Australian Energy Market Commission (AEMC)

6 December 2011

IMPACT OF ELECTRIC VEHICLES AND NATURAL GAS VEHICLES ON THE ENERGY MARKETS

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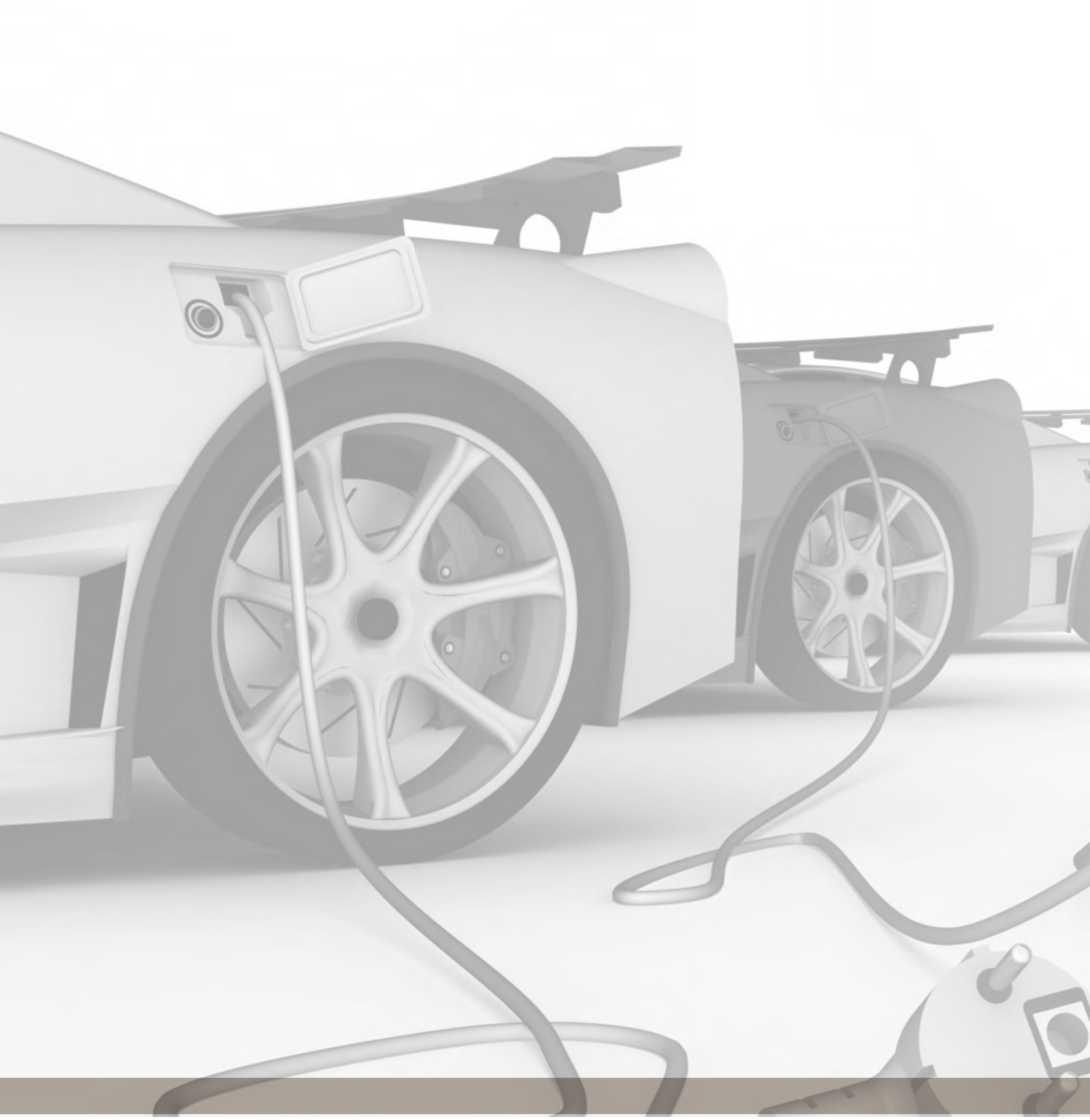
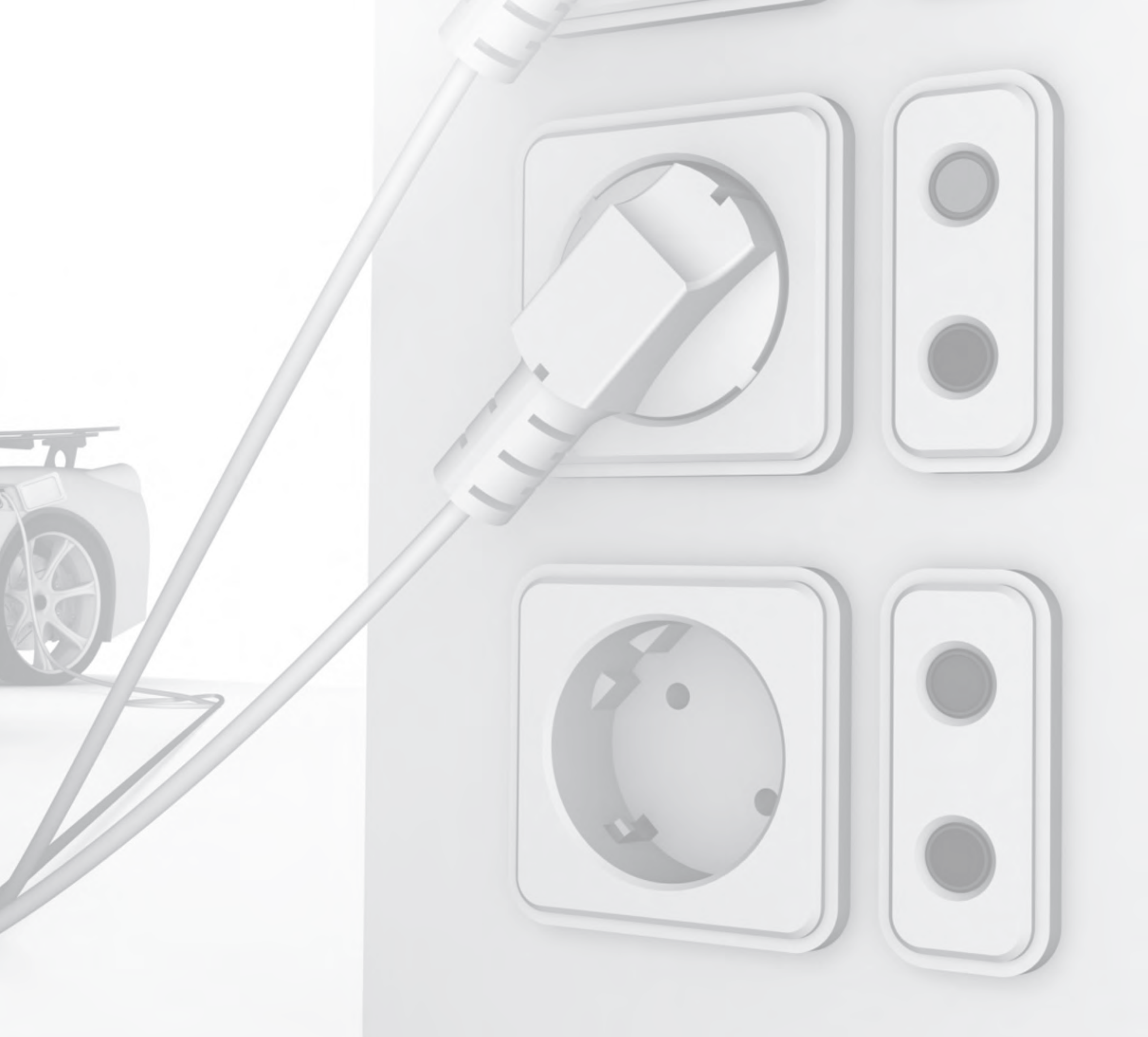




Executive Summary

Executive Summary

The Australian Energy Market Commission (AEMC) has commissioned AECOM to undertake a study to investigate the broad costs and benefits of Electric Vehicles (EVs) and Natural Gas Vehicles (NGVs) on their respective energy markets. The study also identifies the arrangements necessary within these energy markets to facilitate the efficient uptake of these vehicles. This report:

- assesses the potential uptake of EVs and NGVs
- identifies the costs and benefits of EVs and NGVs to the energy markets.

This study considers the impact on the National Electricity Market (NEM) and the South West Interconnected System (SWIS). As such, the study area comprises Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania, South Australia and Western Australia.

Electric vehicles

Electric Vehicles are likely to play an important role in the future of motor vehicles in Australia...

There is a global movement to transition away from motor vehicles powered by petrol and diesel, driven primarily by increased awareness and action on reducing greenhouse gas emissions and a desire by most countries to reduce their dependence on imported oil. As low emission vehicles, EVs have the potential to provide environmental benefits, through reduced greenhouse gas emissions and ambient air pollution, while reducing Australia's exposure to crude oil prices and oil import dependency.

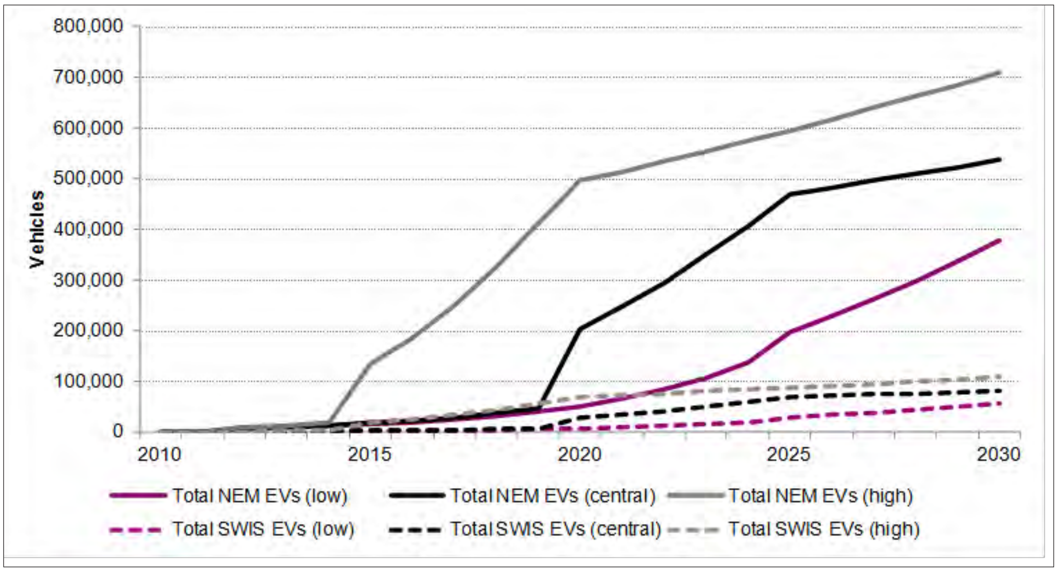
- Our study identified the following key factors affecting the take up of EVs:
- Vehicle price (which is largely driven by battery prices) and rate at which it converges with an internal combustion engine (ICE) vehicle
- Global supply constraints in the EV market
- Supply of infrastructure with research to date suggesting that whilst most charging will occur at home, the provision of infrastructure is necessary to alleviate range concerns
- Fuel prices, particularly higher oil prices which impact on the operating cost of ICE vehicles
- Vehicle range.

Following an extensive literature review on the factors affecting the decision to purchase a vehicle, AECOM developed a vehicle choice model which takes into account the vehicle purchase cost, fuel cost, vehicle range, emissions, availability of refuelling / charging infrastructure and multi-fuel bonus.

There are inherent uncertainties in making forward estimates, so it is important to understand the likely range of take up and the key influencing factors. Therefore, this study has developed three scenarios around the key factors identified as affecting the take up of EVs.

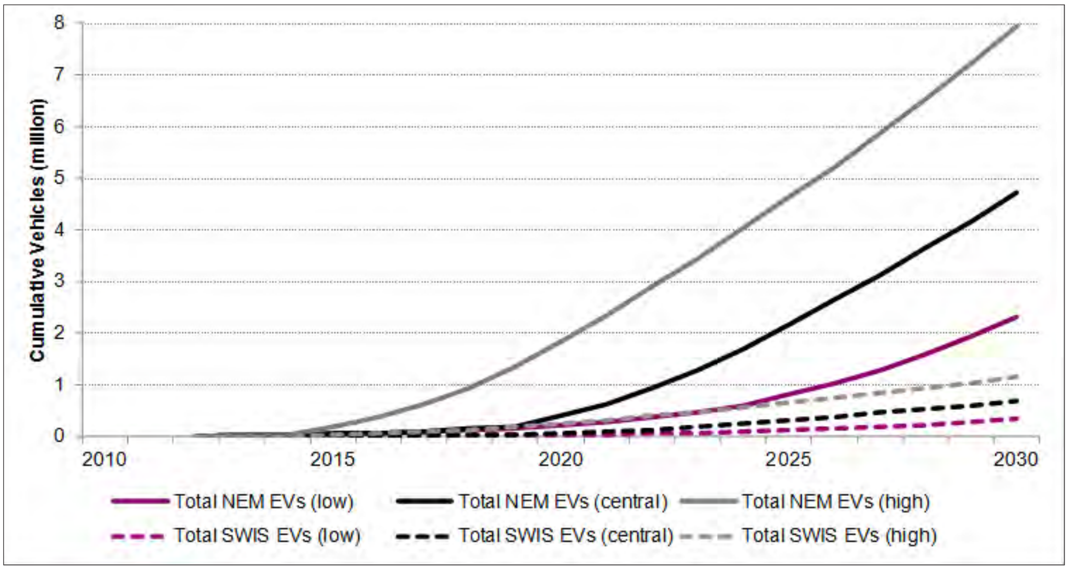
AECOM's analysis suggests that within 10 to 15 years EVs could have a significant presence in the Australian market (See **Figure 1** and **Figure 2**). While vehicle sales are expected to be slow initially, accounting for around 1% to 2% until 2015, once vehicle prices fall, global supply constraints ease and infrastructure availability increases, EV sales are expected to be around 20% of sales by 2020 rising to around 45% of sales by 2030 (See **Table 1**) . Take up could be slower, as illustrated in our low scenario, if EV prices take longer to reach price parity and supply constraints remain in the Australian market. However, it is also possible that take up could be much quicker (as illustrated in our high scenario), if for example, battery prices fall much quicker than currently anticipated, Australia is seen as a key electric vehicle market with supply constraints easing quicker and the emergence of leasing arrangements that reduce the upfront purchase cost.

Figure 1: Estimated annual sales of electric vehicles in NEM and SWIS



Source: AECOM

Figure 2: Estimated number of electric vehicles in NEM and SWIS



Source: AECOM

Table 1: Estimated take up of electric vehicles in the NEM and SWIS as a proportion of new sales

	Central			Low			High		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
NEM									
PHEV	1.3%	18.7%	36.3%	1.4%	4.6%	31.0%	13.0%	41.0%	38.0%
BEV	0.7%	1.5%	7.6%	0.3%	0.6%	2.6%	1.3%	6.0%	15.4%
Total	2.0%	20.2%	43.9%	1.7%	5.3%	33.6%	14.4%	47.0%	53.4%
SWIS									
PHEV	1.3%	18.7%	37.5%	1.3%	4.4%	32.2%	12.8%	42.0%	38.6%
BEV	0.7%	1.6%	8.5%	0.3%	0.6%	2.9%	1.4%	6.6%	17.0%
Total	2.0%	20.3%	45.9%	1.7%	5.1%	35.1%	14.2%	48.6%	55.7%
Total									
PHEV	1.3%	18.7%	36.5%	1.3%	4.6%	31.2%	13.0%	41.1%	38.0%
BEV	0.7%	1.5%	7.7%	0.3%	0.6%	2.6%	1.3%	6.0%	15.6%
Total	2.0%	20.2%	44.2%	1.7%	5.2%	33.8%	14.3%	47.2%	53.6%

Source: AECOM

There are four key findings that warrant further discussion:

- Higher take up of Plug-in Hybrid Electric Vehicles (PHEVs)in early years will minimise the impact on the electricity market

  In early years, the take-up of PHEVs is stronger than that of pure Battery Electric Vehicles (BEVs) due to superior range and the ability to use both electricity and petrol as fuel. However, in later years there is a shift towards BEVs as purchase prices converge to parity with ICE, battery improvements result in increased vehicle range, the provision of more charging infrastructure, and higher fuel prices have the potential to make BEVs more competitive. The higher take up of PHEVs in early years may minimise the impact that EVs will have on the electricity market as PHEVs will typically use less electricity and the dual charging is likely to reduce range anxiety and make PHEV charging more flexible which will in turn reduces the impact on peak load.

- Higher take up of smaller vehicles in early years will minimise the impact on the electricity market

  The take up of EVs also varies significantly by vehicle size and distance travelled. The price premium of an EV is directly related to the battery price, which in turn is directly related to the size and weight of the vehicle. Currently, a large EV has a much higher premium than a small EV. This results in higher take up of small EVs, typically travelling small distances, in the short term. However, as vehicle prices fall, the vehicle range increases and more charging infrastructure becomes available, owners of larger vehicles and vehicles that travel large distances tend to purchase a higher proportion of EVs. This is due to the fact that operating costs are relatively more important for these vehicle owners. The early preference for small vehicles, travelling lower distances, will also minimise the impact that EVs will have on the electricity market.

- Higher take up of EVs in New South Wales, Victoria and Queensland

  At a state and territory level within the NEM, equivalent results are observed in terms of the proportion of new sales; however the magnitude of sales varies between regions. New South Wales (and ACT), Victoria, and Queensland make up the majority of vehicle sales with approximately 90% of take up in the NEM. This is reflective of current vehicle sale patterns.

- Spatial clusters in early years

  Whilst this study focuses on take up at a state level, it is important to recognise there may be spatial patterns especially in early years. Take up is likely to be initially concentrated in urban and major hub areas where people typically drive shorter distances and public and commercial charging infrastructure is more likely to be available. In the short to medium term, take up is also likely to be driven by early adopters, who are typically characterised as having higher incomes, higher levels of education, and being more technologically and environmentally aware. As such, it is likely that early take up could be clustered around areas with these socio-demographic characteristics.

The impact of EVs on the electricity market depends on the ability to incentivise drivers to charge in off-peak periods...

The impact that EVs will have on the electricity markets is largely dependent on the amount of energy used and the timing of charging. In the worst case scenario where EV charging is unmanaged and occurs during existing load peaks, peak load will increase. As a result, distribution and transmission systems will need to be strengthened and more generation built. Conversely, if charging happens in off-peak periods, then it is not expected to increase peak load, even in high take up scenarios.

Table 2 sets out energy usage and the increase in peak load (if charging is unmanaged) under the three take up scenarios. Key highlights include:

- Energy consumption remains relatively low as a proportion of total energy demand even in the high take up scenario for both the NEM and SWIS at 3.7% and 4.3% respectively. The proportion of total energy demand is slightly higher in the SWIS than the NEM but remains low.
- The energy consumption depends on the split between PHEVs and BEVs as well as the size of the vehicle and distance travelled and as such changes over time in line with take up patterns.
- The energy consumption from EVs as a proportion of total energy consumption in New South Wales and Australian Capital Territory, Victoria and South Australia are slightly higher than the total for the NEM, whereas Queensland and Tasmania have lower proportions than the total for the NEM.
- An often discussed concept is the ability of renewable energy generation to supply some or all of the energy demanded by EVs to recharge. Analysis in this study suggests renewable generation is more than capable of supplying the energy requirements of EVs.
- If charging is unmanaged and everyone comes home and charges at peak periods, under the central take up scenario, peak demand is expected to increase by around 740MW by 2020 and 1.9 GW by 2030 in the NEM. Peak demand is expected to increase by around 100MW by 2020 and 300 MW by 2030 in the SWIS. This analysis assumes 80% of charging occurs in peak periods and every EV owner has a level 1 charger (15A). However if 100% of charging occurs in peak periods and every EV owner has a level 2 charger (32A) this results in a 150 per cent increase in the additional peak load.
- The increases in peak load forecast under the EV take up scenarios are relatively small when compared with the increase in peak demand required anyway. The Australian Energy Market Operator (AEMO) forecast an additional 10,000MW will be required by 2020 and an additional 23,500MW by 2030 in their central scenario with 50% probability of exceedence (POE). In the central take up scenario, unmanaged charging of EVs may require an additional 7% of additional peak demand in the NEM by 2020 compared to what is required anyway and an additional 8% by 2030. Additional investment in peak demand in the SWIS is even smaller rising to just over 6% by 2030 in the central take up scenario. Even in the high take up scenario, additional peak load, compared to what is required anyway, will be just over 13% in 2020 in the NEM and 10% by 2020 in the SWIS. These estimates are based on the 50% POE estimates of peak demand in the 2011 Statement of Opportunities. If the 10% POE is used these proportions are smaller.
- In the central take up scenario, unmanaged charging of EVs starts to have a significant impact on peak demand around 2020. This should allow sufficient time for the electricity market to plan and manage the additional increase in peak load that may be required. However, it is possible that take up could be much quicker (as illustrated in our high take up scenario), if for example, battery prices fall much quicker than currently anticipated, in which case the impact of EVs on peak demand, if unmanaged, could be felt as early as 2015 which is just inside the five year planning cycle.

Table 2: **Impact of EVs on the energy market in selected years**

	2015		2020		2030	
	NEM	SWIS	NEM	SWIS	NEM	SWIS
Central take up scenario						
Energy consumption (MWh)	88,300	10,400	648,800	80,900	8,536,700	1,173,800
% of total MWh	0.0%	0.0%	0.2%	0.2%	2.2%	2.6%
Increase in peak load if unmanaged charging (MW)	65	10	740	100	1935	300
% increase in additional peak load	1.3%	0.7%	7.3%	4.9%	8.2%	6.4%
Low take up scenario						
Energy consumption (MWh)	66,400	7,800	323,700	38,900	4,039,300	545,800
% of total MWh	0.0%	0.0%	0.1%	0.1%	1.1%	1.2%
Increase in peak load if unmanaged charging (MW)	55	5	185	25	1,365	210
% increase in additional peak load	1.3%	0.8%	2.4%	1.5%	7.9%	5.9%
High take up scenario						
Energy consumption (MWh)	273,100	32,600	3,035,400	389,000	14,261,400	1,948,700
% of total MWh	0.1%	0.1%	1.1%	1.0%	3.7%	4.3%
Increase in peak load if unmanaged charging (MW)	485	65	1,790	250	2,550	390
% increase in additional peak load	7.6%	4.1%	13.3%	9.8%	7.9%	6.4%

Source: AECOM

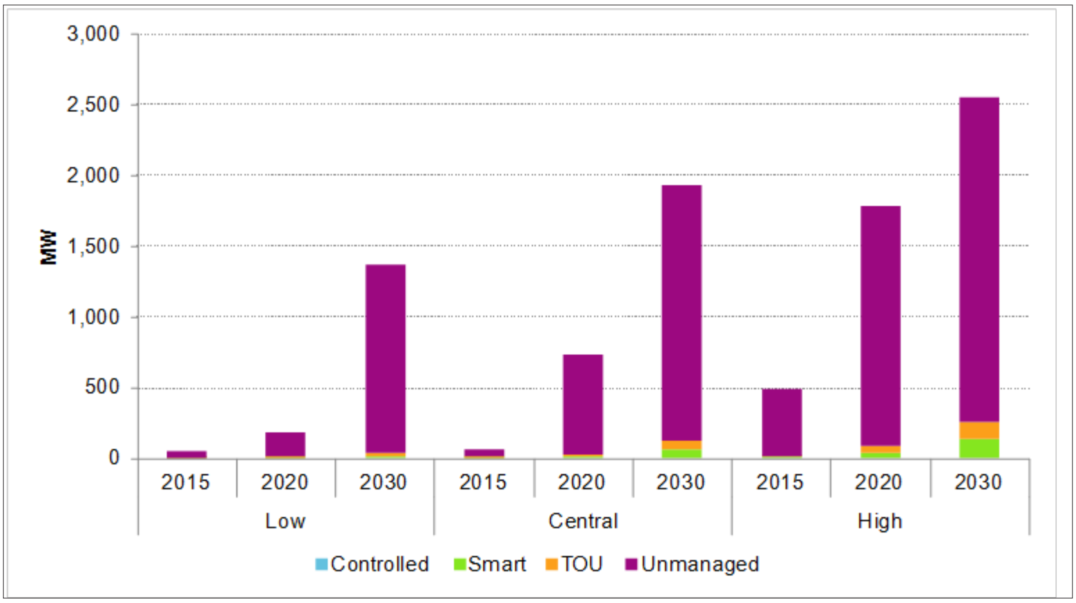
However, unlike many other high energy consumer goods, such as air conditioning, electric vehicle charging has more flexibility. If electric vehicle drivers can be encouraged to charge their vehicles in off-peak periods, either through incentivising customers to charge at off-peak times through time of use charging or smart metering, or enforcing off-peak charging through ripple control or regulation, the impacts fall significantly.

This study examined three charge management scenarios in addition to the base case if unmanaged charging:

- Unmanaged charging – charging occurs when people arrive home from work and coincides with the peak period.
- Controlled charging – charging is forced to occur in off-peak periods, for example, by using controlled load such as ripple control.
- Time of Use (TOU) charging – EV drivers have time of use tariffs that will incentivise a proportion of these to charge during off-peak periods.
- Smart meter charging – EV drivers have smart meters that provide better incentives than TOU pricing for off-peak charging.

Figure 3 highlights the potential benefits from encouraging off-peak charging in the NEM. If charging is unmanaged and 80 per cent of EV users come home and charge at peak periods, under the central take up scenario, peak demand is expected to increase by around 740MW by 2020 and 1.9 GW by 2030. However, if charging occurs in off-peak periods, either through incentivising customers to charge at off-peak times through time of use charging or smart metering, or enforcing off-peak charging through ripple control or regulation, the costs fall significantly. Time of Use charging is expected to result in an increase in peak demand of 20 MW in 2020 and around 120 MW by 2030. Smart metering could reduce this even further to an increase in peak demand of around 10 MW in 2020 and 60 MW by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand. The largest increases in peak load occur in states with the largest take up of EVs. The state with the largest increase in peak load is NSW, followed closely by Victoria. The increase in peak demand is lower in more rural states (such as Queensland) and states with smaller populations.

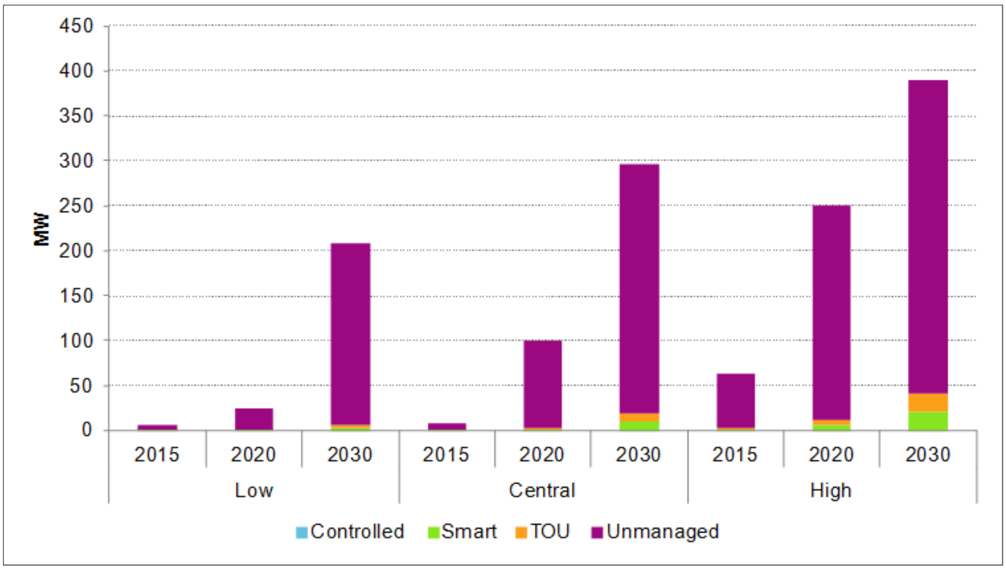
Figure 3: Estimated additional peak demand in NEM (MW)



Source: AECOM. Note: The above chart shows estimated additional peak demand, with increments attributable to each charging type. For example, under the central take up scenario, by 2030, with unmanaged charging 1,900 additional MW are required; for TOU charging this is 120MW and for smart charging an additional 60MW.

Figure 4 highlights the potential benefits from encouraging off-peak charging in the SWIS. If charging is unmanaged and 80 per cent of EV users come home and charge at peak periods, under the central take up scenario, peak demand is expected to increase by around 100 MW by 2020 and 300 MW by 2030. However, if charging occurs in off-peak periods the costs fall significantly. Time of Use charging is expected to result in an increase in peak demand of 3 MW in 2020 and around 20 MW by 2030. Smart metering could reduce this even further to an increase in peak demand of around 1 MW in 2020 and 10 MW by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand.

Figure 4: Estimated additional peak demand in SWIS (MW)

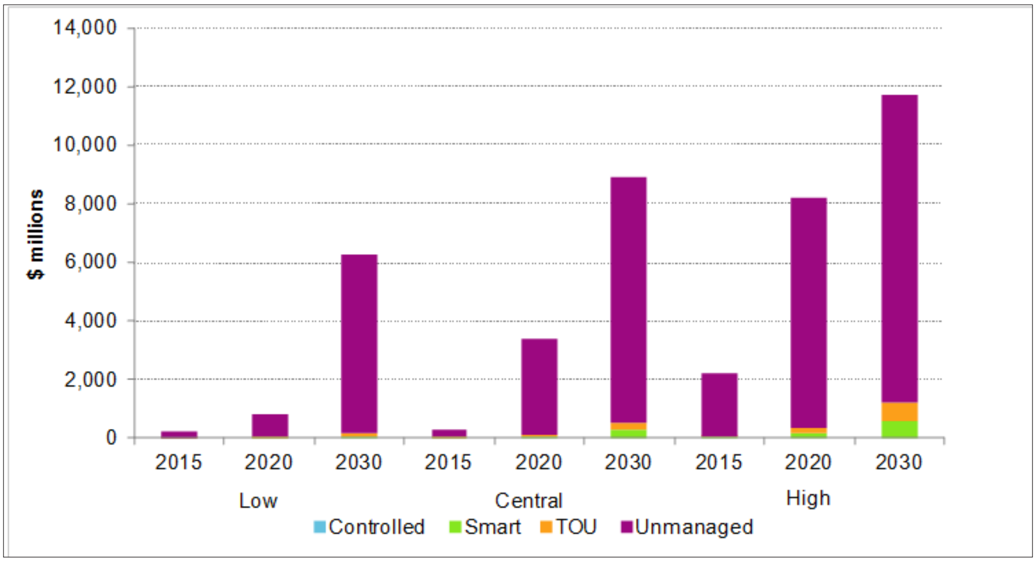


Source: AECOM

Figure 5 shows that, if charging is unmanaged and 80 per cent of EV users come home and charge at peak periods, under the central take up scenario the cost of increased capacity in the NEM could be around $3.4 billion by 2020 and $8.9 billion by 2030. However, if charging occurs in off-peak periods, the costs fall significantly. Time of Use charging is expected to result in additional costs of around $90 million by 2020 and $550 million by 2030. Smart metering could reduce this even further to around $50 million by 2020 and $270 million by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand. These estimates have not been discounted to reflect timing of investments. This analysis assumes 80% of charging occurs in peak periods and every EV owner has a level 1 charger (15A). However if 100% of charging occurs in peak periods and every EV owner has a level 2 charger (32A) this results in a 150 per cent increase in the additional cost of peak load. The largest component of this cost will be driven by investment in distribution, which will account for between 60% and 75% depending on the state. Generation accounts for around 15% to 25% and transmission accounts for around 10% to 20%.

The impacts and costs also vary significantly by state depending on the take up of vehicles in each state. The impact is expected to be bigger in New South Wales, Queensland and Victoria, the states with the largest take up of EVs. Interestingly, the cost of increasing capacity in Queensland could be higher than in Victoria, even though Victoria has a higher estimated increase in peak load, because cost of upgrading capacity in Queensland tends to be higher.

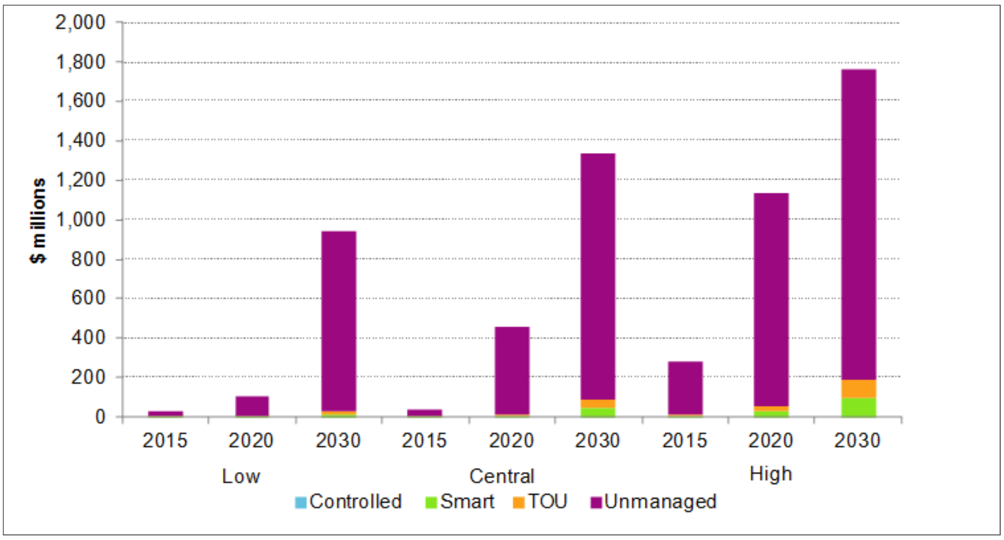
Figure 5: **Estimated cost (for both generation and network upgrades) of additional peak demand in NEM ($ millions undiscounted)**



Source: AECOM

Figure 6 shows that, if charging is unmanaged and 80 per cent of EV users comes home and charges at peak periods, under the central take up scenario the cost of increased capacity in the SWIS could be around $460 million by 2020 and $1.3 billion by 2030. However, if charging occurs in off-peak periods the costs fall significantly. Time of Use charging is expected to result in additional costs of around $10 million by 2020 and $90 million by 2030. Smart metering could reduce this even further to around $6 million by 2020 and $40 million by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand. These estimates have not been discounted to reflect timing of investments.

Figure 6: **Estimated cost (for both generation and network upgrades) of additional peak demand in SWIS ($ millions undiscounted)**



Source: AECOM

It is unlikely that the take up of EVs will have a significant impact on the reliability of the electricity market, at either the generation or network level, for the following reasons:

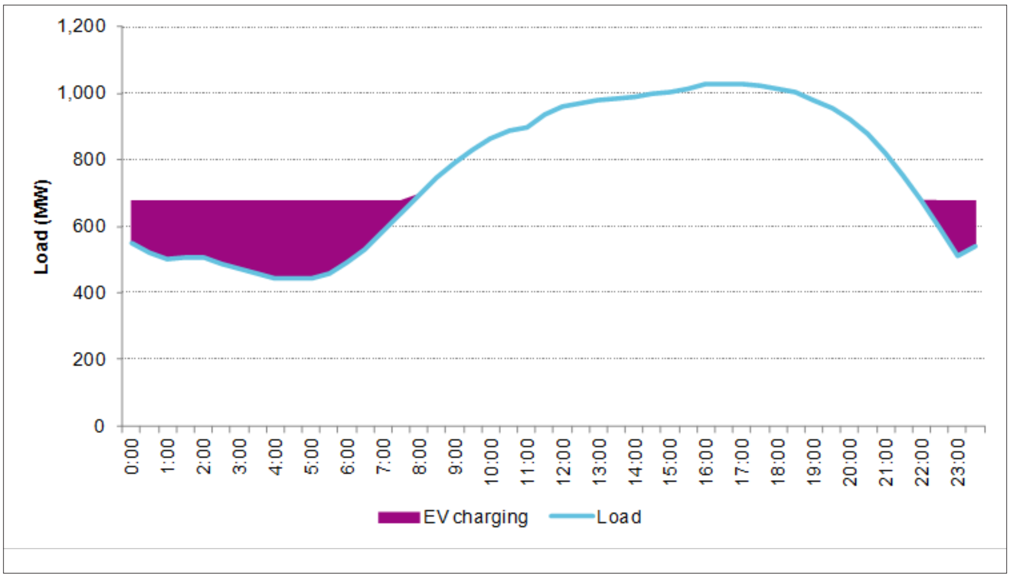
- Take up is likely to be gradual with enough lead time for the market to respond;
- Energy consumption and increases in peak demand due to EVs are relatively small when compared with expected growth without EVs; and
- The electricity markets and regulation should continue to work effectively and provide the right incentives for the generation and network businesses to respond to the take up of EVs.

Consequently, our analysis assumes quality of service (including reliability, congestion and availability of generation) remain unchanged and the cost of maintaining this service is fully reflected in the cost of increased capacity.

As highlighted in **Figure 7**, our analysis shows that even in the high take up scenario, networks will be able to accommodate charging during off-peak periods without increasing the peak load. Based on Net System Load Profiles (NSLP) South Australia had the least available off-peak charging during its day with the highest peak load in 2010. South Australia, therefore, provides the toughest test of the ability to accommodate EV charging in the off-peak. AECOM tested this in other states in the National Energy Market (NEM) and found the same result.

It is recognised that whilst it is possible to accommodate EV charging in off-peak periods without increasing peak load this could cause other impacts in the electricity market. In particular, concern has been raised that there may be issues regarding the adequacy of system capacity, particularly at the generation level. Given off-peak generation is predominantly base load coal and gas, there is unlikely to be major capacity issues as a direct result of EVs charging in off-peak periods. The current electricity market design provides the right incentives and is capable of responding to this issue, particularly given the long lead times before there is significant take up of EVs.

Figure 7: Accommodating EV charging without increasing peak load, South Australia



Source: Net System Load Profiles from AEMO (2011a), EV charging AECOM

Further, if EVs can be managed to ensure the majority of charging occurs in non-peak periods, they present significant opportunities for improving the efficiency of the electricity market.

- Improved load factor: The cost of meeting peak demand is generation and network capacity that is used infrequently. Most networks operate at less than 50% load factor for a large proportion of the day. Going forward, this load factor is expected to deteriorate with peak demand forecast to grow faster than average energy use in the NEM. By flattening the load curve the fixed costs of the network can be spread across a larger base, resulting in improved load factor. Our analysis estimates that EVs can improve the load factor of the network resulting in reductions in retail prices reductions of up to 2% per annum by 2020 and up to 7% per annum by 2030 compared to what might happen otherwise, depending on take up and varying within each state.
- Flexibility benefits: Provided there is some form of dynamic pricing with the charging of EVs, there are further benefits from EVs including managing transmission and distribution networks, managing wholesale price risk and more efficient use of intermittent generation.

Vehicle-to-Grid presents opportunities for further benefits but there are still some issues that need addressing...

EVs also provide an opportunity to act as energy storage devices and feedback electricity to the grid (known as Vehicle-to-Grid (V2G)) or to the house (known as Vehicle-to-House (V2H)). This opportunity 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 vehicle-to-grid depends on a number of factors including:

- Impact on battery life: As yet the full consequences for battery life are unknown and many manufacturers are concerned about warranty of the battery;
- Driver concern: Drivers may be wary about coming back to a vehicle that is discharged. This concern will ease over time as more information is available about charging behaviour, more charging infrastructure becomes available and technology becomes smarter so that it can ensure a minimum battery charge.
- Tariff arrangements: Usher et al (2011) shows the viability of V2G is dependent on EV drivers receiving a higher tariff than they pay for electricity. Also, additional home infrastructure may be needed, as for other feed-in arrangements.
- Take up of EVs: The success of V2G is dependent on a critical mass of EVs. As shown above, significant levels of take up are not expected in the short term, with high take up starting to occur in 10 to 15 years.

Overall, the impact of EVs on the electricity market depends on the ability to incentivise drivers to charge in off-peak periods. AECOM suggest further work is undertaken to determine the optimal way of achieving this.

Natural gas vehicles

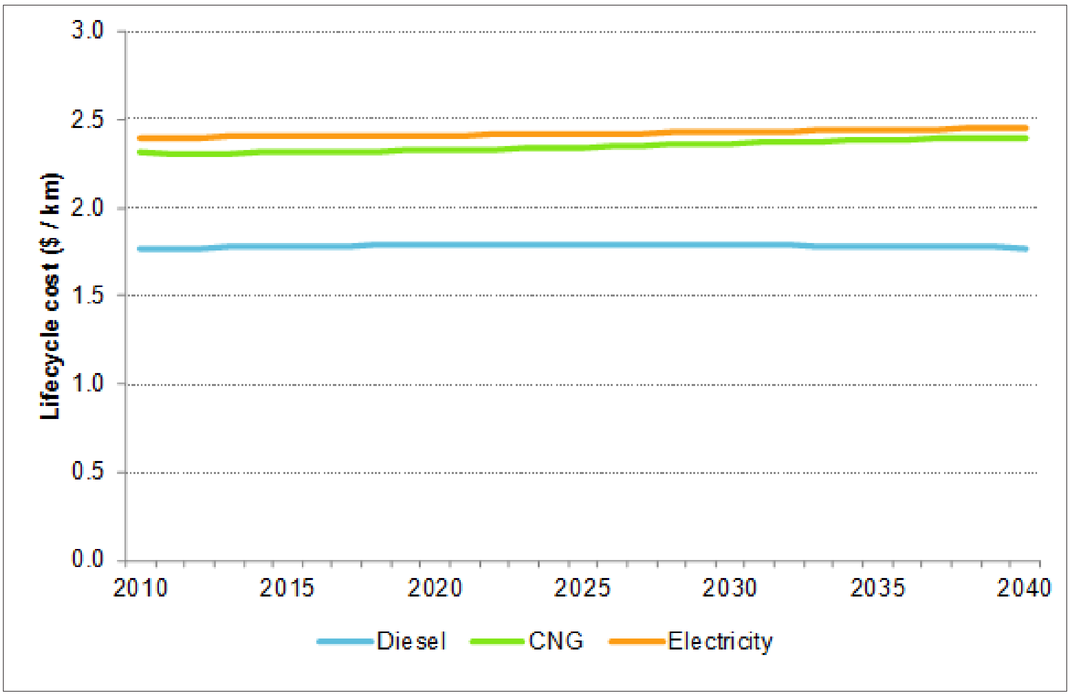
There is unlikely to be high take up of NGVs in the passenger market, but take up may increase in buses and trucks

Like EVs, NGVs offer a lower emissions alternative to the traditional vehicles powered by petrol and diesel.

Whilst NGVs currently have many advantages over EVs in terms of being more cost effective for drivers who travel large distances and superior range, these advantages are likely to diminish over time as the upfront cost of EVs falls, EV vehicle range improves, and gas prices increase relatively more than electricity prices. The use of compressed natural gas (CNG) also has a number of practical impediments, such as the need to be stored under pressure and the requirement for specialised heavy-duty storage tanks on board the vehicle which limit the vehicle range and result in reduced space. In addition, NGVs require substantial investment in refuelling infrastructure and whilst home based refuelling is feasible, it is expensive and there are concerns about safety. In contrast, there is an existing electricity network which will allow recharging of EVs at home relatively easily. Given that EVs are likely to be relatively more competitive once the upfront purchase cost is reduced it is unlikely that significant investment in charging infrastructure for passenger NGVs will occur.

Take up of natural gas vehicles is more likely in buses and trucks, which typically travel longer distances so benefit more from the reduced operating costs. They can also refuel at a central base or specific locations, making it a viable option to install the refuelling infrastructure. Analysis of the life cycle costs from CNG buses suggests they do not offer significant financial benefits compared with diesel buses (see **Figure 8**). However, most buses are operated by government who will face increasing pressure to reduce their greenhouse gas emissions. Given transport typically accounts for a large proportion of greenhouse gas emissions it is possible that there will be increased take up of natural gas buses, despite not being financially viable, to assist in meeting greenhouse gas reduction targets.

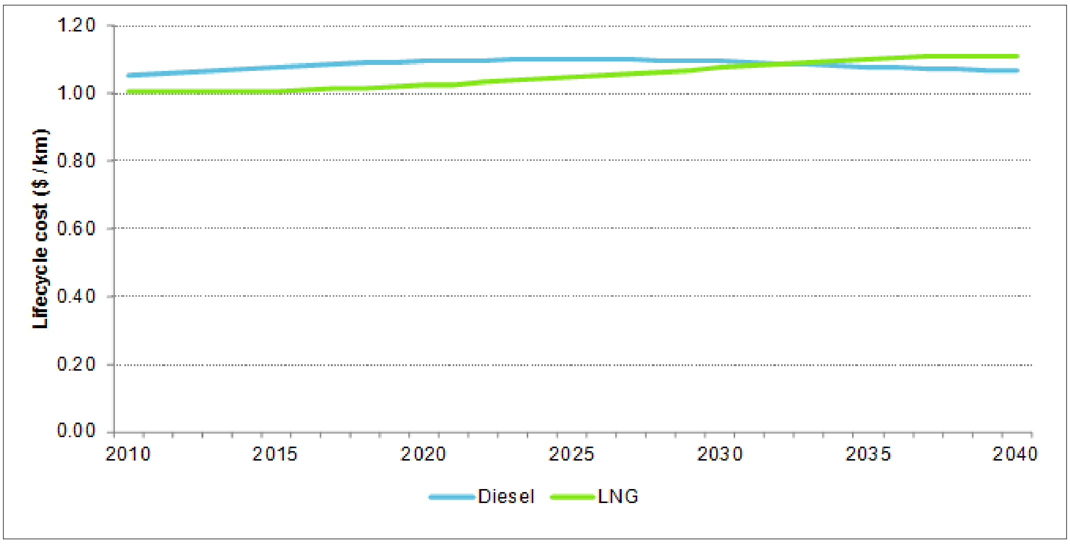
Figure 8: Lifecycle cost of buses



Source: AECOM

Analysis of the lifecycle costs from liquefied natural gas (LNG) trucks showed that a decision to purchase an LNG truck is highly dependent on the distance travelled (see **Figure 9**). A number of businesses are operating LNG trucks, primarily for long haul freight.

Figure 9: Lifecycle cost of trucks

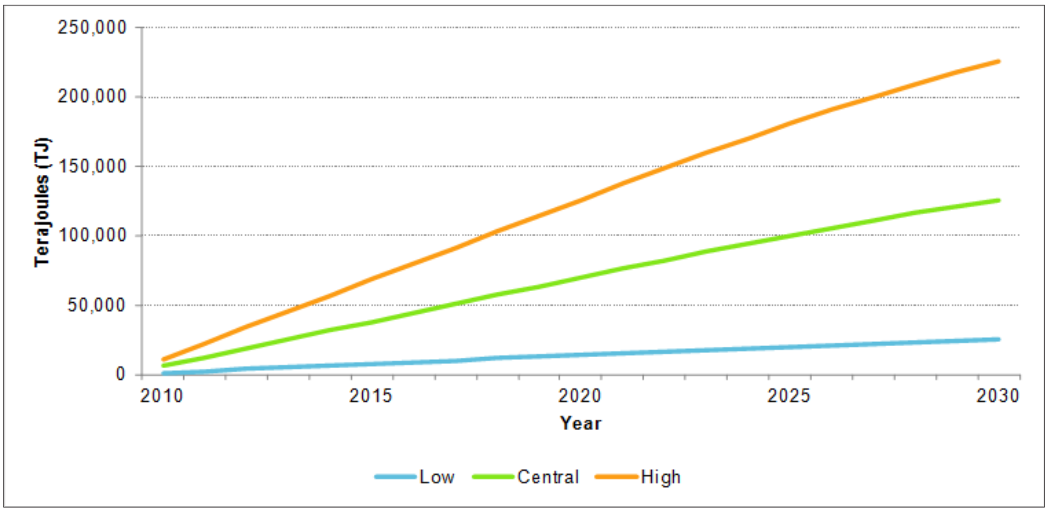


Source: AECOM

As discussed above, on purely financial grounds, take up of CNG buses and LNG trucks is expected to be low. However there are other factors such as greenhouse gas emissions reductions that mean take up may be higher than otherwise expected. Therefore, for the purposes of considering the impact of NGVs on the gas market, three take up scenarios have been considered.

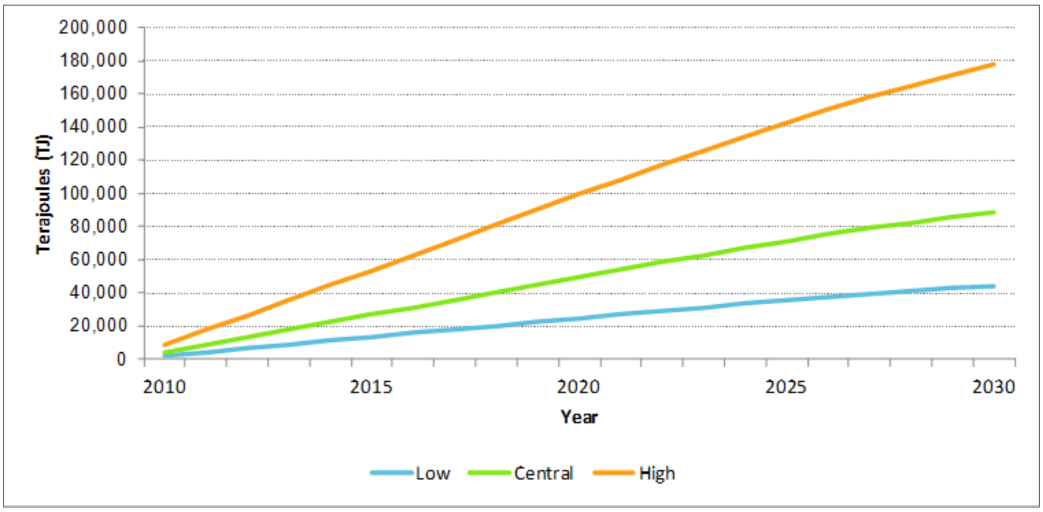
Figure 10 shows gas consumption for CNG buses assuming 10% take up, 50% take up and 90% take up. **Figure 11** shows gas consumption for LNG trucks assuming 10% take up, 20% take up and 40% take up. Under the central scenario, the total gas required would be around 65 PJ (65,000 TJ) of gas by 2015, rising to around 120 PJ of gas by 2020 and around 215 PJ of gas by 2030 in the central case. In the high case volumes could be 120 PJ of gas by 2015, rising to around 225 PJ of gas by 2020 and around 400 PJ of gas by 2030.

Figure 10: CNG bus gas consumption



Source: AECOM

Figure 11: LNG truck gas consumption



Source: AECOM

The take up of NGVs is not anticipated to create any major impacts on the gas markets...

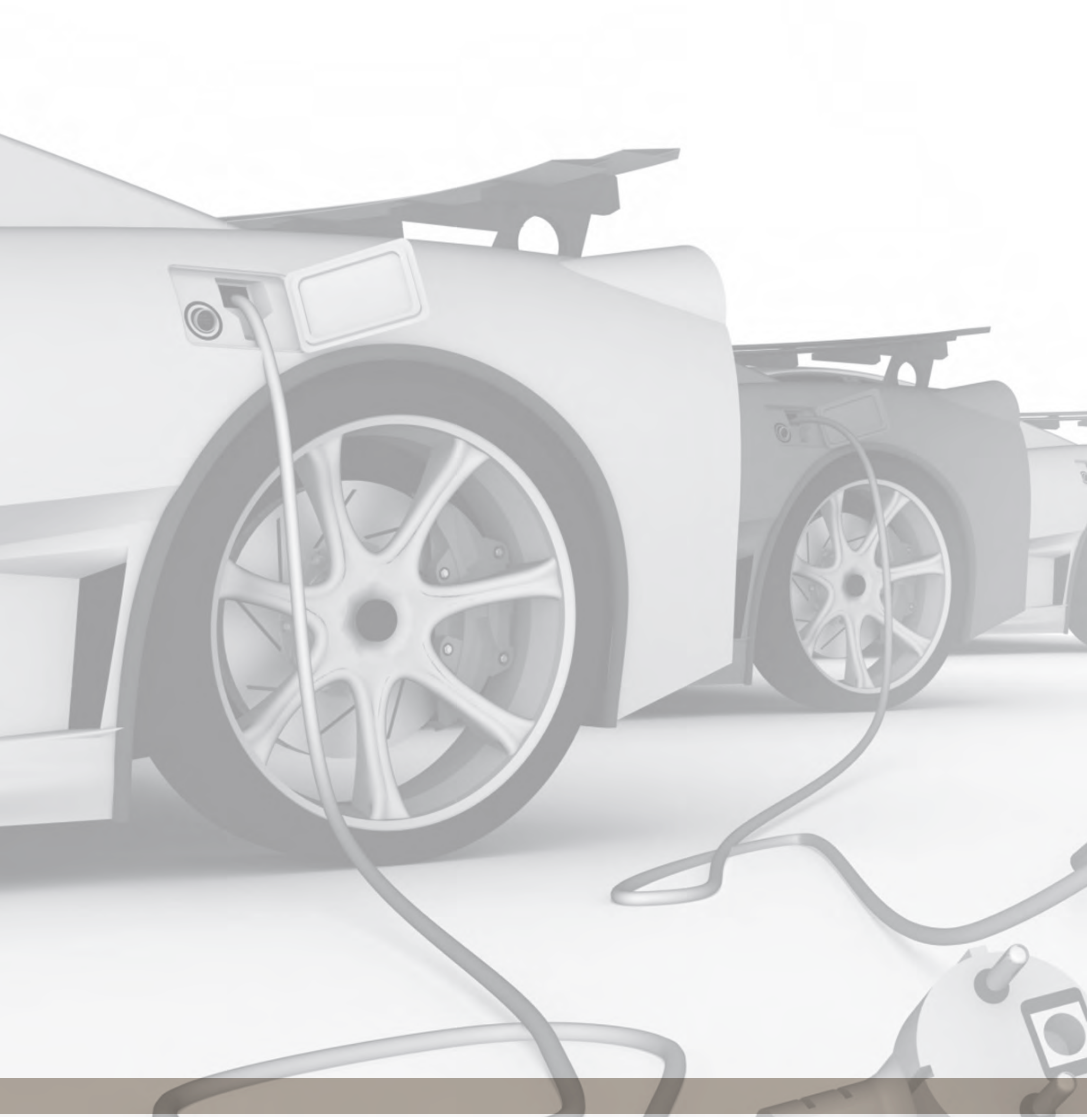
The take up of NGVs is not expected to cause significant issues with eastern or western Australian gas markets predominantly due to relatively low take up of NGVs compared to supply in the gas markets. Unlike the electricity market, timing is less important for gas vehicles refuelling than for electric vehicles, because gas networks can generally balance on a daily basis rather than instantaneously. Further, any additional load is likely to be relatively predictable on a daily basis.

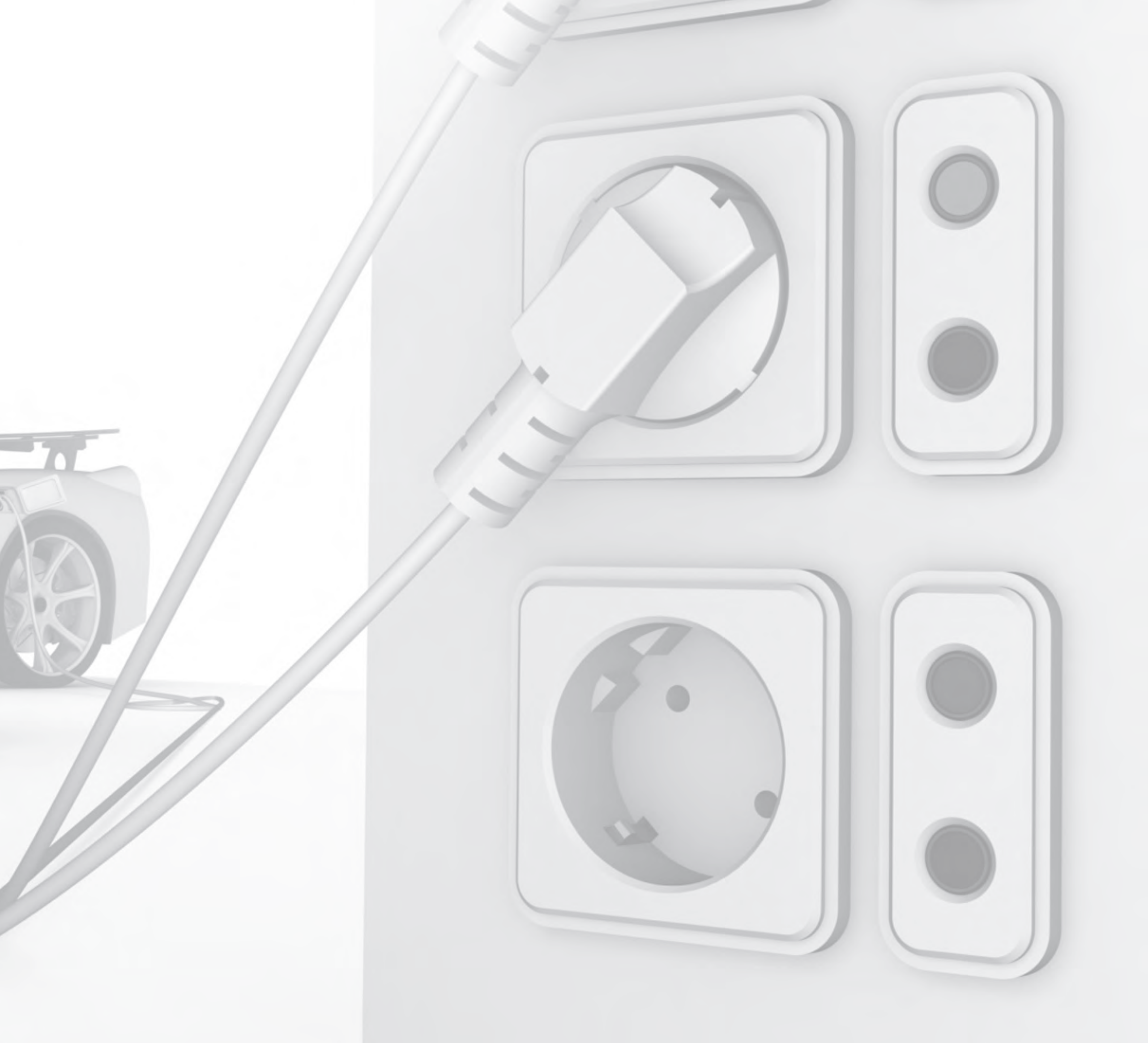
Commercial CNG or LNG vehicles will need specialised refuelling stations, which are likely to be connected either at transmission or sub-transmission level if large quantities of gas are required. Network impacts from commercial refuelling are likely to be small, and presumably customer funded, for the following reasons:

- LNG facilities are likely to require high capacity connections to transmission or sub-transmission pipelines, in order to supply sufficient quantities.
- There are already clear price signals for withdrawals through high capacity connections. These signals recognise the need for gas balancing and the scope for line-pack within high capacity gas networks.
- Facilities will need to provide storage for CNG or LNG prior to distribution to refuelling stations, so should be able to manage their withdrawals to reduce network impacts and costs.

There is unlikely to be much (if any) small customer refuelling from the gas distribution network, because take up of passenger vehicles is likely to be small. Light commercial vehicles are likely to use commercial refuelling stations which are likely to be connected at transmission or sub-transmission level as discussed above.

Potential impacts on transmission networks could be greater but as discussed above are likely to be customer funded. Steps 4 and 5 of the AEMC study will test whether these impacts can be managed within current gas regulatory arrangements, or whether changes will be needed.





Introduction

1.0

Introduction

1.1 Introduction

The Australian Energy Market Commission (AEMC) has commissioned AECOM to undertake a study to investigate the costs and benefits of Electric Vehicles (EVs) and Natural Gas Vehicles (NGVs) on the energy markets and to identify the arrangements necessary within the energy markets to facilitate the efficient take up of these vehicles. The AEMC has developed a five step analytical framework to assist with this project, as set out in **Table 3**.

Table 3: Analytical framework for considering the impact of EVs and NGVs on the energy markets

Stage of Approach	Objective
Step 1	Identify and describe the technology (either EV or NGV).
Step 2	Assess the potential take up of EVs and NGVs.
Step 3	Identify the costs and benefits of EVs and NGVs to the energy markets.
Step 4	Identify the appropriate electricity market or natural gas market regulatory arrangements necessary to facilitate the economically efficient take up of EVs and NGVs.
Step 5	Identify the changes required to achieve the appropriate electricity market or natural gas market regulatory arrangements and propose recommendations.

This report addresses steps 2 and 3 with the objective of:

- Assessing the potential take up of EVs and NGVs
- Identifying the costs and benefits of EVs and NGVs to the energy market.

The analysis in this study is intended to be high level to identify the magnitude of impacts. As such, a number of assumptions and simplifications have been made which do not alter the extent of impacts but mean that this analysis should not be used for any other purpose.

1.2 Study Area

This study considers the impact on the National Electricity Market (NEM) and the South West Interconnected System (SWIS). As such, the study area comprises Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania, South Australia and Western Australia.

1.3 Technology

Multiple vehicle configurations are possible using electric, gas and combustion components. This study focuses on five main types of technology namely internal combustion engine (ICE), hybrid electric vehicles (HEV), plug-in hybrid electric vehicles (PHEV), battery electric vehicles (BEV) and natural gas vehicles (NGV). These are described in **Table 4**. The focus of this study is on EVs that may be charged externally by the electricity grid PHEVs and BEVs, and from natural gas (NGVs). The term electric vehicles (EVs) will denote both PHEVs and EVs.

Table 4: Engine configurations

Configuration	Description
Internal Combustion Engine vehicle (ICE)	Standard Internal Combustion Engine vehicle.
Hybrid electric vehicles (HEV)	HEVs combine both an internal combustion engine with an electric engine, with electrical energy stored in batteries. Vehicle propulsion is a mix of the ICE and electric powertrains typically dependent on vehicle speed (urban/non-urban use). Hybrids are more fuel efficient than regular ICE vehicles as they take advantage of the complementary power generating characteristics of the two technologies.
Plug-in hybrid electric vehicles (PHEV)	PHEVs are similar to regular hybrids in that they combine the use of combustion and electric motors, however PHEVs are capable of being recharged by plugging in to the electricity grid. Charging can be achieved through a conventional household wall socket and at charging stations similar to existing petrol stations.
Battery Electric Vehicles (BEV)	PHEVs are similar to regular hybrids in that they combine the use of combustion and electric motors, however PHEVs are capable of being recharged by plugging in to the electricity grid. Charging can be achieved through a conventional household wall socket and at charging stations similar to existing petrol stations.
Natural Gas Vehicle (NGV)	The batteries in a PHEV are typically larger than those in a hybrid leading to a greater all-electric range that is sufficient for average metropolitan use. The trade off for larger batteries and greater range is increased battery cost, size and weight. The ICE is used to extend driving range beyond battery capacity for longer distances and to recharge the battery itself.
Compressed Natural Gas (CNG)	Vehicles that use CNG refuel their vehicles through the gas distribution network so can recharge in their base location (with an appropriate charging unit) or at a commercial refuelling station. As such, CNG vehicles typically include fleets of buses and other vehicles that operate on a return to base cycle within a limited range.
Liquefied Natural Gas (LNG)	LNG means gas that is in liquid form and requires low temperatures. LNG vehicles are typically heavy duty vehicles where LNG is a substitute for diesel.

Source: AECOM

1.4 Report Structure

The remainder of the report is structured as follows:

Chapter 2.0 provides background information on the Australian vehicle market.

Chapter 3.0 sets out our assumptions and estimates for the take up of EVs.

Chapter 4.0 sets out our assumption of charging behaviour.

Chapter 5.0 looks at the potential costs EVs may impose on the electricity market.

Chapter 6.0 looks at the potential benefits EVs may have for the electricity market.

Chapter 7.0 looks specifically at vehicle-to-grid.

Chapter 8.0 sets out our assumptions and estimates for the take up of NGVs.

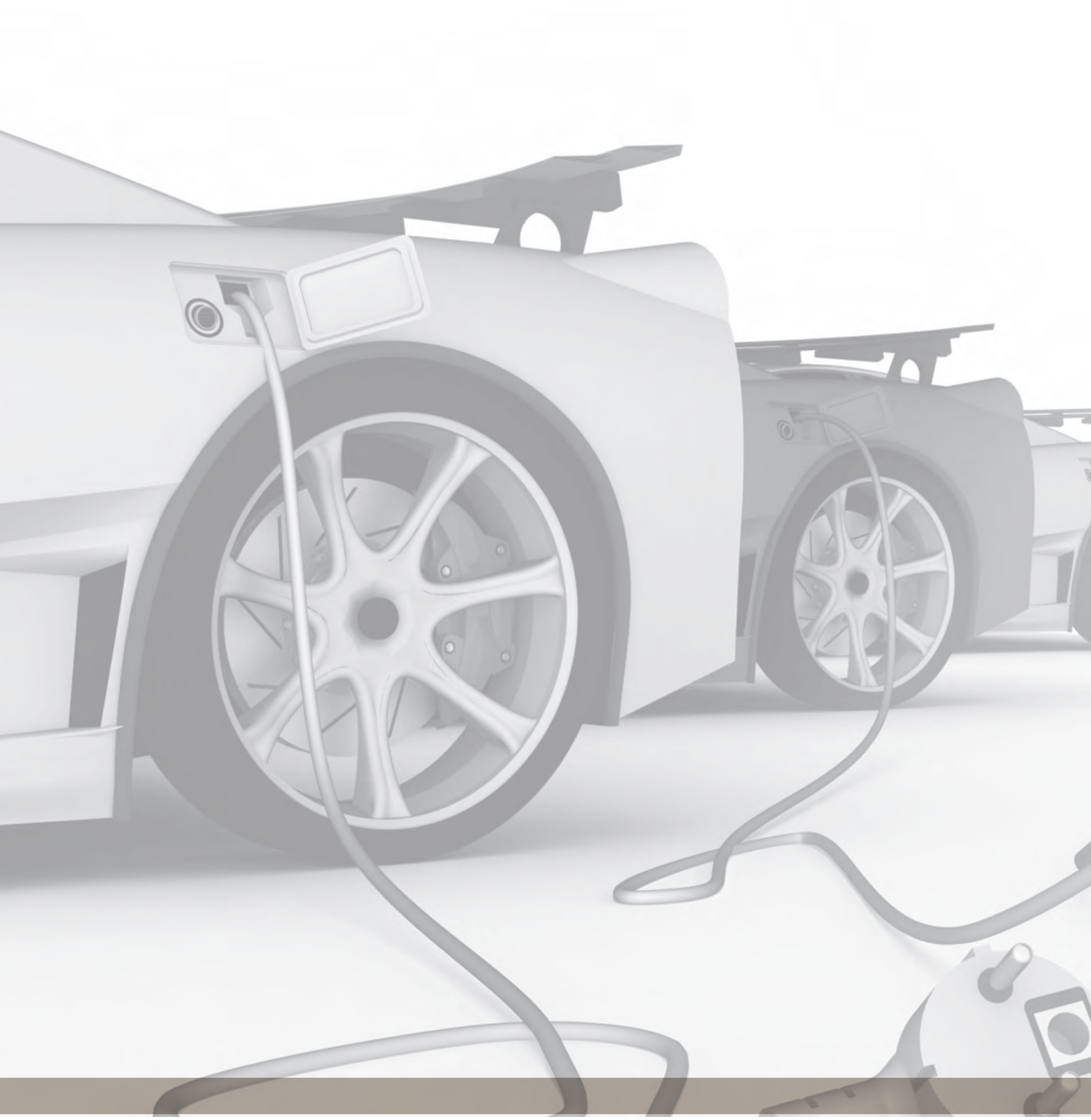
Chapter 9.0 looks at the impact of NGVS on the gas market.

Chapter 10.0 provides references used in this study.

As requested by AEMC, EVs and NGVs are discussed separately – **Chapters 3.0** to **7.0** for EVs and **Chapters 8.0** and **9.0** for NGVs.

1.5 Acronyms

Acronym Definitions			
AC	Alternating current	kW	Kilowatt
A	Ampere	kWh	Kilowatt-hour
AEO	Annual Energy Outlook	LCV	Light commercial vehicle
AEMC	Australian Energy Market Commission	LNG	Liquefied natural gas
AEMO	Australian Energy Market Operator	LPG	Liquid propane gas
AER	Australian Energy Regulator	LRET	Large-scale Renewable Energy Target
BEV	Battery electric vehicle	MJ	Megajoule
CO_2-e	Carbon dioxide equivalent	MW	Megawatt
CPRS	Carbon pollution reduction scheme	MWh	Megawatt hour
CSIRO	Commonwealth Scientific and Industrial Research Organisation	MCE	Ministerial Council of Energy
CNG	Compressed natural gas	NEM	National Energy Market
DoD	Depth of discharge	NSLP	Net System Load Profile
DC	Direct current	PJ	Petajoule
DNSP	Distribution Network Service Provider	PHEV	Plug-in hybrid electric vehicle
EVSE	Electric Vehicle Supply Equipment	SWIS	South West Interconnected System
EV	Electric Vehicle	TJ	Terajoule
EIA	Energy Information Administration	TOU	Time of use
ENA	Energy Networks Association	TNSP	Transmission Network Service Provider
FCAS	Frequency Control Ancillary Services	U.S.	United States
GMLG	Gas Market Leaders Group	VKT	Vehicle kilometres travelled
GJ	Gigajoule	V2G	Vehicle-to-grid
GW	Gigawatt	V2H	Vehicle-to-home
GWh	Gigawatt hour	V	Volt
GST	Goods and Services Tax		
Hz	Hertz		
HEV	Hybrid electric vehicle		
ICE	Internal combustion engine		
IEA	International Energy Agency		



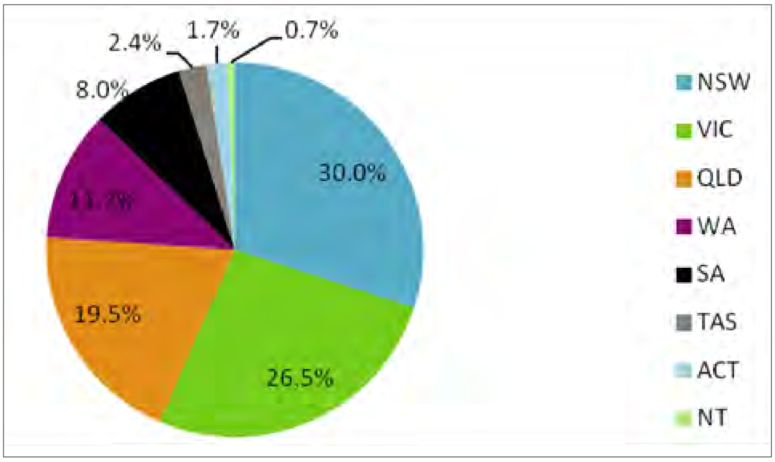
Background to the Australian Vehicle Market

2.0

Background to the Australian Vehicle Markets

The total number of vehicles on Australia's roads in 2011 is estimated to be over 16 million (ABS 2011). **Figure 12** shows that New South Wales has the highest number of vehicles on the road in 2011, with over 4.7 million. Together, New South Wales, Victoria and Queensland have over three quarters of vehicles. In 2010, more than one million new vehicles were sold in Australia, with around 820,000 being passenger vehicle sales.

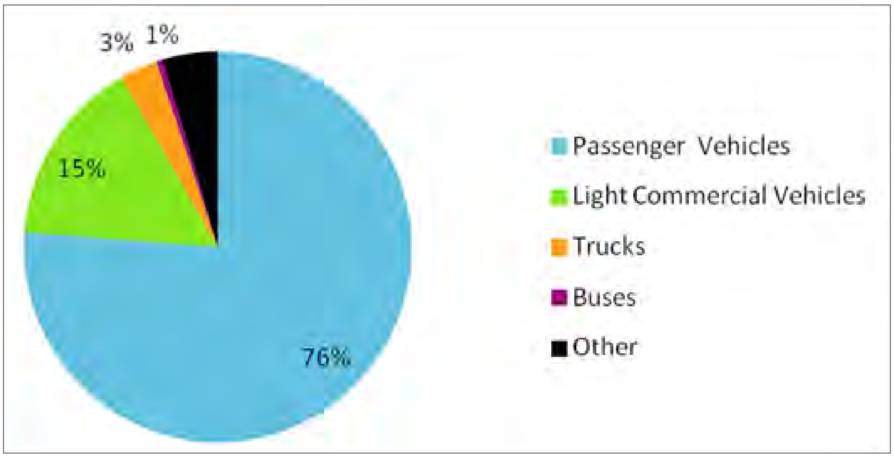
Figure 12: Passenger vehicles in Australia in 2011



Source: ABS (2011)Source: ABS (2011)

Figure 13 shows that 76 per cent of vehicles are passenger vehicles, 15 per cent light commercial vehicles and around 3 per cent are trucks.

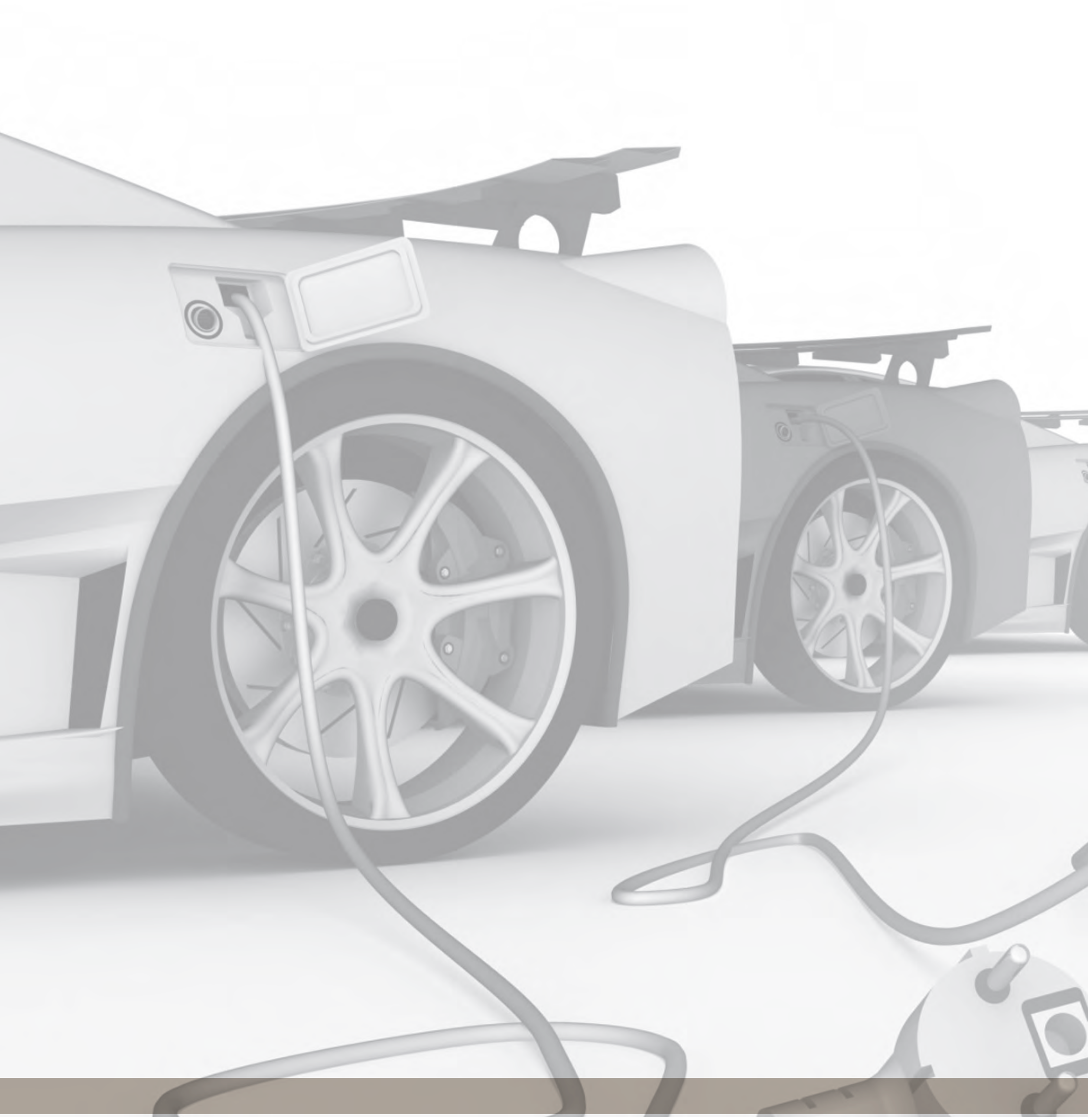
Figure 13: Vehicle types in Australia in 2011

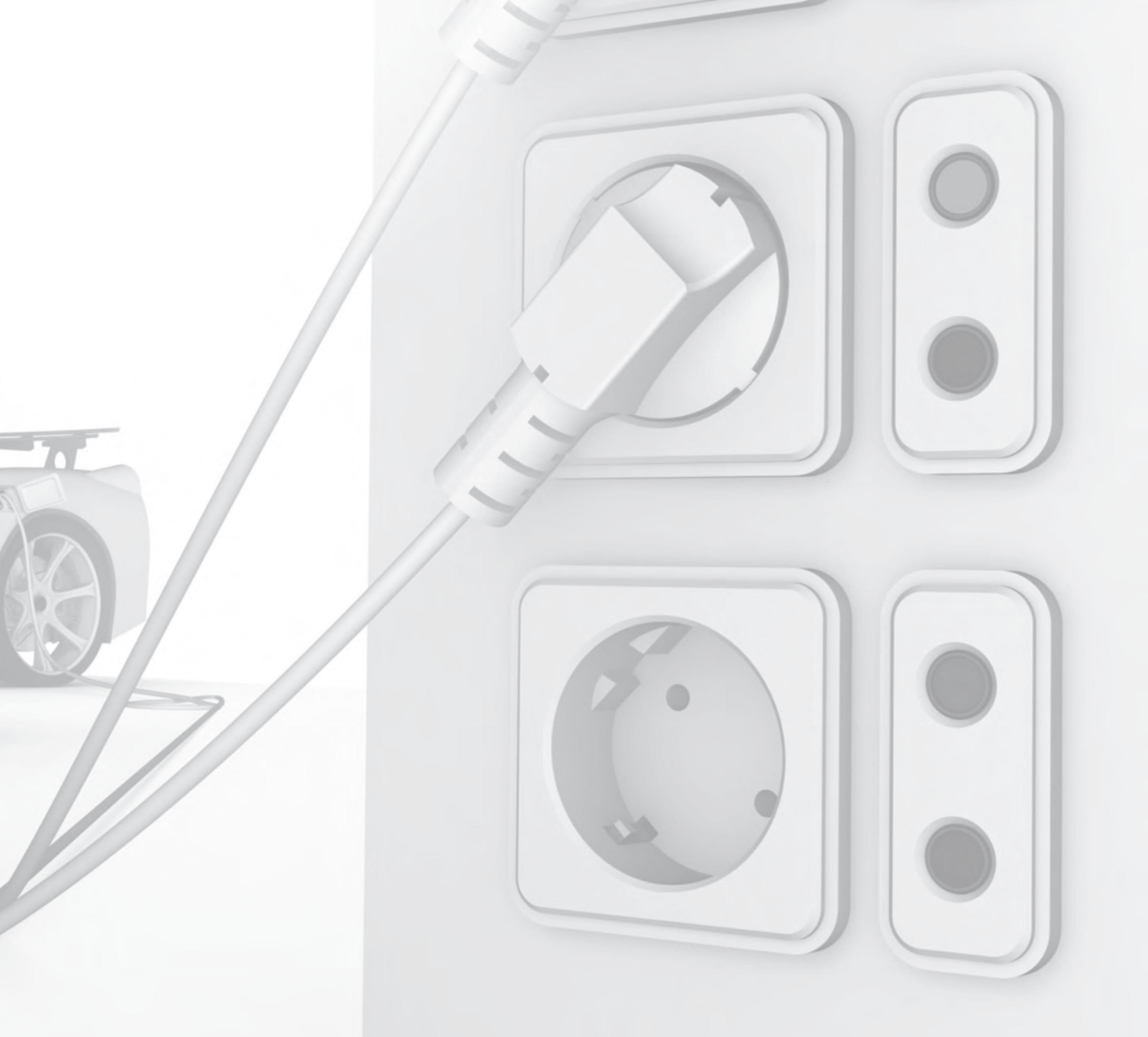


Source: ABS (2011)

Australian passenger vehicles are typically driven for around 12 to 14 kilometres per day, depending on which state they are from. Buses travel an average of around 30 kilometres per day, articulated trucks[1] around 70 kilometres per day and rigid trucks around 20 kilometres per day (ABS 2010b).

1. An articulated truck consists of a prime mover and trailer together.





Electric Vehicles

3.0

Electric Vehicles

3.1 Introduction

Assessing the potential take up in demand for EVs is necessary to determine the impact that EVs will have on the electricity markets. The take up of these EVs is dependent on a number of factors including the relative prices, relative running costs including fuel and maintenance and the availability of charging and distribution infrastructure. This chapter provides an outline of AECOM's methodology for estimating take up, presents key assumptions and discusses the results.

3.2 Overview of methodology

AECOM has previously developed a bespoke passenger and light commercial vehicle (LCV) choice model that estimates the potential take up of EVs through its 'Economic Viability of Electric Vehicles' studies in New South Wales and Victoria. The studies are publicly available:

- Victorian Study: AECOM (2011) available at http://www.transport.vic.gov.au/__data/assets/pdf_file/0010/33499/Economic-Viability-of-Electric-Vehicles-in-Victoria-rev-C-final-issued.pdf
- NSW Study: AECOM (2009) available at http://www.environment.nsw.gov.au/resources/climatechange/ElectricVehiclesReport.pdf

This current study draws substantially on the approach and assumptions of the previous studies, as only high level estimates of vehicle sales for each state and territory were required in order to establish the magnitude of energy consumption and vehicle sales for further analysis.

AECOM's model estimates the take up of passenger vehicles, LCVs and taxis based on a set of assumptions related to vehicle prices, operating costs, charging infrastructure, available supply and so on. These assumptions are input into a vehicle choice model that estimates the proportion of new vehicle sales by engine type (ICE, HEV, PHEV, BEV). Estimates are established for each state.

Figure 14: Overview of approach to estimating take up of electric vehicles

Many studies of this type do not estimate take up of different engine types, but rather make assumptions based on experience elsewhere. In our previous studies, AECOM directly estimated take up of EVs for two reasons. Firstly, as this is a new market, there is not a lot of information on past experience from which to draw meaningful assumptions about the future of EVs in Australia. Secondly, by directly estimating take-up it is possible to consider the impact of various potential sensitivities around prices (such as electricity price, fuel price, vehicle price) and how these affect take up.

Consumers consider a number of factors when considering which vehicle to purchase. Whilst the financial cost plays a significant role, the decision of what vehicle to purchase is influenced by consumer preferences. The approach used in this study tries to capture these preferences. After an extensive literature review on the factors affecting the decision to purchase a vehicle, AECOM developed a vehicle choice model which takes into account the vehicle purchase cost, fuel cost, vehicle range, emissions, availability of refuelling / charging infrastructure and multi-fuel bonus.[2] For full details of the parameters used in AECOM's vehicle choice model please see our previous studies (AECOM, 2011; 2009). AECOM's vehicle choice model calculates the proportions of vehicle sales by engine type, which are applied to forecasts of new vehicle sales to obtain number of vehicles and energy usage.[3]

2. A synthetic multinomial logit choice model was developed to forecast future market shares for ICE, HEV, PHEV and BEV. A multinomial logit model is called synthetic when elasticities are imposed on, rather than derived from, the choice model and where constants are calibrated to better reflect current market shares of existing vehicle classes.

3. This means that factors such as how many vehicles a household has access to are not considered explicitly but are considered through the vehicle choice parameters such as vehicle range and charging infrastructure (which will be more important for households with one vehicle).

3.3 Assumptions

This study makes assumptions about key factors that affect the take up of EVs. There are inherent uncertainties in making forward estimates, so it is important to understand the likely range of take up and the key influencing factors. Therefore, this study has developed scenarios around the key factors identified as affecting the take up of EVs. Three scenarios were modelled:

- Central scenario: represents a likely take up scenario given currently available information and central assumptions on key factors.
- High scenario: represents an upper bound on take up if all of the key factors are favourable to supporting the take up of EVs.
- Low scenario: represents a lower bound on take up if all of the key factors are unfavourable to supporting the take up of EVs.

The following sections provide a high level summary of key assumptions. Given that the primary objective of this study is to identify the impacts of EVs on the electricity market, available NSW and Victorian data were used as a proxy for the other states and territories in the modelling. Specifically, this relates to market shares of engine size for passenger vehicles, annual vehicle kilometres travelled and the share of passenger vehicle segments by VKT and engine size. Further detail on assumptions is provided in AECOM (2011).

3.3.1 Key assumptions

3.3.1.1 General assumptions

The estimates of EVs focus on passenger vehicles and light commercial vehicles, which together account for 92% of all vehicles in Australia. Whilst some electric buses and trucks do exist they are very expensive due to the weight to battery ratio, have limited vehicle range and are unlikely to see significant take up in the next 10 to 15 years until battery prices significantly reduce.

This study does not consider other EVs such as electric golf buggies and electric bikes where additional take up is expected to be smaller in magnitude than in motor vehicles and the impact on the electricity market is likely to be smaller because the distances travelled will typically be small and charging behaviour is likely to be more predictable and easier to incentivise to off-peak charging.

Fleet sales are not considered separately and this study assumes the decision about which vehicle to purchase remains a consumer choice and the majority of people driving fleet vehicles will take their vehicle home at the end of the day. Private fleets are more likely to place a higher weight on the financial viability of EVs which may result in delayed take up of EVs until the upfront cost reduces. However, a large proportion of fleet vehicles are likely to be government owned which will place a higher weight on the environmental benefits of EVs. Most fleet vehicles typically drive further than household vehicles so will benefit more from the fuel cost savings of EVs. Some of the proposed business models, which lease the EV to reduce the upfront vehicle purchase price, may result in higher take up for fleet vehicles in early years as they are likely to benefit more from the fuel cost savings. As our vehicle choice model estimates take up of EVs for different vehicle sizes and distances travelled, fleet vehicles will be captured under these categories.

3.3.1.2 Vehicle sales

As discussed in **Section 2.0**, there are around 800,000 passenger vehicles sold in Australia each year, with around 90 per cent of these sold within the NEM region and around 10 per cent in WA. Whilst vehicle sales vary year by year, there has been a long term trend for annual growth of around 1% to 2.5% depending on the state. **Table 4** sets out our assumptions on future growth in vehicle sales. The central case is based on trend annual growth; the low scenario assumes a trend for fewer vehicles per household so the average long term trend decreases by 0.5% in each state relative to the central case scenario; and the high scenario assumes a trend for more vehicles per household so the average long term trend increases by 0.5% in each state relative to the central case scenario.

Overall sales of passenger vehicles were segmented by vehicle size and average annual kilometres travelled (a total of nine segments) to produce estimated sales for each segment. This is because take up is expected to vary by vehicle size and distance travelled due to disproportionally higher costs of larger vehicles in early years and the fact that people travelling larger distances will benefit more from the fuel efficiency savings.

Table 5: Vehicle sales

	VIC	NSW	ACT	QLD	TAS	SA	WA
2010 passenger sales	232,800	258,300	14,100	157,400	14,800	52,600	90,400
Annual growth							
Low	1.0%	0.5%	0.5%	2.0%	1.0%	1.5%	2.0%
Central	1.5%	1.0%	1.0%	2.5%	1.5%	2.0%	2.5%
High	2.0%	1.5%	1.5%	3.0%	2.0%	2.5%	3.0%

Source: AECOM based on ABS' historic Motor Vehicle Census data

3.3.1.3 Vehicle price

In AECOM's previous studies, new vehicle prices were estimated from a survey of global EV products. An equivalent ICE vehicle was used for the price of ICE vehicles to ensure a consistent comparison.

A review of the price assumptions from AECOM (2011) was conducted for the present study to check if there had been significant changes in vehicle prices. Whilst there seem to be changes in the world supply outlook for non-ICEs, the overall findings suggested that vehicle prices had not changed greatly from the previous assumptions. Therefore this study has retained the vehicle purchase price assumptions presented in AECOM (2011).The vehicle price of an EV currently ranges from around $40,000 to $100,000 depending on the vehicle size. Price premiums vary with the engine type and vehicle size, with the premium for PHEVs and BEVs ranging from $21,000 to $50,000 representing the increase in battery requirements for larger cars.

The previous studies also revealed that, for the cars available in Australia (HEVs), there is a premium of around $10,000 over US prices. This likely reflects the supply constraints for non-ICE vehicles in Australia. It has been assumed that there will be similar supply constraints for PHEVs and BEVs. Some of the business models being proposed include leasing arrangements that reduce the upfront purchase costs of an EV. This is covered in our high take up scenario where EVs reach price parity with ICE vehicles quicker. **Table 6** summarises prices assumed for different engine types and sizes.

Table 6: Vehicle prices in 2010 by size and configuration

Car size	ICE*	HEV	PHEV	BEV
Price premium relative to ICE				
Passenger Small	N/A	$17,000	$21,000	$21,000
Passenger Medium	N/A	$17,000	$30,000	$30,000
Passenger Large	N/A	$18,000	$50,000	$50,000
Light Commercial Vehicle	N/A	$20,000	$64,000	$64,000
Taxi	N/A	$18,000	$50,000	$50,000
New vehicle price				
Passenger Small	$20,000	$37,000	$41,000	$41,000
Passenger Medium	$27,000	$44,000	$57,000	$57,000
Passenger Large	$48,000	$66,000	$98,000	$98,000
Light Commercial Vehicle	$40,000	$60,000	$104,000	$104,000
Taxi	$48,000	$66,000	$98,000	$98,000
Price parity with ICE				
Year	N/A	2020	2025	2025

Source: AECOM and Dr. Andrew Simpson. * An equivalent ICE vehicle was used for the price of ICE vehicles to ensure a consistent comparison.

3.3.1.4 Vehicle price reductions

The future cost reduction of battery packs will play a significant role in bringing down the price of EVs alongside general improvements in drive train technology. However, there is no consensus about the future trajectory of the battery cost curve; with estimates of battery price in 2020 ranging from $250/kWh to $1105/kWh.[4]

There has been a lot of funding in recent years into battery research to reduce costs, reduce weight and improve life. A recent study by the US Department of Energy (2010) on the impact of US investment in batteries estimated that battery prices will fall by 70% by 2015, a further 50% by 2020, and a further 30% by 2030 significantly reducing the purchase price of EVs. This highlights how quickly battery performance and prices could change, particularly with increased investment, and the importance of monitoring the battery industry.

Assumptions on when price parity with ICE vehicles is achieved have been retained from the Victorian study (AECOM, 2011) which was informed by a literature review and consultation with industry. The central scenario assumes HEVs will achieve price parity in 2020, PHEVs and BEVs achieve price parity in 2025. The low and high scenarios assume price parity for all electric vehicle variants in 2030 and 2020 respectively.

3.3.1.5 Supply constraints

Whilst a large number of electric vehicle models are expected to be launched in the near future, there is some uncertainty as to how many will be produced and whether this will be sufficient to meet consumer demand.

World supply estimations for BEVs and PHEVs are constantly being revised as new production plans are announced by manufacturers. In AECOM's 2009 and 2011 studies, global production volume was expected to approach one million units by 2015 based on announcements made in the automotive media. A similar projection has been made by a June 2011 publication by the International Energy Agency (IEA), where 0.9 million units of BEVs and PHEVs are expected to be in production by 2015 and about 1.4 million units per year by 2020 (IEA, 2011).

There is a currently a large amount of uncertainty around world supply constraints for EVs, and given this uncertainty the present study has adopted the same supply constraints assumption as the two previous AECOM studies for HEVs and BEVs, but with sensitivity around the timing of the supply constraint in the different take up scenarios. The assumptions for PHEVs are assumed to be equal to those for BEVs.

Whilst Australia has traditionally not been seen as a key market, it is possible that electric vehicle manufacturers will focus their available supply and marketing efforts on countries with suitable infrastructure, consumer preference and driving habits rather than simply distribute EVs to different markets in the same proportions as conventional vehicles. In addition, companies like Better Place have made agreements with vehicle manufacturers to ensure the availability of vehicles in locations where infrastructure investments will be made. As such, our high take up scenario has supply constraints ended by 2015.

Table 7 shows the vehicle supply parameters applied in this study.

Table 7: Vehicle supply parameters

Parameter	HEV	PHEV	BEV
Australian proportion of global market	1%	1%	1%
Year of first availability	2009	2012	2012
End of supply constraint - Low - Central - High	 2025 2015 2015	 2025 2020 2015	 2025 2020 2015
Initial world supply	1,000,000	500,000	500,000
Annual growth in supply: - To 2015 - From 2016 onwards	 35% 35%	 40% 30%	 40% 30%

Source: AECOM and Dr. Andrew Simpson based on industry consultation

4. See AECOM (2010), **Section 2.6.1** for details.

3.3.1.6 Fuel and electricity prices

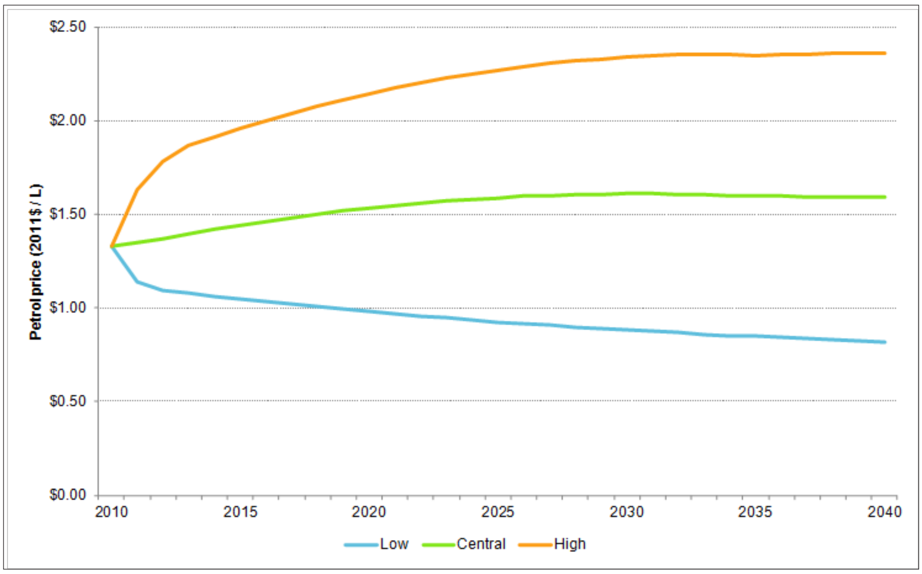
One of the major advantages of EVs over ICE vehicles is the potential cost savings from using electricity instead of petrol or diesel. This section summarises our assumptions on future prices of fuel and electricity.

Crude oil based prices

In order to estimate Australian retail petrol prices, this study adopts the methodology presented in Gargett (2011) that converts global crude oil prices into Australian retail pump prices. Crude oil price projections have been taken from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2011 reference case, high price and low price scenarios (AEO, 2011).

These fuel prices will be used in the low, central and high scenarios. The carbon price does not apply to passenger vehicles and light transport vehicles so have not been included in this analysis.

Figure 15: Petrol prices



Source: AECOM

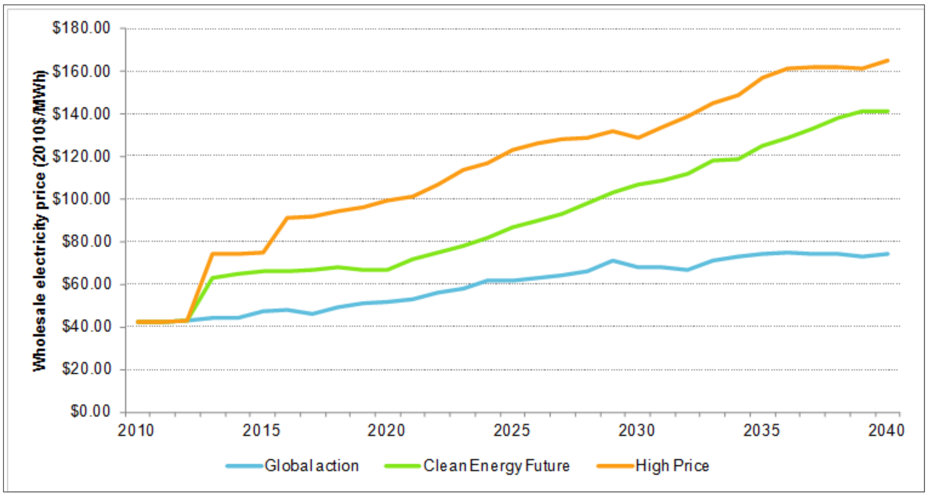
Electricity

Electricity prices paid by consumers are modelled as the sum of wholesale electricity prices, network costs and retail margins, and any carbon pricing component (selected through the carbon emission policy options).

Assumptions on future electricity prices are drawn from the Strong growth low pollution: modelling a carbon price report released by the Australian Treasury in July 2011, which takes into consideration the most up-to-date carbon pricing scenarios for their modelling. For the Central take up scenario the ‘Clean Energy Future’ electricity projection has been adopted; for the low and high take up scenarios the ‘High Price’ and ‘Global Action’ electricity projections were adopted respectively.[5] **Figure 16** shows the electricity prices used in this analysis.

5. The “global action” scenario assumes staged global action on climate change that is broadly consistent with low estimates of the national pledges incorporated in the Copenhagen Accord and Cancun agreement, continuing to at least 2050, but with no carbon price in Australia and no additional mitigation policies. The “high carbon” price scenario assumes a world with a more ambitious 450 ppm stabilisation target and an Australian emission target of a 25 per cent cut on 2000 levels by 2020 and an 80 per cent cut by 2050.

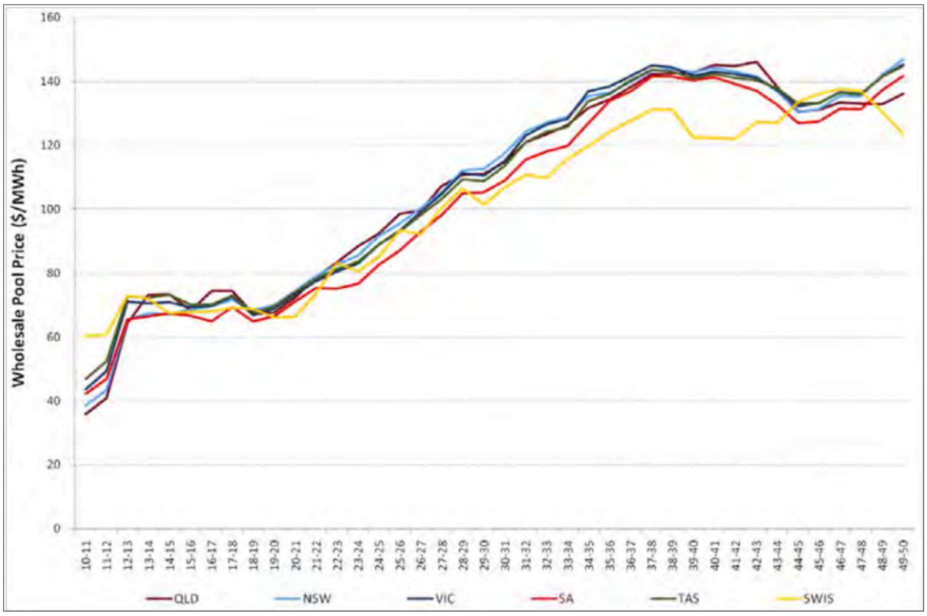
Figure 16: Wholesale electricity prices



Source: Treasury (2011)

This study uses one electricity price for all states and territories. In practice, the wholesale price of electricity will vary between states reflecting the load and generation characteristics of each state, in addition to the trading behaviour of the market participants. For example, **Figure 17** shows the forecast electricity price for each state as prepared by ROAM Consulting (2011) as input to the Treasury modelling of the Clean Energy Future package. Variations between state wholesale prices can be observed however prices are relatively clustered and follow a similar profile. Except for the short term to 2013 and in the long run from about 2030-onwards, wholesale prices in Western Australia also follow a similar profile to the other states. As a result of using one electricity price for all states and territories, the actual take up of EVs in each state may be slightly higher or lower than those presented in **Section 3.4**. However, sensitivity analysis shows that take up is less sensitive to the electricity price than other factors such as vehicle purchase price and higher oil prices.

Figure 17: Wholesale pool electricity price forecasts for each state – central policy



Source: ROAM (2011)

The introduction of a carbon price under the Clean Energy Future package will favour traditional ICE vehicles over EVs. Whilst electricity prices will rise under the carbon price, traditional fuel sources such as petrol and diesel will be exempt for passenger and light commercial vehicles.

This study assumes electricity prices do not increase significantly as a result of EVs. However, as discussed in subsequent sections of this report, there could be significant costs of integrating EVs into the electricity market, particularly if the majority of charging occurs in peak periods and results in a need for increased investment in peak load. For the purpose of forecasting take up of EVs, this study assumes that (1) measures are in place to minimise the impact on peak load and (2) any additional costs will be spread across all electricity customers. This is current practice for other higher electricity consuming goods such as air conditioners. Further, whilst the increase in peak load from EVs could be significant if it is unmanaged, it is small relative to the anticipated increases that will occur without EVs as shown in **Section 5.2.1.3**. It is possible that the increased costs from EVs will be charged to EV customers only. In this case, electricity prices could be significantly higher than assumed and take up of EVs lower. This would likely impact take up in vehicles that travel smaller distances more as these vehicles benefit less from fuel cost savings.

3.3.1.7 Fuel efficiency

Fuel consumption for all engine types has been retained from AECOM (2011). ICE consumption values were estimated from a survey of vehicles on Green Vehicle Guide and ABS data.[6] Efficiencies for hybrids are modelled relative to ICE efficiencies as investments in hybrid technology are expected to generate continued efficiency gains over ICE. Efficiencies for EVs were identified through a survey of current and planned models. The efficiency of a PHEV is simply the efficiency of the ICE powertrain and EV powertrain applied to the respective distanced travelled propelled by each powertrain technology. Future improvements in fuel efficiencies were estimated from a literature review and industry consultation. See AECOM (2011) for further discussion on these assumptions.

Table 8 summarises the assumed fuel efficiencies for each vehicle type in 2010 and the annual change (improvement) in efficiency.

Table 8: Fuel efficiency parameters in 2010 and annual change

	Petrol (L/100km)	Diesel (L/100km)	LPG (L/100km)	Electricity (kWh/100km)	Annual change
ICE					
Passenger small	7.8	5.9	12.3	N/A	0.84%
Passenger medium	9.7	7.3	15.3	N/A	0.84%
Passenger large	13.8	10.4	21.8	N/A	0.84%
Light Commercial Vehicle	11.2	8.4	12.0	N/A	0.84%
Taxi	13.8	10.4	21.8	N/A	0.84%
HEV					
Passenger small	5.3	N/A	N/A	N/A	0.43%
Passenger medium	7.3	N/A	N/A	N/A	0.43%
Passenger large	11.2	N/A	N/A	N/A	0.43%
Light Commercial Vehicle	8.4	N/A	N/A	N/A	0.43%
Taxi	11.2	N/A	N/A	N/A	0.43%
BEV					
Passenger small	N/A	N/A	N/A	19.0	0.45%
Passenger medium	N/A	N/A	N/A	16.5	0.45%
Passenger large	N/A	N/A	N/A	21.5	0.45%
Light Commercial Vehicle	N/A	N/A	N/A	18.5	0.45%
Taxi	N/A	N/A	N/A	21.5	0.45%

6. http://www.greenvehicleguide.gov.au/

	Petrol (L/100km)	Diesel (L/100km)	LPG (L/100km)	Electricity (kWh/100km)	Annual change
PHEV					
Passenger small	7.8	N/A	N/A	19.0	0.84%/0.45%
Passenger medium	9.7	N/A	N/A	16.5	0.84%/0.45%
Passenger large	13.8	N/A	N/A	21.5	0.84%/0.45%
Light Commercial Vehicle	11.2	N/A	N/A	18.5	0.84%/0.45%
Taxi	13.8	N/A	N/A	21.5	0.84%/0.45%

Source: AECOM and Dr. Andrew Simpson; ABS; Green Vehicle Guide.

3.3.1.8 Vehicle range

One of the disadvantages of BEVs over ICE vehicles is the limited vehicle range. Even though the average daily distance travelled is around 12 to 14 kilometres a day (See **Section 2.0**) and drivers do not need a vehicle range of 550km (a typical vehicle range in an ICE vehicle) they still value the option to drive further and worry about the possibility of running out of charge – range anxiety. Vehicle range assumptions, based on a survey of electric vehicles undertaken for AECOM's previous studies, are shown in **Table 9**.

Table 9: Vehicle range assumptions for 2010 (km)

Category	ICE	HEV	PHEV	EV
Passenger Small	500	500	500	120
Passenger Medium	550	550	550	200
Passenger Large	550	550	550	300
LCV	550	550	550	160
Taxi	550	550	550	300

Source: AECOM (2009, **Section 4.13**)

The vehicle range for all vehicles grows over time due to fuel efficiency improvements. ICE and HEV vehicle range increases in line with fuel efficiency improvements. EVs are assumed to grow due to fuel efficiency as well as battery improvements. It is assumed a battery storage capacity improvement of 5% per annum, equivalent to a doubling in vehicle range every 12-13 years. This is consistent with industry expectations which expect a doubling in vehicle range every 10 years. PHEV vehicle range will increase due to both increases in the ICE range and the EV range. It has been assumed to be the maximum of either the ICE range or EV range.

3.3.1.9 Infrastructure

A key factor in the vehicle choice model is the availability of public vehicle charging infrastructure relative to ICE vehicles (e.g. availability of battery swap stations or public charging points relative to the number of petrol stations). The assumptions of level of infrastructure are summarised in **Table 10**.

Table 10: Proportion of available EV charging infrastructure relative to ICE vehicles infrastructure (e.g. service stations)

Category	Low	Central	High
ICE	100%	100%	100%
HEV	100%	100%	100%
PHEV	100%	100%	100%
EV	40% By 2040	80% By 2040	120% By 2040

Source: AECOM

The costs of charging infrastructure are retained from AECOM (2011) and are presented in **Table 11**. The costs of residential charging is assumed to be an upfront cost, along with the vehicle price as set out in **Table 6** that is faced by the consumer. Business charging at dedicated work places will be a combination of residential charging and public charge units. The costs of installing charging infrastructure will vary in each property depending on the circuit available. See **Section 4.3.1** for more discussion on home charging.

If an EV owner is going to use either vehicle-to-grid (V2G) or vehicle-to-home (V2H) there will be additional infrastructure costs with wiring, metering and communication to the grid. The V2G and V2H concept is relatively new and as such the costs are less defined. Both of these concepts are discussed in more detail in **Section 7.0**.

Table 11: Cost of charging infrastructure

Category	Low	Central	High
Residential charging (Level 1 and 2 – single phase only)	$1,500		
Commercial charging - public charge unit (Level 2)	$3,000		
Commercial charging – dedicated commercial premises(DC fast charge or battery swap)	$500,000		
Reduction in cost by 2020	20%	50%	80%

Source: AECOM

3.3.2 Summary of assumptions

Table 12 summarises assumptions in the central, high and low scenario. Detailed discussion of assumptions can be found in AECOM (2011).

Table 12: Summary of key assumptions for each scenario

Assumptions	Scenarios		
	Low	Central	High
Vehicle sales	Current (2010): Taken from ABS (2010a) Annual growth: assumes a trend for fewer vehicles per household so the average long term trend decreases by 0.5% in each state relative to the central case scenario.	Current (2010): Taken from ABS (2010a) Annual growth: average trend growth continues (around 1-2.5% pa in each state)	Current (2010): Taken from (2010a) Annual growth: assumes a trend for more vehicles per household so the average long term trend increases by 0.5% in each state relative to the central case scenario.
Vehicle prices – current prices	Same as central scenario.	Prices in 2012: HEV: Small: $37,000, Medium: $44,000, Large: $66,000, LCV:$60,000 PHEV / EV: Small: $41,000, Medium: $57,000, Large: $98,000, LCV:$104,000 (A review of current prices suggests there has not been significant movement since the Victorian study was undertaken.)	Same as central scenario.
Vehicle prices – year in which reaches price parity with ICE vehicle	HEV: 2025 PHEV: 2030 EV: 2030	HEV: 2020 PHEV: 2025 EV: 2025 (As per Victorian study)	HEV: 2015 PHEV: 2020 EV: 2020
Supply constraints There are expected to be global supply constraints until at least 2012 and as such, a supply constraint has been built into the model to ensure it reflects current market conditions.	Supply into Australia becomes unconstrained at 2025 for HEVs, PHEVs and BEVs respectively.	HEV – 1,000,000 HEVs currently in global production, growing by 35% per year. Australia will receive 1% of global supply. Supply will be constrained until 2015. PHEV – by 2012 there will be 150,000 PHEVs in global production and 1% of these will reach Australia. Production will grow at 20% per year and be constrained until 2020. BEV – by 2012 there will be around 500,000 BEVs in global production and 1% of these will reach Australia. Production will grow at 40% per year until 2015 and by 30% per year from 2016 onwards. Supply will be constrained until 2020.	Australia is seen as a key EV market and Supply of non-ICE vehicles to Australia is unconstrained from 2015.

Assumptions	Scenarios		
	Low	Central	High
Fuel efficiency	Same as central scenario.	ICE Small: 7.8L/100km, Medium: 9.7L/100km, Large: 13.8L/100km, LCV: 13.8L/100km 37% improvement between 2006 to 2050 HEV Small: 47% more efficient than ICE; Medium: 32% more efficient than ICE, Large: 23% more efficient than ICE, LCV: 33% more efficient than ICE. Improvements with an ICE will decrease by 18% between 2010 and 2050 PHEV Assumes currently use 50% EV drive train and 50% ICE power train. This increases to 80% EV / 20% ICE by 2035. BEV Small: 19kWh/100km; Medium: 16.5kWh/100km, Large: 21.5kWh/100km, LCV: 18.5kWh/100km. 20% improvement between 2006 and 2050.	Same as central scenario
Conventional fuel prices	Based on low EIA (2011) oil price forecasts.	Based on reference EIA (2011) oil price forecasts. Oil price reaches around $110/barrel by 2020, and $125/barrel by 2030.	Australia is seen as a key EV market and Supply of non-ICE vehicles to Australia is unconstrained from 2015.
Electricity prices	Based on Treasury (2011) forecasts under a high carbon price scenario once the scheme transitions to a flexible emissions trading scheme in 2015. Price reaches around $99/MWh by 2020, and $129/MWh by 2030.	Based on Treasury (2011) forecasts of wholesale energy price under the Clean Energy Future. Price reaches around $67/MWh by 2020, and $107/MWh by 2030.	Based on Treasury (2011) forecasts under a global action scenario which assumes no Australian carbon price. Price reaches around $52/MWh by 2020, and $68/MWh by 2030.
Maintenance costs	Same as central scenario	ICE Small: 5.86c/km, Medium: 4.45c/km, Large: 4.34c/km, LCV: 5.10c/km (Austroads, 2008) HEV 12% saving relative to ICE PHEV 25% saving relative to ICE BEV 25% saving relative to ICE	Same as central scenario
Other vehicle costs	Same as central scenario (small proportion of total costs and does not vary significantly by vehicle type).	$1500 per annum for insurance, registration, etc.	Same as central scenario (small proportion of total costs and does not vary significantly by vehicle type).

Assumptions	Scenarios		
	Low	Central	High
Vehicle range	Same as central scenario.	ICE and HEV – 500km for small passenger; 550km for all other categories PHEV – range is equal to maximum of EV or ICE BEV Small – 120km Medium – 200km Large – 300km LCV – 160km All grow over time in line with increased fuel efficiencies. BEVs also grow 5% per annum from increases in battery storage.	Same as central scenario
Infrastructure costs	Current costs same as central scenario. Cost of public charging units and dedicated charging stations assumed to decline by 20% by 2020.	Household and business charging: $1500 per household or business for Level 1 and 2 (single phase only) Commercial public charging unit: $3000 per Level 2 public charging unit Commercial charging – dedicated premises: $500,000 per charging station (battery swap or equipped with DC fast chargers) Cost of public charging units and dedicated charging stations assumed to decline by 50% by 2020.	Current costs same as central scenario. Cost of public charging units and dedicated charging stations assumed to decline by 80% by 2020.
Infrastructure provision	Household and business charging: Available to everyone. Commercial Charging – Public/dedicated commercial premises: 40% equivalent to traditional petrol stations by 2040.	Household and business charging: Available to everyone. Commercial Charging – Public/dedicated commercial premises: 80% equivalent to traditional petrol stations by 2040.	Household and business charging: Available to everyone. Commercial Charging – Public/dedicated commercial premises: 120% equivalent to traditional petrol stations by 2040, that is, more accessible than traditional petrol stations because available in car parks.

3.4 Estimated take up of electric vehicles

3.4.1 Key results

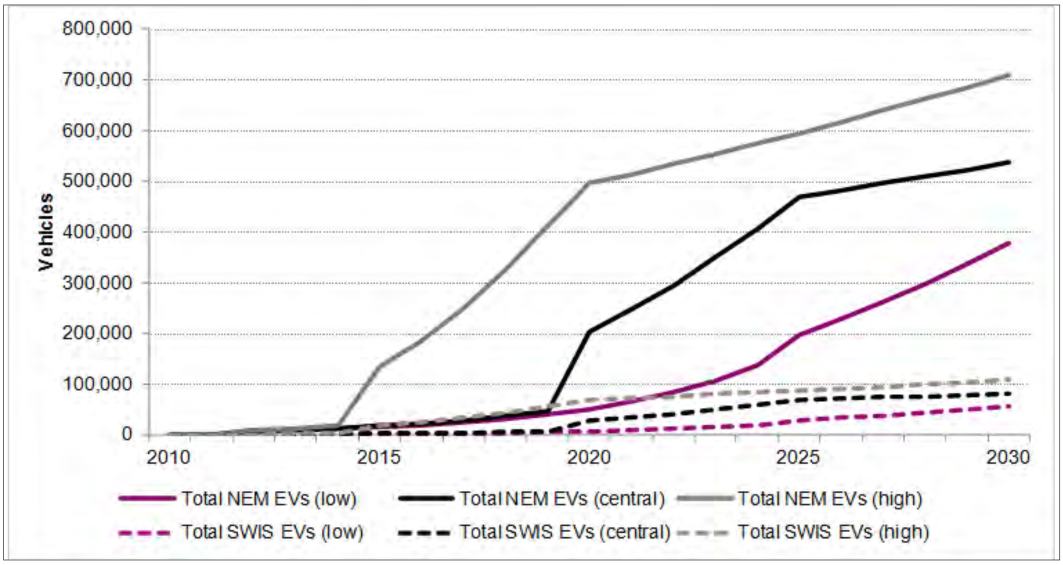
AECOM's analysis suggests that within 10 to 15 years EVs could have a significant presence in the Australian market. While vehicle sales are expected to be slow initially, accounting for around 1% to 2% until 2015, once vehicle prices fall, global supply constraints ease and infrastructure availability increases, vehicle sales are expected to be around 20% of sales by 2020 rising to around 45% of sales by 2030 (see **Table 13** and **Figure 18**). Cumulative sales of EVs are shown in **Figure 19**. Take up could be slower, as illustrated in our low scenario, if vehicle prices take longer to reach price parity and supply constraints remain in the Australian market. However, it is also possible that take up could be much quicker (as illustrated in our high scenario), if for example, battery prices fall much quicker than currently anticipated, Australia is seen as a key electric vehicle market with supply constraints easing quicker and the emergence of leasing arrangements that reduce the upfront purchase cost.

Table 13 Estimated take up of electric vehicles in the NEM and SWIS as a proportion of new sales

	Central			Low			High		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
NEM									
PHEV	1.3%	18.7%	36.3%	1.4%	4.6%	31.0%	13.0%	41.0%	38.0%
BEV	0.7%	1.5%	7.6%	0.3%	0.6%	2.6%	1.3%	6.0%	15.4%
Total	2.0%	20.2%	43.9%	1.7%	5.3%	33.6%	14.4%	47.0%	53.4%
SWIS									
PHEV	1.3%	18.7%	37.5%	1.4%	4.6%	31.0%	13.0%	41.0%	38.0%
BEV	0.7%	1.6%	8.4%	0.3%	0.6%	2.6%	1.3%	6.0%	15.4%
Total	2.0%	20.3%	45.9%	1.7%	5.3%	33.6%	14.4%	47.0%	53.4%
Total									
PHEV	1.3%	18.7%	36.5%	1.3%	4.6%	31.2%	13.0%	41.1%	38.0%
BEV	0.7%	1.5%	7.7%	0.3%	0.6%	2.6%	1.3%	6.0%	15.6%
Total	2.0%	20.2%	44.2%	1.7%	5.2%	33.8%	14.3%	47.2%	53.6%

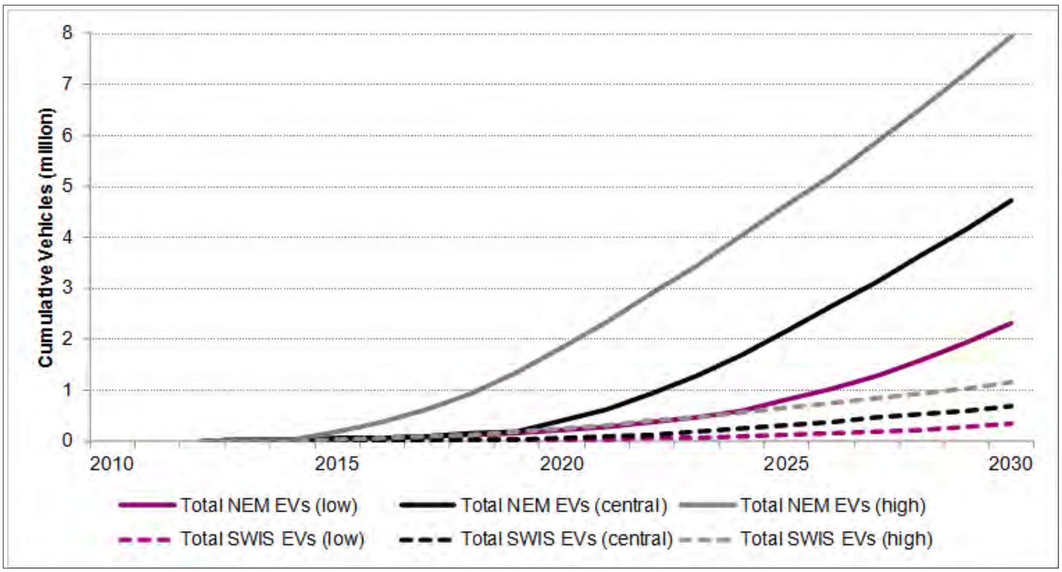
Source: AECOM

Figure 18: Estimated annual sales of electric vehicles in NEM and SWIS



Source: AECOM

Figure 19: Estimated number of electric vehicles in NEM and SWIS



Source: AECOM

More PHEVs than BEVs in the short-to-medium term

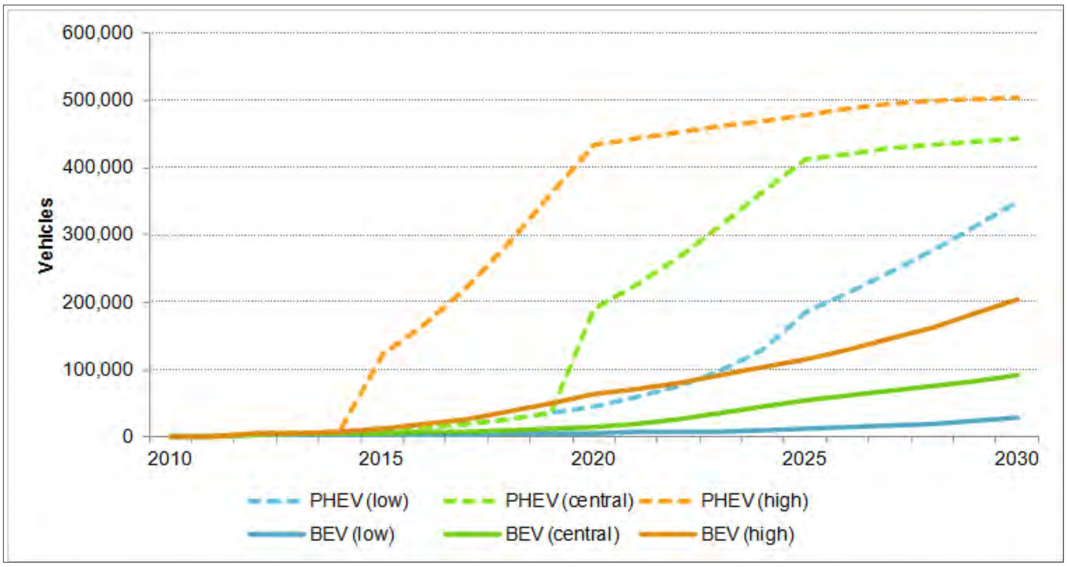
Estimated total annual PHEV and BEV sales for the National Energy Market (NEM) and South West Interconnected System (SWIS) are presented in **Figure 20** and **Figure 21** for the low, central and high take up scenarios.[7] In early years, the take-up of PHEVs is stronger than that of BEVs due to superior range and the ability to use both electricity and petrol as fuel. However, in later years there is a shift towards BEVs as purchase prices converge to parity with ICE, battery improvements result in increased vehicle range, the provision of more charging infrastructure, and higher fuel prices make BEVs more competitive. The higher take up of PHEVs in early years will minimise the impact that EVs will have on the electricity market as PHEVs will typically use less electricity and the dual charging is likely to reduce range anxiety and make PHEV charging more flexible which will in turn reduce the impact on peak load.

Initial sales of PHEVs are subject to supply constraints with sales rising in line with the assumed increase in available Australian PHEV supply. However BEV sales under the low and central scenarios are less than the (constrained) Australian BEV supply as they are relatively uncompetitive against alternative engine types in early years.

Of note are two inflection points in the estimated sales which are most prominent for PHEV sales. For the central scenario these occur at 2020 and 2025 and reflect the assumptions relating to supply constraints and vehicle price parity. Under the central scenario, supply of PHEVs and BEVs are assumed to become unconstrained in 2020 hence the large increase in vehicle sales. In 2025 of the central scenario, the purchase prices of PHEVs and BEVs are assumed to become equal to conventional ICE vehicles. At this point sales of PHEVs slow as BEVs become increasingly competitive. Similar characteristics are observed for the low and high take up scenarios with the differences being the magnitude of sales and the later / earlier dates corresponding with the alternate assumptions about supply constraints and vehicle price parity. This highlights the sensitivity of the results to the year in which price parity occurs and when the supply constraint is removed.

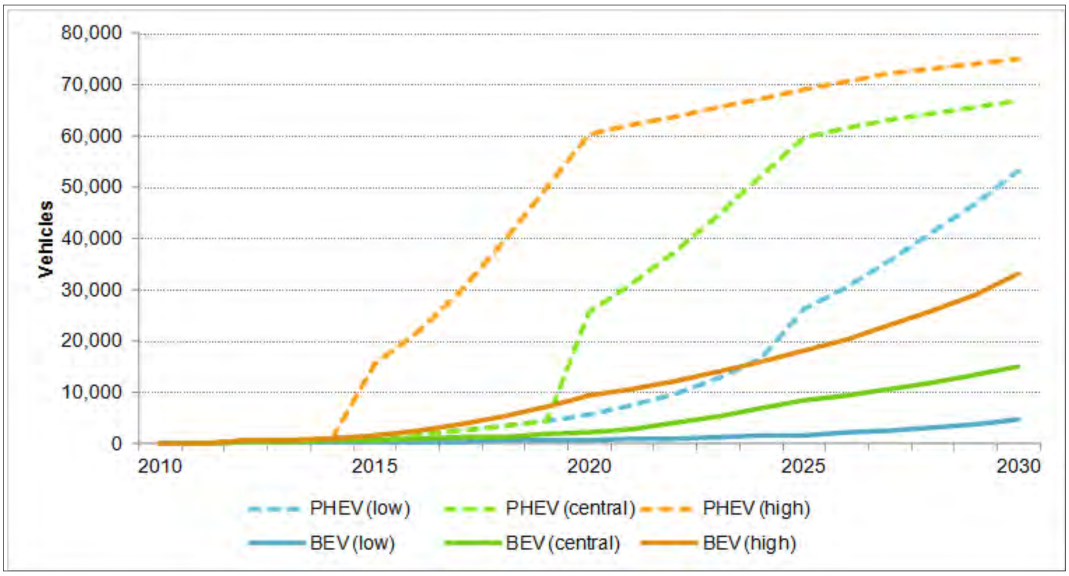
7. For the purposes of this study, it is assumed that all take up of EVs in Western Australia occurs in the SWIS.

Figure 20: Estimated PHEV and EV sales - NEM



Source: AECOM

Figure 21: Estimated PHEV and EV sales - SWIS



Source: AECOM

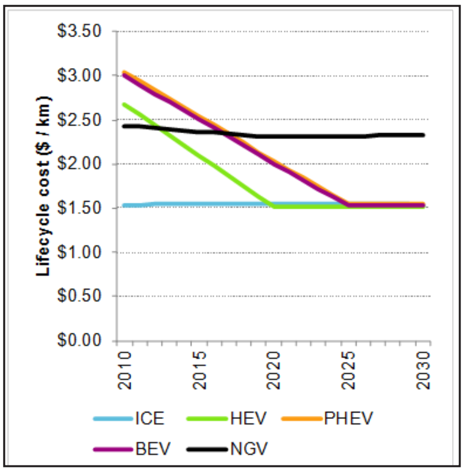
Higher take up for small, low distance vehicles in early years

As noted above, sales of PHEVs are forecast to dominate those of BEVs due to their superior range and ability to use both electricity and petrol as fuel. However, as prices gradually reach parity, vehicle range improves and more charging infrastructure becomes available, larger vehicles and vehicles that travel large distances increase their share of BEV sales. This is primarily due to increased ICE operating costs for (as global oil prices rise) inducing these vehicle owners to switch to more efficient technologies to achieve fuel cost savings.

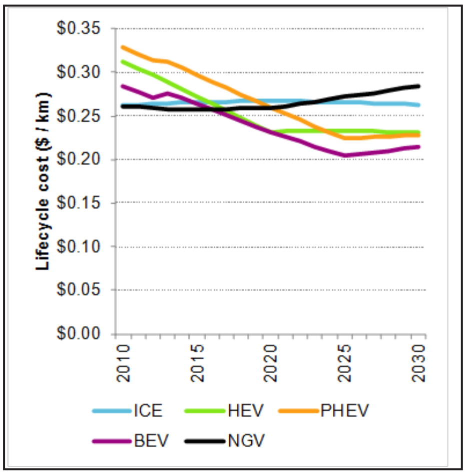
Figure 22 shows the lifecycle costs of small and large cars for low and high VKT. It is evident that over time the lifecycle costs of EVs falls, consistent with the reduction in the purchase price premium until price parity is reached in 2025 under the central scenario. However for both small and large vehicles that have low VKT, the lifecycle cost effectively matches that of ICE vehicles in the long run but does not fall any further. In contrast, for vehicles with high VKT, the lifecycle cost is equal to that of ICE vehicles by around 2015 to 2020 and continues to fall until 2025. After 2025 when price parity is reached the effect of rises in electricity prices causes the lifecycle cost to increase moderately. The lifecycle costs for medium VKT vehicles and medium sized vehicles fall in between the results shown in **Figure 22**.

These figures highlight that in the long run, once vehicle prices decrease, vehicle range increases and infrastructure availability improves, the take up of EVs is more likely by people who travel larger distances and will benefit more from fuel savings.

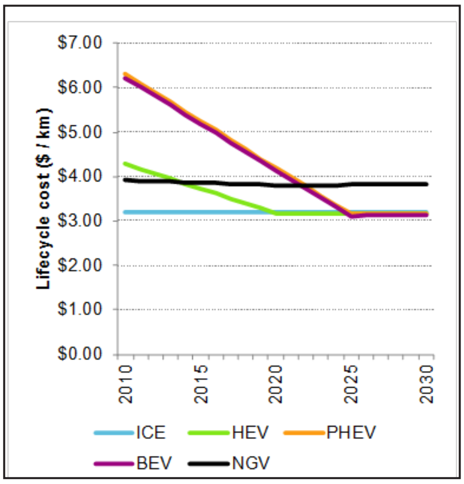
Figure 22: Lifecycle cost small and large car, low and high VKT



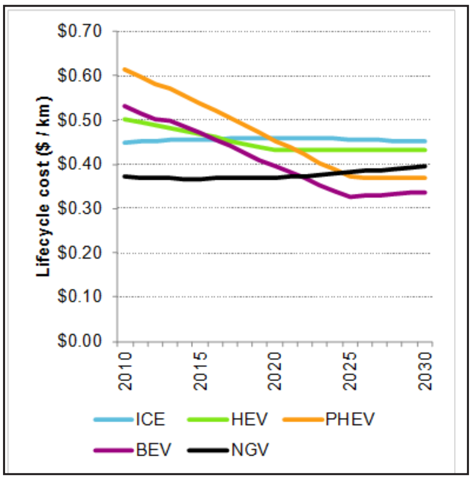
(a) Small car, low VKT



(b) Small car, high VKT



(c) Large car, low VKT



(d) Large car, high VKT

Source: AECOM

Victoria, New South Wales and Queensland account for the most EVs

At a state and territory level within the NEM, equivalent results are observed in terms of the proportion of new sales; however the magnitude of sales varies between regions. The estimated number of vehicle sales in each region is shown in

Table 14 New South Wales (and ACT), Victoria, and Queensland make up the majority of vehicle sales with approximately 90% of take up in the NEM. This is reflective of current vehicle sale patterns.

Corresponding tables for the low and high scenarios are presented in **Appendix A**.

Table 14: **PHEV and BEV sales by state**

	PHEV			BEV			EVs		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	3,800	59,700	134,500	1,900	4,300	25,000	5,700	64,100	159,500
NSW	4,200	63,100	142,000	2,100	5,400	32,000	6,300	68,500	174,100
ACT	200	3,400	7,200	100	200	1,300	300	3,700	8,500
QLD	2,800	45,000	117,600	1,400	3,900	26,400	4,200	48,900	144,000
TAS	300	3,900	9,100	100	300	1,700	400	4,200	10,800
SA	900	14,300	34,200	400	1,000	6,300	1,300	15,300	40,500
Total NEM	12,200	189,400	444,600	6,000	15,100	92,700	18,200	204,700	537,400
WA	1,600	25,800	67,000	800	2,200	15,100	2,400	28,000	82,100

Source: AECOM. Values are rounded to the nearest 100 vehicles.

3.4.2 Spatial take up

The take up estimates in the present study was conducted at a state-wide level, but it is important to note that EV penetration is likely to initially cluster around early adopters and not penetrate the mass market evenly until electric vehicle prices approach parity with ICEs.

Studies have revealed that early adopters of HEVs share a number of characteristics such as, higher average income, higher levels of education, above-average technological skills and above-average age groups (de Haan et al, 2006; Klein, 2007; Scarborough, 2007), and this is likely to be replicated for EVs.

A recent social study conducted by Gardner et al (2011) on attitudes towards EV adoption provides further evidence to this, as the results from their surveys reveal that the most important predictor of take up was concern about climate change. Furthermore, qualitative responses to open-ended questions showed that low vehicle purchase price was the predominant consideration, followed by environmental benefits, running costs, range and recharging issues.

The combination of these factors suggests that short to medium term use of EVs will be concentrated in urban and major hub areas, where charging locations will also initially cluster.

3.4.3 Discussion

AECOM's analysis indicates that within 10 to 15 years EVs will have a significant presence in the Australian market. EV sales are expected to be slow initially, accounting for around 1% to 2% of total passenger vehicle sales until 2015. However, once vehicle prices fall, global supply constraints ease and infrastructure availability increases, vehicle sales are expected to be around 20% of sales by 2020 rising to around 45% of sales by 2030.

These results are broadly in line with those presented in other studies. **Table 15** compares the results of AECOM's three scenarios with the forecast penetration of EVs into the Australian market by ChargePoint and AGL. ChargePoint only forecast in terms of percentage of sales to 2020 rather than absolute volumes of sales. The take up of EVs in AECOM's central scenario is consistent with ChargePoint's forecast.

In contrast, AECOM's central estimate is substantially higher than AGL's medium forecast, which suggested that sales of EVs might reach 25% by 2030. Indeed, AECOM's central scenario more closely matches AGL's high forecast. Therefore AECOM's central case for take up of EVs may provide conservatively high estimates for the impact on the electricity market in subsequent analysis.

Table 15: **Comparison of AECOM results with ChargePoint and AGL**

Share of new vehicle sales	2015	2020	2025	2030
AECOM – Low	1.7%	5.2%	18.8%	33.8%
AECOM – Central	2.0%	20.2%	42.2%	44.2%
AECOM – High	14.3%	47.8%	50.4	53.6%
AGL – Low	1.5%	2.5%	3%	5%
AGL – Medium	2%	6%	13%	25%
AGL – High	3%	20%	37%	50%
ChargePoint	2.5%	18.2%	N/A	N/A

Source: AECOM, ChargePoint submission (2011), AGL submission (2011). Note: AGL values are estimates only.

The estimated take up is also comparable with the targets of international governments (see **Table 16**). The take up in 2015 of the central scenario is somewhat higher than the US target of 0.4% while it is lower than the Spanish target of 4.4% in 2014. However there is a wider range of government targets for 2020 ranging from 2.2% (Germany) to 50% (Japan). The estimated central take up is approximately midway between these bounds, and indeed the low and high take up for 2020 are much closer to the German and Japanese targets respectively.

Table 16: **Global government EV targets**

Country	Vehicles	% of total	Date
US	1,000,000	0.40%	2015
China	500,000	0.30%	2012
UK	100,000	0.40%	–
France	2,000,000	6.20%	2020
Germany	1,000,000	2.20%	2020
Spain	1,000,000	4.40%	2014
Israel	500,000	25.00%	–
Japan	34,583,670	50.00%	2020
Denmark	–	–	–
Netherlands	200,000	2.60%	2020
Ireland	250,000	10.30%	2020
Australia	–		–

Source: AGL submission (2011)

3.4.4 Summary

The take up of EVs starts with small quantities with PHEV sales constrained by limited Australian supply. Take up of PHEVs is greater than BEVs in the short-to-medium term as they have better range, are able to use either petrol or electricity and have refuelling / recharging infrastructure widely available. As such, in the period to 2020, the impact of EV take up on the electricity network is likely to be modest.

Following supply becoming unconstrained in 2020, take up of PHEVs expands markedly due to their continued competitiveness over other engine types because of improving fuel / electricity costs (compared to ICE vehicles) and improving range. In parallel, BEV sales continue to rise however at a more gradual rate.

However once price parity for both PHEVs and BEVs is achieved in 2025, sales of PHEVs plateaus with take up shifting towards BEVs which by 2025 have become competitive with all other engine types. Similar characteristics are observed for the low and high take up scenarios with the key dates shifting later or earlier reflecting the change in assumptions for each scenario.

As expected, Victoria, New South Wales (and ACT) and Queensland dominant the take up of EVs with approximately 80% of total national sales (90% of NEM sales).

3.5 Estimated energy usage

Table 17 and **Table 18** sets out the energy consumption of PHEVs and BEVS over time under the three take up scenarios for the NEM and SWIS respectively.

Energy consumption remains relatively low as a proportion of total energy demand even in the high take up scenario for both the NEM and SWIS at 3.7% and 4.3% respectively. The proportion of total energy demand is slightly higher in the SWIS than the NEM but remains low. Energy consumption of PHEVs increases over time as drivers use a larger share of the electric drive-train. As highlighted in **Table 19**, the energy usage of EVs depends on the size of the vehicle and the distance travelled. Small EVs travelling low distances may use less than 1MWh per annum, where as large EVs travelling longer distances could use around 10 MWh per annum. Importantly the proportion of vehicle size and average distance travelled varies by state.[8]

Table A 4 to **Table A 9** in **Appendix A** provides more detailed data on energy consumption and proportion of energy demand for each state. The energy consumption from EVs as a proportion of total energy consumption in New South Wales and Australian Capital Territory, Victoria and South Australia are slightly higher than the total for the NEM, whereas Queensland and Tasmania have lower proportions than the total for the NEM.

Table 17: Energy consumption from EVs in selected years – NEM

EVs	2015		2020		2030	
	MWh	% of total MWh in NEM	MWh	% of total MWh in NEM	MWh	% of total MWh in NEM
Central take up scenario						
PHEV	40,400	0.0%	462,200	0.2%	6,907,600	1.8%
BEV	48,000	0.0%	186,600	0.1%	1,629,100	0.4%
Total	88,300	0.0%	648,800	0.2%	8,536,700	2.2%
Low take up scenario						
PHEV	40,100	0.0%	240,200	0.1%	3,588,700	0.9%
BEV	26,300	0.0%	83,500	0.0%	450,700	0.1%
Total	66,400	0.0%	323,700	0.1%	4,039,300	1.1%
High take up scenario						
PHEV	190,700	0.1%	2,418,100	0.9%	10,335,100	2.7%
BEV	82,400	0.0%	617,400	0.2%	3,926,200	1.0%
Total	273,100	0.1%	3,035,400	1.1%	14,261,400	3.7%

Source: MWh: AECOM based on take up results presented above; assumptions on fuel efficiency (as presented in **Section 3.3.1.7**); and average annual distance travelled as presented in **Table 19**. Forecasts of total MWh in NEM based on AEMO (2011a), medium forecasts (See **Section 6.1.1.2** for more details).

8. This study uses the proportion of vehicle type and VKT from VIC and NSW and applies this to other studies as data was not available for other States within the study period. For the purposes of estimating the magnitude of impacts this is sufficient but it is suggested this assumption be refined in the future given its importance on take up and electricity consumption.

Table 18: **Energy consumption from EVs in selected years - SWIS**

EVs	2015		2020		2030	
	MWh	% of total MWh in SWIS	MWh	% of total MWh in SWIS	MWh	% of total MWh in SWIS
Central take up scenario						
PHEV	4,800	0.0%	57,100	0.1%	937,600	2.1%
BEV	5,600	0.0%	23,700	0.1%	236,200	0.5%
Total	10,400	0.0%	80,900	0.2%	1,173,800	2.6%
Low take up scenario						
PHEV	4,800	0.0%	28,700	0.1%	481,800	1.1%
BEV	3,000	0.0%	10,200	0.0%	64,000	0.1%
Total	7,800	0.0%	38,900	0.1%	545,800	1.2%
High take up scenario						
PHEV	22,600	0.1%	306,400	0.8%	1,380,500	3.0%
BEV	10,000	0.0%	82,600	0.2%	568,100	1.2%
Total	32,600	0.1%	389,000	1.0%	1,948,700	4.3%

Source: As above for **Table 13**. Forecasts for total MWh in WA from The Chamber of Minerals and Energy of Western Australia (2011)

Table 19: **Average annual energy usage in Victoria and New South Wales by passenger vehicle type and distance travelled, 2011**

Passenger vehicle type	kWh/100km	2015		2020	
		Average annual VKT	Average annual MWh per vehicle	Average annual VKT	Average annual MWh per vehicle
Small car, low VKT	19	3,622	0.7	4,160	0.8
Small car, medium VKT	19	13,422	2.6	14,342	2.7
Small car, high VKT	19	48,565	9.2	40,598	7.7
Medium car, low VKT	16.5	3,621	0.6	4,135	0.7
Medium car, medium VKT	16.5	13,600	2.2	14,719	2.4
Medium car, high VKT	16.5	52,811	8.7	42,475	7.0
Large car, low VKT	21.5	4,037	0.9	4,220	0.9
Large car, medium VKT	21.5	14,785	3.2	14,665	3.2
Large car, high VKT	21.5	52,484	11.3	45,907	9.9
LCV	18.5	22,742	4.2	23,518	4.4
Taxi	21.5	116,079	25.0	130,029	28.0

Source: AECOM calculations based on assumptions as set out in **Section 3.3.1.7** on fuel efficiency and average annual VKT from various state Transport Departments.

3.5.1 Renewable energy

An often discussed concept is the ability of renewable energy generation to supply some or all of the energy demanded by EVs to recharge. **Table 20** shows the megawatt-hour demand by EVs under each scenario for selected years and the proportion of renewable generation that the demand represents. Renewable energy generation has been estimated from Treasury (2011) which forecasts the proportion of electricity generation by fuel source. These proportions were then multiplied by forecast energy demand for the NEM and SWIS from AEMO (2011b) to develop renewable energy generation estimates in megawatt-hours.

It is clear that in the next 5 to 10 years, renewable generation is more than capable of supplying the energy requirements of EVs which is in the order of 0.3% to 8% under the central scenario. Even under the high take up scenario EV energy demand is only around 13% of total renewable energy generation in 2030.

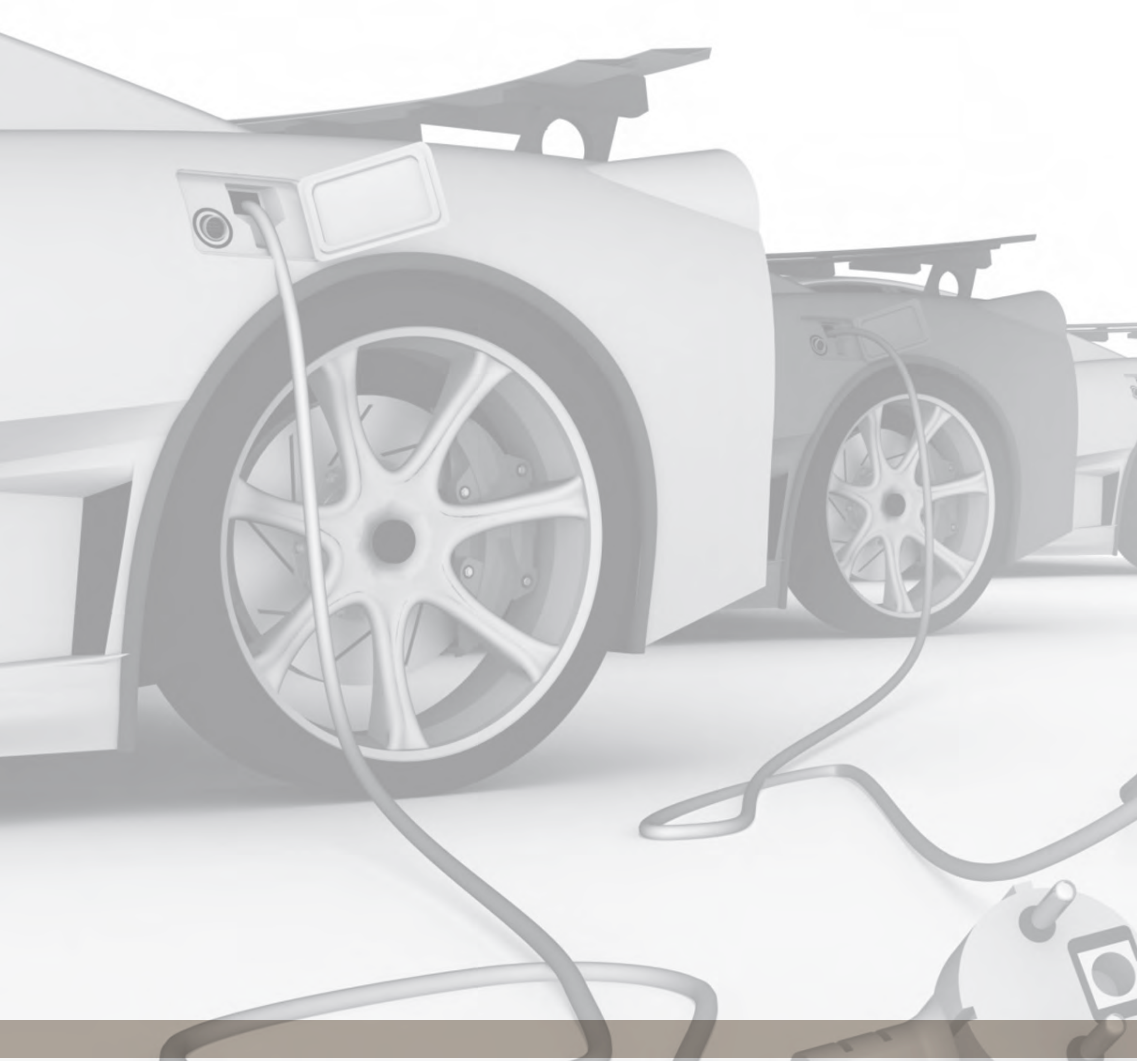
For comparison, **Table 20** also shows EV energy demand as a proportion of the Large-scale Renewable Energy Target (LRET). Annual targets are set at 10,400 GWh in 2011 rising gradually to 41,000 GWh in 2020. From 2020 to 2030 the annual target is held constant at 41,000 GWh (ORER, 2011). These targets are lower than the renewable energy generation calculated from Treasury (2011) and AEMO (2011b) and therefore represent a more conservative estimate of national renewable energy generation. Even with this lower generation, EV energy demand is only estimated to be around 0.5% of the LRET in 2015 rising to 1.8% in 2020 under the central scenario. In 2030, this proportion rises to 24% however the LRET is held constant from 2020 to 2030 whereas it is much more likely that renewable generation will continue to increase over this period.

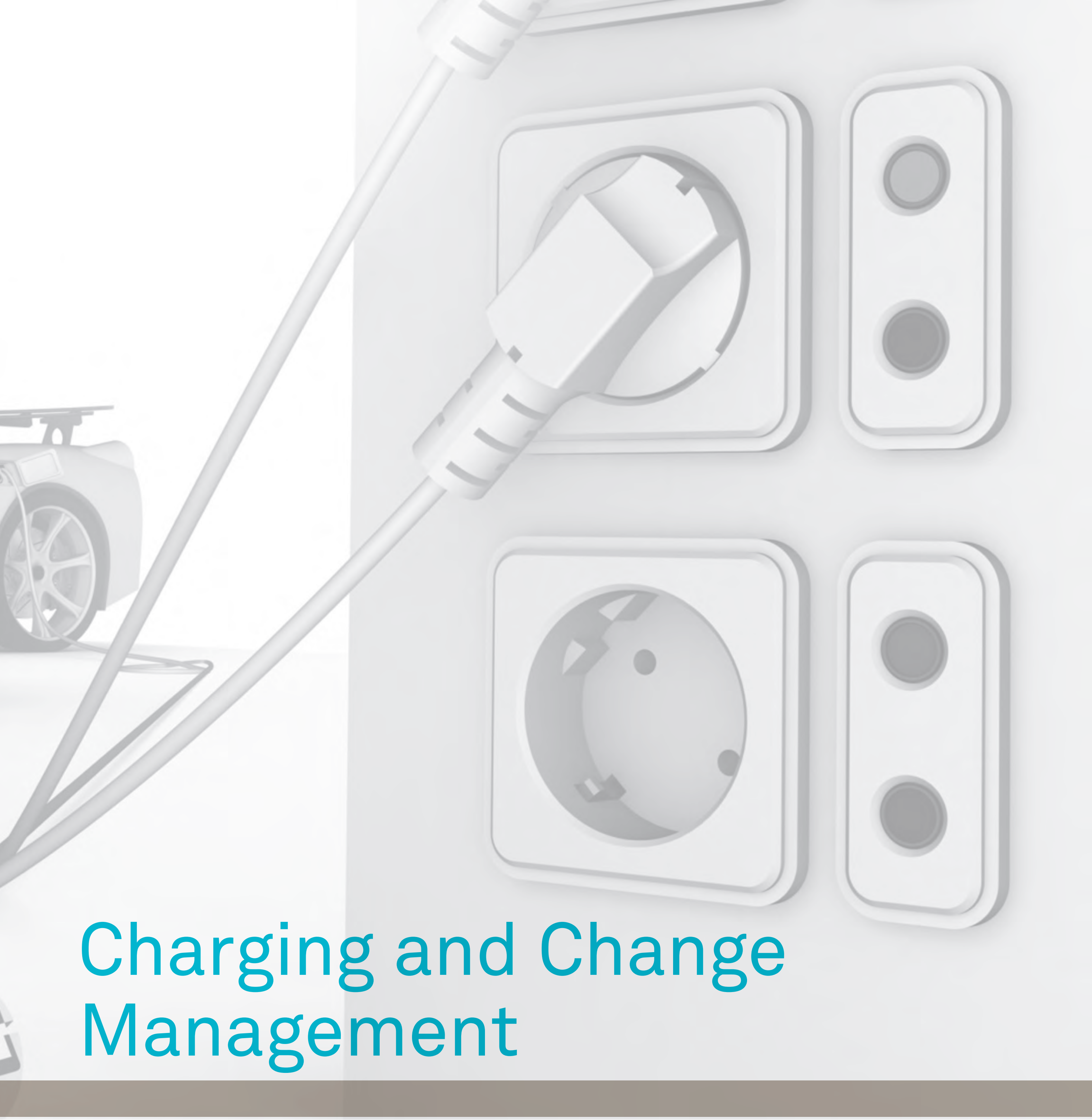
Table 20: EV energy demand as proportion of renewable energy generation

	2015			2020			2030		
	MWh	% of total MWh in NEM or SWIS	% of LRET target	MWh	% of total MWh in NEM or SWIS	% of LRET target	MWh	% of total MWh in NEM or SWIS	% of LRET target
Central take up scenario									
NEM	88,300	0.3%		648,800	1.3%		8,536,700	7.9%	
SWIS	10,400	0.3%		80,900	1.1%		1,173,800	9.1%	
Total	98,800	0.3%	0.5%	729,700	1.2%	1.8%	9,710,500	8.0%	23.7%
Low take up scenario									
NEM	66,400	0.2%		323,700	0.6%		4,039,300	3.7%	
SWIS	7,800	0.2%		38,900	0.5%		545,800	4.2%	
Total	74,200	0.2%	0.4%	362,600	0.6%	0.9%	4,585,100	3.8%	11.2%
High take up scenario									
NEM	273,100	1.0%		3,035,400	6.0%		14,261,400	13.2%	
SWIS	32,600	0.8%		389,000	5.2%		1,948,700	15.1%	
Total	305,700	1.0%	1.7%	3,424,500	5.9%	8.4%	16,210,000	13.4%	39.5%

Source: AECOM.

Market arrangements enable EV owners to purchase GreenPower from their electricity retailer. AECOM's analysis suggests that there may be enough supply of energy from renewable generation to charge EVs. However increased demand for renewable energy may impact on the price of Large-Scale Generation Certificates (LGCs). When customers purchase GreenPower, the electricity retailer purchases Large-Scale Generation Certificates (LGCs), in order to surrender these to the Office of the Renewable Energy Regulator (ORER). As such GreenPower is fully additional to the Government's Renewable Energy Target. If there is a high take up of GreenPower to charge EVs this could increase demand for LGCs and push the price of LGCs higher





Charging and Change Management

4.0

Charging and Change Management

4.1 Introduction

EVs only affect the electricity system when charging (or discharging in the case of V2G). This section considers our charging assumptions and scenarios, focusing on the details that are most likely to impact the electricity market. We focus on three choices in particular:

- **Where will EVs charge?** The wide spread deployment of charging units will decrease the amount of charging needed at any one time and consequently help spread charging over the entire day. Alternatively, if EVs can only charge at home, many users will charge during the period between when they arrive home and go to work.
- **How much power will EV chargers require?** Faster charging will be more convenient for EV drivers but will also increase the power that charging units draw from the network.
- **When will EVs charge (or discharge)?** From a network perspective, the most important choice is when EV's charge. In the worst case scenario, if EV charging is unmanaged and occurs during existing load peaks, peak load will increase. As a result distribution and transmission systems will need to be strengthened and more generation built. Conversely, if charging happens in off-peak periods, then it is not expected to increase peak load, even in high take up scenarios.

We examine the worst case scenario of unmanaged charging and then consider three approaches for managed charging scenarios. In each case, we consider how much charging activity might be moved to off-peak periods and how much might remain in the existing late afternoon / evening peak. We also examine the potential for vehicle-to-grid solutions, which not only manage charging but can also feedback into the grid (See **Section 7.0**).

4.2 Where will EVs charge?

Four main locations for EV charging commonly identified in EV literature are:

- **Home based charging:** Households will be able to charge their vehicle at home.
- **Business charging:** EV drivers will be able to charge their vehicle at their place of work.
- **Commercial charging - Public:** Charging points will be available in public places as well as in the home. For instance, charging facilities provided in public spaces such as car parks, hotels, shopping centres, street parking.
- **Commercial charging - dedicated commercial premises:** Commercial charging will replace existing petrol stations by providing fast charge facilities either through a battery swap or a quick DC (direct current) charge.

For further details on charging infrastructure see AECOM (2011).

Preliminary research, industry consultation and EV trials suggest that, whilst the provision of charging infrastructure is necessary to reduce range anxiety, the majority of charging will take place at home.

As previously discussed in **Section 3.0**, the prevalence of public and dedicated commercial charging facilities is likely to be a key determinant of take up. However, home based charging is likely to be responsible for the majority of charging activity, especially over the short to medium term. Our assumptions on the prevalence of charging locations are shown in **Table 21** below.

Table 21: Charging location assumptions

Assumptions	Scenarios		
	Low	Central	High
Infrastructure provision	Household and business charging: Available to everyone. Commercial Charging - Public/dedicated commercial premises: 40% equivalent to traditional petrol stations by 2040.	Household and business charging: Available to everyone. Commercial Charging - Public/dedicated commercial premises: 80% equivalent to traditional petrol stations by 2040.	Household and business charging: Available to everyone. Commercial Charging - Public/ dedicated commercial premises: 120% equivalent to traditional petrol stations by 2040, that is, more accessible than traditional petrol stations because available in car parks.

4.3 How much power will EV chargers require?

Chargers can be broken down into three levels as shown below in **Table 22**. Charging systems with higher current and higher voltage charge faster but also have a higher power requirement and consequently higher potential electricity market impacts.

Table 22 EV charger power

Level	Voltage / Current	Power
Level 1	15A, 240V AC	3.6 kW
Level 2	32A, 240V AC	7.7 kW
Level 3	125A, 400V – 600V DC	>50-75 kW

Source: ChargePoint presentation, Early Driver Challenges of EV Transportation

4.3.1 Home and work based chargers

Home and work based charging is likely to occur at Levels 1 and 2. Level 1 charging units could be installed in most Australian homes, which are commonly built with at least 20A circuits but multiple power points (Usher et al, 2011). However Level 1, 15A power points should be installed on a single circuit to avoid overloading from other appliances on the circuit. Few residences have 15A outlets in their garage, so some re-wiring may be needed.

Although Level 1 charging would be easy to accommodate, several submitters, including BetterPlace and Ergon Energy, note that there will likely be demand for faster, more powerful chargers. BetterPlace notes in their submission, that in fact most Australian homes have a 14kW to 28kW capacity. However Level 2 charging may require strengthening of household connections to reduce the risk of overloading. Very few households have three phase supply, and Level 2 charging would generally require three phase (although it may be done single phase). The Energy Network Association (ENA) states in their submission “the increase in load could cause problems for electrical systems within the household or premises where charging occurs-this may also necessitate in system augmentation at the premises or site level.”

It is still very unclear how home based charger power will evolve. However, for the purposes of modelling EV impacts we consider two scenarios: everyone has a Level 1 charger with a charger power of 3.6kW (15A) and undertake sensitivity assuming everyone has a Level 2 charger with a charger power of 7.7kW (32A). In reality it is likely there will be a mixture of Level 1 and Level 2 charging facilities. The costs of installing charging infrastructure (discussed in **Section 3.3.1.8**) will vary in each property depending on the circuit available.

It is also worth highlighting that there may be a lack of consumer understanding about the requirements for home charging and the impact home charging may have on their household. It will be important to ensure consumers have the right information to understand the full requirements and impacts of home charging.

4.3.2 Fast charging at commercial charging stations

Commercial fast charging stations will require stronger supply, both on account of higher charging power (Level 3 or more) and multiple charging bays. Given the high power use of charging stations, connecting to the local distribution network is likely to be costly and will probably require an upgrade of local network assets near the point of connection. TRUenergy also notes in their submission a concern that fast charging stations may degrade network performance. However, these costs should and are also likely to be borne by the station developer, rather than existing market participants. This may include paying for network protection schemes and on site facilities to ensure load quality. Also, although commercial charging stations are high power, their overall market share is expected to be low on account of low usage as a percentage of overall charging. AECOM is also aware of possible developments in ultra fast charging, as noted by Blade in their submission. Ultra fast charging will increase the power requirements, but as discussed above, these costs will likely be borne by the station developer as part of their investment costs.

4.4 When will EVs charge?

When EVs charge will determine whether EVs contribute to existing load peaks-leading to increased expenditure to strengthen the network-or instead occur during the off-peak period. Our analysis below shows that, even in the high take up scenario, networks should be able to accommodate charging during off-peak periods without increasing the peak load. Consequently, the key question is: How many EVs will be charging during peak periods? In the worst case, unmanaged charging could see close to one hundred per cent of EVs charging during peak periods, leading to an increase in peak load and greater network costs. However, as is pointed out in many of the submissions to the AEMC approach paper, if EV charging can be incentivised or mandated to occur in off-peak periods, there will be potential benefits to residential customers through spreading the fixed network costs over a larger customer base. Work undertaken by the AEMC suggests fixed costs average around 25% of electricity bills for small residential customers (AEMC, 2011).

The rest of this section sets out four charge management scenarios which are used in subsequent analysis:

- **Unmanaged charging –** charging occurs when people arrive home from work and coincides with the peak period. This scenario requires no change to the current technology.
- **Controlled charging –** charging is forced to occur in off-peak periods, for example, by using controlled load such as ripple control. This scenario would require a meter if controlled load is to be billed at a different tariff.
- **Time of Use (TOU) charging –** EV drivers have time of use tariffs that will incentivise a proportion of these to charge during off-peak periods. This scenario would require a meter either on the vehicle or at the property.
- **Smart meter charging –** EV drivers have smart meters that provide better incentives than TOU pricing for off-peak charging. This scenario would require a smart meter with two way communication.

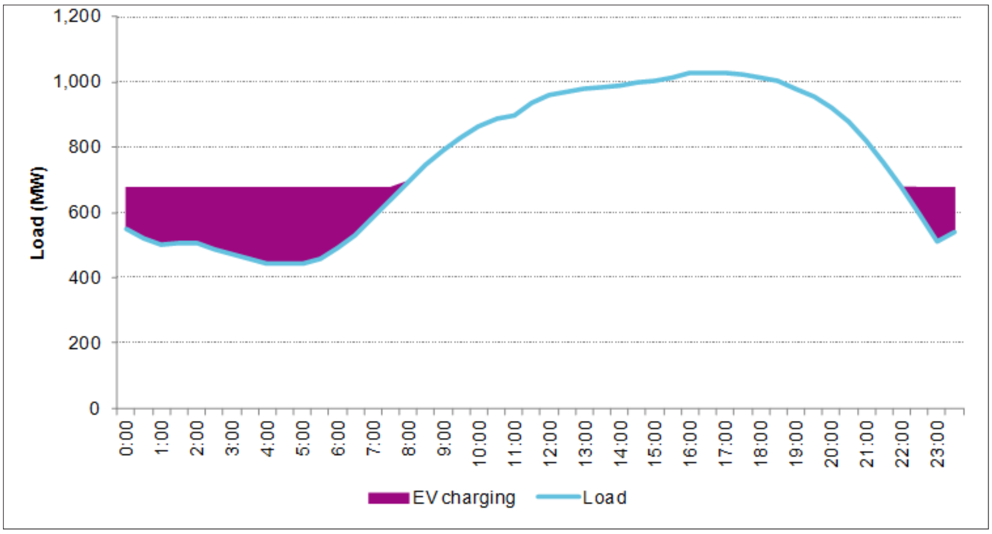
The charge management scenarios represent a spectrum of possible situations from unmanaged charging through incentives designed to encourage off-peak charging, to mandating that charging occurs in off-peak periods. The disadvantage of shifting charging to the off-peak period is that users forgo the option 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 this option and worry about the possibility of running out of charge-range anxiety. Whilst controlled charging ensures off-peak charging of EVs, it may impact on drivers' range anxiety and deter people from purchasing EVs. Therefore approaches that successfully incentivise off-peak charging should be favoured over an approach that mandates off-peak charging.

The purpose of this study is to illustrate how the impact of EVs varies with different charge management scenarios. As such, we have not considered the specific feasibility, in terms of technology or financial viability, of each of these scenarios.

Off-peak charging will not increase peak load

Many reports have noted that there is enough capacity for EVs to charge during the off-peak period and not result in increased peak load. We demonstrate that this is clearly the case by modelling smart off-peak charging in South Australia, using the Net System Load Profile (NSLP) from last year's maximum load day and using the daily energy requirements of EVs in 2030, under the high up-take scenario, as shown in **Figure 23**. The NSLP measures the system load that is not metered on a half hourly based and generally consists of residential and SME load connected to the distribution network. As such, the NSLP provides a very conservative estimate of unused capacity during off-peak periods. Based on NSLPs in the NEM, South Australia had the least available off-peak charging during its day with the highest peak load in 2010. South Australia therefore provides the toughest test of the ability to accommodate EV charging in the off-peak. AECOM also tested that there is sufficient charging capacity below the annual peak on a 'typical' day for each state.

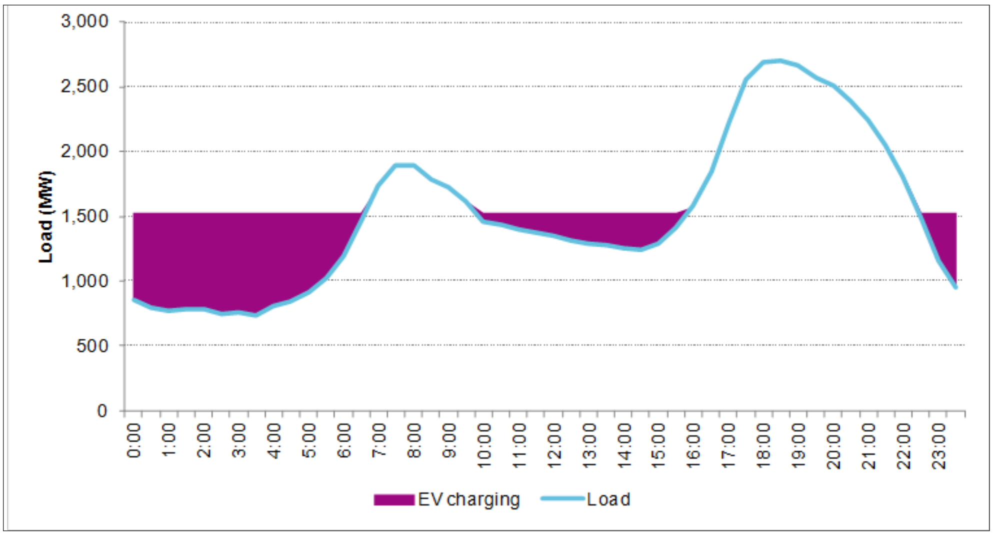
Figure 23: Accommodating EV charging without increasing peak load, South Australia



Source: Net System Load Profiles from AEMO (2011a), EV charging AECOM

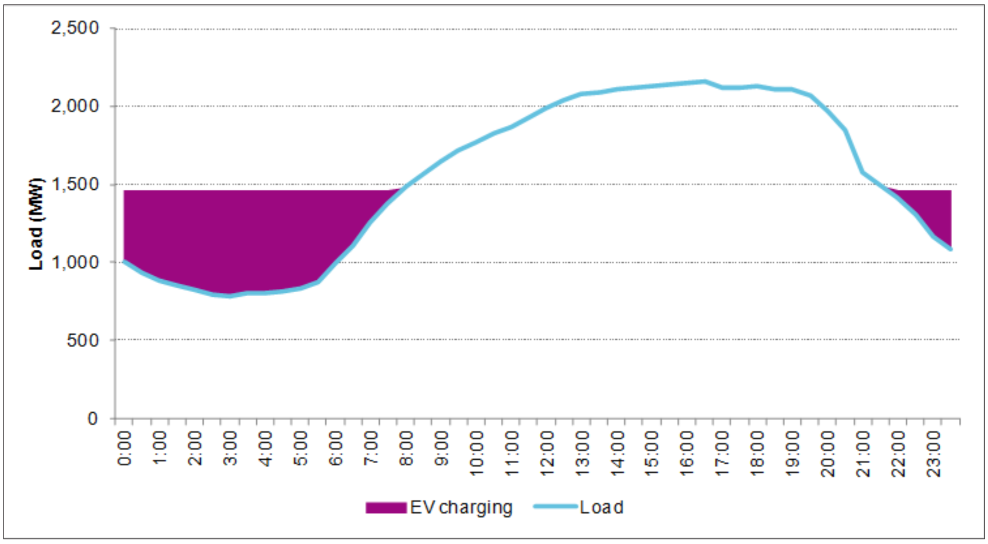
AECOM tested this in other States in the NEM and found the same result. **Figure 24** and **Figure 25** demonstrate that New South Wales and Queensland can accommodate the charging of EVs in the high take up scenario during off-peak periods with no requirement for additional peak load.

Figure 24: Accommodating EV charging without increasing peak load, New South Wales



Source: Net System Load Profiles from AEMO (2011a), EV charging AECOM

Figure 25: Accommodating EV charging without increasing peak load, Queensland



Source: Net System Load Profiles from AEMO (2011a), EV charging AECOM

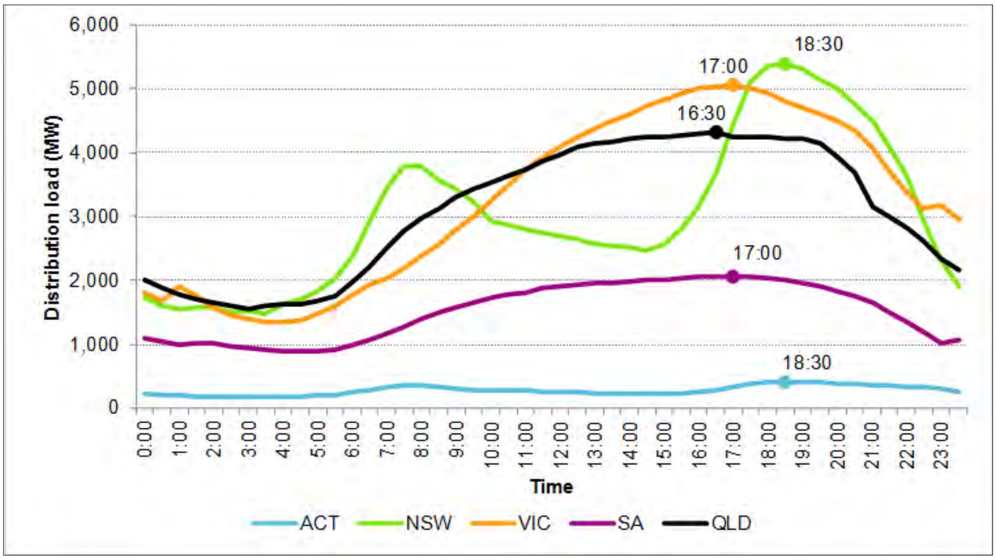
Off-peak charging also has the added benefit being in the night time when temperatures are generally lower. At lower temperatures, transmission and distribution network components, especially conductors and transformers, can actually take higher loads without being damaged. Consequently, overall transmission and distribution capacity is actually higher at night time.

It is possible to accommodate EV charging in off-peak periods without increasing peak load this could cause other impacts in the electricity market. In particular, concern has been raised that there may be issues regarding the adequacy of system capacity, particularly at the generation level. Given off-peak generation is predominantly base load coal and gas, there is unlikely to be major capacity issues as a direct result of EVs charging in off-peak periods. The increased demand in off-peak electricity will likely increase off-peak prices which would encourage generators to bid into the market. There could be potential frequency issues if all EVs start charging at the same time. However, the Frequency Control Ancillary Services (FCAS) market is design to address this issue. AECOM believes the current electricity market design provides the right incentives and is capable of responding to this issue, particularly given the long lead times before there is significant take up of EVs.

4.4.1 Unmanaged Charging (worst case scenario)

Without any form of charge management it is likely that EV owners will simply charge when they arrive home in the evenings. This would roughly correlate with existing periods of peak load (as estimated from NSLPs) which occur between 16:30 and 18:30, as shown in **Figure 26**. Our unmanaged charging scenario assumes 80 per cent of EVs are charging during existing periods of peak load. To test the sensitivity of results to this assumption we include a scenario where all EVs charge during the peak period.

Figure 26: Distribution level load during maximum load days in 2010



Source: Net System Load Profiles from AEMO (2011a). Data for Tasmania and WA was not available.

Although EVs charging during the existing early evening peak is clearly the worst case scenario, preliminary research suggests this is likely. Due to EVs being relatively new to the market, there is limited data on how people will charge their vehicles. Early feedback from the Victorian Electric Vehicle Trial suggests that people typically arrive home and start charging their vehicle.[9] Those that are interested in different charging behaviour do not have the right information to understand their options and the impact this will have on them.

ChargePoint found that business customers charged throughout the workday with a peak from 3pm to 5pm. Private charging also occurred throughout the day but peaked between 6pm and 9pm (ChargePoint, 2011). SP AusNet also suggests the likelihood of unmanaged charging occurring predominantly in peak periods. However AGL (2011) suggests that diversity could be higher, noting that only 12% of vehicles arrive home during periods of peak demand.

Other research by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and AGL examines the availability of EVs for charging by examining transport data in Victoria. This shows the majority of EVs are likely to arrive home between 5pm and 8pm. However, night time charging is likely to continue for several hours, especially if EVs do not have access to chargers during the work day. Consequently, charging activity from motorists returning home would likely occur in peak periods, clustering around 8pm.

The Smart Grid Smart City Project suggests that people are charging their vehicles when they arrive at work. However, this is a unique characteristic of the stage in the EV trial as people do not have charging facilities available at home (Smart Grid Smart City, 2011).

The charging behaviour of EV drivers will likely evolve over time depending on the availability of charging infrastructure.

4.4.2 Controlled Charging

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.

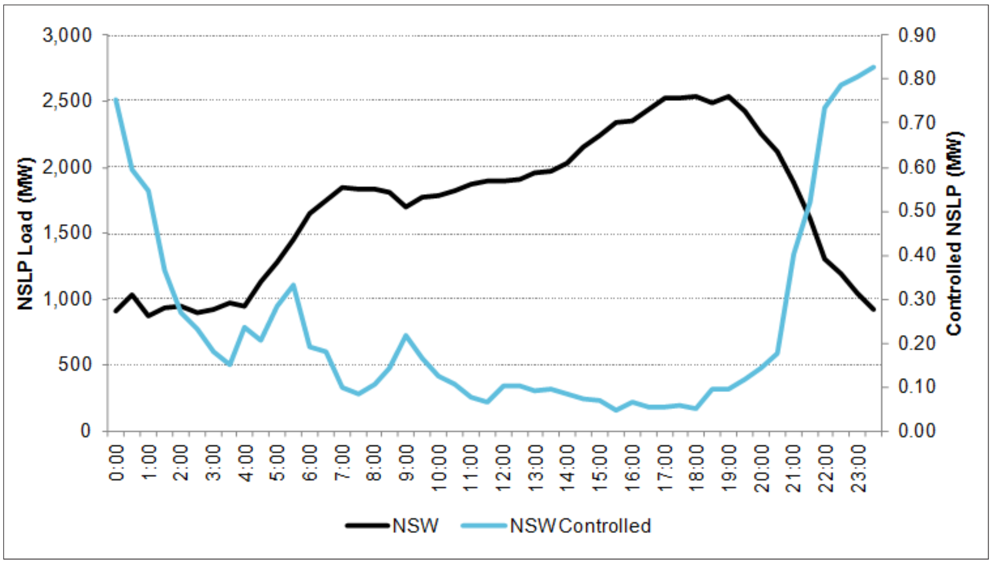
Controlled charging could operate in a similar way to existing active controlled load schemes that allow distribution businesses to control water heaters.[10] This is commonly implemented using ripple control which injects a high frequency signal into the electricity supply which is then picked up by switching equipment on the hot water cylinder. SP AusNet notes that controlled charging would need to be staggered to eliminate step changes. Staggering charging could also help coordinate charging in areas where EV take up is very high.

9. Discussions with Project Manager for the Victorian Electric Vehicle Trial. Actual data will be available within the coming months.
10. Passive load control schemes move load to non-peak periods using a timer and are not controlled by the distribution business in real time.

In Australia controlled load is currently used in NSW, South Australia and Queensland. As can be seen in **Figure 27**, controlled load in NSW successfully moves the bulk of hot water heating to the off-peak period.

As well as moving load to off-peak periods, controlled charging would allow the market to reduce EV charging in response to unexpected network demand and increase EV charging if demand was lower. This dynamic response enables benefits beyond a peak load reduction. These are discussed further in **Section 6.2**.

Figure 27: Net system load profile for NSW: normal and controlled load (23 February 2011)



Source: AEMO (2011a)

4.4.3 Time of Use (TOU) Charging

TOU charging would give EV drivers an incentive to charge during off-peak periods by offering a reduced tariff in off-peak periods. Similar schemes are already offered in Australia, for example Origin offer an almost 30 cent difference between peak / off-peak tariffs as shown in **Table 23**. The amount of savings will vary depending on the amount of electricity used to charge the vehicle, which varies by distance travelled. A small vehicle with medium VKT consuming around 0.2MWh a month could expect to save around $65 a month. However, a large vehicle with high VKT consuming around 0.9MWh a month could expect to save around $280 a month.[11] TOU charging could also be conveniently implemented as an automated default charging option for EV chargers, eliminating the need to remember to switch EV chargers on. However, large switching of off-peak load at a particular time can require fast response generation, priced as frequency response services in the ancillary services market.

Table 23: Time of use tariff offered by Origin

Usage	Rate (inc. GST)
Peak Energy (Mon-Fri, 7am-9pm)	43.472 (c/kWh)
Off-peak Energy (all other times)	13.640(c/kWh)
Supply Charge	57.387 (c/day)

Source: http://www.originenergy.com.au/2933/Smart-Time-of-Use

As discussed above, the disadvantage of shifting charging to the off-peak period is that it may exacerbate range anxiety. As such, not everyone will be incentivised to charge in off-peak periods. However, two groups of users are unlikely to be affected by this concern: households with two or more vehicles (assuming at least one is a PHEV or ICE vehicle) and PHEV drivers. Households with more than one vehicle can switch to their PHEV or ICE vehicle if need be and so are unlikely to experience range anxiety. Similarly, PHEV drivers are unlikely to experience range anxiety because they can refuel at conventional service stations, if they run out of charge.

11. See Table 19 for charging requirements for different vehicle types.

The 2006 census showed that 35.45% of households in Australia owned more than one car (ABS, 2006). For the purpose of modelling the impact of TOU charging, we assume 35.45% of EV drivers and all PHEV drivers charge during off-peak periods.

Importantly, because take up of PHEVs is higher than for BEVs in the early years, and it is believed PHEV drivers may be more likely to respond to TOU tariffs, TOU charging may be sufficient to manage the charging in off-peak periods in the early years. It is suggested further work is undertaken to test the responsiveness of PHEV and BEV drivers to TOU pricing.

According to Ausgrid (2011), implementation of TOU pricing had reached 334,000 customers at the time of release of their discussion paper, AEMC review of strategic priorities for Energy Market Development in May 2011. Ausgrid reports the need to service a further 1.25 million customers who are currently using an accumulation meter.

Trials have shown that technology can play a significant role in communicating price signals to customers; especially if the impact of their own behaviour can be made visible to them. In-home displays (IHDs) or web-based interfaces (portals) that can display energy usage and its consequence on price and bills allow consumers to make informed decisions about their consumption patterns; leading to increased response to changes in tariffs.

4.4.4 Smart Charging

Smart charging will provide the EV charger with a sophisticated communication and load management system. This will enable EV chargers to decide whether to turn on or off based on better real time information from a variety of data sources. Some of the information likely to be considered includes:

- **A retail electricity price signal:** In the simplest case retailers offer a static TOU tariff. However, retailers could also offer a changing tariff based on the time, overall household demand, and the wholesale electricity price. This would reduce wholesale price risk for retailers and possibly give EV users access to low price charging windows, throughout the day.
- **Distribution and transmission grid conditions:** Distribution businesses and transmission operators may offer incentives to reduce or increase EV charging to address congestion, intermittent generation and planned and unplanned outages. Incentives could be offered directly but are more likely to come from an aggregator who maintains demand response arrangements with EV owners.
- **Household electricity demand and available capacity:** Smart charging may integrate EV charging into a wider Energy Management System for managing major household load including heating, air conditioning, water heating and pool pumps. By managing major loads, a household can flatten its overall load profile to stay within the physical capacity of the home circuit (avoiding upgrade costs) or any capacity limit imposed by the local distribution business.
- **User preferences:** Crucially, smart charging systems will learn how much charge users need, when and how concerned their user is about running out of charge. A good example of this approach is the recently released Nest thermostat which adapts home heating to suit individual users but also allows users to adjust the temperature at will. Overtime, the Nest uses this information to determine each user preferences (Nest, 2011).

Under a smart charging scenario users are likely to face incentives at least as strong as those under TOU. However, incentives may be even stronger during periods of actual, as opposed to anticipated, periods of high demand. Consequently, smart charging is better able to shift EV charging when it counts and less likely to incentivise shifting when it is not needed. The ability to learn user preferences, if effective, will also encourage users to entrust charging to their smart charger rather than default to charging as soon as they arrive home.

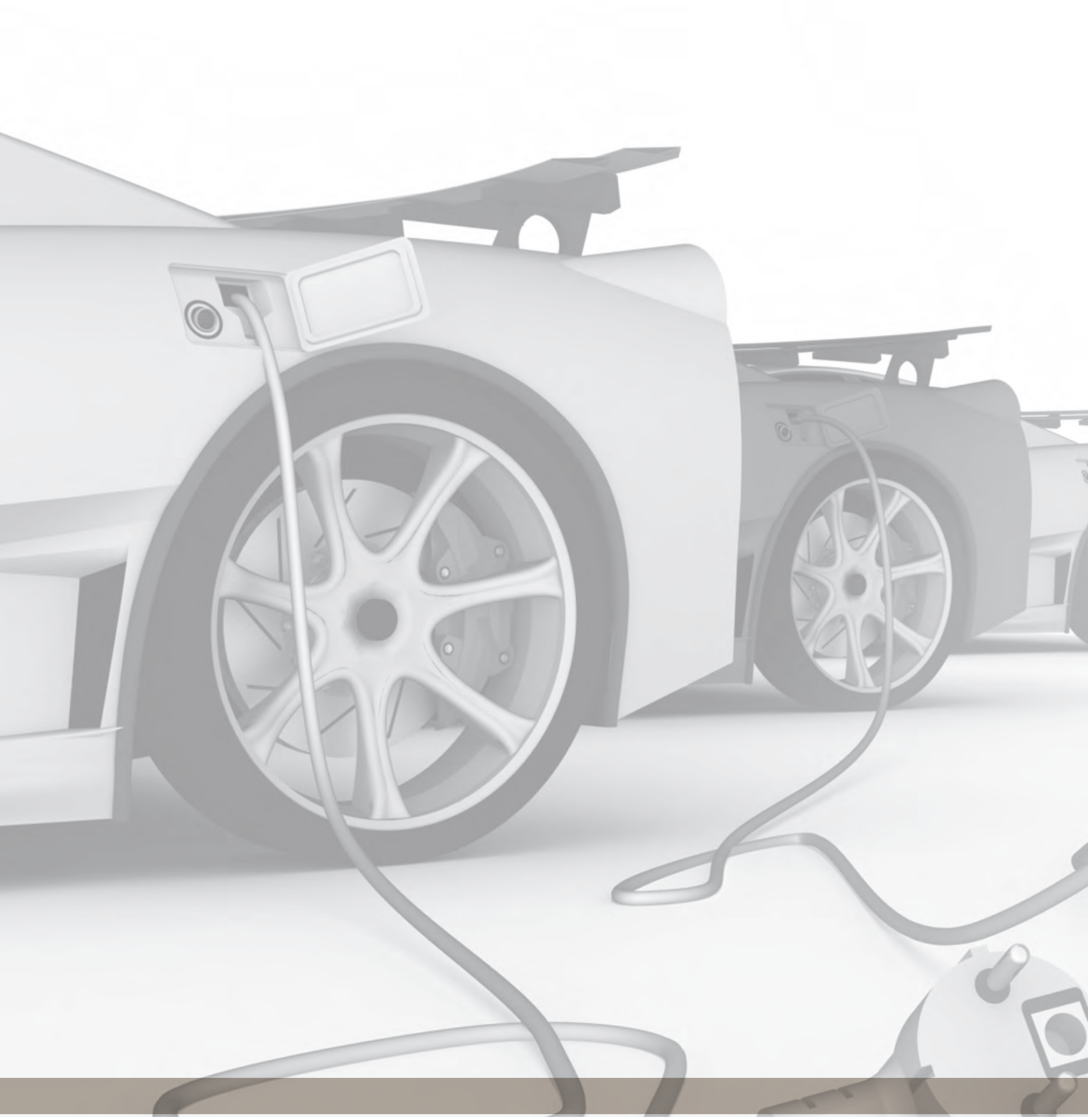
The success of smart metering in shifting EV charging activity will depend on the development and more importantly the adoption of new technology, as well as the development of business models that incentivise charging behaviour. For simplicity, we have assumed that smart charging will achieve a further 50% reduction in additional peak load compared to the TOU charging option.

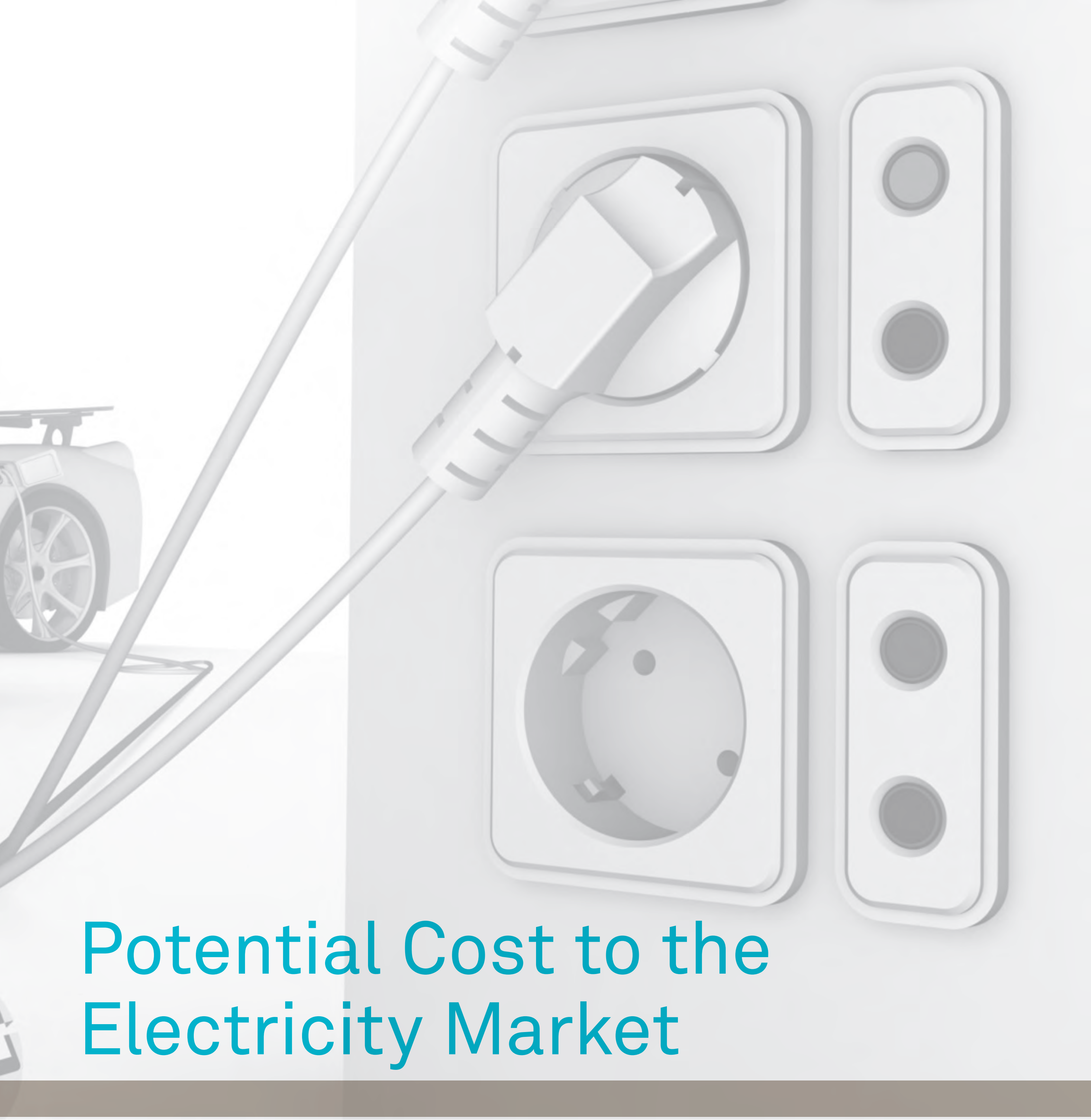
4.5 Summary of assumptions

Table 24 summarises the key assumptions on where people will charge, how much power will be required and the timing of charging.

Table 24: Summary of charge management assumptions

Assumption	Description
Where will EVs charge?	EV charging could occur at work, in parking spaces, at commercial re-charge stations and in the home. However, most charging will occur at home.
How much power will EV chargers require?	For the purposes of modelling EV impacts we consider two scenarios: everyone has a Level 1 charger with a charger power of 3.6kW (15A) and everyone has a Level 2 charger with a charger power of 7.7kW (32A).
When will EVs charge?	
Unmanaged (Worst case scenario)	Majority of EVs are charging over the existing early evening peak load period (80% charging in evening peak and sensitivity with 100% charging in evening peak).
Controlled charging	All home, work and public EV chargers are controlled through a ripple control scheme by a distribution company, a retailer or an aggregator. All EV charging occurs during off-peak periods.
Time of Use	PHEVs and households with more than one vehicle charge in off-peak periods.
Smart charging	Compared to TOU, a further 50% of users charge in the off-peak period, due to stronger incentives during critical periods.





Potential Cost to the Electricity Market

5.0

Potential Cost to the Electricity Market

This section estimates the cost to the electricity wholesale, network and retail markets of accommodating EVs. Our research and the submissions received show that the cost of increasing capacity is by far the most significant cost resulting to the electricity market from the introduction of EVs.

5.1 Assumptions and Approach

Demand for electricity has been steadily increasing and is forecast to keep growing over the foreseeable future. For all but the most extreme scenarios-unmanaged high take up-EVs will add only a fraction of the already forecast load growth. Like other types of load the main determinant of cost will be the increase in peak load. Our approach focuses on estimating the additional cost of this additional peak load and then considers factors and costs unique to EVs.

Reliability

It is unlikely that the take up of EVs will have a significant impact on the reliability of the electricity market, at either the generation or network level, for the following reasons:

- Take up is likely to be gradual with enough lead time for the market to respond;
- Energy consumption and increases in peak demand due to EVs are relatively small when compared with expected growth without EVs; and
- The electricity markets and regulation should continue to work effectively and provide the right incentives for the generation and network businesses to respond to the take up of EVs.

The direct effect of any increase in peak load on electricity supply (holding everything else constant) is a decrease in the quality of service: distribution networks become less reliable, transmission becomes congested and demand may exceed the supply of generation; resulting in an increase in black-outs. However, all of these quality-of-service issues can be addressed by investing in increased capacity. The electricity market has two mechanisms for ensuring this happens:

- **The revenue and quality regulation of transmission and distribution companies by the AER:** The current regulatory system includes strong incentives for utilities to maintain and improve their quality of service.
- **The competitive market for electricity supply:** The Electricity Statement of Opportunities (SOO) by AEMO is produced annually and includes assumptions about the adoption of EVs. Provided the take up of EVs is monitored and included in the SOO the market will provide the additional generation required to support EVs. Generators sell electricity into a competitive market. As supply becomes tight prices increase, providing a strong incentive for new generation. In the NEM this new generation need not be from the same state but could instead be imported via an interconnector. We assume the market will respond to EV's in the same way in the future.

Consequently, our analysis assumes quality of service (including reliability, congestion and availability of generation) remain unchanged and the cost of maintaining this service is fully reflected in the cost of increased capacity.

Our approach to estimating the cost of increased capacity

The cost of increasing capacity has been estimated in three steps:

- First, we estimate the increase in peak load based on the number of EV vehicles (see **Section 3.4**) and the proportion of these vehicles charging at times of existing peak demand. **Section 4.0** develops our assumptions regarding these proportions under the four charge management scenarios and the likely power of the most common EV chargers.
- Second, we estimate the cost of expanding distribution, transmission and generation capacity to allow for increased peak load. This approach is necessarily high level and designed to provide an indication of the magnitude of costs. As such, many issues such as losses and diversity have not been addressed in any detail. The analysis below uses published data to estimate the potential costs but utilities will have better information on the costs applicable to their local area.
- Third, we multiply the estimated cost of expansion by the estimated increase in peak load.

5.1.1 Cost of increasing transmission and distribution capacity

We have estimated the cost of increasing capacity in transmission and distribution networks by analysing recent regulatory determinations by the Australian Energy Regulator (AER). Each determination contains a estimate of capital expenditure and peak load growth during the regulatory period. A high level estimate of the cost of capacity for each DNSP (distribution network service provider) or TNSP (transmission network service provider) can be made by dividing growth related investment in one year by growth in the next, as shown below in **Table 25**, for distribution and **Table 26**, for transmission.[12] Expenditure was only categorised as growth if there it was clearly growth related. For instance items like "Augmentation" and "Growth". Other expenditure items, for example those related to reliability, will also be partially affected by peak load growth, but have not been included in these estimates.

Table 25: Cost of increasing capacity in distribution networks (2011$)

DNSP	State	Location	Estimated Capex / Growth ($M / MW)
Energex	QLD	Gold Coast, Sunshine Coast and Brisbane	2.8
Ergon	QLD	Country and regional Queensland	3.7
Ausgrid	NSW	Inner, northern and eastern metropolitan Sydney	2.7
Essential Energy	NSW	Country and regional NSW; southern regional Queensland	3.3
ActewAGL	ACT	ACT	2.9
Powercor	VIC	Western Victoria	2.1
SP Ausnet Distr	VIC	Eastern Victoria	2.2
United Energy	VIC	South eastern metropolitan Melbourne	2.7
Citipower	VIC	Inner metropolitan Melbourne	3.3
Jemena	VIC	Western metropolitan Melbourne	2.2
ETSA Utilities	SA	South Australia	3.5
Aurora Energy	TAS	Tasmania	4.8
Capacity weighted average			2.9
Ausgrid Estimate			1.2 - 4.0

Source: AECOM estimation based on various AER regulatory determinations. See for example, Energex (2011); Ausgrid (2011); ActewAGL (2008); Powercor (2010); SP Ausnet (2010); United Energy Distribution (2010); Citipower (2010); Jemena (2010). Note: currency in 2011 prices.

12. Capex is divided by growth in the following because investments necessarily need to occur before growth actually takes place.

Our analysis suggests that the cost of capacity is between $2.1 and $4.8 million per megawatt. This range is close to that proposed by Ausgrid in their recent submission to AEMC, namely $1.2 to $4 million per megawatt.[13] Growth tends to be more expensive in the DNSPs that service rural areas, for example Aurora Energy, Ergon and ETSA Utilities. This makes sense since networks in rural areas tend to be less connected and less dense, reducing the opportunity for load sharing. In the absence of better data, the weighted average of $2.9 million per megawatt was used as the cost of distribution growth in Western Australia.

Table 26: Cost of increasing capacity in transmission networks

TNSP	State	Estimated Capex / Growth ($M / MW)
Powerlink	QLD	0.85
TransGrid	NSW	0.90
SP AusNet	ACT	0.90
SP AusNet	VIC	0.47
ElectraNet	SA	0.37
Transend	TAS	1.66
Capacity weighted average		**0.66**
Ausgrid estimate		**0.4 – 1.1**

Source: AECOM estimation based on AER (2007; 2008; 2009b); Powerlink (2011) and ElectraNet (2008).

The cost of transmission growth was estimated to be between $0.37 and $1.66 million per megawatt, with a weighted average of $0.66 million. Again, the range was consistent with the estimate reported by Ausgrid (2011) of $0.4 to $1.1 million per megawatt, with the exception of Transend (again in Tasmania), which had the most expensive growth. It is worth noting that Transend owns a lot of distribution assets which may influence their cost estimates.

It is important to note that the cost of growth may be significantly different in the future. Several factors could affect this including, changes in technology, network topology and the approach to planning and building networks. Further, as highlighted above, this analysis has been undertaken based on published data to provide an order of magnitude of the likely costs. This approach is reasonable for the purposes of this study but should not be used for any other purpose.

5.1.2 Cost of increasing generation capacity

Increases in peak load will also require an increase in generation capacity. We have assumed that the increase in generation will be met by new gas fired peaking generation. Ausgrid (2011) estimates new peaking generation will cost in the range of $0.75 – $1.5 million per megawatt. Consistent with this range, ACIL Tasman (2008) reports that the cost of new Open Cycle Gas Turbine generation is around $0.94 million per megawatt (adjusted to 2011 dollars). We use the ACIL figure in our modelling.

5.1.3 Summary of estimated costs of increasing capacity

Our assumptions on costs per MW of installed capacity are summarised in **Table 27**. The total costs of increasing capacity are around $5 million per MW but vary by state. Distribution makes up the largest component of this cost accounting for between 60% to 75% of the total cost. Generation accounts for around 15% to 25% and transmission accounts for around 10% to 20%. Whilst the proportions vary between each state, distribution is the largest proportion for each sate and will be where the majority of additional costs from EVs will be incurred.

13. Ausgrid (2011), AEMC review of strategic priorities for Energy Market Development

Table 27: Summary of capacity cost assumptions

State	Generation ($M / MW)	Transmission ($M / MW)	Distribution ($M / MW)	Total ($M / MW)
QLD	0.94	0.85	3.10	4.88
NSW	0.94	0.90	2.92	4.76
ACT	0.94	0.90	2.94	4.78
VIC	0.94	0.47	2.49	3.89
SA	0.94	0.37	3.54	4.85
WA	0.94	0.66	2.93	4.53
TAS	0.94	1.66	4.77	7.37

Source: Estimated by AECOM based on published information.

5.1.4 Diversity and losses

There is very little information available on diversity in EV charging load beyond that discussed in **Section 4.4**. We have taken a conservative approach to diversity, essentially assuming there is no diversity at the distribution or transmission level, beyond that outlined under the charge management scenarios. This approach, allows us to estimate the worst case scenario. However, significant diversity is likely at the state level, even in the unmanaged case, which will decrease the need for transmission and new generation.

Network losses have not been included in the analysis at this point. However, their inclusion would require slightly more transmission and generation capacity. Network losses tend to be between 2% and 5% of sent out generation.

5.1.5 Distribution and transmission opex

Increased system capacity may or may not lead to slightly higher operational costs in the long-term. However, we have assumed these costs are likely to be negligible for the following reasons:

- **Opex is not strongly related to peak load.** Opex is mostly determined by line length and customer density rather than being directly related to peak load.
- **Capacity upgrades will replace and augment old assets with new assets.** New assets typically have lower opex.
- **On an annualised basis capital costs tend to dominate opex.** For example, an AER determination of Energex and Ergon Energy in 2009 (AER, 2009) showed annualised capital costs accounting for 75 per cent of costs and opex for only 23 per cent.

Although an EV related increase in peak load is unlikely to have a significant impact on opex, higher utilisation could and is discussed in **Section 6.1**.

5.2 Results

5.2.1 Impact on peak demand

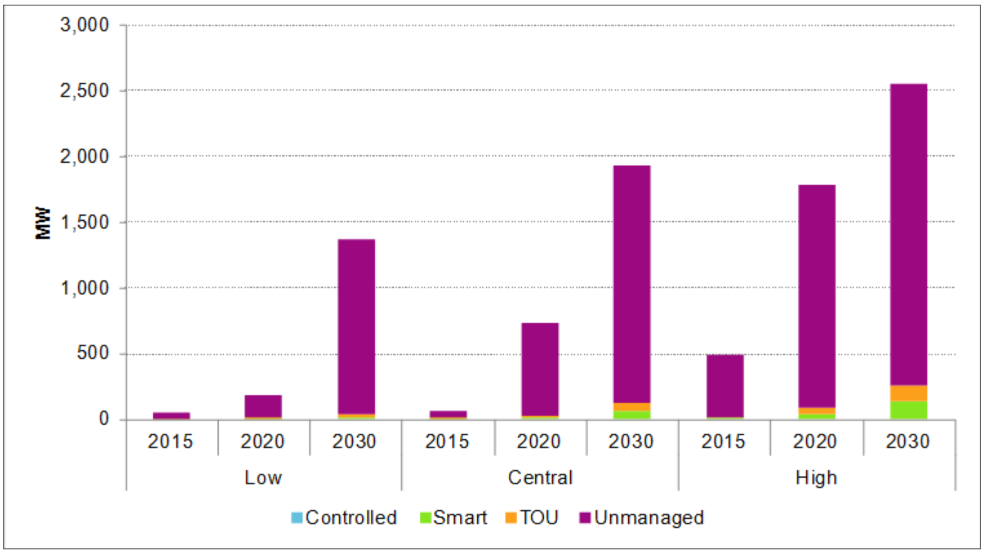
As highlighted in **Figure 28**, the impact of EVs on peak demand depends to a large degree on the level and rate of take up of EVs as well as when charging of the vehicle occurs.

In the central take up scenario, unmanaged charging of EVs starts to have a significant impact on peak demand around 2020. This should allow sufficient time for the electricity market to plan and manage the additional increase in peak load that may be required. However, it is possible that take up could be much quicker (as illustrated in our high take up scenario), if for example, battery prices fall much quicker than currently anticipated, in which case the impact of EVs on peak demand, if unmanaged, could be felt as early as 2015 which is just inside the five year planning cycle.

5.2.1.1 Impact of peak demand in the NEM

If charging is unmanaged and 80 per cent of EV users come home and charge at peak periods, under the central take up scenario, peak demand is expected to increase by around 740MW by 2020 and 1.9 GW by 2030. However, if charging occurs in off-peak periods, either through incentivising customers to charge at off-peak times through time of use charging or smart metering, or enforcing off-peak charging through ripple control or regulation, the costs fall significantly. Time of Use charging is expected to result in an increase in peak demand of 20 MW in 2020 and around 120 MW by 2030. Smart metering could reduce this even further to an increase in peak demand of around 10 MW in 2020 and 60 MW by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand.

Figure 28: Estimated additional peak demand in NEM (MW)

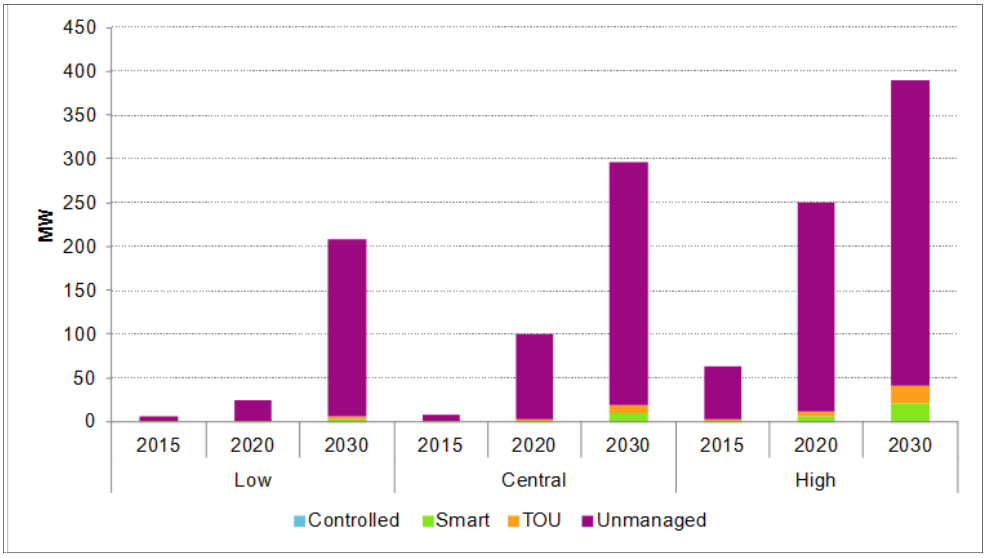


Source: AECOM. Note: The above chart shows estimated additional peak demand, with increments attributable to each charging type. For example, under the central take up scenario, by 2030, with unmanaged charging 1,900 additional MW are required; for TOU charging this is 120MW and for smart charging an additional 60MW.

5.2.1.2 Impact of peak demand in the SWIS

If charging is unmanaged and 80 per cent of EV users come home and charge at peak periods, under the central take up scenario, peak demand is expected to increase by around 100 MW by 2020 and 300 MW by 2030. However, if charging occurs in off-peak periods the costs fall significantly. Time of Use charging is expected to result in an increase in peak demand of 3 MW in 2020 and around 20 MW by 2030. Smart metering could reduce this even further to an increase in peak demand of around 1 MW in 2020 and 10 MW by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand.

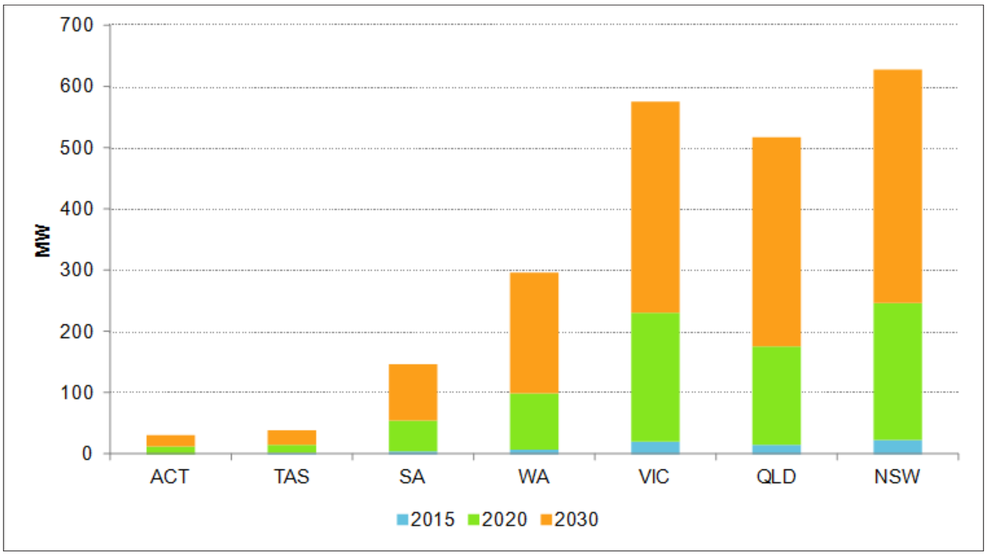
Figure 29: Estimated additional peak demand in SWIS (MW)



Source: AECOM

The largest increases in peak load occur in states with the largest take up of EVs (including PHEVs). As shown in **Figure 30**, the state with the largest increase in peak load is NSW, followed closely by Victoria. The increase in peak demand is lower in more rural states (such as Queensland) and states with smaller populations.

Figure 30: Additional peak demand in central take up scenario if charging is unmanaged

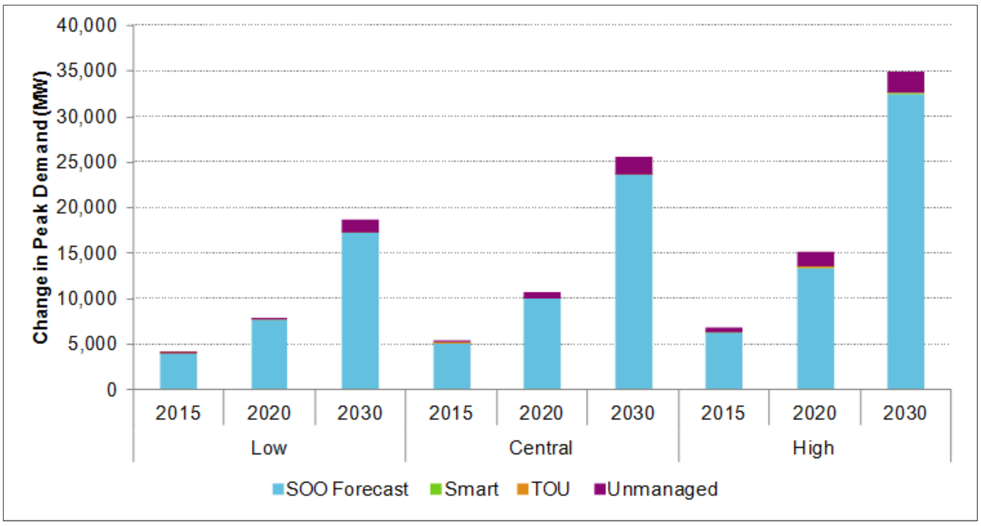


Source: AECOM

5.2.1.3 Impact of EVs on peak demand compared to peak demand required without EVs

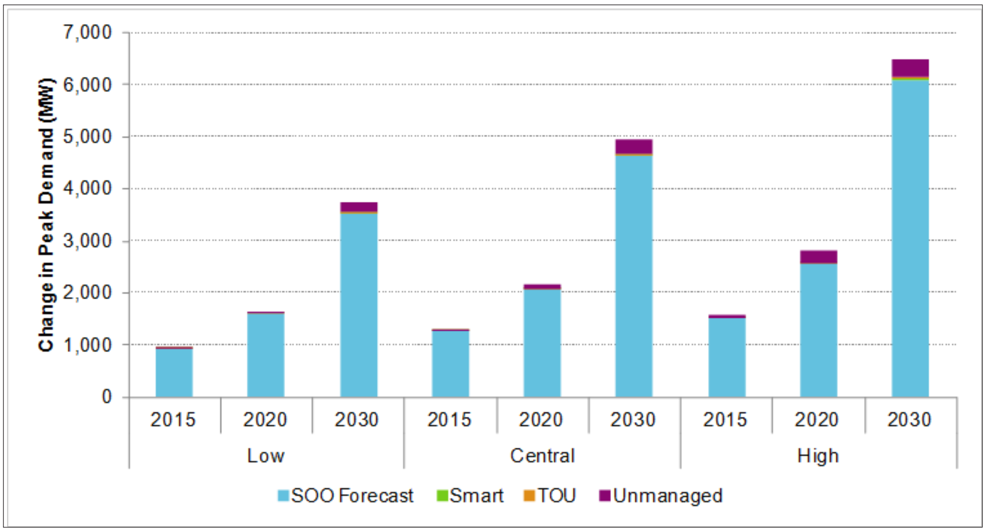
Figure 31 and **Figure 32** illustrates that for both the NEM and SWIS, the increased peak demand from EVs is minimal compared to the increase in peak demand required anyway. In all states, forecast growth due to EVs in the unmanaged scenario is small in comparison to growth already forecast. In the managed charging scenarios, the forecast growth due to EVs is negligible compared to growth already forecast. As a proportion of already forecast growth, EV related growth is greatest in Victoria, South Australia, and NSW and ACT. **Figure A1** to **A7** in **Appendix A** shows detailed graphs for each state. This analysis is based on the AEMO 50% probability of exceedence (POE) forecasts. If the 10% POE forecasts are used the proportional increase is even smaller.

Figure 31: Additional peak demand for EVs compared to additional peak demand needed without EVs – NEM



Source: AECOM and AEMO (2011a). SOO forecasts are based on the 50% probability of exceedence. SOO forecasts include a medium, low and high growth scenario representing different economic growth scenarios. These scenarios have been matched with the central, low and high take up scenarios.

Figure 32: Additional peak demand for EVs compared to additional peak demand needed without EVs – SWIS



Source: AECOM and AEMO (2011a)

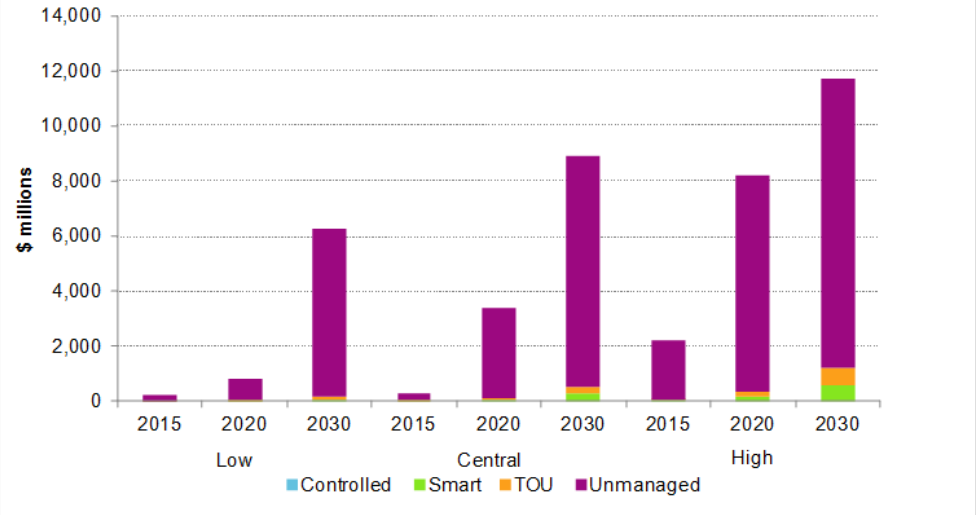
5.2.2 Cost of increased capacity

5.2.2.1 Cost of increased capacity in the NEM

As described above, the estimated impact, and hence costs, of EVs on additional peak demand depends on the rate of take up and the demand management scenario used to managing charging.

Figure 33 shows that, if charging is unmanaged and everyone comes home and charges at peak periods, under the central take up scenario the cost of increased capacity in the NEM could be around $3.4 billion by 2020 and $8.9 billion by 2030. However, if charging occurs in off-peak periods, either through incentivising customers to charge at off-peak times through time of use charging or smart metering, or enforcing off-peak charging through regulation, the costs fall significantly. Time of Use charging is expected to result in additional costs of around $90 million by 2020 and $550 million by 2030. Smart metering could reduce this even further to around $50 million by 2020 and $270 million by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand. These estimates have not been discounted to reflect timing of investments. As discussed above, in **Section 5.1.3**, the largest component of this cost will be driven by investment in distribution, which will account for between 60% and 75% depending on the state. Generation accounts for around 15% to 25% and transmission accounts for around 10% to 20%.

Figure 33: Estimated cost (for both generation and network upgrades) of additional peak demand in NEM ($ millions undiscounted)

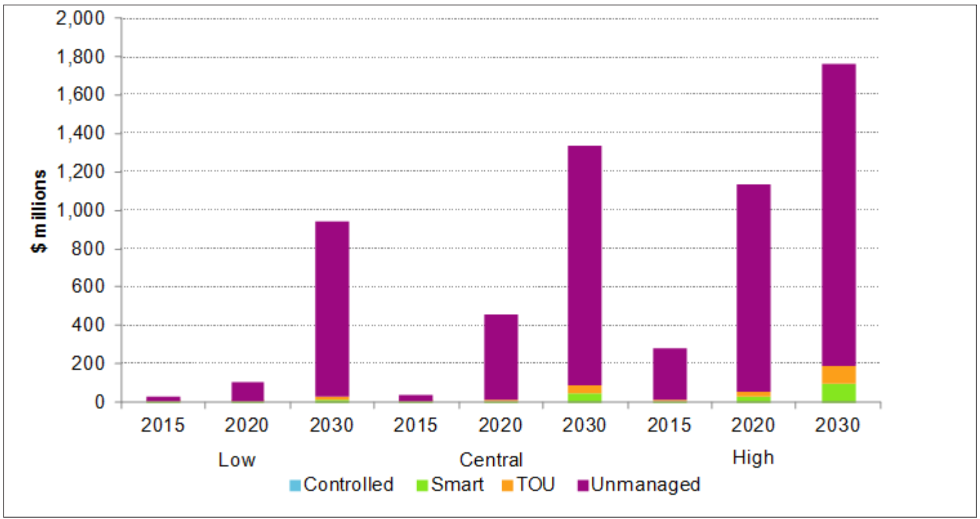


Source: AECOM

5.2.2.2 Cost of increased capacity in the SWIS

Figure 34 shows that, if charging is unmanaged and everyone comes home and charges at peak periods, under the central take up scenario the cost of increased capacity could be around $460 million by 2020 and $1.3 billion by 2030. However, if charging occurs in off-peak periods the costs fall significantly. Time of Use charging is expected to result in additional costs of around $10 million by 2020 and $90 million by 2030. Smart metering could reduce this even further to around $6 million by 2020 and $40 million by 2030. Controlled charging, which would ensure all charging occurs off-peak, would result in no additional increase in peak demand. These estimates have not been discounted to reflect timing of investments.

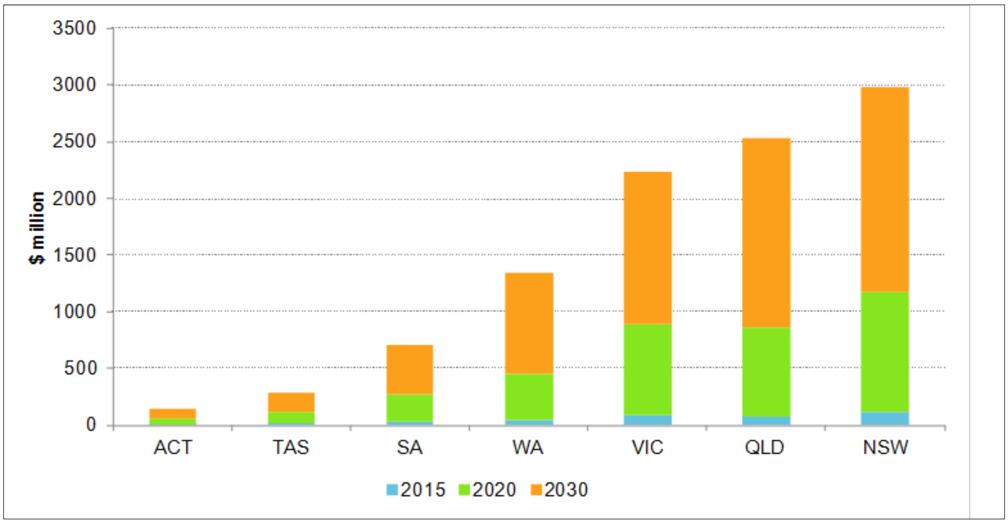
Figure 34: Estimated cost (for both generation and network upgrades) of additional peak demand in SWIS ($ millions undiscounted)



Source: AECOM

The impacts and costs also vary significantly by state depending on the take up of vehicles in each state. As can be seen in **Figure 35**, the impact is expected to be bigger in New South Wales, Queensland and Victoria, the states with the largest take up of EVs. Interestingly, the cost of increasing capacity in Queensland is likely to be higher than in Victoria, even though Victoria has a higher estimated increase in peak load. This is because cost of upgrading capacity in Queensland tends to be higher.

Figure 35: Costs of additional peak demand in central take up scenario if charging is unmanaged ($million undiscounted)



Source: AECOM

Overall, the analysis shows that the impact of EVs on peak demand depends on the level and rate of take up and the ability to induce charging in off-peak periods either through incentivising customers to charge at off-peak times through time of use charging or smart metering, or enforcing off-peak charging through regulation. The impacts also vary by state in line with vehicle usage and take up of EVs.

Whilst the analysis above provides some guidance to the likely take up and charging of EVs, there is considerable uncertainty so it is difficult to make precise assessments of the implications for electricity networks. The costs above are based on planned upgrades built into longer-term asset replacement plans. It is possible that there will be a rapid unexpected take up of EVs, which will result in unexpected investment at much higher cost. This highlights the importance of demand management policies to ensure the charging of EVs occurs during off-peak periods and does not impact of peak demand.

5.2.3 Sensitivity to charging behaviour

Peak load and cost outcomes are particularly sensitive to the time of charging and charger power. **Table 28** shows the peak load and cost results for a more extreme charging scenario where all EVs charge during the peak period in the unmanaged scenario and EVs charge at 32 A rather than the 15 A we have modelled. In the unmanaged case this results in a 150 per cent increase in the additional peak load and cost imposed by EVs. **Figure A8** to **Figure A13** in **Appendix A** provide further analysis.

Table 28: Results with more intensive charging during existing periods of peak demand

		Low			Central			High		
		2015	2020	2030	2015	2020	2030	2015	2020	2030
Change in peak demand (MW)										
SWIS	Smart	1	1	6	1	3	20	2	10	50
	TOU	1	2	10	2	6	40	5	30	90
	Unmanaged	20	50	440	20	220	630	130	540	830
NEM	Smart	4	8	40	8	20	130	20	90	280
	TOU	8	20	80	20	40	250	30	170	560
	Unmanaged	120	390	2,920	140	1,570	4,130	1,040	3,820	5,450
Cost of upgrading capacity ($m)										
SWIS	Smart	2	5	30	5	15	95	10	60	200
	TOU	5	10	60	10	30	200	20	100	400
	Unmanaged	70	200	2,000	80	1,000	2,900	600	2,400	3,800
NEM	Smart	20	40	200	40	95	600	80	400	1,300
	TOU	40	75	400	75	200	1,200	200	800	2,600
	Unmanaged	500	1,800	13,400	600	7,200	19,000	4,700	17,500	25,000

Source: AECOM

5.3 Other costs to the electricity market

Whilst the impact on peak demand and costs associated with increasing capacity are clearly the major costs to the electricity markets of EV, there are a range of other costs that may occur. This section identifies other potential costs, drawing on submissions to the AEMC Approach Paper.

5.3.1 Frequency Control Ancillary Services (FCAS)

The frequency of AC (alternating current) power in the NEM changes slightly when an increase or decrease in demand (or generation) is not matched by generation (or demand). The system is allowed some tolerance and is allowed to operate in a band from 49.9 to 50.1 Hz (AEMO, 2010). To keep within these bounds the Australian Energy Market Operator (AEMO) operates eight frequency control ancillary services (FCAS) markets. Six of these are used to raise or lower frequency in response to a contingency-the loss of a generator or a large load-over 6 second, 60 second and 5 minute horizons. The remaining two, known as the regulation raise and lower markets, are used to keep the frequency within the regulated range during normal operation

EV charging could increase the amount of FCAS actions AEMO needs to take in the regulation raise and lower markets, if chargers turn on or off simultaneously. This is possible under managed charging scenarios. For instance, most automated TOU EV chargers would likely switch on at the beginning of off-peak periods. This choice of timing would provide users with more charge earlier, thereby providing greater convenience. Similar problems can easily arise under controlled charging and smart charging scenarios, if chargers collectively respond to the same signals.

Although EV charging could easily increase FCAS actions, this need not happen if the switching on of EV charging is graduated or staggered. There are relatively simple technical solutions to achieve this. Controlled load can be staggered using a multi-channel ripple control system. Similarly, smart charging could be staggered through direct communication with individual chargers. Staggering automated TOU chargers may prove slightly more difficult but may be achieved by introducing shoulder rates, in addition to off-peak rates.

While, load staggering is simple to achieve from a technical perspective it may create policy issues. Users, who are allowed to begin charging first, essentially receive a priority service and it is unclear how this priority service should be allocated.

5.3.2 EVs will have the largest impact at the distribution level

AECOM's analysis and several submissions to the AEMC Approach Paper stress the impact of EVs near the customer end of the electricity supply chain. Ergon Energy notes the impacts at the distribution transformer and zone sub-station level. Energex also emphasises cost at the distribution level and argues that the cost could be even higher on the Low Voltage (LV) parts of a distribution network. Two reasons emerge for this higher cost:

- Higher cost of increasing capacity: As shown in **Section 5.1** the cost of increasing capacity in the distribution network is greater than the combined cost of transmission and generation capacity upgrades. One reason for this is that the quantity of assets (for instance length of line) per customer increases further down the supply chain.
- Diversity is lower at the distribution level: As noted in the Energex submission "The least diversified component of the electricity supply chain is the low voltage distribution network". Diversity decreases further down the supply chain because assets service fewer customers, raising the possibility simultaneous use of network assets.

Distribution level impacts therefore warrant further consideration and charge management solutions may be most effective if they are responsive to distribution level constraints. The Energy Network Association goes even further arguing that "The ability of distribution businesses to control or at least influence the time and rate (in terms of kW) of EV charging will determine the level of impact".

5.3.3 EV clustering and local coordination

Ergon Energy notes that "The uptake of EVs is likely to vary by location reflecting the socio-economic attributes of their customers in geographic areas". Broadly, take up is likely to be higher in affluent areas where the population share more environmentally focused values. If charging is unmanaged, this localised take up may create clusters of EV users that require rapid capacity upgrades of their local network and incur costs that are then spread over all customers in served by that DNSP.

Clustering may even create overloading in off-peak periods if several users decide to charge during the same off-peak period. This is most likely under a TOU charging regime, where automated TOU EV chargers would collectively turn on at the beginning of the off-peak or shoulder tariff period.

Upgrading the network may be avoided if EV users and local DNSPs can coordinate charging to ensure local diversity. This is important not only to avoid overloading the network, but also to avoid step changes in load (SP AusNet submission). SP AusNet notes that this can be achieved by staggering controlled load.

Smart charging may offer another solution if the controller has the ability to influence the rate and timing of EV charging in real-time at a neighbourhood or even individual level. However, this fine level exacerbated of influence will likely lead to greater complexity and cost and this may be exacerbated by an incentive, rather than using a command and control, approach.

5.3.4 Rural EV users

Rural drivers tend to cover greater distances, which will initially not be suited to the range of EVs. Rural take up is therefore expected to be low. However, where take up does occur, the impact on network is likely to be greater. There are two main reasons for this. Firstly, the cost of upgrading rural networks is already generally higher. Secondly, as noted by SP AusNet rural single phase substations typically have a very low capacity and so even one or two EV chargers could overload the system.

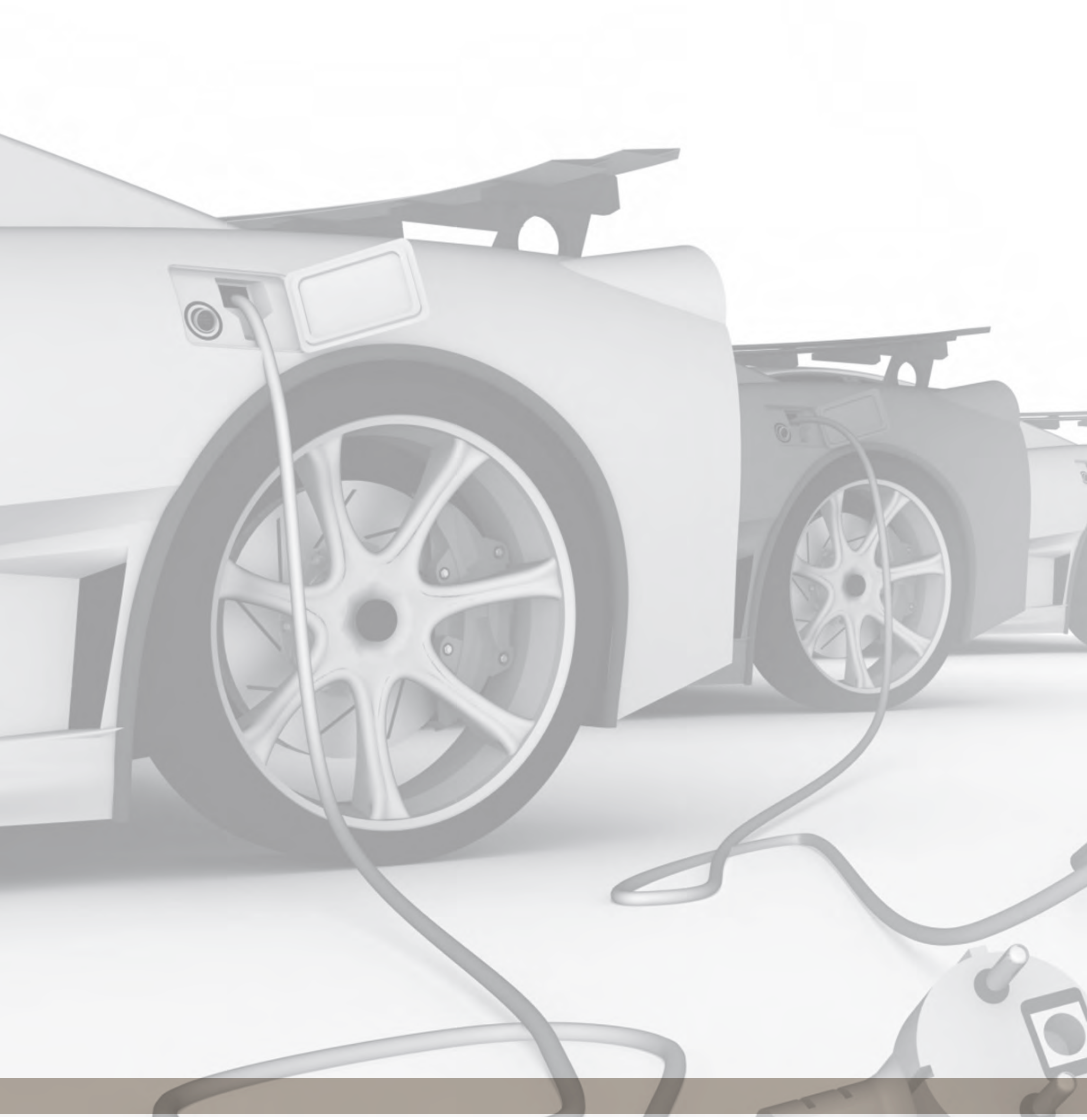
5.3.5 Network protection

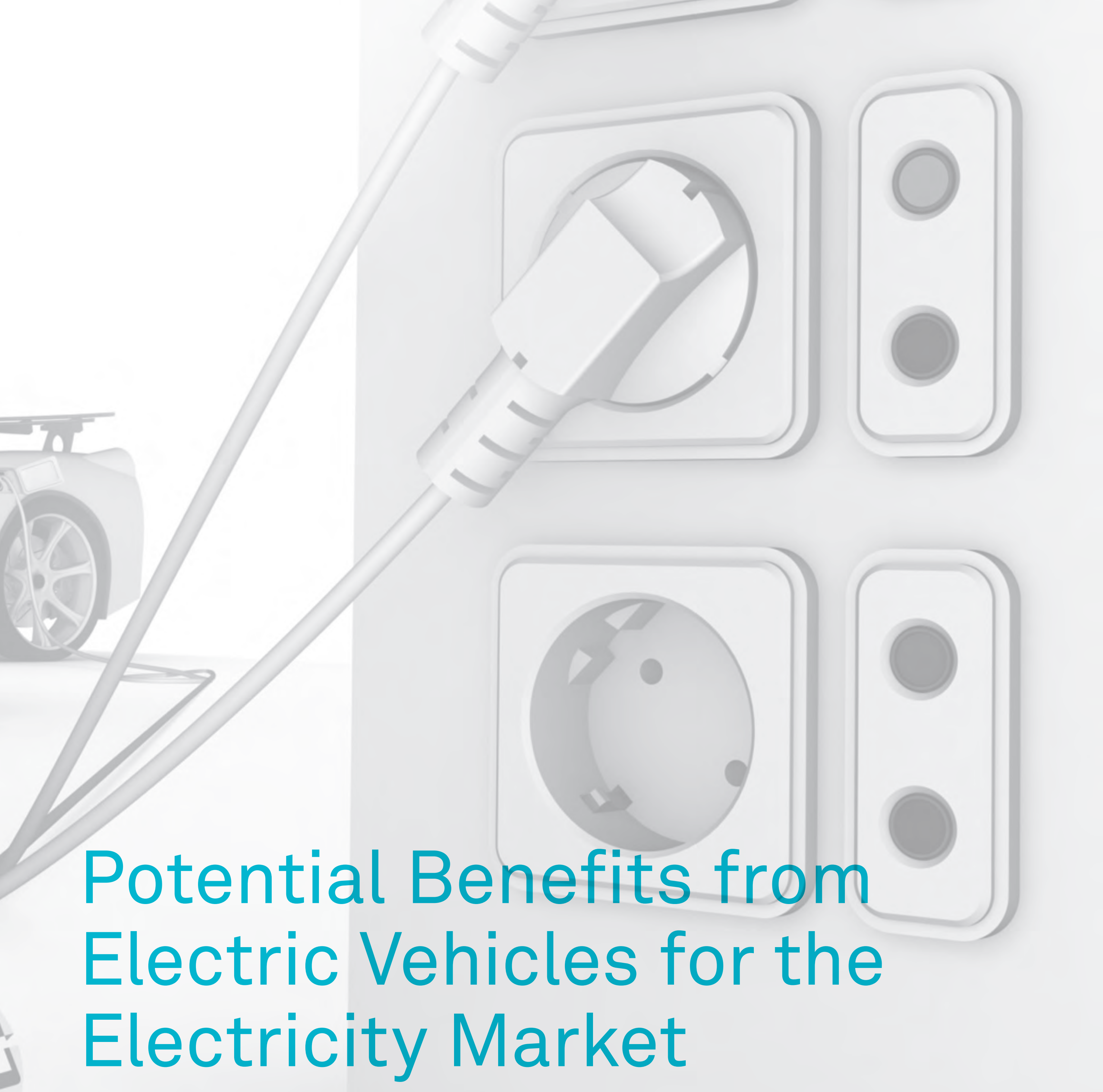
Energex notes that EV charging has the potential to affect network protection arrangements and that these impacts would cost more if take up is rapid. However, Energex also notes that this issue is not unique to EVs and only needs to be considered when particular arrangements to support EVs are being considered.

5.3.6 Metering and EV charge control systems

Our results show that controlled and smart charging have the lowest overall impact on peak load. However, TRUenergy notes that controlled or smart charging may also have their own costs including:

- **Development of new IT and communication systems:** Dynamic EV charging systems will take account of current conditions in the network and market. Consequently, DNSPs, EV users and potentially retailers will need to invest IT and communications systems capable of sending, receiving and processing real-time market and network data.
- Development and operation of tariffs: DNSPs and retailers will need to develop new tariffs for controllable and smart charging. This leads to higher costs in both cases. However, in the case of smart charging, the tariff is likely to be considerably more complicated, imposing higher costs and risks for the business.
- **Separate metering arrangements:** Charge management solutions which apply different tariff arrangements to EVs compared to the rest of the household load will likely require separate meters. The installation of new meters will be costly. However, this cost may be partially reduced if new meters are able to automate functions such as meter reading.





6.0

Potential Benefits from Electric Vehicles for the Electricity Market

Potential Benefits from Electric Vehicles for the Electricity Market

6.1 Improved load factor of network assets

An improved load factor of network assets allows the electricity system to deliver more energy with the same assets. If the market was efficient, customers should benefit from a lower electricity price than they would pay in the absence of EVs. This section estimates how much lower residential electricity prices might be for the delivery of electricity. However, it is important to recognise that this is not a new economic benefit but a financial transfer to non EV electricity consumers.

6.1.1 Assumptions and approach

6.1.1.1 Calculating the percentage decrease in fixed costs

If the absolute cost of the electricity system remains the same but demand increases then the cost per unit of demand will decrease.

In order to keep costs constant (with the addition of EV charging load) we base our estimate on off-peak demand only, since an increase in peak demand imposes costs (already addressed in **Section 5**).

6.1.1.2 Energy assumptions

Transmission level energy assumptions are shown below in **Table 29** and distribution level assumptions are shown in **Table 30**.

Table 29: Transmission level energy demand assumptions (MWh)

State	2015	2020	2030*	Average Growth (%)
QLD	72,924	90,657	159,315	5.8%
NSW + ACT	81,637	88,844	105,157	1.7%
VIC	53,115	60,639	76,122	2.3%
SA	16,401	18,017	22,617	2.3%
TAS	12,499	14,192	17,816	2.3%
WA	35,000	40,000	45,515	1.3%

Source: AEMO (2011a) (for NEM data); CMEWA (2009). *The estimate for 2030 is extrapolated based on average energy growth.

At the distribution level customers can be divided into half hourly metered customers, who are typically large industrial users, and commercial and residential customers. We have based our estimate of the decrease in residential prices, off the existing demand at the distribution level from commercial and residential customers, which is approximated by Net System Load Profiles. However, this is only an approximation and since industrial users do in fact share parts of the distribution network assets, especially at the high voltage and sub-transmission level. Consequently, the estimate of price decreases at the distribution level is likely to be optimistic.

Table 30: Distribution level energy demand assumptions (MWh)

State	2015	2020	2030*	Average Growth (%)
QLD	72,924	90,657	159,315	5.8%
NSW + ACT	81,637	88,844	105,157	1.7%
VIC	53,115	60,639	76,122	2.3%
SA	16,401	18,017	22,617	2.3%
TAS	12,499	14,192	17,816	2.3%
WA	35,000	40,000	45,515	1.3%

Sources: Net System Load Profiles published by AEMO (2011a), Wessex Consult (2010). Notes: 2015, 2020 and 2030 estimates are based on average growth in **Table 29**.

6.1.1.3 Calculating the decrease in residential tariffs

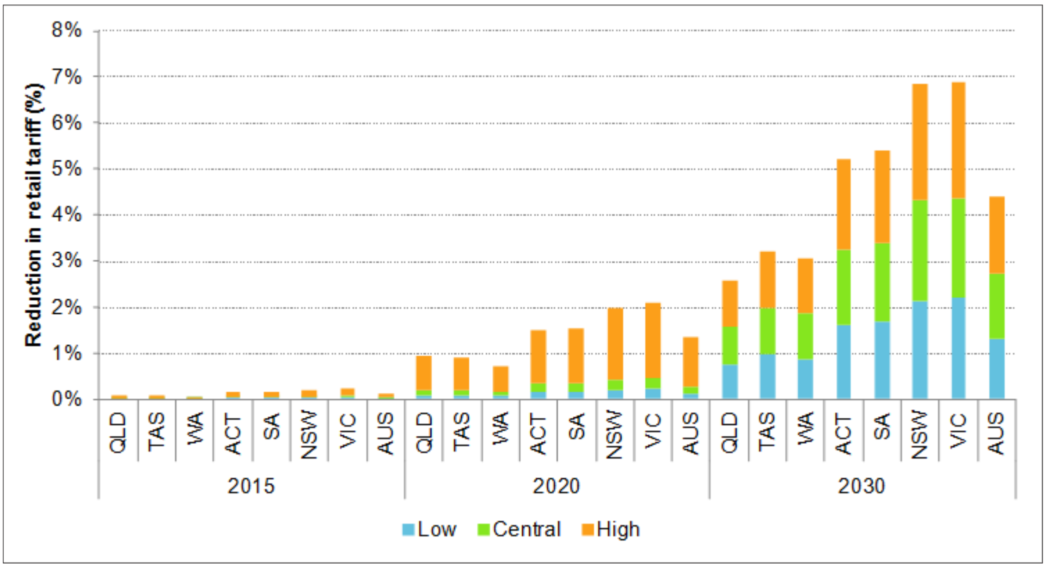
To calculate the percentage change in residential tariffs we add the per cent change in cost for transmission to that of distribution, weighted by their contribution to residential tariffs. We assume transmission makes up 11% and distribution 44% of residential tariffs. These assumptions are consistent with Garnaut (2011) who states that "About 10 percentage points of the movement costs are for transmission and 40 per cent for distribution" and Treasury modelling which shows that network costs will actually make up around 55% over the next 20 years (Treasury, 2011).

6.1.2 Results

Figure 36 provides an estimate of the potential reductions in retail tariffs from improved utilisation of network asset assuming controlled charging. Controlled charging ensures 100% off-peak charging and as such represents the maximum benefit. The impact of time of use and smart metering depends on its success at shifting charging into off-peak periods. The results highlight the potential reduction in retail tariffs is directly linked to the timing of EV take up, with the larger reductions occurring towards 2030 when take up is higher.

Across the study area, the potential reduction in retail tariff is up to 5% in the high take up scenario by 2030 compared to what might happen otherwise. However, the potential savings vary from around 2.6% in Queensland to around 7% in New South Wales and Victoria. This difference is driven by higher take up rates and the base level of electricity demand. For example, as highlighted in **Table 30**, Queensland currently accounts for around 20% of energy demand but by 2030 this is expected to grow to around 40%.

Figure 36: Estimated reduction in retail tariff from improved load factor of network assets with off-peak charging (assuming controlled charging)

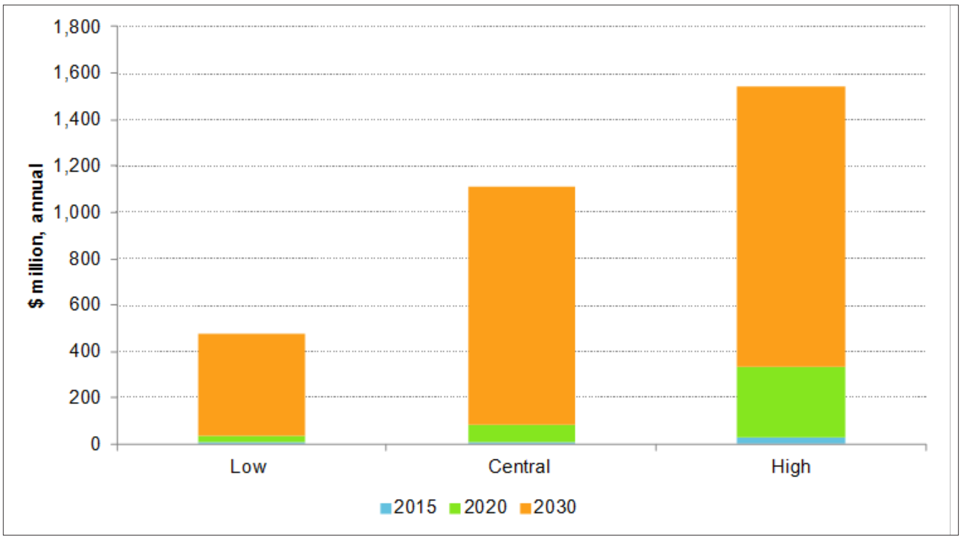


Source: AECOM

Figure 37 shows the estimated value from reduced retail prices in the NEM. Again, the value depends on the take up scenario but could potentially range from around $7 million to $28 million a year in 2015, $35 million to $330 million a year by 2020 and $475 million to $1.5 billion a year by 2030 compared to what might happen otherwise. It is clear, even in the low take up scenario, that as take up increases the potential benefits from improved load factor of network assets are significant.

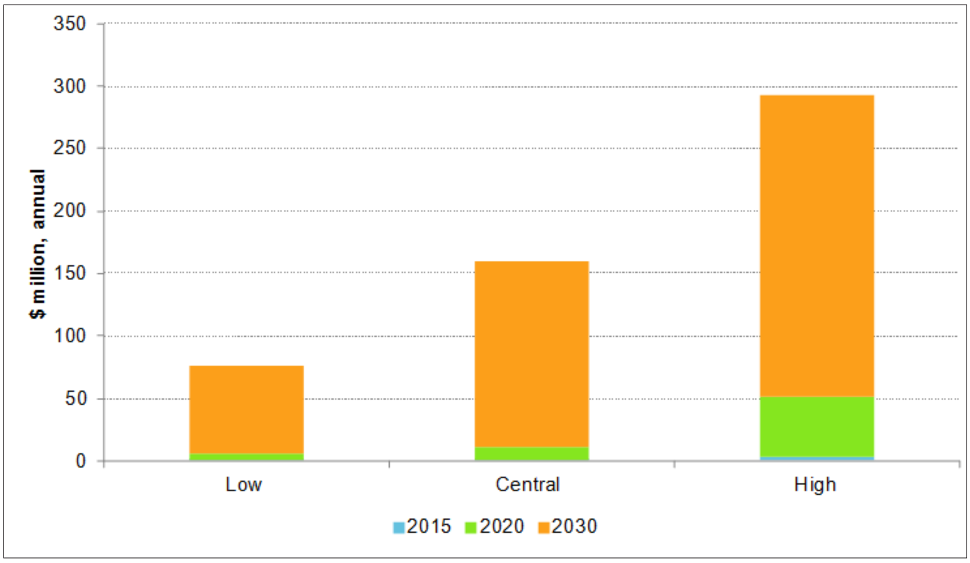
Figure 38 shows the estimated value from reduced retail prices in the SWIS. Depending on the scenario, the value of reduced retail prices could range from $1 to $4 million in 2015, $5 to $45 million by 2020 and $70 to $240 million by 2030.

Figure 37: Estimated value from reduction in retail tariff from improved load factor of network assets with off-peak charging (assuming controlled charging) – NEM



Source: AECOM

Figure 38: Estimated value from reduction in retail tariff from improved asset load factor with off-peak charging (assuming controlled charging) – SWIS



Source: AECOM

6.1.2.1 Discussion

An improved load factor was clearly identified as a major potential benefit in many of the submissions, including Ergon Energy, Energex, Western Power, SP AusNet and the University of South Australia. Both Western Power and the University of Australia highlight the direct link between improved load factor and pricing, which is also borne out in AECOM's analysis. Ergon concurs that this would lead to downwards price pressure.

6.1.3 Impact of improved load factor on generation

A higher load factor will also benefit generation, by allowing the return on generation capital to be spread over many more megawatt hours. However, these benefits are unlikely to flow on to customers until the generation mix changes and in the short run prices may even be higher as the market adapts. In the short run, off-peak prices will likely rise, increasing the return to capital intensive base load generation. As a result, in the medium to longer term we should expect more base load generation and because this new generation is also available during peak periods, lower peak prices. The result overall should be a decrease in price volatility and average electricity bills. However, average prices-over the course of a full day-may go up or down.

The West Australian energy market includes a separate market for capacity-the Reserve Capacity Scheme. Consequently, at least part of the capital cost of new generation is recovered through the capacity market leading to less volatility and lower peak prices than would otherwise be the case. This muting affect is likely to reduce the impact of EVs on wholesale prices. There may be a need for the IMO to review the allocation of reserve capacity credits and reserve capacity requirements as EVs are introduced.

6.1.4 Operating and maintenance costs

Improved load factor of network assets may have other costs in terms of increased operating and maintenance costs and reducing the life of the asset. ChargePoint notes in their submission that "the introduction of mass market EV's will accelerate the need for replacement and upgrading of ageing or inadequate infrastructure". This section substantially addresses the need to upgrade inadequate infrastructure. However, EV charging may also accelerate the deterioration of some assets-transformers in particular-by extending the period of time assets operate at or above rated values. This may be a particular problem where EV charging extends the period of peak demand into the evening. SP AusNet also allude to this in their submission stating that "consideration will be required of the impact of improved utilisation on the life of assets".

6.2 Potential Flexibility Benefits

The use of smart metering for EV charging which will expose electricity consumers to real time costs of consuming electricity provides flexibility benefits to DNSPs, TNSPs and retailers. Theses flexibility benefits will provide opportunities for increased revenue for retailers and generators. Network businesses will face the biggest cost from EVs (see **Section 5.1.3**). However because they are regulated and their prices are capped, they have limited opportunities to capture the benefits EVs can provide.

This section discusses the additional potential benefits that arise from the flexibility offered by controllable and smart charging, in particular:

- How much flexibility can EVs provide?
- How can EV charging flexibility be used?

Flexibility in the electricity market is the ability to adapt to changing conditions in real time. This flexibility could allow EV users to take advantage of unexpected or local opportunities in the generation, transmission or distribution sectors, or react to unexpected constraints to avoid unnecessary cost. The key to providing flexibility is the ability to react in real time rather than in a planned way. Static schemes for demand management, such as TOU charging and controlled load through a timer cannot provide these benefits.

Flexibility can technically be provided by either controlled or smart charging. However, to be successful appropriate incentives need to be provided. This could include real time price signals from either retailers, distributors or an intermediary such as an aggregator. These options will be explored in more depth in step 4 of this study (See **Table 3** for an overview of the overall study framework). Here we merely identify the potential benefits, and assume that EV users are exposed to incentives commensurate with the real time cost of consuming electricity, currently borne by DNSPs, TNSPs, and retailers.

6.2.1 How much flexibility can EVs provide?

How much flexibility is available at any time depends on how much power can be turned on or off at that time. At one extreme, all EVs would be connected and able to be switched on. **Table 31** shows the potential flexible load from EV charging, in the situation where all EVs are connected to the grid. Somewhere near this amount may be available in the late evening or morning, if workplaces have charging facilities. However, most of the time only some EVs will be plugged in and available.

Flexibility is also unlikely to be symmetrical in that you can turn the same amount of power on as you can turn off at one point. The amount of power that can be turned on and off will depend on the time of day because of the charge level. For example, in the early evening when most vehicles are expected to be charging there will be more load to turn off than to turn on. Also, in practice, there is likely to be limited ability to reduce load at peak periods if a TOU charging regime is used, since this would tend to move most load to off-peak periods anyway. One solution to this may vehicle-to-grid, which is discussed further in Chapter 7.0.

Table 31 Potential flexible EV load (with all EVs connected)

	Low			Central			High		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
Level 1 charging (15 amps) - MW									
NEM	55	184	1,366	66	737	1,935	485	1,788	2,552
SWIS	7	24	208	9	101	295	63	251	389
Level 2 charging (32 amps) - MW									
NEM	117	393	2915	140	1571	4127	1035	3815	5445
SWIS	15	51	444	18	215	630	134	536	830

Source: AECOM

The availability of widespread charging infrastructure will increase flexibility by allowing users to connect to chargers more often. The sale of flexibility may even provide a small income stream to help fund public and work place charging points.

The rate and timing of charging may also prove important, since fully charged vehicles (unless they have vehicle-to-grid capacity) are unable to offer any flexibility to the network. This suggests that there is value in diverse charging times, even during off-peak periods. This runs counter to the interests of EV owners who-in the absence of incentives- will be keen to charge as soon as possible.

6.2.2 How can EV charging flexibility be used?

Flexible EV load may have several uses, including:

- Congestion and network management
- Managing price risk
- Making use of intermittent generation

6.2.2.1 Congestion and network management

Transmission can become constrained either during periods of high demand, planned outages or unexpected asset failures. At the transmission level, this can increase the risk of lost load or actually result in lost load. In some cases, the transmission service provider will be able to put in place temporary (but potentially expensive) measures to support the network, in others the network will have to operate at lower level of reliability. Dynamic EV charging can help by reducing charging activity and peak load during these critical periods.

At the distribution level, dynamic flexible EV charging can operate in a similar way, helping DNSPs address high demand, planned outages and asset failures. The distribution benefit is likely to be much higher than transmission benefit, because EV charging will make up a proportionally bigger share of the load. DNSPs will realise these benefits through existing reliability incentive schemes and potentially through reduced costs during planned maintenance. At the margin, networks may also be able to delay some network augmentation.

In the case of controlled charging, ripple control provides a very clear and existing mechanism to allow DNSPs or TNSPs to influence EV charging. However, this comes at the cost of consumer control. Incentivised behaviour through smart charging could offer an alternative.

6.2.2.2 Managing wholesale price risk

Retailers offer residential customers a fixed price but pay the market price. Consequently, retailers carry price risk that is ultimately passed on to customers through higher prices. Smart charging could help manage this risk by allowing EV users to react to the current retail price, buying less when prices are high and more when they are low. Overall, this would lead to lower average prices for EV owners and reduced price risk for retailers. However, it is unclear if this would be passed on directly to EV owners or to customers more generally. In the long term, better management of price risk would likely further impact the generation mix in much the same way as that described in **Section 6.1.3**, increasing the amount of base load generation.

Both AusGrid and Western Power noted the potential value of flexible EV charging in managing wholesale price risk. Western Power noted that, in Western Australia, flexible EV load is likely to have the biggest effect on the half hour ahead market for balancing energy. AusGrid also noted that flexibility in the West Australian market could be valued at $186,000 per MW per annum-the penalty for unmatched demand.

Smart charging could manage price risk by supplying a real time price signal or some other incentive, either through an aggregator or directly from the retailer. The opportunity to manage price risk through controlled load depends on who is responsible for managing the load. In the past, controlled load has been directly managed by DNSPs and is generally directed at whole areas rather than specific retail customers. Consequently, controlled charging may not be as effective. However, it should be noted that DNSPs will tend to reduce controlled load during periods when prices are high-indirectly managing retail price risk-and DNSPs may also contract to act on behalf of retailers. How and when this happens and the treatment of revenue arising from these actions should be considered in more detail.

6.2.2.3 Integrating intermittent generation

Intermittent generation, such as wind and solar, create price volatility in the electricity market. First, because the market cannot rely on intermittent generation to run, additional firm generation is needed to cope with peak load. Second, wind and solar generation have zero fuel costs and so can, when they are operating, deliver large amounts of energy to the market, at very low prices. The Renewables 2011 Global Status Report (Ren21, 2011) notes that the increased share of renewable energy into the grid creates reliability and stability issues and has raised concerns in places like in Germany and Spain with respectively 14% and 21% of electricity coming from intermittent renewable energy.

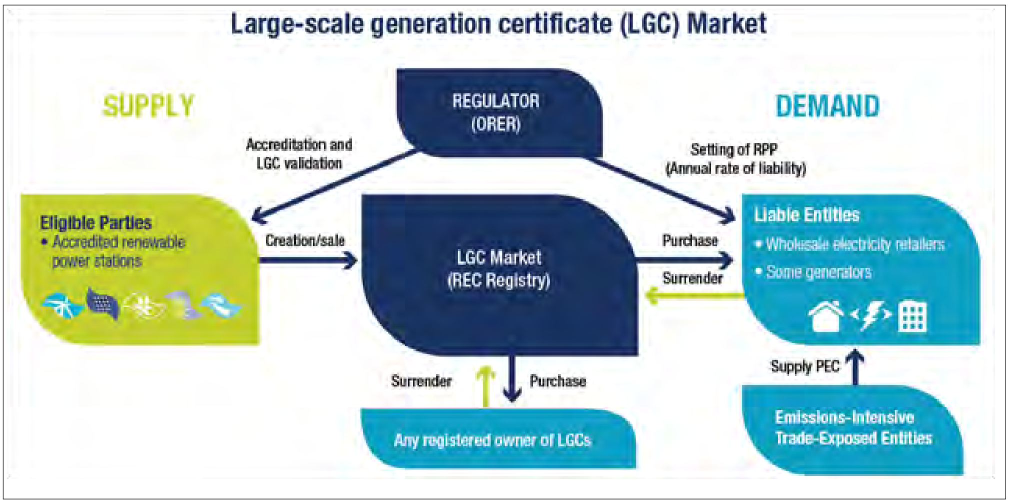
Large amounts of electricity are sometimes generated at night when demand is low. By encouraging EVs to charge at night renewable resources can be managed more effectively. Origin Energy and the University of South Australia both noted that smart charging has the ability to help integrate renewable generation by absorbing fluctuations in generation. Essentially this would involve EVs taking advantage of low prices (provided by a real time price signal) and charging when intermittent generation is available. Efficiency in the wholesale or ancillary services market could also be improved by aggregators matching uncertain supply, such as renewable generation, with variable load, such as EVs. The existing market design should enable price signalling, for example, higher off-peak demand should increase off-peak prices.

EVs also offer the possibility of distributed storage, if they can feed back into the grid. This is discussed **Chapter 7.0**.

Interaction with the existing Renewable Incentives

Flexible EV charging has the potential to facilitate intermittent renewable energy. However we need to consider what interaction this will have with the existing incentives, under the Large-scale Renewable Energy Target (LRET). Currently, the LRET sets an overall target for renewable energy in Australia. To meet this target the Office of the Renewable Energy Regulator (ORER) allocates individual renewable energy targets to liable entities, including wholesale electricity retailers and some generators. To demonstrate compliance, liable entities buy Large-scale Generation Certificates (LGC) from the LGC market, which are in turn earned and sold by renewable energy generators. This system, which is also known as the market for Renewable Energy Certificates (RECs) is illustrated in **Figure 39** below.

Figure 39: The Renewable Energy Certificate (REC) market



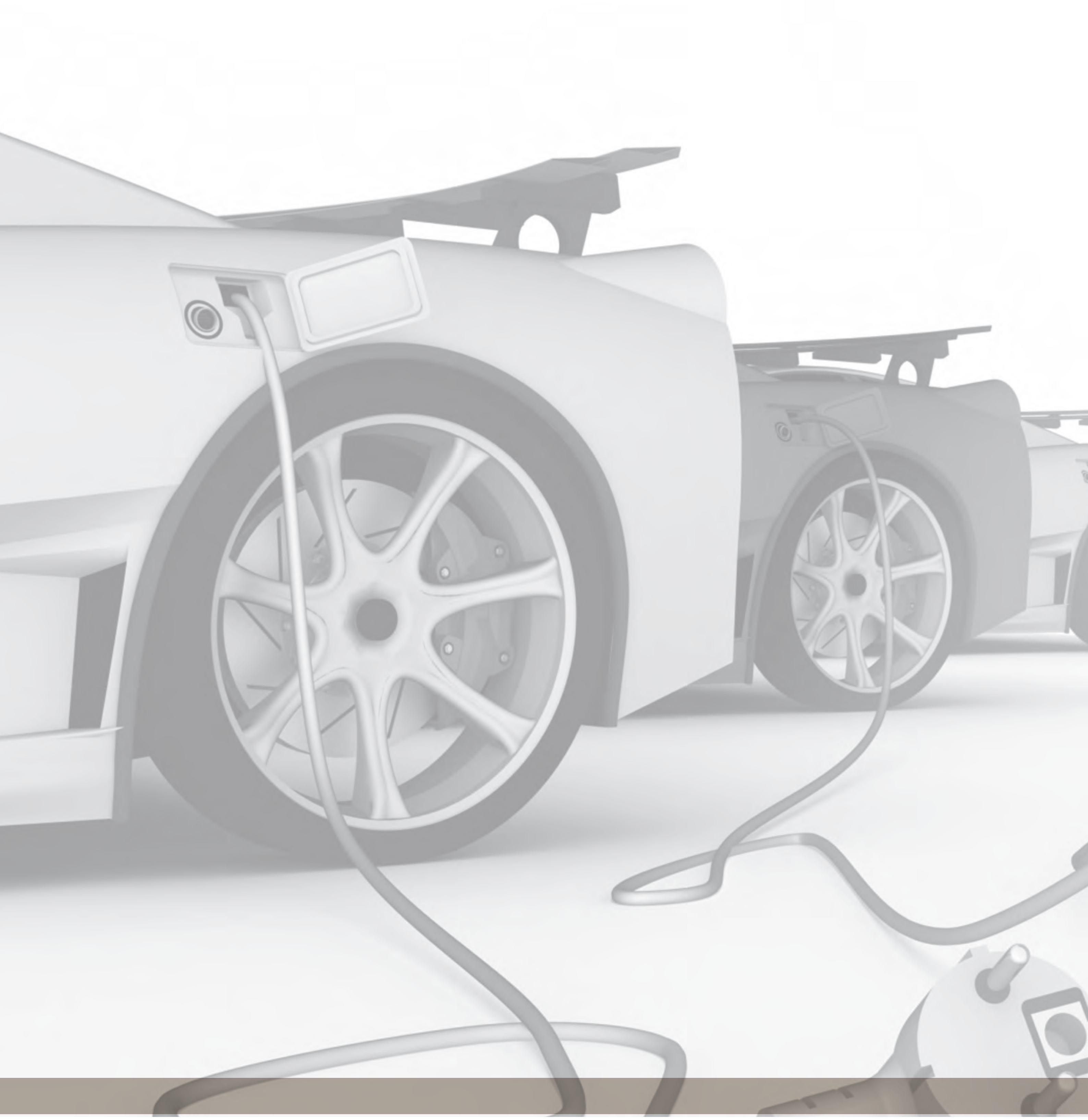
Source: ORER (2011)

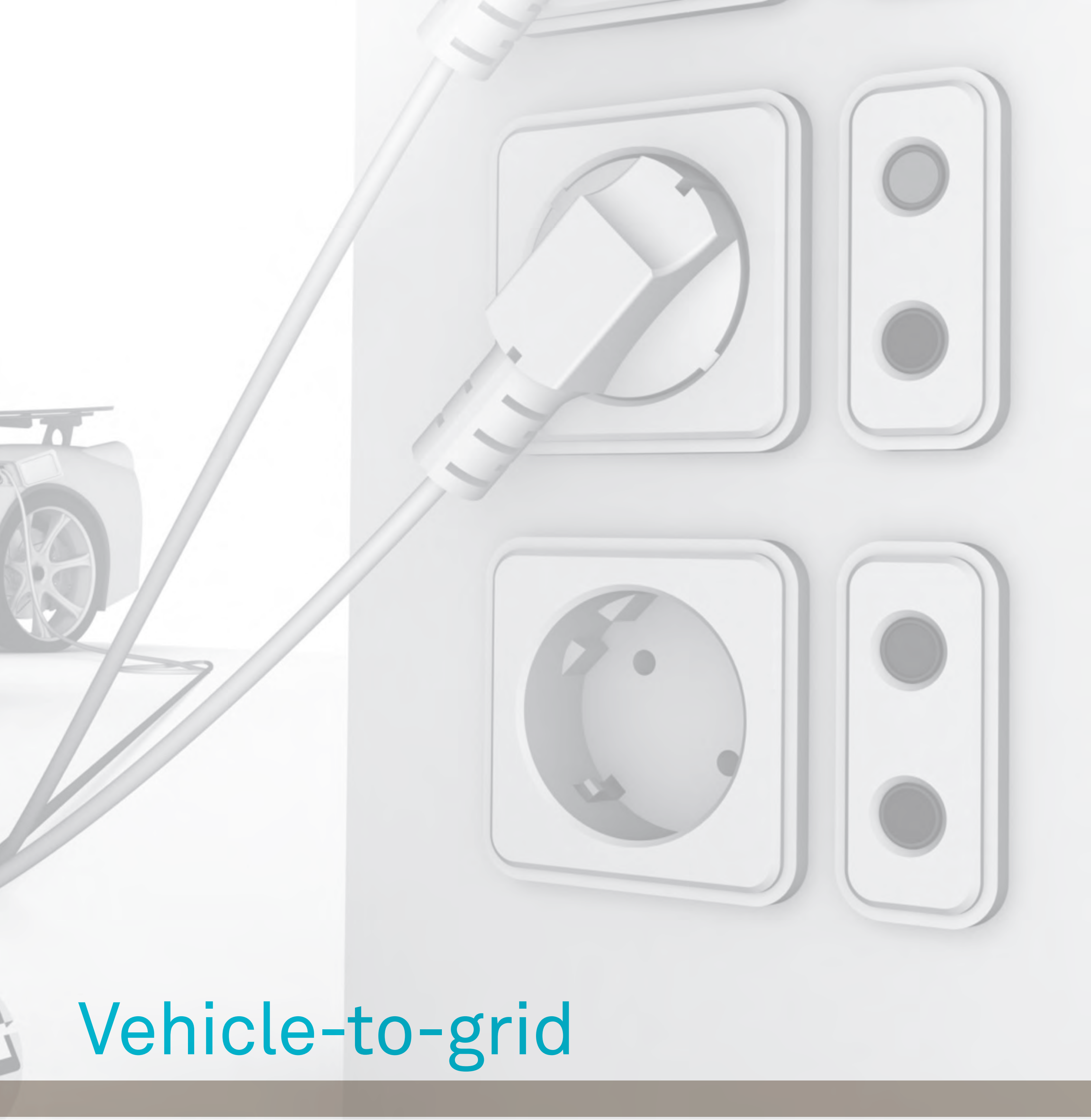
Flexible EV charging, matched to intermittent renewable energy generation, is likely to interact with the REC market. Greater use of intermittent generation by EVs may help maintain higher energy prices and increase the profits of renewable energy generators. In turn, this may encourage the development of more renewable energy and unless the LRET is increased, will result in lower LGC prices, over the medium term. However, this would be offset by increased demand for GreenPower, if enough consumers choose to purchase GreenPower for charging EVs.

However as discussed in **Section 3.5.1** take up of EVs is not expected to be significant enough by 2020 to impact on the LRET.

6.2.2.4 Facilitating smart network infrastructure

A variety of smart network technologies, such as smart meters, already exist which could be applied across the network and in people's homes to help manage demand and react to changing conditions on the network. To date these technologies have not been widely adopted. However, a major application like smart EV charging could facilitate this much wider growth. For example, installing a smart charging solution would likely require a smart meter (to record TOU information) and communications equipment to relay real time tariffs. Once installed, the smart meter and real time tariffs could be applied to general household load and facilitate the management of other flexible residential loads, such as refrigeration, washing machines and pool pumping. With higher take up of smart metering, the flexibility benefits discussed above would be increased.





Vehicle-to-grid

7.0

Vehicle-to-grid

Vehicle-to-Grid (V2G) technologies use EV batteries to provide energy storage and a flexible energy supply. This results in a greater amount of many of the same kinds of flexibility benefits provided by smart charging, as well as the potential to provide some ancillary services. However, V2G will also require some additional investment and create some new challenges, and overall it is unclear if these costs are justified. A promising alternative (and complement) is vehicle to home, which is briefly explored in **Section 7.4**. Subsequent sections explore V2G by asking three questions:

- What are the benefits of V2G?
- What support will V2G need?
- What does the industry think?

7.1 What are the benefits of V2G?

7.1.1 Flexibility benefits

V2G will provide the same type of flexibility benefits as smart metering (see **Section 6.2**). However, V2G can feed electricity back to the grid so the amount of flexibility and its availability will be greater when it is really needed. For instance, if smart charging is used to encourage off-peak charging, there will be very little scope for decreasing peak load further during high priced events such as maintenance, after an asset failure, or during a critical peak load. V2G on the other hand can begin supplying the grid at this point and effectively reduce peak load.

Table 32: Functions of V2G compared to smart metering

Function	Smart Charging	V2G	Price signal
Turn charging on	✓	✓	Low price
Turn charging off	✓	✓	High price
Power home		✓	Very high price
Feed in to the grid		✓	Very high price

7.1.2 Ancillary services

The following is a list of possible ancillary services that could be performed by EVs, as identified by Kempton & Tomic (2005a, 2005b) and Clement-Nyns et al (2011):

Frequency 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 Frequency Control Ancillary Services (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 (Usher et al, 2011). An aggregator could contract with EV owners to offer FCAS services in the market.

Spinning reserves

Spinning reserves refers to additional generating capacity that can deliver power quickly upon the request from the grid operator; it is paid for by the length of time they are available and ready. Contracts duration is typically short, lasting around 10 minutes but can be much longer depending on the specific case.

There is the potential for V2G to assist with grid support during maintenance. However, DNSPs would need to be certain of availability, so are unlikely to contract V2G for such services until there is more certainty around provision of services (see discussion below on managing vehicle availability).

7.1.3 Better integration of renewable energy

Storage technologies are expected to play an important role in a broad adoption of renewable energy. V2G has the potential to facilitate the penetration of renewable energy, when the fleet is used as distributed storage. Kempton and Dhanju (2005) analysed the possibility to use EV as distributed storage for large wind in the US and found "the majority of need for storage could be met by small storage that would be called frequently - an ideal application for V2G". However, a study on the impact of V2G on wind power in California highlights that this benefit is only realised when there is more than 20% of generation supplied from wind as below this level the system can cope without subsequent electricity storage additions (Bri-Mathias et al, 2010).

7.2 What support will V2G need?

Overall, V2G needs everything smart charging needs, plus a bit extra. Metering and tariff/ incentive or control systems need to provide service for outgoing as well as incoming energy; V2G households will need to invest in extra equipment; and DNSPs will need to invest in new IT and communications systems.

7.2.1 V2G needs smart two-way metering

V2G needs two way metering for billing purposes, in addition smart metering or otherwise coordinated charging is essential, so that the services can be delivered at appropriate, and in timely manners, with the least amount of labour (by way of monitoring changes to the electricity market) burden placed on vehicle owners.

The timing at which EVs discharge energy into the grid must take account of the requirements of the grid operator. One option for achieving this is through smart meters, which allow EV charging to be controlled remotely so that charging can be shifted to off-peak loads to achieve load levelling. Another option is through smart charging, where the EVs self-regulate charge timing. This mechanism generally refers to the ability of EVs to either be centrally controlled, or respond to price or other signals to regulate their charging behaviour (Usher et al, 2011).

If EVs can accurately and meaningfully maintain up-to-date communication with the energy grid and subsequently discharge power when it is required, then V2G may become a viable provider of ancillary services.

7.2.2 Distribution network costs

Technologies which feed-in electricity from the household level into the distribution network-such as solar feed-in- have the potential to reverse power flows in distribution substations. This can create new technical problems for distribution networks requiring additional investment in capacitor banks and static variable compensators (SVC). However with V2G, this is unlikely to be a problem 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).

There may be some operational issues with V2G that may require standards and possibly regulation. Feed-in technologies must provide supply that meets prescribed standards to avoid network issues. For existing solar feed-in generation, this quality of supply is accredited by the Clean Energy Council. It is unclear who would bear this responsibility for a V2G scheme.

A further cost to the controller is likely to come when they try to use V2G to actively manage their network. To do this will need investment in compatible IT and communication equipment as well as development of appropriate incentive schemes. If this capability is developed after EVs are widely adopted, they may run the risk of incompatibility issues. Step 4 may consider whether this should be regulated or unregulated activities.

7.2.3 Investment from V2G owners

In addition to the contribution that V2G can make to energy demand management, there is also potential for V2G-capable vehicles to produce a revenue stream. This may accrue to DNSPs, retailers or owners. Such revenue needs to justify extra investment, given potential impact on lifetime ownership cost of EVs. The economic benefit associated with EV ownership depends on a number of factors, some of which are presented in **Table 33**.

Table 33: Revenue and costs associated with V2G-capable EVs

Revenue factors	Cost factors
Market rate of electricity ($/kWh)	Cost per energy unit produced
Amount of power dispatched (kW)	Electric energy dispatched over a given year
Total time of power dispatched (hours)	Purchased energy cost
	Equipment degradation cost as a result of V2G

Source: Factors mentioned in Kempton & Tomic (2005)

Costs

Projected costs entailed with V2G system technologies vary. Turton & Moura (2008) identifies wiring, metering, communication to the grid manager and safety systems as components of V2G system infrastructure. An indicative cost for V2G infrastructure is US$400 for a capacity of 6.6kW for a basic system, and an additional US$1,500 for an upgrade to 15kW. This cost would likely be incurred as an additional upfront cost to the infrastructure costs set out in **Section 3.3.1**.

In the case of equipment degradation cost, a crucial element that must be considered is the rate at which battery performance degrades through the repeated charge and discharge made through V2G. Battery life is typically expressed in cycles measured at a specific depth-of-discharge (DoD), with shallow cycling having less impact on battery life than deep cycling.14 The economic benefit accrued to EV owners may not exceed the battery degradation cost, and research is still in progress to determine the impact that V2G charge and discharge behaviour has on battery life cycle. If the degradation costs are too high relative to the price at which electricity is purchased and resold for V2G purposes, then EV owners will not participate.

Revenue

Economic benefits for V2G investors depend on the assumptions employed on these and other revenue and cost factors. In one calculation conducted by Kempton & Tomic (2005a), a net profit of US$2,554 a year is observed for V2G-capable EV owners when, as a component of the cost factor, US$650 for wiring for V2G is assumed. The net profit falls to US$1,731 if V2G wiring is assumed to cost US$1,500.

Moreover, the tariff at which electricity discharged from the electric vehicle is sold back into the grid plays a significant role in determining the revenue stream for vehicle owners. In Usher et al (2011), the net benefit for participants to V2G arrangements is less than A$50 in one scenario where battery packs have assumed capacity of 10kWh, electricity is purchased at $0.10 kWh, resold at $0.24kWh and battery degradation cost is assumed to be $0.10 per kWh per cycle. When the assumptions are changed such that the battery pack storage is set at 20kWh and electricity resale price at $0.60 per kWh, the annual net revenue becomes closer to $1530.

It is clear that the case for V2G capabilities is largely influenced by various revenue and cost factors, and contractual arrangements. As such, the idea that V2G can contribute to the return on investment for electric vehicle consumers must be considered with some level of caution. Going forward, as battery prices fall and cost of electricity rises, the viability of V2G will improve. However, further work needs to be undertaken on the impact of V2G on battery life and opportunities to provide a tariff that incentivises customers to use V2G and allows them to capture a share of the benefits that the electricity market will gain from V2G.

Feed-in tariff rates and consumer understanding of the return on investment of V2G will likely play a significant role in the success of V2G, since, without a simple-to-understand, coherent and predictable set of policies governing the present and future trajectory of feed-in tariff rates and other revenue and cost factors, consumers will be exposed to too much risk associated with investing in V2G.

7.2.4 A mechanism for managing vehicle availability

Quinn et al (2010) note that one of the potential quality issues that may arise under V2G is the availability profile of ancillary services under this system. The presence and availability of ancillary service resources is dependent on the "probabilistic (and uncontrolled) presence of vehicles at charging stations, and the location of the charging stations" (ibid, p.1502). The degree to which ancillary services can be provided is dependent on numerous variables related to driving and charging behaviour of EV owners, as well as the geographical distribution of EV ownership.

Furthermore, reliability issues for V2G are dependent on the architecture under which it is rolled out. There are two approaches (as shown in **Figure 40**):

* 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; and
* Aggregative architecture whereby an intermediary is inserted between the vehicles performing ancillary services and the grid system operator.

Figure 40: Dispersed architecture of V2G versus aggregative architecture of V2G

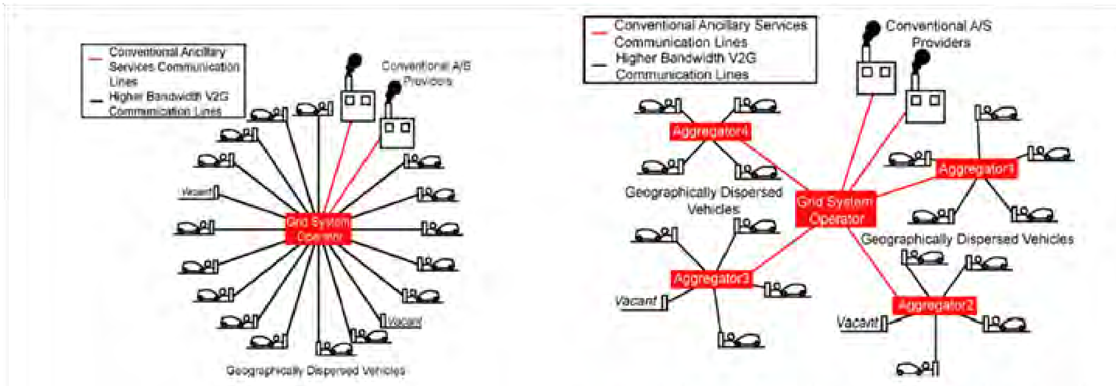


Fig. 1. Example plug-in vehicle-to-grid network showing geographically dispersed communications connections under the direct, deterministic architecture.

Fig. 2. Example plug-in vehicle-to-grid network showing geographically dispersed communications connections under the aggregative architecture.

Source: Quinn et al (2010)

Quinn et al (2010) show that including an aggregating entity in the command and contracting architecture can improve the scale and reliability of vehicle-to-grid ancillary services, thereby making vehicle-to-grid ancillary services more compatible with the current ancillary services market. However, the aggregative architecture has the adverse effect of reducing the revenue accrued by plug-in vehicle owners relative to the default architectures. Over time, as take up of EVs increases and more charging infrastructure becomes available, the risks of V2G are reduced and the management of V2G should become easier.

7.3 What does the industry think?

The cost for establishing V2G capabilities is still largely unknown; mainly due to the lack of industry standards and agreement over what kind of capital is required to perform the various potential V2G ancillary services. A quick review of the latest AEMC submission papers reveals the various perspectives on V2G held by different industry stakeholders.

- Recognising AEMC's statement that V2G is indeed "currently at a nascent stage," Energex (2011) raises the issue on additional aspects of embedded generation in the form of 'microgrids' within the energy network that needs to be assessed. This is because EVs may discharge under V2G settings but may only do so at a less than 100% capacity of its energy storage, and at different levels to the distribution network.

- The timing of V2G as a realistic demand management solution is uncertain (Jarvinen et al, 2011). They raise the point that state Governments would need to fully deregulate retail pricing to facilitate the widespread adoption of V2G technology, and a critical mass of EVs would need to be on the road before they meaningfully contribute to the alleviation of peak demand.
- Energex (2011) argues that the requirement to install two-way inverters to achieve V2G ignores the notion that some or all of the technology needed to accommodate this benefit could be ‘on board’ the EV (along with metering and other systems). This would negate the requirement for DNSPs to implement new infrastructure specifically for EVs.
- Unless existing meters in homes can distinguish between EVs and other household appliances, there will be a requirement to install a separate meter (Usher et al,2011).
- Charge Point (2011) notes the need for recharging devices to include “an embedded revenue grade meter and the appropriate communications device.” It is also argued that the separation of EV energy consumption requiring separate metering, and administration will increase overhead and operational burdens on the current regulatory climate. (This position is also taken by Origin Energy- that the introduction of a separate National Metering Indicator would increase cost and complexity for consumers and the industry).
- Usher et al (2011) reports that the additional cost to vehicle owners to implement V2G-compatible technology shouldn’t be prohibitively expensive, especially if the existing onboard electronics from the motor, motor inverter and charger are used. Separate grid-tie inverters, on the other hand, come at a much larger cost.

7.4 Vehicle-to-home (V2H) Supply

Vehicle-to-home (V2H) is another method for utilising EV energy storage capabilities. Instead of feeding electricity back to the grid as in the case of V2G, the power is used in household appliances so that the demand on the electricity from the grid is temporarily substituted by the EV. V2H could be set up either stand-alone or in conjunction with a V2G system. When set-up with V2G, the V2H system would first meet the home supply and then feed-in to the grid.

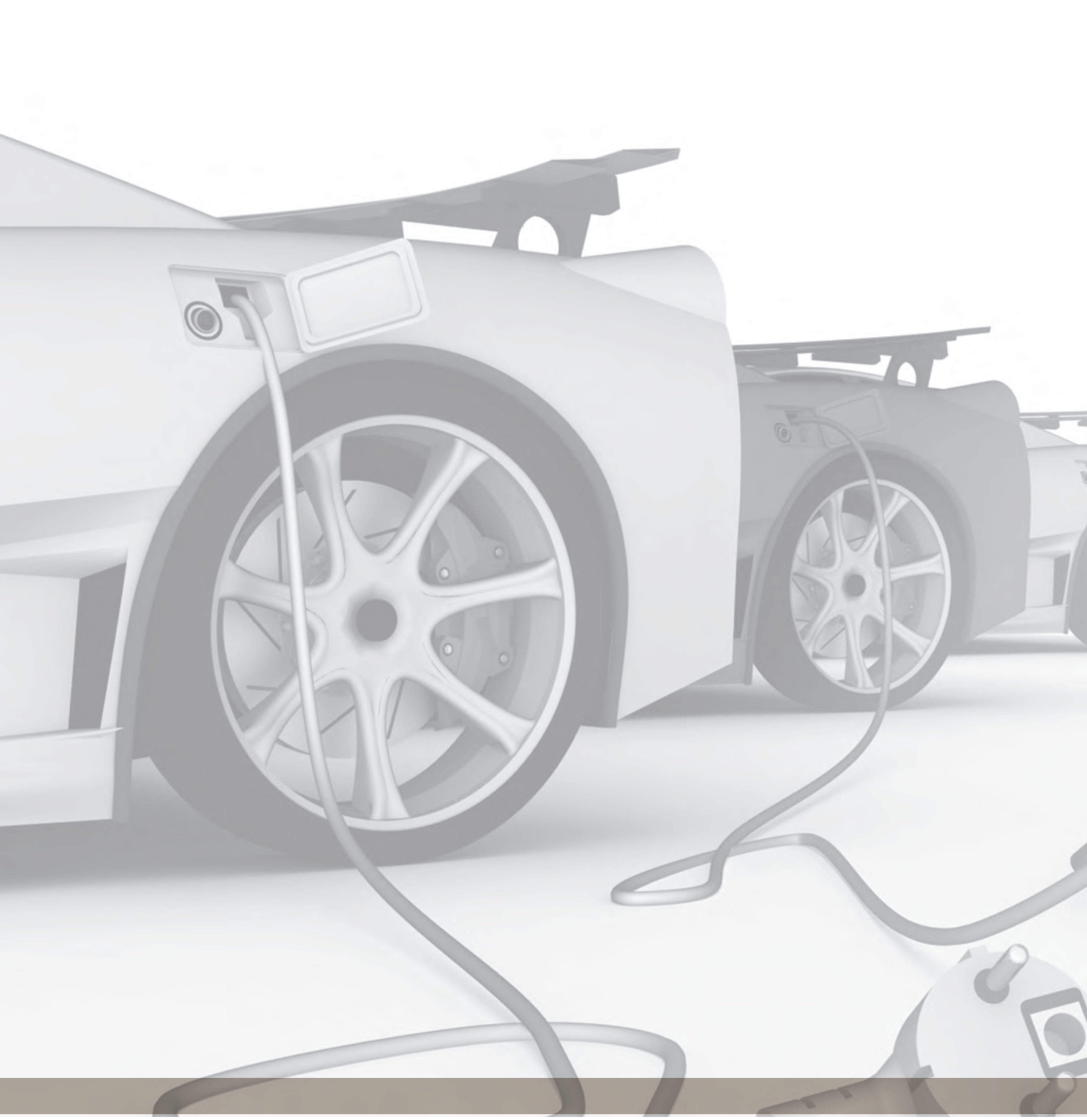
Energex (2011) notes that the V2H system will have “nearly all the benefits and none of the problems associated with vehicle-to-grid systems present to the distribution network.”

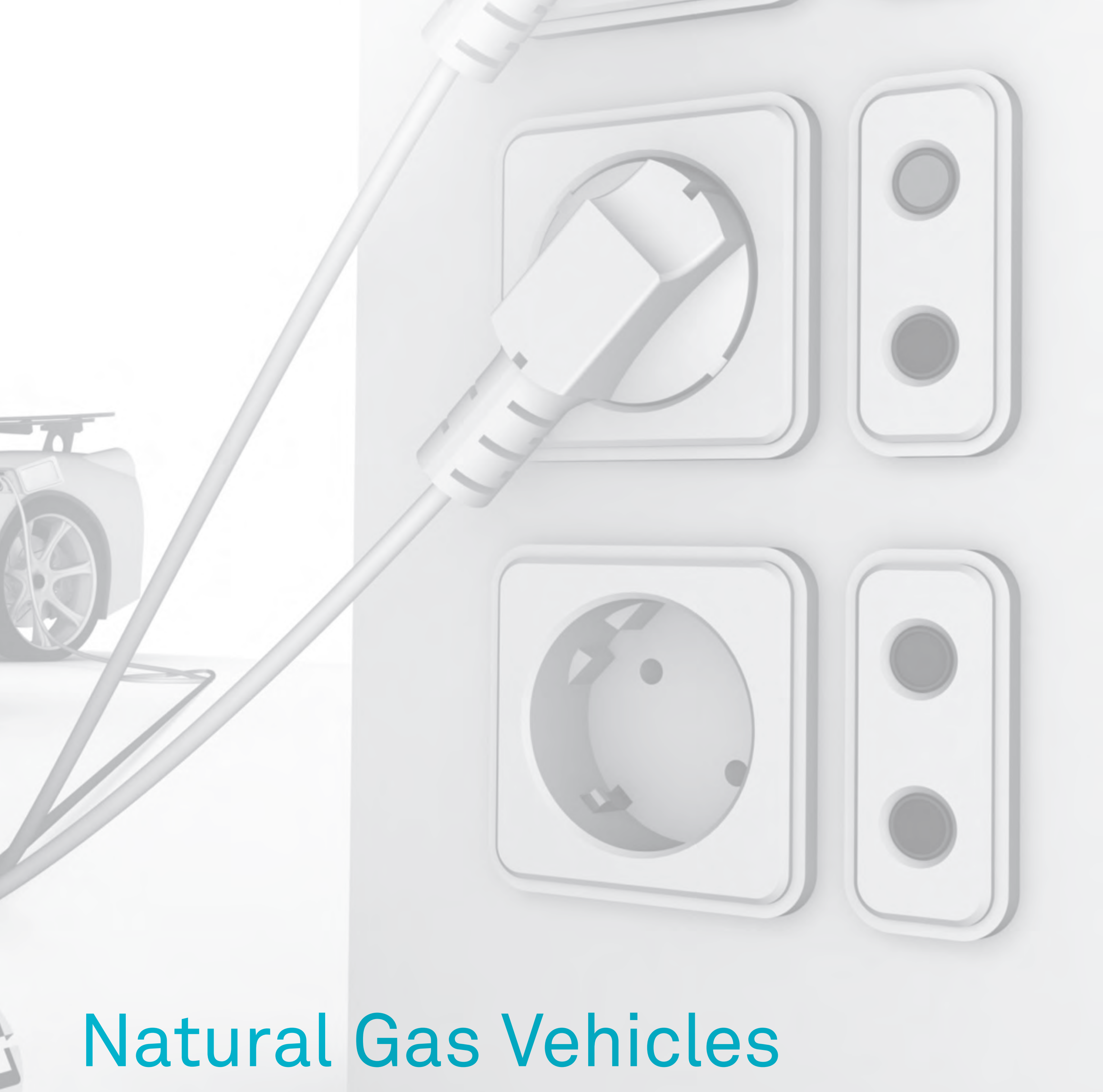
V2H would have the benefit of slightly lower losses from internal usage rather than drawing from the grid. However, it is unlikely that V2H would be completely cost and problem free. V2H arrangements would require some sort of infrastructure investment on the house. A switchboard mechanism would still be required for the household to source its energy from its EV, either to prevent flows back into the grid or, at least, isolate the EV when the grid is de-energised.

7.5 Conclusions

EVs 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 vehicle-to-grid depends on a number of factors including:

- If V2G is to be a viable provider of ancillary services, smart two way meters will be required to ensure the timing at which EVs discharge electricity back to the grid is responsive to the needs of the grid operator.
- DNSPs will need to invest in compatible IT and communication equipment as well as develop appropriate incentive schemes. Some of the technology needed to accommodate this benefit could be ‘on board’ the EV.
- V2G households will need to be convinced to participate. V2G households will require investment in extra equipment and need to overcome concerns about battery life and coming back to a vehicle that is discharged. As yet the full consequences for battery life are unknown and many manufacturers are concerned about warranty of the battery. Further, drivers may be wary about coming back to a vehicle that is discharged. These concerns will ease over time as more information is available about charging behaviour, more charging infrastructure becomes available and technology becomes smarter so that it can ensure a minimum battery charge.
- The success of V2G is dependent on a critical mass of EVs. As shown above, significant levels of take up are not expected in the short term, with high take up starting to occur in 10 to 15 years.





Natural Gas Vehicles

8.0

Natural Gas Vehicles

8.1 Overview

Natural gas vehicles use either compressed natural gas (CNG) or liquefied natural gas (LNG) as fuel, both of which are derived from methane (CH4), commonly known as natural gas. In Australia, CNG-fuelled and LNG-fuelled vehicles exist predominantly in the heavy vehicle market such as bus fleets, garbage trucks and long distance freight trucks (DRET, 2011a).

LNG-fuelled vehicles are a recent development in Australia; largely due to technological improvements in storage vessels and gas dispensers that have led to improved safety and performances of LNG vehicles. They have ranges and refuelling times that are similar to diesel-fuelled vehicles with little or no power-to-weight disadvantages. In order to be in its liquefied state, LNG must be stored at less than -162°C; the latest LNG cylinders allows for the fuel to be kept in liquid from for two weeks or more (IANGV, 2011).

CNG as a transport fuel, on the other hand, faces a number of practical barriers. For instance, CNG-fuelled vehicles have comparably shorter ranges than diesel or petrol fuelled vehicles, because CNG must be stored under pressure, which means vehicles must carry large CNG storage tanks at the expense of space (Envestra, 2011). The very limited availability of specialised refuelling stations also serves as an impediment to its widespread diffusion. Home refuelling is feasible, however requires a compressor, due to the low pressure of gas supplied into the home making it relatively expensive. Further, refuelling at home can take several hours to complete.

According to the International Association of Natural Gas Vehicles (IANGV), the total number of NGVs across the world grew by 11.6 per cent between 2009 and 2010, totalling 12.7 million units. Market penetration of NGVs is predominantly in developing countries, with the top five countries being Pakistan, Iran, Argentina, Brazil and India. These countries collectively held approximately 9.3 million NGVs in 2010, which is equivalent to 73 per cent of the world NGV population. In Pakistan's case, NGVs represent approximately 60 per cent of their national fleet.

The NGV market in Australia is very small by comparison. ABMARC reports that there are fewer than 3000 NGVs domestically; which is equivalent to approximately 0.02 per cent of the national fleet (GoAuto.com.au, 2011). Whilst CNG and LNG have been exempt from fuel excise, this exemption is due to end on 1 December 2011, with excise rates to be phased in over four years, with a final rate of 26.13 cents per kilogram from 1 July 2015 (ATO, 2011).

8.2 Passenger vehicles

AECOM's vehicle choice model, as described in **Section 3.0**, was used to estimate the take up of passenger NGVs. AECOM's modelling assumes that people make their decisions to purchase a new vehicle based on a number of factors including vehicle price, fuel costs, available infrastructure, vehicle range and preference for greener vehicles. They also tend to make decisions based on an average ownership of four to five years. AECOM's vehicle choice model tries to include these factors into the analysis.

8.2.1 Assumptions

The majority of assumptions discussed in **Section 3.0** for ICE and electric passenger vehicles also apply for gas passenger vehicles. Specific NGV assumptions are summarised in **Table 34** and discussed below.

- **Vehicle price.** There are currently no natural gas vehicles available for purchase directly from manufacturers in Australia. Internationally, there are a small number of CNG variants of certain models, such as the Honda Civic GX NGV which is sold in the United States. The price premium for the Civic GX NGV over the standard Civic DX is approximately US$10,000. In comparison, conversion costs for an existing ICE vehicle range from around $3000 (Australian estimate of direct cost) to over $10,000 (NGVAmerica, 2011). For simplicity, a price premium of $10,000 has been adopted in this study.
- **Natural gas consumption.** Fuel efficiencies of gas vehicles and conventional ICE vehicles are broadly comparable when converted into equivalent units. Gas consumption of about 23.3 litres per 100km has been assumed based on a tank with a 70 litre capacity and range of 300km. This is equivalent to 0.21 GJ per 100km; in comparison, petrol consumption of 8 litres per 100km is equivalent to 0.276 GJ per 100km.
- **Gas prices.** This study has adopted an observed retail CNG price of $1.06 per kg from ActewAGL's Fyshwick station which is equivalent to $22 per GJ. This gas price is indexed to changes in wholesale gas prices adopted from modelling in Strong growth, low pollution (Treasury, 2011). The price of gas is anticipated to increase significantly over the next five to ten years in Australia due to development of LNG facilities on the east coast of Australia, which will increase prices in line with the export gas market, and a higher use of gas in electricity generation. There is much uncertainty around future gas prices in Australia, so a low and high price scenario was modelled.
- **Availability of refuelling infrastructure.** Whilst residential charging of NGVs is technically feasible, the gas pressure delivered to residential dwellings is relatively low and requires a specialised refuelling unit. The relatively high cost of installing refuelling units, maintenance requirements for refuelling equipment, long time required to refuel at home (typically a home based recharging unit takes around 6 hours to charge an average vehicle) and safety concerns means home charging is likely to be minimal. Given the almost total absence of commercial refuelling stations and the reticulated gas network covering mostly metropolitan regions only (compared to the electricity network which is widespread), this study has assumed that there is very limited opportunity for refuelling of NGVs.

Table 34: Passenger NGV assumptions

Parameter	Unit	Value
Price premium over comparable ICE vehicle	$	10,000
Consumption Assumes range of 300km for 70L tank of CNG; density 0.185 kg / L at 20MPa; energy content 48 MJ / kg.	L / 100km GJ / 100km	23.3 0.21
Gas price – current	$ / kg $ / GJ	1.06 22
Gas price – escalation – Central price series – Low price series – High price series	 Index based on Treasury (2011) 20% lower than central series 20% higher than central series	

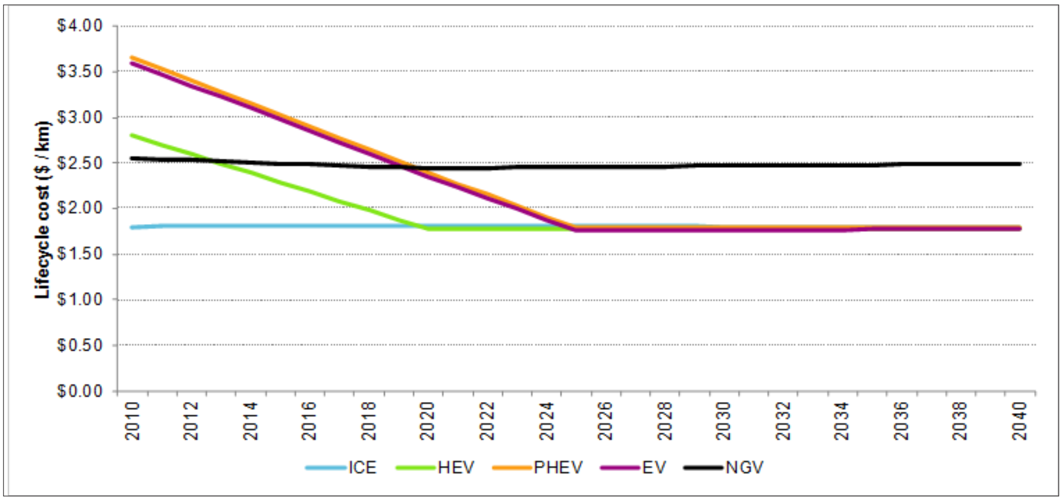
Sources: AECOM; ActewAGL (2011); Treasury (2011)

8.2.2 Results

Analysis of the lifecycle cost of passenger NGVs shows that only vehicles that travel large distances are competitive against other ICE vehicles and EVs. **Figure 41** and **Figure 42** illustrate the range of lifecycle costs ($ / km) for different engine types of a medium sized car with low and high vehicle kilometres travelled respectively. The figures show that for vehicles travelling short distances, NGVs are uncompetitive with ICE for all years, and only competitive with EVs in the short to medium term. After 2020, when the upfront cost of EVs has fallen, NGVs have the highest lifecycle cost. For a vehicle that travels longer distances, NGVs are again only competitive against all technologies in the short to medium term and are only marginally better than ICE vehicles in the short term. Similar results are observed for small and large vehicles.

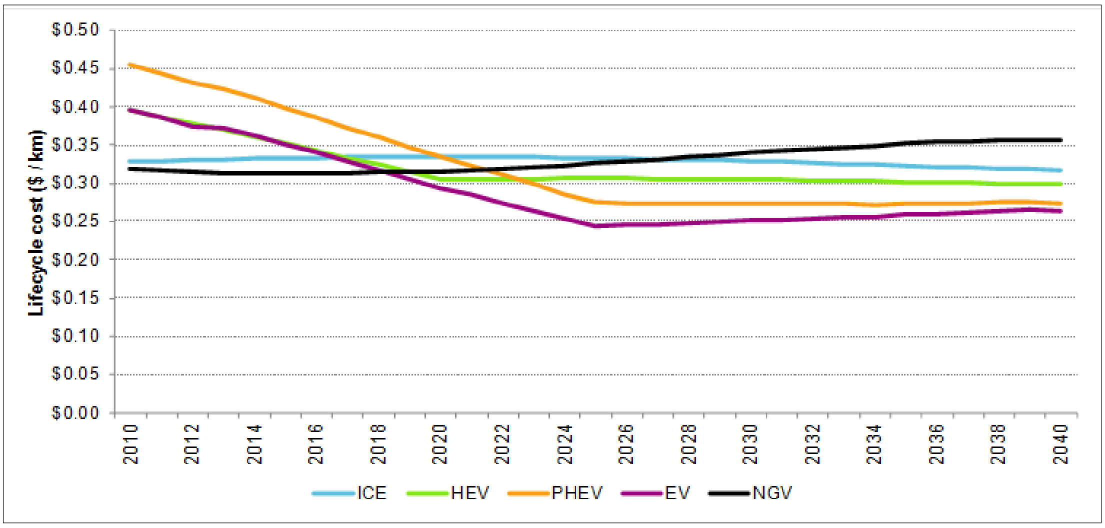
Therefore demand for NGVs is likely to be minimal in all segments of the passenger market except for those that travel large distances. This is consistent with the observed take up of LPG, which is predominantly seen in the taxi market where vehicles are travelling large distances so benefit more from the cheaper fuel. Furthermore, this demand will be concentrated in the short to medium term due to a combination of stable gas prices (in the short run) and relatively expensive EVs. From around 2020, as EV supply constraints are removed, and continued purchase price reductions and efficiency improvements occur, the relative competitiveness of NGVs is eroded.

Figure 41: Lifecycle cost – medium car, low VKT



Source: AECOM

Figure 42: Lifecycle cost – medium car, high VKT



Source: AECOM

The vehicle demand model predicts that the take up of NGVs is very low under each scenario with sales highest in the early years of the analysis which then gradually taper off from 2015 onwards. This occurs for three main reasons. Firstly, the availability of refuelling infrastructure is very limited when compared to conventional transport fuels and electricity which is available in every property. Secondly, EVs become more competitive because supply becomes unconstrained (HEVs in 2015 and PHEVs / BEVs in 2020), purchase prices of EVs ultimately reach parity with an ICE vehicle, and range / battery improvements continue to occur. Thirdly, gas prices are stable up to 2015 (zero or modest real growth) after which more rapid annual increases in the order of 3.5% to 4.5% are assumed to occur. The combination of these factors serves to strongly reduce the competitiveness of NGVs against other engine types.

8.3 Buses and trucks

As discussed above, people make their vehicle purchase decisions based on a number of factors. However, the purchase of a bus or truck is principally a commercial decision. As such, the estimation of take up of natural gas buses and trucks uses an alternate methodology and only considers the financial costs over the operating life of the vehicle.[15]

8.3.1 Assumptions

There is a moderate amount of uncertainty surrounding the characteristics of CNG buses and LNG trucks primarily due to commercial confidentiality. As such, this study has made a number of assumptions in order to conduct the analysis.

Table 35 summarises the assumptions applied in the financial analysis with each of these assumptions discussed in more detail below. The assumptions were developed based on AECOM's research and industry consultation.

15. For this analysis "trucks" are assumed to be the prime mover only and excludes trailers.

Table 35: Truck and bus assumptions

Parameter	Bus			Truck	
	Diesel	CNG	Electric	Diesel	LNG
Price	$450,000	$650,000	$750,000	$350,000	$510,000
Consumption	30 L / 100km	2.5 GJ / 100km	120 kWh /100km	56 L / 100km	2.2 GJ / 100km
Vehicle life	7.5 years	7.5 years	7.5 years	7.5 years	7.5 years
Annual distance travelled (VKT)	45,000	45,000	45,000	90,000	90,000
Maintenance	$0.35 / km	$0.51 / km	$0.25 / km	$0.18 / km	$0.26 / km

Sources: AECOM; ABS; NSW state Transit; Adelaide City Council / Dr Andrew Simpson

Purchase prices

Diesel bus purchase price were obtained from a manufacturer which also stated that an equivalent CNG bus is approximately 45% more expensive. For a truck, the prime mover purchase price is based on AECOM experience. To obtain an equivalent LNG truck (prime mover) price a premium of 45% has been applied based on the bus premium. The cost of an electric bus is estimated from the Tindo electric bus trial being conducted in Adelaide (Adelaide City Council, 2011).

Consumption

Diesel consumption data from the ABS Survey of Motor Vehicles was adopted for bus and truck fuel consumption, while consumption for a CNG bus was based on Cockroft & Owen (2007). Data from truck trials based on RARE Consulting (2010) was used to estimate LNG consumption which in energy terms is essentially equal to that implied by the ABS diesel consumption data. The Tindo bus trial has available energy of 235 kWh for a range of approximately 200km (no air-conditioning) which yields a consumption rate of around 120 kWh / 100km.

Vehicle life

The life of both buses and trucks has been assumed equal to the effective tax life as determined by the ATO of 7.5 years.

Annual distance travelled (VKT)

The annual average distance travelled per bus as implied by NSW state Transit performance statistics shows that buses travel approximately 42,000 km per year (state Transit, 2010). For simplicity this study has assumed 45,000 km.

An assumption of 90,000 km travelled annually for truck has been made based on ABS data for articulated trucks. However industry sources indicate that only high VKT trucks (approximately 150,000km) are likely to find gas a viable option.[16]

Maintenance costs

Maintenance costs for diesel vehicles were adopted from the *Guide to Project Evaluation* (Austroads, 2008). Information provided by a CNG bus manufacturer suggest that maintenance costs for a CNG bus is approximately 45% higher than for an equivalent diesel bus. This relativity has also been adopted for LNG trucks in the absence of more specific information. A review of the Tindo electric bus indicates that maintenance costs are in the order of 9 c/km however the report emphasises that detailed records of maintenance were difficult to extract and interpret. In light of this uncertainty, this study has assume that maintenance costs for an electric bus are approximately 30% lower than for an equivalent diesel bus, analogous to the assumptions made for passenger EVs.

Vehicle sales

Vehicle sales have been estimated from the stock of buses and trucks (ABS, 2010a) and the assumed vehicle life of 7.5 years as discussed above. **Table 36** summarises the current volume of sales and assumed annual growth under each take up scenario.

16. http://www.fullyloaded.com.au/industry-news/articleid/40793.aspx

Table 36: Bus and truck sales

State	2010 Sales		Annual sales growth		
	Bus	Truck	Low	Central	High
VIC	740	3350	1%	1.5%	2%
NSW	910	2480	1%	1.5%	2%
ACT	40	20	1%	1.5%	2%
QLD	780	2520	1%	1.5%	2%
TAS	100	220	1%	1.5%	2%
SA	200	1040	1%	1.5%	2%
WA	540	1680	1%	1.5%	2%

Source: AECOM; ABS

Fuel prices

As with passenger vehicles, electricity prices have been adopted from Treasury modelling and diesel prices estimated using the methodology from Gargetts (2011). (See **Section 3.3.1.6** for more detail)

CNG prices in the NEM states and Western Australia are based on Treasury modelling for wholesale gas prices in the NEM and non-NEM regions.

LNG prices in Western Australia are based on prices in Inquiry into domestic gas prices report by the Western Australian Economics and Industry Standing Committee. LNG prices in eastern states are assumed to be lower than in Western Australia, though are expected to rise following the commencement of LNG exports from the East Coast around 2015.

The Commonwealth Government seeks to establish an effective carbon price for heavy on-road liquid fuel use (including heavy trucks and buses) from 1 July 2014. This will improve the relative fuel costs for gas vehicles.

8.3.2 Results

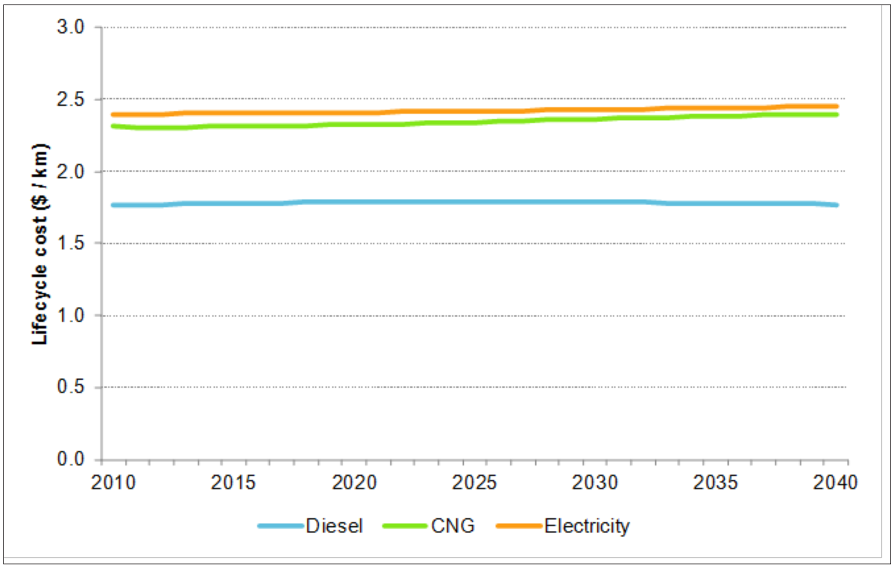
Financial analysis

Figure 43 highlights that it is not financially viable to purchase and operate CNG buses compared with diesel buses. In comparison, the financial viability of LNG trucks is marginal (see **Figure 44**). It should be noted that the financial analysis does not include consideration of a residual resale value. Resale values of diesel buses and prime movers are likely to be higher than for CNG buses and LNG trucks given the scarcity of refuelling gas infrastructure. Inclusion of a resale value is therefore likely to worsen the viability of CNG buses and LNG trucks relative to their diesel equivalents.

A recent industry forum supports these views (Ecostation, 2011):

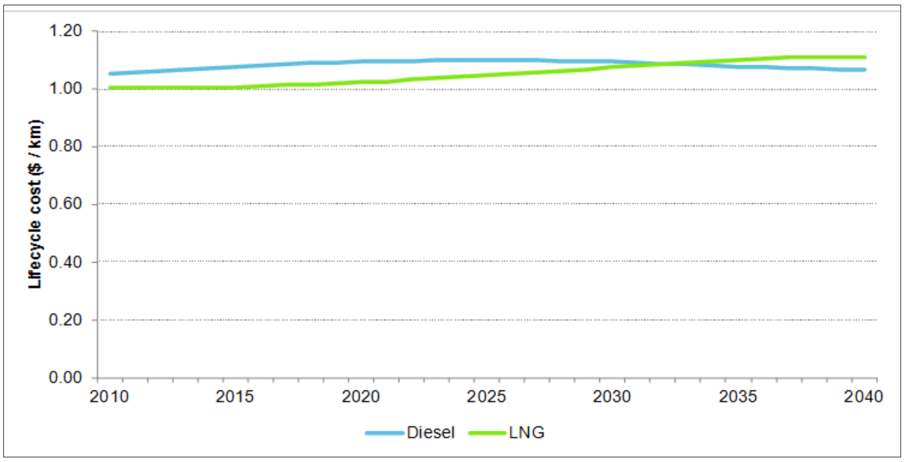
> "On the whole participants felt there was a good future for LNG, although at the moment the participants who have trialled LNG recognise no real financial benefits. ..."
>
> "Nobody wants to buy a used LNG truck" was a statement that went unchallenged."

Figure 43: Lifecycle cost of buses



Source: AECOM

Figure 44: Lifecycle cost of trucks



Source: AECOM

On a purely financial decision demand for CNG buses is likely to be low. However, a number of CNG buses are already in operation around Australia in metropolitan transit fleets. Most buses are operated by government who will face increasing pressure to reduce their greenhouse gas emissions. Given transport typically accounts for a large proportion of greenhouse gas emissions it is possible that there will be increased take up of natural gas buses, despite not being financially viable, to assist in meeting greenhouse gas reduction targets.

For trucks, the financial analysis showed that the decision to purchase an LNG truck was marginal and depends on a few key assumptions - principally annual VKT. A number of businesses are currently operating some LNG trucks for a variety of activities, primarily long haul freight. Wesfarmers (Gas Today Australia, 2009) notes that LNG vehicles can closely match their diesel equivalent, and can be fitted with sufficient LNG fuel tanks to suit journeys of up to 1,200 km.

As discussed above, on purely financial grounds, take up of CNG buses and LNG trucks is expected to be low. However there are other factors such as greenhouse gas emissions reductions that mean take up may be higher than otherwise expected. Therefore, for the purposes of considering the impact of NGVs on the gas market, three take up scenarios (see **Table 37**) have been considered.

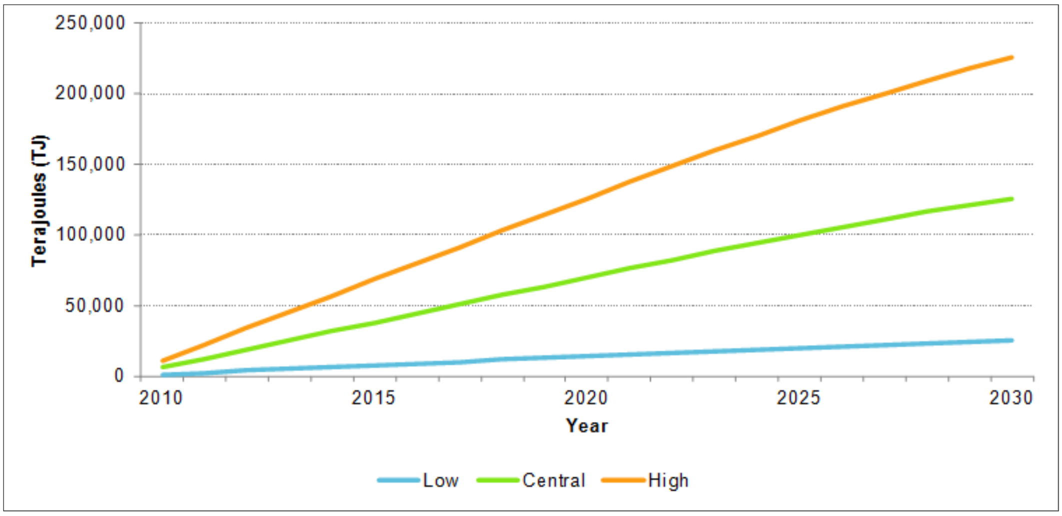
Table 37: Proportion of sales in each scenario

Scenario	Bus – CNG sales (%)	Truck – LNG sales (%)
Low	10%	10%
Central	50%	20%^
High	90%	40%

Source: AECOM. ^ Based on Westport submission (Westport, 2011)

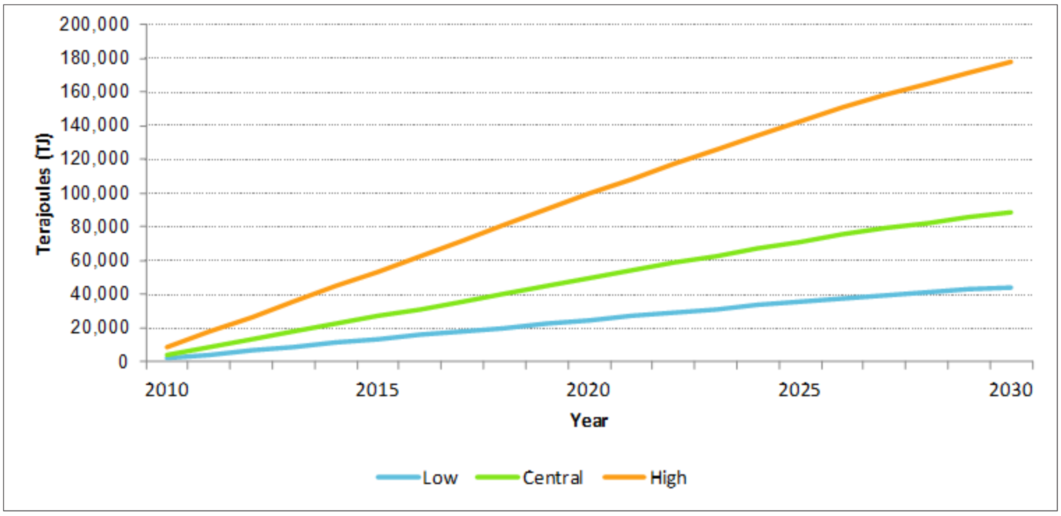
Figure 45 and **Figure 46** summarise the consumption of gas for buses and trucks respectively. The high take up scenario could see around 120,000 TJ of gas by 2015, rising to around 225,000 TJ of gas by 2020 and around 400,000 TJ of gas by 2030.

Figure 45: CNG bus gas consumption

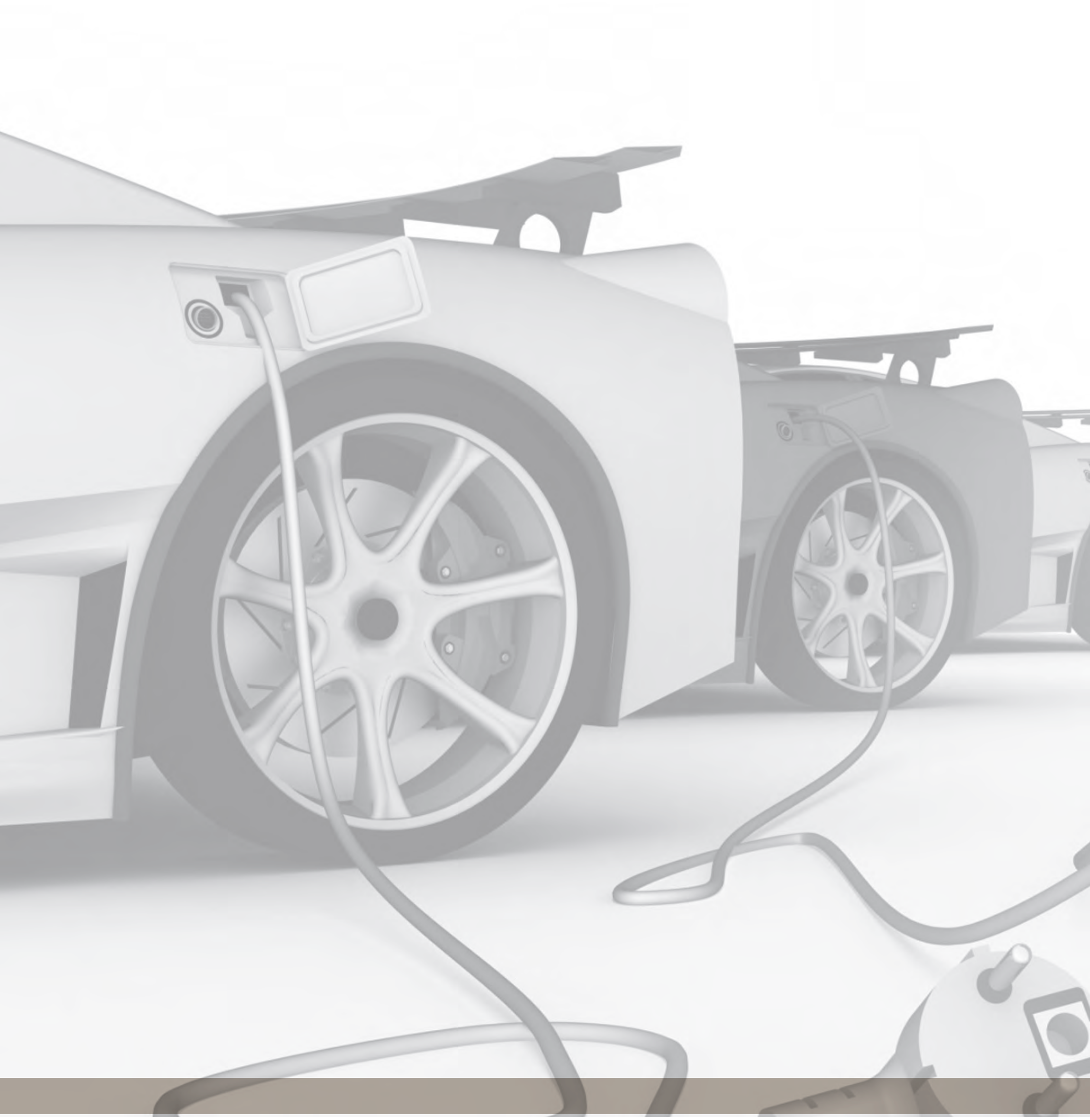


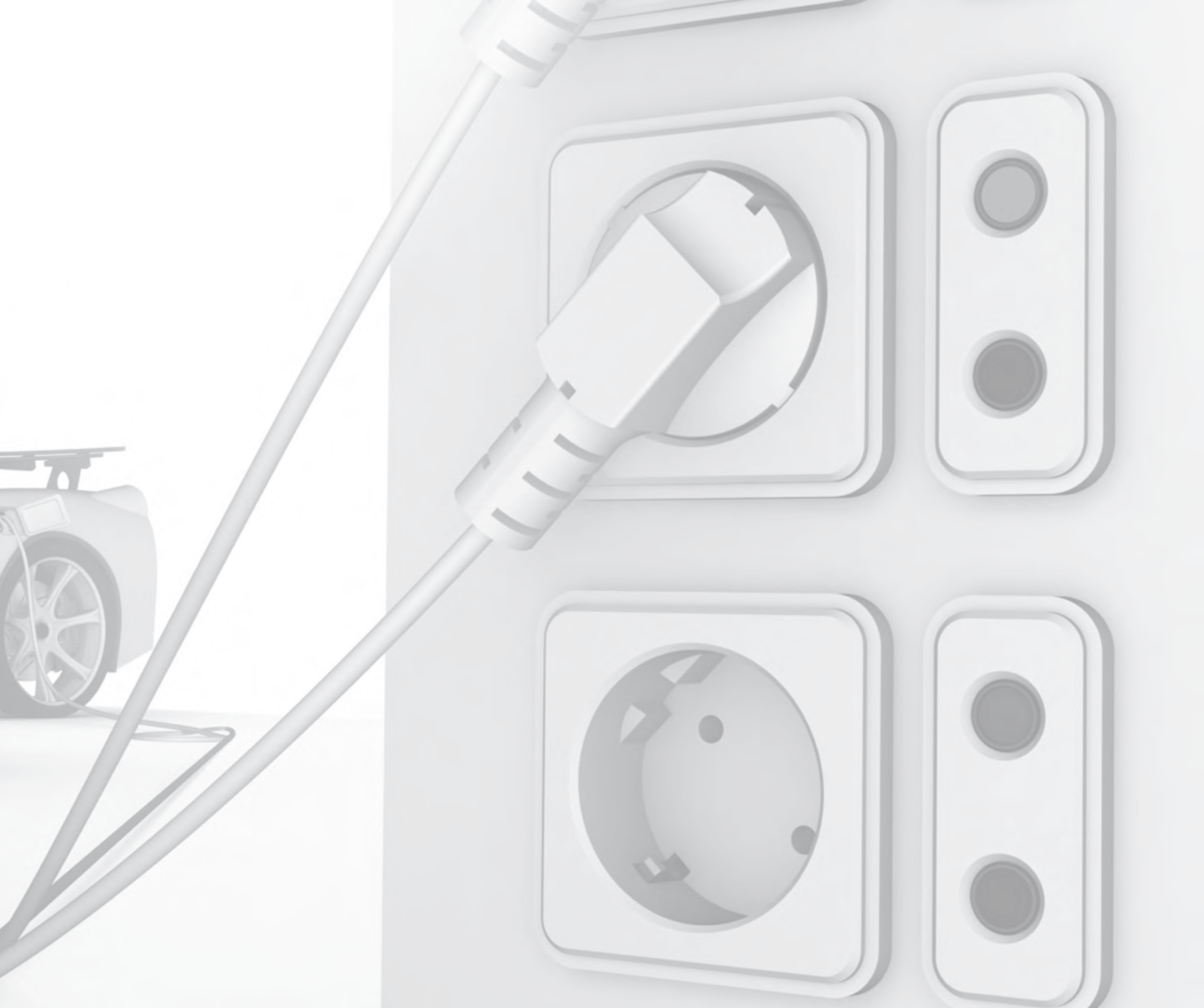
Source: AECOM

Figure 46: LNG truck gas consumption



Source: AECOM





Impact of Natural Gas Vehicles on the Gas Market

9.0

Impact of Natural Gas Vehicles on the Gas Market

9.1 Description of current gas market

9.1.1 General

Gas producers sell natural gas in wholesale (contract and spot) markets to major industrial, mining and power generation customers, and to energy retailers which on-sell it to business and residential customers. Gas is carried from fields through a network of transmission pipelines, as shown in **Figure 47** below. In cities, gas is delivered through networks of distribution pipelines.

Figure 47 Gas pipelines

Source: AER (2010a)

9.1.2 Gas market developments

Natural gas is expected to play a key transitional role in meeting Australia's energy needs in the move towards a carbon constrained economy. With associated growth in the use of natural gas for electricity generation, there are also growing links and interdependencies between the gas and electricity markets.

The Department of Resources, Energy and Tourism[17] drives Commonwealth gas market policy in the energy market reform program being implemented by the Ministerial Council on Energy. Key streams of this program include the development of a national regulatory regime for gas pipelines and retail markets, and further market development to improve transparency, competition and trading opportunities. The MCE has also established the Gas Market Leaders Group (GMLG), a collection of key representatives from all sectors of the gas supply and demand chain, to further reform the operation of gas markets around the country. The GMLG:

- developed a gas market Bulletin Board, a website which provides daily information about gas infrastructure and gas supply and demand, and provides market participants with opportunities for trading gas
- designed a new gas wholesale trading market, to be implemented in Sydney and Adelaide initially, with Brisbane expected to follow in 2011; and
- developed the annual Gas Statement of Opportunities, published by the Australian Energy Market Operator. This document provides a source of information to assist industry participants and other interested parties in their planning and identification of potential investment opportunities and is also an information tool for policy makers examining the projected short and long-term reliability of the nation's gas supply.

9.1.3 Production

Figure 48 below shows gas production in 2010, by state and by end market (AER 2010). Most of the production is delivered to customers, after allowing for energy used in compressing gas for transmission and some losses from leaks. The Western Australian domestic market used 358 PJ in the year 2009-10. The eastern Australian market used 660 PJ, of which 465 PJ comprised conventional gas and 195 PJ coal seam gas.

Figure 48: Natural gas production and reserves (2010)

Gas Basin	Production (Year To June 2010)		Proved And Probable Reserves (30 June 2010)	
	Petajoules	Percentage of Domestic Sales	Petajoules	Percentage of Australian Reserves
Western Australia				
Carnarvon	354	34.2%	68 353	64.3%
Perth	4	0.4%	23	0.0%
Northern Territory				
Amadeus	10	1.0%	156	0.1%
Bonaparte	9	0.8%	1 198	1.1%
Eastern Australia				
Cooper (South Australia – Queensland)	103	10.0%	1 157	1.1%
Gippsland (Victoria)	228	22.0%	5 233	4.9%
Otway (Victoria)	105	10.1%	1 245	1.2%
Bass (Victoria)	12	1.2%	275	0.3%
Surat-Bowen (Queensland)	16	16%	196	0.2%
Total Conventional Natural Gas	842	81.2%	77 836	73.2%

17. http://www.ret.gov.au/energy/energy_markets/gas_market_development/Pages/GasMarketDevelopment.aspx

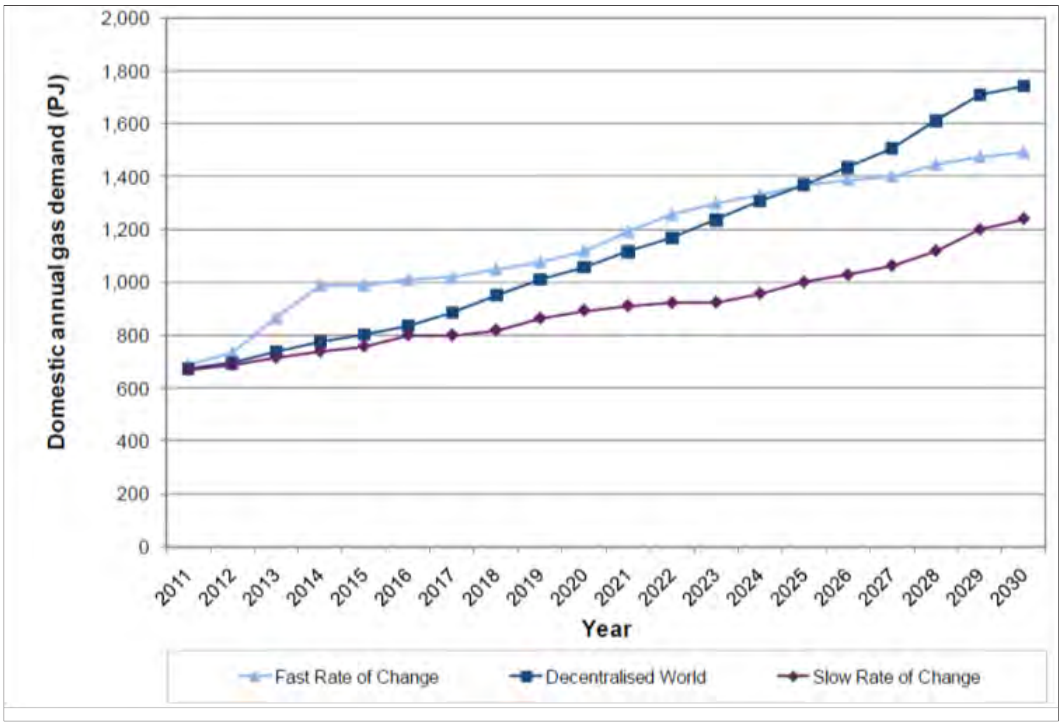
Gas Basin	Production (Year To June 2010)		Proved And Probable Reserves (30 June 2010)	
	Petajoules	Percentage of Domestic Sales	Petajoules	Percentage of Australian Reserves
Coal Seam Gas				
Surat-Bowen (Queensland) AL N	189	18.2%	26 008	24.5%
New South Wales basins	6	0.6%	2 466	2.3%
Total coal seam gas	195	18.8%	28 474	26.8%
Australian Totals	1 036	100.0%	106 310	100.0%
Liquefied Natural Gas (Exports)				
Carnarvon (Western Australia)	862			
Bonaparte (Northern Territory)	12			
Total liquefied natural gas	874			
Total Production	1 911			

Source: AER (2010a)

1. Conventional Natural Gas reserves include LNG and ethane
2. Proved Reserves are those for which geological and engineering analysis suggests at least a 90 per cent probability of commercial recovery. Probable reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery

Figure 49 shows forecast aggregate annual gas demand in the eastern Australian domestic market (excluding LNG exports) under 3 scenarios that are described in the 2010 Gas Statement of Opportunities.

Figure 49 **Forecast aggregate annual gas demand in the eastern Australian domestic market**



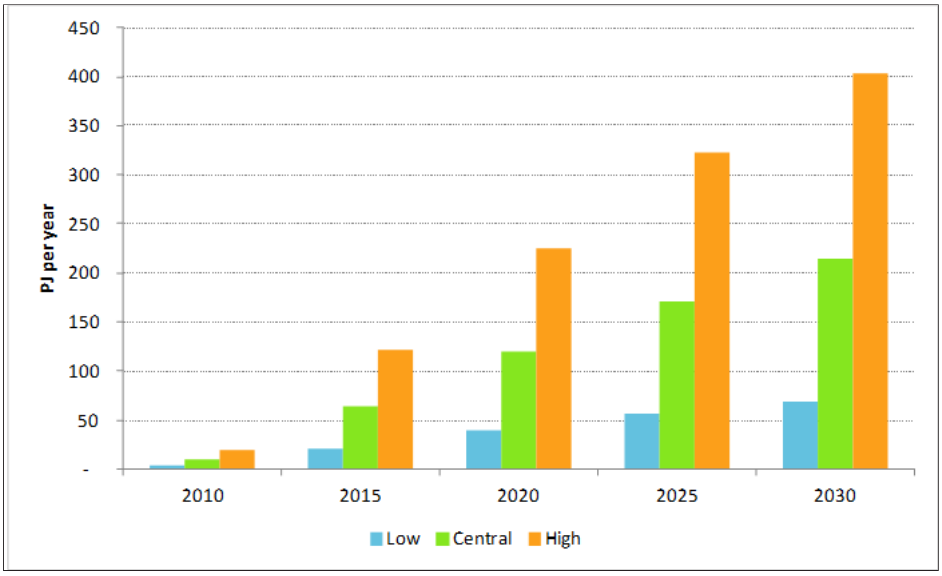
Source: AEMO (2011b)

9.2 Possible impacts on gas wholesale and retail markets

9.2.1 AECOM's analysis

As discussed in **Section 8.0**, if the take up of NGV buses and trucks are 50% and 20% respectively under the central scenario, the total gas required would be around 65 PJ (65,000 TJ) of gas by 2015, rising to around 120 PJ of gas by 2020 and around 215 PJ of gas by 2030 in the central case. In the high case where 90% of buses are CNG and 40% of trucks are LNG, volumes could be 120 PJ of gas by 2015, rising to around 225 PJ of gas by 2020 and around 400 PJ of gas by 2030.

Figure 50 Scenarios of gas volume for NGVs



Source: AECOM

In 2015, AECOM's central estimate of gas demand for NGVs is 65PJ, which is less than 5% of projected annual demand nationally. Gas demand is estimated to grow by 4% per year, which is the same rate as domestic demand shown in **Figure 49**. AECOM's central estimate of aggregate demand until 2040 is 4,600 PJ, which is less than 5% of current proven and probable reserves (shown in **Figure 48**). The volumes of gas for NGVs can therefore be supplied in the market, although there may be marginal price impacts.

In Australia, wholesale gas is sold mostly under confidential, long term contracts. The trend in recent years has been towards shorter term supply, but most contracts still run for at least five years. Foundation contracts underpinning new production projects are often struck for up to 20 years. Such long term contracts are commonly argued as being essential to the financing of new projects because they provide reasonable security of gas supply, as well as a degree of cost and revenue stability.

Large gas customers (say more than 1 PJ per year) are likely to enter into medium term, wholesale contracts. The following section presents market-based evidence that such contracts have been available at commercially viable prices. Smaller gas customers, such as individual drivers, will purchase gas either from a retailer or reseller (such as Wesfarmers). AECOM's analysis shows that the viability of NGVs is very sensitive to gas prices, and that NGVs are not attractive to customers paying retail prices for gas.

Future gas price movements in the eastern Australian market will depend on availability of LNG export terminals (and then global LNG market) and supply of coal seam gas. Gas price movements in Western Australia are already linked to the global LNG market. Steps 4 and 5 of the study will test whether there is any need for special gas market regulation to cater for NGVs.

9.2.2 Submissions and other evidence

In recent years there have been significant developments in LNG infrastructure for truck refuelling across Australia, demonstrating a growing trend for heavy vehicles to use LNG instead of diesel or fuel.

In 2009, Wesfarmers Energy opened an LNG plant in Kwinana, Western Australia which is capable of supplying 175 tonnes per day (9.7 TJ per day or 3.5 PJ per year) for power stations and 130 heavy vehicles. (Gas Today 2009, http://gastoday.com.au/news/wesfarmers_opens_kwinana_lng_plant/001437/)

In 2011 German gas company BOC opened its Westbury Micro-LNG plant in Tasmania to supply LNG to over 120 heavy vehicles in the region. The plant has the capacity to produce 50 tonnes of LNG per day, the equivalent of 70,000 litres of conventional diesel. BOC signed an agreement in 2010 that will deliver 100 tonnes of LNG per day (5.5TJ per day or 2 PJ per year) to heavy vehicle refuelling stations along Australia's east coast. Under the agreement, Australian coal seam gas explorer and producer QGC will supply 30 PJ (1 PJ is equal to 20 000 tonnes of gas) of coal seam gas to BOC over 15 years from July 2011, with an option for a further 15 years. (Minister for Resources Energy and Tourism, http://minister.ret.gov.au/MediaCentre/MediaReleases/Pages/MicroLNGPlant.aspx, http://minister.ret.gov.au/MediaCentre/MediaReleases/Pages/BOC-APADealGetsLNGintotheTransportFuelMarket.aspx)

9.3 Potential impacts on gas networks

9.3.1 AECOM's analysis

Timing is less important for gas vehicles refuelling than for electric vehicles, because gas networks can generally balance on a daily basis rather than instantaneously. Unlike electric vehicles, there is little need to analyse timing of refuelling, namely unmanaged, time of use, managed or smart charging.

Commercial CNG or LNG vehicles will need specialised refuelling stations, which are likely to be connected either at transmission or sub-transmission level if large quantities of gas are required. Network impacts from commercial refuelling are likely to be small, for the following reasons:

- LNG facilities are likely to require high capacity connections to transmission or sub-transmission pipelines, in order to supply sufficient quantities.
- There are already clear price signals for withdrawals through high capacity connections. These signals recognise the need for gas balancing and the scope for line-pack within high capacity gas networks.
- Facilities will need to provide storage for CNG or LNG prior to distribution to refuelling stations, so should be able to manage their withdrawals to reduce network impacts and costs.

There is unlikely to be much (if any) small customer refuelling from the gas distribution network, because AECOM's modelling shows that passenger NGVs are not attractive at current retail gas prices. However technology exists for refuelling passenger NGVs from the gas distribution network, as explained in the following article from Gas Today:

> OES CNG is in the final stages of developing its compressed natural gas home refuelling stations. Gas Today profiles the technology and the development of the CNG-fuelled vehicles market.
>
> ... OES CNG has developed a new compressed natural gas (CNG) refuelling system that can be installed outside domestic garages. CNG@HOME works by drawing gas from the domestic natural gas supply and compressing it into the vehicle's CNG cylinder. It takes approximately three hours to fill a standard passenger car, which will give it a range of 200-250 km.
>
> ... OES CNG sees a "big future" for urban deliveries, taxis, tradesmen and private commuters. As such, the range to be brought to market includes two domestic models and two commercial units. The domestic units will have a capacity of 6 cubic metres per hour (m^3/h) - equivalent to 6.6 litres of petrol - with one unit to be a standard slow-fill unit and the other to have some internal storage capacity to provide a partial boost (rapid) fill. The light commercial units will have compression capacities of 10 and 13 m¬¬3/h respectively and will both have internal storage capacity.

http://gastoday.com.au/news/a_home-grown_home_refueller/056464/

Some gas distribution networks operate at low pressure, to reduce losses from leaks in older pipes. Any distribution connected equipment will therefore need to be approved by the relevant network service provider. For example, ACTEW-AGL's Gas Connection & Supply Standard Customer Contract (http://www.actewagl.com.au/~/media/ActewAGL/ActewAGL-Files/About-us/Natural-gas-network/Natural-gas-network-prices/Gas-connection-and-supply-contract.ashx) allows customers to draw up to 6 cubic metres per hour. OES CNG's domestic units meet this requirement. It is possible that older gas networks might need upgrading to cater for large amounts of distribution connected refuelling of NGVs.

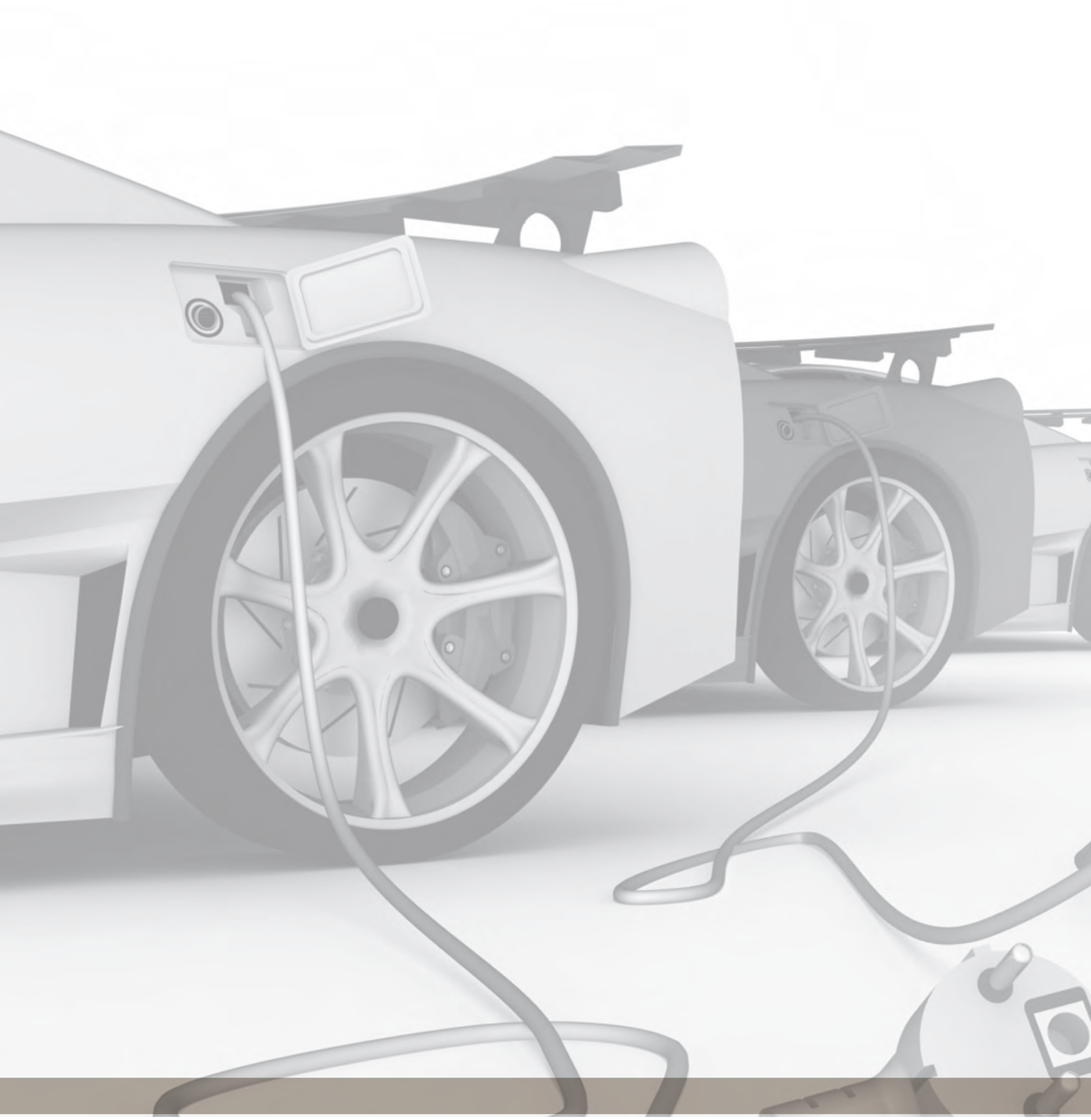
Low take-up of passenger NGVs should mean that potential impacts on distribution networks are likely to be low. Light commercial vehicles are likely to use commercial refuelling stations which are likely to be connected at transmission or sub-transmission level as discussed above. Potential impacts on transmission networks could be greater but presumably will be customer funded. Steps 4 and 5 of the AEMC study will test whether these impacts can be managed within current gas regulatory arrangements, or whether changes are needed.

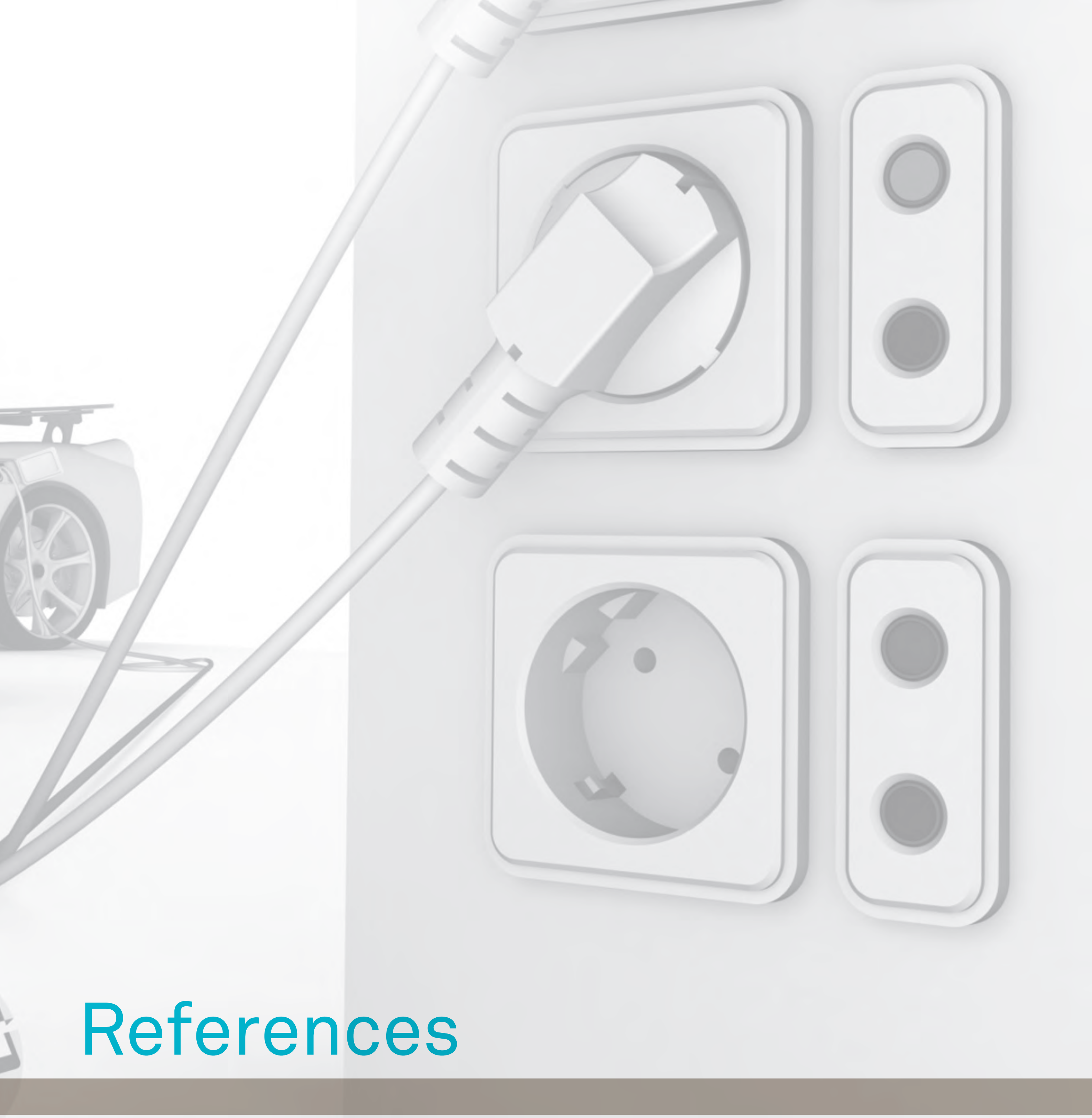
9.3.2 Submissions and other evidence

SP AusNet's submission agrees that network impacts are likely to be small (SP AusNet 2011, p.22):

"Network Impact

> Presently peak durations are of relatively short durations and hence the impact of NGV charging in residential areas is likely to only impact extended networks.
>
> The growth in the NGV market will probably be concentrated in fleet vehicles rather than the residential market. These types of customers (eg Toll, Wesfarmers) are likely to install large charging facilities, with associated storage, requiring a reasonable capital allocation and hence any gas network augmentation requirements will need to be funded by the customer. This will ensure that residential customer tariffs are not impacted."





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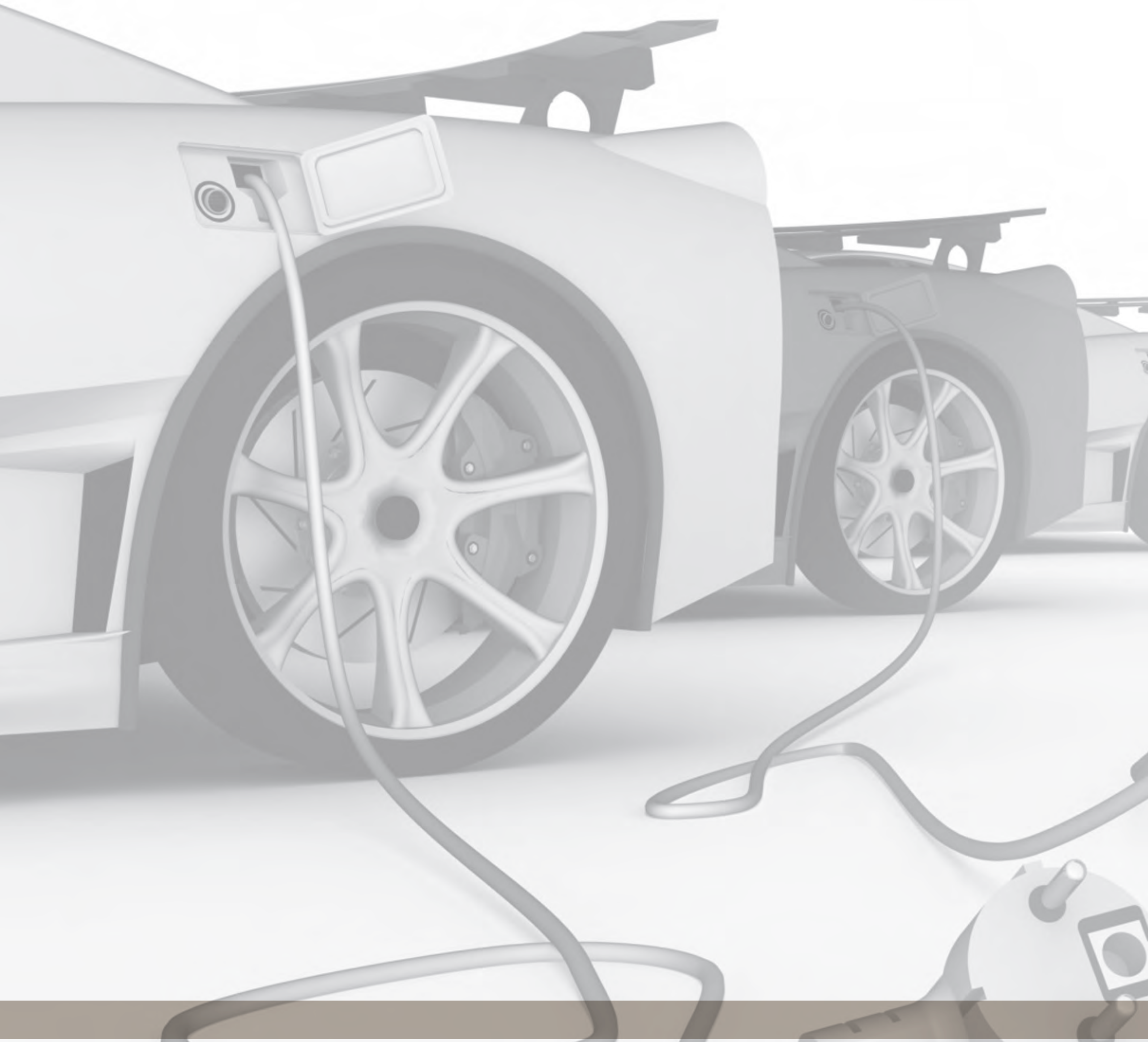
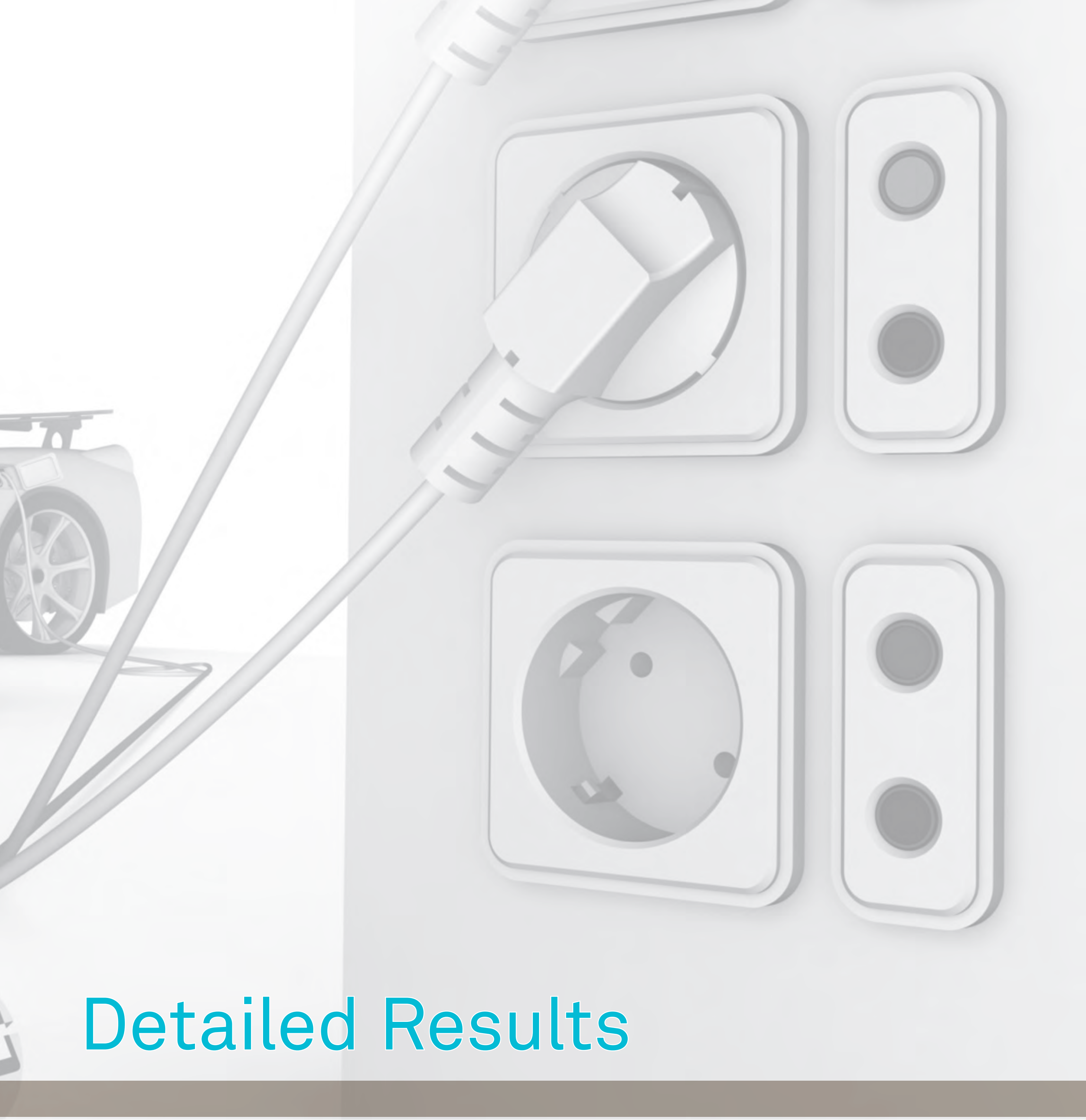
Submissions

Submissions in response to the AEMC Approach Paper were made by the organisations listed below. These are available at: http://www.aemc.gov.au/Market-Reviews/Open/Energy-Market-Barriers-for-Electric-and-Natural-Gas-Vehicles.html

Australian Automobile Association	**Late submissions:**
better place	ACT Government
ChargePoint	AGL Energy
Energex	Alternative Technology Association
Energy Networks Association	Ausgrid
Energy Retailers Association of Australia	Blade Electric Vehicles
GE Energy	Ergon Energy
Origin Energy	Government of South Australia
SP AusNet	Western Power
TRUenergy	
University of South Australia	
Westport Innovations (Australia) Pty Ltd	





Detailed Results

A

Detailed Results

Vehicle sales results

Table A1: PHEV and BEV sales by state – central scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	3,800	59,700	134,500	1,900	4,300	25,000	5,700	64,100	159,500
NSW	4,200	63,100	142,000	2,100	5,400	32,000	6,300	68,500	174,100
ACT	200	3,400	7,200	100	200	1,300	300	3,700	8,500
QLD	2,800	45,000	117,600	1,400	3,900	26,400	4,200	48,900	144,000
TAS	300	3,900	9,100	100	300	1,700	400	4,200	10,800
SA	900	14,300	34,200	400	1,000	6,300	1,300	15,300	40,500
Total NEM	12,200	189,400	444,600	6,000	15,100	92,700	18,200	204,700	537,400
SWIS	1,600	25,800	67,000	800	2,200	15,100	2,400	28,000	82,100

Source: AECOM. Values are rounded to the nearest 100 vehicles.

Table A2: PHEV and BEV sales by state – low scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	3,800	14,000	105,200	1,000	1,800	7,900	4,800	15,800	113,100
NSW	4,200	15,700	112,400	1,000	2,100	10,100	5,300	17,800	122,500
ACT	200	800	5,600	100	100	400	300	900	6,000
QLD	2,800	10,300	93,200	700	1,500	8,300	3,500	11,800	101,500
TAS	300	1,000	7,100	100	100	500	300	1,100	7,700
SA	900	3,300	26,800	200	400	2,000	1,100	3,700	28,800
Total NEM	12,200	45,100	350,300	3,100	6,000	29,200	15,300	51,100	379,600
SWIS	1,600	5,800	53,100	400	900	4,700	2,000	6,700	57,800

Source: AECOM. Values are rounded to the nearest 100 vehicles.

Table A3: PHEV and BEV sales by state – high scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	39,500	132,700	155,400	3,700	17,400	55,600	43,200	150,100	211,000
NSW	41,600	146,400	159,200	4,400	22,900	70,300	46,000	169,300	229,500
ACT	2,300	7,500	8,300	200	1,000	3,000	2,500	8,400	11,300
QLD	27,400	105,900	131,500	2,900	16,500	57,900	30,300	122,400	189,500
TAS	2,500	8,900	10,500	200	1,200	3,700	2,800	10,100	14,200
SA	9,200	32,200	39,400	900	4,200	14,100	10,000	36,400	53,500
Total NEM	122,500	433,600	504,300	12,300	63,200	204,600	134,800	496,700	709,000
SWIS	15,700	60,400	74,900	1,700	9,400	33,100	17,400	69,800	108,000

Source: AECOM. Values are rounded to the nearest 100 vehicles.

Energy usage results

Table A4: Energy consumption from EVs (MWh) – central take up scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	13,900	159,400	2,299,200	17,000	62,400	499,200	30,800	221,800	2,798,400
NSW	13,000	144,400	2,096,500	15,200	60,500	529,400	28,100	204,900	2,626,000
ACT	800	9,100	124,800	1,000	3,600	27,300	1,800	12,700	152,000
QLD	8,500	100,500	1,653,400	9,800	41,400	415,000	18,300	141,900	2,068,400
TAS	1,000	10,700	157,600	1,100	4,000	33,800	2,000	14,700	191,400
SA	3,300	38,100	576,100	3,900	14,700	124,500	7,200	52,800	700,600
Total NEM	40,400	462,200	6,907,600	48,000	186,600	1,629,100	88,300	648,800	8,536,700
SWIS	4,800	57,100	937,600	5,600	23,700	236,200	10,400	80,900	1,173,800

Source: AECOM. Values are rounded to the nearest 100 MWh.

Table A5: Energy consumption from EVs (MWh) – low take up scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	13,800	82,300	1,199,300	9,500	29,200	141,800	23,300	111,500	1,341,200
NSW	12,900	77,200	1,093,100	8,100	26,200	144,300	21,000	103,400	1,237,400
ACT	800	4,800	65,500	600	1,700	7,800	1,400	6,500	73,400
QLD	8,500	50,900	849,800	5,200	17,800	112,200	13,700	68,600	961,900
TAS	900	5,700	82,100	600	1,900	9,400	1,600	7,500	91,500
SA	3,300	19,500	298,900	2,200	6,800	35,100	5,400	26,300	333,900
Total NEM	40,100	240,200	3,588,700	26,300	83,500	450,700	66,400	323,700	4,039,300
SWIS	4,800	28,700	481,800	3,000	10,200	64,000	7,800	38,900	545,800

Source: AECOM. Values are rounded to the nearest 100 MWh.

Table A6: Energy consumption from EVs (MWh) – high take up scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	67,600	821,800	3,466,600	28,000	195,400	1,199,400	95,600	1,017,200	4,666,000
NSW	59,600	758,600	3,145,100	26,700	206,100	1,281,800	86,300	964,700	4,426,900
ACT	4,000	46,600	189,500	1,600	11,100	65,500	5,600	57,800	255,000
QLD	39,500	538,400	2,434,100	17,600	144,900	998,900	57,100	683,400	3,432,900
TAS	4,400	55,000	237,000	1,900	13,000	81,600	6,300	68,000	318,600
SA	15,800	197,600	862,700	6,600	46,900	299,100	22,300	244,500	1,161,900
Total NEM	190,700	2,418,100	10,335,100	82,400	617,400	3,926,200	273,100	3,035,400	14,261,400
SWIS	22,600	306,400	1,380,500	10,000	82,600	568,100	32,600	389,000	1,948,700

Source: AECOM. Values are rounded to the nearest 100 MWh.

Table A7: Energy consumption from EVs as a proportion of energy demand – central take up scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	0.0%	0.3%	3.0%	0.0%	0.1%	0.7%	0.1%	0.4%	3.7%
NSW and ACT	0.0%	0.2%	2.1%	0.0%	0.1%	0.5%	0.0%	0.2%	2.6%
QLD	0.0%	0.1%	1.0%	0.0%	0.0%	0.3%	0.0%	0.2%	1.3%
TAS	0.0%	0.1%	0.9%	0.0%	0.0%	0.2%	0.0%	0.1%	1.1%
SA	0.0%	0.2%	2.5%	0.0%	0.1%	0.6%	0.0%	0.3%	3.1%
Total NEM	0.0%	0.2%	1.8%	0.0%	0.1%	0.4%	0.0%	0.2%	2.2%
WA	0.0%	0.1%	2.1%	0.0%	0.1%	0.5%	0.0%	0.2%	2.6%

Table A8: Energy consumption from EVs as a proportion of energy demand – low take up scenario

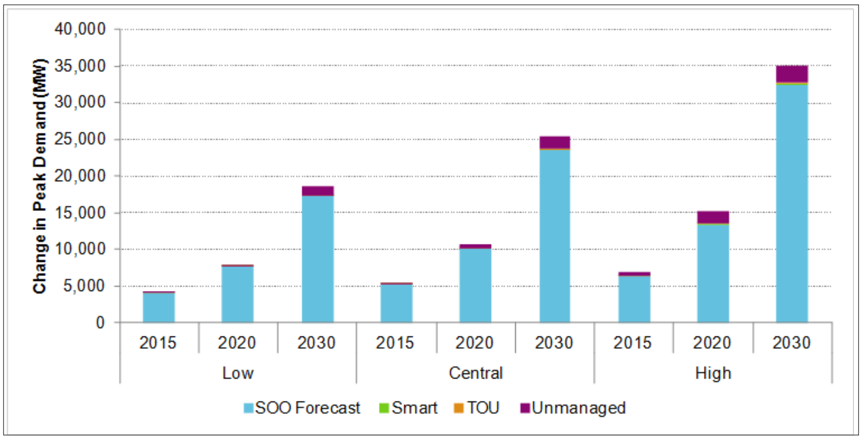
	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	0.0%	0.1%	1.6%	0.0%	0.0%	0.2%	0.0%	0.2%	1.8%
NSW and ACT	0.0%	0.1%	1.1%	0.0%	0.0%	0.1%	0.0%	0.1%	1.2%
QLD	0.0%	0.1%	0.5%	0.0%	0.0%	0.1%	0.0%	0.1%	0.6%
TAS	0.0%	0.0%	0.5%	0.0%	0.0%	0.1%	0.0%	0.1%	0.5%
SA	0.0%	0.1%	1.3%	0.0%	0.0%	0.2%	0.0%	0.1%	1.5%
Total NEM	0.0%	0.1%	0.9%	0.0%	0.0%	0.1%	0.0%	0.1%	1.1%
WA	0.0%	0.1%	1.1%	0.0%	0.0%	0.1%	0.0%	0.1%	1.2%

Table A9: Energy consumption from EVs as a proportion of energy demand – high take up scenario

	PHEV			BEV			Total BEV and PHEV		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
VIC	0.1%	1.4%	4.6%	0.1%	0.3%	1.6%	0.2%	1.7%	6.1%
NSW and ACT	0.1%	0.9%	3.2%	0.0%	0.2%	1.3%	0.1%	1.2%	4.5%
QLD	0.1%	0.6%	1.5%	0.0%	0.2%	0.6%	0.1%	0.8%	2.2%
TAS	0.0%	0.4%	1.3%	0.0%	0.1%	0.5%	0.1%	0.5%	1.8%
SA	0.1%	1.1%	3.8%	0.0%	0.3%	1.3%	0.1%	1.4%	5.1%
Total NEM	0.1%	0.9%	2.7%	0.0%	0.2%	1.0%	0.1%	1.1%	3.7%
WA	0.1%	0.8%	3.0%	0.0%	0.2%	1.2%	0.1%	1.0%	4.3%

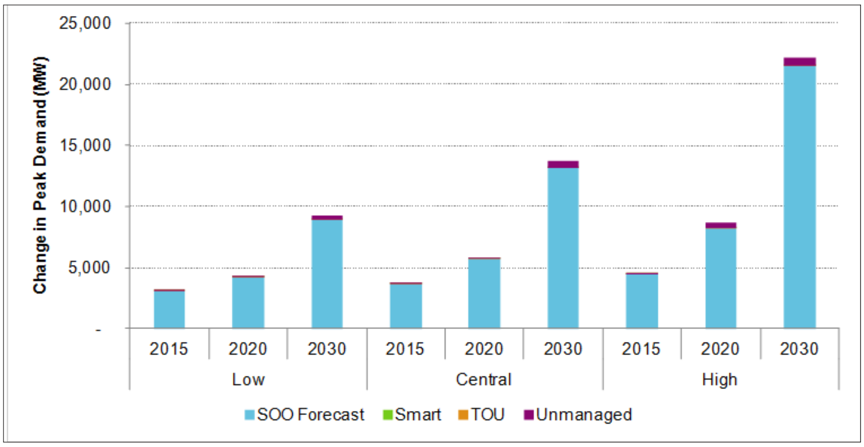
Impact of EVs on peak demand compared to the increase in peak demand required without EVs – state analysis

Figure A1: Forecast change in peak demand for the NEM (Since 2010-2011)



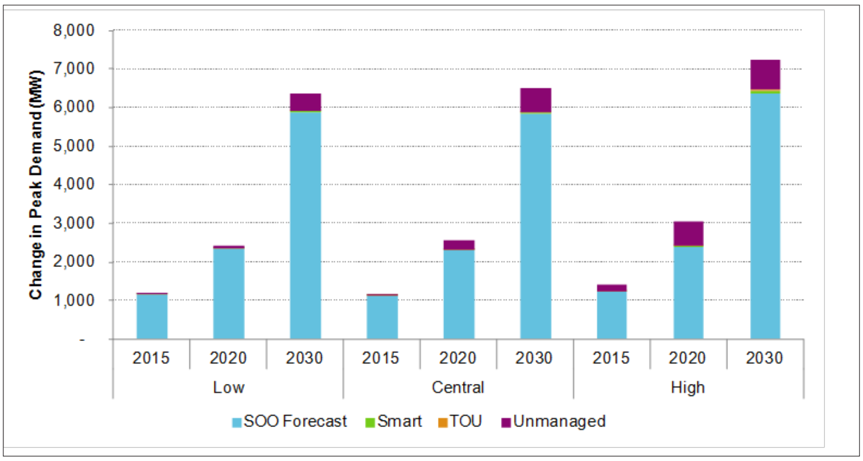
Source: AECOM

Figure A2: Forecast change in peak demand for Queensland (Since 2010-2011)



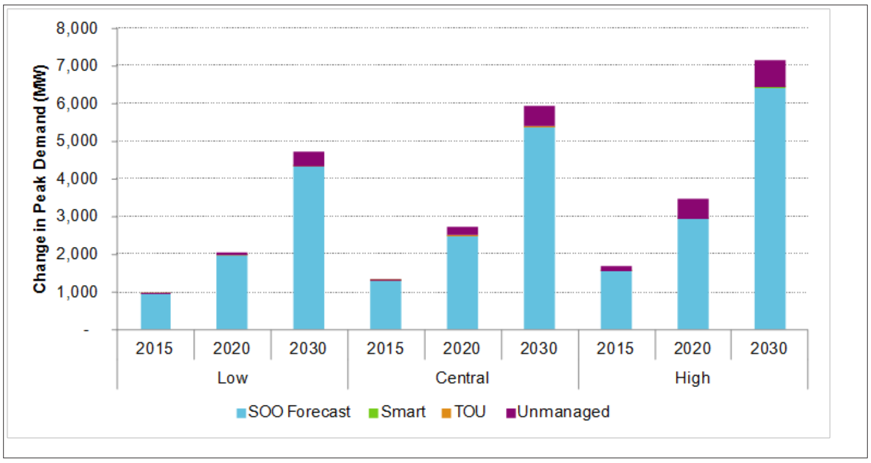
Source: AECOM

Figure A3: Forecast change in peak demand for NSW and ACT (Since 2010-2011)



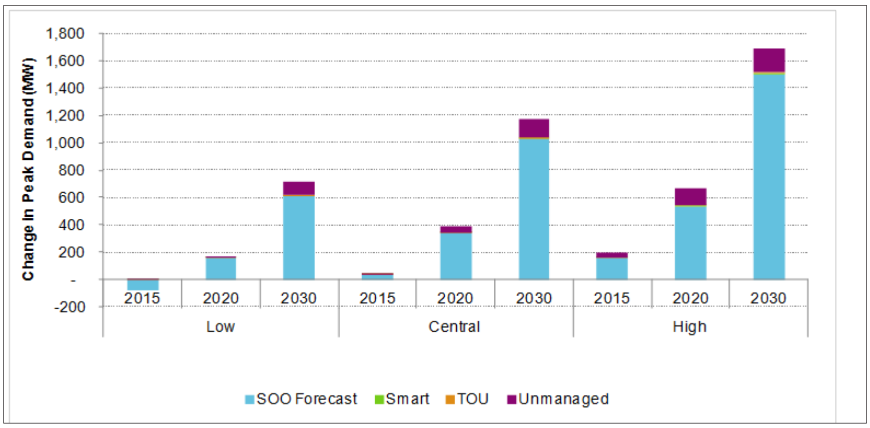
Source: AECOM

Figure A4: Forecast change in peak demand for Victoria (Since 2010-2011)



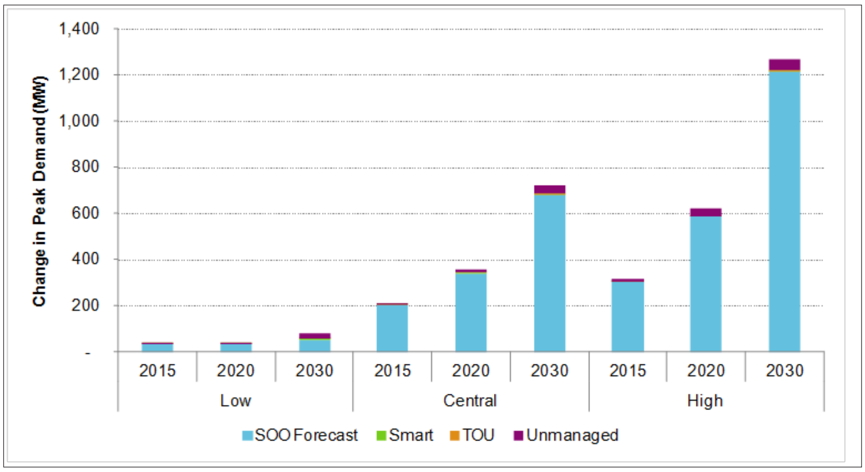
Source: AECOM

Figure A5: Forecast change in peak demand for South Australia (Since 2010-2011)



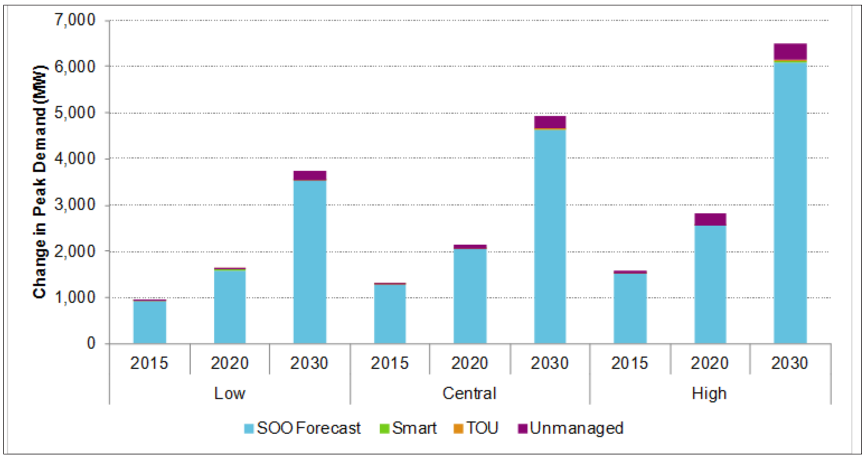
Source: AECOM

Figure A6: Forecast change in peak demand for Tasmania (Since 2010-2011)



Source: AECOM

Figure A7: Forecast change in peak demand for Western Australia (Since 2010-2011)

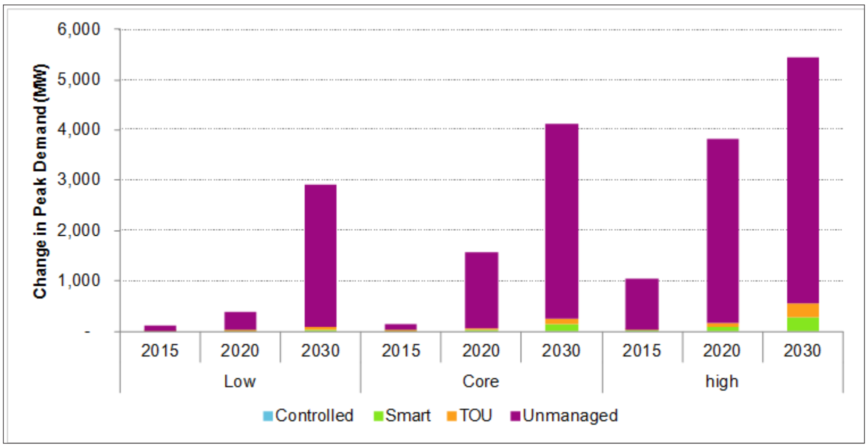


Source: AECOM

Sensitivity Analysis of Peak Load Impacts

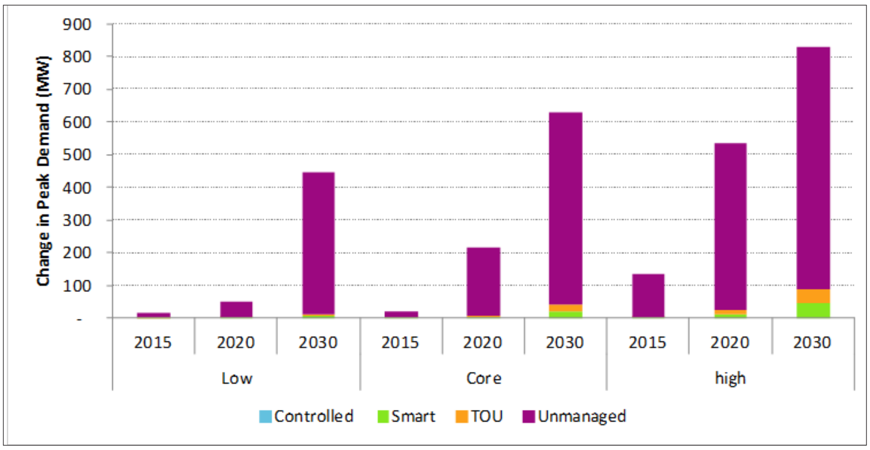
This analysis repeats the analysis in **Section 5.2** under slightly more extreme assumptions. We assume that 100 per cent of electric vehicles are charging during the peak period and that all chargers are level 32 amp chargers.

Figure A8: Estimated additional peak demand in NEM (MW)



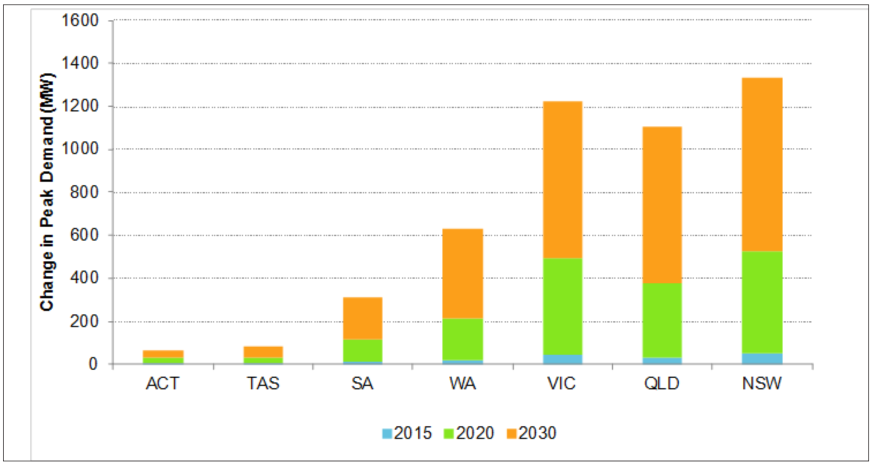
Source: AECOM

Figure A9: Estimated additional peak demand in SWIS (MW)



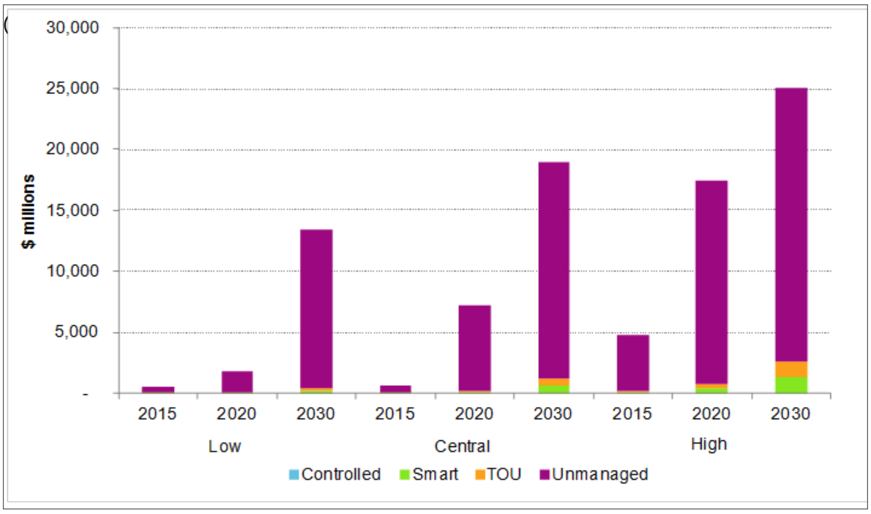
Source: AECOM

Figure A10: Additional peak demand in central take up scenario if charging is unmanaged



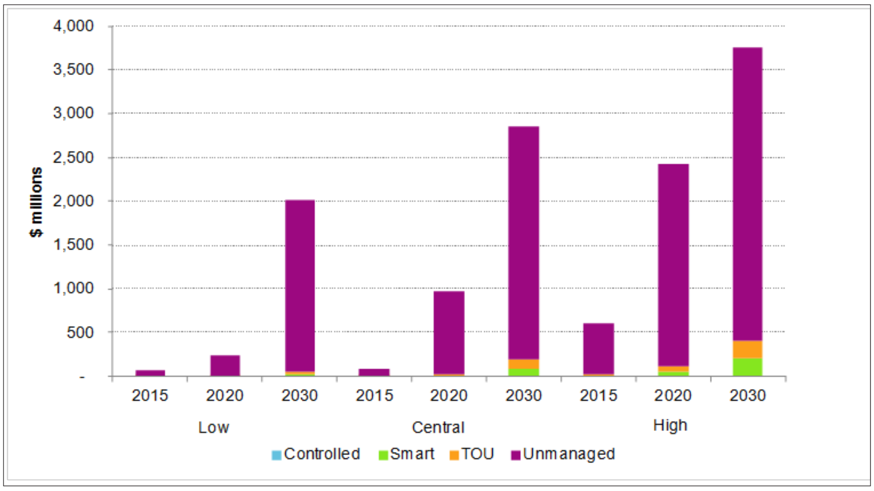
Source: AECOM

Figure A11: Estimated cost (for both generation and network upgrades) of additional peak demand in NEM



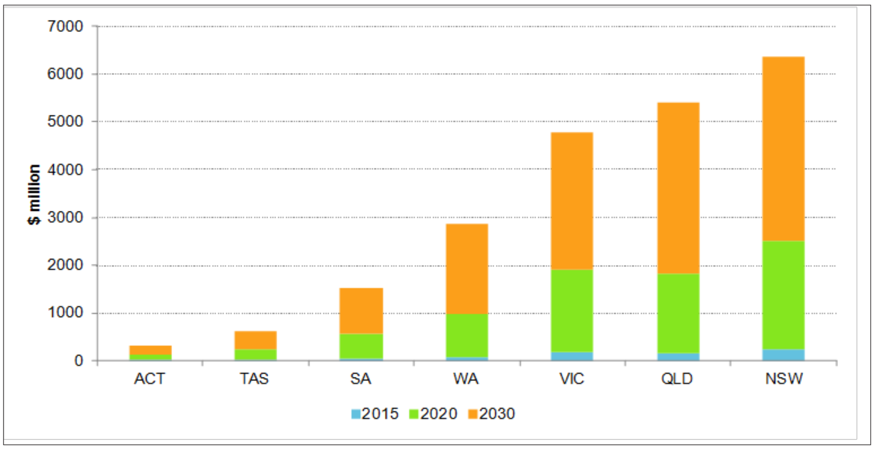
Source: AECOM

Figure A12: Estimated cost (for both generation and network upgrades) of additional peak demand in SWIS ($ millions undiscounted)



Source: AECOM

Figure A13: Costs of additional peak demand in central take up scenario if charging is unmanaged ($ million undiscounted)



Source: AECOM

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