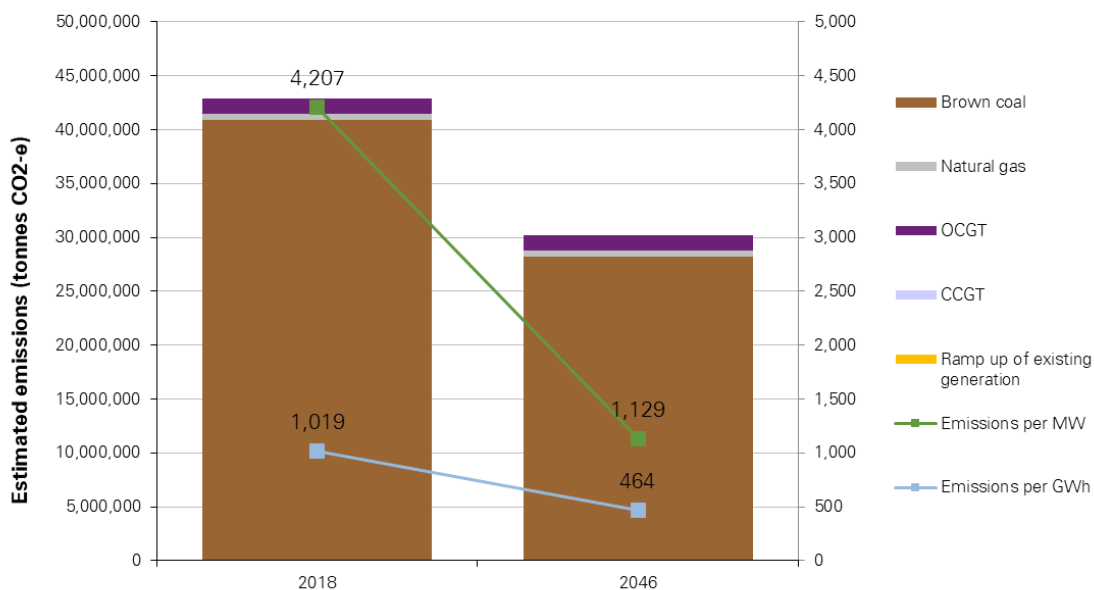
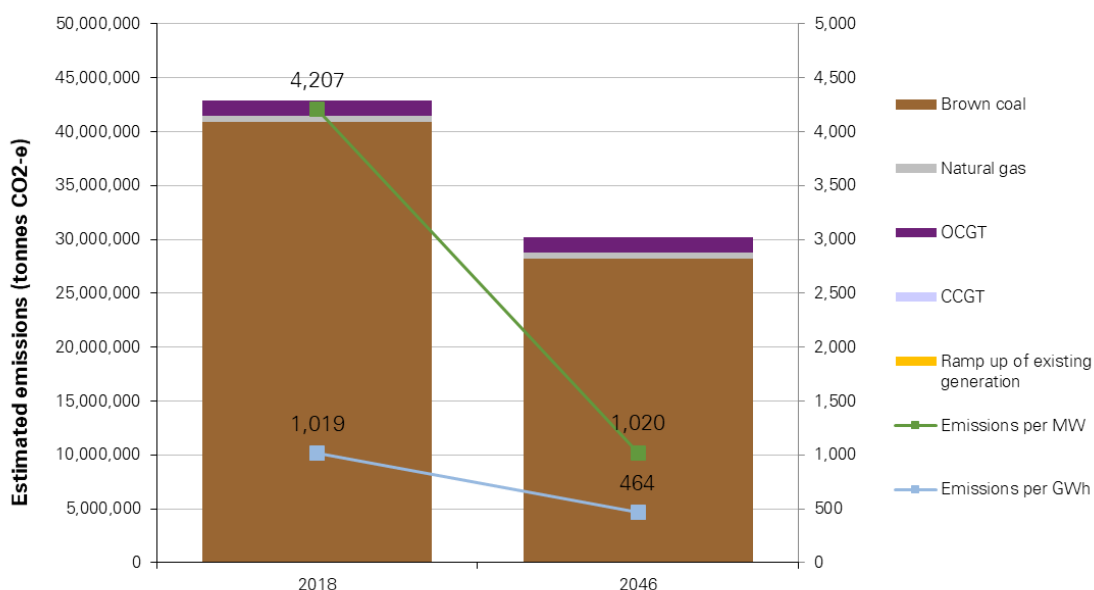


Figure 41 – Electric Avenue, non-incentivised, average emissions



4.4.4 Network investment requirements

Long run marginal cost analysis

AEMO’s maximum demand forecast excluding BEVs increases by 512 MW between 2018 and 2046 (see Figure 16). We have assumed that this increase in maximum demand will affect all five distribution networks, in proportion to the number of cars assumed to be in each network area.



BEVs add different amounts to maximum demand in different networks, depending on the peak hours in a particular network and the relative share of the network in terms of BEVs. Table 44 and Table 45 summarise the impact on the network in terms of additional maximum demand by 2046 under the incentivised and non-incentivised scenarios respectively.

At the LRMC per MW per year for distribution and transmission for each network the total cost in net present value terms (at 7% real weighted average cost of capital) to accommodate this increase is \$1,435 million for distribution and \$593 million for transmission in the incentivised scenario and \$2,193 million for distribution and \$908 million for transmission in the non-incentivised scenario.

Table 44 - Electric Avenue, incentivised, impact on network demand

	Dead End (MW)	EV (MW)	Total (MW)	Share	Total (MW)
AusNet	512	3,349	3,861	26.6%	1,029
CitiPower	512	3,349	3,861	5.8%	226
Jemena	512	3,349	3,861	14.0%	539
Powercor	512	3,349	3,861	34.1%	1,315
UE	512	3,349	3,861	19.5%	752

As demonstrated in Table 44 above, under the incentivised Electric Avenue scenario, CitiPower is expected to experience the lowest network investment requirement at 226 MW. This is followed by Jemena with 539 MW, United Energy with 752 MW, AusNet with 1,029 MW and Powercor with 1,315 MW.

Table 45 - Electric Avenue, non-incentivised, impact on network demand

	Dead End (MW)	EV (MW)	Total (MW)	Share	Total (MW)
AusNet	512	4,738	5,251	26.6%	1,399
CitiPower	512	4,738	5,251	5.8%	307
Jemena	512	5,716	6,228	14.0%	870
Powercor	512	5,716	6,228	34.1%	2,122
UE	512	5,716	6,228	19.5%	1,214

As demonstrated in Table 45 above, the non-incentivised scenario has a significantly larger impact on network demand across all DNSPs. Once again, CitiPower is estimated to require the lowest additional investment, at 307 MW. Followed by Jemena increasing to 870 MW, United Energy to 1,214 MW, AusNet to 1,399 MW and Powercor increasing to 2,122 MW.

Spatial analysis

Spatial analysis has considered each DNSP's zone substations, their expected maximum demand in 2046, and whether their expected maximum demand exceeds current rated capacity by 0%-10% (low exceedance) or 10%+ (high exceedance).

As demonstrated in Table 46 and Figure 42, under the incentivised Electric Avenue scenario, of AusNet's 52 substations, 16 are expected to be in low exceedance, with 12 in high exceedance. Citipower should expect four of their 37 substations to be in low exceedance, with a further two in high exceedance. Three of Jemena's 30 substations are expected to be in low exceedance, with nine in high exceedance. 13 of Powercor's total 58 substations are expected to be in low exceedance, with a further 22 in high exceedance. United Energy can



expect five of their substations to be in low exceedance, with no substations with an exceedance greater than 10%.

Table 46 - Electric Avenue – incentivised, projected capacity minus rated capacity by DNSP

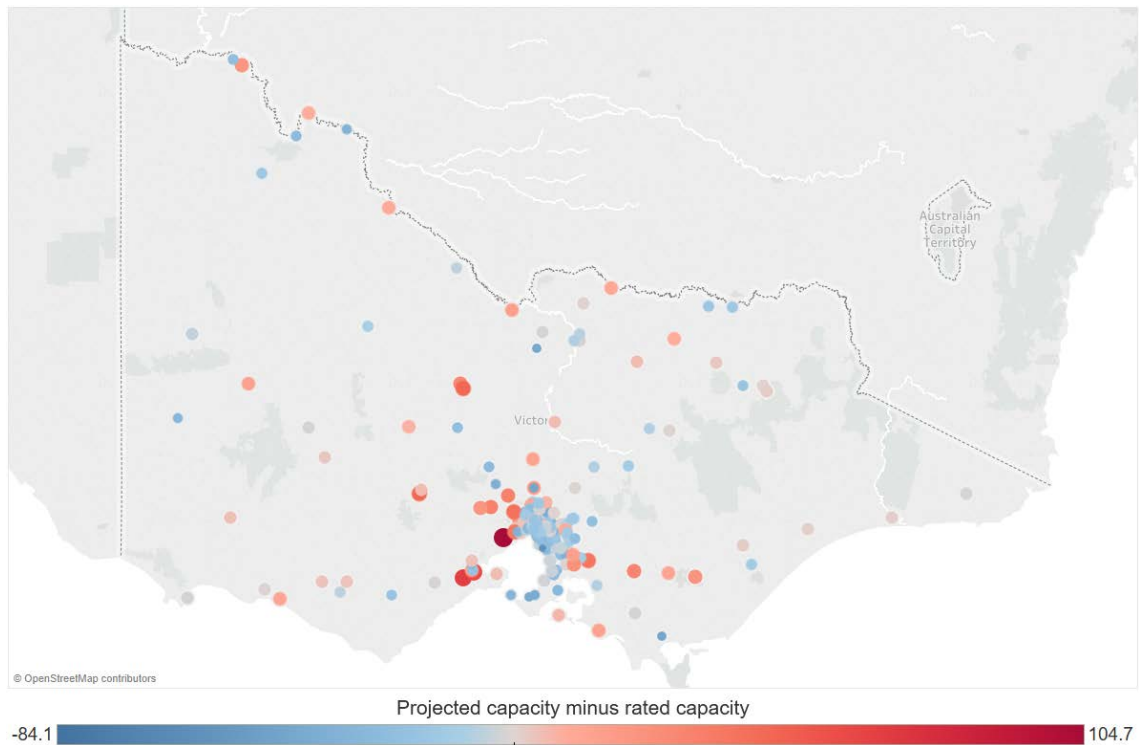
	AusNet	Citipower	Jemena	Powercor	United
# zone substations (ZS)	52	37	30	58	47
#ZS projected MD < current rated capacity	24	31	18	23	42
#ZS projected MD > current rated capacity (exceedance 0%-10%)	16	4	3	13	5
#ZS projected MD > current rated capacity (exceedance 10%+)	12	2	9	22	0

Table 47 - Electric Avenue – incentivised, location of top five zone substations where gap between MD and current capacity is greatest by DNSP

	AusNet	Citipower	Jemena	Powercor	United
	Pakenham	Kew	Thomastown	Werribee	Mornington
Location of top five zone substations where gap between MD and current capacity is greatest	Warragul	Prahran	Sydenham	Waurm Ponds	Carrum
	Traralgon	Riversdale	Sunbury	Geelong East	Burwood
	Clyde North	Richmond	Watsonia	Ballarat South	Frankston
	Kilmore South	Brunswick	Preston	Bendigo	Dandenong



Figure 42 - Electric Avenue – incentivised, projected capacity minus rated capacity by zone substation



As demonstrated in Table 48 and Figure 43, these figures increase substantially under the non-incentivised scenario. AusNet should expect 14 of their 52 substations to be in low exceedance, with 20 expecting demand to exceed capacity by greater than 10%. Citipower can expect four of their 37 substations to exceed capacity in low range, with a further four subject high exceedance. Of Jemena’s 30 zone substations, seven are expected to have maximum demand in low exceedance, with 11 of these being in high exceedance. Powercor can expect 10 of their 58 substations in low exceedance of current capacity, with 29 of these in high exceedance, while United Energy expects eight of their 47 substations in low exceedance with seven being in high exceedance, up from zero under the incentivised scenario.

Table 48 - Electric Avenue – non-incentivised, projected capacity minus rated capacity by DNSP

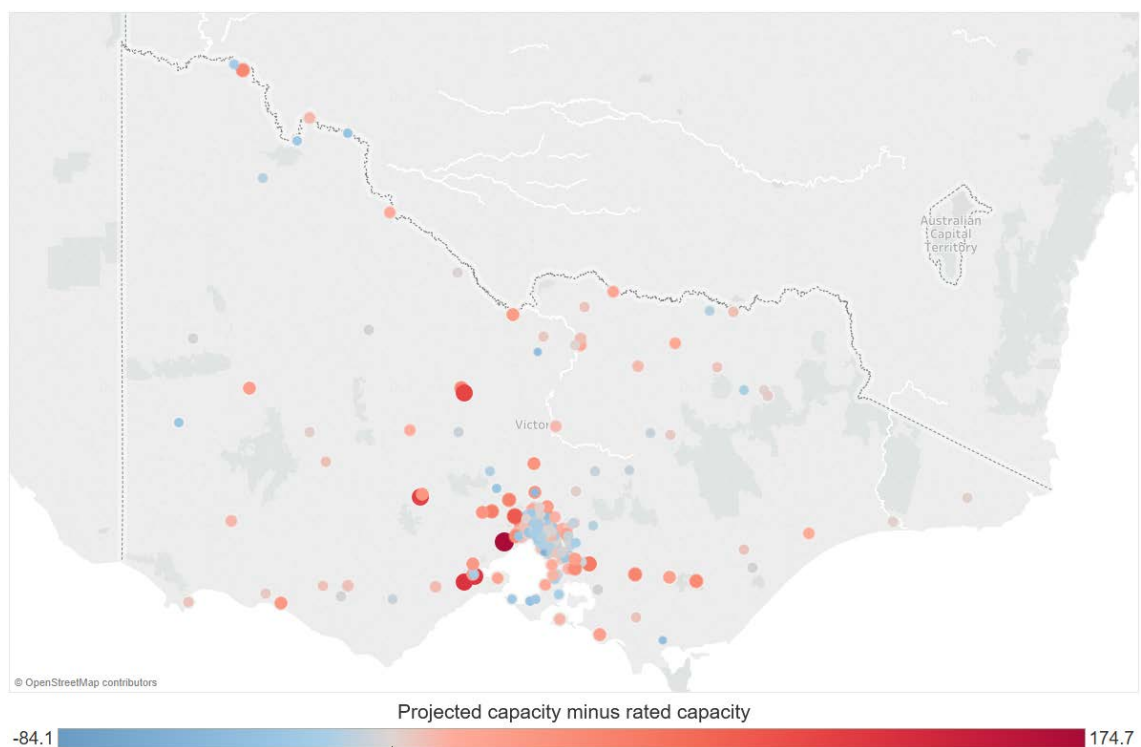
	AusNet	Citipower	Jemena	Powercor	United
# zone substations (ZS)	52	37	30	58	47
#ZS projected MD < current rated capacity	18	29	12	19	32
#ZS projected MD > current rated capacity (exceedance 0%-10%)	14	4	7	10	8
#ZS projected MD > current rated capacity (exceedance 10%+)	20	4	11	29	7



Table 49 - Electric Avenue – non-incentivised, location of top five zone substations where gap between MD and current capacity is greatest by DNSP

	AusNet	Citipower	Jemena	Powercor	United
	Pakenham	Kew	Sydenham	Werribee	Mornington
Location of top five zone substations where gap between MD and current capacity is greatest	Warragul	Prahran	Thomastown	Waurm Ponds	Carrum
	Traralgon	Riversdale	Sunbury	Geelong East	Nunawading
	Clyde North	Richmond	Watsonia	Ballarat South	Frankston
	Kilmore South	Brunswick	Preston	Bendigo	Burwood

Figure 43 - Electric Avenue – non-incentivised, projected capacity minus rated capacity by zone substation



4.5 Scenario: Private Drive

4.5.1 Scenario description

In the Private Drive scenario, in 2046, the fleet is entirely composed of privately owned and automated electric vehicles. Table 50 provides a summary of the key assumptions in the



Private Drive scenario. As noted in Section 3.2.1, based on input from Infrastructure Victoria, our results are based on the “empty running” permutation of the Private Drive scenario as modelled by MABM.

Table 50 - Private Drive Assumptions Summary

Description		Assumption
Number of vehicles	#	4,137,808
Total annual BEV consumption	GWh	24,100
Number of cars	#	3,752,904
Average VKT per day	km	46.78
Efficiency per 100 km	kWh	20
Network and charging losses	%	10%
Required electricity per day	kWh	10.40
Annual consumption of cars	GWh	13,328
% cars charged at home	%	10%
Chargers at home		50/50 Type 1 (3 kW) and 2 (9.5 kW)
Chargers out of home		Type 3 (240 kW)
Number of freight vehicles	#	384,904
Average VKT per day	km	57.11
Efficiency per 100 km	kWh	129.11
Network and charging losses	%	10%
Required electricity per day	kWh	81.92
Annual consumption of freight	GWh	10,771
Freight vehicle charger		Type 2 (9.5 kW)

4.5.2 Contribution to maximum demand

We have considered two permutations under the Private Drive scenario, reflecting an “incentivised” and a “non-incentivised” charging profile. The incentivised profile is illustrated in Figure 44. The non-incentivised load profile is illustrated in Figure 48. The non-incentivised profile concentrates demand (electricity used at a particular time) to the evening peak in Victoria, which is around 5 to 7 pm. The incentivised profile has more limited demand in the same time window.



Figure 44– Private Drive load profile – incentivised

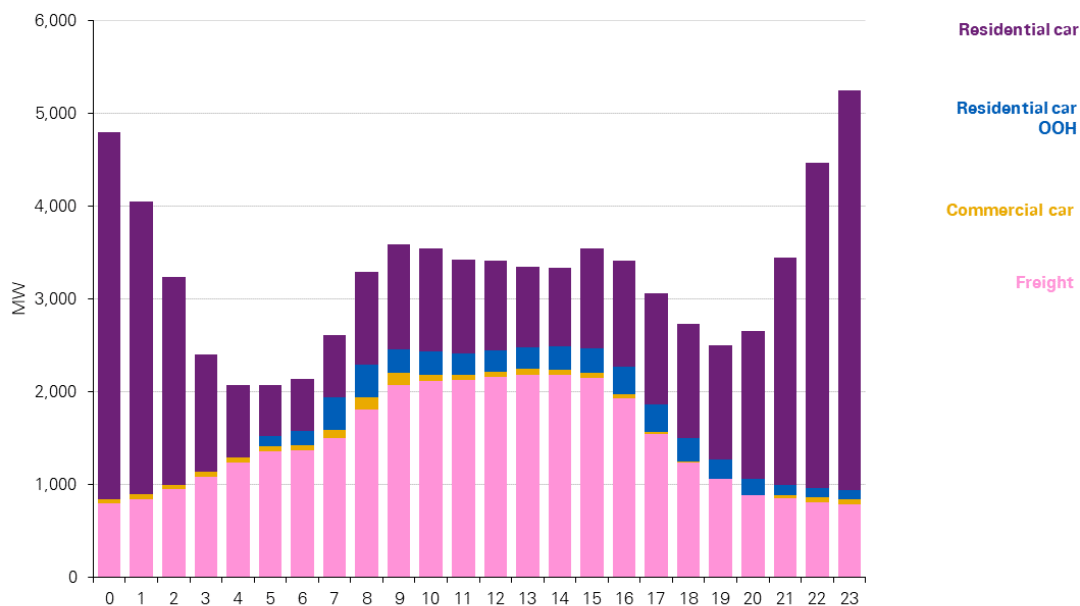
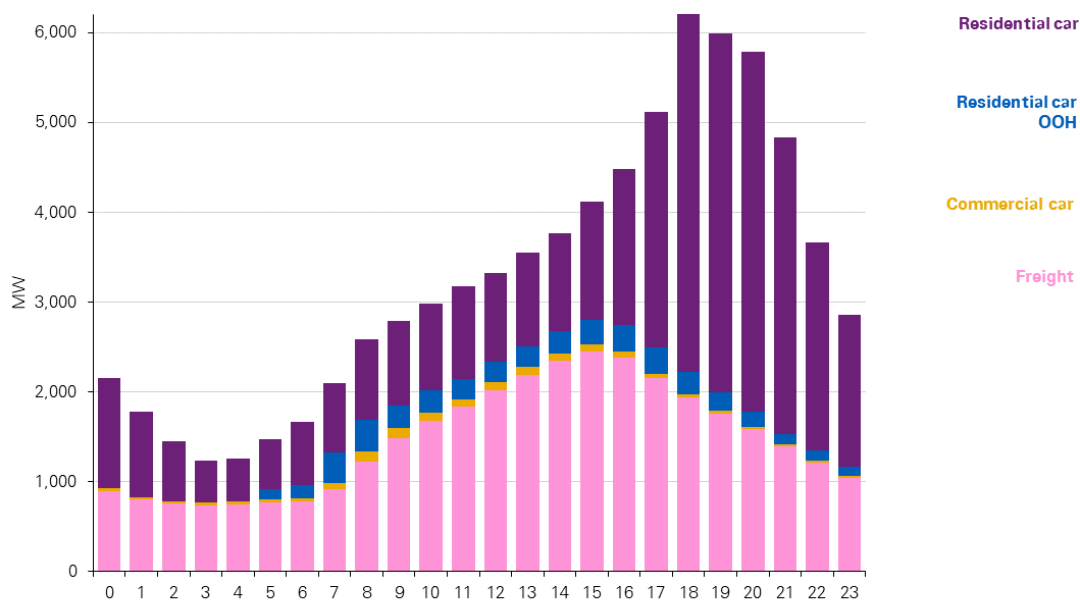


Figure 45– Private Drive load profile – non-incentivised



4.5.3 Generation investment requirements

In the Private Drive – Incentivised scenario, EVs add a total of 3,061 MW to maximum demand during peak hours. In the Private Drive – Non-Incentivised scenario, EVs add a total of 6,261 MW to maximum demand during peak hours.

In the incentivised scenario, a total of 3,861 MW additional dispatchable capacity is required to meet both the demand from EVs and other sources (that is, 3,061 MW from BEVs and 800



MW from other sources, as discussed in the Dead End scenario) In the non-incentivised scenario, a total of 7,061 MW of additional dispatchable capacity is required to meet all demand. We assume that this is met by a combination of batteries and pumped hydro (zero emissions technologies), as well as by any “firm” capacity from wind and solar PV installed to meet the total consumption of electricity.

As noted Table 50, the total consumption of electricity by EVs in 2046 is estimated as 24,100 GWh. This total consumption requirement is the same regardless of the charging profile. If we assume that the total generation (GWh) of electricity remains constant from its 2017 levels, plus committed capacity and assumed LRET and VRET capacity at average capacity factors, less the assumed retirement of Yallourn in 2032, then there is an 22,245 GWh shortfall of generation in 2046 (noting that storage technologies to meet maximum demand do not in and of themselves add to total generation). This equates to 4,232 MW of wind capacity and 6,046 MW of solar PV capacity at 30% and 21% capacity factors respectively. This is approximately 30 wind farms at the current average size of existing and committed wind farms in Victoria (140 MW), and 81 solar farms at the average size of committed solar PV farms in Victoria (75 MW).

The dispatchable and non-dispatchable capacity required is illustrated in Figure 47 and Figure 48 for the incentivised and non-incentivised scenarios respectively.



Figure 46 - Private Drive - Incentivised, generation investment requirements

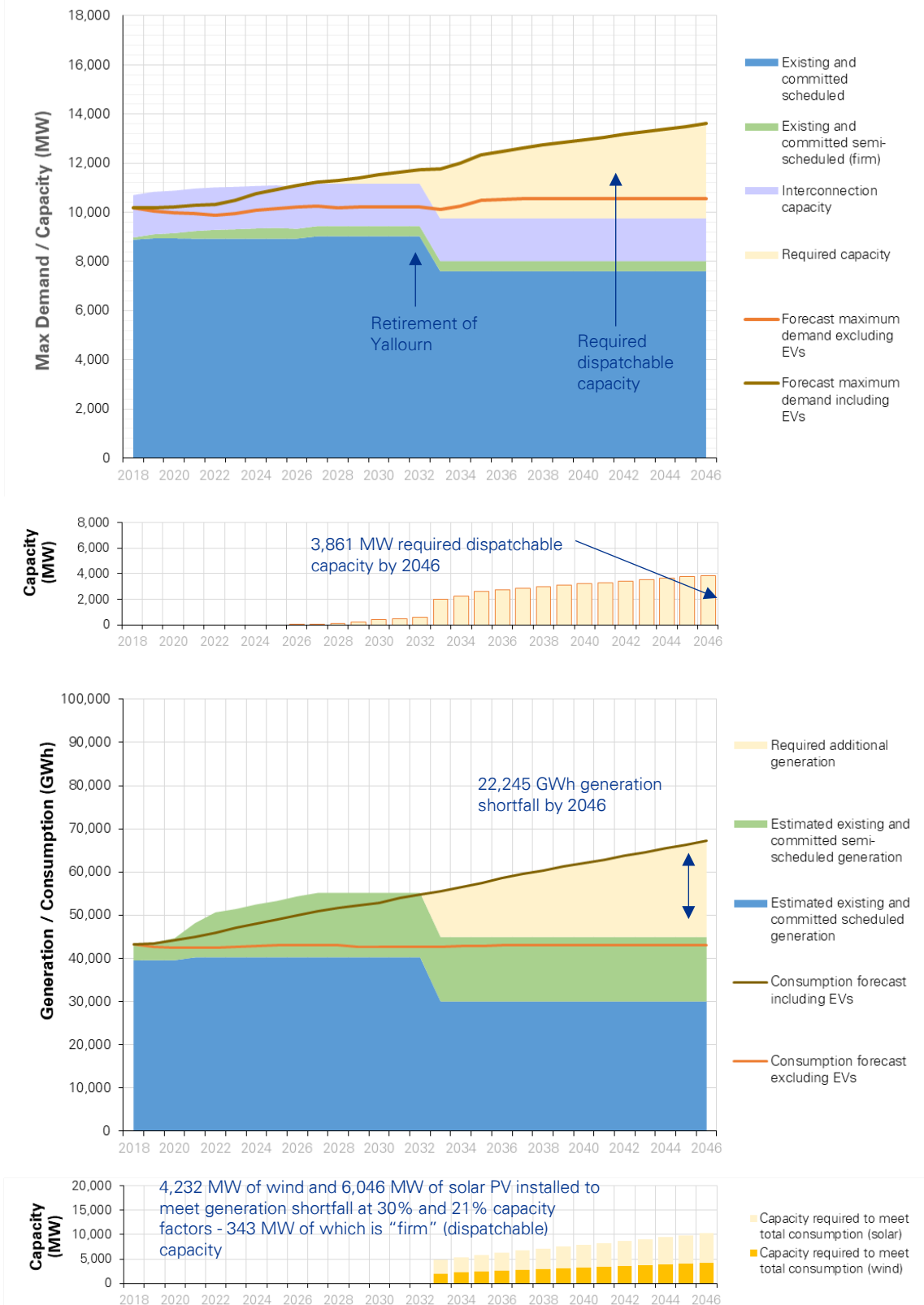




Figure 47– Private Drive – Non-Incentivised, generation requirements

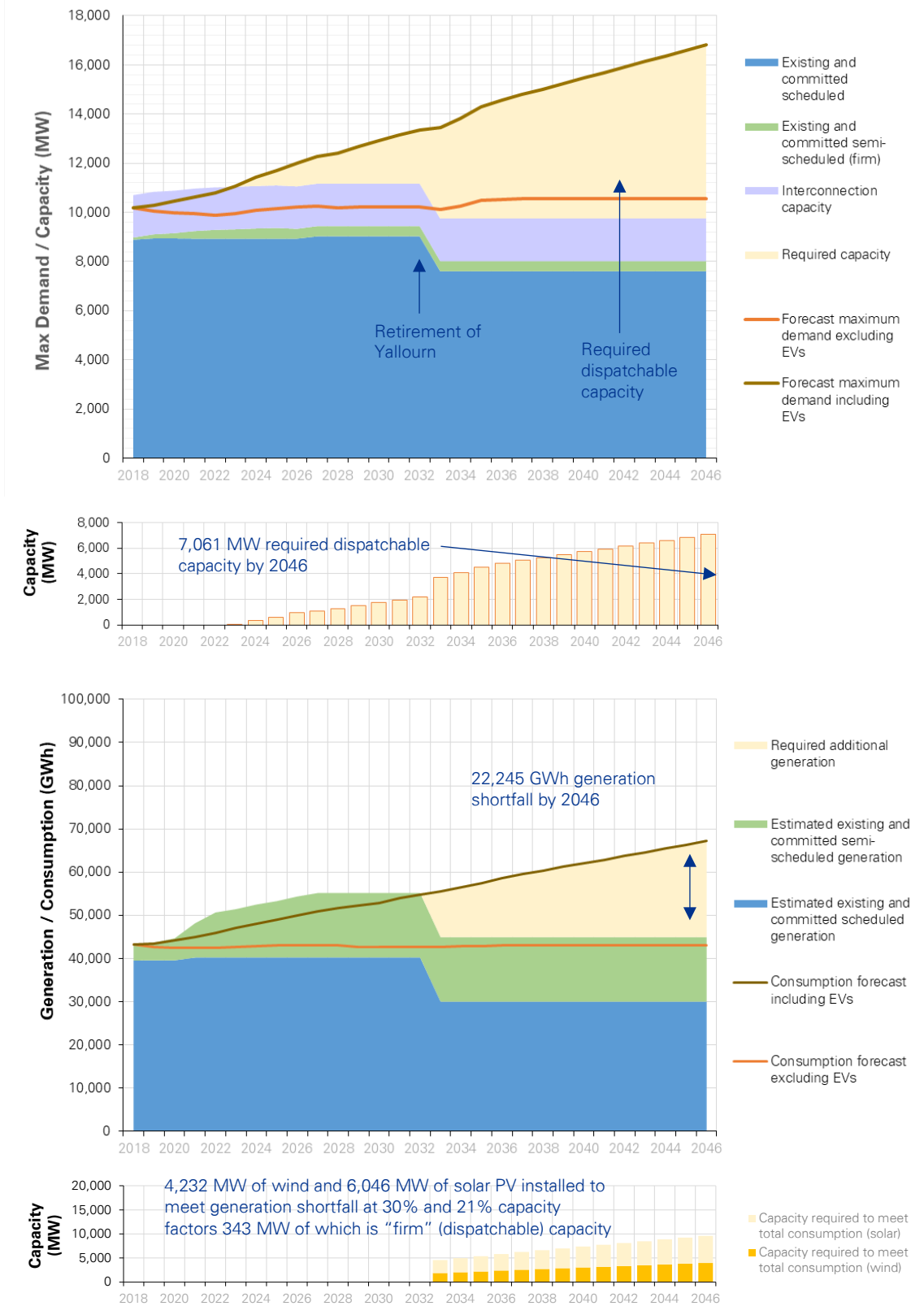




Table 51 summarises the total cost in net present value terms (at 7% real weighted average cost of capital) of new capacity (capital and connection costs only, not ongoing operating expenses) installed when required, as illustrated in Figure 46 and Figure 47 respectively. Note that the dispatchable capacity installed of 3,519 MW (incentivised permutation) reflects the dispatchable capacity “required” (i.e. 3,061 MW from BEVs and 800 MW from the Dead End scenario), less the “firm” peak contribution of the new non-dispatchable capacity installed (343 MW⁹⁴).

These results assume that no existing capacity ramps up generation to meet the additional consumption of electricity, and that no further retirements are made beyond Yallourn in 2032 (irrespective of the age of existing generation sources). Further, it reflects no reduction in either maximum demand (through for example increased demand side participation) or total consumption (through for example investments in energy efficiency) in response to a constrained supply situation, either or both of which may occur before the instalment of new capacity. We consider some sensitivities to these assumptions in 4.10.

Table 51– Private Drive, total cost of installed capacity

	Dispatchable capacity installed	Total cost (NPV): Dispatchable capacity	Non-dispatchable capacity installed	Total cost (NPV): Non-dispatchable capacity	Total cost (NPV): All capacity	Total cost (NPV): Incremental to dead end scenario
Dead End	800 MW	319 m	0 MW	0 m	319 m	
Private Drive (Incentivised)	3,519 MW	1,346 m	10,279 MW	4,052 m	5,399 m	5,079 m
Private Drive (Non-Incentivised)	6,719 MW	2,911 m	10,279 MW	4,052 m	6,963 m	6,644 m

The installed capacity and generation mix resulting in the Private Drive – Incentivised scenario is illustrated in Figure 48. The installed capacity and generation mix resulting in the Private Drive– Non-Incentivised scenario is illustrated in Figure 49. A comparison of the two figures reveals that the non-incentivised scenario involves additional storage capacity (light and dark green) to accommodate the additional maximum demand resulting from demand being concentrated in peak hours.

⁹⁴ Calculated as 4,232 MW of wind multiplied by the “firm” contribution factor of 8.1%, please see chapter 3 for more detail.



Figure 48– Private Drive – Incentivised, capacity and generation mix

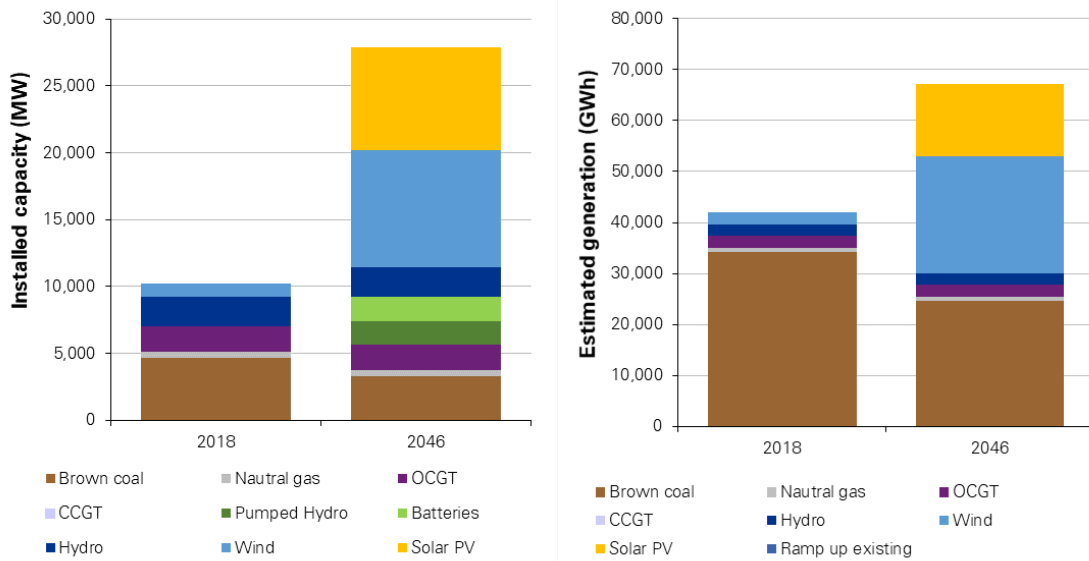
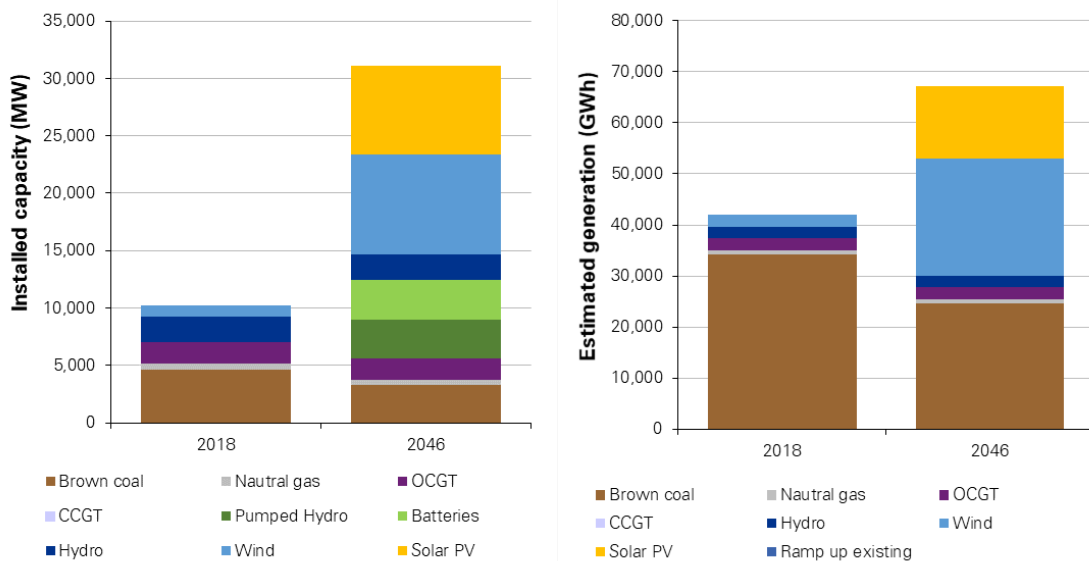


Figure 49– Private Drive, non-incentivised, capacity and generation mix



The new capacity and generation mix in 2046 is associated with no more emissions than in 2018, as all new capacity is assumed to be zero emissions (pumped hydro, batteries, wind and solar PV). However, the average emissions (tonnes CO₂-e) per MW and GWh respectively fall as demand and consumption of electricity increases. This is illustrated for the incentivised and non-incentivised scenario in Figure 50 and Figure 51 respectively. The average emissions per MW is slightly lower in the non-incentivised case as a result of additional capacity being installed to meet a higher maximum demand than in the incentivised scenario.



Figure 50– Private Drive, incentivised, average emissions

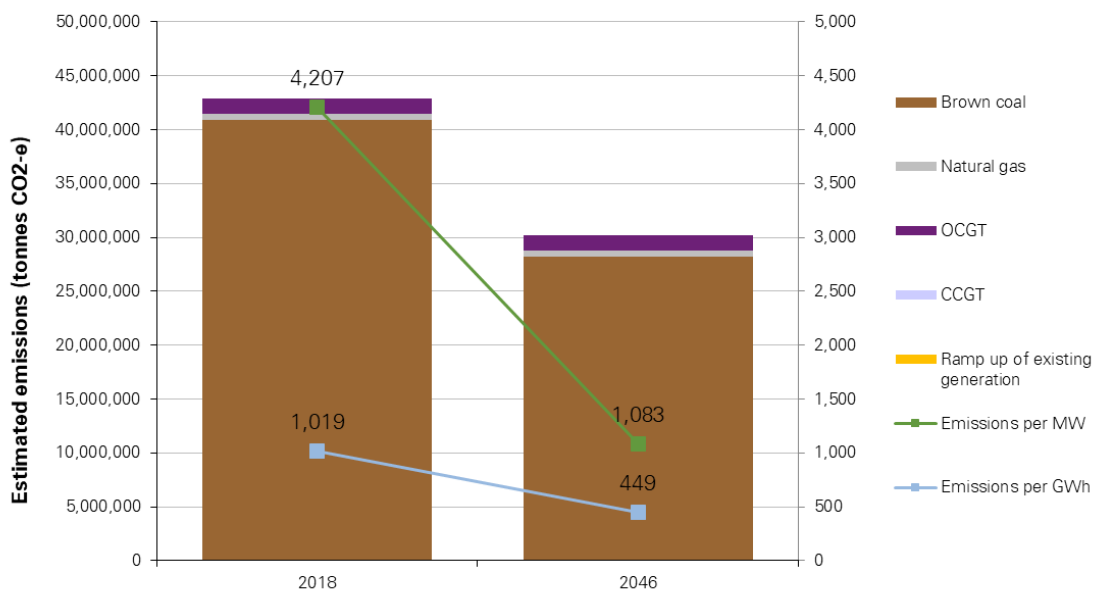
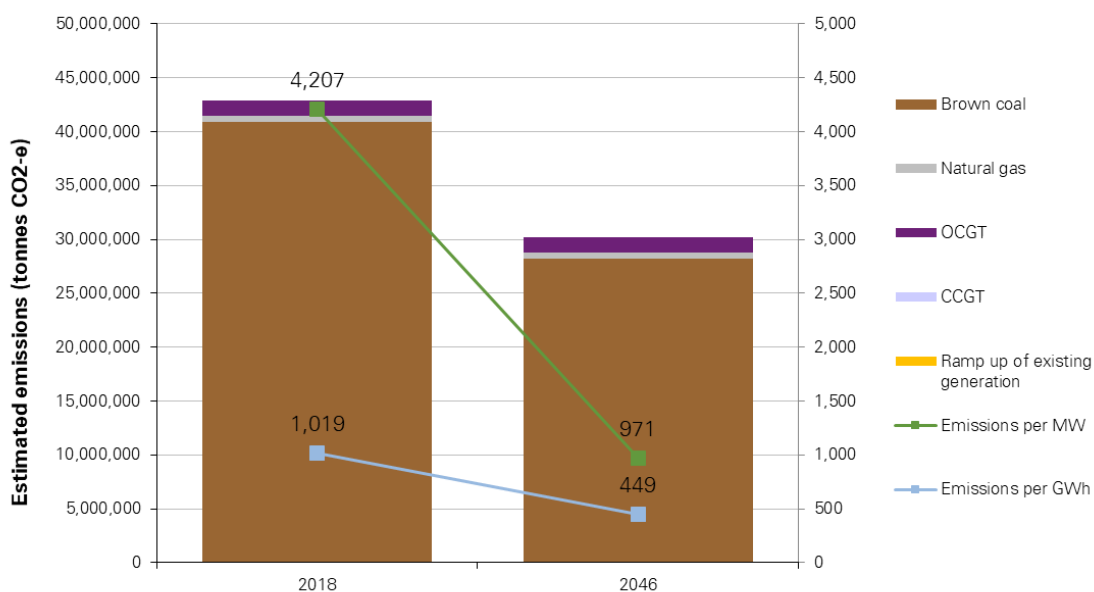


Figure 51 – Private Drive, non-incentivised, average emissions



4.5.4 Network investment requirements

Long run marginal cost analysis

AEMO’s maximum demand forecast excluding EVs increases by 512 MW between 2018 and 2046 (see Figure 16). We have assumed that this increase in maximum demand will affect all five distribution networks, in proportion to the number of cars assumed to be in each network area.



BEVs add different amounts to maximum demand in different networks, depending on the peak hours in a particular network and the relative share of the network in terms of BEVs. Table 52 and Table 53 summarise the impact on the network in terms of additional maximum demand under the incentivised and non-incentivised scenarios respectively.

At the LRMC per MW per year for distribution and transmission for each network the total cost in net present value terms (at 7% real weighted average cost of capital) to accommodate this increase is \$1,506 million for distribution and \$623 million for transmission in the incentivised scenario and \$2,370 million for distribution and \$983 million for transmission in the non-incentivised scenario.

Table 52 – Private Drive, incentivised, impact on network demand

	Dead End (MW)	EV (MW)	Total (MW)	Share	Total (MW)
AusNet	512	3,544	4,057	26.2%	1,062
CitiPower	512	3,544	4,057	6.8%	275
Jemena	512	3,544	4,057	14.3%	578
Powercor	512	3,544	4,057	33.1%	1,343
UE	512	3,544	4,057	19.7%	799

As per Table 52 above, under the incentivised Private Drive scenario, CitiPower can expect the lowest impact on network demand with 275 MW, followed by Jemena with 578 MW. United Energy can expect the third highest impact on network demand with 799 MW, AusNet with 1,062 MW and finally Powercor with 1,343 MW.

Table 53 – Private Drive, non-incentivised, impact on network demand

	Dead End (MW)	EV (MW)	Total (MW)	Share	Total (MW)
AusNet	512	5,118	5,630	26.2%	1,474
CitiPower	512	5,118	5,630	6.8%	381
Jemena	512	6,261	6,774	14.3%	966
Powercor	512	6,261	6,774	33.1%	2,242
UE	512	6,261	6,774	19.7%	1,334

As per Table 53 above, these figures increase significantly under the non-incentivised scenario, with CitiPower increasing to 381 MW, Jemena to 966 MW, United Energy to 1,334 MW, AusNet to 1,474 MW and Powercor increasing to 2,242 MW.

Spatial analysis

As demonstrated in Table 54 and Figure 52 below, under the incentivised Private Drive scenario, of AusNet’s 52 substations, 16 are expected to be in low exceedance, with 13 in high exceedance. Citipower should expect four of their 37 substations to be in low exceedance, with a further two in high exceedance. Three of Jemena’s 30 substations are expected to be in low exceedance, with nine in high exceedance. 13 of Powercor’s total 58 substations are expected to be in low exceedance, with a further 22 in high exceedance. United Energy should expect seven of their 47 substations in low exceedance, with no substations with expected maximum demand to exceed current capacity.



Table 54 - Private Drive – incentivised, projected capacity minus rated capacity by DNSP

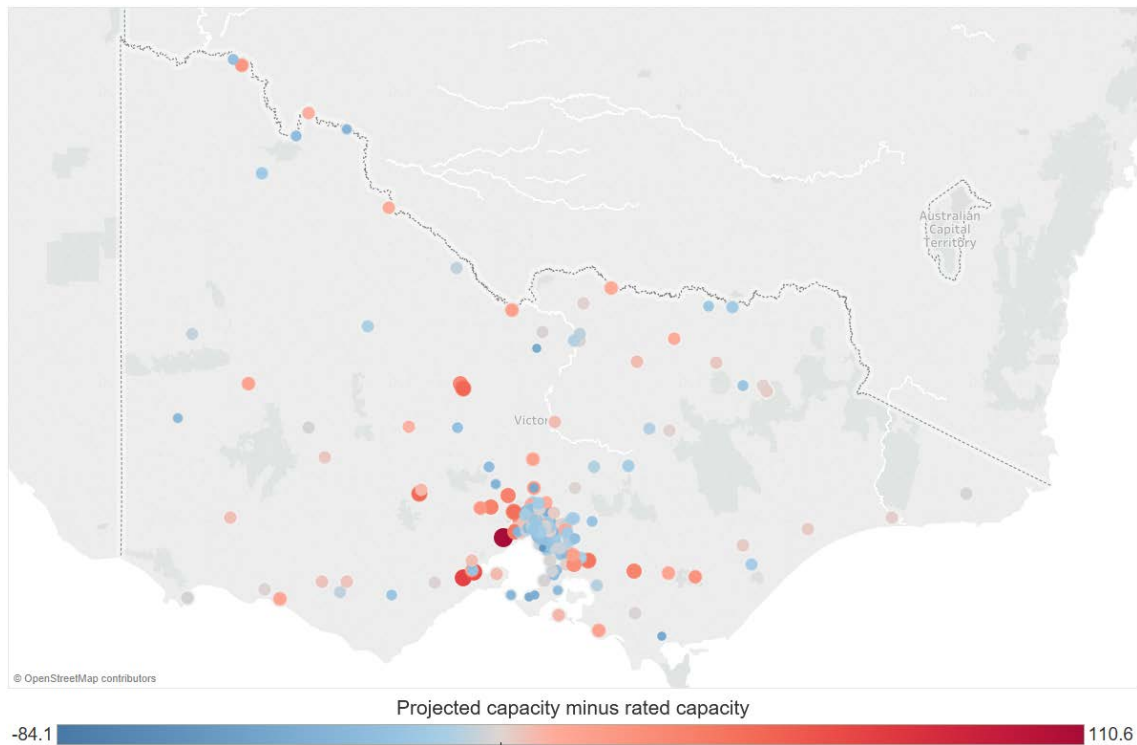
	AusNet	Citipower	Jemena	Powercor	United
# zone substations (ZS)	52	37	30	58	47
#ZS projected MD < current rated capacity	23	31	18	23	40
#ZS projected MD > current rated capacity (exceedance 0%-10%)	16	4	3	13	7
#ZS projected MD > current rated capacity (exceedance 10%+)	13	2	9	22	0

Table 55 – Private Drive – incentivised, location of top five zone substations where gap between MD and current capacity is greatest by DNSP

	AusNet	Citipower	Jemena	Powercor	United
	Pakenham	Kew	Thomastown	Werribee	Mornington
Location of top five zone substations where gap between MD and current capacity is greatest	Warragul	Prahran	Sydenham	Waurm Ponds	Carrum
	Clyde North	Richmond	Sunbury	Geelong East	Burwood
	Traralgon	Riversdale	Watsonia	Ballarat South	Frankston
	Kilmore South	Laurens Street	Preston	Bendigo	Dandenong



Figure 52- Private Drive – incentivised, projected capacity minus rated capacity by zone substation



As demonstrated in Table 56 and Figure 53 below, these figures increase substantially under the non-incentivised scenario. AusNet should expect 12 of their 32 substations to be in low exceedance, with 23 expecting demand to exceed capacity by greater than 10%. Citipower can expect four of their 37 substations to exceed capacity in low range, with a further four subject high exceedance. Of Jemena’s 30 zone substations, five are expected to have maximum demand in low exceedance, with 13 of these being in high exceedance. Powercor can expect 10 of their 58 substations in low exceedance of current capacity, with 32 of these in high exceedance, while United Energy expects seven of their 47 substations in low exceedance with a further 10 being in high exceedance, up from zero under the incentivised scenario.

Table 56 - Private Drive – non-incentivised, projected capacity minus rated capacity by DNSP

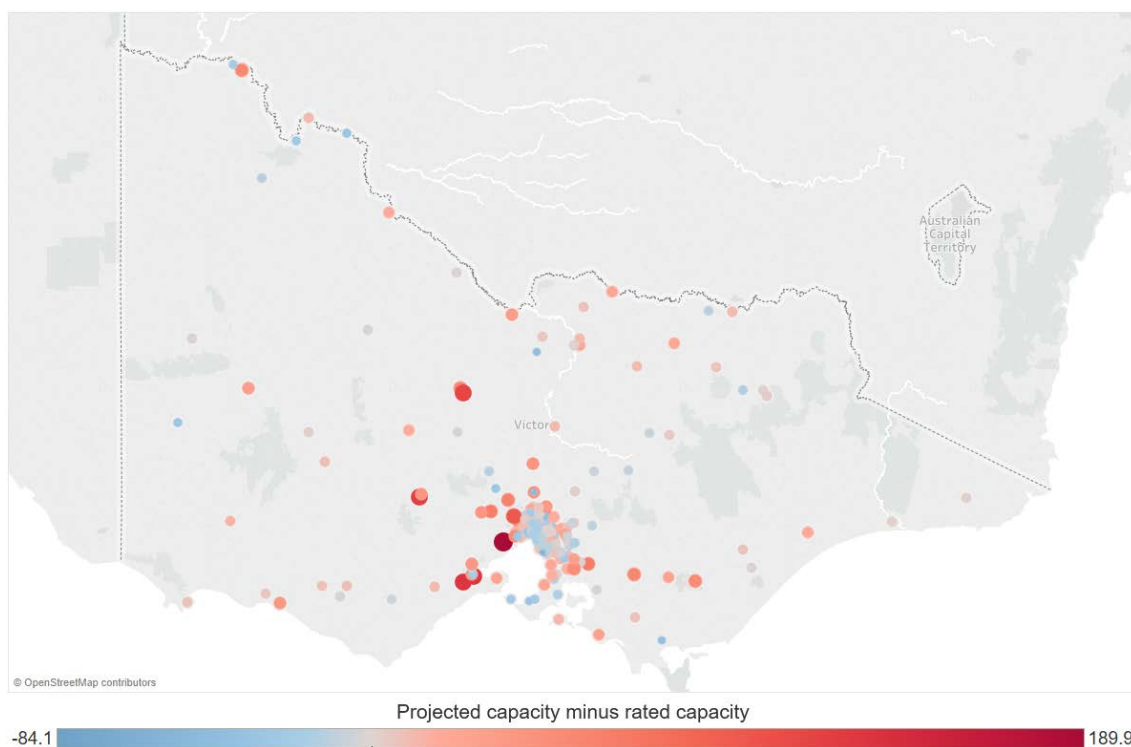
	AusNet	Citipower	Jemena	Powercor	United
# zone substations (ZS)	52	37	30	58	47
#ZS projected MD < current rated capacity	17	29	12	16	30
#ZS projected MD > current rated capacity (exceedance 0%-10%)	12	4	5	10	7
#ZS projected MD > current rated capacity (exceedance 10%+)	23	4	13	32	10



Table 57 – Private Drive – non-incentivised, location of top five zone substations where gap between MD and current capacity is greatest by DNSP

	AusNet	Citipower	Jemena	Powercor	United
	Pakenham	Kew	Sydenham	Werribee	Mornington
Location of top five zone substations where gap between MD and current capacity is greatest	Warragul	Prahran	Thomastown	Waurin Ponds	Carrum
	Traralgon	Richmond	Watsonia	Geelong East	Nunawading
	Clyde North	Riversdale	Sunbury	Ballarat South	Dandenong south
	Kilmore South	Brunswick	Preston	Bendigo	Frankston

Figure 53- Private Drive – non-incentivised, projected capacity minus rated capacity by zone substation





4.6 Scenario: Fleet Street

4.6.1 Scenario description

In the Fleet Street scenario, in 2046, the fleet is entirely composed of shared and automated electric vehicles. Table 58 provides a summary of the key assumptions in the Fleet Street scenario.

Table 58 – Fleet Street Assumptions Summary

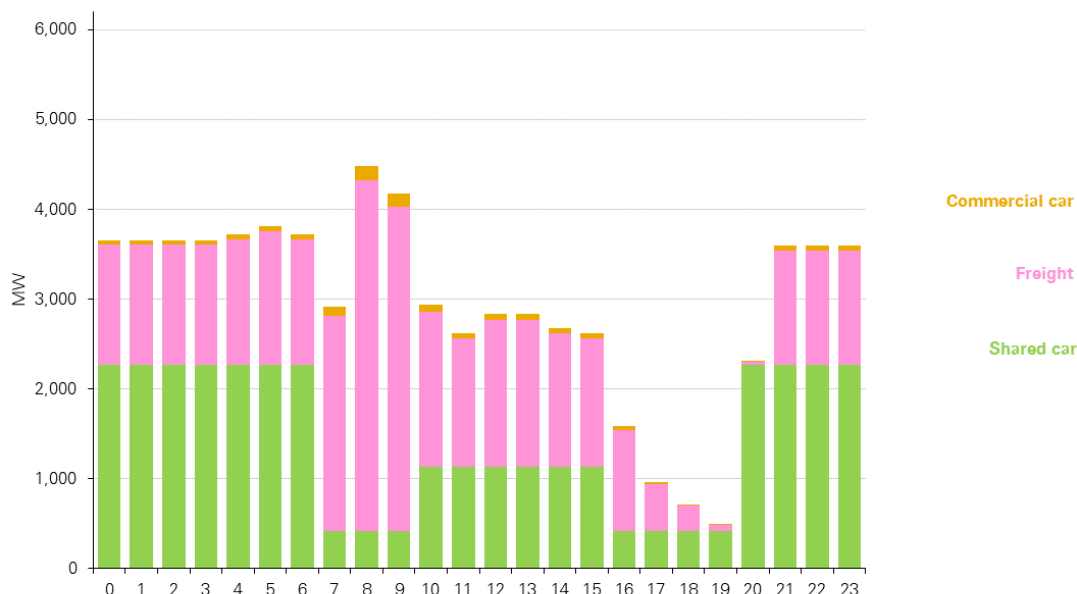
Description		Assumption
Number of vehicles	#	638,622
Total annual BEV consumption	GWh	21,762
Number of cars	#	256,490
Average VKT per day	km	568.46
Efficiency per 100 km	kWh	20
Network and charging losses	%	10%
Required electricity per day	kWh	126.33
Annual consumption of cars (factor 341.6)	GWh	11,068
Car charger		Shared cars Type 2 (9.5 kW), commercial cars Type 3 (240 kW)
Number of freight vehicles	#	382,132
Average VKT per day	km	57.11
Efficiency per 100 km	kWh	129.11
Network and charging losses	%	10%
Required electricity per day	kWh	81.92
Annual consumption of freight	GWh	10,694
Freight vehicle charger		Type 3 (240 kW)

4.6.2 Contribution to maximum demand

The Fleet Street load profile is illustrated in Figure 54. The profile concentrates demand (electricity used at a particular time (MW)) away from the evening peak in Victoria, which is around 5 to 7 pm.



Figure 54– Fleet Street load profile



4.6.3 Generation investment requirements

In the Fleet Street scenario, EVs add a total of 958 MW to maximum demand during peak hours.

A total of 1,758 MW additional dispatchable capacity is required to meet both the demand from EVs and other sources (that is, 958 MW from BEVs and 800 MW from other sources, as discussed in the Dead End scenario). We assume that this is met by a combination of batteries and pumped hydro (zero emissions technologies), as well as by any “firm” capacity from wind and solar PV installed to meet the total consumption of electricity.

As noted in Table 58, the total consumption of electricity by EVs in 2046 is estimated as 21,762 GWh . If we assume that the total generation (GWh) of electricity remains constant from its 2017 levels, plus committed capacity and assumed LRET and VRET capacity at average capacity factors, less the assumed retirement of Yallourn in 2032, then there is an 19,908 GWh shortfall of generation in 2046 (noting that storage technologies to meet maximum demand do not in and of themselves add to total generation). This equates to 3,788 MW of wind capacity and 5,411 MW of solar PV capacity at 30% and 21% capacity factors respectively. This is approximately 27 wind farms at the current average size of existing and committed wind farms in Victoria (140 MW), and 72 solar farms at the average size of committed solar PV farms in Victoria (75 MW).

The dispatchable and non-dispatchable capacity installed generation are illustrated in Figure 55.



Figure 55– Fleet Street, generation investment requirements

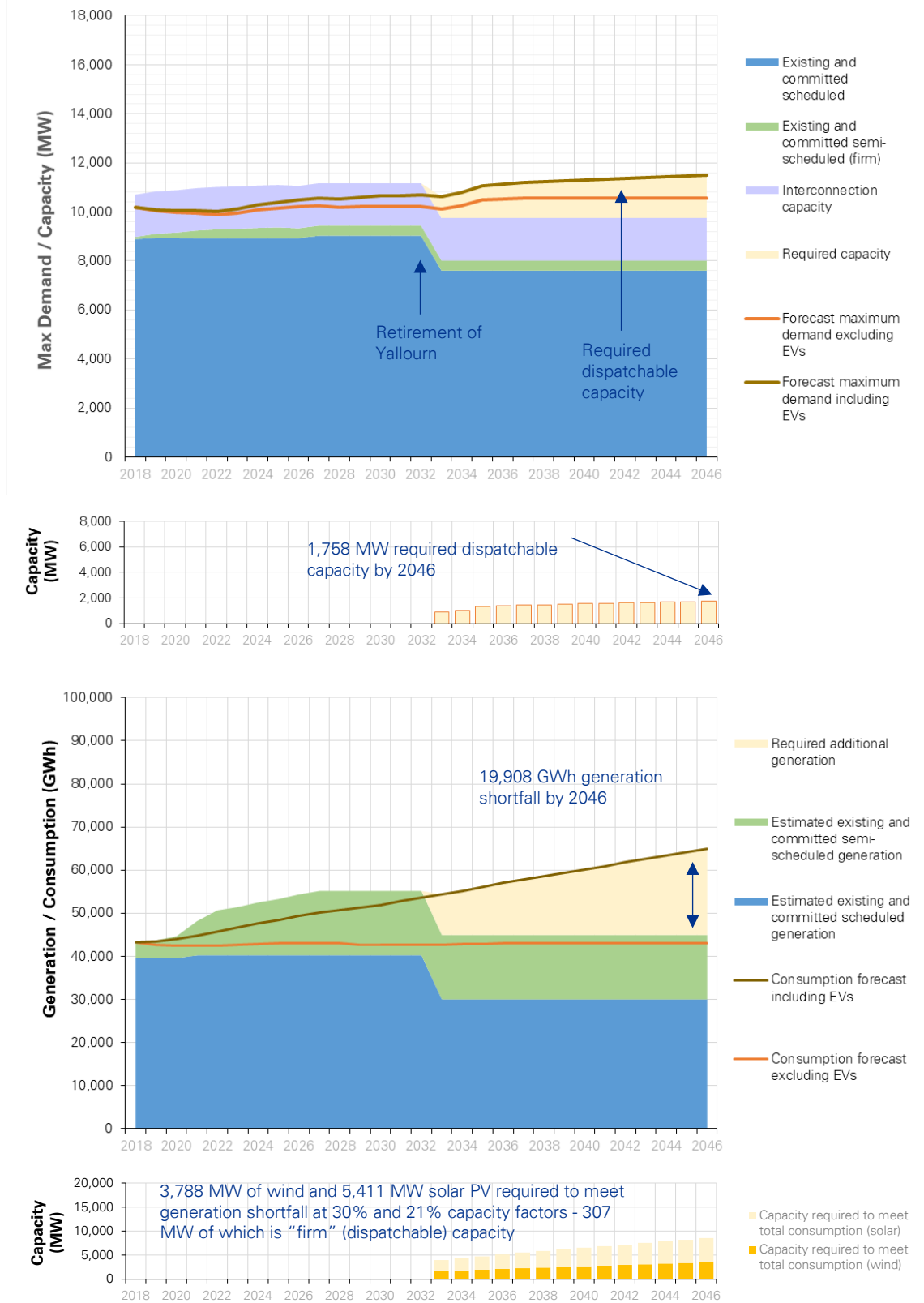


Table 59 summarises the total cost in net present value terms (at 7% real weighted average cost of capital) of new capacity (capital and connection costs only, not ongoing operating



expenses) installed when required, as illustrated in Figure 55. Note that the dispatchable capacity installed of 1,451 MW reflects the dispatchable capacity “required” (i.e. 958 MW from BEVs and 800 MW from the Dead End scenario), less the “firm” peak contribution of the new non-dispatchable capacity installed (307 MW⁹⁵).

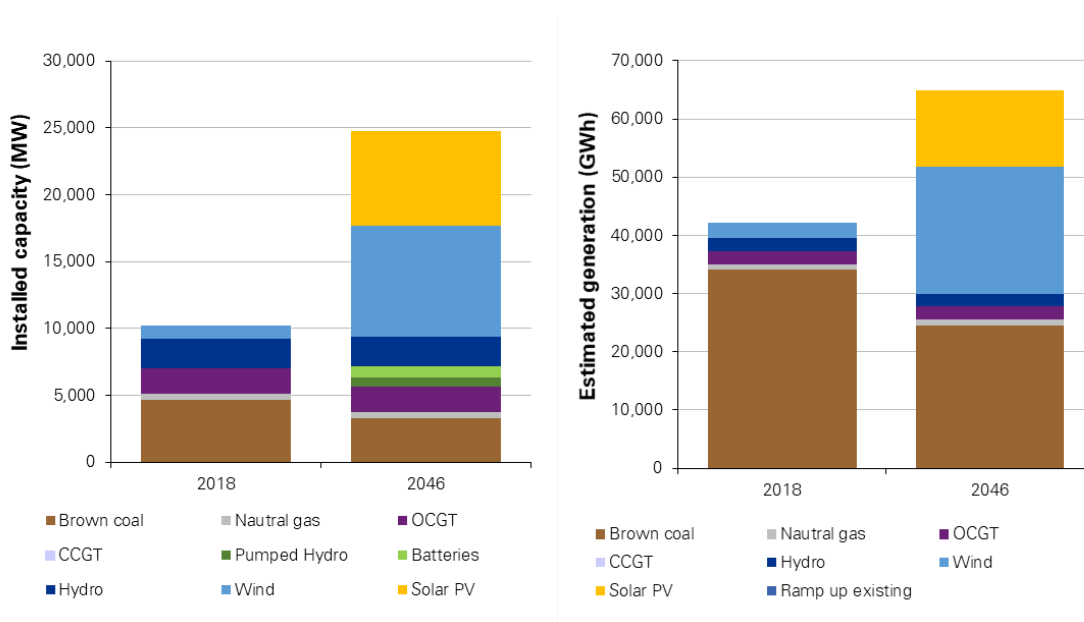
These results assume that no existing capacity ramps up generation to meet the additional consumption of electricity, and that no further retirements are made beyond Yallourn in 2032 (irrespective of the age of existing generation sources). Further, it reflects no reduction in either maximum demand (through for example increased demand side participation) or total consumption (through for example investments in energy efficiency) in response to a constrained supply situation, either or both of which may occur before the instalment of new capacity. We consider some sensitivities to these assumptions in 4.10.

Table 59 – Fleet Street, total cost of installed capacity

	Dispatchable capacity installed	Total cost (NPV): Dispatchable capacity	Non-dispatchable capacity installed	Total cost (NPV): Non-dispatchable capacity	Total cost (NPV): All capacity	Total cost (NPV): Incremental to dead end scenario
Dead End	800 MW	319 m	0 MW	0 m	319 m	
Fleet Street	1,451 MW	543 m	9,198 MW	3,616 m	4,159 m	3,840 m

The installed capacity and generation mix resulting in the Fleet Street scenario is illustrated in Figure 56.

Figure 56 – Fleet Street, capacity and generation mix

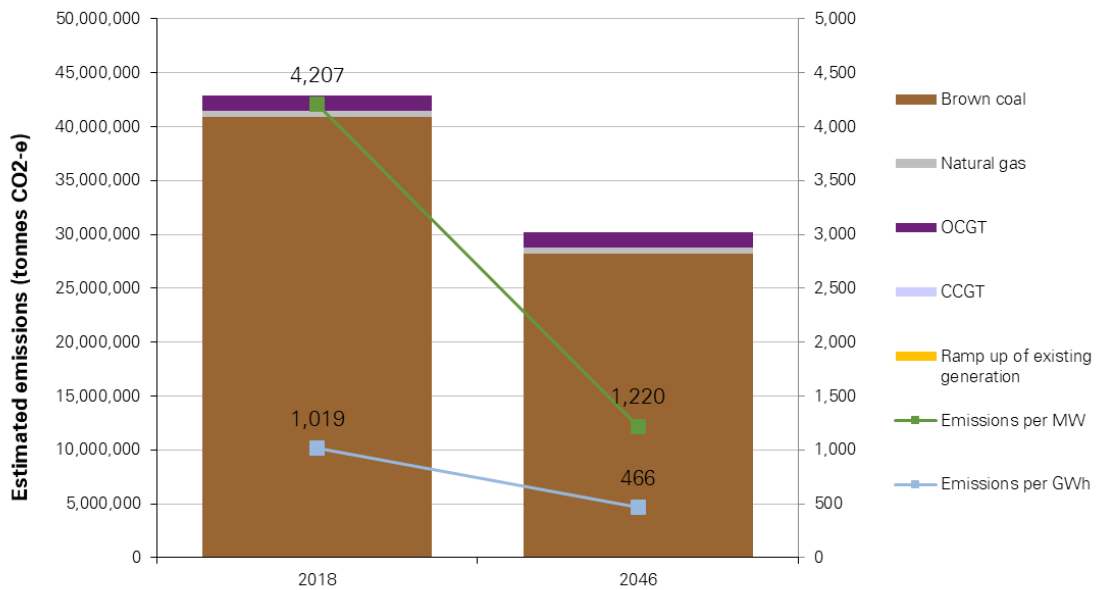


The new capacity and generation mix in 2046 is associated with no more emissions than in 2018, as all new capacity is assumed to be zero emissions (pumped hydro, batteries, wind and solar PV). However, the average emissions (tonnes CO₂-e) per MW and GWh respectively fall as demand and consumption of electricity increases. This is illustrated in Figure 57.

⁹⁵ Calculated as 3,788 MW of wind multiplied by the “firm” contribution factor of 8.1%, please see chapter 3 for more detail.



Figure 57 – Fleet Street, average emissions



4.6.4 Network investment requirements

Long run marginal cost analysis

AEMO’s maximum demand forecast excluding EVs increases by 512 MW between 2018 and 2046. We have assumed that this increase in maximum demand will affect all five distribution networks, in proportion to the number of cars in each network area.

EVs add different amounts to maximum demand in different networks, depending on the peak hours in a particular network and the relative share of the network in terms of ZEVs. Table 60 summarises the impact on the network in terms of additional maximum demand under the incentivised and non-incentivised scenarios respectively. According to Table 60, under the Fleet Street scenario, CitiPower is expected to experience the lowest network investment requirement at 186 MW. This is followed by Jemena with 424 MW, United Energy with 599 MW, AusNet with 877 MW and Powercor with 1,077 MW.

At the LRMC per MW per year for distribution and transmission for each network the total cost in net present value terms (at 7% real weighted average cost of capital) to accommodate this increase is \$1,178 million for distribution and \$486 million for transmission.

Table 60 – Fleet Street, impact on network demand

	Dead End (MW)	EV (MW)	Total (MW)	Share	Total (MW)
AusNet	512	2,680	3,192	27.5%	877
CitiPower	512	2,931	3,444	5.4%	186
Jemena	512	2,617	3,129	13.6%	424
Powercor	512	2,617	3,129	34.4%	1,077
UE	512	2,617	3,129	19.1%	599



Spatial analysis

Under the Fleet Street scenario, of AusNet’s 52 substations, 15 are expected to be in low exceedance, with 11 in high exceedance. Citipower should expect six of their 37 substations to be in low exceedance, with no substations in high exceedance. Four of Jemena’s 30 substations are expected to be in low exceedance, with eight in high exceedance. 13 of Powercor’s total 58 substations are expected to be in low exceedance, with a further 18 in high exceedance. United Energy can expect just one of their 47 substations in low exceedance.

Table 61 - Fleet Street, projected capacity minus rated capacity by DNSP

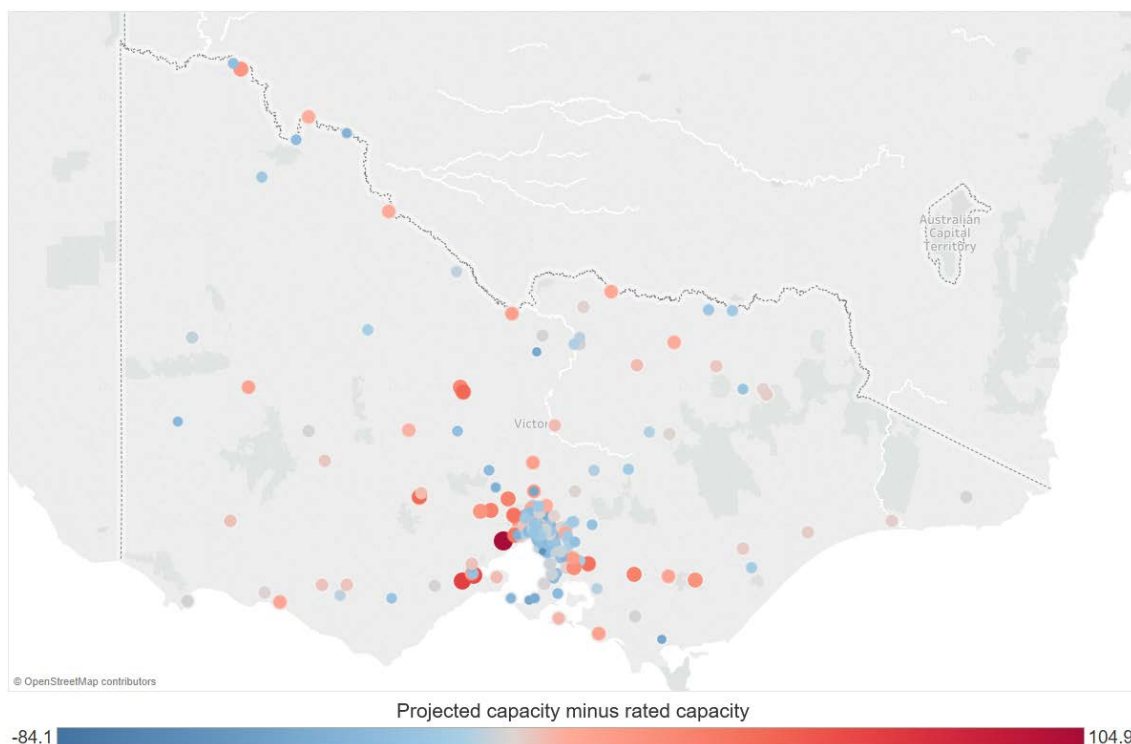
	AusNet	Citipower	Jemena	Powercor	United
# zone substations (ZS)	52	37	30	58	47
#ZS projected MD < current rated capacity	26	31	18	27	46
#ZS projected MD > current rated capacity (exceedance 0%-10%)	15	6	4	13	1
#ZS projected MD > current rated capacity (exceedance 10%+)	11	0	8	18	0

Table 62 – Fleet Street, location of top five zone substations where gap between MD and current capacity is greatest by DNSP

	AusNet	Citipower	Jemena	Powercor	United
	Pakenham	Prahran	Thomastown	Werribee	Mornington
Location of top five zone substations where gap between MD and current capacity is greatest	Warragul	Kew	Sydenham	Waurm Ponds	Burwood
	Clyde North	Riversdale	Sunbury	Geelong East	Frankston
	Traralgon	Richmond	Watsonia	Ballarat South	Carrum
	Kilmore South	Laurens Street	Kalkallo	Bendigo	Sandringham



Figure 58- Fleet Street, projected capacity minus rated capacity by zone substation



4.7 Scenario: High Speed

4.7.1 Scenario description

In the High Speed scenario a full shift to automated, electric vehicles as an on-demand service occurs by 2031. Table 63 provides a summary of the key assumptions in the High Speed scenario.

Table 63– High Speed Assumptions Summary

Description		Assumption
Number of vehicles	#	415,674
Total annual BEV consumption	GWh	15,986
Number of cars	#	211,069
Average VKT per day	km	640.38
Efficiency per 100 km	kWh	20
Network and charging losses	%	10%
Required electricity per day	kWh	142.31
Annual consumption of cars	GWh	10,260
Car charger		Shared cars Type 2 (9.5 kW), commercial cars Type 3 (240 kW)
Number of freight vehicles	#	204,605

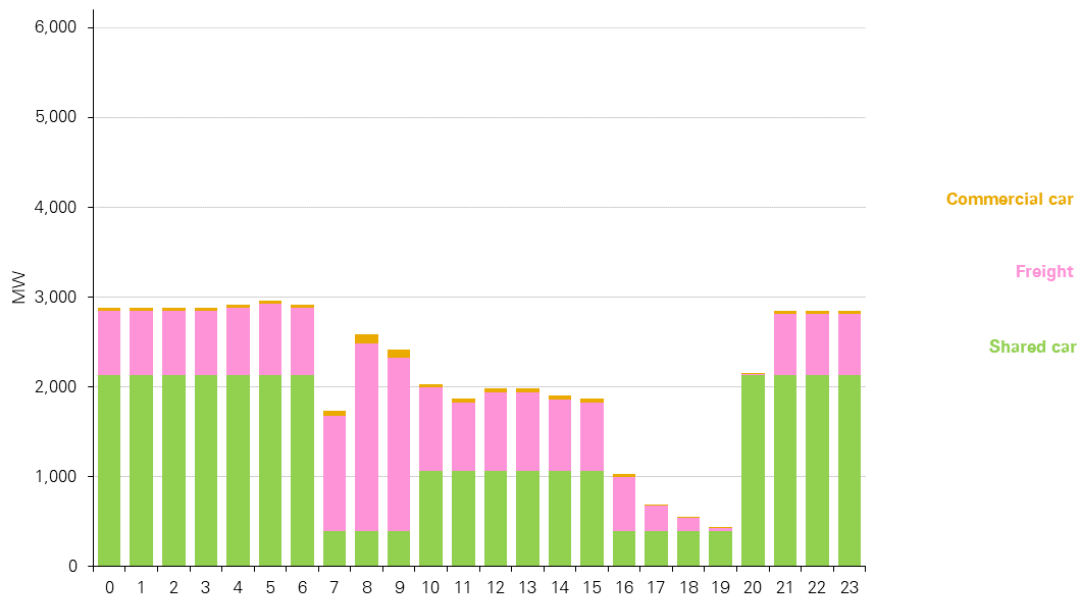


Description		Assumption
Average VKT per day	km	57.11
Efficiency per 100 km	kWh	129.11
Network and charging losses	%	10%
Required electricity per day	kWh	81.92
Annual consumption of freight (factor 341.6)	GWh	5,726
Freight vehicle charger		Type 3 (240 kW)

4.7.2 Contribution to maximum demand

The High Speed load profile is illustrated in Figure 59. The profile concentrates demand (electricity used at a particular time) away from the evening peak in Victoria, which is around 5 to 7 pm.

Figure 59– High Speed load profile



4.7.3 Generation investment requirements

In the High Speed scenario, EVs add a total of 683 MW to maximum demand during peak hours (between 5 – 6 pm) by 2031. No additional dispatchable capacity is required to meet this demand, nor any additional demand from other sources, in 2031.

As noted in Table 63, the total consumption of electricity by EVs in 2046 is estimated as 15,986 GWh in 2031. If we assume that the total generation (GWh) of electricity remains constant from its 2017 levels, plus committed capacity and assumed LRET and VRET capacity at average capacity factors, then there is an 3,541 GWh shortfall of generation in 2031. This equates to 674 MW of wind capacity and 963 MW of solar PV capacity at 30% and 21% capacity factors respectively. This is approximately 5 wind farms at the current average size of existing and committed wind farms in Victoria (140 MW), and 13 solar farms at the average size of committed solar PV farms in Victoria (75 MW). The generation investment requirements for dispatchable and non-dispatchable generation are illustrated in Figure 60.



Figure 60– High Speed, generation investment requirements

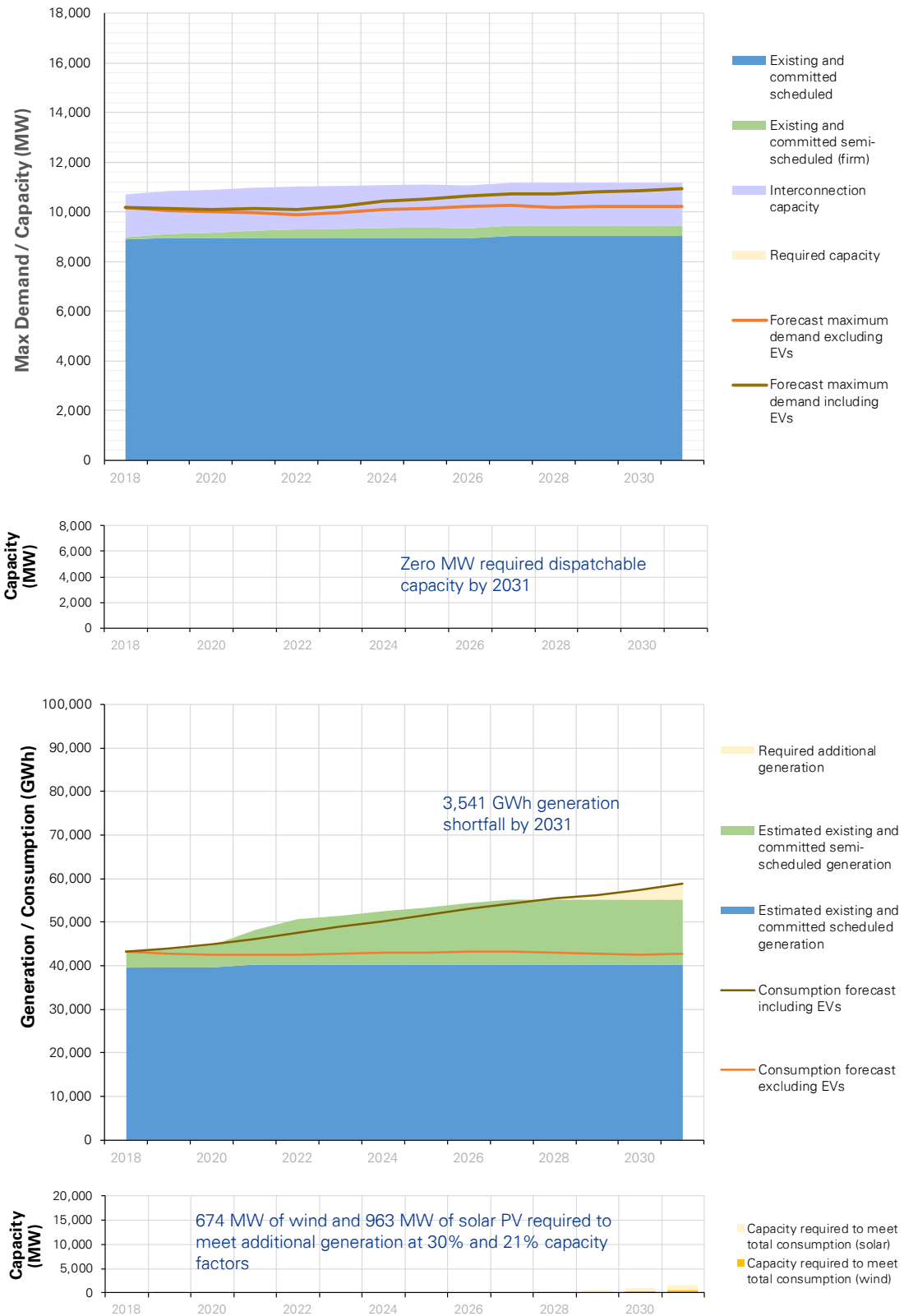




Table 64 summarises the total cost in net present value terms of new capacity (capital and connection costs only, not ongoing operating expenses) installed when required, as illustrated in Figure 60.

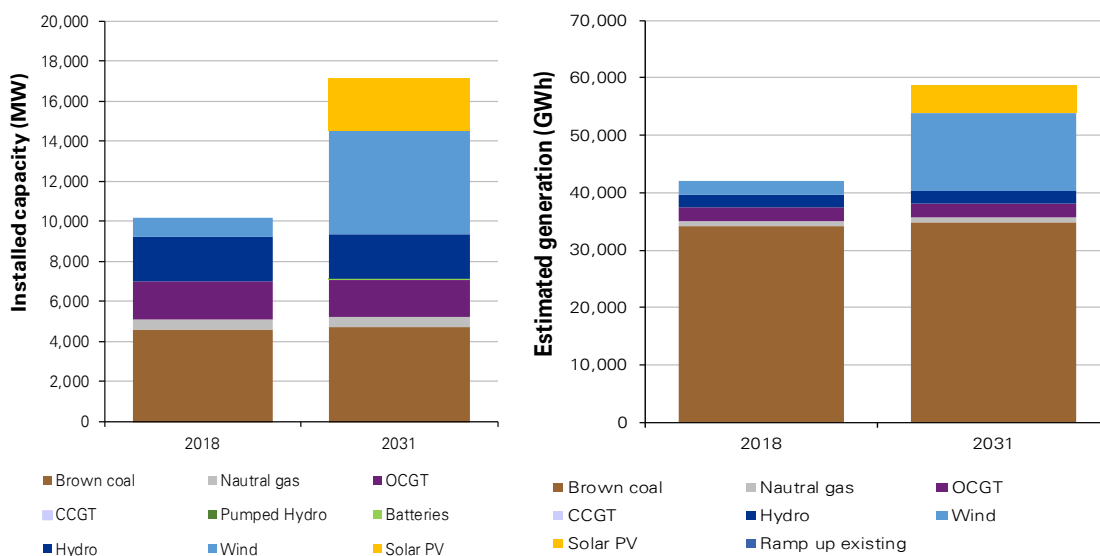
These results assume that no existing capacity ramps up generation to meet the additional consumption of electricity. Further, it reflects no reduction in either maximum demand (through for example increased demand side participation) or total consumption (through for example investments in energy efficiency) in response to a constrained supply situation, either or both of which may occur before the instalment of new capacity. We consider some sensitivities to these assumptions in 4.10.

Table 64 – High Speed, total cost of installed capacity

	Dispatchable capacity installed	Total cost (NPV): Dispatchable capacity	Non-dispatchable capacity installed	Total cost (NPV): Non-dispatchable capacity	Total cost (NPV): All capacity	Total cost (NPV): Incremental to dead end scenario
Dead End	800 MW	319 m	0 MW	0 m	319 m	
High Speed	0 MW	0 m	1,636 MW	1,108 m	1,108 m	1,108m

The installed capacity and generation mix resulting in the High Speed scenario is illustrated in Figure 61.

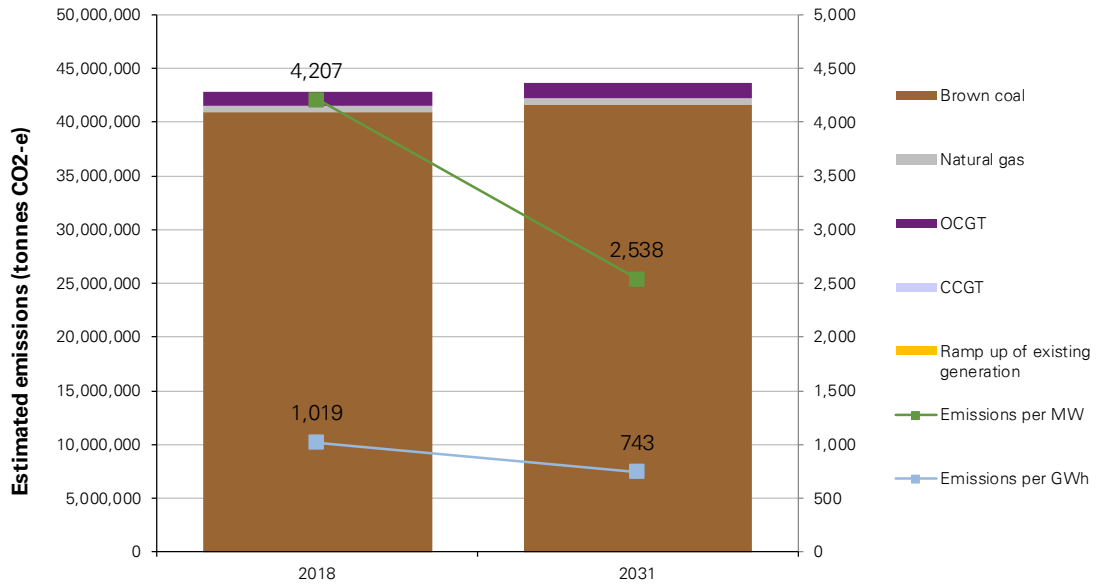
Figure 61 – High Speed, capacity and generation mix



The new capacity and generation mix in 2046 is associated with no more emissions than in 2018, as all new capacity is assumed to be zero emissions (pumped hydro, batteries, wind and solar PV). However, the average emissions (tonnes CO₂-e) per MW and GWh respectively fall as demand and consumption of electricity increases. This is illustrated in Figure 62.



Figure 62 – High Speed, average emissions



4.7.4 Network investment requirements

Long run marginal cost analysis

AEMO’s maximum demand forecast excluding EVs increases by 103 MW between 2018 and 2031. We have assumed that this increase in maximum demand will affect all five distribution networks, in proportion to the estimated number of cars in each network area.

EVs add different amounts to maximum demand in different networks, depending on the peak hours in a particular network and the relative share of the network in terms of ZEVs. Table 65 summarises the impact on the network in terms of additional maximum demand under the incentivised and non-incentivised scenarios respectively. According to Table 65, under the High Speed scenario, CitiPower can expect the lowest impact on network demand with 115 MW, followed by Jemena with 305 MW. United Energy can expect the third highest impact on network demand with 430 MW, AusNet with 550 MW and finally Powercor the biggest impact with 774 MW.

At the LRMC per MW per year for distribution and transmission for each network the total cost in net present value terms (at 7% real weighted average cost of capital) to accommodate this increase is \$704 million for distribution and \$291 million for transmission.

Table 65– High Speed, impact on network demand

	Dead End (MW)	EV (MW)	Total (MW)	Share	Total (MW)
AusNet	103	1,897	2,000	27.5%	550
CitiPower	103	2,033	2,136	5.4%	115
Jemena	103	2,145	2,136	13.6%	305
Powercor	103	2,145	2,248	34.4%	774
United Energy	103	2,145	2,248	19.1%	430



Spatial analysis – High Speed

Under the High Speed scenario, of AusNet’s 52 substations, eight are expected to be in low exceedance, with two in high exceedance. Citipower should expect one of their 37 substations to be in low exceedance, with none in high exceedance. Four of Jemena’s 30 substations are expected to be in low exceedance, with five in high exceedance. 12 of Powercor’s total 58 substations are expected to be in low exceedance, with a further 10 in high exceedance. United Energy has no substations with expected maximum demand to exceed current capacity.

Table 67b- High Speed, projected capacity minus rated capacity by DNSP

	AusNet	Citipower	Jemena	Powercor	United
# zone substations (ZS)	52	37	30	58	47
#ZS projected MD < current rated capacity	42	36	21	36	47
#ZS projected MD > current rated capacity (exceedance 0%-10%)	8	1	4	12	0
#ZS projected MD > current rated capacity (exceedance 10%+)	2	0	5	10	0

4.8 Scenario: Slow Lane

4.8.1 Scenario description

In the Slow Lane scenario, in 2046, 50% of the fleet is composed of shared electric vehicles, and 50% of non-electric vehicles. Table 66 provides a summary of the key assumptions in the Slow Lane scenario.

Table 66 - Slow Lane Assumptions Summary

Description		Assumption
Number of vehicles	#	315,032
Total annual BEV consumption	GWh	10,096
Number of cars	#	122,741
Average VKT per day	km	505.97
Efficiency per 100 km	kWh	20
Network and charging losses	%	10%
Required electricity per day	kWh	112.44
Annual consumption of cars	GWh	4,714
Car charger		Shared cars Type 2 (9.5 kW), commercial cars Type 3 (240 kW)
Number of freight vehicles	#	192,291
Average VKT per day	km	57.11

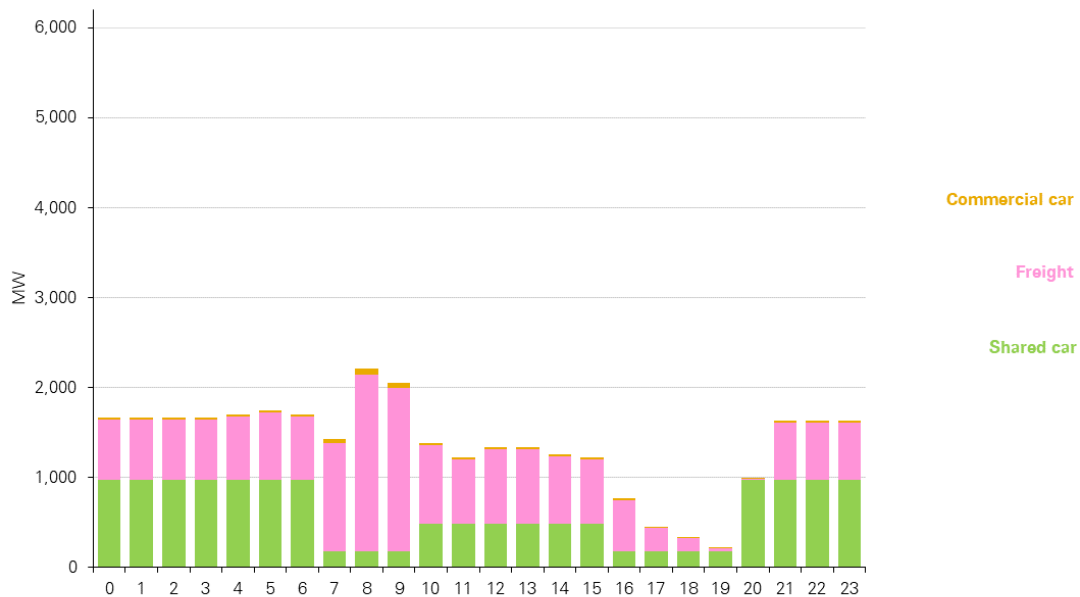


Efficiency per 100 km	kWh	129.11
Network and charging losses	%	10%
Required electricity per day	kWh	81.92
Annual consumption of freight	GWh	5,381
Freight vehicle charger	Type 3 (240 kW)	

4.8.2 Contribution to maximum demand

The Slow Lane load profile is illustrated in Figure 63. The profile concentrates demand (electricity used at a particular time (MW) away from the evening peak in Victoria, which is around 5 to 7 pm.

Figure 63 – Slow Lane load profile



4.8.3 Generation investment requirements

In the Slow Lane scenario, EVs add a total of 448 MW to maximum demand during peak hours. A total of 1,248 MW of additional dispatchable capacity is required to meet both the demand from EVs and other sources (that is, 448 MW from BEVs and 800 MW from other sources, as discussed in the Dead End scenario). We assume that this will be met by a combination of batteries and pumped hydro (zero emissions technologies), as well as by any “firm” capacity from wind and solar PV installed to meet the total consumption of electricity.

As noted above, the total consumption of electricity by EVs in 2046 is estimated as 10,096 GWh . If we assume that the total generation (GWh) of electricity remains constant from its 2017 levels, plus committed capacity and assumed LRET and VRET capacity at average capacity factors, less the assumed retirement of Yallourn in 2032, then there is an 8,241 GWh shortfall of generation in 2046 (noting that storage technologies to meet maximum demand do not in and of themselves add to total generation). This equates to 1,568 MW of wind capacity and 2,240 MW of solar PV capacity at 30% and 21% capacity factors respectively. This is approximately 11 wind farms at the current average size of existing and committed wind farms



in Victoria (140 MW), and 30 solar farms at the average size of committed solar PV farms in Victoria (75 MW). The dispatchable and non-dispatchable capacity required is illustrated in Figure 64.

Figure 64– Slow Lane, generation investment requirements

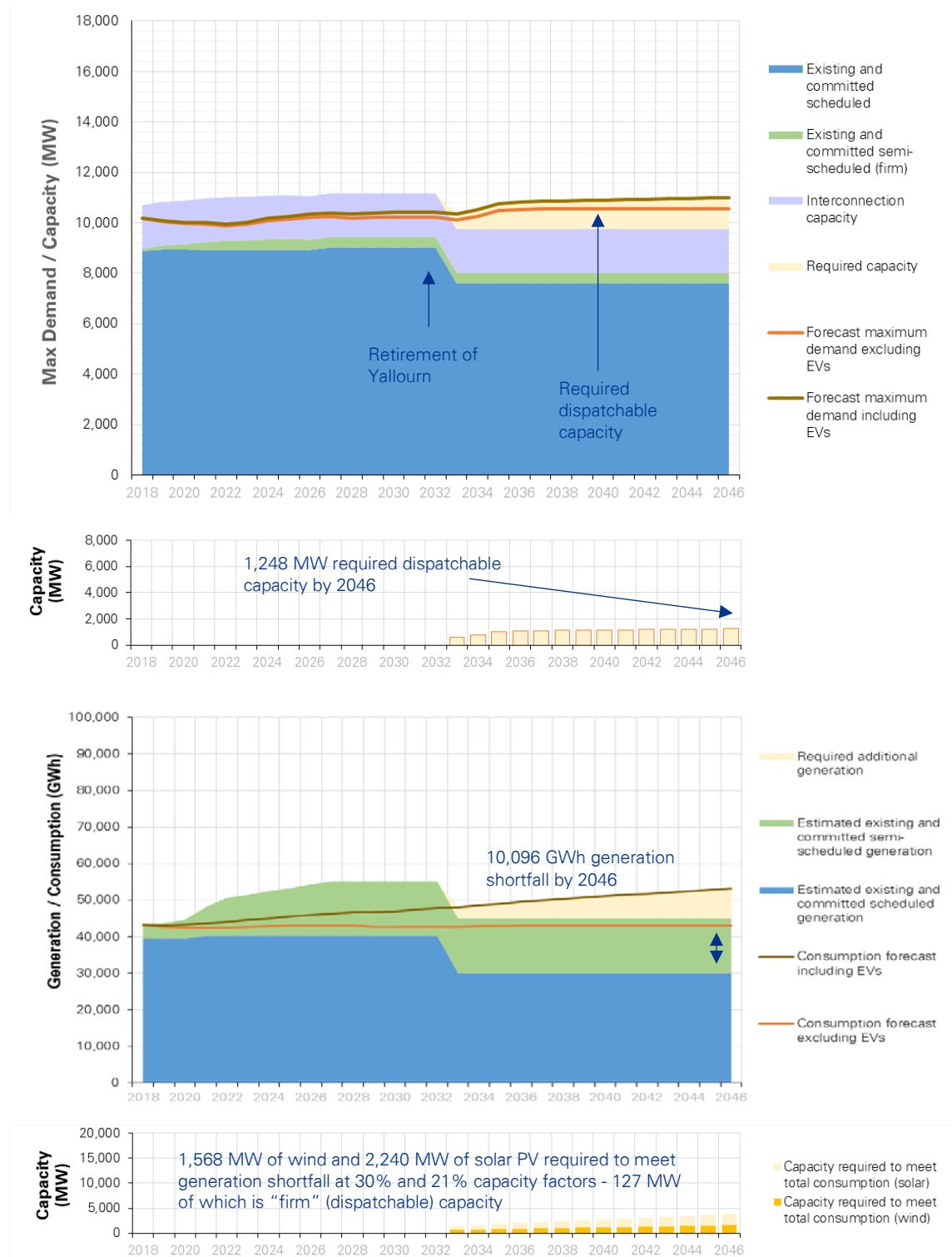




Table 67 summarises the total cost in net present value terms (at 7% real weighted average cost of capital) of new capacity (capital and connection costs only, not ongoing operating expenses) installed when required, as illustrated in Figure 64. Note that the dispatchable capacity installed of 1,121 MW reflects the dispatchable capacity “required” (i.e. 448 MW from BEVs and 800 MW from the Dead End scenario), less the “firm” peak contribution of the new non-dispatchable capacity installed (127 MW⁹⁶).

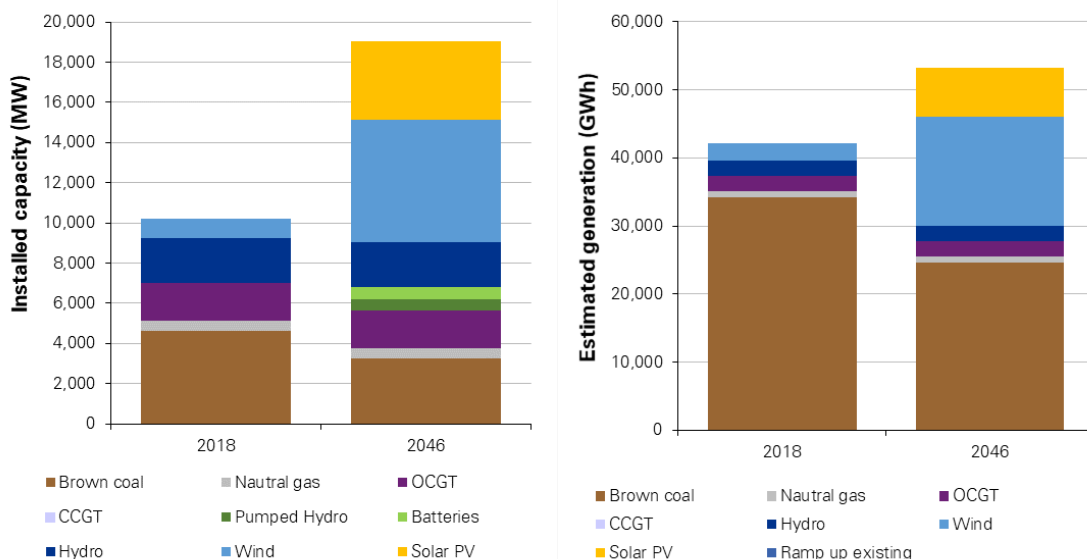
These results assume that no existing capacity ramps up generation to meet the additional consumption of electricity, and that no further retirements are made beyond Yallourn in 2032 (irrespective of the age of existing generation sources). Further, it reflects no reduction in either maximum demand (through for example increased demand side participation) or total consumption (through for example investments in energy efficiency) in response to a constrained supply situation, either or both of which may occur before the instalment of new capacity. We consider some sensitivities to these assumptions in section 4.10.

Table 67 - Slow Lane, total cost of installed capacity

	Dispatchable capacity installed	Total cost (NPV): Dispatchable capacity	Non-dispatchable capacity installed	Total cost (NPV): Non-dispatchable capacity	Total cost (NPV): All capacity	Total cost (NPV): Incremental to dead end scenario
Dead End	800 MW	319 m	0 MW	0 m	319 m	
Slow Lane	1,121 MW	429 m	3,808 MW	1,440 m	1,869 m	1,549 m

The installed capacity and generation mix resulting in the Slow Lane scenario is illustrated in Figure 65.

Figure 65 – Slow Lane, capacity and generation mix



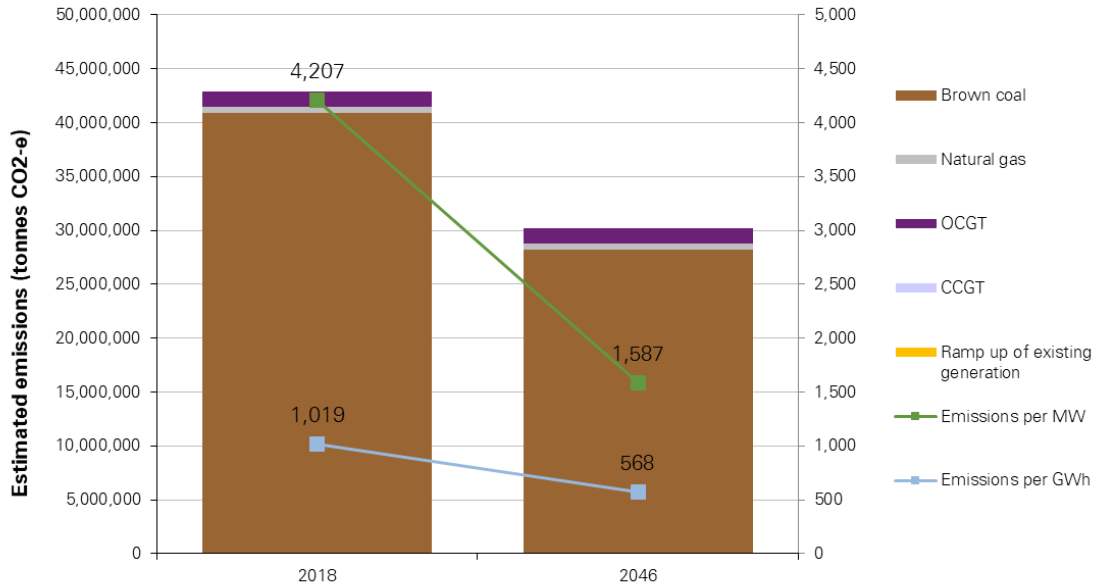
The new capacity and generation mix in 2046 is associated with no more emissions than in 2018, as all new capacity is assumed to be zero emissions (pumped hydro, batteries, wind and

⁹⁶ Calculated as 1,568 MW of wind multiplied by the “firm” contribution factor of 8.1%, please see chapter 3 for more detail.



solar PV. However, the average emissions (tonnes CO₂-e) per MW and GWh respectively fall as demand and consumption of electricity increases. This is illustrated in Figure 66.

Figure 66– Slow Lane, average emissions



4.8.4 Network investment requirements

Long run marginal cost analysis

AEMO’s maximum demand forecast excluding EVs increases by 512 MW between 2018 and 2046. We have assumed that this increase in maximum demand will affect all five distribution networks, in proportion to the number of cars in each network area.

EVs add different amounts to maximum demand in different networks, depending on the peak hours in a particular network and the relative share of the network in terms of ZEVs. Table 68 summarises the impact on the network in terms of additional maximum demand under the incentivised and non-incentivised scenarios respectively. As Table 68 demonstrates, under the Slow Lane scenario, CitiPower can expect the lowest impact on network demand with 113 MW, followed by Jemena with 240 MW. United Energy can expect the third lowest impact on network demand with 337 MW, Ausnet with 475 MW and finally Powercor with 590 MW.

At the LRMC per MW per year for distribution and transmission for each network the total cost in net present value terms (at 7% real weighted average cost of capital) to accommodate this increase is \$653 million for distribution and \$270 million for transmission.

Table 68– Slow Lane, impact on network demand

	Dead End (MW)	EV (MW)	Total (MW)	Share	Total (MW)
AusNet	512	1,256	1,768	26.9%	475
CitiPower	512	1,381	1,894	6.0%	113
Jemena	512	1,224	1,737	13.8%	240
Powercor	512	1,224	1,737	34.0%	590
UE	512	1,224	1,737	19.4%	337



Spatial analysis

Under the Slow Lane scenario, of AusNet’s 52 substations, 13 are expected to be in low exceedance, with two in high exceedance. Citipower should expect two of their 37 substations to be in low exceedance, with none expecting high exceedance. Four of Jemena’s 30 substations are expected to be in low exceedance, with a further six in high exceedance. 13 of Powercor’s total 58 substations are expected to be in low exceedance, with a further 11 in high exceedance. United Energy has no substations with expected maximum demand to exceed current capacity.

Table 69 - Slow Lane, projected capacity minus rated capacity by DNSP

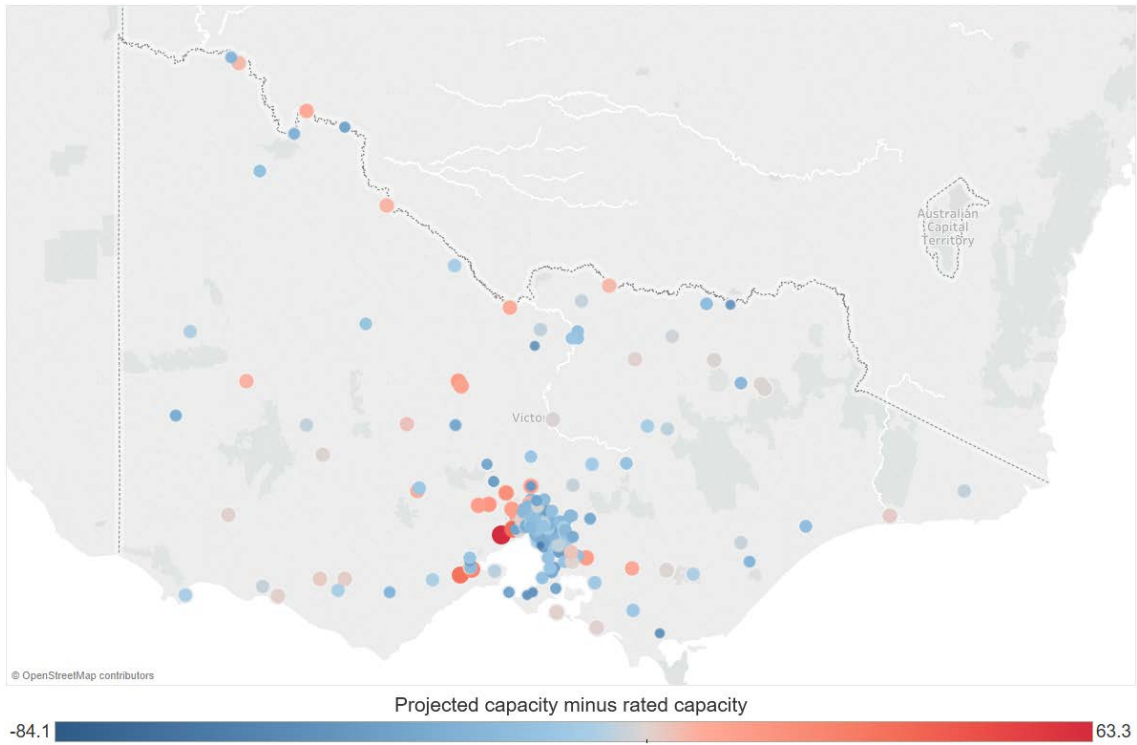
	AusNet	Citipower	Jemena	Powercor	United
# zone substations (ZS)	52	37	30	58	47
#ZS projected MD < current rated capacity	37	35	20	34	47
#ZS projected MD > current rated capacity (exceedance 0%-10%)	13	2	4	13	0
#ZS projected MD > current rated capacity (exceedance 10%+)	2	0	6	11	0

Table 70 – Slow Lane, location of top five zone substations where gap between MD and current capacity is greatest by DNSP

	AusNet	Citipower	Jemena	Powercor	United
Location of top five zone substations where gap between MD and current capacity is greatest	Pakenham	Prahran	Thomastown	Werribee	Burwood
	Warragul	Kew	Sunbury	Waur Ponds	Sandringham
	Clyde North	Richmond	Sydenham	Laverton	Keysborough
	Berwick North	Laurens Street	Watsonia	Geelong East	Frankston
	Wonthaggi	Riversdale	Kalkallo	Sunshine	Carrum



Figure 67 - Slow Lane, projected capacity minus rated capacity by zone substation





4.9 Scenario: Hydrogen Highway

4.9.1 Scenario description

The methodology underpinning the Hydrogen Highway modelling was discussed in Section 3.7 of this Report. Given the differences between FCVs and BEVs, modelling of the Hydrogen Highway required a different approach to provide relevant outputs.

In summarising the methodology defined earlier in this Report, our modelling for Hydrogen Highway undertook the following:

- Calculation of the total amount of hydrogen required based on vehicle efficiency statistics.
- Derivation of the resource requirements, and associated emissions, to meet the modelled hydrogen demand from three production sources: electrolysis, coal gasification and natural gas reforming.
- Application of sensitivities to test 'what if' options that may reduce the overall hydrogen requirement.

Our key findings from the Hydrogen Highway modelling are as follows:



A significant requirement for hydrogen fuel

Based on an annualised VKT of nearly 63 billion kilometres in 2046, there is a potential requirement for nearly 1.26 billion kilograms of hydrogen to support FCVs on Victoria's road network under our base case scenario.



New industry for Victoria

The Hydrogen Highway would present the opportunity for a new large-scale hydrogen industry in Victoria to meet the demands of road users.



High resource requirements for production

Our modelled electrolysis base case scenario indicates an electricity requirement in excess of Victoria's current levels of consumption to produce the necessary levels of hydrogen.

Similarly for coal and natural gas methods, the scale of hydrogen required will need significant levels of resources to allow for ongoing production.

In any case, technological advancements and improvements to both production processes and vehicle efficiency may assist in reducing hydrogen requirements.



Emissions are a key challenge for a zero emissions future

Where electrolysis technology is adopted (and powered by renewable energy), the production process is zero emissions.



However, the use of natural gas or brown coal to produce hydrogen will generate emissions of between 12 million and 36 million tonnes of CO₂ each year respectively, which would require full carbon capture and storage implementation to be considered zero emission.



Don't forget about water usage

All production methods considered have a significant annual water requirement of between 14 and 23 gigalitres of water for the base case options, which is equivalent to approximately 6,000 Olympic-sized swimming pools for the lowest water consumption method.

With water security an ever-important issue, this requirement would need to be balanced against Victoria's total water consumption requirements to ensure water security.

4.9.2 Resource consumption requirements

Hydrogen requirement

The results presented in Table 71 indicates that there is a significant amount of hydrogen required to support a road network of FCVs in 2046. We note our commentary regarding vehicle efficiency was detailed in Section 3.7.2.

Table 71– Hydrogen requirement by vehicle

	Annualised VKT (km)	Vehicle efficiency (km/kg H ₂)	Hydrogen required (kg H ₂)
Passenger vehicle	55,616,262,846	107.83	515,796,172
Freight	7,376,674,576	9.86	747,828,351
Total	62,992,937,422		1,263,624,523

We stress that the above efficiency numbers, which drive the overall hydrogen requirement, are subject to change in a 2046 reality. In particular, as there are currently no freight FCVs in commercial production, we have had to base our efficiency figures for this vehicle type upon prototype vehicles which may not be reflective of eventual real-world use.

Accordingly, we place particular caution on the freight requirements shown in Table 71 as this exceeds the requirement for passenger vehicles despite having much lower VKT. Improvements in technology as freight FCVs reach mass production may significantly alter the vehicle efficiency and thus reduce the impact on production requirements.

In any case, these results help present an idea of the level of hydrogen that may be required. These results indicate a significant level of infrastructure to establish a suitable supply chain, which could be met in a number of ways. Section 5.6 will consider supply chain elements further, including potential options for the transportation and distribution of hydrogen.

With the above hydrogen requirement, we have then modelled the likely resource consumption by technology type, which is presented below.

Resource usage

Table 72 sets out the resource requirements to support a road network of FCVs in Victoria in 2046 based on the outputs of MABM. The various assumptions behind the resource requirement inputs were discussed in Section 3.7.3 of this report.



Table 72– Base case resource requirements by technology

Resource	Electrolysis	Coal gasification	Natural gas reforming
Electricity (terawatt hour)	63.60	2.71	1.78
Water (gigalitres)	19.04	14.25	23.20
Brown coal (tonnes)	0.00	14,342,138	0.00
Natural gas (terajoule)	0.00	0.00	207,712

Electricity usage

Factors concerning electricity usage will be discussed in Section 4.9.3 below.

Water usage

Water usage varies between each technology and is required for differing purposes (i.e. it is core to the electrolysis reaction whereas part of the water usage in natural gas reforming is for cooling purposes). Depending on the use case, there is potential to recycle water to reduce the overall impact.

Under all technologies, there is a significant water requirement that would need to be met to ensure uninterrupted production of hydrogen. As highlighted in Section 4.9.2, water requirements vary between approximately 14 gigalitres for coal gasification and 23 gigalitres for natural gas reforming. A gigalitre comprises approximately 444 Olympic size swimming pools⁹⁷, so even under the lowest base water consumption process (coal gasification), hydrogen production at 2046 levels would consume over 6,000 Olympic sized swimming pools of water each year.

For practical reference, AGL Loy Yang consumed 37.52 gigalitres of water in FY17⁹⁸ as part of its operations (noting that AGL employs water recycling and other water management techniques). For electrolysis, it is important to note the water requirement presented in Table 72 does not consider upstream requirements. As a result, electricity being consumed in a production process may have been generated from sources that utilise water (both coal-fired and gas-fired turbines consume significant amounts of water), which would increase the overall water requirement across the supply chain.

What if technology improves?

As was discussed in Section 3.7.3, the resource requirements were based upon case studies provided by the U.S. Department of Energy. Particularly for electrolysis, while a 2025 future case study, there is noted potential for efficiency to improve further.

An important factor in this analysis is that we examining a potential outlook in 2046 and it is expected that technological advancements will occur to make processes more efficient. Particularly if hydrogen-based technology was to progress from its current state to fully

⁹⁷ 4618.0 – Water Use on Australian Farms, 2005-06, <http://www.abs.gov.au/ausstats/abs@.nsf/mediareleasesbytitle/B3EBBE603A417600CA2573360019081C?OpenDocument>

⁹⁸ Water consumption by facility, AGL, <http://agl2017.reportonline.com.au/data-centre/environment#tab-166>



commercialised, large scale usage, it is likely that both production of hydrogen and the amount consumed by vehicles would improve.

Accordingly, Table 73 presents the three possibilities modelled to highlight the impact of technological advancements in hydrogen generation, and consumption by vehicles. The sensitivities applied were as follows:

- **Base case:** As per modelled output, assumes no technology advancements.
- **Weak shift:** FCVs have become more efficient and their hydrogen consumption per 100km has decreased by 10%. Electrolysis technology met its 2020 targets set by the U.S. Department of Energy while coal gasification and natural gas reforming now consume 10% fewer resources.
- **Strong shift:** Further technological breakthroughs allowed FCVs to become even more efficient and hydrogen consumption per 100km has decreased by 20%. Electrolysis technology met its theoretical minimum energy usage while coal gasification and natural gas reforming consume 20% fewer resources.

Table 73– Impact of technological advancement on 2046 primary resource requirements

	Base case	Weak shift	Strong shift
Electrolysis - electricity required	63.60 TWh	50.54 TWh	41.49 TWh
Coal gasification – brown coal usage	14.34 million tonnes	11.73 million tonnes	9.56 million tonnes
Natural gas reforming – gas consumption	207,712 TJ	169,946 TJ	138,474 TJ

4.9.3 Generation investment requirements

Implications for electricity network

We assume that there is no additional contribution to maximum demand from FCVs as production can be shifted to non-peak times to minimise costs. We have also assumed production of hydrogen through electrolysis will be done solely through renewable sources.

The implicit total consumption of electricity by FCVs in 2046 is estimated as 63,598 GWh (or 41,489 GWh in the strong shift case scenario) in the electrolysis base case (strong shift case) in 2046. If we assume that the total generation (GWh) of electricity remains constant from its 2017 levels, plus committed capacity and assumed LRET and VRET capacity at average capacity factors, less the assumed retirement of Yallourn in 2032, then there is an 61,744 GWh (39,634 GWh) shortfall of generation in 2046 in the base case (strong shift case). This equates to 11,747 MW of wind capacity and 16,782 MW of solar PV capacity at 30% and 21% capacity factors in the base case. This is approximately 84 (54) wind farms at the current average size of existing and committed wind farms in Victoria (140 MW), and 225(144) solar farms at the average size of committed solar PV farms in Victoria (75 MW) in the base case (strong shift case).

These amounts fall to 7,541 MW of wind capacity and 10,773 MW of solar PV capacity under the strong shift case. The number of installations are a lot lower with approximately 54 wind farms and 144 solar farms required. The dispatchable and non-dispatchable capacity required in the base case and strong shift case are illustrated in Figure 68 and Figure 69 respectively.



Figure 68– Hydrogen Highway electrolysis base case, generation investment requirements

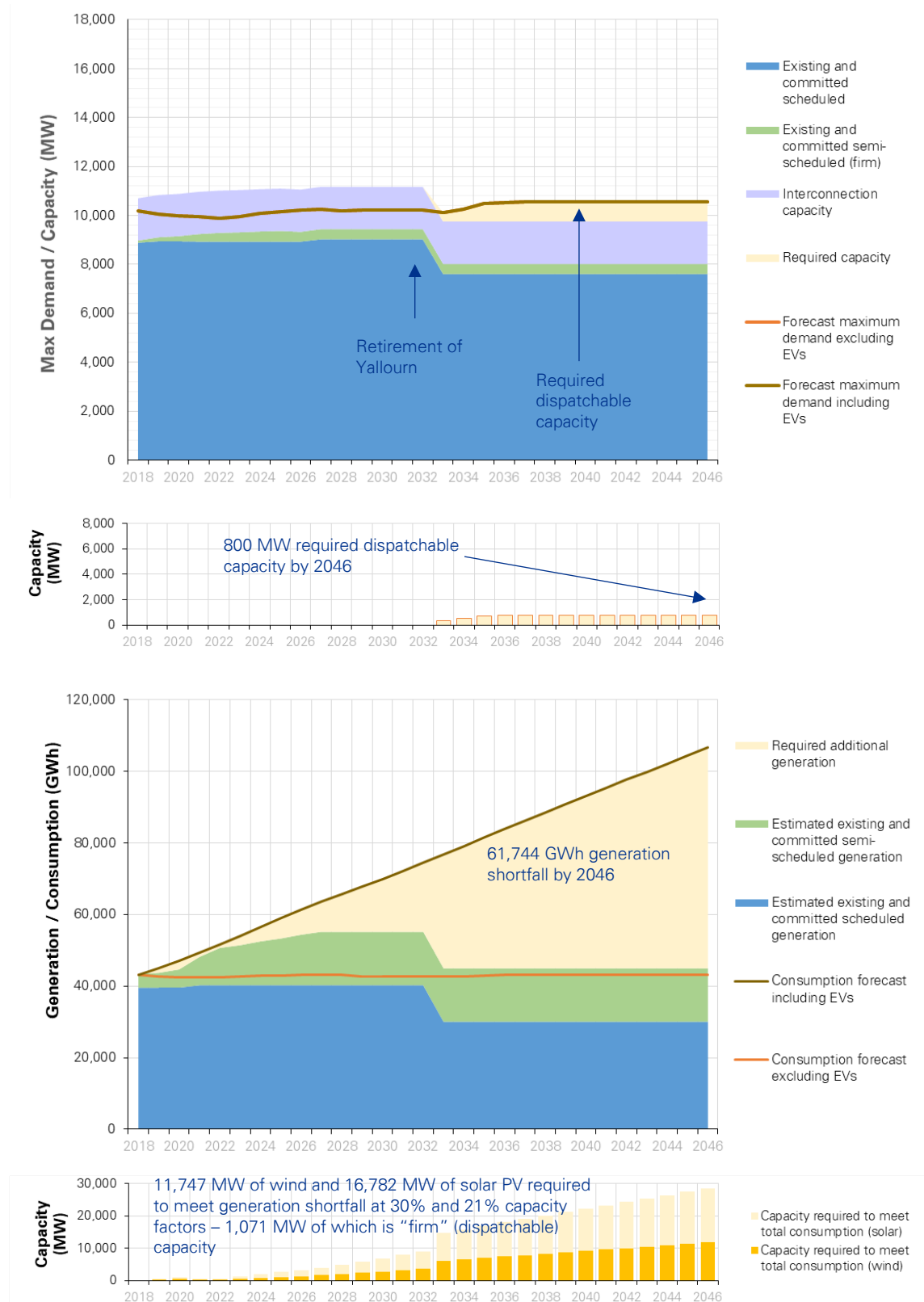




Figure 69 - Hydrogen Highway electrolysis strong shift case, generation investment requirements

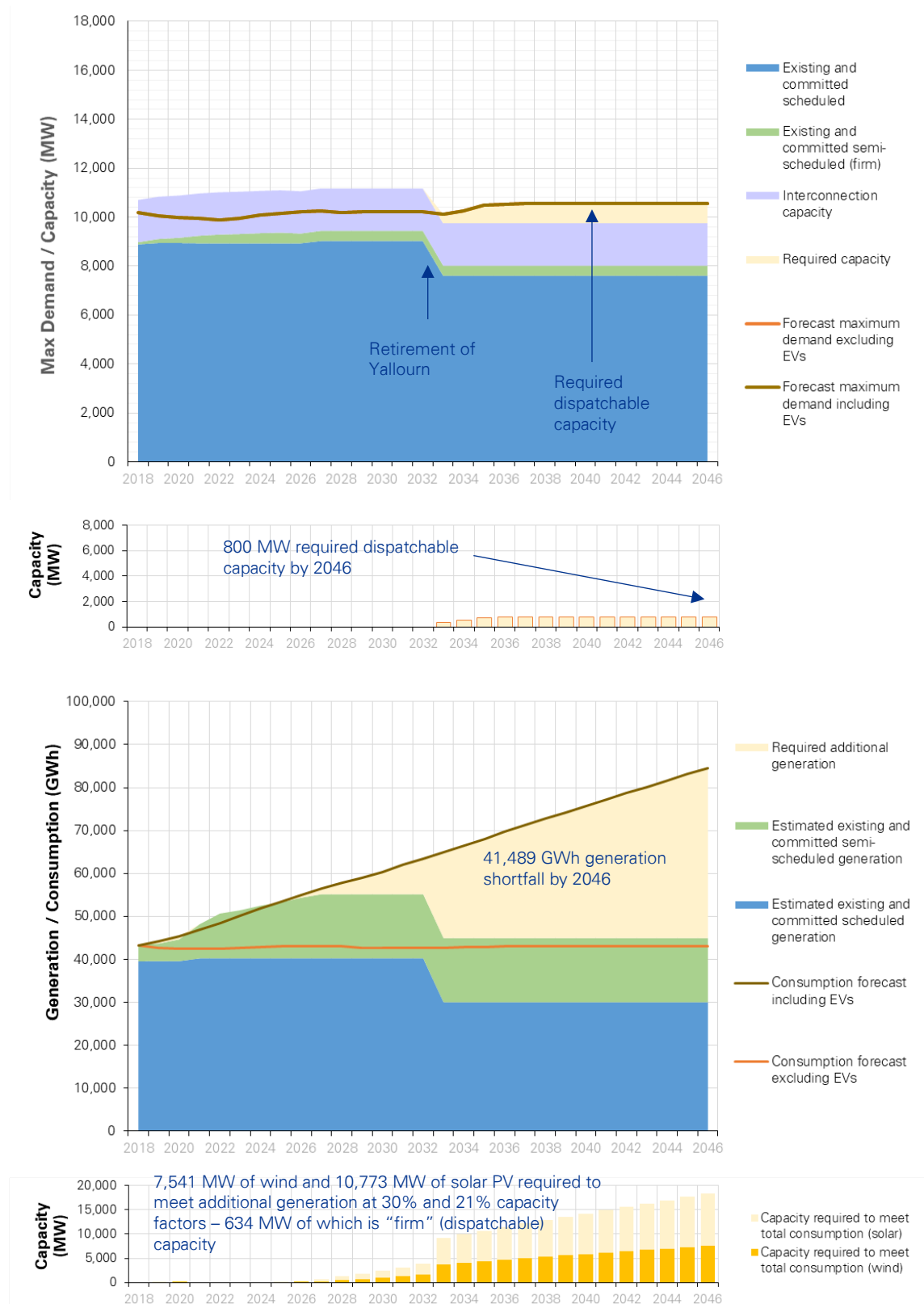




Table 74 summarises the total cost in net present value terms (at 7% real weighted average cost of capital) of new capacity (capital and connection costs only, not ongoing operating expenses) installed when required, as illustrated in Figure 68 and Figure 69 respectively. Note that the dispatchable capacity installed is zero MW because the “firm” contribution of the new wind and solar capacity is more than the required 800 MW.

These results assume that no existing capacity ramps up generation to meet the additional consumption of electricity, and that no further retirements are made beyond Yallourn in 2032 (irrespective of the age of existing generation sources). Further, it reflects no reduction in total consumption (through for example investments in energy efficiency) in response to a constrained supply situation, which may occur before the instalment of new capacity.

Table 74 – Hydrogen Highway, total cost of installed capacity

	Dispatchable capacity installed	Total cost (NPV): Dispatchable capacity	Non-dispatchable capacity installed	Total cost (NPV): Non-dispatchable capacity	Total cost (NPV): All capacity	Total cost (NPV): Incremental to dead end scenario
Dead End	800 MW	319 m	0 MW	0 m	319 m	
Hydrogen Highway - Electrolysis - Base case	0 MW	0 m	28,529 MW	14,843 m	14,843 m	14,524 m
Hydrogen Highway - Electrolysis - Strong shift	166 MW	66 m	18,313 MW	8,306 m	8,372 m	8,053 m

The installed capacity and generation mix resulting in the Hydrogen Highway base case and strong shift scenarios are illustrated in Figure 70 and Figure 71 respectively.

Figure 70 – Hydrogen Highway electrolysis base case, capacity and generation mix

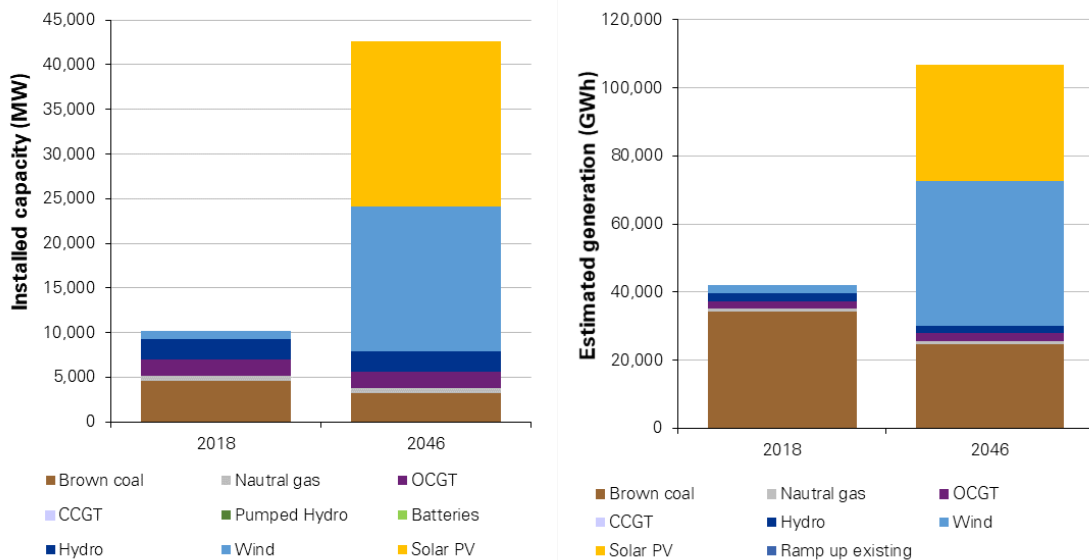
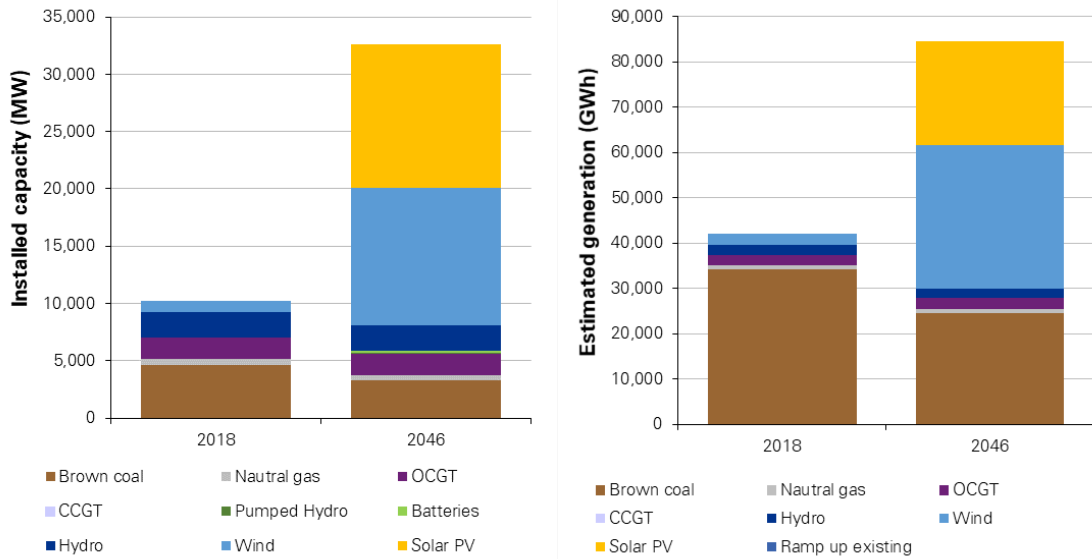




Figure 71 – Hydrogen Highway electrolysis strong shift case, capacity and generation mix



The new capacity and generation mix in 2046 is associated with no more emissions from the electricity sector that in 2018, as all new capacity is assumed to be zero emissions (pumped hydro, batteries, wind and solar PV). The average emissions (tonnes CO₂-e) per MW and GWh respectively fall as demand and consumption of electricity increases. This is illustrated in Figure 72 and Figure 73. The total emissions is the same in both cases (due to the existence of legacy plant), but this is divided by a greater total consumption / capacity in the base case, so lower on average.

Figure 72– Hydrogen Highway electrolysis base case, average emissions

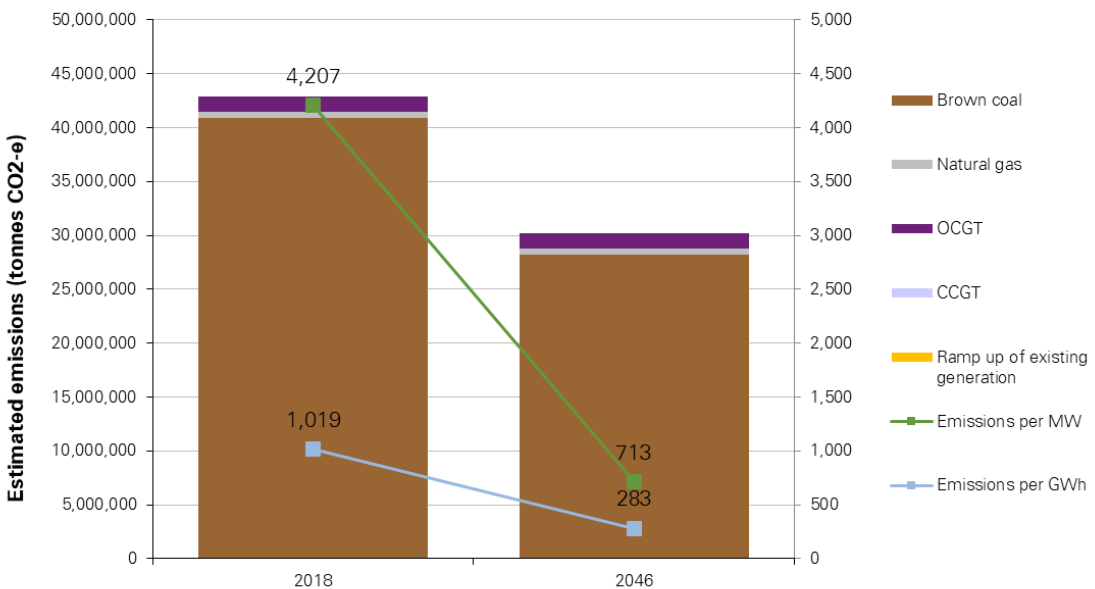
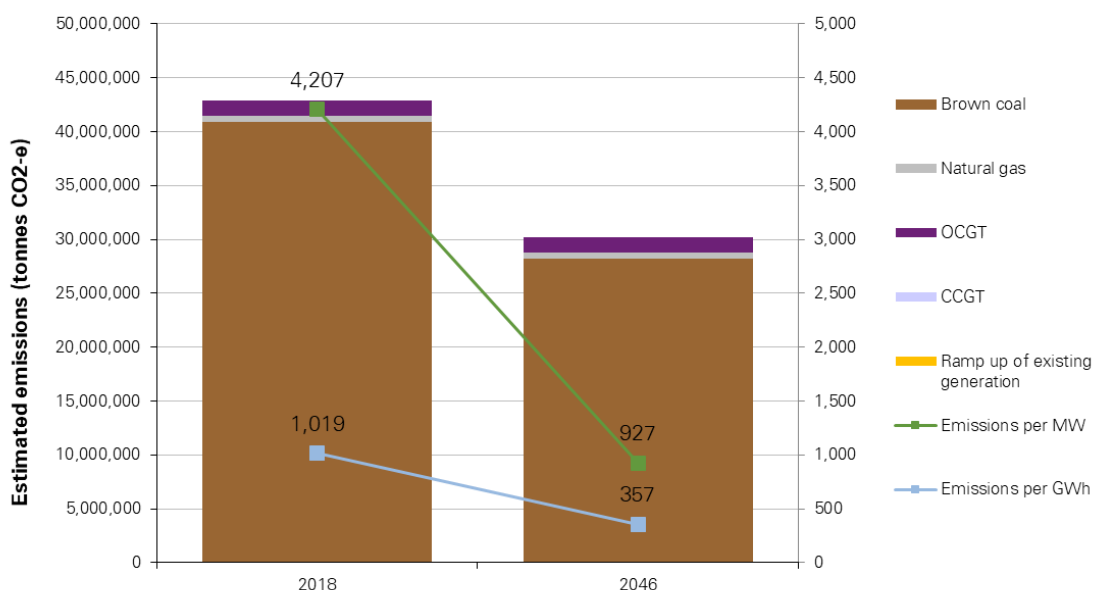




Figure 73– Hydrogen Highway electrolysis strong shift, average emissions



4.9.4 Network Investment requirements

As FCVs are assumed to not contribute any additional maximum demand, and therefore the network investment requirements are the same under both the Hydrogen Highway electrolysis base case and the strong shift as under the Dead End scenario.

4.9.5 Emissions

Based upon the assumptions provided within the relevant case studies, downstream emissions are modelled and represented in Table 75. Consistent with an objective of zero-emissions future, we have assumed that carbon capture and storage was perfected and 100% of production emissions could be sequestered.

Table 75 – Emissions statistics in 2046

Method	CO ₂ produced (tonnes CO ₂ annual)	CO ₂ sequestered (tonnes CO ₂ annual)	Net CO ₂ (tonnes CO ₂ annual)
Electrolysis	0.00	n/a	0.00
Coal gasification	35,672,120	100%	0.00
Natural gas reforming	11,701,163	100%	0.00

Particularly for electrolysis, which is considered a zero emission production method, the upstream emissions discussed in Section 4.9.3 would need to be considered in achieving a supply chain zero emissions target. As noted above, for the purposes of this analysis we have assumed 100% renewable generation.



4.10 Sensitivity analysis

As explained earlier the modelling results are very sensitive to a range of inputs and assumptions. To help understand the relative influence of key assumptions this section discusses a range of sensitivity analysis for the Electric Avenue –incentivised permutation. This is to provide an indicative of the potential change in impact under different assumptions. This is not a completed list of the material factors to the modelling results, plus the extent of the sensitivities will differ across the other scenarios.

Many of these sensitivities results do not estimate the impacts on network costs as we only model the sensitivity impact on generation supply, but in reality each of these issues could have implications for networks.

Table 76 - Sensitivity Analysis Summary for Electric Avenue – Incentivised

Electric Avenue (Incentivised)	Dispatchable capacity installed	Non-dispatchable capacity installed	NPV of generation requirement	NPV of network requirement
	MW	MW	\$ m	\$ m
Default settings	3,331	9,308	4,918	2,028
Absence of OOH charging	-133	0	-57	-66
Increased DSP	-1,024	0	-478	-27
Constrained interconnector availability	1,555	0	834	0
No fossil fuels in 2045	4,855	12,846	3,084	0
Ramp up of existing generation	31	-931	-355	0
Using charging to flatten demand	2,100	0	1,005	828

4.10.1 Absence of out-of-home charging

In the original Electric Avenue, incentivised scenario, 10% of non-commercial cars were assumed to be charging out of home using superfast charging (240 kW). If we assume no out of home charging takes place, the total required capacity to meet maximum demand falls from 3,331 MW to 3,198 MW.

The total consumption and non-dispatchable generation requirement remains the same. The total cost in NPV value terms for generation falls from \$4,918 m to \$4,861 m, and for networks it falls from \$2,028 m to \$1,962 m.

4.10.2 Increased demand side participation

In the original Electric Avenue, incentivised scenario, there is no increased DSP to counteract the increased maximum demand. If we assume that a 10% fall in the underlying maximum



demand, then the total required capacity to meet maximum demand falls from 3,331 MW to 2,307 MW. The total consumption and non-dispatchable generation requirement remains the same. The total cost in NPV value terms for generation falls from \$4,918 m to \$4,440 m, and for networks it falls from \$2,028 m to \$2,001 m.

4.10.3 Constrained interconnector availability

In the original Electric Avenue, incentivised scenario, there is no constraint on the interconnector from AEMO's assumptions on the capacity available during maximum demand. If we apply a constraint that only 10% of this capacity is available between 2030 and 2046, then the total capacity required to meet maximum demand increases from 3,331 MW to 4,886 MW (the interconnector capacity falls from 1,728 MW to 172.8 MW). The total consumption and non-dispatchable generation requirement remains the same. The total cost in NPV value terms for generation increases from \$4,918 m to \$5,752 m. This does not impact the network cost.

We have modelled the impact of this sensitivity on the network costs. However it is likely that there would be a need for increased intra-regional network investment for security and reliability reasons if the interconnection into Victoria became more limited.

4.10.4 No fossil fuels

In the original Electric Avenue, incentivised scenario, Loy Yang A, Loy Yang B, Newport and all OCGT generation is expected to retire after the modelling period up to 2046. If we bring these retirements forward to 2045, then the total capacity required to meet maximum demand increases from 3,331 MW to 8,186 MW. The non-dispatchable generation requirement increases from 9,308 MW to 22,154 MW. The total cost in NPV value terms for generation increases from \$4,918 m to \$8,002 m. This does not impact the network cost.

4.10.5 Ramp up of existing generation

In the original Electric Avenue, incentivised scenario, the generation requirement met by existing generation is at 0%. If we assume that 10% of the generation requirement is met by existing generation, then the total required capacity to meet maximum demand increases from 3,331 MW to 3,362 MW given the assumptions about load factors. The non-dispatchable generation requirement falls from 9,308 MW to 8,377 MW. The total cost in NPV value terms for generation falls from \$4,918 m to \$4,563 m. This does not impact the network cost.

4.10.6 Using managed charging to avoid extra maximum demand

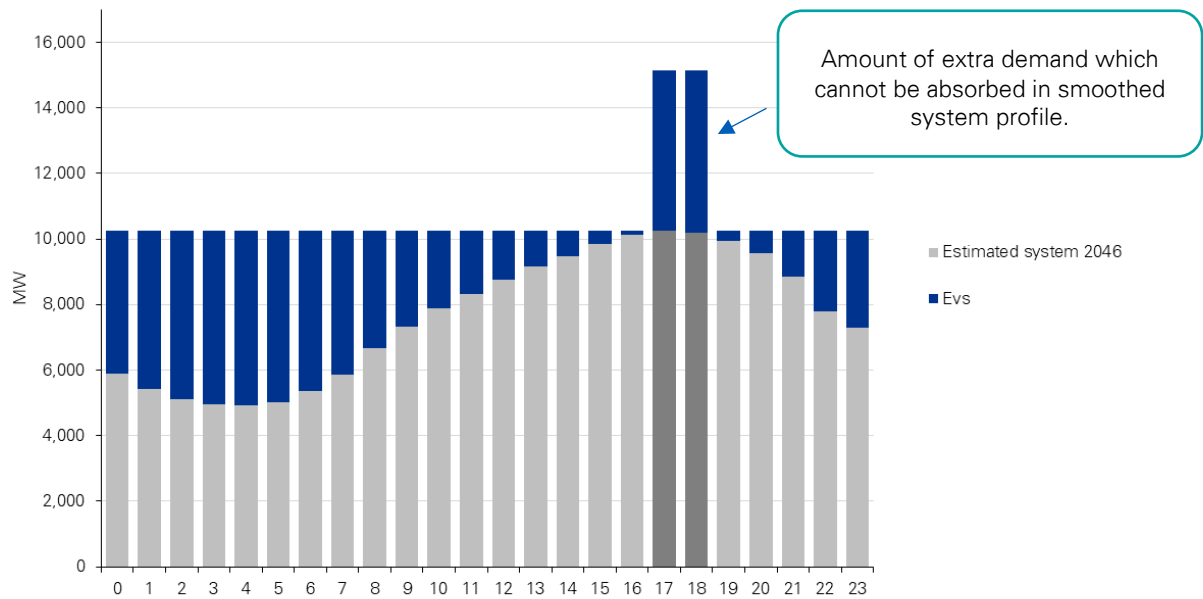
In the original Electric Avenue, incentivised scenario, the charging occurs as per the load profile shown in Figure 34. If managed charging occurs to shift consumption, to the extent possible, in out of system peak hours, we also conducted a sensitivity to see if it would be possible to avoid any additional demand during the system peak hours of 5-7 pm.

The results are shown in Figure 74. The implied EV load profile is illustrated in blue in the chart below, on top of an estimated system load curve based on the maximum demand forecast for 2046 under the dead end scenario. This shows that for this scenario it would not be possible to avoid any impact on system peak.

If the excess demand falls into the system peak period, then the total NPV for generation rises from \$4,918 m to \$5,923 m, and for networks increases from \$2,028 m to \$2,856 m. Maximum demand increases from 3,331 MW to 5,430 MW. The non-dispatchable generation and total consumption remains the same. This is probably the extreme outcome as under controlled charging some of that excess could in theory be smoothed out over the period.



Figure 74 – Ability to amend charging profile to minimise system peak impacts – Electric Avenue incentivised scenario





Infrastructure responses



5 Infrastructure responses

5.1 Introduction

The discussions provided in this Report thus far have focused on the modelling of the seven scenarios as part of the automated and zero emissions vehicles advice to Infrastructure Victoria. The final chapter of this Report will build on these prior discussions to consider a range of related issues regarding how the market will respond and provide the infrastructure that may be required in light of the results provided by the Victorian energy market impacts modelling.

This section explores determinants of infrastructure responses to understand how these can have an impact, including the role of the private and public sectors plus includes discussion of the response required of each aspect of the electricity network, as well as the determinants of change that may influence potential responses.

Under a high penetration of ZEVs, the infrastructure response challenge will impact a range of diverse parties, including both regulated and commercial businesses. This will also include both existing service providers and new entrants. From an infrastructure and energy perspective, key parties will include:

- Charging infrastructure manufacturers and maintenance providers.
- Energy generators, and retailers.
- Electricity network businesses, both transmission and distribution
- Distributed energy providers who will seek to set up peer-to-peer style energy trading, taking advantage of new technologies such as V2G, batteries, and smart grids.
- Charging infrastructure services providers (possibly a range of differing parties) that are crucial to roll out the required charging equipment to support BEVs.

Each of these parties will make separate investment and commercial decisions under the scenarios. However, the collective sum of these individual decisions will determine the effectiveness of the infrastructure response. How the regulatory and policy arrangements will promote align and consistency in decision making across these parties will be important. This chapter also evaluates some of the policy and regulatory matters which need to be resolved.

The structuring of this chapter is:

- a) Charging infrastructure response
- b) Benefits from BEVs, including vehicle to grid
- c) Generation and transmission infrastructure responses
- d) Distribution network infrastructure response
- e) Response under Hydrogen Highway



5.2 Charging infrastructure

This chapter discusses the range of issues associated with charging infrastructure needed to support penetration of BEVs. A range of different options and business models are likely to emerge to respond to customer preferences and requirements between now and 2046. As the volume of BEVs on the roads grows, the market for charging services will no doubt evolve and providers will adapt and refine their product offerings as competition grows.

This section provides a summary of the potential charging infrastructure technologies and discusses the range of factors which could influence the nature and extent of these responses. It also raises a number of policy and regulatory matters which impact on charging infrastructure response. How these issues are resolved will impact on the timing and nature of the infrastructure response.

The range of charging infrastructure available will be key to be effective integration of BEVs and managing the energy market impacts. Charging infrastructure will influence the rate of charging, the time of day of charging and the options for customers which in turn determines the impact on demand over the course of the day. Our modelling demonstrates the potential savings from having more incentivized charging.

This discussion is primarily from the perspective of BEVs. Issues associated with the Hydrogen Highway scenario is discussed in Section 5.6.

5.2.1 Overview of charging infrastructure

The uptake of BEVs requires a paradigm shift for drivers in how they drive their vehicles and keep them running. The current system with ICE vehicles sees drivers refuel their vehicles at external filling stations, with a refill taking a matter of minutes. These filling stations are widely available and have propagated alongside vehicle demand over a number of years.

With BEVs, this is expected to change. As electricity is widely available, a driver has many new opportunities to 'top-up' their car, whether this be at home, at work, at a shopping centre or along a highway. However, this necessitates a lot of new infrastructure to meet this demand.

Table 84 sets out the current classification of charging infrastructure, noting that these definitions do vary based on source. A range of power draws have therefore been presented. Further detail of each classification's characteristics will be provided below.



Table 77– Current EV charging infrastructure options

Type	Indicative Power Draw ⁹⁹	Charging speed	Cost	Use case
Slow	1.9kW to 3kW			Home
Fast	7kW to 22kW			Home or destination
Rapid	50kW to 120kW			Service or shared fleet
Ultra	120kW to 1MW			Service or shared fleet

Slow

Slow chargers, as the name suggests, are the slowest option available for charging a BEV and typically represents charging via household mains electricity, although some older charging stations may be slow chargers. The charging rate of slow chargers means that it would typically take 6 – 12 hours to charge a BEV at 3kWh thus are best suited for household uses where an EV could be charged overnight or for long time periods. From a consumer adoption perspective, it also does not require behavioural change as a driver would plug in their BEV on returning home from work in a similar fashion to how mobile phones are currently charged overnight.

In the UK, Councils are already phasing out slow charging infrastructure at public stations due to the charging speed¹⁰⁰ and replacing this with faster charging options as it is unlikely a driver would spend enough time with their vehicle plugged in to such stations to gain a high degree of benefit.

Fast

Fast chargers are the next level of charging, with typical charging rates at 7kW or 22kW⁹⁹, which would charge current BEVs in approximately 3 – 5 hours or 1 – 2 hours respectively. These may be used as a form of destination charging, where such infrastructure is available at movie theatres or shopping centres where a consumer may spend sufficient time such that the car receives a substantial charge.

The speed of charging may represent a challenge for a service-based model at dedicated charging points or service stations where a consumer leaves their car solely for charging thus expects it to occur very quickly. Thus, the technology may not represent the best use case for this scenario. As well as this, the increasing range of BEVs will also increase the charge time due to the higher capacity of the vehicles and may not be suitable for high mileage use cases where the owner requires their vehicles to always be available.

Rapid

Rapid charging infrastructure encompass a number of different options to the consumer, with some proprietary infrastructure being rolled out. For example, Tesla are rolling out their

⁹⁹ Charging speeds & connectors, ZapMap, <https://www.zap-map.com/charge-points/connectors-speeds/>

This compares to an average power draw of a Victorian household of 3 kW.

¹⁰⁰ Electric Vehicle Charging Infrastructure, APSE Briefing 17/38, October 2017,

<http://apse.org.uk/apse/index.cfm/members-area/briefings/2017/17-38-electric-vehicle-charging-infrastructure/>



Supercharger technology globally with free annual credits offered to subsidise charging for drivers. However, these stations are only usable by Tesla-branded BEVs at present. CHAdeMO and Combined Charging System, two competing DC standards, are also being rolled out that are supported by a greater number of vehicles. A discussion of these charging standards and their implications can be found at Section 5.5.4 of this Report.

Rapid chargers may utilise either AC or DC, with the former providing an 80% charge in less than an hour while the latter is the more common option rapid charging, and can deliver 80% charge in 30 minutes.

Given their fast charging time and higher power draw, a rapid charger would be best suited to public places along motorways or at service stations. This is the approach already adopted by Tesla who are placing Supercharger stations along the Hume Highway between Melbourne and Sydney, and on the Western Highway between Melbourne and Adelaide. Tesla have taken a similar approach in other jurisdictions, as have other charging infrastructure projects which will be discussed below

As well as this, rapid charging may represent a viable option under shared fleet scenarios whereby vehicles are undertaking daily high mileage and require fast recharging so they spend more time on the road to maximise revenue for the operator. In this manner, shared vehicle depots would likely contain a number of rapid chargers (or 'ultra chargers' as technology advances), and the capital outlay for this would need to be considered.

Due to the power draw, and typical household behaviours, it is unlikely that placing a rapid charger into each Victorian household would be a suitable option. The current cost of these chargers would be a deterrent from a pricing perspective, however, the power drawn would be a bigger concern for the Victorian electricity network. Regulation may also be used here to legislate allowable limits for home-based BEV charging.

Ultra charging and future developments

While the speed of BEV charging has currently reached a point where a rapid charger can provide approximately 80% charge in 30 minutes, further development is required into 'ultra charging' to reduce charging time to a current ICE refilling level (approximately 5 – 10 minutes). It is estimated that a 100kWh EV, capable of a range of nearly 500km, could be charged in 8 minutes with a 750kW charger¹⁰¹.

Current projects in Europe are looking to roll out future-proof charging infrastructure that could potentially support 350kW 'ultra charging'.

Ultra charging may be useful to owners of shared fleets that are undertaking regular, heavy mileage. Such vehicles would require quick charging to be returned to the road to earn more revenue. In addition, freight providers are likely to require ultra charging infrastructure at freight depots. This is not so much for the speed of charge (which is still important), but rather the increased energy requirements of these heavy vehicles that would have significant battery packs.

As an illustrative example, some heavy BEV trials have indicated power draws in excess of 100kWh/100km¹⁰². For long distance or interstate freight trips, the battery packs required to support these journeys may require ultra-fast charging infrastructure to restore this level of energy in a suitable timeframe. One article from American Chemical Society estimated that

¹⁰¹ The Tipping Point for Electric Vehicle Charging, Engineering.com, 12 December 2017, <https://www.engineering.com/ElectronicsDesign/ElectronicsDesignArticles/ArticleID/16172/The-Tipping-Point-for-Electric-Vehicle-Charging.aspx>

¹⁰² California Air Resources Board 2018, Battery Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicles.



current technology may require battery packs in excess of 3,000kWh for approximately 1,500km of range¹⁰³. Such a vehicle may require over 8 hours of charging with 350kW “ultra charging” to replenish this. We do note that this is a long-haul example and the modelling undertaken for this advice considers low kilometer average trips that do not have such a requirement. However, this is nevertheless a practical consideration as long-haul freight needs to be considered in a transition to full BEV uptake if this scenario occurs.

Based on current technology, vehicles themselves are limiting the potential level of charging. There are two scale-up issues when using higher levels of electricity to charge¹⁰¹:

- Motors in excess of 1,000V have issues with electricity arcing, whereby a sudden discharge may damage components due to significant heat.
- Metal plates between an EV and charging plug are at risk of burning when high currents are provided.

It is expected that technological developments in battery and charging technology will occur over time to facilitate faster charging infrastructure to bring charging times down to that of a conventional ICE vehicle. However, the impact on electricity networks is likely to be the area where the impact of this infrastructure will be felt most. As the charging capability of infrastructure improves, it will increase loads on an energy network.

Accordingly, a suitable infrastructure response will likely implement a range of different charging technologies that are suited to particular applications. For example, it is unlikely that a household would require ‘ultra-fast’ charging in excess of 500kWh as BEVs can be charged overnight or while residents are home. Such chargers may be reserved for strategic uses or the power output would be scaled appropriately.

5.2.2 Current situation

Australia

The early stages of charging infrastructure rollout has demonstrated that a number of parties, both public and private, have played a role in providing charging infrastructure. However, Australia has lagged behind the rest of the world in providing charging infrastructure given the low number of BEVs on the road.

Current initiatives in Australia include:

- Chargepoint offers over 150 charging points in Australia and is supported by a mobile app, with a mix of free and paid stations available.
- Tesla has installed its ‘Supercharger’ charging stations between Adelaide and Brisbane, with nearly 20 sites listed and more planned.
- The Royal Automobile Club in Western Australia has installed 11 fast-charging stations.
- The NRMA launched a \$10 million project in 2017 to deliver at least 40 charging stations in NSW and the ACT. The stations will offer free EV charging for NRMA members.
- Mitsubishi and the City of Adelaide council have rolled out 8 DC fast-charging stations in Adelaide with another 11 planned¹⁰⁴.
- Queensland Electric Super Highway from the Gold Coast to Cairns and from Brisbane to Toowoomba in a low or zero emissions vehicle.

¹⁰³ Sripad S & Viswanathan, V 2017, Performance Metrics Required of Next-Generation Batteries to Make a Practical Electric Semi Truck, ACS Publications, pp. 1670.

¹⁰⁴ Mitsubishi rolls out EV charging stations in Adelaide CBD, CarAdvice, 29 September 2017, <https://www.caradvice.com.au/588168/mitsubishi-rolls-out-ev-charging-stations-in-adelaide-cbd/>



Global developments

Table 85 below provides a summary of the number of charging stations located in several countries. Please note that this is not the number of chargers but rather unique locations that a car could charge. Some stations may contain multiple devices for charging.

Table 78– BEV charging stations in selected countries

Country	Number of charging stations
China	213,903 ¹⁰⁵
Netherlands	32,875 ¹⁰⁶
Germany	25,241 ¹⁰⁷
Japan	23,000 ¹⁰⁸
United States of America	20,714 ¹⁰⁹
United Kingdom	5,756 ¹¹⁰

Throughout the world, there have been many projects and initiatives to encourage the uptake of charging stations for BEVs. A brief discussion of projects in Europe and the United States will be touched on below. Both have made substantial inroads into providing charging infrastructure, particularly in Europe where EU member states are cooperating to ensure chargers are available on highways between countries.

European initiatives

There have been many initiatives in the European Union to encourage BEV uptake and increase the availability of charging infrastructure. The European Commission’s *Connecting Europe Facility* provides funding for several projects, typically constituting a mix of public and private funds.

The structure of the European Union makes it ideal for supporting highway networks of charging infrastructure between member states. Indeed, a number of projects observed focus on rollouts across a number of EU member states to construct ‘super networks’ of chargers along highways.

Importantly, a number of projects being funded in Europe are looking to the ‘next generation’ of BEVs that are expected to offer driving ranges of approximately 500 kilometres, which would put their range on par with a conventional ICE vehicle. In doing so, ‘ultra-charging’ stations are

¹⁰⁵ China has the most public EV charging stations worldwide, ChinaDaily, 11 January 2018, <http://www.chinadaily.com.cn/a/201801/11/WS5a5759d9a3102c394518e9e1.html>

¹⁰⁶ Total number of PEV charging positions, European Alternative Fuels Observatory, <http://www.eafo.eu/electric-vehicle-charging-infrastructure>

¹⁰⁷ Ibid.

¹⁰⁸ Japan paves way for gas stations to charge up electric cars, Nikkei Asian Review, 21 February 2018, <https://asia.nikkei.com/Politics/Japan-paves-way-for-gas-stations-to-charge-up-electric-cars>

¹⁰⁹ Alternative Fueling Station Locator, Alternative Fuels Data Center, U.S. Department of Energy, https://www.afdc.energy.gov/stations/#/analyze?fuel=ELEC&ev_levels=all&show_private=true

¹¹⁰ Charging point statistics 2018, ZapMap, <https://www.zap-map.com/statistics>



being rolled out that support charging up to 350kW, which would facilitate long-range charging at fast speeds.

Some examples of projects currently underway or planned for Europe include:

- The Fast-E project is currently the largest charging infrastructure project funded by the European Commission. It aims to install 307 charging stations (supporting fast charging) in Belgium, Germany, Czech Republic and Slovakia to provide charging across a 20,000 kilometre road network¹¹¹.
- Central European Ultra Charging commenced in 2018 and will target the installation 118 charging stations capable of charging at up to 350kW across 7 European countries¹¹².
- EUROP-E is being led by BMW, Daimler and Volkswagen, and seeks to provide infrastructure to support the next generation of BEVs with a 500km range. The project will deliver 340 'ultra-charging' stations (up to 350kW) in 13 European countries, predominately placed along highways¹¹³.
- Announced in April 2018 with €29 million in funding provided by the European Commission, the MEGA-E project will aim to provide 322 'ultra-charging' stations (up to 350kW) in metropolitan areas of 10 European countries, with the first stations due to be opened in June 2018¹¹⁴.

United States initiatives

While the European Union consists of member states who may be a beneficiary of particular projects, the United States is instead faced with the challenge of a singular country spread across a large landmass, which requires an extensive network of charging infrastructure to facilitate interstate driving.

The EV Project was an early-adoption study commencing in 2009 that aimed to understand user preferences and the likely need for charging infrastructure as BEV uptake increased into the future. While the project was not completed in full, it saw over 12,500 charging stations delivered across the United States¹¹⁵ in both residential and out-of-home locations. As well as this, a wealth of knowledge was gathered which was shared with both the public and private sectors.

The largest project in the United States supporting BEVs is the Electrify America project. This is a 10 year, US\$2 billion investment into BEVs throughout America, with 40% specifically allocated to California and the balance being spread across the remainder of the United States.

The Electrify America project is largely focused on providing charging infrastructure across the United States. The first investment cycle through to the year 2027 is aiming to achieving the following¹¹⁶:

¹¹¹ Fast Charging Study Europe, <http://www.fast-e.eu/be-de/>

¹¹² Central European Ultra Charging, Innovation and Networks Executive Agency, European Commission, <https://ec.europa.eu/inea/en/connecting-europe-facility/cef-transport/2017-eu-tm-0065-w>

¹¹³ EUROP-E: European Ultra-Charge Roll Out Project – Electric, Innovation and Networks Executive Agency, European Commission, <https://ec.europa.eu/inea/en/connecting-europe-facility/cef-transport/europ-e-european-ultra-charge-roll-out-project-electric>

¹¹⁴ EU Commission co-finances MEGA-E project with 29 million euros, Allego, 25 April 2018, <https://www.allego.eu/eu-commission-co-finances-mega-e-project-with-29-million-euros/>

¹¹⁵ What Can be Learned From The EV Project to Inform Others Who May be Interested in a Similar Study?, The EV Project, December 2015
<https://avt.inl.gov/sites/default/files/pdf/EVProj/WhatWouldEVPDoDifferently.pdf>

¹¹⁶ Our Plan, Electrify America, <https://www.electrifyamerica.com/our-plan>



- Establishing a network of non-proprietary BEV charging equipment at 650 community sites and 300 highway sites across the United States.
- The rollout will be focused on 17 metropolitan areas including New York City, Boston, Miami and Los Angeles.
- Community-based charging stations will support charging up to 150kW and will be based at workplaces, shopping centres and local government buildings.
- Highway charging stations will feature up to 350kW 'ultra charging' and will be rolled out with multiple charging points at each station to support the charging of up to 10 cars at one time.

5.2.3 Implications per model findings

Residential charging

Our modelling indicates that a large amount of charging for privately owned passenger vehicles is likely to occur at the home as this is convenient for drivers. On returning to their home, a driver plugs in and their car will charge, ready to use for the next trip.

Therefore, for the Electric Avenue and Private Drive scenarios, consideration would need to be given to the potential number of households that may seek to install their own Type 2 charging infrastructure. For households that own multiple vehicles, they may seek to add multiple chargers if this is deemed necessary.

Table 86 below presents Victoria-specific statistics from the 2016 Australian Census on occupied dwellings and vehicles per household. For example, if every current household (based on average number of motor vehicles) installed a charger for each BEV, the potential number of Type 2 chargers could be higher than the modelled number.

Table 79 – Victorian 2016 Census Statistics¹¹⁷

Occupied Victorian dwellings	
Separate house	1,546,945
Semi-detached (i.e. townhouse)	300,918
Flat or apartment	246,040
Other	11,093
Total Victorian occupied dwellings	2,104,996
Vehicle statistics	
Dwellings with 0 vehicles	166,061
Dwellings with 1 vehicle	722,675
Dwellings with 2 vehicles	776,286
Dwellings with 3+ vehicles	374,426

¹¹⁷ 2016 Census QuickStats Victoria, Australian Bureau of Statistics,
http://www.censusdata.abs.gov.au/census_services/getproduct/census/2016/quickstat/2?opendocument



Average motor vehicles per dwelling 1.8

While the population in Victoria will increase between now and 2046, this nevertheless aids in providing an idea of scale for the potential number of chargers in households. As discussed in Section 5.4, DNSPs may face challenges if a large number of households opt to install charging infrastructure, particularly at higher levels of charge.

Based on Table 86, the following should be noted in considering the level of residential charging infrastructure:

- Noting that the average number of motor vehicles per dwelling is 1.8, there are likely to be scenarios whereby households will seek to install 2 (or more) Type 2 chargers so each vehicle can be charged at the same time. Particularly for households with for example two full-time workers, both may wish to charge their BEVs on returning home at the end of the day.
- 17.7% of the households surveyed had 3 or more motor vehicles registered to a dwelling. This may pose localised issues due to the high level of charging occurring from one household.
- The cost of charging infrastructure, and any potential connection costs, may limit the capacity or number of charging infrastructure installed. If the cost of Type 2 charging significantly decreases, there may be many more drivers who wish to install such chargers.
- The emergence of smart charging technology may minimise the number of chargers required as one charger may be sufficient to manage charging of two cars. Alternatively, a multi-connector charger could be utilised to charge vehicles from one charger.
- Flats or apartments may be limited in their charging infrastructure availability. The onus may fall on a body corporate or building owner to provide charging infrastructure within the parking spaces reserved for residents who do not have standalone parking.
- Street parking will be a challenge to overcome. Many drivers currently park their vehicles on the street overnight due to a lack of parking at their residence. It would need to be decided who provides this charging infrastructure as this parking is on public land and a BEV owner may not have an ability to request charging infrastructure.

Out of home charging

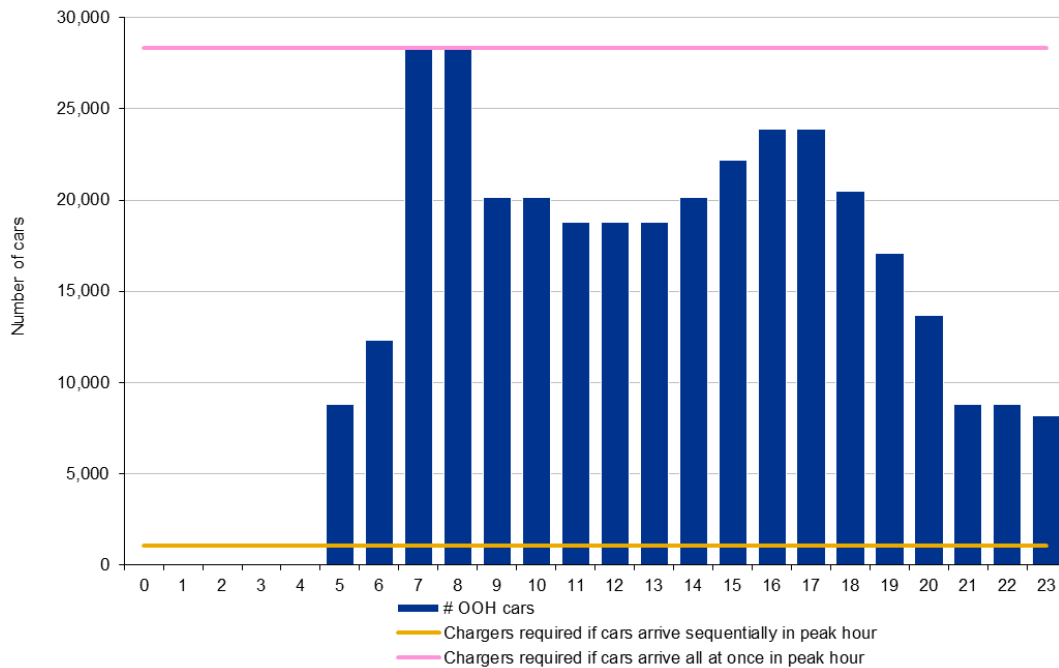
The Electric Avenue and Private Drive scenarios both assume that 10% of all residential cars are charged out of home using Type 3 chargers (240 kW). This charging is assumed to occur during the day, in particular in the morning, at a workplace or a similar location. Type 3 chargers are able to charge the daily requirement of cars in the Electric Avenue and Private Drive scenarios in only a couple of minutes (9.25 and 10.4 minutes respectively).

The requirement for Type 3 charging stations away from homes will be highly dependent on the extent to which cars simultaneously need to use it. In Electric Avenue Scenario, 341,491 cars are assumed to be charged out of home (10% of all residential cars). 28,344 of these cars are assumed to charge between 7 and 8 am and 8 and 9 am in the morning (peak). If these cars all arrive sequentially to one another (and there is no time lost between cars, likely only a theoretical possibility), then 1,092 Type 3 chargers would be required. If these cars all arrive at the start of the hour however, then a full 28,344 Type 3 chargers would be required to avoid any time spent waiting.

This is illustrated in Figure 85 below, and shows how highly dependent the requirements are on the specific timing of use of the infrastructure. The actual number of public Type 3 chargers installed will fall between these two extremes.



Figure 75 – Potential charging infrastructure required under Electric Avenue scenario



Although not explicitly modelled, out of home charging infrastructure will likely also be required along highways and major roads to address “range anxiety” during longer distance driving. In this scenario cars may require more electricity than the average daily VKT travelled, but this would occur less frequently.

Further, it is possible to contemplate a situation where many workplaces and other car parks have bays with Type 1 (~3 kW) or Type 2 (~9.5 kW) chargers, where cars are parked for several hours whilst drivers work or go about their day away from their car. However, this would require more charging infrastructure than the modelled situation where cars only use the (much faster) charging infrastructure to charge, and not to park, thereby precluding others from using it once the car is fully charged.

5.2.4 Business models and ownership options

Charging infrastructure is a key part of the BEV ecosystem, and is itself a subsystem in which many agents interact – the Electric Vehicle Supply Equipment (EVSE) owner and operator who provide the physical charging equipment in the home, office, or at a public pole, and the Electric Vehicle Service Provider (EVSP).

There are several parties who are currently bridging the gap and providing the necessary infrastructure to support BEVs. Table 87 below sets out likely providers of charging infrastructure for each sector.

Table 80– Charging infrastructure providers

Sector	Potential provider	Rationale
Public	<ul style="list-style-type: none"> Federal Government 	<ul style="list-style-type: none"> Provides investment to support charging infrastructure in areas that private sector may not find profitable (i.e. rural areas).



	<ul style="list-style-type: none"> • State Government 	<ul style="list-style-type: none"> • Support for Government fleet vehicles.
Private	<ul style="list-style-type: none"> • Automakers • Dedicated charging businesses • Retail groups and hoteliers • Shared fleet owners 	<ul style="list-style-type: none"> • Providing the necessary infrastructure to support customers purchasing BEVs. • Business model of paid charging networks in a form of 'charging-as-a-service'. • Encourages consumers to visit shopping centres or hotels knowing their vehicle can be charged.
Clubs	<ul style="list-style-type: none"> • Automotive clubs • Peak automotive bodies • Tourism bodies 	<ul style="list-style-type: none"> • Providing benefits to club members which will be seen as a necessary service to justify membership fees. • Less likely to have a profit focus, particularly in initial years to drive uptake of BEVs.

Shared fleet operators

Particular consideration should be given to shared fleet owners as they will have differing requirements to a private owner. Much of the discussion of this section concerns private BEV ownership whereby an owner would have a home-base that also requires charging out-of-home.

For a shared fleet of autonomous vehicles, these would likely be housed in depots and be making regular trips throughout the day, leading to high daily mileage. As was seen in our modelling results, autonomous vehicles under the Fleet Street scenario were averaging over 550km per day. Accordingly, there is a requirement for charging infrastructure that maximises vehicle time on the road. Offsetting this is that rapid (or ultra) charging infrastructure will have a much higher capital cost.

Therefore, a shared fleet owner would need to balance the following factors:

- An appropriate fleet size based upon charging requirements and time spent on the road.
- The necessary number of charging stations at a depot, and the speed of that charging infrastructure.
- The use of smart metering or other technology to monitor electricity prices to optimise charging against road revenues.
- Whether storage technology should be used to store electricity from low-demand periods to reduce the cost of BEV charging.
- Capability of local network to support this higher draw of electricity.



Impact of plug types

At present, there are several different standards applicable to charging infrastructure. This can make the rollout of charging infrastructure difficult where vehicles may only be compatible with certain connectors. For infrastructure providers, this may mean one of two things:

- A loss of potential customers as not all vehicles can be charged at a charging station.
- Infrastructure providers construct charging stations with adapters or connectors to support various plug types, which may increase station cost but allows more vehicles to utilise the charging point.

Table 88 presents the various plug types currently available for BEVs.

Table 81– Current charging plug standards

Plug Type	Use-case	Key countries	Examples of supported manufacturers
SAE J1772 (Type 1)	Widespread EV charging	America, Japan	Nissan, Mitsubishi
Mennekes (Type 2)	Widespread EV charging	Europe	Renault, Audi, Volkswagen, BMW
CHAdEMO (Type 4)	DC fast charging standard	Worldwide	Nissan, Toyota, Mitsubishi
Combined Charging System	Combines J1772/Mennekes and DC charging into standard plug	Worldwide	BMW, Chevrolet, Volkswagen
Tesla Supercharger	Proprietary fast charging of Tesla vehicles	Worldwide	Tesla

Implications for consumers and infrastructure providers

The current trend for plug types appears to be that particular plugs are being adopted in certain areas of the world by differing interest groups. To compound matters, competing infrastructure has emerged both for AC charging and DC charging.

While the Combined Charging System aims to use pre-existing AC plugs to couple with the DC part of the charger, the competing CHAdEMO standard for DC charging is an entirely different plug. To complicate matters, Tesla have their own proprietary Supercharger technology which no other BEV can use. A lack of clear standard in the market presents challenges for infrastructure providers and consumers.

Consumers

From a consumer perspective, charging infrastructure needs to be widely available and easy to use. While there are different fuel types for ICE vehicles, pumps for each fuel are standardised and a consumer does not have to consider whether a particular service station includes a pump that fits their fuel tank.

Mass adoption of BEVs requires a system that is not complicated for a consumer, with an expectation that their vehicle could be charged at any charging station. Where a consumer has to search for a correct charging station, or visit multiple stations, this would impede uptake.



This is a particular consideration for Australia currently as no charging standard has been selected as a preferred model.

Currently, a consumer in Australia would have to factor this into their purchasing decision when selecting a BEV, noting that the Australian market only has limited models available. A Tesla or Renault vehicle would require a Mennekes connector whereas a choice for a Mitsubishi or Nissan car may instead use the SAE J1772 connector.

The numerous different types of charging plug, as well as the added layer of AC and DC charging, is likely to confuse consumers who may not understand these differences. It is likely that an ongoing education program would have to be carried out by BEV advocates between now and 2046 to support a transition away from ICE vehicles. There is a role for Government here to not only lead by example (such as early adoption of BEV fleets) but also in education of consumers.

Infrastructure providers

For countries such as Australia that have not adopted a charging standard, infrastructure providers may be faced with a greater challenge in supporting all vehicle types.

No matter whether Government, automobile clubs or vehicle manufacturers opt to provide charging infrastructure, consideration would have to be given to the plugs available at a charging station. While it may increase costs, infrastructure providers may opt to provide a mix of charging plug options at their charging stations to ensure that a large number of consumers are able to use this station.

A defined charging standard would send a clear message to infrastructure providers on what equipment to provide for charging stations and minimises the additional costs of providing multiple plugs or chargers.

The way forward

For all parties involved, a common standard allows for a clear understanding of the technology that needs to be adopted. While the Australian Government has not yet mandated a particular standard, there has been progress in moving towards standardised charging infrastructure.

The Federal Chamber of Automotive Industries (FCAI), Australia's peak industry body for automotive manufacturers, announced a commitment to harmonising charging infrastructure standards in September 2017. FCAI has agreed that its member companies (which include Tesla and Nissan) will support the following plug types in their vehicles sold after January 2020¹¹⁸:

- AC charging: Mennekes (Type 2) plug.
- DC charging: Combined Charging System or CHAdeMO.

It is important to ensure into the future that there remains consistent standards should technology change. There is a risk that a plug may become obsolete and a new technology appears. It would then be necessary to ensure that a new standard is adopted at this time to avoid the issue of competing replacements.

Business models to facilitate an infrastructure response

Any scenario contemplating a full fleet of BEVs would need to contemplate who would provide the necessary infrastructure to support the charging required. In the context of our modelling, key questions arise:





¹¹⁸ Federal Chamber of Automotive Industries, FCAI technical statement on EV charging standards for public recharging infrastructure, 18 September 2017, <https://www.fcai.com.au/news/codes-of-practice/index/year/all/month/all/publication/99>



- If home owners want specific charging infrastructure, is there a way this can be provided at an attractive cost?
- For shared fleet operators under the Fleet Street, High Speed, or Slow Lane scenarios, how could they be provided with rapid charging infrastructure given high capital outlays?
- As ICE vehicles are phased out, could petrol stations become charging infrastructure providers?

In the following section, we will discuss a number of potential business models and how they may assist in providing the required infrastructure responses for charging equipment. Table 89 summarises a number of potential key players in this space.

Table 82– Summary of infrastructure providers

Provider	Infrastructure response	Residential 	OOH 	Commercial 	Shared 
Utility	Constructs charging infrastructure and bundles charging packages into electricity deals. “Mobile phone” style plan to provide charging equipment that is paid over time.	✓	✓	✓	✓
Infrastructure or vehicle manufacturer	Could provide charging equipment as part of vehicle/fleet package or constructs public network of chargers.	✓	✓	✓	✓
Dedicated charging network operator	Provides a network of charging infrastructure with a subscription fee model.	x	✓	✓	✓
Service provider	Provides public charging stations at parking towers, service stations or shopping centres.	x	✓	x	x

Distribution network service providers

DNSPs are able to utilise their existing position in the market to provide residential customers with a bundled service in addition to a standard home electricity package. In this way, discounts and pricing incentives can be provided to consumers. The utility provider may assist in constructing charging infrastructure, either in the home or at public points, for their consumers to access as part of the bundle.



This model is a flexible infrastructure response to rolling out charging infrastructure. As utility providers offer services to both residential and commercial customers, packages to roll out charging infrastructure could be tailored to meet each of the charging needs identified by our modelling.

Regulatory factors for public charging stations

Regulatory factors in Australia are a key consideration in the context of DNSPs as owners or providers of charging infrastructure. There is a risk of DNSPs becoming a barrier to competition as their market position allows:

- The ability to cross-subsidise a competitive service from its regulated activities.
- The ability to use information gained through the provision of regulated services to gain advantage in competitive markets.
- The ability to discriminate in favour of a DNSP's own subsidiary.
- The ability to restrict access of other participants in contestable markets to infrastructure services provided by the DNSP, or providing access on less favourable terms than to its related electricity service providers.

Based on the current regulations, DNSPs are not permitted to provide services in contestable markets, other than through a fully ring-fenced affiliate. Ring-fencing is the identification and separation of regulated monopoly business activities, costs and revenues from those associated with providing services in a contestable market.

By imposing ring-fencing requirements, the intention is to provide a level playing field for all market participants. While it is possible to obtain a waiver in certain, limited circumstances, these are not expected to be issued very often and are unlikely to apply to BEV charging infrastructure.

Consequently, assuming the provision of BEV public charging infrastructure is competitive, DNSPs would provide these services through an affiliate and comply with strict requirements.

Regulatory factors for equipment at premises

There are further barriers preventing distribution networks from also owning charging infrastructure at customers' premises. Currently under the National Electricity Rules, DNSPs are not permitted to own equipment behind the residential meter or large charging stations. This means they are limited in their ability to become a provider of charging infrastructure.

Under the National Electricity Rules, DNSPs are not permitted to recover the costs of installing equipment "behind the meter"¹¹⁹ via their regulated revenue. In effect, this prevents them from installing or owning any equipment behind the meter. Instead the distribution network is required to contract third party providers such as customer aggregators or infrastructure owners in order to access the network benefits from BEVs.

This issue arises because new technologies are capable of providing multiple value streams across the regulated and non-regulated parts of the electricity market. For example, V2G technology allows customers to store energy when prices are low (or their solar panels are generating excess energy) and sell this when prices are high. Battery storage can also provide value to DNSPs by allowing them to manage the security and reliability of their network if there are a large network of BEVs.

¹¹⁹ "Behind the meter" refers to the location behind a customer's connection point. The connection point is taken to be the dividing line between equipment that is owned and operated by the DNSP versus the customer or a third party.



Further discussion of issues specific to the distribution network is contained in Section 5.4.

Equipment and electricity package

Through negotiation with utilities networks, there may be potential for infrastructure manufacturers, vehicle manufacturers, or a middle-man, to provide a bundled offering to consumers. Under this model, charging infrastructure would be leased to the customer, which might be residents or businesses. Incentives could be included (i.e. free electricity for charging for a temporary promotional period) as part of the ongoing package. It is likely the bundle offered to consumers would pay off the charging infrastructure over time, after which ownership passes to the consumer.

This would allow greater access to faster charging infrastructure that otherwise may be too expensive for a one-off purchase. In this way, the bundled model is akin to that of a mobile phone plan, whereby the customer would be charged on a 12 or 24-month period and they then own the charger.

As this model relies on leasing equipment to the customer that is paid off over time, such a model could function as an infrastructure response to meet any charging scenario per Table 89. This is also likely to be key to the Fleet Street, High Speed, or Slow Lane scenarios as shared fleet owners could enter into a contract that provides their required charging infrastructure at a manageable cost rather than upfront capital payment.

Providing the 'correct' charging infrastructure would need to be considered under this model such that households aren't leasing or being placed on an equipment plan for expensive, fast charging infrastructure that may not be necessary in a home environment and would serve to place stress on the electricity network.

Dedicated charging offering

Bundle packages may also be offered by a dedicated charging provider to give a consumer access to a wide, public charging network. As an infrastructure response, these businesses would construct networks of charging stations along highways and other high-use areas for consumer use. Commercial solutions could also be considered to provide charging infrastructure to fleet owners. Consumers would then be charged a fee to access the charging network, with the availability of rapid or 'ultra-fast' chargers for quick charging.

For deployments in public areas and depots, this would serve as a response to the need for "out-of-home", commercial, and shared fleet charging scenarios. A subscription based model for public stations would not suit providing charging infrastructure for home use which is likely better responded to by other models.

Such an offering would realistically only be viable in a market whereby there are relatively few service providers and those that exist operate large networks. If a wide and easily accessible network is not available, consumers will not be interested in signing up with a provider, or multiple providers, that either experiences network congestion or does not have chargers placed at the necessary spots required by a consumer.

There is also the risk of monopolised assets under this model if a provider emerges as the dominant charging network provider, either through significant investment into their own network or through acquiring competitors. In either case, there would be a role for Government to consider how to regulate such a scenario as charging infrastructure may potentially become a regulated asset subject to tariffs.



Service network offering

Another opportunity may exist for infrastructure owners to offer a bundled ‘service package’ to consumers that would include an array of related services, including the electricity required to charge a car¹²⁰. This would likely be priced on a pay-per-use basis.

As an infrastructure response, this is likely to act in a similar method to service stations today. A provider would construct charging stations with amenities (i.e, convenience store or food options) and charging would be billed to the customer based on an electricity rate. These would be located along highways and within urban areas, with sizing scaled to fit demand.

Figure 7676 – Examples of service provider models



Parking towers or shopping centres

- Access to fast charging station.
- Time-based parking included.



Service stations

- Access to fast charging station.
- Use of car wash facilities, air pumps, and other amenities.
- Included credits for food/drink from convenience store.

5.2.5 Interaction with electricity markets

Table 90 below provide a summary of how the structure and diversity of charging infrastructure responses could influence the materiality of the impacts to the electricity markets under the scenarios. It identifies the trades off between the flexibility of the charging load, customer preferences and the impacts on the electricity market.

Table 83 – BEV charging infrastructure and impact on electricity markets

Type	Indicative Power Draw ¹²¹	Flexibility of load	Electricity market impact
Slow	1.9kW to 3kW	Medium	Low
Fast	7kW to 22kW	High	Medium
Rapid	50kW to 120kW	Low	High
Ultra	120kW to 1MW	Very low	High

Given these trade-offs, the interaction with the pricing and compensation arrangements under the electricity markets, and the behaviour of market participants will have an influence on the nature and extent of the charging infrastructures. This is discussed further in the sections on benefits from EVs and the distribution network responses.

¹²⁰ <http://www.wik.org/fileadmin/Konferenzbeitraege/netconomica/2011/Lorenz.pdf>

¹²¹ Charging speeds & connectors, ZapMap, <https://www.zap-map.com/charge-points/connectors-speeds/>



5.2.6 Policy and regulatory issues

This section provides an initial overview of some of the policy and regulatory issues which will arise and influence the extent and timing of the response needed with respect to charging infrastructure to manage the number of vehicles under the modelled scenarios. This is not an exhaustive list and there are possible other issues to be resolved.

Interoperability

The BEV ecosystem, that is the whole value chain from vehicles, charging infrastructure and related communications infrastructure, is an excellent example of a network in which coordination and interoperability or compatibility are central to competitive effects and system efficiency.

Interoperability is a measure of how easy or difficult it is for different parties to communicate with each other via communications-enabled infrastructure, such as smart meters. A communications platform is the system that provides the communications link between two points. In the case of smart meters, for example, this link enables the conveyance of metering data and status information from the smart meter to the market operator, network business and retailer, as well as commands, messages and software updates back to the meter.

Interoperability means that only one set of processes is required to communicate with other parties. Without interoperability, costs are likely to be higher as parties would need to have the capability to communicate using different protocols. Multiple communication protocols can also become problematic and costly if existing infrastructure needs to be upgraded to be able to interact with new standards.

In the context of EV charging there are two areas where interoperability is important:

- Inter-operability between different charging infrastructures to allow roaming and seamless billing for customers
- Inter-operability between a customer's smart meter and the charging equipment to maximize demand side participation value

To achieve inter-operability requires agreeing on a common or shared communications standard that allows seamless communication between different charging stations, and between a customer's smart meter and their charging equipment.

In the context of public charging infrastructure, interoperability will allow customers to use a single payment type across all public charging points, even where these points are owned by different service providers. We note that having different payment methods between charging points can cause frustration for customers, where users may need to carry a "whole fistful of different swipe cards from different firms". As well as enabling roaming and billing, a common communications standard and ICT platform can provide a single clearing house that simplifies financial transactions and contract management.

In the context of home charging and smart meters, having a common communications standard will facilitate demand side participation by customers in the energy market. As BEVs can effectively operate as battery storage, customers that have some flexibility in the use of their EV could, in return for a payment, permit their retailer, DNSP or a third party to control the use of the charging infrastructure via a smart meter. This would allow the EV to provide value to the market at times when network support was required e.g. during periods of high demand, when the EV could be discharged

The transition during the gradual uptake of BEVs will be important. The arrangements should be guided by a vision of what would be required given mass roll-out and extensive roaming, to avoid expensive re-engineering at the later date. This could justify the need for government intervention early.



Does charging constitute a sale of electricity?

A factor influencing charging models and operators is whether the charging of BEV would constitute a legal sale of electricity under the current legislation.¹²² This is important for potential infrastructure providers as they would be required to obtain additional authorisation if their business models constitute a legal sale of electricity.

The potential nature of BEV charging could complicate the question of whether this is a sale of electricity. A sale of energy tends to be considered to have occurred when a person passes on a charge for energy as a separate charge. However, when that energy is part of another charge (for example, a hotel tariff which includes energy costs in the charge), then this does not constitute a sale of electricity.

As discussed, the supply of electricity for BEV charging can be bundled with other goods and services (for example, free kilometres with the vehicle purchase), at which point they may not be considered a legal sale of electricity. Hence it is not straightforward that all BEV charging products would constitute a sale of electricity especially if the charging is ancillary or incidental to other services.

If the supply of electricity for the charging of a BEV is found to constitute a sale of electricity (as legally defined), then the energy market arrangements relating to the electricity retail licensing regime would apply to the BEV service provider. Under this regime, the sale of electricity is prohibited unless the seller obtains a retailer authorisation or an exemption.

Electricity market consumer protections would also apply to these consumers if there is a legal sale of electricity. Consumer protections in this case refer collectively to measures such as maintaining connection of supply, choice of retailer, payment/billing and customer hardship provisions. This provides an extra layer of regulation and customer management that would need to be adopted by a service provider if their business models constitutes a legal sale of electricity.

Network connection issues

From an electricity network perspective, BEV charging generally occurs at two points on a network:

- At a direct connection to the distribution network. This occurs at a connection point either via a retailer to the distribution network or directly to a distribution network.
- At a connection to an embedded network. An embedded network is a network connected to but not forming part of a transmission or distribution network and it provides electricity to a third party. For example, a network within a shopping centre complex providing electricity to tenants. This occurs through an on-selling arrangement where a person acquires energy from a retailer following which the person acquiring the energy sells this energy for use within the limits of premises owned, occupied or operated by the person.

The National Electricity Rules and National Energy Retail Rules set out the high level requirements for connecting electrical installations to the distribution network. These include obligations on both DNSPs and the connecting party, from when an initial connection enquiry is lodged through to the acceptance of a connection offer. For historical reasons, different access and connection regimes are in place depending upon the type of connected party.

Connection of DER, such as rooftop solar PV or household batteries, is covered by Part 5A of the NER. The connection process depends upon whether any augmentation of the distribution network is required to accommodate the new connection. If no augmentation is required, the

¹²² For the National Electricity Market jurisdictions, this would be the National Energy Retail Law and Electricity Supply Act (2004) in Western Australia.



DNSP must provide the connection in accordance with an AER-approved “model standing offer”. If, on the other hand, augmentation is required, the DNSP is not obliged to make any standing offer and the connection terms are negotiated.

The intention of Rule 5A is to exclude deep system augmentation charges for retail customers. Under current arrangements, it is expected that it would be difficult for a consumer to connect BEV charging infrastructure on parts of the network where augmentation would be needed, i.e. where the “hosting capacity” for such resources has already been exhausted.

Presumably, the DNSP could undertake augmentation to create new hosting capacity in such areas. However, we are not aware of any rules or regulations that oblige the DNSP to do this, and the regulatory framework creates incentives on DNSPs to avoid incurring any unnecessary cost. The current arrangements therefore provide for:

1. Where there is adequate hosting capacity, connection of a DER may be seen as relatively straightforward and involves no subsequent restrictions on access specific to that resource;
2. Where there is inadequate hosting capacity, connection of a DER may not be commercially viable, at least for small consumers; and
3. A DNSP is not obliged to augment the network to provide new hosting capacity where this has been exhausted, and is financially discouraged from doing so if this would incur significant cost not approved in the regulatory determination.

Further, any charging infrastructure connection would have to comply with technical standards. Such standards for connecting to the distribution network are set out in state-based Service and Installation Rules (SIRs). The governance arrangements for the SIRs vary between jurisdictions, with varying degrees of oversight by state governments or regulators. Consequently, DNSPs across the NEM have different requirements for approving connections.

These technical standards and DNSPs’ individual connection policies have the potential to become a barrier to installing charging equipment for electric vehicles. Indeed, restrictions already exist in at least two states. In Queensland, Energex and Ergon require the use of BEV charging equipment to be under a certain current rating. If the rated current exceeds 40 amperes for a three phase system or 20 amperes for a single phase system in a residential building, the installation must be approved by the DNSP.¹²³ South Australia Power Networks has a similar restriction.¹²⁴

These types of restrictions are not limited to BEV charging equipment. DNSPs have been challenged by the rapid uptake of a range of new technologies, including solar PV and battery storage. While distribution networks can cope with a small number of such technologies on their networks, as penetration increases, it is more difficult for DNSPs to keep their networks within secure operating limits. If these limits are breached, the quality, reliability and security of supply to all customers will be impacted.

Charging solutions for common end-of-trip sites

At premises like apartment buildings and corporate office parks where vehicle parking facilities are located in basements or spread across a large campus, there are often significant costs in reaching unmetered supply to establish a new connection to the distribution network for the new BEV charging equipment. The most cost-effective metering configuration is a sub-meter for the BEV charging load, with the accredited Meter Provider for the site taking responsibility

¹²³ Queensland Electricity Connection and Metering Manual, Service and Installation Rules, 1 December 2017, clause 4.2.5.

¹²⁴ South Australia Power Networks, Service and Installation Rules Manual No. 32, August 2017, clause 6.5.7.



for undertaking the subtraction task and preparing separate data-streams for the BEV charging load and the rest of the premises.

However, there are a number of barriers in the current arrangements on such charging solutions. Hence, the metering (metrology) arrangements in Victoria will influence the nature of charging infrastructure for locations where there is common charging across multiple users.

5.2.7 Government involvement

There is a potential for Government to be involved in a number of areas concerning the provision of charging infrastructure, of which the following will be considered below:

- Standards.
- Interoperability.
- Construction and location of charging infrastructure.
- Reforms to distribution connection arrangements.

Without Government intervention, there is a risk that a suboptimal outcome is achieved at a statewide (or national) level as particular parties may be disadvantaged. This could present in a number of ways, whether it is due to a lack of clear standard, not enough infrastructure in rural areas or particular market participants being unable to play a role due to regulatory constraints.

Standards

As was noted in Section 5.5.4, the FCAI have announced a commitment for their members to adopt a harmonised approach in charging standards and ensure common plug types are included on vehicles sold into the Australian market. This commitment will see member companies, which includes major auto manufacturers, use the same plug types on their vehicles sold from 2020.

However, there is not yet a formal Australian Standard for charging infrastructure. While Government does not develop standards in Australia, the reference to Australian Standards in legislation makes a standard mandatory¹²⁵. This approach is currently used for particular standards to set a benchmark or for public safety requirements.

Government would need to carefully consider whether intervention to make charging standards mandatory is necessary. If there are signs that industry are moving towards a common standard, a logical step may instead be for there to be a formal Australian Standard developed by Standards Australia and Government allows the sector to harmonise without intervention.

Interoperability

From our prior discussions, interoperability has been noted as the ability for various systems to work together. This is of importance to BEVs charging stations, vehicles, charging cables and more all required to function together. Coupled with this is the emergence of multiple standards and options for many of these systems.

As an example, the following areas will require consideration to achieve interoperability within the BEV ecosystem:

- Using common protocols to communicate between individual charging stations and a charging network.
- Adopting uniform payment methods at charging stations.

¹²⁵ What is a Standard?, Standards Australia, <https://www.standards.org.au/standards-development/what-is-standard>



- Ensuring consistency of the BEV ecosystem as drivers move between the states in Australia. A driver should not face different platforms when driving between Melbourne and Sydney.

To understand potential options available to Government in Australia to aid in achieving interoperability, a number of international examples are presented to provide ideas:

- In Norway, government entity 'Enova' collaborated with the Norwegian EV Association to develop a free, public database to collect BEV-relevant data¹²⁶. Navigation systems scrape this data so BEV drivers can be provided up-to-date maps of infrastructure in their car.
- The US Department of Energy and the European Commission's Joint Research Centre established 'EV-Smart Grid Interoperability Centers', which are R&D focused labs to test facets of interoperability. The joint agreement is aiming to facilitate global interoperability of BEVs.
- The European Union issued a directive in 2014 calling for policy action by respective Governments to provide non-proprietary charging solutions to ensure interoperability across the EU.

Accordingly, Government involvement in creating policy in Australia to support interoperability may prove useful. An evidence-based approach that collaborates with existing international efforts, local industry, and guided by lessons learned is likely to be a sensible approach to achieving this. A submission by RACV to the Parliament of Victoria's Inquiry into Electric Vehicles supported Government involvement in encouraging BEV uptake, noting the critical importance of appropriate standards and interoperability¹²⁷.

As well as providing policy support, following the lead of other jurisdictions and establishing research organisations to investigate interoperability (and other BEV issues) will likely be important. There may be a role for Government in funding Australian universities and research organisations to incentivise these investigations.

The use of non-proprietary solutions are important to facilitate a widespread, public network that all players can access. Technologies such as the Open Charge Point Protocol, an open protocol that facilitates communication between charging stations and the greater network, should be considered.

Construction and location of charging infrastructure

Construction

In Section 5.5.4, a number of different infrastructure providers were identified that may benefit from potential business models in providing charging infrastructure. For many of these providers, they will only provide infrastructure where it can be deemed commercially viable for them to do so. This may not always lead to an equitable outcome for all drivers.

For example, Tesla's Supercharger technology is a key benefit for owners of the supported vehicles however it does not allow other vehicles to take advantage of these fast charging speeds. Likewise, a large industry player could potentially create a monopoly of public charging stations and stifle competition, which may impede the rollout of widespread charging infrastructure.

While in 2046 it would be expected that there is ample infrastructure for BEVs to be charged at, it may be necessary for Government to play a role in assisting in the rollout of infrastructure as

¹²⁶ Lorentzen et al 2017, Charging infrastructure experiences in Norway – the world's most advanced EV market, EVS30 Symposium, Germany.

¹²⁷ Parliament of Victoria 2018, Inquiry into electric vehicles, pp. 45.



BEV uptake increases. A number of potential options will be briefly discussed for Government to play a role in providing an infrastructure response.

Planning policy

Government may opt to implement particular policy that mandates the provision of charging infrastructure. This could be a useful response at initial stages as it provides minimum levels of required infrastructure. There are a number of different approaches that could be used within policy, with examples of these being:

- Minimum levels of charging infrastructure would be included in certain developments. For example, a new shopping centre may be required to provide a certain number of charging stations.
- To act as an example in supporting infrastructure rollouts, new Government-provided facilities (such as parks, libraries etc.) may be required to provide charging stations
- The Federal Government may set national targets for charging infrastructure and allocate particular targets to each State.

Planning policy has already been applied in other jurisdictions to mandate the construction of charging infrastructure. For example, the government in China designated 88 pilot cities whereby 1 charging point had to be constructed for every 8 BEVs that were on the road and that these must be within 1km of the city centre. This was coupled with Government funding to incentivise infrastructure providers to meet this mandate¹²⁸.

Subsidies

The use of subsidies by a government to meet market needs is not new. Subsidies have been used specifically by governments historically in the transport sector to encourage the uptake of ICE vehicles.

A partial subsidy could be offered to private sector parties to reduce the cost of entry. As the cost of providing charging stations is reduced, this may encourage competition in the sector by allowing more players (and business models) to enter the market and provide public charging infrastructure. For the consumer, this could lead to an increased availability of charging stations as well as a higher degree of choice if a number of business models are supported.

Alternatively, Government may fully subsidise a certain level of infrastructure by undertaking its own infrastructure rollouts. This equipment would then be wholly owned by the Government and may be offered to customers free-of-charge, either temporarily or as a permanent measure. It is likely this would be employed in initial stages of rollout (i.e. for the next five years) to support a certain level of infrastructure before phasing back to partial (or nil) subsidy if the private sector is seen as able to provide remaining infrastructure.

In either case, Government would need to decide the level of funding that they wish to allocate to subsidising charging infrastructure. Not only would this need to be considered as part of greater budgetary planning, other elements of the BEV ecosystem may also need to be reviewed to determine where Government funds are best allocated.

Public-private partnerships

Public-private partnerships (PPPs) are commonplace in the infrastructure sector as a model to provide public infrastructure. Under this model, the private and public sectors collaborate to deliver a project, which could be achieved through a number of forms.

¹²⁸ Hall, D & Lutsey, N 2017, Emerging best practices for electric vehicle charging infrastructure, The International Council on Clean Transportation, https://www.theicct.org/sites/default/files/publications/EV-charging-best-practices_ICCT-white-paper_04102017_vF.pdf



PPPs have already been used around the world to provide charging infrastructure, including the following:

- In Japan, the Development Bank of Japan (wholly Government-owned) partnered with Nissan, Toyota, Honda and Mitsubishi to create the Nippon Charge Service (NCS)¹²⁹. The NCS provided financial support for businesses and other parties to install charging stations. NCS managed the charging infrastructure and provided a charging card to car owners to use the chargers.
- A review of PPP projects in China found that there were 7 such examples launched between 2014 and 2016, with long-term terms (no fewer than 13 years) to provide charging infrastructure for cars and buses within various cities in China.

Such a response by Government is likely to be best placed for large rollouts of charging infrastructure across Victoria. Again, it may be best suitable for initial rollouts that facilitate the requirement for a network of charging infrastructure to be constructed. “Charging highways” are one such example of a project that may be suited to a PPP.

Location

Where the market is left to determine how charging infrastructure is provided, there is a risk that charging infrastructure is not deployed in all locations where it is needed by drivers. In the relevant scenarios contemplated, full uptake of BEVs have been modelled in Victoria. Therefore, to ensure equitable outcomes for all drivers, there will need to be sufficient charging infrastructure located both in urban and rural Victoria.

As rural areas tend to consist of smaller, dispersed populations, aspects of the private sector may neglect to provide public charging stations as they will be unable to recoup sufficient revenue to justify the capital outlay. There is also a dilemma as rural populations are likely to require public charging infrastructure more than many urban drivers given the longer distances travelled and the lack of extensive public transport options¹³⁰.

As a result, there may be a necessary role for Government to assist in ensuring that the whole state receives public charging infrastructure. While subsidies are a likely approach to encourage infrastructure to be provided to the whole state, a targeted package to provide rural charging infrastructure may be appropriate. In this way, particular incentives (which may need to be greater than what is offered in urban scenarios) can be targeted to provide a stronger signal to the market. Alternatively, Government may take this role on itself and provide charging infrastructure directly to rural areas.

5.2.8 Concluding observations

Different providers are developing different business models to serve customer needs. As the volume of BEVs on the roads grows, the market for charging services will no doubt evolve and providers will adapt and refine their product offerings as competition grows. The regulation of BEV charging services needs to reflect the early-stage nature of the market and encourage innovation and competition among business models and providers.

¹²⁹ Japan Automakers Advance Electric Charging Infrastructure With New Company, Nippon Charge Service, Mitsubishi Motors, 30 May 2014, https://www.mitsubishi-motors.com/publish/pressrelease_en/corporate/2014/news/detail530.html

¹³⁰ If you built it, they will charge – Sparking Australia’s electric vehicle boom, The Australia Institute, October 2017, <http://www.tai.org.au/sites/default/files/P233%20If%20you%20build%20it%20they%20will%20charge%20FINAL%20-%20October%202017.pdf>



Ensure adequate and suitable charging infrastructure is publicly available

Australia is already seeing initial progress at having a charging network to meet driver needs, however there is much work required between now and 2046. Learnings could be applied from current (and past) projects in both the European Union and the United States in rolling out a widely available and future-proof network of charging infrastructure across Australia.

With regard for future technologies, the correct speed of charging should be deployed that is balanced against Victoria's electricity network to avoid 'overloading' areas of the network with excess charging infrastructure.



Adopt a common charging standard across Australia

As was noted, the current situation with charging plugs may confuse consumers and make adoption difficult. The adoption of a common charging standard will send a clear message to infrastructure providers and vehicle manufacturers as to how to service the market. The announcement of the FCAI for its members to adopt common standards is a promising development and there may be a role in Government making standards mandatory.



Educate consumers on charging infrastructure

As a transitional issue between now and 2046, both the private and public sector needs to consider the best way to educate consumers on BEVs and how they charge. There is a paradigm shift compared to refuelling with petrol. Consumers should be educated on the different plug types (unless these are standardised to one only), the cables, different charging speeds, AC and DC charging, and how to adapt charging where necessary (i.e. bringing different cables to a charging station that uses a differing plug).



Consider differing business models and the regulatory constraints that may apply to some infrastructure owners

A number of different players may emerge as providers of charging infrastructure, including DNSPs. As was comprehensively discussed, DNSPs in particular face a range of regulatory challenges around how they may potentially bundle or sell charging infrastructure to consumers. Currently regulatory regimes may potentially need to be reviewed to aid charging infrastructure rollouts.



Government is likely to have a role to play

A common theme for charging infrastructure rollouts globally has been Government involvement to encourage providers to build infrastructure where it is required. Where left entirely to market forces, there is a risk of suboptimal outcomes as the private sector may focus on deployments to maximise revenue. As a result, rural drivers or those in dispersed areas may miss out on infrastructure they need most. A number of mechanisms were discussed that may alleviate this concern.

In addition to this, there may be a role for Government in education and research into BEV issues such as interoperability to guide the use of common and open standards to allow



communication between various charging infrastructure implementations. An open network will provide drivers with a greater degree of information which can inform their decision making.



5.3 Capturing benefits

There are four main types of benefits that the penetration of BEVs may provide to the energy system:

5. improving the load factor of the system (that is, enhance asset utilisation);
6. harnessing the flexibility benefits of BEVs in terms of managing costs and risks across the system such as network limitations or wholesale price prices;
7. providing specialised, technical ancillary services which could be of high value in certain situations. Energy markets require reserves of various forms, collectively called ancillary services, to balance supply and demand in every second and satisfy all constraint; and
8. supporting efficient integration of renewable/intermittent generation into the market.

The flexibility of BEV loads refers to the ability to respond to changes in the electricity system. BEVs create flexibility through two ways:

- As a discretionary load where the charging is not time crucial and can occur at various times during the day.
- Through storage of electricity in the vehicle's batteries which could be transported back into the grid during system stress.

This section is presented in two parts. The first part describes the main benefits arising from the penetration of electric vehicles and identifies the conditions needed to facilitate those benefits. The potential flexibility with BEVs could lead to substantial value across all sectors of the electricity supply chain – generation, network and retail. However the mobility requirements, load unpredictability of customers, and challenges in co-ordination will simultaneously set challenges in capturing such benefits. Following on from this, the second part of this section evaluates some of the conditions required to realise these benefits.

5.3.1 Improved load factor and increased asset utilisation

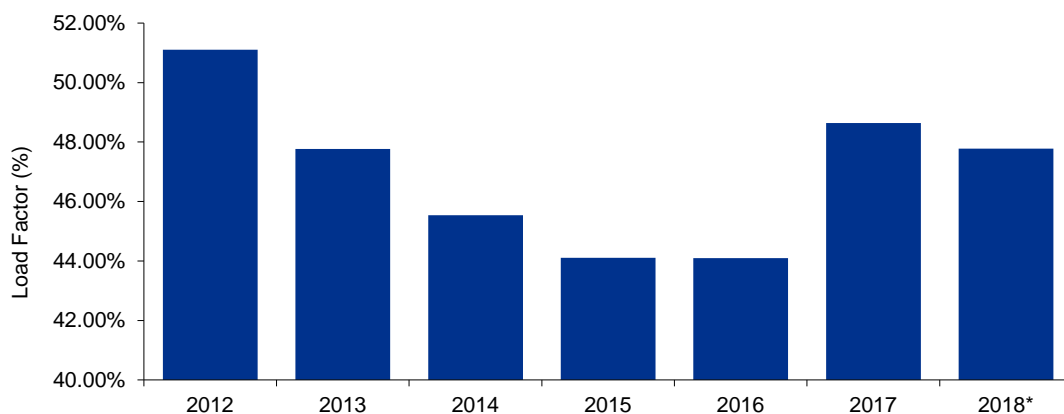
Australia's energy system is undergoing a transformation driven by changing consumer choices and rapidly evolving technology. Meanwhile, various policy settings – including a lack of an emission reduction policy while there is ongoing renewables investment – are having a profound influence on consumption, reliability of supply, and security of the system. These effects are feeding through the operational decisions of networks and the generation system operator (AEMO) to manage the additional uncertainty. As a result, consumers are experiencing higher prices and a perception that the electricity system is less reliable.

Against this background, the increased energy consumption from BEVs modelled by KPMG could drive a range of benefits to customers and improve the operational efficiency of the system. This is achieved through improving the system load factor which in turn leads to improved utilisation of the assets in the electricity supply chain.

Load factor is defined as the ratio between average demand to peak demand and is a measure of the degree that energy assets are used efficiently and regularly. As shown in Figure 77 below, the average load factor in the Victorian electricity market was on a downward trend through to 2016, before it increased in 2017. The exit of Hazelwood in 2017 has likely decreased the annual load factor into 2018 given it operated above the average of c. 48%.



Figure 77- Victorian Electricity Market Average Annual Load Factor



Increased load factors should lower average prices for customers. By increasing the load factor of networks, the fixed costs of the network are spread across a larger consumer base, resulting in downward pressure on average network tariffs. However, there is a limit to the extent of increasing the asset utilisation as the system always requires some redundancy capability (e.g. to facilitate maintenance). As well as this, this downward pressure on prices may be offset by an increase in costs due to the extra investment needed to service the extra peak demand.

Increased volumes could also have benefits for the efficiency of generation and retail markets. The extent of this benefit will depend on how BEV volumes change the shape of the total system demand over the course of the day.

The extent of the benefits to improve efficiency of the power system will depend on the charging profile of BEVs. This is because the profile will determine how the generation mix responds to, and services, the demand created by BEVs. Off-peak BEV charging is likely to lead to increased efficiency and asset utilisation of the system through night time valley filling. This is driven by the increased dispatch of base load and mid-merit plants, and a net increase in the capacity factors of generation due to increased utilisation of these plants. Off-peak charging is likely to lead to improved integration of wind generation (which is discussed further below). A flattened demand profile could help retailer contracting and purchasing costs as it avoids the need to increase flexibility in contracts to manage the variability associated with peak profiles.

However, charging through peak times is likely to decrease the efficiency of the system as a result of:

- Increase in the disparity between the daily peak load and the average daily base load.
- An increase in dispatch capacity for mid-merit generation plants with low capacity factors, and inefficient peaking plants.
- A reduction in the dispatch and capacity factors of base load plants to accommodate the mid-merit and peaking plants.

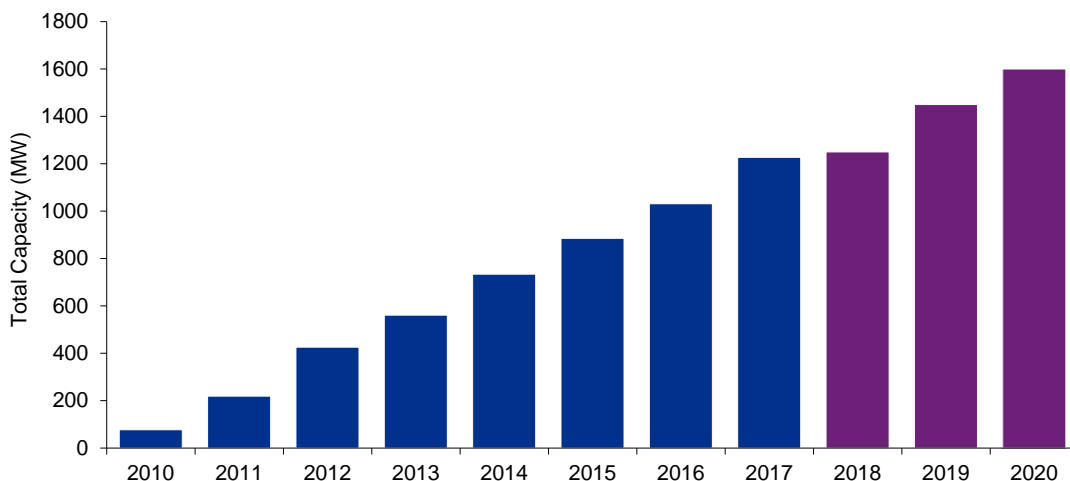
These effects under peak time charging will also impact the operation and maintenance benefits for generators due to plants operating infrequently and incurring costs associated with production volatility.

BEV charging consumption can also help to resolve the operational challenges being experienced following increased penetration of solar PV which influence consumption profiles during the day. The emergence of distributed energy resources such as small-scale PV systems (of which there are now around 5,700MW in the NEM) have been assisted by heavily subsidised jurisdictional feed-in tariffs plus the Government small-scale renewable energy scheme.



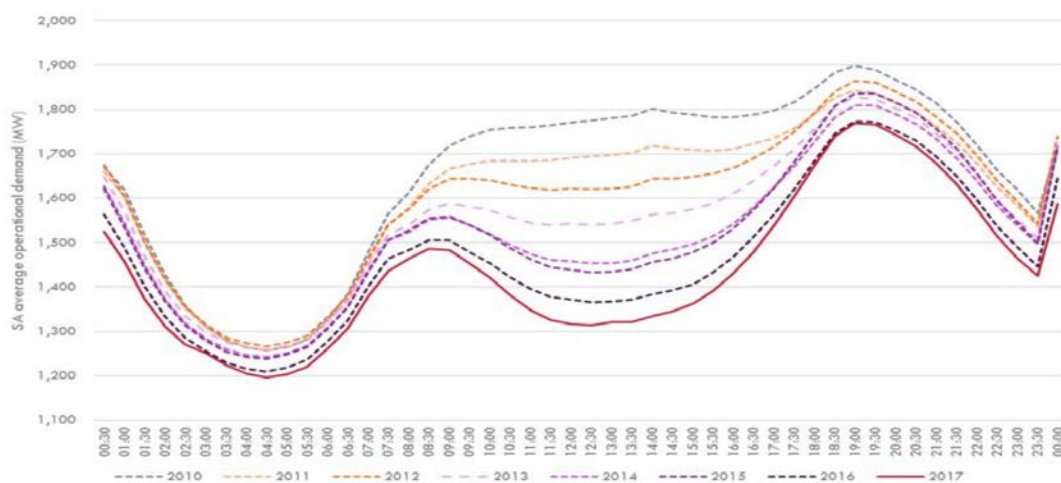
AEMO estimate by 2036-37 that nearly 20,000MW of rooftop solar PV will have been installed, together with more than 5,500MW of residential and commercial battery storage. This provides a lot of potential as an efficient source of back up capacity in some circumstances.

Figure 78 - Victoria Total Rooftop Solar PV Installed Capacity (MW)¹³¹



This is resulting in an operational challenge for AEMO through the trend of declining and low grid demand in the middle of the day with a high ramp up in the evening as solar production tapers off (this is often referred to as the duck curve effect).

Figure 79 – Effect of growing rooftop solar on system demand¹³²



¹³¹ <https://www.cleanenergycouncil.org.au/policy-advocacy/reports/clean-energy-australia-report.html>. Forecast: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-WEM-ESOO-Methodology-Report---Projections-of-Uptake-of-Small-scale-Systems.pdf

¹³² AEMO observations: Operational and market challenges to reliability and security in the NEM, March 2018, Australian Energy Market Operator.



Figure 79 demonstrates the average operational demand in South Australia, highlighting the impact of installed rooftop solar PV. These trends are also emerging in other regions of the NEM and in the Western Australian Wholesale Energy Market. The resulting challenge is to have sufficient minimum levels of generation available to respond to changes in demand in the evening and at some levels may cause voltage changes and instability in the system. This has increased the possibility of interruptions in some regions.

The installation of high levels of embedded solar PV generation across the NEM is leading to a later and shorter peak in the 'operational demand' or net demand on the system. An increasingly 'peaky' system demand will require resources that respond quickly and for a relatively short duration. Where BEV consumption adds to demand in the mid-afternoon, this issue becomes easier to resolve provided there is sufficient generation capacity which enters the market to serve the additional demand.

This effect can also mean that there is value in optimising the time of charging to occur during the mid-afternoon as well as shifting charging to off-peak periods.

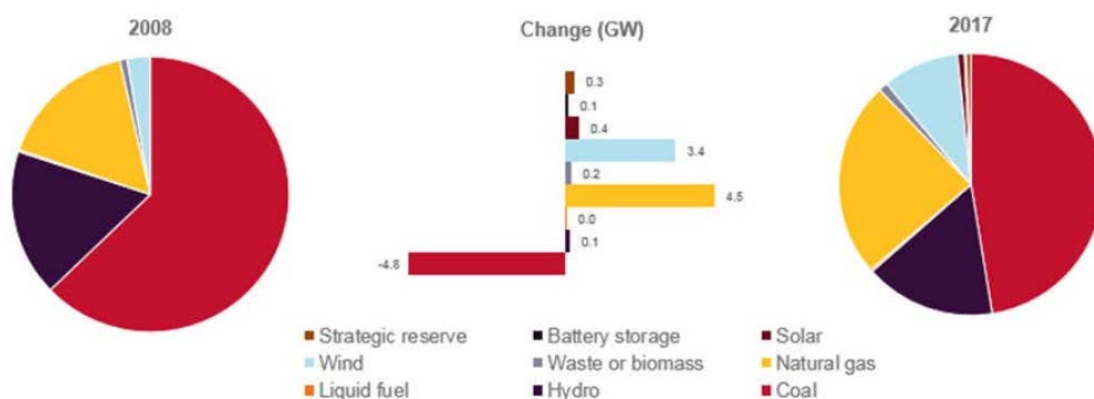
5.3.2 Integrating renewable generation

There are two ways that BEVs could assist in integrating a penetration of renewable generation:

- 1 Where BEVs are used to recharge during high levels of renewable generation, this can help to manage disruptive impacts of renewable generation on the market.
- 2 Where the BEV fleet is used as source of short term and distributive storage of excess electricity generated by renewable sources which can be re-supplied during peak times.

The increased uptake of renewable generation has occurred due to subsidies available under the Federal Government LRET scheme and the corresponding retirement of conventional thermal generation. Figure 80 demonstrates how the generation mix for the National Electricity Market has changed in the past 10 years.

Figure 80– Generation plant mix change between 2008 and 2017¹³³



This changing mix has caused disruption to the power system. Traditional thermal types of generation (i.e. coal and gas), are 'synchronous', that is, spinning units driven by a steady fuel source. Synchronous generation provides system security benefits such as inertia and,

¹³³ Australian Energy Market Operator 2018, AEMO observations: Operational and market challenges to reliability and security in the NEM.



relevantly for the purpose of this advice, it is scheduled. Their output can be controlled and immediately called upon to increase or decrease at any time.

On the other hand, variable renewable generation is non-dispatchable (in lieu of storage) as it relies on weather factors to generate electricity. This means that AEMO cannot rely on these generators to ramp up when a generation shortage is looming. If the wind is not blowing or the sun is not shining, these plants are not able to provide a reliability-firming response, constraining the flexibility in generation capacity to manage the power system.

This concept is shown in Figure 81 which maps out the profile of daily wind and rooftop solar production in Victoria against daily system demand for a typical summer peak day.

Figure 81– Victorian wind and rooftop solar production against system demand

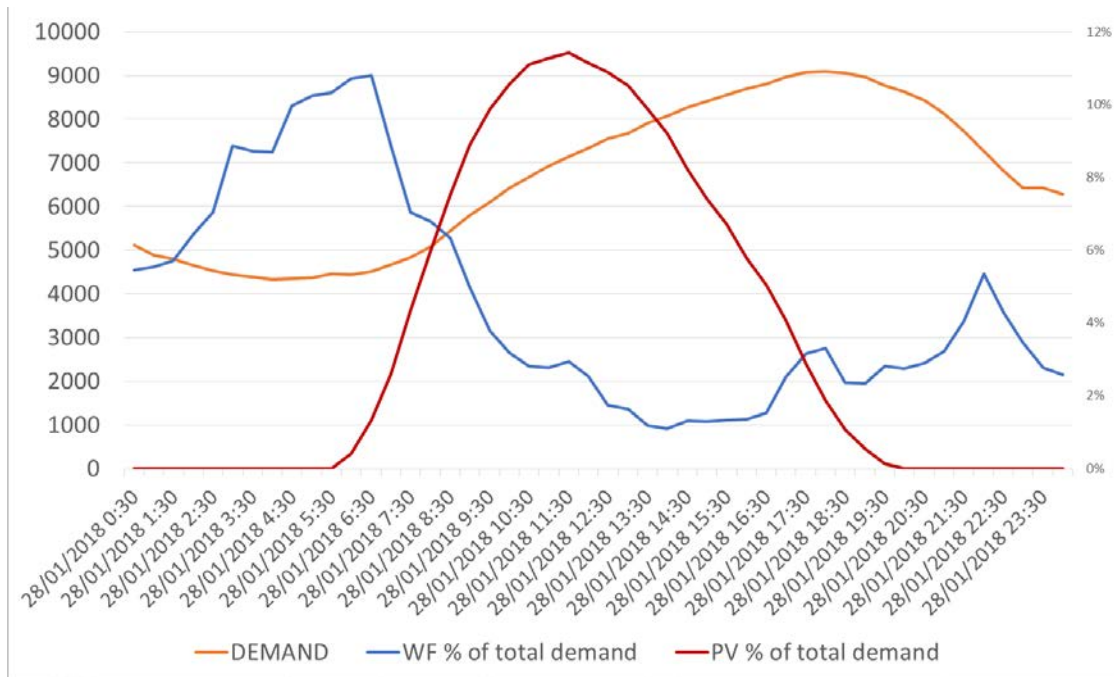


Figure 81 highlights that the bulk of renewable production occurred at times when system demand was low. The uptake of BEVs can aid in addressing this mismatch through two ways. Firstly, a smart charging profile may encourage the charging of BEVs during periods of high renewable generation. Secondly, BEV batteries could be used as a store of renewable energy which can be discharged during high levels of system demand.

Other challenges to the power system includes:

- The intrinsic intermittency of wind and solar plants can make it considerably harder to forecast their output in comparison to other forms of generation, making it harder to plan, co-ordinate, and dispatch the market as a whole.
- Declining technical support (i.e. ancillary services) from generation. The rules of physics dictate various technical features that are needed for system security including frequency control, inertia, and voltage parameters. Coal, gas and hydro generation have spinning generators, motors, and other devices that are synchronised to the frequency of the power system. This synchronous generation provides a number of aspects of system security almost as a by-product. Wind and solar photovoltaic powered generators do not readily provide these features easily although the relevant technology is evolving. As the



proportion of non-synchronous generation rises, the security of the power system is becoming more at risk.¹³⁴

BEVs can potentially benefit the power system through both improving reliability – having an adequate amount of supply (both generation and demand response) to meet consumer needs – and also system security – or the ability to operate the system within defined technical limits. When considering the benefits of BEVs, it is important to be aware of this distinction between security and reliability.

The change in generation mix has also had price impacts on customers. In the short term, subsidised wind generation had the effect of increasing supply and putting downward pressure on wholesale energy purchase costs. However, this was only temporary, as depressed wholesale prices will likely force unprofitable generators to exit the market, and the consequent reduction in supply has eventually put upward pressure and volatility on wholesale prices.

Finally, the power system has become more weather dependent due to the entrance of technologies such as wind and solar PV. While weather has always had an influence on the operation of power systems,¹³⁵ weather itself is now a major fuel source. This factor, plus the changing climate in terms of temperature, and the extremity and scale of weather events, has impacted the resilience of the power system.

These challenges further illustrate the benefits of a broad mix of generation technologies, as well as improving the engagement of price responsive demand as a viable resource to meet customer demand. In this context, the additional consumption from BEV penetration can help to resolve these challenges through the following:

1. Facilitating increased investment and entry of generation
2. Acting as a source of ancillary technical services through vehicle-to-grid (discussed in the next section) maximising the value of BEV batteries as a source of energy.
3. Efficiency in the wholesale or ancillary services market would be improved by matching uncertain supply, such as renewable generation, with variable load, such as BEVs. In order for BEVs to be matched with renewable generation, this will require some form of managed charging, such as controlled charging, or smart meter charging with TOU price signals.

Smart grid management schemes are useful for optimising the integration of renewable energy sources. By controlling the charging process and shifting it to certain time slots, the usage of renewable energy (e.g. from solar photovoltaic) can be optimised. However, this is limited by the mobility needs of the BEV driver. To ensure customer satisfaction, the system might use an energy buffer to compensate time offsets between generation and demand. As smart technology develops, it may be possible for the BEV to learn driver habits to accurately estimate a suitable energy buffer for each vehicle.

Importantly, it is necessary that there be a certain level of certainty or firmness to the timing and flexibility of the BEV load so that it can better integrate with renewable generation.

Further, the extent of these benefits will depend on the magnitude of renewable generation in the market. Once renewable generation (most importantly solar and wind plants) surpasses

¹³⁴ This has led to problems such as decreases in available system inertia, resulting in increased challenges to maintain system frequency following disturbances plus deteriorating frequency performance of the system under normal operating conditions.

¹³⁵ High demand days have been associated with cooling and heating needs, infrastructure is designed to withstand levels of extreme weather, and the capacity of networks to transmit power is related to contingencies and ambient temperature. So, the system is designed and operated with a view to the weather



over 30% of total electricity production, compensation power in the range of 30-40% of the average vertical grid load will be required to balance fluctuations. Tackling intermittency can generally be achieved with a level of spare capacity to act as security including backup or storage. "Backup" refers to generators that can be turned on to provide power when the renewable source is insufficient. "Storage" can also be turned on in times of low power supply but additionally has the advantage of being able to absorb excess power. Using BEVs as a source of storage may lessen the need to invest in backup generation or large scale batteries.

5.3.3 Vehicle-to-grid potential

Vehicle-to-grid (V2G) technologies use BEV batteries as a source of energy storage to provide a flexible energy supply to the system. Within a smart network, where electricity is consumed and stored intelligently, battery storage is an attractive solution to bridge intermittency and provide flexibility. In this context, V2G technology can be a key enabler to an intelligent integration of BEVs into the grid. However, V2G will also require additional investment and creates new challenges concerning policy and regulatory arrangements.

V2G is different from the cost savings generated by smart charging of BEVs. V2G can feed electricity back to the network so the amount of flexibility and its availability will be greater when V2G is required. For instance, if smart charging is used to encourage off-peak charging, there will be little scope for decreasing peak load during high price events such as maintenance (after an asset failure) or during a critical peak load. V2G on the other hand can begin supplying the network at this point and effectively reduce peak load. Further, V2G offers the possibility of supporting increased use of localised small scale renewables.

This section provides a summary of the range of benefits under V2G. The conditions needed for V2G benefits to be captured are evaluated in Section 5.2.4.

Vehicle-to-home

Vehicle-to-home (V2H) utilises BEV energy storage capabilities and feeds electricity to be used in other household appliances rather than relying on the grid. V2H could be setup on a stand-alone basis or in conjunction with the greater V2G system. V2H could provide a level of similar benefit to the individual customer as V2G but it would not have the same impact relating to system integration and communications.

Benefits of vehicle-to-grid

The unique advantage of using BEVs as mobile storage is that they follow where people travel. People move to city centres in the day, where large loads are located, and to residential places in the evening, which also mirrors the demand on the electricity network. Facing the integration of a growing number of DER and renewable generation, a network of agile BEV storage could have a high value for society.

DER, including BEVs, are capable of providing multiple value streams to different energy users. For example, DER can help DNSPs manage grid security by alleviating network constraints and maintaining voltage levels. Generation from DER can also be sold into the spot market and potentially provide ancillary services to AEMO or other regional markets. This provides opportunities for customers to earn additional revenue from their investment in DER, by selling services to DNSPs, AEMO, or selling energy into the wholesale market.

Cost savings for customers

V2G can create cost savings for customers. These savings could be direct savings to the BEV owners or general market savings which benefit all customers.

Direct savings are generated when BEV owners are rewarded for their V2G potential. By earning revenue from their vehicle, the cost of ownership associated with BEVs will reduce. Further, charging costs could be reduced if renewable generation is integrated with the grid as



it may be more competitive than traditional power generation. This also reduces the charging-related emissions from the utility plants.

The general market savings generated from V2G relate to the avoided costs due to having a localised source of storage. For example, V2G should result in fewer losses from transporting electricity over long distances, and with voltage conversion in the overall network. AEMO notes that typical losses on the Australian network are approximately 10% of total electricity transported from power stations to customers¹³⁶. Further savings are possible from avoiding network investment given that distributed energy storage relieves network bottlenecks by reducing loads on constrained network lines.

Technologies which feed-in electricity from the household level to the distribution network (such as solar feed-in) have the potential to reverse power flows in distribution substations. This could create new technical problems for DNSPs requiring additional investment in capacitor banks and static variable compensators (SVC). However, this is unlikely to be a problem with V2G because unlike solar panels - which feed-in whenever the sun shines - V2G would only feed-in during periods of high demand (or high wholesale prices if contracted to a retailer), or if requested to do so by the network operator.

Arbitrage of wholesale prices

The efficient price of electricity varies considerably by time of use, and location. At times of low residual demand (that is, total demand less the supply of renewables and other low variable cost and/or inflexible plant), the scarcity value of wholesale power is low (and possibly near zero). At times of high residual demand where inefficient peaking plant running on expensive fuel (gas) is at the margin, the wholesale cost can be very high, not just because of high variable fuel costs, but because the capital costs of such plant should be recovered at times of peak residual demand.

Tariff arbitrage is the practice of purchasing electricity from the electricity grid when it is cheap, and storing it for later use when grid electricity is expensive.

The introduction of the Hornsdale Power Reserve into South Australia provides a local and practical example of how a battery could be utilised in an arbitrage function. Box 3 below provides an overview of this project and its ability to participate in both market arbitrage and as a provider of Frequency Control Ancillary Services (FCAS) services. FCAS is discussed further below.

Box 3: Impact of grid-scale batteries

Delivered to much fanfare and media coverage, Tesla and Neoen switched-on the Hornsdale Power Reserve in South Australia in late 2017, representing the largest lithium-ion battery in the world and was built in under 100 days.

The Hornsdale Power Reserve is a 100MW battery connected to the NEM and plays a dual-role in providing grid stability and load management. 30MW is allowed for commercial operation while 70MW is reserved for power system reliability purposes¹³⁷.

Interaction with electricity prices

The unique ability of a battery is its fast response time to respond to market movements. As can be seen in the chart below, the rate of charging of the Hornsdale Power Reserve spikes

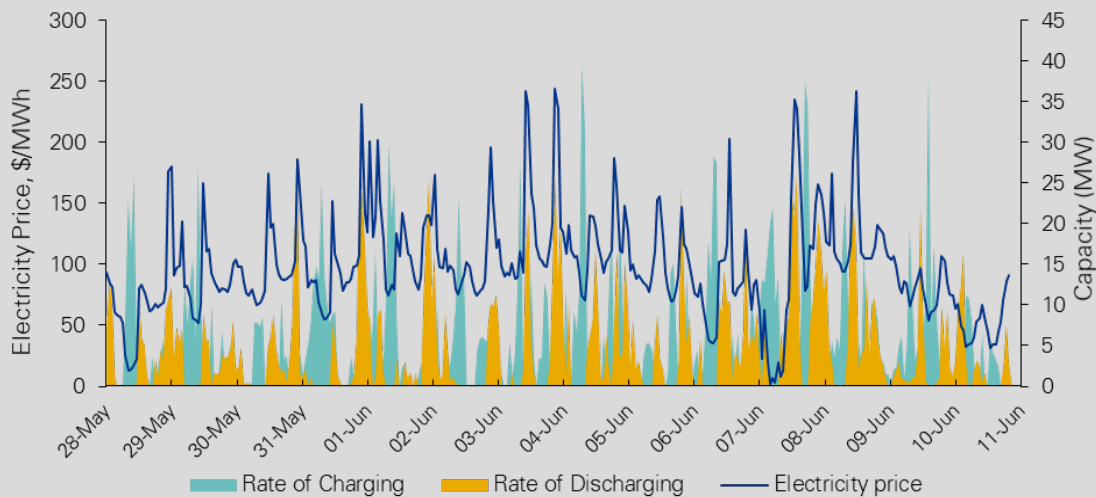
¹³⁶ <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries>

¹³⁷ Initial operation of the Hornsdale Power Reserve Battery Energy Storage System, Australian Energy Market Operator, April 2018, https://www.aemo.com.au/-/media/Files/Media_Centre/2018/Initial-operation-of-the-Hornsdale-Power-Reserve.pdf



when there are troughs in electricity prices, to minimise the cost of charging the battery and maximise potential revenue.

The arbitrage ability of a battery is therefore highlighted by the rate of discharging, which typically aligns to spikes in electricity prices. The Hornsdale Power Reserve is able to use its rapid response time to charge and discharge in the manner which optimises the value between low prices and high prices. A collection of BEV batteries could in theory be organised to operate in a similar way.

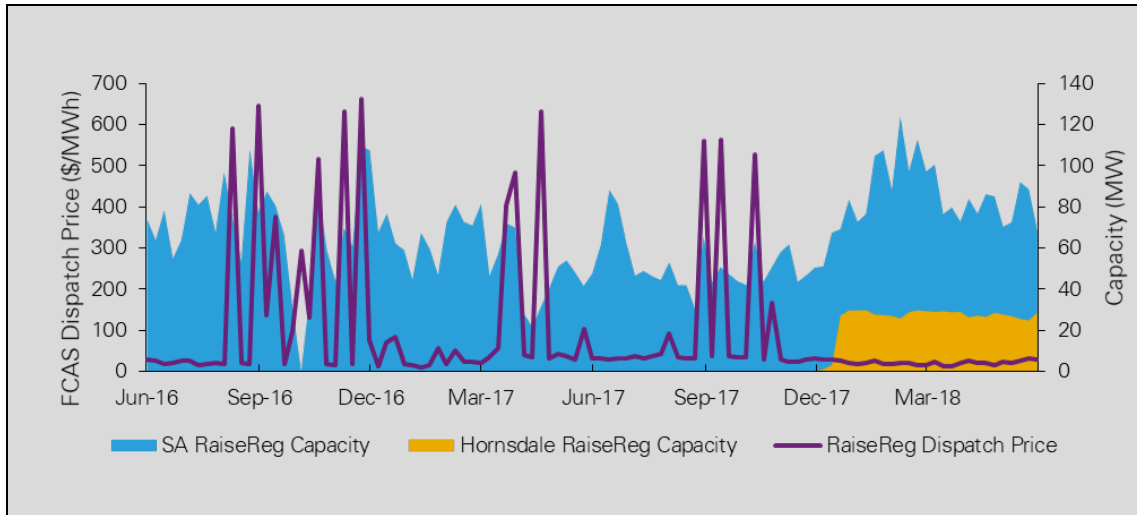


Role as FCAS provider

The Hornsdale Power Reserve is registered to provide all eight FCAS services and actively participates in these markets. AEMO has commented that the Hornsdale Power Reserve has demonstrated an ability for the system to provide rapid and accurate frequency response services, particularly in comparison to conventional providers.

The figure shown below demonstrates the impact that the Hornsdale Power Reserve has had on the pricing of FCAS. Historically, these prices can spike significantly depending on market conditions.

However, this chart illustrates that the Raise Regulation price (regulation FCAS managed by AEMO to raise frequency) has remained consistently low since the introduction of the Hornsdale Power Reserve. This is mainly a market response as the Hornsdale Power Reserve is a new participant bidding for FCAS services at a lower price than other providers.



Ancillary services to network and generation sectors

V2G also have a range of complementary benefits across the network and generation sectors through providing specialised, technical ancillary services which could be of high value in certain situations. Energy markets require reserves of various forms, collectively called ancillary services, to balance supply and demand in every second and satisfy all constraints.

The range of ancillary services can differ between the network and generation sectors, and includes the following items.

Frequency control regulation

Providing power reserves to maintain frequency and voltage to facilitate the efficient handling of imbalances and/or congestion is an important aspect of grid management. Frequency regulation requires direct and real-time control by the grid operator, who continuously monitors the generator to load demand balance; responding within a minute or less by increasing or decreasing the output of the generator.

In Australia's case, regulation services are a subset of what is commonly referred to as FCAS. The aim of FCAS is to keep frequency within the operating range of 49.9Hz to 50.1Hz, and the FCAS providers bid their services where they receive payment for availability, and for actual delivery of services as they arise.

BEVs can potentially provide frequency control services through increasing or reducing the rate of charge for those BEVs who are in a position to offer increases or reductions. An aggregator could contract with BEV owners to offer collective FCAS services in the market. Box 3 above provided a practical example of how the Hornsdale Power Reserve, a 100MW battery, has impacted the FCAS market since its introduction. An aggregated set of BEVs could provide these same services into the FCAS market.

Maintaining outages and emergencies

BEVs may export their stored energy to assist in grid outages and maintenance, as well as disaster recovery efforts. Therefore the BEV could assist in reducing outages on the network.

Spinning reserve

Spinning reserve refers to additional generating capacity that can deliver power quickly upon request from the system operator; it is paid for by the length of time they are available and ready. Contract duration is typically short, lasting around 10 minutes but can be much longer



depending on specific cases. Having sufficient BEV batteries which can collectively be discharged at short notice could provide a credible source of spinning reserve.

5.3.4 Environment required to capture benefits

Connecting a BEV to the grid not only brings opportunities, such as increased reliability and power security, but also challenges. Market participants are unlikely to contract for the benefits from BEVs unless there is certainty in the availability of flexibility provided by BEVs. This in turn will depend on the costs of coordinating BEV charging and discharging. It also depends on the scale and geographical dispersion of BEVs across the system, given that some of the value of BEVs will be location specific.

In considering the conditions required to capture the identified benefits, it is important to recognise the flexibility benefits from BEVs to the electricity system are created through two broad ways:

1. Optimising the timing of charging of BEVs across the day in order to minimise costs and support reliability and security.
2. Having the ability to access the BEV battery and discharge stored energy when required, often at short notice through V2G solutions.

There is substantial overlap in the conditions needed to support benefit capture in the two items identified above. For example, there is a common reliance on rewarding BEV owners for flexibility, and on the systems required to manage and coordinate charging and discharging of BEVs.

Furthermore, V2G requires a number of conditions and costs to be effective and commercial. This is in relation to both technology (i.e. V2G requires a bidirectional charger and a smart inverter), and policy arrangements, such as the framework for BEVs to export power with a reasonable level of predictability. So far, a handful of V2G pilot projects have been launched so there are limited lessons on how best to address these challenges. Operational issues may arise that could potentially require new standards or regulation to counteract.

This section first explores the arrangements to achieve optimal timing of BEV charging. Then, it discusses at a high level some of the conditions needed to capture flexibility benefits and ensure the effective integration of BEVs with electricity markets. The list of conditions described below is not exhaustive and there will be other factors which will influence effective integration.

Some of the challenges identified for BEVs also apply to other forms of DER owned by customers. DER are generally defined as devices which are located at a customer's premises and are able to inject power into the local distribution system, such as embedded generation or battery storage resources, or which assist in the management of load at the premises

Achieving optimal charging of BEVs

As explained above, the value and cost of electricity production can vary over the course of a day as the supply and demand balance changes. In addition, flows on the network are not constant and vary in accordance in customer usage patterns. This means that the costs of providing and transporting electricity to meet demand from BEVs will change over the course of a day.

BEVs can be considered to be a form of demand side participation (DSP) for the electricity system. This is because BEV loads are typically flexible in nature because a BEV can be charged at different times of the day. While charging of BEVs at low demand times can help to minimise the costs for the BEV owner, it can also help capture the benefits from BEVs discussed above in helping to smooth out total consumption and improve asset utilisation.

There are two broad mechanisms to achieve optimal charging:



1. A price incentive to reward customers who charge at off-peak times during the day; or
2. Managed (or controlled) charging where the management of the BEV charging load is assigned to another party (network, retailer or a third party DSP provider, such as an aggregator) in accordance with an agreed contract with the consumer.

The infrastructure needs are similar under both mechanisms. They both require a smart meter to record BEV charging at regular intervals and relay the data in real time. In addition, controlled charging needs a device which can control consumption remotely. Such technology is standard and relatively cheap, plus is currently installed across a number of appliances such as air-conditioners, hot water boilers, and pool pumps.

With an increased uptake of BEVs, both mechanisms are likely to exist in parallel. Some customers will prefer to be subject to price incentives and remain in control of charging while others will enjoy the freedom gained through assigning responsibility to a third party. Ultimately, this will depend on customer preferences, driving patterns, charging times, and the difference in savings/payments to the BEV owner between the mechanisms.

Achieving optimal charging of BEVs will be important for all customers, not just BEV owners. Charging at peak time can lead to substantial extra system costs which are recovered across all customers. Therefore there will be pressure on policy makers and governments to ensure that the regulatory framework facilitates the right charging behaviours by BEV owners.

Price incentives

Electricity prices that consumers face are composed of three broad components:

- Cost of electricity from the wholesale market;
- Cost of transportation through network tariffs from the transmission and distribution network; and
- Cost of retailing associated with providing electricity supply.

The first two components can vary over the day in accordance with demand and supply conditions. Network costs also vary by when peak demand triggers limitations on network capacity. This is likely to vary by geographical location across the network, and time of day.

The key issues with designing price incentives solutions are:

- Will the price signal comprise both a generation and a network component?
- Will the price signal vary by location?
- How easy will be it for the BEV owner to predict the cost impact of its charging decisions under the price signal?
- Will the BEV owner seek to have the price signal apply only to the BEV load or to the full consumption at its premise?

The current design of electricity prices in Australia may not promote efficient decisions under high penetration of distributed generation or BEVs. Issues such as poorly defined peak periods, high fixed charges, or consumption based tariffs means that a tariff fails to accurately reflect the impacts of BEV charging behaviour. Jurisdictional policy constraints can also impact on the effectiveness of price signals.

There are a wide range of different structures and designs to electricity prices which could provide an effective incentive to charge BEVs at optimal times. Effectively, there needs to be a substantial difference between the rate for charging in peak times and the rate applicable at other times.

In overseas markets, electric utilities are creating rate structures specific to BEVs. The design of rate structures potentially considers different objectives to encourage BEV adoption, align with utility cost, and/or incentivise charging behaviour that harmonises grid operations. In January 2018, the Electric Power Research Institute (EPRI) published a review and assessment



of Electric Vehicle Rate Options in the United States. This study evaluated 51 different tariffs, or rate options, from 21 electric power companies. The key findings of the report are presented in Box 4.

Box 4: Review of BEV tariff options in the United States

In January 2018, ERPI published a review and assessment of Electric Vehicle Rate Options in the United States. This study evaluated 51 different tariffs, or rate options, from 21 electric utility companies. The key findings of the report are:

Frequency by customer class

Rate options for residential customers are more pervasive than options for non-residential customers. All 21 utilities reviewed had residential rate options. Only six utilities offer business customer rate options.

Seasonal differentiation

All rate options with seasonal differentiation reviewed have two seasons - summer and winter – except for one utility, which has three seasons: winter, summer and peak summer.

Price differentials

The differentials¹³⁸ of energy charges (\$/kWh) between on-peak and off-peak hours range from 111% - 943% in summer and 100% - 485% in winter. The differentials of energy charges between summer and winter range from 87% - 507% across the on-peak prices and 84% - 109% across the off-peak prices. It was found that price differentials were successful in encouraging customers to charge their BEVs overnight during off-peak times.

Demand charges

The pervasiveness of demand charges in the rate options is low. Only three utilities reviewed use demand charges in their BEV rate design. APS and Pacific Power have demand charges in their residential rates, and SCE has an option of business rate with a demand charge.

Public charging option

Most of the public charging specific rate options have fees per charging session; one company charges on an hourly basis. One utility offers a fee per hour rate option as well as a rider option for business customers and another similarly offers a fee (\$2.50) per charging session for public charging.

Distribution of rate options for three customer classes

		Customer Classes		
		Residential	Non-residential	
			Business	Public charging
Number of utilities		21	6	5
Number of rate options		29	14	8
Rate structures	TOU energy charges	26	7	5
	Monthly/daily fixed charge	26	12	0
	Demand change	2	2	0

¹³⁸ Calculated as 100% * \$ on-peak / \$ off-peak



Seasonal differentiation	19	3	1
Separate rate, fee, or rider	1	2	0
Discount/bonus offer	2	3	0

The effectiveness of any price signal depends on balancing the goals of cost reflectivity and predictability. Cost reflectivity seeks to capture all the incremental costs impacts caused by the consumption decision to ensure that a tariff reflects the contribution of each consumer to both the cost of the network and the cost of generation.

However, the design of the electricity price structure should be such that a consumer can make an accurate estimate of the amount they have to pay. If the user wants to act on the price, they need to be able to make a prediction on how taking a certain action, like applying energy saving lighting, would impact their tariff. If this is not the case, the user would have no incentive to minimise their usage even if the cost reflectivity is high.

There are limits to the extent that pricing signals are able to encourage efficient behaviour. With respect to energy prices, mass market consumers (which include BEV consumers) may not want to be exposed to such volatile prices over the course of a day.

The penetration of distributed generation sources in recent years has placed greater emphasis on the development of cost reflective network tariffs in order to promote, among other factors, greater efficiency (through the provision of more information in relation to the network) in the decisions of distributors investing in the network and consumers investing in DER. For example, such efficiency may be identified whereby cheaper DER investment leads to avoided network costs for a given location.

With respect to network pricing signals, it may be difficult to define or measure the marginal cost of distribution services by time of use and by location at a sufficient level of granularity. Providing a locational signal to residential and small business consumers in the distribution network is also likely to be challenging, for example, because of the shared nature of many of the assets they use, which makes it difficult to attribute precisely the cost of the assets to specific consumers.

There may also be equity implications of this approach and jurisdictional constraints on locational pricing. Concerns about whether non-BEV owners are neutral to the recovery of costs associated with BEVs have also been raised.

Under new cost reflective pricing rules introduced in 2014 in Australia, DNSPs are required to develop network prices that reflect the efficient cost of providing network services to individual customers. Specifically, each network tariff must be based on the long run marginal cost (LRMC) of providing the service, subject to certain other requirements.

Cost reflective network tariffs calculated based on LRMC are intended to signal the cost incurred by DNSPs in investing in their network to meet future demand. As such tariffs reflect the costs of increasing capacity at different locations across the network, they should therefore reflect the network value caused by distributed generation reducing the need to build additional capacity. Hence if customers are faced with a LRMC network tariff, the decision to install distribution generation will be rewarded through lower network tariffs. In theory, the size of that reward will be equal to the avoided capacity investment benefit caused by the DER.

A shift towards greater cost reflectivity is currently occurring in Victoria with all five DNSPs offering demand charges from 1 January 2017 (although for small customers these tariffs are opt-in due to a Victorian Government obligation).



Controlled Charging

Under controlled charging, the BEV owner enters into a contract to a third party, assigning the right and responsibility for charging the vehicle to that party. That third party will then decide the best time to charge the BEV to optimise the flexibility value for the energy market subject to any constraints relating to customer preferences in the contract.

The technology for controlled charging is well established and currently deployed across a range of different appliances. Currently, controlled load of hot water heating is directly managed by distribution networks in a number of regions and is generally directed over whole network areas rather than at specific retail customers.

Controlled charging will be more reliable than price incentives as the third party has guaranteed access and ability to charge at the appropriate times. Further, the third party can make appropriate decisions on the best time for charging, to respond to energy and network market effects, overcoming co-ordination and sequencing problems with multiple BEV owners. Accordingly, the savings to the electricity market should be greater. BEV owners may also prefer committing controlled charging services as they do not need to worry about timing their charging, and there may be cost benefits.

The key issues with controlled charging solutions are:

1. Which party contracts with BEV owners for the controlled charging?
2. How are technical and security considerations taken into account in the charging decisions, especially if the charging party is not the network operator?

The party could either be a direct market participant, such as networks or retailers, or a separate business such as an aggregator (discussed later), or a BEV charging service provider. Given the potential range of diverse benefits from BEVs and the different drivers for network and generation costs, there could be conflicting objectives to the management of controlled loads between these parties. Therefore, the choice of charging party will influence how the benefits from BEV charging are maximised.

Separate parties such as aggregators or BEV charging service providers may have more incentive to seek to maximise the benefits across the supply chain. However, an optimal charging control scheme must co-optimize economic and technical objectives, and therefore the interaction with the network operator will be key. The network operator may seek to impose constraints on controlled charging in the interests of protecting the network. Furthermore, the network operator may seek to deal directly with BEV customers through its own controlled charging scheme.

Controlled charging of BEVs could also assist in minimising network losses and reducing charging costs¹³⁹. Controlled charging was proposed to meet multiple objectives for the operator including flattening of load profiles, minimising costs to consumers, or maximising the use of renewable generation. As these decisions are made by the party controlling charging, a consumer may be faced with the possibility that their BEV is being used for network benefits rather than direct cost savings. Careful consideration would need to be given to deciding how the third party contracts with BEV owners to utilise their resources.

Modelling analysis

The issues relating to achieving optimal charging of BEVs are common to all forms of DER. We recognise that while pricing incentives are necessary to encourage efficient behaviour, it may not always be sufficient to achieve intended outcomes given the existing market and regulatory context.

¹³⁹ O'Connell et al 2012, Controlled charging of electric vehicles in residential distribution networks, Institute of Electrical and Electronics Engineers.



Technology advances could make resolution more straight-forward. In a smart grid, the energy management system efficiently communicates information in a BEV charging network between the grid, BEV service providers and BEV owners. This information can be utilized by third parties to develop efficient operation strategies for intelligent load aggregation, customer cost reduction and demand satisfaction, and system overloading prevention.

The modelling shows that the average cost to charge an electric vehicle will be around \$1,700 per year for the Electric Avenue and Private Drive (see Table 77) based on the current price of 28.6 cent per kWh.¹⁴⁰ The amounts are obviously significantly higher for shared fleet scenarios given the lower number of vehicles. Our modelling estimates that the shared fleet operator will be required to pay approximately around \$10,000 per year on average to charge each vehicle.

Given these substantial amounts, there should be a strong incentive on the BEV owner to try to minimise the costs through taking advantage of any price incentives and charging at optimal times.

Table 84 – Average annual cost to charge BEV in 2046 at current prices

	# vehicles in 2046	GWh consumed in 2046	Total cost in 2046 (excluding GST @28.6 cents / kWh)	\$/vehicles in 2046 (excluding GST @28.6 cents / kWh)
Electric Avenue	3,910,885	21,999	\$6,289 m	\$1,608
Private Drive	4,137,808	24,100	\$6,890 m	\$1,665
Fleet Street	638,622	21,762	\$6,222 m	\$9,742
High Speed (2031)	415,674	15,986	\$4,570 m	\$10,995
Slow Lane	315,032	10,096	\$2,886 m	\$9,162

We note that cars make up about 90% of vehicles in the Electric Avenue (Incentivised) scenario, but only 50.6% of total consumption of electricity. This is because cars require about 20 kWh of electricity per 100 km, compared to 129.11 kWh of electricity per 100 km for freight vehicles.

That is, cars require about 3,160 kWh per year in this scenario, which we note is only marginally less than what a representative customer in Victoria was consuming in a year in 2016/17 (3,865 kWh). Effectively, on average, purchasing a BEV could potentially double the household electricity consumption and hence bill based on the modelling results.

Conditions to capture BEV flexibility

This section provides an initial evaluation of the range of conditions which would help maximise the benefits from BEVs to the energy market. With modelling estimating that there would over 4 million privately-owned electric vehicles in 2046 under the Private Drive scenario, the potential value is substantial.

¹⁴⁰ AEMC, Residential electricity price trends report 2016. The AEMC reports that a representative residential customer in Victoria consumes 3,865 kWh of electricity per year, and that this customer would have paid \$1,435 exclusive of GST on a standing offer and \$1,105 exclusive of GST on a market offer in 2016/17. As 90% of Victorian residential customers are on market offers, we assume an average price per kWh of electricity of 28.6 cents (\$1,105 / 3,865 kWh).



The effective capture of the benefits from BEV flexibility will require co-ordination and integration between customer behaviour, and the market and policy frameworks.

From the customer perspective, the issues include:

- Will the customer be willing to invest in additional equipment to facilitate the benefits?
- How will user preferences and driving patterns impact on the availability to deliver the benefits?

From the market arrangements perspective, the key issues to be resolved are:

- Will the arrangements result in sufficient reward for BEV owners?
- How is vehicle availability managed to fully capture the value of BEVs?
- For private fleets, how to co-ordinate and aggregate the incremental value across large number of BEV owners.
- How to co-optimize the capturing of benefits across the various segments of the energy supply chain.
- How to ensure system interoperability between energy market, and BEV charging and discharging.
- For V2G, will exports into the grid always be allowed?

The conditions described below are not exhaustive and there will be other factors which will influence the effective integration of the transport sector with the energy sector.

Cost investment by BEV owners

BEV households will need to be convinced to participate in any energy market flexibility scheme. The main costs relate to the metering technology, communication systems, and potentially any costs associated with controlling charging patterns. Further, if a customer solely wants their BEV load to act as a flexibility demand which can be shifted across the day, they may need to incur the costs of an additional smart meter to isolate the BEV demand from the rest of the household.

There are extra costs associated with V2G arrangements. For BEV owners that want to participate in a V2G scheme, they will require investment in extra equipment (e.g. such as bidirectional charger, communications) and need to overcome concerns that their BEV may not be fully charged. As yet, the full consequences for battery life are unknown under V2G and manufacturers have expressed concern regarding battery warranties.

These concerns will ease over time as more information is available about charging behaviour, and technology becomes smarter so that it can ensure a minimum battery charge. However, the energy market arrangements would need to offer well designed incentives and the certainty of payment streams in order for customers to want to participate given the additional inconvenience and costs involved. However, this may be difficult given that the value of V2G may be for limited specific circumstances (e.g. network emergency or unscheduled generation outages) which are difficult to predict.

Approach for managing vehicle availability

One of the potential quality issues that may arise under V2G is the availability profile of the battery stock to provide the mentioned benefits. The presence and availability of resources for ancillary services is dependent on the numerous variables related to driving and charging behaviour of BEV owners, as well as the geographical distribution of BEV ownership. It will also depend on the proportion of BEV owners who opt in to providing V2G benefits.

Therefore, factors such as BEV ownership models, driving patterns, and charging preferences are important as these will determine the extent of any benefit from the BEV fleet. Location will be also of the important as the some of the benefits from V2G such as ancillary services and grid support will only be material in certain parts of the network.



Vehicle availability could be impacted by a range of issues. For example, it is recognised that recharging at work could be attractive to drivers, and if drivers feel that they need to recharge during the day at work then this will limit the extent of any discretionary BEV load which can be transferred to the evening. Alternatively, unless drivers feel that this recharging is necessary for them to complete their daily trips, it could instead be completed at home. Further, public charging stations might offer subscription fee structures that remove any price signal for when the BEV can be charged (e.g. pay as you go, or monthly subscription). Obviously these issues do not exist to the same extent if the BEV fleet is shared as the shared fleet operator can act as controller and coordinator of their fleet's charging.

Networks and retailers are unlikely to contract for BEV vehicle flexibility unless there is certainty around provision and quantity. To do this, there would need to be coordination and redundancy within the BEV fleet to provide a reliable source of available energy to be discharged back into the system when required. Over time, as take up of BEVs increase and more charging infrastructure becomes available, the reliability risks of V2G are reduced and the management of V2G should become easier. Hence, the success of V2G is dependent on a critical mass of BEVs.

Compensation for BEV owners

The question is at what point market arrangements result in sufficient compensation for BEV owners to want to incur the additional costs in making their vehicle available to the electricity network. The efficiency of the system would be maximised when the reward for V2G reflects the benefits and cost savings achieved from the charging and discharging actions.

This will depend on the policy and regulatory frameworks as these will determine how electricity market benefits are priced and treated. Compensation for BEV owners could occur through three payment channels:

1. Savings (or avoided costs) for the BEV owner from not charging at peak times. The extent of these savings will depend on electricity price design.
2. Fee payments by market participants to BEV owners for their flexibility.
3. Payments for electricity that is exported back to the grid.

Network tariffs will be the primary signal of the value created from distributed generation services. The value of the network component from DER in terms of deferring capital expenditure could in theory be signalled through the structure of network charges. For example, when a customer makes a demand response decision, they will automatically receive a "payment" corresponding to the network value (through lower network charges). Whether that payment reflects the true value will depend on whether the network charge is fully cost reflective. It will also depend on how retailers pass through such tariffs in their retail offers.

However, there are other reasons why location specific, LRMC network tariffs may not adequately reflect the full value of network savings from V2G:

1. LRMC network tariffs are calculated to reflect the incremental cost of serving additional demand at the location. They do not capture other potential benefits from DG such as operational cost savings and improved reliability outcomes for customers which would need to be compensated through a separate payment channel.
2. LRMC network tariffs are calculated based on the capital costs of augmenting the network to manage additional demand. V2G can also create network value through deferring the need to replace existing assets. To the extent that there are differences in the cost of replacement compared to augmentation, then LRMC tariffs will not properly remunerate the network value of BEV flexibility.

A challenge to designing appropriate compensation is to attribute a fair and accurate value to these energy benefits from BEVs. This is because there is no clear instruction available to value



a complex set of technical and financial opportunities (and challenges) raised from integration of these resources into the system. Moreover, adopting distributed resources to defer demand driven grid reinforcement requires extending the traditional business model of distribution companies.

As discussed, the introduction of V2G and other storage solutions can have potential benefits and negative impacts on distribution network operations. The quantum of these impacts – both positive and negative – are constrained by varying factors including location, time, controllability, and size. For example, the nature of the impact of DG depends crucially on time, location, and the local network conditions. Where there is existing excess network capacity, V2G is unlikely to add significant value to the network. On the other hand, where BEV charging coincides with peak demand in areas where the network would otherwise be stressed, network benefits could arise by deferring the need to invest in additional network capacity.

There is no regulatory mechanism which explicitly requires the calculation of network value from small scale generation and storage in all situations. This makes it difficult for third parties to enter the market and deliver services based on capturing the value of BEV flexibility.

Feed in tariffs for exports

The final option to compensate BEV owners is for them to be paid for any electricity they export back to the grid.

Since 2017, customers in Victoria are offered a feed-in tariff of 11.3c/kWh¹⁴¹ (a large increase from the previous tariff of 5c/kWh) for electricity they provide back to the grid, which represents the minimum rate that retailers must offer to their customers. This tariff is available for renewable energy systems that are below 100kW. For reference, the 2016 average system size for solar PV was 5.6kW, which has steadily increased annually since the 2009 average of 1.28kW¹⁴². In a BEV context, the Tesla Model S contains a 100kWh battery, therefore consumers in the future will have to consider the extent to which they may be able to access feed-in tariffs using their BEV’s battery.

From July 2018, the feed-in tariff will include a time-based model (in addition to a flat tariff) to provide greater rewards to those that contribute during peak periods. This feed-in tariff is illustrated in Table 78.

Table 85– Time-based feed-in tariffs for Victoria from July 2018¹⁴³

	Off-peak	Shoulder	Peak
Weekday periods	10:00PM – 7:00AM	7:00AM – 3:00PM 9:00PM – 10:00PM	3:00PM – 9:00PM
Weekend periods	10:00PM – 7:00AM	7:00AM – 10:00PM	N/A
Rate (c/kWh)	7.1c/kWh	10.3c/kWh	29.0c/kWh

This system is currently in place for households that have solar PV installed on their roof. Such a tariff may favour BEV owners who can tailor their patterns to supply electricity to the grid at peak times when they will receive the greatest reward.

¹⁴¹ Victorian feed-in tariff, Department of Environment, Land, Water and Planning Victoria, <https://www.energy.vic.gov.au/renewable-energy/victorian-feed-in-tariff>

¹⁴² Clean Energy Australia Report 2016, Clean Energy Council, Melbourne, Australia.

¹⁴³ Minimum electricity feed-in tariffs to apply from 1 July 2018, Essential Services Commission, Melbourne, Australia,



A factor to consider for this is the source of electricity. The feed-in tariff system presently rewards those that generate electricity using their renewable assets and is providing “new generation” electricity into the grid. However, BEVs are a storage medium and not a generator themselves, so they would be recycling stored energy generated at other times and returning it to the grid.

Accordingly, while the move to a time-based feed-in tariff is likely to favour BEVs given their storage capability, a “live” tariff may need to be considered that responds to changing demand. If we consider that every person owns a BEV that can return electricity to the grid, peak demand may shift if a large portion of BEV owners decide to supply to the grid given generous tariffs.

Aggregators

While customers with DER such as V2G are an important potential source of grid support, it is challenging for a DNSP to negotiate with and coordinate DER from potentially thousands of customers across their network. Similarly, due to information barriers, it is likely to be challenging for customers themselves to negotiate with DNSPs and, due to the size of any one DER, customers may be precluded from participating in the wholesale energy market.

Aggregators play a core role in allowing customers to maximise the value of their energy technologies by facilitating their participation in markets for energy services. Aggregators do this by combine multiple DER assets to form a portfolio, and sell the products or services derived from that portfolio. Aggregators can also facilitate demand response from residential customers that have appropriate metering technology in place (i.e. smart meters).

While aggregators have contractual relationships with individual customers, facilitating service provision, the aggregator is not necessarily a retailer and the relationship does not involve the supply of electricity.

There are number of potential business models that aggregators could adopt. There are two dimensions to consider:

1. The services that aggregators offer.
2. The way in which aggregators earn revenue.

In terms of services, aggregators could currently provide any combination of the following services:

- Demand response aggregation by providing reserves to the market operator.
- Small Generation Aggregator services by aggregating generation and selling it into the wholesale market.
- Market ancillary service provider services by offering FCAS services.
- Network support services (NSS) by providing DNSPs with aggregated supply.

Aggregators can earn revenue by paying a fixed amount to customers in return for being able to aggregate their DER or demand response. An aggregator’s profit is composed of the service charges paid by the market participants for the BEV flexibility minus the operator price paid to the customer. Under this approach, the aggregator bears the risks of any variation in the price paid, or demand for the services. The aggregator may also offer to pay for the necessary technology needed.

Alternatively, the aggregator could charge a fixed fee for aggregating DER or demand response and pass the revenue through to customers. Under this approach, it is the customer that bears the risk of any variance.

There are a number of other factors that aggregators and their customers will need to consider, including who pays for any assets required to be installed in order to allow the services to be provided (such as demand management systems).



A number of conditions are required to enable aggregators to provide services. First, regulatory arrangements may need to be amended or introduced to prevent any barriers to entry. Two recent examples of changes to the National Electricity Rules to help facilitate the operation of aggregators to add value to the energy market are:

- Small Generation Aggregator Framework, which sought to reduce the barriers to entry faced by owners of small generators in actively participating in the wholesale market. The rule did this by introducing a new type of market participant, a Small Generator Aggregator, which could sell the output of multiple small generating units without the expense of individually registering every generating unit. This framework has allowed small generating units to have a more direct exposure to market prices, increasing the efficiency of the wholesale market.
- Demand Response Mechanism and Ancillary Services Unbundling, which sought to open up competitive opportunities to offer services to help AEMO control the frequency on the electrical system. The rule did this by introducing a Market Ancillary Service Provider, which is a new type of market participant that can offer certain ancillary services loads or aggregated loads into the Frequency Control Ancillary Service (FCAS) market.

However some barriers remain, which are currently being considered by the AEMC, who are concerned that the following aspects of the regulatory arrangements may need to be amended to encourage greater aggregation of demand response:

- The requirements for there to be a single entity that is financially responsible for energy flows at a customer's connection point.
- Difficulties faced by retailers offering demand response products that are valued by customers and recovery of costs associated with investments in demand response capability.

Importantly, a market still needs to develop in some of these areas and until there is both sufficient supply (of which BEVs are only one source) and demand for DER services, opportunities for aggregators may be limited. For example, there has been limited participation by DNSPs to date in purchasing network support services. There are a number of reasons why this is the case. As DER becomes accepted as a viable alternative to investment in traditional network assets, and DNSPs become more comfortable with the 'firmness' of response that they are capable of providing, the aggregator business model should strengthen.

Co-optimisation of benefits

When BEV batteries act as a source of energy storage which can be injected back into the grid, they take the same features as other types of DER such as solar PV, and other battery technologies. A critical feature of any type of DER is their potential to be used in multiple applications and hence their ability to deliver both network and energy related benefits to the systems.

Therefore, a single installation of energy storage has the potential to provide multiple services to several entities with compensation provided through different revenue streams. The ability to "stack" the incremental values a DER may provide across these multiple uses – i.e. the wholesale market, distribution networks, retailers and customers – may be necessary to make DER solutions such as V2G economically viable.

However there are a range of potential regulatory or market barriers limiting the ability of DER resources to capture all the value across multiple revenue streams.

In delivering network support, a DER will generate, or consume, energy at times that are of most value to the distribution network. In delivering energy, on the other hand, the DER will operate based on the value to the energy market (and the buyer of the DER service) in which it



is selling its output at a given point in time. While these times might coincide, often they will not. For example, high wholesale energy prices may coincide at times when there are export constraints in the distribution network. A DER would need to increase output to deliver energy but decrease output to deliver network support.

As network support and energy delivery may conflict, the owner of a BEV (or aggregator) will be required to choose between the two. A rational owner will choose to deliver to the market that provides the higher value. This choice – or series of decisions – is a “co-optimisation” of service delivery across the various benefit streams markets.

Co-optimisation decisions can take place in different timescales. In the example above, the DER owner has to make a “spot” decision about whether to increase or decrease output from the DER. However, the decision may have already been made in an earlier transaction. For example, the DER owner may have contracted the control of its DER to a distribution network, in which case the DER will deliver network support rather than energy, for the period of the contract (at least, when the DNSP decides to operate and control the contracted DER).

Given the complexity of the co-optimisation problem, few consumers would be able to undertake this task effectively and are likely to default to only contracting with the DNSP for the procurement of NSS.

Regarding achieving co-optimisation, the key issue is not which party should be responsible for controlling the charging load but how the framework can facilitate the appropriate contracts to capture the full value of controlling the BEV charging. This may require arrangements enabling coordination of the decisions to control the load across parties such that the full benefits of controlling the load is utilised, or the introduction of intermediaries (i.e., energy services companies) which can act on the consumer’s behalf.¹⁴⁴

It is possible DERs (with the appropriate technology) could switch between the provision of multiple services almost instantaneously. An electric storage resource receiving regulated revenues for providing one service may also be technically capable of providing other market-based rate services. However, in situations where the DNSP need for such resources is not reasonably predictable as to size or the time, the regulated NSS service may be the only service that the DER resource could provide.

In all cases, a well-functioning market for NSS will depend on the capabilities of technologies connected to the area of the distribution network subject to the DNSP platform. This means that any DER procured by the DNSP will be required to be maintained so that the necessary state of response (i.e. battery charge or discharge) can be achieved when necessary to provide the service compensated through the DNSP regulated revenue

In this situation, the ability of the DER to access other revenue streams will depend on:

- Whether the priority for which the DNSP will require the DER resource is reasonably predictable as to size and the time it will arise on a given day of the year. If so, the DER resource should be permitted to deviate at other times of the day in order to provide other, market-based rate services;
- The terms and conditions under the DNSP procurement of the DER resource for network support services, including the penalty rates for non-compliance;

¹⁴⁴ Consideration should also be given to a distributor’s position to prevent the development of other contestable markets for DER products and services. For example, where a DER is contracted and controlled by a distributor, this may prevent it from participating in other markets for DER products and services – leading to lower liquidity in that market. This will be subject to the contractual arrangements entered into by a distributor and DER owner



- The framework for how the DNSP can recover costs through regulated revenues; and
- Obligations on the DNSP for maintaining a reliable, safe and secure network, and how those obligations are translated into access and connection arrangements for DER.

An issue which may get overlooked is how co-ordination of charging and discharging by multiple parties impacts on battery degradation. This is important to protect the BEV owner's investment.

Systems integration and interoperability

Since scale will be the key to the success of using BEV flexibility, interoperability will be necessary. With respect to BEV, interoperability is often considered in the context of the standardization of BEV charging stations to be compatible with electrical connection ports. However, for capturing energy market benefits, the issue relates to how energy market systems can communicate and control plus coordinate the charging and discharging of large number of separate vehicles. Having a large number of local devices connected to the low voltage grid producing, consuming, and storing electricity drives the need for integration and control.

Interoperability is a measure of how easy or difficult it is for different parties to communicate with each other via communications-enabled infrastructure, such as smart meters. A communications platform is the system that provides the communications link between two points. In the case of smart meters, for example, this link enables the conveyance of metering data and status information from the smart meter to the market operator, network business and retailer, as well as commands, messages and software updates back to the meter.

To achieve interoperability requires agreeing on a common or shared communications standard that allows seamless communication between different charging stations, and between a customer's smart meter and their charging equipment.

There are two approaches:

- Deterministic architecture whereby there exists a direct line of communication between the grid system operator and the vehicle so that each vehicle can be treated as a deterministic resource to be commanded by the grid system operator.
- Aggregative architecture whereby an intermediary is inserted between the vehicles performing ancillary services and the grid system operator.

The complementary character of storage capacities and renewable energy supply calls for an intelligent integration as the benefits can only fully be realised if they are managed jointly within a network.

Architecture can improve the scale and reliability of V2G ancillary services, thereby making V2G ancillary services more compatible with the current ancillary services market. However, the aggregative architecture has the adverse effect of reducing the revenue accrued by vehicle owners relative to the default architectures. Over time, as take up of BEVs increases and more charging infrastructure becomes available, the risks of V2G are reduced and the management of V2G should become easier.

BEVs with the capability of bidirectional charging are not only energy storage units but also controllable energy consumers within a grid system. To activate this potential, the grid needs to be 'smart' and include a power management system by incentivising energy consumption and allocating energy reserves where they are needed most. Given that the scenarios modelled primarily deal with a 2046 outlook, it is likely that a smart grid will be established and such issues are managed. However, if this smart capability is developed after BEVs are widely adopted, they may run the risk of compatibility issues.



Reliability of exports onto the network grid

For V2G to be commercially viable, its ability to discharge into the network needs to be reliable and predictable. However, a policy and regulatory issue to consider is the degree to which network operators are required to provide sufficient capacity and network capability to manage such exports from V2G sites.

Subject to the volume of all types of DER installed across an individual network, and importantly the type of technologies adopted by consumers, exports from V2G could reverse the energy flows across the network. These export flows can cause voltage, protection and thermal network problems.

Hence while V2G capability can create opportunity for the network to better manage its grid and avoid costs, exports of energy back to the grid can create operational challenges and additional costs. How the network balances these issues will depend on a range of factors relating to the existing quality and capability of the network, the regulatory arrangements, and also the location of vehicles.

To manage these issues, a DNSP may seek to limit connection or access for new generation in problematic areas of the network. Voltage and thermal problems are not unique to export constraints. Similar issues arise around import flows. The penetration of air-conditioners over the last decade would have created serious problems for networks if DNSPs had not taken active steps to manage them – primarily by adding new network capacity. However, regulatory arrangements could discourage networks from making similar investments to support V2G exports.

The problem is that, unlike with imports, there is no reliability standard that mandates the level of access that must be provided for exports. Thus, a consumer looking to export to the network from a DER has uncertain “access” to the network under the current arrangements.

At present, networks have “load shedding” systems to curtail conventional distribution services when a network would otherwise be overloaded or insecure. However, there are no corresponding systems to curtail exports when needed. Thus, distribution networks need to be more conservative in allowing generating devices to connect. An export reliability standard could allow for some level and frequency of curtailment to exports, just as existing reliability standards allow for a certain (albeit very low) level of curtailment to imports.

While networks will use access and connection agreements to protect network security under a scenario of high export back to the grid, a concern might arise if networks seek to restrict access to the BEV battery or imposes substantial conditions on the right of V2G. For example, a DNSP might require – as a condition of connection – that an inverter can be remotely controlled by the DNSP so that DERs can effectively be dispatched by the DNSP to manage export (and even import) constraints. This is a concern as it goes against the principles of open and non-discriminatory access and could impede the ability of BEV owners to maximise the revenue from their V2G capability.

For any site seeking V2G capacity the ability to connect may end up operating effectively on a “first come, first served” basis. This would especially be the case for large BEV connection sites (i.e. commercial depots, shared robotaxi depots) which would need to go through additional network approval processes compared to residential connections.

We understand that some networks have had to turn down solar PV applications due to system constraints. Therefore, the absence of an export reliability standard on a DNSP may create an additional barrier to investment in V2G capability.

5.3.5 Concluding observations

There are a range of policy and regulatory challenges which need to be resolved in order to capture the benefits identified. These issues are not unique to BEVs and apply to all forms of



distribution generation and storage. However such issues need to be resolved in a predictable and robust manner to facilitate the investment and business models needed to get the appropriate infrastructure responses.



While presenting a challenge for the electricity network, BEVs have the opportunity to provide numerous benefits

Electric system capacity can be strained by unmanaged BEV loads, especially at the distribution level where the capacity bottlenecks are most easily reached. On the other, if charging demand flexibility can be harnessed by implementing smart charging strategies, not only can costly grid capacity upgrades be minimised and wholesale energy prices dampened, but the operation of energy systems can be enhanced making use of a potentially very large responsive storage constituted by the batteries of grid connected BEVs.

Overall, the integration of BEVs into the electricity network may provide opportunities to take advantage of renewable generation, provide ancillary services, generate cost savings for consumers, and could provide benefits to a number of stakeholders. However, this will require the correct environment to succeed, with numerous items identified within this section to capture these benefits.



V2G benefits could be extensive if correctly captured

Using V2G technology, BEVs provide an opportunity to act as energy storage devices and feedback electricity to the grid or to the house. This facility could be used to reduce strain on the grid during periods of peak demand, provide ancillary services, or power a home. The benefits of V2G could be large, however, the success of V2G depends on a number of factors. Furthermore, the impact on a consumer's vehicle (particularly the batteries) would need to be considered from potentially frequent charging and discharging.

To capture these benefits there will be a need to consider what role BEVs will play in electricity markets and how the value of BEV flexibility be captured and rewarded across the network and generation sectors.



A robust, integrated framework that adequately considers consumer needs is critical

As BEV penetration increases, there is a greater emphasis by market and policy makers to resolve challenges in a timely manner, otherwise uptake may be hampered, or there are negative market outcomes. However, there is a risk that such policy reforms are done in an inconsistent and piece-meal fashion across multiple organisations which are reacting to issues as they arise. We believe this could lead to sub-optimal outcomes.

Realising the full benefits of vehicle electrification will necessitate a systems-level approach that treats vehicles, buildings, and the grid as an integrated system. V2G only makes sense if the vehicle and power market are matched. An integrated framework which provides long term confidence to market participants will help facilitate the commercial models and infrastructure investment needed for effective integration. Any such framework needs to be forward-thinking and places the customer at the centre, as their preferences, driving patterns, and behaviour will determine the extent of benefits from BEVs.



5.4 Generation and transmission infrastructure

The generation market in the National Electricity Market (NEM) is in a state of change. The level of renewable generation is increasing, demand patterns are changing, and there is significant uncertainty about Government policy in regards to both energy and emissions. This has impacted the investment environment, as well as the ability of the electricity system to provide reliable and secure supply. There are currently a wide range of policy initiatives which seek to provide a more robust framework for the generation sector going forward. There are also many state based policies and targets which will affect electricity generation, including by encouraging the uptake of renewable energy over emissions intensive generation sources.

A significant uptake of EVs will place more pressure on the generation sector to ensure that sufficient capacity is available to meet the additional consumption of electricity, as well as any additional maximum demand. The latter will depend on when during the day charging takes place, and the extent to which this coincides with system peak demand. However, as demonstrated by our scenario analysis, even if charging can be coordinated to occur outside of times of system stress, there will still need to be a substantial amount of new generation to serve the extra consumption under high levels of EV uptake.

This section explores some of the challenges and policy issues relating to how the energy generation sector responds to the investment challenges under a high level of uptake of electric vehicles. The issues discussed are also applicable to the Hydrogen Highway scenario (electrolysis case), given the high level of electricity required for hydrogen production.

5.4.1 Current situation

The NEM was established to introduce competition in the wholesale electricity sector with the objective of decentralising the operational and investment decisions to commercial parties, who are better placed to bear the costs and manage the risks of those decisions. The focus of the NEM was to facilitate competition between electricity generators across the interconnected system, while supporting development of a competitive contracting market between generators and retailers.

Future investment in generation is determined by market participants on the basis of market signals. That is, on the basis of expectations of future spot prices, and retailers' willingness to enter into contracts to hedge against future price risk. Therefore, investment in generation assets in the NEM is intended to be market-driven, taking into account - amongst other things - expectations of future demand, the location of the energy source, access to land and water, and proximity to transmission.

However, Government policy around renewable energy and emissions of the electricity sector, together with falling costs of wind and solar PV technologies, are impacting investment in generation assets. The variability of renewable energy sources is creating new challenges for a power system that was designed around coal, natural gas and hydro. Events in South Australia and New South Wales in 2016 and 2017 have raised the public profile of electricity supply and focused attention on the functioning of the market.

The wholesale electricity market design must deliver a secure, reliable and affordable supply of electricity, with a decreasing emissions intensity under Australian international commitments. For this to happen, the right investments need to be made across the supply chain at the right



time and at least cost. There are two factors in particular that could impede this outcome under the current National Electricity Market design:

- A failure to integrate emissions reduction policy into the wholesale electricity market, which creates policy uncertainty and discourages investment.
- Not identifying and pricing all services necessary to incorporate increased variable renewable energy into the power system, such that market participants can respond to these price signals and provide ancillary services like inertia, ramping and fast frequency response.

Maintaining system security elements, such as frequency and voltage, has become more complex as renewables form a greater proportion of the energy mix. This is a significant challenge facing the market. In 2016/17 there were 11 instances of the system being operated outside its secure limits for greater than the maximum allowable time of 30 minutes.¹⁴⁵

System security challenges are currently being resolved through a series of reforms across the sector. By our count, there are a total of 46 policies or initiatives being considered, with 16 focused on reliability, eight on security, 16 on emissions reduction and six on affordability.¹⁴⁶ The major reform is the National Energy Guarantee (NEG) (see Box 1 in Section 3.4.2) which focuses on both the reliability of supply and a target level of emission intensity in the market. The NEG stipulates that retailers supply power on a secure, uninterrupted basis and ensures that the average emissions level of electricity supply supports Australia's international emission reduction commitments.

The outcomes of these reforms will determine the investment framework for the foreseeable future, and hence how the market responds to the increased demand for electricity under significant uptake of BEVs. The NEG's rules will place additional value on sources of generation which are dispatchable and clean, and will boost investment in small and large-scale batteries, pumped hydro and demand side participation to firm up other, non-dispatchable, electricity supply sources.

In June 2016, the Victorian Government committed to a renewable energy generation target of 25% by 2020, and 40% by 2040 (referred to as Victorian Renewable Energy Target (VRET)). In providing a platform for increasing their commitment to renewable energy, the VRET was developed by the Victorian Government to also respond to increasing electricity prices, and to deliver higher investor certainty in the region. By establishing a plan to bring forward investment in renewable energy projects in Victoria, the VRET aims to secure Victoria's electricity supply along with the creation of thousands of jobs. The Victorian Government has also made a policy commitment to achieve zero net emissions by 2050, which will favour low or zero emissions technologies

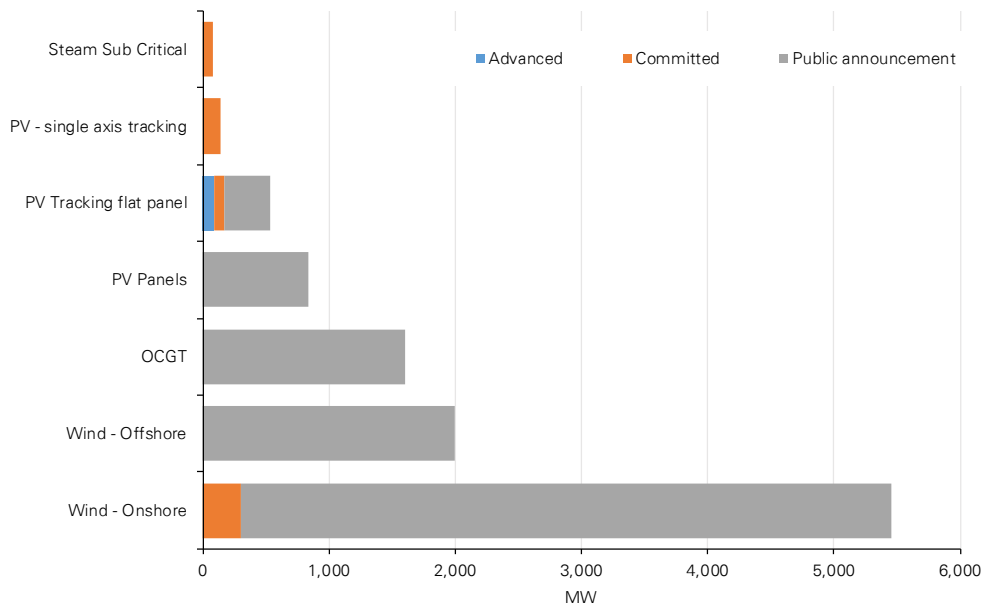
Figure 90 presents the range of generation projects currently under development in Victoria, as collated by AEMO. The increase in wind and solar plants are being driven largely by the VRET and the LRET. No pumped hydro, large scale batteries or combined cycle gas turbines have been publicly announced (except the Victorian Government large scale battery initiative). However, there is over 1,600 MW of publicly announced gas peaking plans (OCGT) currently under consideration.

¹⁴⁵ AEMC Reliability Panel, Annual Market Performance Review 2017 (2018)

¹⁴⁶ Responsibility for these is spread across the Energy Security Board, the Australian Energy Market Commission, the Australian Energy Market Operator, the Commonwealth Government and four state governments.



Figure 82 - Current Generation Projects under development in Victoria



5.4.2 Summary of the modelling results

Table 79 sets out a summary of the extent of generation investment needed under the different EV uptake scenarios. The Victorian generation capacity is currently 10,090 MW, which is significantly less than what will be required under all scenarios except the Slow Lane scenario (which involves less than 100% uptake of EVs). The impact is greatest under the Hydrogen Highway scenario where electrolysis is used.

Table 86 - Summary of generation investment needs by scenario

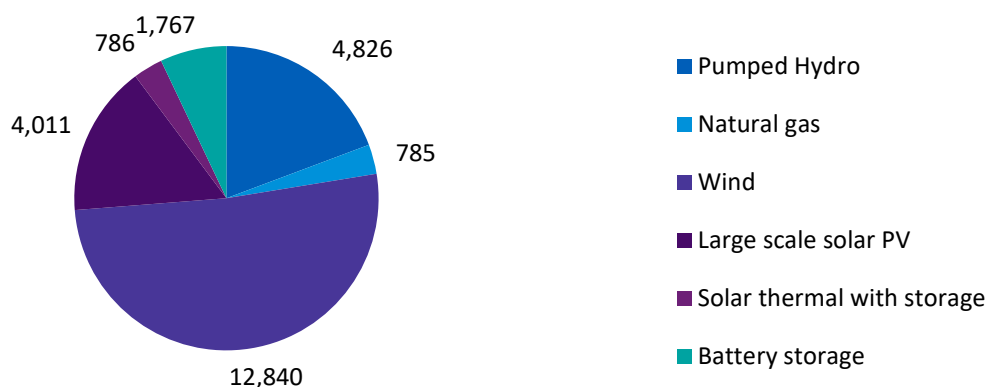
Scenario	Dispatchable generation required	Non-dispatchable generation required	Total cost (NPV): Dispatchable generation	Total cost (NPV): Non-dispatchable generation	Total cost \$ (NPV): All generation	Total cost (NPV): Incremental to dead end scenario
	MW	MW	\$ m	\$ m	\$ m	\$ m
Dead End	800	0	\$319	-	\$319	-
Electric Avenue (Incentivised)	3,331	9,308	1,257	\$3,660	\$4,918	\$4,599
Electric Avenue (Non-incentivised)	6,205	9,308	2,650	\$3,660	\$6,311	\$5,992
Private Drive (Incentivised)	3,519	10,279	1,346	\$4,052	\$5,399	\$5,080
Private Drive (Non-incentivised)	6,719	10,279	2,911	\$4,052	\$6,963	\$6,644
Fleet Street	1,451	9,198	543	\$3,616	\$4,159	\$3,840
High Speed	0	1,636	0	\$1,108	\$1,108	NA
Slow Lane	1,121	3,808	429	\$1,440	\$1,869	\$1,550
Hydrogen Highway - Electrolysis base case	0	28,529	0	\$14,843	\$14,843	\$14,524
Hydrogen Highway - Electrolysis strong shift	166	18,313	66	\$8,306	\$8,372	\$8,053



The estimated additional cost of the generation infrastructure response under the BEV scenarios ranges from \$1.9 billion in the Slow Lane scenario to \$7.0 billion for the Private Drive scenario with a non-incentivised load profile.

These figures need to be viewed within the context of the investment challenge facing the generation sector. A report prepared for the Australian Energy Council (AEC)¹⁴⁷ estimates that the scale of new investment in generation required through the transition to 2030 is approximately \$23 billion across the National Electricity Market. Figure 83 shows the expected split of new generation types. This figure does not assume the impact of BEVs which would place further requirements on the sector as demonstrated by our modelling.

Figure 83 - AEC estimated generation investment requirement by type (\$m)



5.4.3 Key issues

The magnitude of response by the generation sector over the next 25 to 30 years will need to be substantial if there is a high uptake of BEVs in Victoria. The nature of the response will be influenced by government policy and market design arrangements. This section briefly explores some of the factors which will impact on the generation response:

- Constraints on the development of certain types of supply to meet additional demand.
- The availability of transmission capacity to transport electricity from new generation source to customers.
- The likelihood of significant BEV uptake to be complemented with increased demand side participation and thereby a reduced need to invest in new generation capacity.
- The ability of technology and/or other initiatives to assist in improving the reliability of renewable generation sources.

Potential supply constraints on generation investment

As explained in Section 3.4, we have modelled generation entry on the basis of its ability to serve maximum demand, its emissions intensity, and its levelised cost of energy. However, our model does not explicitly take into consideration potential constraints on the entry of new generation. Such constraints will differ across the different types of generation and could relate

¹⁴⁷ The AEC represents major electricity and downstream natural gas businesses operating in competitive wholesale and retail energy markets. See “The Investment Challenge, Investment in Australia’s electricity generation sector to 2030” prepared for the Australian Energy Council by Newgrange Consulting, <http://www.energycouncil.com.au/media/11829/newgrange-consulting-investment-challenge-for-aec.pdf>



to environmental considerations, planning permission, costs, and access to fuel. Such constraints could limit the extent to which a particular type of generation enters the market, and therefore places more pressure on other technologies.

Our analysis assumes that both pumped hydro and batteries will play a key role in the future electricity capacity mix, to serve an increase in maximum demand associated with BEVs. This is consistent with the current thinking of AEMO as set out in its Integrated Planning Report plus supports the objective that BEVs would be zero emission along the total supply chain.

Table 80 sets out the estimated capacity requirements for pumped hydro and batteries under the various scenarios (assumed at an equal split by design, i.e. in the Dead End scenario 400 MW of pumped hydro and 400 MW of batteries are required). Please note that for high speed the results are for 2031 and there is no need for such infrastructure as this is before any assumed retirements of coal fired generation.

Table 87 - Pumped hydro and battery capacity requirement by scenario (MW)

Dead End	Electric Avenue - Incentivised	Electric Avenue – Non-incentivised	Private Drive - Incentivised	Private Drive – Non-incentivised	Fleet Street	High Speed	Slow Lane
400	1,665	3,103	1,759	3,359	726	0	561

Regarding pumped hydro, recent ANU research says there is enormous potential for pumped hydro all over Australia, including in Victoria. Specifically, it identifies 4,400 sites in Victoria with a total approximate energy storage of 11,000 GWh.¹⁴⁸ Further, the Victorian Government backed a plan to convert some of the state’s abandoned gold mine shafts into pumped hydro energy resources, with the concept to undergo full feasibility studies after initial investigations returned promising results.¹⁴⁹ However, climate and water access issues could affect the commercial viability of some pumped hydro projects.

Batteries are also assumed to play a key role in meeting peak demand growth in the market. This is based on the expectation of substantial large decreases in the cost of batteries. However, effective development of V2G technology (as discussed in Section 5.2.3) as a reliable source of stored energy could lessen the magnitude needed under the scenarios.

If a significant uptake of EVs occurs in the near term, it is possible that gas-fired peaking generation is developed to meet maximum demand requirements, rather than pumped hydro or large scale batteries. This would be consistent with AEMO’s published register of committed projects, which includes three OCGT projects under consideration, but no large scale batteries and pumped hydro.

However, there are currently concerns about the availability and price of natural gas. AEMO’s Gas Statement of Opportunities¹⁵⁰ notes that declining gas production may result in insufficient gas to meet projected demand. For Victoria, AEMO is estimating a minor gas shortfall for gas powered generation in 2021.

The development of OCGT (and to a greater extent CCGT as it operates more frequently) will be dependent on the ability to secure reasonably priced gas. Market responses which could alleviate risk of forecast gas or electricity shortfalls include increasing production from existing fields (including additional supplies through the NGP or re-directing gas earmarked for LNG),

¹⁴⁸ <http://www.anu.edu.au/news/all-news/anu-finds-22000-potential-pumped-hydro-sites-in-australia>

¹⁴⁹ <https://www.premier.vic.gov.au/pumped-hydro-study-in-bendigo-a-success>.

¹⁵⁰ Gas Statement of Opportunities for Eastern and South-Eastern Australia, Australian Energy Market Operator, March 2017, http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf



alternatives to GPG (other forms of generation, and storage), or exploration and development of new gas fields to supply gas in the longer term.¹⁵¹

Supply constraints in Victoria may not apply in other jurisdictions, and hence the interconnectors may be needed to play a bigger role in serving any increased demand in Victoria.

Transmission investment to support generation

A further potential supply constraint is the availability of transmission capacity to transport energy from new renewable generation to customers and businesses. We understand that this is currently an issue today with renewable projects being affected by the limitations in the existing transmission grid. This section provides an overview of the current arrangements and the potential for this issue to materially impact on the generation infrastructure response.

Transmission network service providers (TNSPs) must go through an extensive planning and assessment process in order to deliver new transmission investment. TNSPs are able to recover their costs from electricity customers. To ensure that these costs are efficient, and that TNSPs have invested in the optimal solution, they must conduct a Regulatory Investment Test for Transmission (RIT-T). However another potential constraint on generation investment would be if transmission investment did not pass the RIT-T process.

The RIT-T applies to all projects that are anticipated to have capital costs in excess of \$5 million, except in certain circumstances. The purpose of the RIT-T is to identify investment options which best address an “identified need” in the network.¹⁵²

The RIT-T is not a perfect tool and a number of issues have been raised with its application. This includes that the RIT-T does not adequately capture relevant costs and benefits. In particular:

- While the RIT-T is capable of capturing the economic value of environmental policy, there is limited guidance on how environmental factors can be captured in a RIT-T assessment, and therefore how any reduction in emissions can be identified and included as a benefit.
- While the RIT-T allows option value to be considered as a class of market benefits, there is some uncertainty as to how it should be calculated and taken into account. Option value is important, particularly in a rapidly changing environment, as it allows the benefits of retaining a degree of flexibility to be taken into account.

A further challenge arises with efficiently connecting renewable generation to the grid. Historically, large coal-fired generation plants have located near their fuel source and transmission has been built to transport power to load centres. However, renewable generation

¹⁵¹ Whilst there are several offshore brownfield and greenfield projects in the Gippsland and Otway basins currently being considered for exploration and development by producers in the next five years, according to AEMO’s Victorian Gas Planning Report in 2018, none of these are expected to be like-for-like replacements of legacy fields that have been supplying Victoria for nearly 50 years and are now nearing depletion. The fields are also costly and time consuming, especially off-shore projects (onshore exploration is not currently permitted in Victoria, with a moratorium in place until June 2020 and fracking permanently prohibited).

¹⁵² The RIT establishes the processes and criteria that must be applied by TNSPs in identifying investment options which most efficiently address an identified need on the network. Essentially, it requires TNSPs to assess the costs and, where appropriate, the benefits of each credible investment option to address a specific network problem to identify the option which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

The types of costs and benefits to be considered are set out in the national electricity rules and include factors such as the costs of construction, operating and maintenance costs, costs of complying with laws (including the impact of environmental policies), and reductions in generation dispatch costs, among others.



has different characteristics from coal-fired generation. First, the best locations for renewable generation are typically not located close to existing transmission networks. Second, renewable generation tends to be smaller in scale than the relatively large coal-fired plants. It is not possible to scale down transmission investment to match smaller scale generation.

These issues mean there are challenges in coordinating renewable generation and transmission investment. Significant investment may be required to connect large-scale renewable energy generation in areas where there is currently limited transmission. However, neither generators nor TNSPs have the incentive or the ability to undertake the necessary investment to promote an efficient, well-coordinated outcome.

To help resolve this issue, a number of processes are underway. First, the Australian Energy Market Operator has been tasked with developing an Integrated System Plan (ISP) that will facilitate the efficient development of renewable energy zones (REZ). The first ISP is due to be published in June 2018. This ISP is intended to deliver a strategic infrastructure development plan which can facilitate an orderly energy system transition under a range of scenarios. In particular, this ISP will consider:

- What makes a successful REZ and, if REZs are identified, how to develop them.
- Transmission development options.

At the same time, the AEMC has been considering the coordination of transmission network planning and renewable generation investment, including the development of REZs to facilitate the connection of new renewable generators to the transmission network. In a discussion paper released in April 2018, the AEMC considered four ways in which to define REZs:

- Enhanced information provision, whereby AEMO and TNSPs would enhance their coordinated planning to signal potential REZs for development by the market.
- Generator coordination, whereby generators connecting in the same area work together to coordinate the connection process.
- TNSP speculation, whereby TNSPs would undertake speculative investment to build the REZ.
- TNSP prescribed service, whereby TNSPs would build infrastructure in anticipation of generators connecting to a REZ, with this being funded by electricity customers.

This process is ongoing.

Internationally, a number of jurisdictions have adopted some form of mechanism to better coordinate transmission and generation investment. In Texas, for example, a directive was passed to establish competitive renewable energy zones (CREZ).

To establish CREZs, the Electricity Reliability Council of Texas (ERCOT) provided a study of wind energy production potential in Texas and of the transmission constraints most likely to limit the deliverability of wind energy resources. The Public Utilities Commission of Texas designated CREZs based on ERCOT's study, taking into account a number of considerations. A competitive bidding process was carried out to implement the plan, with electricity costs recovered from customers.

In California, the California Energy Commission (CEC), California Public Utilities Commission (CPUC) and the California Independent System Operator (CAISO) initiated the Renewable Energy Transmission Initiative 2.0 (RETI). The RETI helps identify transmission projects needed to accommodate California's renewable energy goals.

RETI is in charge of assessing CREZs. RETI then prepares detailed transmission plans for those zones identified for development, which is then used by the CAISO to refine scenarios used in the transmission plan and make investment decisions. There are special arrangements where



transmission projects are necessary to connect generators in certain remote areas. The costs for such projects are socialised and recovered from electricity customers before generators are connects. Once connected, costs are assigned to generators going forward on a pro-rata basis until the line is fully subscribed. At that point the transmission owner is 're-paid' for its initial investment.

Role of demand side participation

Historically, a 'reliable' power system invariably meant back-up generation, that is, the availability of additional generating units if others failed. However, the emergence of new technologies and ensuing regulatory developments have meant that reliability is no longer the exclusive domain of 'supply-side' solutions. Rather, the demand-side – including residential customers – now has a potentially important role to play in delivering a reliable power system at the lowest possible cost.

Demand side participation (DSP) covers any action by the customer to change the quantity and timing of their electricity use. Examples of DSP by consumers can include (but are not limited to) peak shifting, electricity conservation, fuel switching, utilisation of distributed generation, and energy efficiency.

Similar to the benefits of electric vehicles, DSP initiatives can help to reduce the need for infrastructure investments in both generation and networks. Therefore a higher than forecast DSP will have an impact of lowering the investment requirements to serve BEVs.

DSP to date has played a very limited role in the energy system due to a range of different barriers. However, consumers are now better-equipped than ever to manage and control their energy use and contribute to reliability, which will only improve in the future. Smart technology and distribution generation sources are providing more capability and flexibility for customer to actively adapt their consumption patterns in response to system events.

Increased uptake of BEVs could act as a catalyst for greater DSP in the market. There are three potential reasons for this. Firstly, the extent of BEV demand which is time discretionary will create value to be captured from demand side initiatives. This will encourage market participants and commercial service providers to offer innovative solutions to customers to capture this value. Secondly, the increased purchase of BEVs will place more impetus on the presence of cost reflective price signals to encourage customers to shift energy use away from peak times given the costs associated with charging EVs at peak times.

Finally, customers who purchase BEVs will have greater incentive to become more active consumers for their consumption load. Given the increased potential for reward payments, they are more likely to invest in smart home energy management systems and other enabling technology. Table 81 provides an overview of the impact of reducing underlying maximum demand (i.e. excluding maximum demand attributable to EVs) by 10% by scenario.

Table 88 - Increasing demand side participation sensitivities

Scenario	Generation savings	Network savings	Total savings
	\$ m	\$ m	\$ m
Dead End	-319	-27	-346
Electric Avenue (Incentivised)	-478	-27	-504
Electric Avenue (Non-incentivised)	-763	-26	-790
Private Drive (Incentivised)	-500	-27	-527
Private Drive (Non-incentivised)	-791	-27	-818
Fleet Street	-413	-27	-440



High Speed	0	-5	-5
Slow Lane	-404	-28	-432

Firming up renewable generation

A key factor to the challenges for the generation system is the lack of certainty over the timing of renewable generation. In our analysis, we introduce storage solutions (pumped hydro and large scale batteries) to ensure enough “firm” capacity is available to meet demand at peak times.

However, there may be other initiatives and ways which can help to firm up renewable generation, which may lessen the requirements for storage solutions.

A characteristic of wind generators is that they can forecast their expected output with a relatively high degree of accuracy in the short term. Data from AEMO’s Australian wind energy forecasting system shows 95% accuracy within 40 hours and around 80% accuracy within 6 days.

If a liquid short term contract market existed, wind and potentially solar generators may be able to sell long term hedge contracts, and manage the risk of these positions closer to dispatch by buying back contracts. In this way they would become a ‘synthetic’ firm generator.¹⁵³

Thermal generators, hydro plant and batteries could use this market to sell contracts to renewables generators and lock-in an arbitrage position. This would be achieved by selling a peak contract to a renewable generator and backing this with a buy position for an off-peak electricity contract; or, in the case of a gas-fired generator, purchasing spot market gas (or using contracted gas).

Effectively this results in a better allocation of the risks associated with renewable generation, thereby lessening the requirements for back-up supply or batteries. We consider that this type of market framework could be implemented quickly at a reasonable cost.

5.4.4 Concluding observations

Full uptake of BEVs on the Victorian road network will necessitate a significant infrastructure response to ensure that the electricity network generates a sufficient amount of electricity to serve demand at all times, which would need to be considered alongside the requirements of all other energy users.

This section has discussed a number of factors that may impact the generation response in the context of our modelling results, with the following observations summarising some of these.



A significant generation requirement to balance with ongoing needs

Our modelling has indicated an additional generation infrastructure response valued between \$1.9 billion and \$7.0 billion to meet the electricity requirements for BEVs under the various scenarios contemplated by this advice.

This would need to be managed in-line with all other requirements on the electricity network as new generation capacity is planned. The AEC has estimated a \$23 billion investment across the NEM to transition to 2030, indicating significant requirements before 100% BEV uptake is factored in. Ideally, future investment into generation capacity would be based upon a reasoned

¹⁵³ Contracts could be listed on ASX Energy, a platform commissioned by industry participants or AEMO’s existing exchange-traded platform. Products could be traded out 6-7 days and be tailored to participants’ needs, such as 24-hour base, peak, off-peak, super-peak, weekend contracts etc.



and consolidated infrastructure response that considers generation required to support the whole-of-network requirement into the future, including BEVs.



Constraints to new projects will need to be managed

While the results of our modelling has considered that a particular level of new generation would be required, each new project would face a series of constraints. Environmental considerations, site availability, planning permissions, costs, and access to required fuels all constrain new generation projects. These will all need to be considered and managed by developers.

Furthermore, a rapid uptake of BEVs in the short-term may see a use of gas-fired generation constructed to meet demand. These implications would need to be considered in the context of a zero emissions future.

As noted in section 3, we have not assumed any supply constraints which could impact on the feasibility of the market to respond and provide the additional generation capacity under the scenarios.



Flow-on effects to the transmission network need to be considered

The location of new generation projects, particularly wind and solar, may place stress on the transmission network. This is already being warned of within certain areas in Victoria as renewable penetration increases.

Significant investment may be required to provide transmission infrastructure to connect large-scale renewable generation in constrained areas. Neither the generator nor the transmission network service provider are incentivised to undertake this investment to deliver an efficient, well-coordinated outcome. Work is currently ongoing by AEMO and AEMC to develop efficient renewable energy zones.



5.5 Distribution network infrastructure

5.5.1 Overview and current situation

BEVs present both opportunities and challenges for network businesses which will compound as increased penetration of BEVs occurs across the Victorian networks. While new opportunities and challenges are created, the core or traditional roles performed by a network business will continue to be essential to the overall operation of the system. These roles include, among others, planning, investment, operation and maintenance of the distribution network ensuring for continued system security, safety and reliability of supply. How network businesses respond to the impacts of BEVs while performing these roles will be key to the effective integration of BEVs to the energy system.

This section provides a high level overview of some of the challenges and policy issues relating to how the network sector responds to the investment requirements under a high level of BEV penetration. This section deals primarily with the infrastructure required at the distribution network level. Within Section 5.3 we discussed the need for transmission network investment to respond to the substantial number of new renewable plants required under the scenarios. In addition, the increased consumption due to BEV charging will also have investment implications for transmission businesses.

Table 82 provides information on the current status and outputs of the five Victorian electricity distribution networks and shows that there are quite substantial differences in the size and demand characteristics across the networks.

Table 89 - Key statistics for Victorian electricity distribution networks¹⁵⁴

Network	Customer numbers	Line Length (circuit KM)	Electricity transmitted (GWh) 2015-16	Maximum demand (MW) 2015-16	Asset base (\$ million 2018)	Current regulatory period
Powercor	777,161	74,452	10,713	2,299	3,819	
AusNet	706,424	44,349	7,686	1,815	3,958	
United Energy	664,549	12,873	7,604	1,894	2,363	1 January 2016 – 31 December 2020
CitiPower	327,907	4,505	5,944	1,287	2,014	
Jemena	321,417	6,252	4,212	924	1,416	

¹⁵⁴ Australian Energy Regulator, State of the Energy Market, May 2017, <https://www.aer.gov.au/system/files/AER%20State%20of%20the%20energy%20market%202017%20-%20A4.pdf> RAB values are from the AER final determinations for 2015-2020 regulatory control period.



Currently, distribution networks are subject to revenue regulation, which places a cap on the total distribution revenue that a DNSP can obtain through network tariffs. The cap is based on an estimate of the efficient cost of providing distribution services; or, put another way, the total cost of distribution inputs and is reset every five years.

Some of the challenges with integrating BEVs into the grid have already been recognised through the issues occurring under the increased penetration of solar PV. There are currently 1.8 million households in Australia which have solar panels installed. Given the likely increase in distributed energy technologies by customers, Energy Networks Australia and the Australian Energy Market Operator have recently released a consultation paper which explores options on how to effectively support the integration of distributed generation and batteries in an optimised manner which provides maximised value to customers. The issues discussed in this report are applicable to any further penetration of BEVs.¹⁵⁵

5.5.2 Summary of modelling results

The nature and range of investment responses for distribution networks triggered by BEV charging will range across the following four board categories:

1. Investment at the connection point to reinforce and strengthen the connection.
2. Augmentation to provide additional capacity to serve demand from BEVs.
3. Expenditure to manage network security impacts from BEVs.
4. Investment in communications and technology to support the capture of benefits from BEVs.

The pricing arrangements under the National Electricity Rules will determine how the costs are split between the owner of the BEV and the general customer base. Currently, it is likely that the majority of these costs, except for the first category, will fall on all customers. This may create equity concerns amongst customers, especially in the early years of BEV uptake, where some customers may not be happy to subsidise those that decide to adopt BEVs early.

Our modelling only attempts to estimate the costs associated with the second category - augmentation to provide additional capacity to serve demand from BEVs. As explained earlier, our modelling is likely to be an approximation as it is based on the average LRMC for each of the five distribution networks and the impacts from BEV charging will be quite varied and depend on local conditions. It is likely that BEV uptake will in many cases lead to distribution transformers failing (or generally needing to be replaced) much earlier than zone substations. It is also possible that the additional demand placed on the distribution network will require replacement of local assets such as overhead cables, or subdivision of the distribution network via installation of additional distribution transformers.

Table 83 below demonstrates the impact of a potential required infrastructure response for each DNSP, based on their 2018 RAB. As can be seen, the impacts of such responses will vary by scenario. In addition, the use of incentives in the Electric Avenue and Private Drive scenarios highlight the advantage in shifting charging away from peak demand, with potential investment declining in both cases where incentivised charging is present.

¹⁵⁵ AEMO, ENA, Open Energy Networks, June 2018.



Table 90 – DNSP Distribution NPV as percentage of 2018 RAB

Distribution \$ m / RAB	Ausnet	Citipower	Jemena	Powercor	United Energy	Ausnet - transmission
	\$ m	\$ m	\$ m	\$ m	\$ m	\$ m
Dead End	1.3%	0.5%	1.9%	1.7%	1.6%	2.4%
Electric Avenue (Incentivised)	9.7%	4.2%	14.2%	12.8%	11.8%	18.2%
Electric Avenue (Non-incentivised)	14.8%	6.4%	21.6%	19.6%	18.1%	27.8%
Private Drive (Incentivised)	10.0%	5.1%	15.2%	13.1%	12.6%	19.1%
Private Drive (Non-incentivised)	15.7%	8.0%	23.9%	20.5%	19.8%	30.1%
Fleet Street	8.2%	3.2%	11.3%	10.6%	9.5%	14.9%
High Speed	4.9%	1.9%	6.7%	6.3%	5.7%	8.9%
Slow Lane	4.4%	1.9%	6.4%	5.8%	5.4%	8.3%

Impact of charging infrastructure

The charging infrastructure will have a key impact on the network. An average home has a load impact of around 3 kW which means that even a level 1 charger effectively adds another home to the network when a BEV is being charged.

For our modelling, we made a highly simple assumption that residential charging is proportioned equally between Type 1 and Type 2 charging. It is highly uncertain what the proportion will be in 2046 and the impacts will be exacerbated if more customers opt for higher capacity chargers. It could reasonably be expected that given the long charging times associated with Type 1 charging, customers will opt for a faster option of Type 2 charging and absorb the extra costs. Adding a 9.5 kW charger equates to the equivalent of over 3 new homes being connected to the local network. For a superfast charger of 240 kW, this would equal to approximately 80 new homes being connected.

A UK study estimates that 32% of the low voltage feeders will require reinforcement by 2050 to cope with clustered BEV uptake. This would cost approximately £2.2 billion by 2015 based on the assumption that approximately 50% of customers have a Type 1 charger.¹⁵⁶ These findings are supported by a recent report from the Sacramento Municipal Utility District which forecasted that BEV related overloads could necessitate replacing 17% of its transformers by 2030 at an estimated cost of USD \$89 million.¹⁵⁷

The impacts of the choice in charging infrastructure on distribution networks will obviously differ under a shared fleet scenario. While the number of vehicles will be substantially lower (MABM estimates that only 7% of the total vehicles under the Private Drive scenario will be required for the Fleet Street scenario), the fleet will be clustered in a number of common depots. Each depot would represent a significant large load, with a material number of vehicle charging simultaneously. The distribution networks impacts will be affected further if the shared fleet operator installs Type 3 fast chargers.

¹⁵⁶ Electric Avenue (<http://myelectricavenue.info>) and ICF (2016): Overview of the Electric Vehicle Market and the potential of charge points for demand response.

¹⁵⁷ SEPA and Black & Veatch (2017), Planning for the distributed energy future Vol II:A case study by Sacramento Municipal Utility District



There are a range of diverse variables which a shared fleet operator will consider in deciding upon the number and location of depots. The operator will have to weigh up customer demand characteristics and locations, access to customers, cost of electricity, network charges and number of vehicles in deciding its strategy. The operator may decide to have a higher number of vehicles in order to have some redundancy in their fleet and hence flexibility on when the fleet will be charged. Alternatively, the operator could invest in on-site battery storage to help manage electricity costs.

As the shared depot will be classified as a large load, the operator will be liable for all the network connection costs under the current rules. This would include any costs to augment and reinforce the network upstream of the connection to support the depot charging. The magnitude of cost could be quite substantial depending on the existing capacity at the connection point and the number of vehicles assigned to the depot. Further, shared depots may want to connect into medium to high voltage lines (such as 66kV) instead of distribution feeders for reliability and speed of charging reasons. The distribution network may desire encouraging the operator to locate their depots close to such lines for network security and cost reasons, and could seek to prevent depots connecting at low voltages. However, the location of these high voltage lines could be further away from the customer base¹⁵⁸.

The price signals which the energy market provides to the shared fleet operator will be key in promoting efficient integration of the shared fleet into the market. As discussed in Section 5.2, having a shared fleet operator should make it a lot easier to co-ordinate charging and discharging times and hence maximise the market benefits from BEVs. Therefore, there should be a high level of engagement between shared fleet operators and network businesses on the location of shared fleet depots, and the optimal charging patterns for the shared fleet.

5.5.3 Key issues

With respect to the effective integration of BEVs into the electricity networks, it is important to recognise that distribution networks will have two roles to play. Firstly, they will facilitate the choice to purchase BEVs by ensuring that there is sufficient network capacity and connections to serve the additional demand. Secondly, distribution networks will also act as an enabler for capturing the market benefits through facilitating transactions between customers and participant plus also through buying the demand response and ancillary services available from BEVs. In this regard, the network business could be the party which controls when BEVs are charged and discharged back into the grid.

The ability of customers to sell electricity back into the grid, trade electricity with their neighbours, and provide network support services depends crucially on the grid evolving to support connection of distributed energy technologies such as BEVs and managing the resulting two way flows. On the other hand, network decisions about how they invest in and operate their network will influence both the ability of consumers to take advantage of these services, and for the wider market benefits of BEV to be realised.

This section briefly explores some of the factors and policy issues that will influence the extent and effectiveness of the response at the distribution network level:

- Diversity in the local impacts of BEV charging
- Access and connection arrangements

¹⁵⁸ In general, transmission lines are high-voltage lines, those with voltage ratings of 500, 330, 220, 132 kV while distribution lines have lower voltages ratings, such as 66, 33, 22, 11 & 6.6 kV. There could be situations where the shared fleet is better to connect to the transmission network despite the likely additional kilometres needed.



- Managing uncertainties in the regulatory framework
- Transition to a distribution system operator role

As noted in Section 5.2, some of the issues are not explicit to BEVs but apply to other forms of technologies such as solar PV and batteries which customers are installing at their premises. The Federal and State Governments plus policy makers, such as AEMO, have initiated a series of policy reviews and consultations to ensure that the market and policy frameworks support the successful integration of customer led technologies.

5.5.4 Diversity in the local impacts of charging on distribution networks

Electric vehicle uptake will have a profound impact on distribution networks, with charging behaviour influencing the scale of demand requirements. However, as distribution capabilities and assets vary geographically, it is important to note the localised impacts of BEV charging, where size, timing, and particular location of isolated loads can have significant effects on network reliability as a whole.

As a result, it is important to consider spatial distribution and location capabilities when forecasting network impacts, as the localised results may differ significantly from average effects. This is a key limitation of our modelling methodology set out earlier.

Voltage stability refers to the upper and lower voltage bounds that the network must maintain. Likewise, transformers, transmission lines, harmonic distortion, and phase unbalance all have constraints that must be kept within. As many networks were built decades ago and were inherently designed to meet the projected capacities from the time of construction, BEV charging was not considered when building the infrastructure. The result being that significantly increased loads put the network at greater risk of breaking these constraints.

The impacts may not be felt incrementally either, where in one study the network felt the same impact from 45 BEV charging loads near the transformer, as was felt with one BEV charging load elsewhere in the network¹⁵⁹. The same study ran a simulation based on 114 houses in Melbourne, with different scenarios representing different BEV charging profiles¹⁵⁹. The simulation found that the network always failed when a certain BEV uptake was added to the weakest nodes, yet never failed when identical charging loads were added to the more robust nodes. This sounds intuitive, however identifying these weaker nodes can be unclear.

Real world and simulation trials have agreed that end-of-line measurements are not reliable indicators of voltage stability, due to high impedance or phase unbalance. This considered, older distribution systems, particularly underground systems, and transformers with capacities lower than 25 kVa are considered to be most susceptible to overload¹⁶⁰. Interestingly, BEV charging loads added to robust locations in some instances showed to actually improve network reliability. This resulted from the additional load rebalancing an unbalanced network, as the load added to the least loaded phase lowered the current in the neutral line.

Identification of these localised impacts will become important as more BEVs are connected to the network. This will also be impacted by the distribution of BEVs across the system. Within cities, BEV penetration will unlikely be evenly distributed and penetration will at the start be higher in certain areas, where BEVs cluster due to peer influencing, higher incomes, infrastructure availability and other factors which encourage early adoption.

¹⁵⁹ De Hoog, J. et al. (2014). The importance of spatial distribution when analysing the impact of electric vehicles on voltage stability in distribution networks. Doi. 10.1007/s12667-014-0122-8

¹⁶⁰ Maitra, A. (2011). Potential impacts of Vehicles on the Grid.



A further consideration with regards to load location is the charging requirements of those with greater distances travelled. While rural distribution infrastructure may be lacking in capability, the effects are compounded as BEVs in these locations generally have further to travel, and therefore require greater charging durations – and hence have a preference for fast charging infrastructure¹⁶¹. The limited range of BEVs have traditionally discouraged uptake in rural areas, however as battery technology develops and BEVs become more practically feasible for long-distance commuters, this high battery recharge requirement will begin to increase its impact on the network.

BEV uptake patterns are also heavily persuaded by external factors such as peer influence and socio-economics. BEVs generally carry a greater price tag than comparable ICE vehicles, resulting in greater uptake in localised areas with greater wealth¹⁶². Infrastructure availability is a further consideration over BEV uptake. As BEV charging technology currently prevents “fast re-fuelling” as is commonplace with ICE vehicles, range anxiety is considered to be a factor limiting uptake. BEV uptake is generally greater in locations where BEV charging infrastructure is readily available.

The effectiveness of the network infrastructure response will therefore depend on having a credible and comprehensive approach which takes localised spatial distribution into consideration, analysing the effects of specific and isolated contingency events on the network across all scales. If not, there is a risk there will be unequal treatment for BEV owners across the grid or potentially network reliability and security problems caused by BEV charging.

However, a potential problem for the distribution network is knowing which customer has purchased a BEV. Unless a BEV owner requests works on a distribution connection point, there is no current means for the distribution network to require the BEV owner to register their purchase. Likewise, an electricity retailer will not know of the presence of a BEV unless the owner informs them of the purchase. While evaluating consumption data trends would help to inform networks and retailers of the likelihood of BEV charging, they will not be able to confirm with certainty. There may be a potential response for BEVs to be specifically registered with VicRoads, with this information made available to relevant stakeholders. However, this may create data privacy concerns, and it does not definitively identify where the BEV may be charging.

While energy market arrangements should be technology-neutral, there are important grounds for retailers and networks to be able to identify where a large load is in the electricity system. This would enable retailers and networks to manage these large loads (for example, through pricing signals and metering arrangements) to yield efficient outcomes for the electricity system. Identifying a BEV load or a similar large load is important for the electricity system for two reasons:

- Network security - it enables the DNSP to manage large loads on its network by identifying locations under stress; and
- Pricing signals - it enables the DNSP and retailer to offer efficient and flexible tariffs to consumers to manage impact on system demand.

This issue has already been identified with respect to other distributed technologies, such as batteries¹⁶³, and solar PV. The COAG Energy Council has submitted a rule change request to

¹⁶¹ Concept. (2018). “Driving change” – Issues and options to maximize the opportunities from large-scale electric vehicle uptake in New Zealand

¹⁶² Vector. EV Network Integration, Green Paper, 2017.

¹⁶³ Small-scale behind the meter batteries are being installed in homes and businesses across Australia and deployments are expected to accelerate as costs fall. Bloomberg New Energy Finance has projected that 100,000 batteries could be installed by 2020, and one million by 2030. There are also safety risks to



the AEMC that proposes to establish a national register of distributed energy resources, including small-scale battery storage systems and solar. Consideration will be needed in the future on whether such a register should be extended to also include BEVs.

5.5.5 Network access and connection arrangements

When faced with a new distributed energy technology such as BEVs, a distribution network is faced with evaluating the impact on network security or safety and whether there is a need to consider placing new obligations on connection and access (or in certain extreme cases disallowing connection). The rights and obligations around connecting these technologies behind the meter will likely need to differ from conventional load connections (e.g. a new air-conditioner).

Specifically, connection rights and obligations may need to be developed to allow the distribution network to manage these impacts. These might include connection standards around control systems (e.g. autonomous voltage-controlling inverters or inverters that can be remotely controlled). These rights and obligations are yet to be fully developed, creating uncertainty for both DNSPs and consumers looking to invest in DER technologies, which could include V2G.

This could mean that distribution network operators may need to deny or limit access for some customers, while allowing their neighbours to charge without limitation. Further networks may seek to impose constraints on higher capacity chargers (i.e. Type 2) in certain areas or apply a prohibition to rapid Type 3 chargers. However, BEV range is likely to have a bearing on necessary charging technologies as average battery size and capacity increases. Faster charging technologies are likely to become necessary, where larger batteries may render overnight charging unfeasible with current charging technologies. Consumer charging behaviour additionally compounds the need for faster charging capabilities.

Such issues are already seen in the installation of rooftop PV systems, where some home owners are not allowed to install such systems on their rooftops due to their location in the network or due to their neighbours already having more solar PV than the network can handle.

While DNSPs will need to ensure that updates to their standard connection offers are made over time to accommodate and reflect new customer technologies (such as BEVs), it is important that such amendments are conducted from a market efficiency perspective rather than the perspective solely of network operation.

Providing a network with discretion to strike the right balance between market efficiency and network safety/security in connection agreements may not promote the right outcomes for the broad market. The connection arrangements could be too stringent or result in complexity and high costs for the BEV owners, which in turn could act as a barrier to BEV uptake.

Further there is a possibility that the connection costs would vary substantially across the network for BEV owners, depending on the existing capacity and load characteristics at their point of connection. In other words, issues of fairness may arise, and a decision will need to be made whether everyone should in principle be allowed equal access to the network (and an equal right to own an electric vehicle), or whether some home owners will face limitations.

Therefore, the rights of BEV owners to receive the network connection to support their choice of charging infrastructure plus allowance for access to the network to discharge their BEVs will influence the growth of BEVs and the corresponding network infrastructure response. As a result, any new connection arrangements for electric vehicles must reflect a market-wide consideration under the regulatory arrangements.

workers, installers and the general public - due to emergency services and line workers or electricians not having adequate information on sites with a battery.



Specifically, connection rights and obligations may need to be developed to allow the DNSP (as system operator) to manage these impacts. These might include connection standards around BEV infrastructure control and communications systems. There is likely to be further issues with respect to Vehicle to Grid capability connections.

These rights and obligations are yet to be fully developed, creating uncertainty for both DNSPs and consumers looking to invest in BEV charging infrastructure. Further under current arrangements, the connection framework could differ across the five DNSPs in Victoria and is likely to be different across the jurisdictions.

5.5.6 Managing uncertainty under the regulatory cost recovery framework

At a simple level, the ability of distribution networks to make the required investments to support BEV integration will be determined by the regulatory framework.

Regulated network businesses must periodically apply to the AER to assess their revenue requirements (typically, every five years). Chapters 6 and 6A of the National Electricity Rules lay out the framework we apply in undertaking this role for distribution and transmission networks respectively. The AER will set a ceiling on the revenues or prices that a network can earn or charge during a regulatory period.

In determining the revenues or prices that a network business can charge, the AER will forecast how much revenue a business needs to cover its efficient costs (including operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities) and provide a commercial return on capital. It is the AER's role to protect customers from inefficient expenditure being passed on through higher prices.

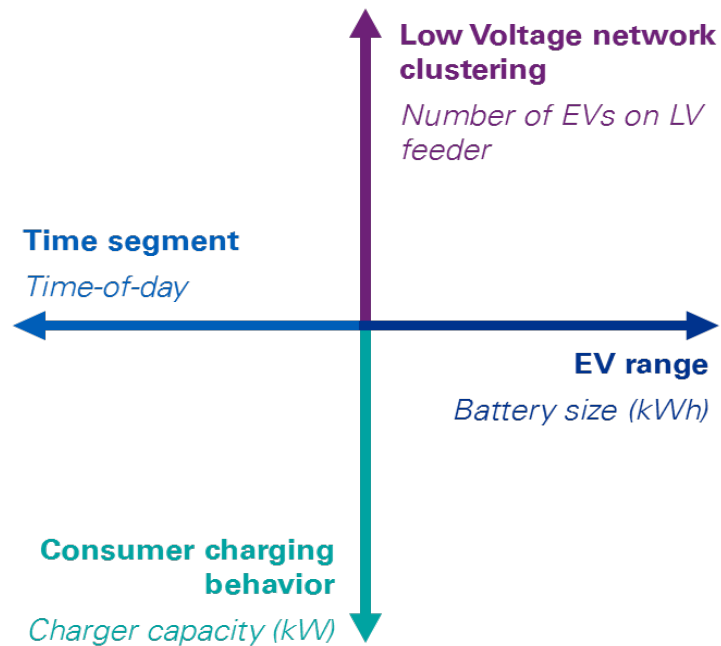
This framework will therefore set the level of expenditure which networks are allowed to spend to increase capability and support the integration of BEVs. This would then be reviewed periodically every five years, in line with the current framework.

Therefore, the effectiveness of this framework will depend on sufficient expenditure being allowed to enable DNSPs to increase the level of capacity needed to serve the expanding BEV fleet as well as managing all the impacts from BEV network integration within their network. However a key problem is how the regulatory framework will manage uncertainty arising from BEVs, especially in the early years of adoption.

Figure 84 demonstrates the four broad uncertainties which will influence the extent of impacts on distribution networks and the level of investment needed.



Figure 84 - Factors impacting on the networks response to BEV charging



BEV uptake has been observed internationally to be exponential and unevenly spread across neighbourhoods. Further, BEV owner charging behaviour and choice of charging type will change over time.

All these factors will make it extremely hard for network businesses, and also for the regulator, to reliably predict the extent of the impacts on the grid from BEV charging. However, the current regulatory framework is based on the principle that the regulator will only allow network expenditure when there is sufficient robust evidence that justifies customers paying for that expenditure. This could be difficult, especially in the initial period of BEV uptake, to obtain the necessary evidence to satisfy this requirement.

Uncertainty in forecasting the number of BEVs likely to connect during a regulatory period can have implications for DNSP revenue. As total allowable revenue includes a forecast of investment necessary to connect an expected number of BEVs, a larger than expected number of connections will negatively affect DNSP revenues. However, the regulator may not want to expose customers to the risks of unnecessary expenditure if the BEV impacts are over-estimated at the start of the five year regulatory period. In turn, the network business may not want to manage such a risk and would seek to defer connections until the next regulatory period.

Therefore, a key risk is the pressure placed on the role of regulatory frameworks and the regulator to ensure that the outcomes best promote customer interests. The regulator will be put in the position of making an expenditure assessment of the grid impacts of BEVs.

The difficulty of this increased pressure on the regulator will depend on the resulting uncertainty and complexity associated with all forms of DER. This penetration of DER is expected to lead to increased volatility and unpredictability in network flows requiring the DNSP



to have better system management tools and the ability to access the potential of DER to manage network costs.¹⁶⁴

The regulatory framework will also be important for providing the appropriate incentives on networks to fully capture the energy market benefits associated with BEVs (see Section 5.2). A DNSP is likely to be the only available purchaser of ancillary services from V2G on their respective network. Therefore, there is potential for a DNSP to underpay a BEV owner for the benefits provider compared to the associated network value. This is a reflection of the cost minimisation incentives under the existing economic regulatory framework.

There could be a further issue of whether a DNSP can provide certainty of revenue flows to DER owners or intermediaries/aggregators to promote investment decisions. A DNSP procurement of DER may be tied to the five yearly regulatory control periods, and the need to seek AER approval to operational expenditure. This is further emphasised by the existing economic regulatory framework whereby the DNSPs are required to forecast, plan, and manage the operation of their individual networks in accordance with defined service targets, and reliability performance measures.

While a DNSP, and the existing economic regulatory framework, may not provide for investment certainty for a DER owner, this may not be a barrier to wider investment given the other drivers at play for consumers seeking to invest in such assets. For example, an investment in rooftop solar PV and/or battery storage are likely to be primarily driven by a desire on behalf of the consumer to better manage their energy usage, at a hopefully lower cost moving forward.

5.5.7 Transformation to Distribution System Operator

Distribution networks have traditionally operated as a passive intermediary which receives power from the transmission network and transfers it to the end user without having much control over the power flows. In this situation, the grid only relies on the reserve element of capacity to avoid outages and other rare events.

Integration of BEVs might result in bidirectional power flow under V2G, which the current distribution grids are not designed for. The main issues confronting the grid as a result of distributed generation connection include islanding, voltage regulation, harmonics, reverse power flow effects, over-voltage condition, metering, and system losses.

With increased distributed energy resources, including electric vehicles connecting to the network, the distribution business may need to become a more active manager of system operations and flows. Therefore, the distribution network provider could transform to becoming a distribution system operator (DSO) who controls a portfolio of generation, demand response, and storage technologies, to effectively use them for efficient operation of the distribution network.

A DSO will be able to manage a network with increased flexibility and control over the power flow and voltage profile. The flexibility of power flow and control in the network along with access to the demand and generation response will enable the DSO to contribute to balancing of the power system.

A DSO would be responsible for procuring network capacity and network support services as needed. This responsibility presents a number of issues in relation to the role a DSO may have

¹⁶⁴ It is not guaranteed that increased penetration of DER and the resulting DER services will lead to increased pressure on network capacity and security. DER could instead make customers more responsive to signals which will remove some of the operational need for active control by distributors. In addition, with the high level of automation to DER technology (e.g. battery management systems), forecasting flows and customer behaviour could become more predictable.



in a distribution-level market and importantly its ongoing participation in that market. Active management of networks requires real time control and management of DGs and distribution network equipment based on real time measurement of primary system parameters such as voltage and current. This is to ensure that these parameters remain within their operating constraints.

Penetration of BEVs in a low voltage network requires a shift in operational philosophy of distribution network operators. Therefore, the extent to which such technology requires distributors to move from a passive role to one of responsibility for actively balancing energy flows at a distribution level, remains unclear. For any given network, and more specifically any given point on a network, a tipping point exists where the potential volume of transactions leads to network constraints as a result of the operation of distributed energy resources. For example, these constraints may arise as a result of reverse power flows affecting a DSO's voltage control or more generally as flows approach the capacity of network assets.

Past this tipping point, the role of the DSO would be to actively manage the flows and dispatch of customer appliance to maintain system security and operations. In doing so, it would seek full use of smart techniques to create value for the wider electricity system, e.g. by undertaking an element of regional balancing, and providing reserve and frequency response services to the national system operator.

The infrastructure response by networks will be different under the DSO role as it would require greater installation of smart technologies, data monitoring, and control systems to better manage flows across the network. This could help to facilitate capturing the benefits from a high penetration of BEVs.

5.5.8 Concluding observations

This section has identified a range of issues that will impact upon the distribution network and how infrastructure responses may be influenced by these factors. The introduction of BEVs at the consumer level introduces loads that are typically not seen by households at this time. Issues of connections, the current regulatory framework, localised impacts of BEVs, and the ongoing DNSP role are all challenges faced by DNSPs that will need to be responded to allow for full uptake in 2046.



Identifying localised distribution network impacts of BEVs is a challenge

Due to the localised nature of the electricity network, it is likely that particular areas of the distribution network are at a high risk of overloading when BEVs are introduced while others will not face issue, even if the same level of charging is applied to both. In order to provide suitable infrastructure responses, the DNSPs will need to have a clear picture of where in their network different levels of BEV charging will occur.

As there is currently no way for a DNSP to identify BEV charging, there may be a future requirement for a BEV owner to notify the DNSP (or their retailer) of a BEV purchase. Without this, there is a risk for consumer inequity, or network instability.



Consideration should be given to connection arrangements

The uptake of solar PV currently has seen issues arise whereby some homeowners have been denied the ability to install particular sized systems due to the DNSP forming a view that the localised network is already at a certain level which disallows further additions.



Investment in charging infrastructure by both a DNSP and a consumer may be limited if there is not a clear direction for the management of BEV uptake across a DNSP's network. Late adopters may be disadvantaged where their neighbours purchased BEVs (and associated infrastructure) first, and connection limits are imposed.

Fairness issues may also arise if BEV owners face different connection costs based upon existing capacity and load characteristics.



The regulatory framework will need to appropriately allow for DNSPs to undertake augmentation works to support BEVs

The current regulatory framework dictates DNSP capital investment as their proposed expenditure must be approved by the regulator before it can be carried out. The effectiveness of the regulatory framework will depend upon sufficient expenditure being allowed to enable DNSPs to increase the level of capacity needed to serve the expanding BEV fleet.

Uncertainty during early adoption may make it difficult for a DNSP, and the regulator, to reliably predict the extent of BEV impacts to approve a particular level of capital expenditure. As the regulator requires robust evidence to approve expenditure, understanding an appropriate infrastructure response can present a challenge.



The role of the DNSP may transform

While DNSPs have traditionally operated as a passive party between the transmitter and end-user, the introduction of BEVs (and other distributed technologies) may see a requirement for the DNSP to become a distribution system operator. In this role, the DNSP would control a portfolio of generation, demand response, and storage technologies that could be used to effectively operate the distribution network.

The transformation of the DNSP's role may impact their infrastructure responses through a greater installation of smart technologies, data monitoring, and control systems to undertake such a role. However, this may also introduce risks as this party may bias its own projects, and role, over third party needs.



5.6 Hydrogen Highway

5.6.1 Overview

This section of the Report will discuss the issues and potential infrastructure responses for the Hydrogen Highway scenario, including:

- Production methods available to meet supply, based on the methods modelled by KPMG and discussed in Sections 3 and 4.
- Distribution possibilities, and required infrastructure, to transport hydrogen from production point to a filling station.
- An overview of particular cost items to provide context on the level of infrastructure response required.

As the hydrogen industry is still in its infancy and a number of technologies are yet to reach commercial scale, a number of assumptions have been made throughout. These will be discussed and documented to present our rationale. Nevertheless, we still caveat the below on the fact this is a developing industry and any hydrogen reality in 2046 may not be representative of the assumptions presented.

5.6.2 Hydrogen supply chain

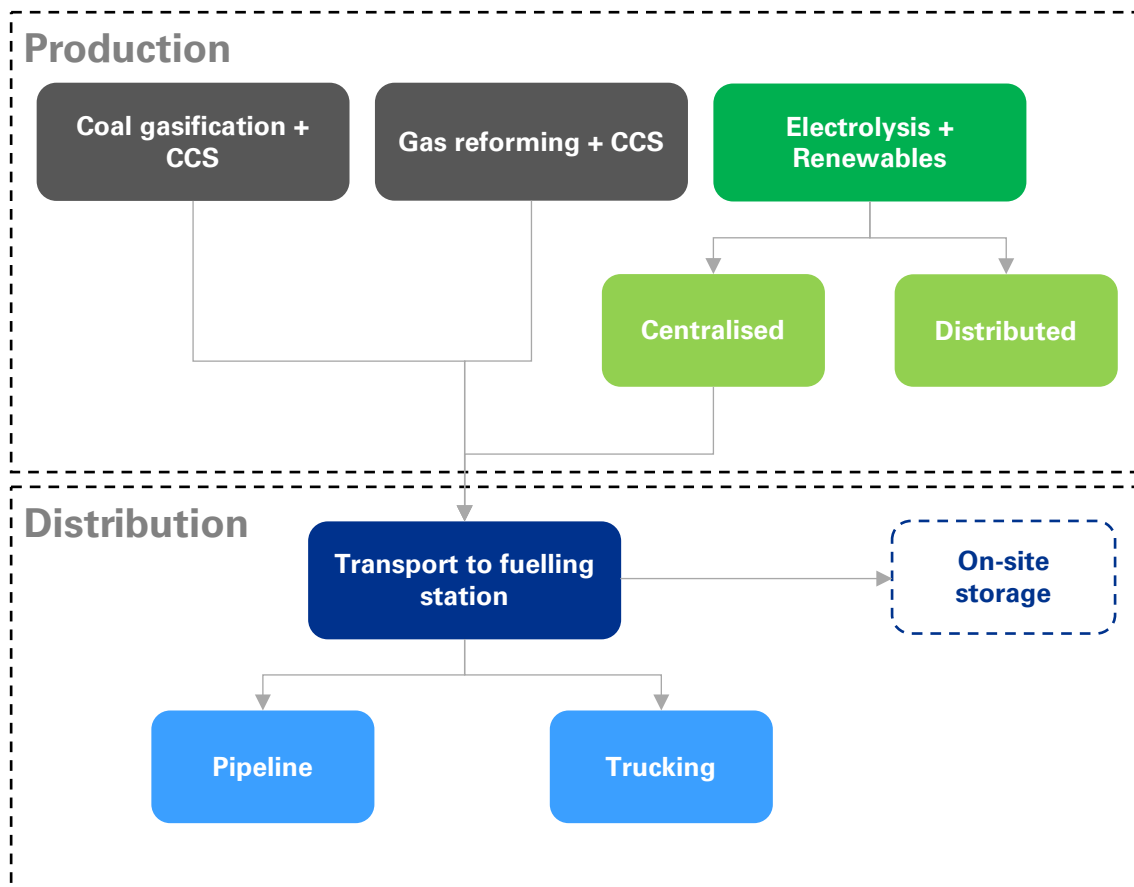
Recapping our discussion from Section 2.2.2, the present-day story in Victoria is that there is no hydrogen fuelling infrastructure or large-scale hydrogen production industry. Significant infrastructure responses would be called for to establish a new hydrogen supply chain to enable the Hydrogen Highway scenario in 2046.

As with the development of petrol stations as ICE vehicles became mainstream, we would expect a gradual roll-out of a hydrogen supply chain between now and 2046 to reach the 100% FCV uptake contemplated in the Hydrogen Highway scenario.

Per Figure 87 below, we have presented potential options for a Victorian supply chain that will be evaluated further when this section and is in line with the modelling undertaken for the Hydrogen Highway scenario. While a hydrogen supply chain could be achieved in a number of ways, we have elected to explore three methods that we believe would have the most potential in a Victorian context.



Figure 85 – Indicative hydrogen supply chain choices



From modelling undertaken by KPMG, we understand that significant new infrastructure would be needed to support a hydrogen supply chain in Victoria for the Hydrogen Highway scenario. Some of the potential infrastructure required may include:

- **Production:** New power stations, development of carbon capture and storage deposits, and production plants (to support the chosen production method).
- **Distribution:** Upgrades to existing natural gas pipelines, development of new hydrogen pipeline infrastructure, construction of hydrogen refuelling station network, and deployment of trucking fleets across the state.

The final infrastructure mix would depend upon the preferred supply chain. For example, the use of distributed electrolysis would not require an extensive distribution network but would instead rely on the local electricity network or rooftop solar. The choice to use coal gasification to take advantage of Victoria’s vast lignite reserves would necessitate gasification plants, CCS facilities and a distribution network of trucks or pipelines. As a whole, there is a degree of interoperability within the hydrogen supply chain which allows a number of infrastructure responses to be deployed.

5.6.3 Hydrogen production

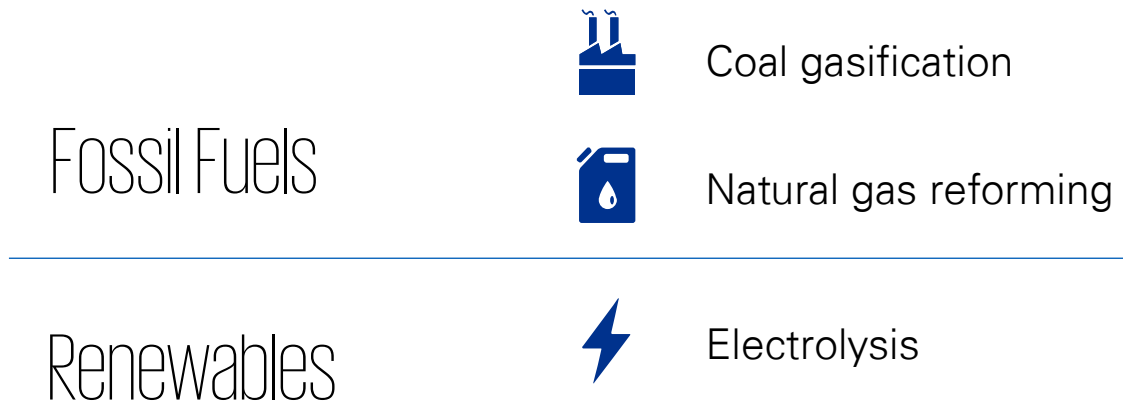
While hydrogen is the most abundant element of Earth, it does not exist in a free-form that can be easily gathered. Instead, hydrogen is bound to other elements and production processes extract the hydrogen from a base material, such as coal or water. The process to produce hydrogen is typically energy-intensive which presents a practical challenge for the Hydrogen Highway scenario.



KPMG modelling indicated that 1.26 billion tonnes of hydrogen would be required in 2046 to meet the demands of the road network under our base case of the Hydrogen Highway scenario. Accordingly, there is a significant requirement for large-scale production facilities to meet this demand.

We are exploring three methods to produce hydrogen for the Hydrogen Highway scenario in Victoria and are represented in Figure 88 below.

Figure 86 – Hydrogen production methods



Two of the methods identified require fossil fuels as a base resource. To ensure hydrogen FCVs are truly zero emissions, a carbon capture and storage solution (or another similar technology) would need to be included with these production methods.

Electrolysis plus renewables

Hydrogen from electrolysis is produced in a relatively simple fashion. An electrical current is passed through two electrodes in a water solution which breaks chemical bonds, resulting in the production of hydrogen and oxygen.¹⁶⁵

Hydrogen from electrolysis is currently being rolled out at a number of hydrogen fuelling stations across the world to meet fledgling FCV demand. The key benefit is that renewable energy can be integrated to avoid the creation of emissions in the production cycle.

Furthermore, electrolysis is scalable. Small, distributed electrolyzers could be rolled out across Victoria. Alternatively, large centralised facilities may be constructed, which introduces a need for transportation. A likely infrastructure response is to provide a mix of electrolyzers to fit differing needs between customers in urban Melbourne and those in rural areas such as Gippsland or Shepparton.

Figure 89 below presents a summary of electrolysis, including its advantages and challenges in a Victorian context.

¹⁶⁵ Hydrogen Production Technologies: Current State and Future Developments, <https://www.hindawi.com/journals/cpis/2013/690627/>



Figure 87– Electrolysis summary of technology

Electrolysis

Development stage	Advantages	Barriers and challenges
<ul style="list-style-type: none"> Proven technology with ongoing research to improve process. 	<ul style="list-style-type: none"> Flexible technology – can be scaled to fit differing needs in Victorian towns and cities. Deployable across the entire state – an on-site electrolyser simply requires electricity and water. Supports Victoria’s zero-emissions future. Where renewable electricity is used, there are no emissions. 	<ul style="list-style-type: none"> Cost is higher than fossil-fuel based methods currently. Further technology development may bring cost to parity (or below). Efficiency of method is still improving, although progress has been made in a relatively short space of time. The construction of distributed electrolysis facilities in urban areas may present safety and regulatory issues.

The current challenges for electrolysis are the cost and efficiency of the method. When compared to natural gas reforming, the predominant method for current hydrogen production, electrolysis does not presently make for a cost-efficient method to produce hydrogen at scale. It is estimated that hydrogen produced from natural gas has historically been one-third of the cost of electrolysis¹⁶⁶. However, ongoing efforts are underway to reduce the cost of electrolysis, with progress being made in areas such as efficiency, scale and use of new catalysts.

As discussed in Section 4.9.2, our modelled base case of Hydrogen Highway requires 63.60 TWh of electricity when using electrolysis, which exceeds Victoria’s 2018 energy consumption. Storage and the use of excess renewables could play a part in meeting this demand without adding excessive cost.

The theoretical electricity consumption limit of electrolysis is 39.4 kWh per kilogram¹⁶⁷ of hydrogen (which we have modelled in our ‘Strong Shift’ case of Hydrogen Highway), which reduces electricity consumption to approximately 41.49 TWh in 2046. While this is a 22 TWh improvement over the base case and is a significant reduction, this represents a limit for the technology.

Electrolysis could be deployed in two different ways to meet demand in the Hydrogen Highway scenario:

¹⁶⁶ The lowdown on hydrogen – part 2: production, <http://energypost.eu/the-lowdown-on-hydrogen-part-2-production/>

¹⁶⁷ Reference for theoretical minimum of 39.4kwh/kg H2 (100% efficiency of H2 = H2 HHV): http://www.fch.europa.eu/sites/default/files/study%20electrolyser_0-Logos_0_0.pdf



- **Centralised** – large, centralised facilities produce hydrogen for distribution to filling stations by truck or pipeline; and/or
- **Distributed** – smaller electrolyzers are deployed directly at refuelling stations or throughout small networks to create a distributed electrolysis network across Victoria. This reduces the level of distribution infrastructure required.

We will detail these two methods below. The core technology for each are similar and it is distribution to filling stations that differ.

Central electrolysis

A central electrolysis production method creates hydrogen at large-scale facilities, utilising economies of scale to reduce the cost of production. These facilities can be built in away from urban areas in locations with favourable renewable and water resources.

To support a central production model, a suitable distribution network to transport hydrogen to each filling station would be needed. Our discussion of hydrogen distribution is contained within Section 5.6.4 of this report, where we have considered transport via truck or pipeline as potential options.

As the hydrogen is produced off-site and delivered to a fuelling station, the likely footprint for each hydrogen filling station would be reduced and may be more suitable in dense urban areas within Melbourne. Suitable storage would be required on-site for delivered hydrogen, which could take a gas or liquid form.

Distributed electrolysis

Unlike centralised electrolysis, the distributed electrolysis approach favours a network of smaller hydrogen production facilities to meet localised demand. There are two main methods of deploying distributed electrolyzers:

- An “at-pump” production method where electrolyzers are installed directly at fuelling station and requires no transportation.
- A “hub-and-spoke” method of distributed electrolyzers that supply a local network of nearby filling stations.

In either case, storage facilities would likely be contained on-site to store hydrogen until required for fuelling. The size of necessary facilities would be dependent on the number of daily customers and level of deliveries.

Globally, several suppliers are offering ‘ready-to-use’ solutions for hydrogen refuelling stations, including ITM Power and Proton Onsite. These simply require a supply of water and electricity for hydrogen production and makes installation simple for a station operator.

In March 2018, ITM Power announced the opening of a hydrogen refuelling pump alongside petrol and diesel pumps at a Shell service station in Beaconsfield, one of the busiest in the UK¹⁶⁸. This represents the fifth refuelling station provided by ITM Power in the UK, who were also provided with £4.3 million in funding from the UK Department of Transport to build a further 4 hydrogen fuelling stations and upgrade 5 existing facilities¹⁶⁹.

The ability for a fuelling station to meet driver demand is key when considering 100% FCV uptake in the Hydrogen Highway scenario. Acknowledging this is a fledgling industry, ITM Power’s HFuel1000 product can provide 92 refuels within a 24hr window¹⁷⁰, which may not

¹⁶⁸ New Shell fuelling station opened at Beaconsfield, ITM Power, 27 March 2018, <http://www.itm-power.com/news-item/new-shell-fuelling-station-opened-at-beaconsfield>

¹⁶⁹ £8.8m OLEV Funding for Refuelling Infrastructure and FCEVs, ITM Power, 26 March 2017, <http://www.itm-power.com/news-item/8-8m-olev-funding-for-refuelling-infrastructure>

¹⁷⁰ HFuel | ITM Power, <http://www.itm-power.com/product/hfuel>



meet demand at high-use filling stations. A balance of production capability and storage would need to be achieved to service demand while also dealing with space constraints. This may represent a practical challenge that would require engineering and regulatory consideration.

Ease of installation and 'ready-to-use' solutions would facilitate retrofitting today's petrol stations for hydrogen use in the Hydrogen Highway scenario. In early stages, key petrol stations across Melbourne could have hydrogen pumps fitted alongside petrol/diesel pumps, with this progressing to full station conversions as FCV adoption increases. Retrofitting would be important in reducing capital costs, which will be discussed further in Section 5.6.4.

Victorian and Federal Governments would need to consider suitable safety standards related to the production and storage of hydrogen on-site, which for the purposes of this Report we have assumed was undertaken in the period between 2018 and 2046. Regulation would need to deal with the fuelling pumps, storage tanks and any other infrastructure on-site.

The rollout of distributed electrolysis at fuelling stations could be achieved across the whole of Victoria as only water and electricity are required. In providing the electricity to an electrolyser, renewable electricity would be required to ensure the whole supply chain is zero emission. The use of rooftop solar could assist in providing some of the required electricity to ease the burden on the electricity network. For low-use stations with sufficient storage, there may be the possibility to rely on rooftop solar or excess renewable generation in off-peak times to produce and store hydrogen.

Fossil fuel production methods with CCS

We are considering two fossil fuel reliant methods for the Hydrogen Highway - coal gasification and natural gas reforming. Both methods generate significant emissions, and therefore present significant challenges to be overcome to be considered zero-emission.

Natural gas reforming

Natural gas reforming is the most widely used hydrogen production method, accounting for approximately 95% of the United States' production¹⁷¹. It is a proven and low-cost application to produce hydrogen, particularly for large-scale uses such as fuelling a network of vehicles. The principal method, steam-methane reforming, reacts natural gas with high temperature steam to produce hydrogen. This process also creates carbon monoxide and carbon dioxide as by-products.

Figure 90 summarises the advantages and barriers of using natural gas reforming as a production method for hydrogen in Victoria.

The price of natural gas is a critical factor that influences cost-effectiveness. A cost of US\$1 per kilogram of hydrogen can be achieved when gas prices are low. However, industry and Government in Australia would need to consider gas prices in the ongoing context of the local gas market to ensure this method can be cost effective.

¹⁷¹ Hydrogen Production: Natural Gas Reforming, <https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming>



Figure 88– Natural gas reforming summary of technology

Natural gas reforming

Development stage	Advantages for Victoria	Barriers and challenges
<ul style="list-style-type: none"> Well-established and mature technology. Most widely used method to produce hydrogen. 	<ul style="list-style-type: none"> Proven technology capable of being scaled-up. Low-cost production method. Not location dependent and can utilise existing gas pipeline network to deliver gas. Lower emissions than a coal-based process. 	<ul style="list-style-type: none"> Dependent on CCS to be considered zero-emissions. Gas market in Australia may present cost competitiveness challenges. Additional costs of CCS may make overall process uncompetitive.

As this technique is proven for large-scale production, it represents an ideal method for the Hydrogen Highway scenario (except for the emissions produced). Achieving a cost-efficient CCS method (or another emissions reduction process) is critical in utilising natural gas reforming in a zero emissions future.

Coal gasification

Coal gasification is a process that uses coal to produce syngas consisting of hydrogen, carbon monoxide and typically carbon dioxide¹⁷². Hydrogen in this syngas is captured for use and the emissions can be isolated for CCS. The potential benefit of coal gasification is that it may offer a cheap method to produce large quantities of hydrogen under the Hydrogen Highway scenario.

Figure 91 summarises coal gasification within a Victorian context. Given Victoria’s unique brown coal deposits, these represent an opportunity for a cheap source of hydrogen. However, this is offset by the significant emissions component that requires a CCS solution to be perfected to capture all carbon.

¹⁷² The Hydrogen Economy: Opportunities, Costs, Barriers and R&D Needs
<https://www.nap.edu/read/10922/chapter/20#206>



Figure 89 – Coal gasification summary of technology

Coal gasification

Development stage	Advantages for Victoria	Barriers and challenges
<ul style="list-style-type: none"> Established technology based on historical processes. 	<ul style="list-style-type: none"> Provides opportunity to utilise Victoria's extensive brown coal reserves. Cost effective technology, particularly given the low cost of Victorian brown coal. 	<ul style="list-style-type: none"> Highest emitting production method considered. CCS required to be zero-emissions, which has not yet been proven at the scale required. May face significant public opposition given coal's image and the level of plant required to support 100% uptake of FCVs.

Victoria has significant deposits of brown coal, particularly within the Latrobe Valley that represent a cheap and plentiful resource for hydrogen production. This would need to be coupled with sufficient water access for large-scale production. Within the Latrobe Valley, the needs of Victoria's remaining coal fired power stations would need to be considered in determining whether a hydrogen production industry could coexist.

The scheduled closures of coal-fired power stations in the Latrobe Valley may represent opportunities to re-use or re-purpose their infrastructure, including the nearby brown coal mines. This may reduce the cost of hydrogen entry, allow a faster scaling-up of production, and utilises existing assets that may otherwise have no use.

The Hydrogen Energy Supply Chain Project was announced in April 2018¹⁷³ and proposes to use lignite from the Latrobe Valley to produce hydrogen via coal gasification. Should this project (or similar projects) be commercialised, it could pave the way for large-scale production facilities to support the Hydrogen Highway scenario.

As coal has a high carbon content, carbon emissions produced by coal gasification are higher than any other conversion technology¹⁷⁴. As such, CCS would need to be considered to make the process zero emissions. We will discuss the CCS method briefly below.

¹⁷³ Hydrogen Energy Supply Chain Pilot Project,

<https://industry.gov.au/resource/LowEmissionsFossilFuelTech/Pages/Hydrogen-Energy-Supply-Chain-Pilot-Project.aspx>

¹⁷⁴ The Hydrogen Economy: Opportunities, Costs, Barriers and R&D Needs

<https://www.nap.edu/read/10922/chapter/20#206>



Carbon capture and storage

CCS has been proposed as a potential solution to dealing with the emissions generated by fossil fuel production methods¹⁷⁵ ¹⁷⁶. CCS operates by capturing emissions at the point of production and then storing them in a suitable deposit (such as a depleted gas well).

The U.S. Energy Information Administration notes that there are currently two carbon capture and storage projects operating¹⁷⁷ alongside coal-fired power generation sites. One of these, the Boundary Dam project, has recently surpassed 2 million tonnes of sequestered carbon dioxide. Data from the Global CCS Institute indicates that there are currently 17 large-scale operating projects that incorporate CCS in some fashion, with a further 5 currently under construction¹⁷⁸.

In a local context, the CarbonNet Project in Victoria is investigating the potential of establishing a commercial-scale CCS network that would sequester carbon dioxide in the Bass Strait. This project is considered to be key in identifying suitable deposits for dealing with the high level of emissions produced from large-scale fossil fuel hydrogen production.

Several issues need to be considered regarding CCS being used in the Hydrogen Highway scenario:

- CCS technology would need to be developed to allow for commercial viability. The cost of CCS has been cited as a key downside to the technology that needs to be addressed. While we have noted that natural gas and coal production methods may offer a cost-competitive solution, the inclusion of CCS may make their costs too high compared to electrolysis with renewables.
- There is an ongoing requirement for large deposits for long-term storage. KPMG modelling of the Hydrogen Highway scenario estimated emissions of approximately 31 million tonnes and approximately 12 million tonnes each year using coal gasification and natural gas reforming respectively. Significant storage deposits would need to be available to sequester this level of annual emissions, and represents an ongoing burden while these production methods are used.
- CCS's social license to operate. A CCS facility at the scale required to support the Hydrogen Highway scenario is likely to face significant opposition from particular stakeholders which presents a challenge that would need to be overcome by parties that opt to produce hydrogen via this method.

The viability of CCS at the scale required for the Hydrogen Highway scenario is currently unclear. Reliance on fossil fuels for hydrogen production creates an ongoing and long-term requirement to sequester carbon emissions. The emissions produced in creating sufficient hydrogen to support the Hydrogen Highway scenario would need to be carefully considered in the context of a zero emission future in Victoria.

¹⁷⁵ The Hydrogen Economy: Opportunities, Costs, Barriers and R&D Needs
<https://www.nap.edu/read/10922/chapter/9>

¹⁷⁶ Co-production of hydrogen and electricity by coal gasification with CO₂ capture, International Energy Agency, <https://hub.globalccsinstitute.com/publications/co-production-hydrogen-and-electricity-coal-gasification-co2-capture-updated-economic-analysis/co-production-hydrogen-and-electricity-coal-gasification-co2-capture>

¹⁷⁷ Petra Nova is one of the two carbon capture and sequestration plants in the world
<https://www.eia.gov/todayinenergy/detail.php?id=33552>

¹⁷⁸ Large-scale CCS facilities, Global CCS Institute, <http://www.globalccsinstitute.com/projects/large-scale-ccs-projects>



5.6.4 Hydrogen distribution

The production of hydrogen is one part of the required supply chain for the Hydrogen Highway scenario. After producing hydrogen, there needs to be sufficient infrastructure in place to take hydrogen from production point and to the end-user.

If hydrogen is produced directly “at the pump”, there is no requirement for a distribution network. However, where production occurs off-site, a distribution network would need to be created. We will discuss two approaches to this below:

- Hydrogen is produced off-site and is loaded onto trucks that make scheduled deliveries to fuelling stations. The hydrogen could be transported in a gaseous or liquid form.
- A hydrogen pipeline network is established to deliver hydrogen directly to a fuelling station. Existing gas pipelines could be used or alternatively a new, dedicated pipeline network is constructed.

Supporting a full road network of FCVs require significant fuelling infrastructure to be built in Victoria. No matter how hydrogen is delivered (or produced on-site), there will still be a requirement for a network of filling stations. Cost considerations of filling infrastructure are discussed in Section 5.6.5

On-site electrolysis

Where electrolysis is carried out on-site at a filling station, there is no need for additional hydrogen distribution infrastructure. Electricity would be sourced from the grid and water would be drawn from existing piping.

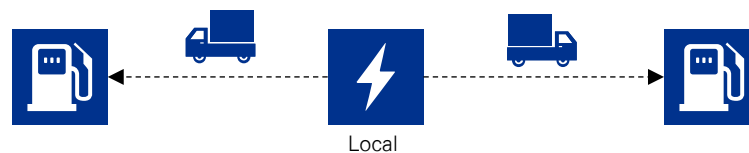
As previously noted, the retrofitting of petrol stations is a key consideration from an infrastructure responses perspective as Victoria transitions from petrol to hydrogen. Unlike options that rely on a distribution network, producing hydrogen on-site is likely to increase the footprint of each fuelling station.

As the scale of on-site production increases, as does the required site sizing. Fitting the necessary production and storage facilities at existing filling stations, while ensuring all safety regulations are met, may pose a practical challenge for high-use stations in dense, urban areas such as Melbourne CBD.

Hub-and-spoke distribution

A mid-point between on-site electrolysis and a centralised electrolysis model would be to adopt a hub-and-spoke approach. Figure 92 below illustrates how such a method would function.

Figure 90– Hub-and-spoke distribution method



With the hub-and-spoke method, production facilities would be deployed throughout Victoria to produce hydrogen for local networks of filling stations. These facilities would not require consumer amenities so available space can be dedicated to hydrogen production. A hub-and-spoke distribution method is unlikely to be suitable for coal gasification as this benefits from large, centralised facilities that would not be suitable for deployment in urban areas. This



method may be suitable for natural gas reforming as small reformers could be utilised and can take advantage of the cost-effectiveness of the method¹⁷⁹.

This model is best-served when there are a number of filling stations close by, meaning that the hub-and-spoke method is likely suitable for Greater Melbourne and potentially large regional areas. On-site production could then be used to fill any gaps where the hub-and-spoke method is deemed inefficient.

These dedicated production facilities may be able to include renewables on-site (i.e. solar PV) to reduce their reliance on the electricity network for production needs. Furthermore, there may be cost benefits realised by integrating renewables.

A drawback compared to on-site electrolysis is that distribution would likely require trucks to transport hydrogen from the production facility to the local network of filling stations. Unlike distribution of centrally produced hydrogen, the likely transport distances would be short and each production hub can tailor their delivery routes.

From an infrastructure response perspective, the focus of the hub-and-spoke model is determining suitable locations for these networks. Key issues to consider would be available space and regulatory requirements. Cheaper real estate in industrial areas should be utilised to reduce this element of cost. Depending on facility location, regulatory requirements of these production facilities alongside other businesses or homes may need to be considered.

It would be expected that the private sector could collaborate to establish networks to supply an efficient number of filling stations, which may require connections between producers, logistics providers and filling station operators. The smaller footprint of the filling stations may allow for more existing petrol stations to be repurposed. Consideration would therefore focus on optimising transport routes and storage capability to meet consumer demand while also being cost efficient.

The hub-and-spoke method represents a viable option to supporting the growth of Victoria's hydrogen supply chain as it requires a lower level of capital investment as a centralised facility and "test areas" can be developed for initial rollouts.

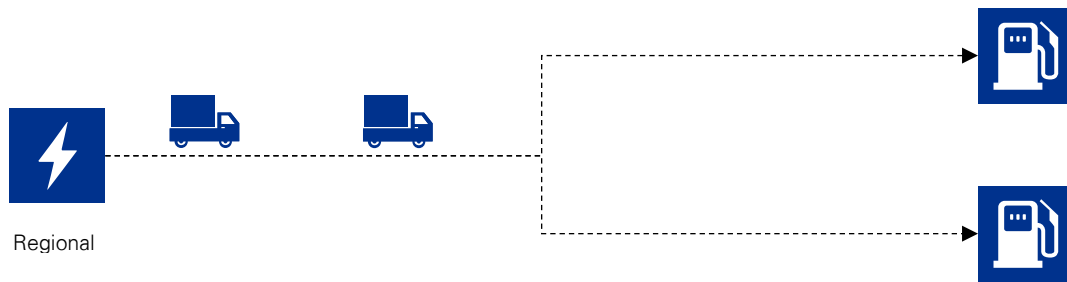
Centralised distribution via truck

A suitable method to deliver centrally produced hydrogen could be to utilise trucks, as represented by Figure 93. Current hydrogen deployments have used trucks with pressurised tubes to carry hydrogen from production point to a hydrogen fuelling station in a gaseous or liquid form. In this way, the distribution method is similar to conventional petrol and diesel station logistics.

¹⁷⁹ Distributed Hydrogen Production from Natural Gas – Independent Review, National Renewable Energy Laboratory, October 2006, <https://www.hydrogen.energy.gov/pdfs/40382.pdf>



Figure 91– Centralised distribution via truck method



In the United States, current hydrogen transport trucks can carry approximately 280kg of hydrogen within regulated limits, with new storage vessels potentially able to carry more than 700kg of hydrogen while meeting road requirements¹⁸⁰. Given that a Toyota Mirai currently has a 5kg hydrogen capacity, one would need to consider how many refuels a hydrogen filling station could support from each delivery, and the level of storage required. Large petrol tankers currently can transport 37,000 litres of fuel¹⁸¹, highlighting the significant transport requirements to deliver fuel in an efficient manner to meet the demand of ICE vehicles.

Liquid hydrogen may be an effective and cost efficient alternative for high-use stations however there are safety concerns that would need to be addressed to ensure suitability in urban environments. A 2014 study of current regulations in California found that no reviewed petrol stations could be converted to liquid hydrogen storage while a number could support gaseous hydrogen¹⁸². Liquid hydrogen storage tanks under these regulations required a high level of space around tanks for safety that increased station footprint size.

A 2017 study examined designs of hydrogen stations¹⁸³, including those supplied with centrally distributed hydrogen and considered the distribution cycle, which is demonstrated in Figure 94 below.

¹⁸⁰ Hydrogen Tube Trailers, Office of Energy Efficiency & Renewable Energy, U.S. Department of Energy, <https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers>

¹⁸¹ On the road with a fuel tanker driver, BP Global, 17 September 2013,

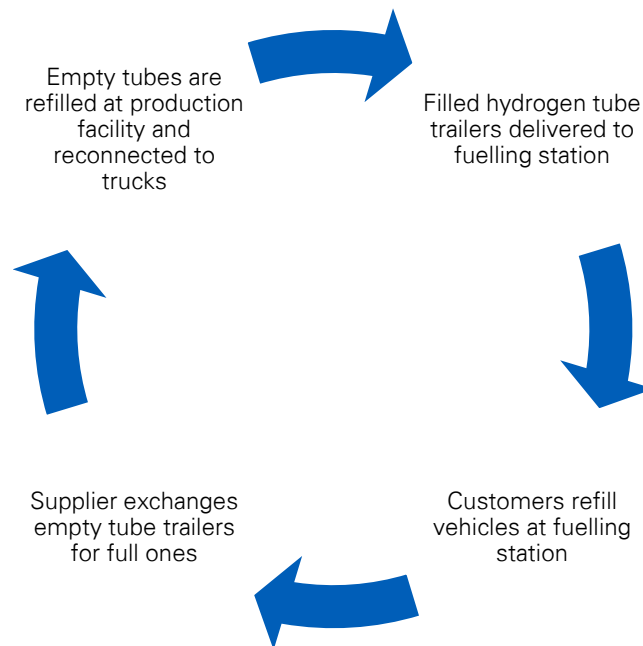
<https://www.bp.com/en/global/corporate/bp-magazine/locations/uk-fuel-tanker-driver.html>

¹⁸² Harris, A.; Dedrick, D.; LaFleur, C.; San Marchi, C. Safety, Codes and Standards for Hydrogen Installations: Hydrogen Fueling System Footprint Metric Development. SAND2014-3416. Livermore, CA: Sandia National Laboratories, 2014.

¹⁸³ Hecht, E & Pratt, J 2017, Comparison of conventional vs. modular hydrogen refuelling stations, and on-site production vs. delivery, <https://www.energy.gov/sites/prod/files/2017/03/f34/fcto-h2first-reference-station-phase2-2017.pdf>



Figure 92– Hydrogen distribution method via truck



This study, as illustrated in Figure 94, proposes that trailers are left on-site (which are leased by the station owner) which were found to require near-daily swapping, which introduces many trucks onto roads to manage logistics across a network of hydrogen refuelling stations. This study assumed deliveries would be made by diesel trucks whereas the Hydrogen Highway would require tankers to run on hydrogen.

On-site storage could instead be implemented, which would increase the capital cost of each hydrogen fuelling station. The proposed distribution process would be similar to Figure 94, however, a delivery vehicle would top-up fuel storage tanks rather than leaving trailers on-site. Large on-site storage capabilities would require less frequent deliveries, which may drive cost efficiencies in the process.

In either case, the impact of the trucks required to deliver hydrogen would need to be considered. Given the density of hydrogen and current technology, less hydrogen can be delivered compared to petrol in each trip. Furthermore, the Hydrogen Highway scenario would see FCV trucks making hydrogen deliveries throughout Victoria.

If frequent, low volume deliveries are being made, there may be inefficiencies in this distribution method given the degree of hydrogen consumed by a delivery truck. We do note that future advances and the use of liquid hydrogen may minimise this concern.

Hydrogen pipeline network

Rather than rely on trucks for distribution, it is possible to transport hydrogen via pipeline. This would take advantage of large-scale hydrogen production facilities to distribute hydrogen en-masse. Using this method, it alleviates potential issues with a large fleet of trucks that may be required to otherwise deliver hydrogen.

In transporting hydrogen, there are two potential options:

- Blending, whereby hydrogen is blended with natural gas in existing pipelines up to a given ratio; or
- Full hydrogen transportation within a dedicated pipeline.



The infrastructure response for pipelining will differ greatly depending on whether existing pipelines can be used or if new infrastructure is required. The benefit of utilising pipelines is that hydrogen can serve other use-cases (such as heating) in addition to transport.

Blending

Blending is a process whereby hydrogen is integrated into an existing gas network up to a certain ratio. Hydrogen can be blended into a gas network at numerous points upstream, then separated and extracted at the city-level for use in FCVs.¹⁸⁴

While estimates vary within the literature as to the acceptable level of blending, it has been proposed that blends of up to 28% hydrogen would be considered safe¹⁸⁵, although much higher levels may be possible. Estimates vary due to the condition of gas pipelines and the materials they are constructed with. Thus, proper assessments of current pipelines would need to be carried out to determine safe levels of hydrogen to be blended.

The benefit of blending is that it progresses the early development of a hydrogen distribution network given it utilises existing infrastructure¹⁸⁶. As infrastructure requirements for a hydrogen supply chain have been identified as an impedance to proliferation, using existing infrastructure helps ease this concern. Blending may be considered as a potential means to progress the initial hydrogen supply chain while the industry is scaled up to the level required in 2046.

As set out in Table 91, there are three gas distribution network providers currently operating gas networks in Victoria¹⁸⁷. Two of these, Multinet and Australian Gas Networks, are part of Australian Gas Infrastructure Group. These parties may represent a suitable operator to provide hydrogen within their existing networks, particularly in the initial period to support lower levels of demand.

Table 91 - Gas distribution network providers in Victoria

Network	Area Covered	Customer Numbers	Length of pipeline mains (km)	Asset Base valuation (\$m)
AusNet	Across central and western Victoria	647,000	10,480	1,362
Multinet	South and East areas of metropolitan Melbourne, Yarra Ranges and South Gippsland Towns.	687,000	10,030	1,126
Australian Gas Networks	Northern, outer eastern and southern areas of Melbourne, Mornington Peninsula, rural communities in northern, eastern and north-eastern	648,000	11,000	1,193

¹⁸⁴ Hydrogen Infrastructure Cost Estimates and Blending Hydrogen into Natural Gas Pipelines, https://www.hydrogen.energy.gov/pdfs/htac_nov12_3_melaina.pdf

¹⁸⁵ Safe operation of natural gas appliances fueled with hydrogen/natural gas mixtures. http://conference.ing.unipi.it/ichs2007/fileadmin/user_upload/CD/PAPERS/13SEPT/6.0.00.pdf

¹⁸⁶ Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, <https://www.nrel.gov/docs/fy13osti/51995.pdf>

¹⁸⁷ Australian Energy Regulator, State of the Energy Market Report, May 2017, pg. 101.



Victoria, and south-eastern
rural townships in Gippsland.

Dedicated hydrogen pipelines

The second option, and perhaps more suitable to a large-scale hydrogen network, is to use dedicated pipelines that would only transport hydrogen. This could be achieved by either repurposing existing gas pipelines, or constructing a new hydrogen pipeline network. This latter option would be a cost-intensive option while the former depends on the availability of existing pipelines for repurposing to hydrogen.

It has been noted that the conversion of existing natural gas pipelines for hydrogen transportation may require significant modification^{188 189}, therefore the operators noted in Table 91 need to be consulted to understand the condition and suitability of Victoria's existing gas infrastructure. As well as this, future demand for natural gas would need to be considered as operators may not be willing to repurpose their pipelines if this market is still strong.

If new pipelines are required, these operators (or other large gas providers in Australia) may provide the necessary infrastructure and utilise a tariff system to charge those that transport hydrogen through their network. As part of structuring their tariffs, network operators include capital recovery within their model to pay off the high capital outlay. This may assist in overcoming the capital cost burden of new infrastructure for hydrogen as the gas network provider could provide the required investment. This approach to pipelines is used by gas networks in Australia and many pipelines are regulated, requiring the network operator to submit their proposed tariff model to a regulator for approval.

Key issues to consider in the design of a suitable hydrogen pipeline is corrosion and susceptibility of leakage¹⁹⁰. The chemical properties of hydrogen mean that pipelines are at risk of cracking or leakage if proper materials are not used. Hydrogen easily ignites in the atmosphere, meaning that pipelines must be fit for purpose. This is likely to be less of an issue in new pipelines but where existing pipelines are being repurposed, suitable engineering work and safety standards would need to be adhered to.

The H21 Project is a UK-based project to explore the feasibility of implementing a dedicated hydrogen distribution network in the city of Leeds. The project proposed to utilise elements of the existing Leeds gas network, particularly at end-points at the city-level. It was estimated that the entire distribution system, encompassing pipelines from production facilities to the existing Leeds distribution network would incur an estimated capital expenditure of £230 million (approximately AUD\$409 million)¹⁹¹.

5.6.5 Hydrogen infrastructure cost estimates

Production

In this section, we have considered cost estimates to produce hydrogen in 2046 based upon production costs for the various methods modelled in the Hydrogen Highway scenario. These will be shown in Table 92 below.

¹⁸⁸ Hydrogen Pipelines, <https://www.energy.gov/eere/fuelcells/hydrogen-pipelines>

¹⁸⁹ Hydrogen to be injected into Adelaide's gas grid in 'power-to-gas' trial, <http://www.abc.net.au/news/2017-08-08/trial-to-inject-hydrogen-into-gas-lines/8782956>

¹⁹⁰ DESIGN BASIS DEVELOPED FOR H2 PIPELINE, <https://www.ogj.com/articles/print/volume-88/issue-22/in-this-issue/pipeline/design-basis-developed-for-h2-pipeline.html>

¹⁹¹ H21 Final Report, H21 Leeds.



Given that there is not commercial scale of hydrogen production for many technologies explored, we have turned to case studies and models to provide an illustrative cost for context. This data below is caveated on the following points:

- Costs have been converted from \$USD to \$AUD on 30 May 2018.
- The “future cost case” for the electrolysis methods are based on 2020 targets set by the U.S. Department of Energy. For coal gasification and natural gas reforming, these were based on H2A case studies for an assumed 2025 start-up year. Default values were used in all circumstances.
- The coal gasification cost is based on black coal being a U.S. estimate, with approximately 20% of total cost representing resource inputs. The cost of brown coal would therefore affect this estimate.
- The levelised cost of production includes the cost inputs required to produce hydrogen (i.e. it includes an assumed resource price for electricity or natural gas) which are based on American factors given the source of the data.
- Volume production per day (quoted below) were based on default values in the various sources used.

Table 92– Illustrative production costs under Hydrogen Highway scenario

	2011 cost status	Future cost case
KPMG modelled H ₂ required in 2046	1,263,624,523 kg	1,263,624,523 kg
Central electrolysis (50t/day)		
Levelised cost of production (per kg)	\$5.45 ¹⁹²	\$2.66 ¹⁹²
Estimated annual cost	c. \$6.89 billion	c. \$3.36 billion
Distributed electrolysis (1.5t/day)		
Levelised cost of production (per kg)	\$5.58 ¹⁹²	\$3.06 ¹⁹²
Estimated annual cost	c. \$7.05 billion	c. \$3.87 billion
Coal gasification (250t/day)		
Levelised cost of production (per kg)	–	\$2.66 ¹⁹³
Estimated annual cost	–	c. \$3.36 billion
Natural gas reforming (380t/day)		
Levelised cost of production (per kg)	–	\$3.15 ¹⁹⁴
Estimated annual cost	–	c. \$3.98 billion

As can be seen, there is a large cost component involved in producing the hydrogen for a full road network. We stress this is an indicative illustration with several caveats and is presented to provide context of the level of scale required. Economic analysis of proposed production in facilities would provide a more accurate picture of the likely unit costs achievable.

¹⁹² DOE Technical Targets for Hydrogen Production from Electrolysis, <https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-production-electrolysis>, \$USD figures converted to \$AUD on 30/05/2018

¹⁹³ Rutkowski, M 2008, Future Central Hydrogen Production from Coal with CO₂ Sequestration version 2.1.1

¹⁹⁴ Rutkowski, M 2012, Future Central Hydrogen Production from Natural Gas with CO₂ Sequestration version 3.101



These costs demonstrated represent production only, and do not consider costs to distribute the hydrogen which would need to be considered separately based on the chosen production method.

With current petrol prices in Australia, it can cost approximately \$50 - \$70 to fill a small passenger car with an approximate range of 500 – 650km. The 500km range of the Toyota Mirai, with 5kg hydrogen tanks, could cost approximately \$50 to refill at a retail hydrogen price of \$10/kg, placing it on par with ICE vehicles. Achieving the cost targets shown in Table 90 alongside reasonable distribution costs may make the supply chain amenable to consumers and potentially at a cost below ICE vehicles.

With technology advances and potential economies of scale, it may be possible to reduce these prices further. If the price of gas, coal or electricity were to significantly change, this would influence the cost of production. It has been estimated that with low natural gas prices (approximately AU\$4/mmBTU), the cost to produce 1kg of hydrogen may fall to AU\$1.33/kg. However, we note that this does not include costs such as CCS which are likely to increase production costs.¹⁹⁵

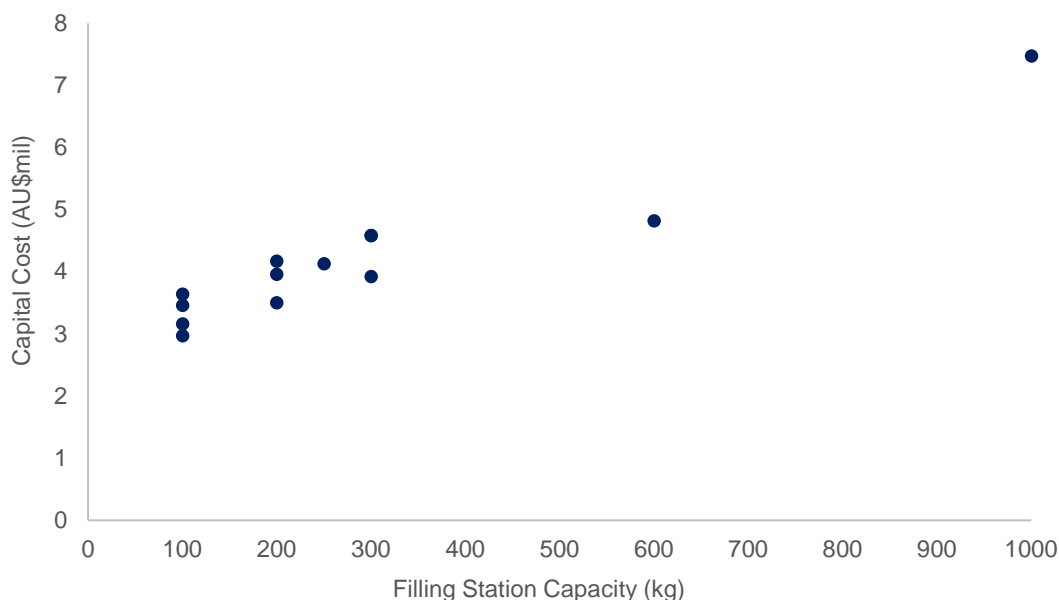
Filling infrastructure

Fuelling stations with on-site production

Where a fuelling station contains an on-site electrolyser, the cost of this fuelling station is stand-alone as no consideration is given to other production or distribution requirements. Accordingly, there will be a higher capital cost for each fuelling station as these stations will all require their own production equipment.

Shown in Figure 95 below are a range of capital cost estimates for a hydrogen fuelling station with an on-site electrolyser from current literature. As can be seen, a facility with a capacity of between 100kg to 300kg has an estimated capital cost in the range of \$3 to \$5 million.

Figure 93- Capital cost estimates for hydrogen fuelling stations with on-site production



¹⁹⁵ https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-26726.pdf, \$USD figure converted to \$AUD on 30/05/2018



For practical context, the ACCC reported that there were 864 fuel retail sites located within Melbourne in 2017¹⁹⁶. If each of these were replaced on a 1:1 basis with a hydrogen fuelling station with on-site electrolysis, this would incur approximate capital costs between \$2.5 billion and \$4.35 billion based on the range of estimate costs highlighted above. However, as has been discussed, it is likely that existing sites can be repurposed or otherwise modified so there may be a lessened requirement for “new build” filling stations to reduce capital costs.

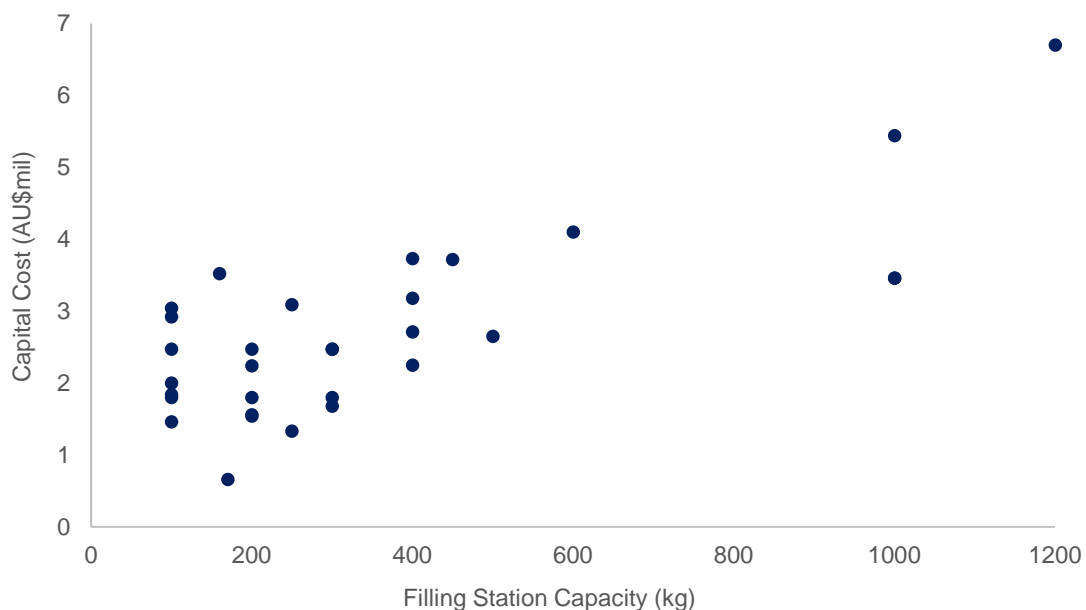
Fuelling stations with no production on-site

For this analysis, we are considering fuelling stations whereby the hydrogen has been produced offsite, be that through centralised electrolysis, natural gas reforming or coal gasification.

As there has not yet been a large-scale rollout of filling infrastructure, we have analysed a range of sources from literature to plot indicative costs. The below costs reflect the capital cost for fuelling stations for delivered hydrogen. Differing literature sources consider varying supply methods (trucking vs pipelining) however for the station itself, a majority of the required equipment will still be similar.

Figure 96 below highlights this difference in cost. As can be seen, for a station between 150kg – 500kg of capacity, capital costs vary between \$1 million and \$4 million. This variance is mainly due to the current infancy of rollout such that studies apply different parameters or assumptions. However, the below is useful for providing an indicative cost. It would be expected through deployment efficiency that the cost of various components would decrease.

Figure 94 – Capital cost estimates for hydrogen fuelling stations with no production



Applying the same analysis to Melbourne fuelling stations noted above (there being 864 retail fuel sites), there would be an approximate capital cost range of \$860 million and \$3.5 billion to replace these sites with hydrogen fuelling stations. Again, utilising existing facilities would be key in reducing these costs to avoid new builds where possible.

¹⁹⁶ Petrol prices are not the same: report on petrol prices by major retailer in 2017, Australian Competition & Consumer Commission, May 2018, https://www.accc.gov.au/system/files/1411_Report%20on%20petrol%20prices%20in%202017_FA.pdf



When contrasted against Figure 95, it can be seen that there is an approximately \$1 - \$2 million capital cost reduction by not installing electrolysers on site. This would need to be considered against the costs of distribution to determine the trade-offs between installing electrolysers at filling stations compared to centralised infrastructure which would then require pipelines or trucking.

The cost of production would also be a factor to consider, as the economies of scale achieved by centralised production would need to sufficiently produce cost savings over distributed equipment to make the option viable.

5.6.6 Concluding observations

The preceding discussion has raised many observations relevant to the Hydrogen Highway scenario. This scenario presents a unique challenge as it is the only scenario that contemplates FCV uptake, which would require a markedly different approach to BEVs. A new hydrogen supply chain would need to be developed from production through to distribution to consumers.

A number of our key observations relevant to the infrastructure responses relevant to the Hydrogen Highway scenario are noted below.



Selecting the preferred production method is important

There are multiple methods available to produce hydrogen, with electrolysis, coal gasification and natural gas reforming all considered in this Report that all require specific, new infrastructure. Each method brings its own strengths and weaknesses that would need to be balanced.

Particularly for coal gasification and natural gas reforming, these methods introduce significant emissions (36 million and 12 million tonnes annually respectively) that would need to utilise carbon capture and storage (or another neutralisation technology) to be considered zero emission.

The massive scale of hydrogen required presents challenges around sufficient production facilities to meet ongoing demand and will require a large degree of capital investment. There may be a role for Government to support initial projects and fund research to improve production methods.



Allow the market to select an optimal supply chain to meet demand

As hydrogen production and distribution methods are largely interoperable, it may be feasible for Government to allow the market to solve the hydrogen demand issue as it builds relevant facilities between now and 2046 to meet demand growth. Government support may be required in the form of subsidies, pilot funding or other mechanisms to aid in encouraging development of a supply chain.

With a potential number of participants playing a part in the supply chain, it may be possible to share the infrastructure burden such that it does not fall onto one party. As a practical example, one company may focus on production while another constructs a tariffed pipeline network and current oil and gas companies may undertake retrofitting of their existing filling stations to hydrogen.



Adequate filling stations will need to be available across Victoria



As with BEVs and charging infrastructure, FCVs require their own network of infrastructure to provide fuel. Commonly cited as a key barrier to FCV uptake, rolling out a network of filling stations is a challenge given their high capital cost. Unlike BEV charging infrastructure, there are fewer potential providers for infrastructure, with specific fuelling businesses likely to emerge as they did for the petroleum industry. The use of existing filling stations may be crucial to reduce the cost burden associated with “new build” facilities.



Distribution may prove challenging

Where centralised facilities are opted for to produce the required levels of hydrogen, distributing these to a filling network may pose challenges. Based on current technology, distribution by truck may be problematic owing to the limited amount of hydrogen that can be transported, which may lead to a high level of freight making constant round trips to supply filling stations. Hub-and-spoke distribution or liquefaction may aid in this regard.

If pipelines are used to send hydrogen to filling stations, careful consideration of the current network would need to be undertaken, whether there is hydrogen blended into existing natural gas or if 100% hydrogen pipelines are employed. Embrittlement is a key risk in pipelines that are not fit for purpose and may pose a danger to the public.



Government will need to carefully consider safety regulation

Hydrogen filling stations represent a new challenge for Government to consider necessary safety regulations and requirements to allow these stations to be placed in high density areas. Where distributed electrolysis is adopted, a filling station would include production, storage and distribution (in the form of filling hoses for cars) facilities all in one small station. Therefore, safety regulations would need to be informed on hydrogen research to facilitate the building of stations while also balancing public safety.

On the distribution side, there are also safety regulation issues to consider. Whether pipelines or trucks are used to distribute hydrogen, these both would require adequate thought from Government in crafting relevant and applicable legislation.



Appendix A: Impact on System Peak timing under scenarios

The overall system peak may change under certain uptake levels and charging profiles of EVs. The average maximum demand in 2018 to date (until end of April), and the maximum demand on the highest demand day of 2018, suggested a current peak of around 5 to 7 pm in the evening (shown in the darker columns in the figures below). Thus, our analysis has analysed the extent to which EVs under different scenarios add to demand in the window of 5 to 7 pm. Of course, it is not possible to know exactly how this profile will change between 2018 and 2046 (or 2031). It is possible that the peak will shift later into the evening with additional uptake of rooftop solar, when the contribution from rooftop solar falls but temperatures are still high.

The figures below illustrate if and how the overall system peak changes using a 2046 (2031) load profile estimated based on AEMO’s maximum demand estimate for 2046 (10,240 MW in the neutral scenario) and the shape of the load profile on the maximum day in 2018 (until end of April).

In four out of seven permutations (the incentivised permutations and fleet scenarios) the peak shifts to earlier in the afternoon, as there is more limited charging happening in the 5 – 7 pm window. In the earlier afternoon it is possible that the contribution of solar PV in particular is higher than it is for the early evening, meaning that less dispatchable generation may be required than if the peak occurred when the contribution of solar was more limited. In two scenarios (the non-incentivised scenarios), the peak remains in the 5 – 7 pm window. In the High Speed scenario the peak shifts until later in the evening.

Figure 95 – Private Drive (Incentivised)

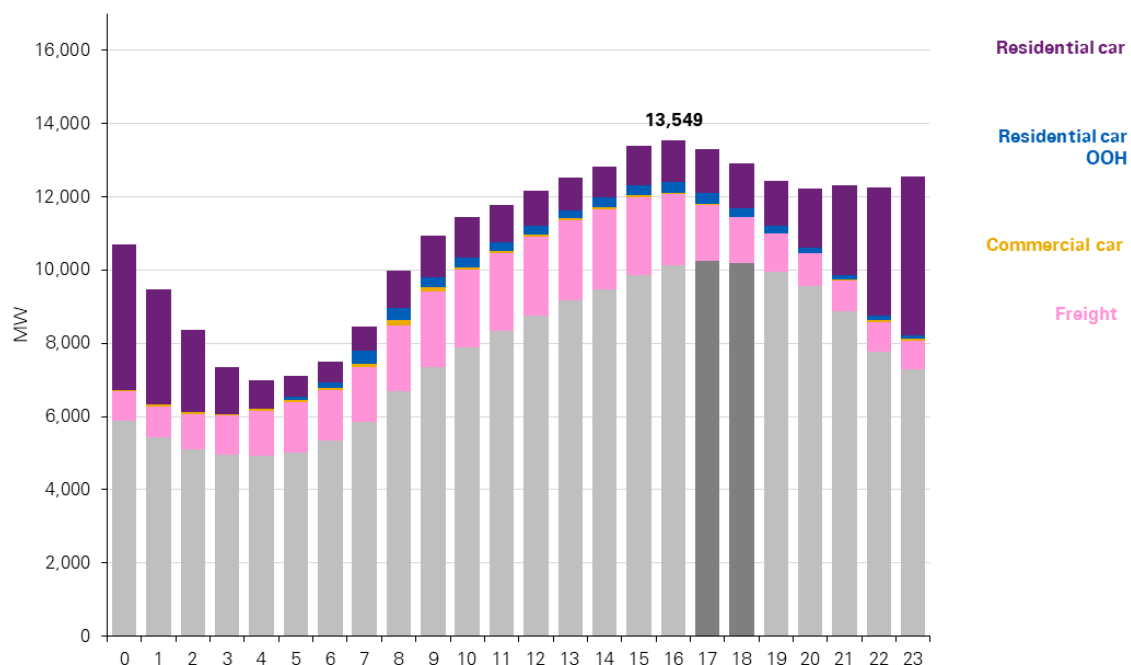




Figure 96 – Private Drive (non-incentivised)

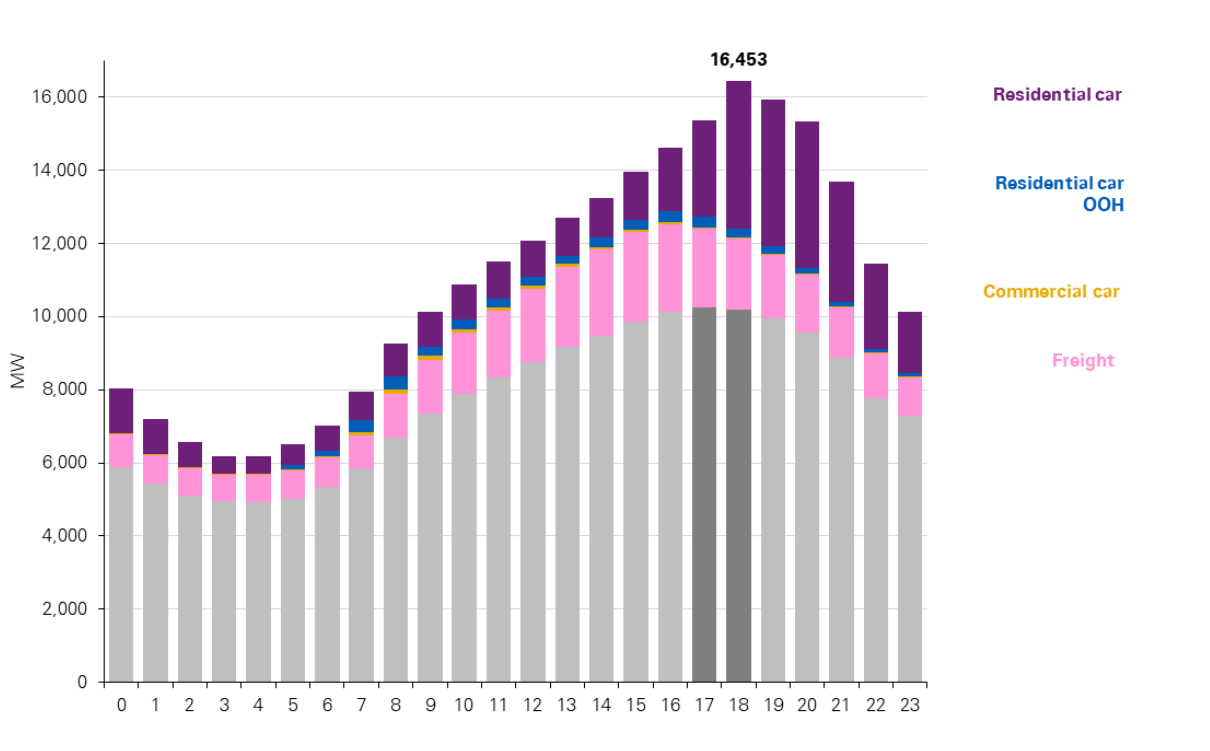


Figure 97 – Fleet Street

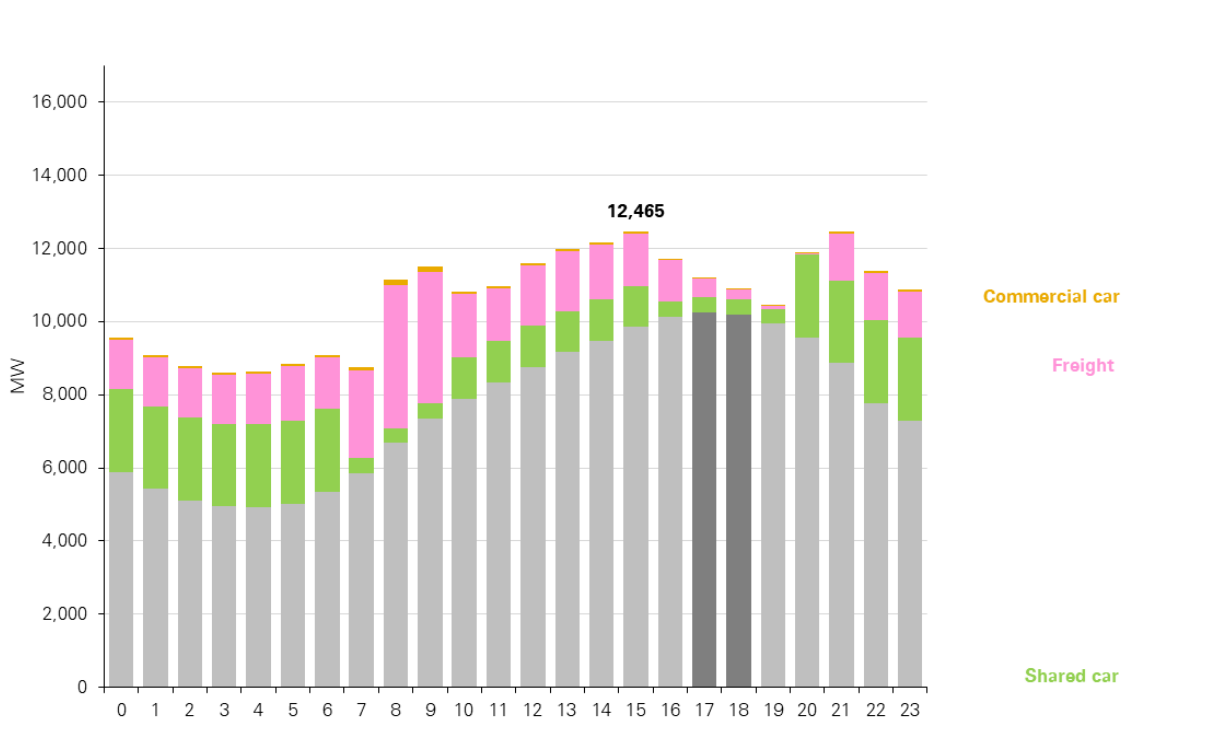




Figure 98 – High Speed

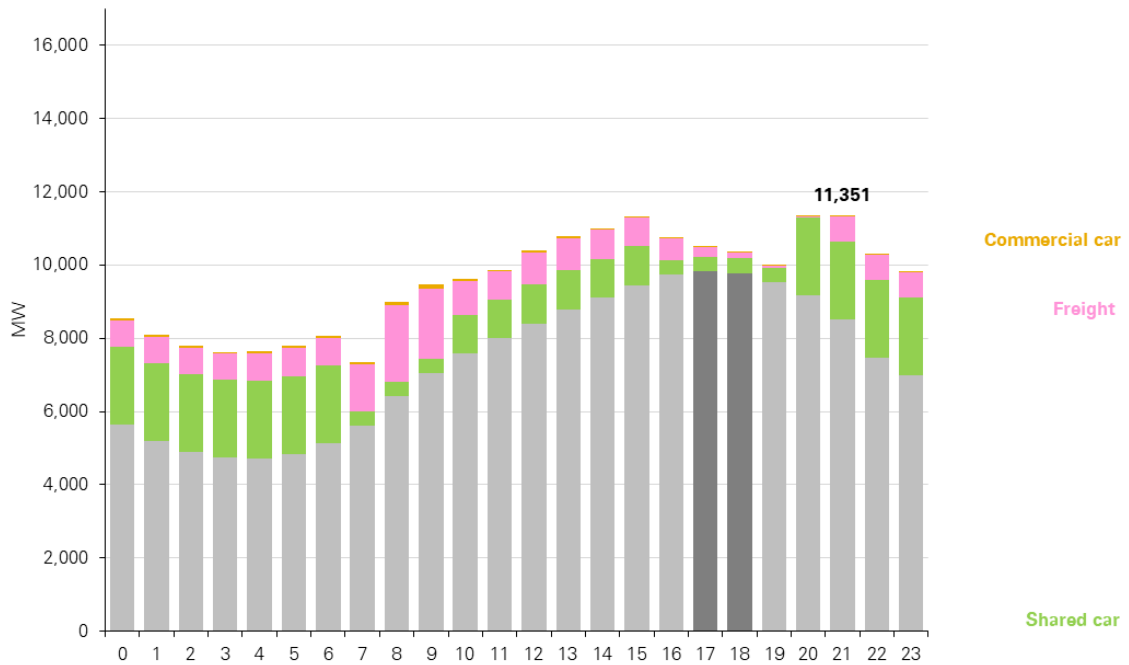
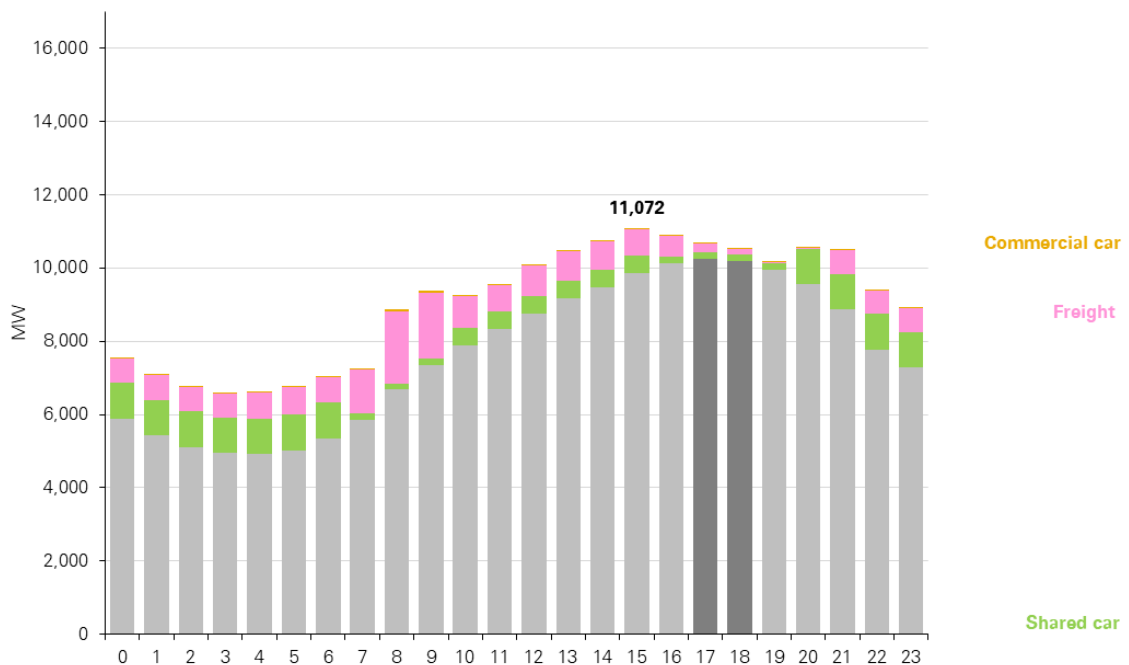


Figure 99 – Slow Lane





Contact us

Sabine Schleicher

Partner

+61 7 3233 3233

sschleicher@kpmg.com.au

Eamonn Corrigan

Director

+61 2 9335 8555

ecorrigan1@kpmg.com.au

kpmg.com.au

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