

Title: **Recommendations for Electric Vehicle Integration**

Synopsis: This report presents a series of techno-economic, regulatory and policy recommendations for the grid integration of Electric Vehicles (EVs), also considering the current Australian plans and activities for integration of distributed energy resources. The integration of mass EV adoption into existing power systems is a complex technical task per se. Furthermore, besides technical aspects, a wider perspective is required. Hence, this report looks towards real implementation issues and opportunities to enable integration of EVs in an efficient and cost-effective manner from a whole-system outlook. The objective of the recommendations is to ensure an efficient grid integration of EVs while considering relevant residential customers' perspectives and market developments and making as efficient use as possible of the existing network assets.

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Executive Summary

The report at hand corresponds to the Milestone 10 deliverable “Recommendations for EV Integration”, part of the 2-year collaborative project on ‘EV integration into the electricity grid’ between Energy Networks Australia (ENA), the Australian Power Institute (API), the Centre for New Energy Technologies (C4NET), and The University of Melbourne, as part of the ENA and API’s Australian Strategic Technology Program.

This report aims to provide a clear set of techno-economic, regulatory and policy recommendations to enable network, system and market integration of electric vehicles (EVs) in a cost-effective manner that makes as efficient use of existing network assets. This is done in consideration of the Australian current plans for distributed energy resources (DER), as well as international smart charging trends seen in the United Kingdom (UK) and United States of America (USA).

Overview of Australia’s EV and DER Integration Plan

When considering the Australian plans for DER integration, as well as smart charging trends in the UK and USA, in terms of EV integration, over the next five years, it is clear that EV smart charging will come soon to Australia. This is a clear fundamental pillar around ensuring customers are encouraged and rewarded for flexible demand, in part to avoid “grid congestion”, but ultimately to integrate EVs in a cost effective manner [1].

An economic consultancy firm on behalf of the Energy Security Board (ESB), estimated that that DER and flexible demand could reduce system costs for the NEM by \$6,337 million in net present value (NPV) terms to 2040 and \$13,003 million in undiscounted terms [2]. The government estimated \$224 million of electricity network upgrade costs can be avoided for the integration of EVs by 2030 with the Future Fuels and Vehicles Strategy [3].

Smart meters are being increasingly rolled out across Australia, further empowering retailers to offer innovative tariffs that can reward flexibility (beyond just EV charging). Smart meters are required for tariffs that are cost reflective, such as time-of-use (TOU) tariffs. **Cost reflective network tariffs** (the charge that distribution network service providers (DNSPs) pass to retailers, who then decide how to package it to customers) is the idea that the charge paid by users of the networks should reflect the underlying costs of the network in the provision of the service to the customer. If the retailer passes this cost on in some manner, then the retail tariff would be (more) cost reflective and it could also be possible to have a cost reflective retail tariff that might include other aspects of underlying costs too, such as wholesale energy acquisition (e.g., dynamic tariffs). Cost reflective tariffs are not possible with an accumulation meter since the time of consumption is not known and as such is a clear barrier for cost reflective tariff reform [4]. Tariff reform is a key part of the plan for EV integration since it can help encourage customers to charge their EV outside of peak demand hours and help prevent network reinforcement. Furthermore, cost reflective tariffs aim to prevent customers subsidising the cost of network augmentation for usage which does not contribute to the need of augmentation.

An **EV smart charger** is defined by its ability to adjust EV charging in accordance with external communication signals (be that from the customer or retailer, etc.). EV smart chargers make it very convenient to implement flexible demand, such as following a TOU tariff. This is because an EV smart charger can be set via the customer to automatically start charging at specific times (and/or electricity price, etc.), or can be controlled externally by the retailer to get a low cost of charging - in addition to the possibility of other market services from the EV (such as demand response). Because EV smart chargers also often have **submetering capabilities**, retailers can offer EV specific tariffs to further incentivise flexible demand and off-peak charging. It is understood from the previous stages of the project [5], that in terms of distribution network impact on peak demand days, TOU based responses up to 40% adoption can help improve EV hosting capacity. If issues around second peaks following the end of a TOU period (due to a loss of diversity) can be overcome, for example through a wider range of TOU options from retailers and/or randomized delay functions, this might enable greater TOU benefits at higher TOU adoption rates and for deeper EV penetration.

If EV smart charging is combined with the proposed tariff reforms from DNSPs to pass on cost reflective network tariffs to retailers [6, 7], it will provide a further boost to encourage customers to be flexible in

how they charge an EV. The combination of cost reflective tariffs and the convenience of smart charging is the key plan to integrate EVs in the short to medium term (in a cost-effective manner) in Australia.

EV chargers with smart functionality are required in South Australia from 2024 [8], and several trials are ongoing, including the AGL smart charging trial (including EV APIs that can adjust EV charging without a smart charger) with the Fleetcarma aggregation platform [9].

Work is ongoing on ensuring there are correct standards (i.e., communication protocols), interoperability and cyber security to ensure a smooth uptake of EV smart charging [10]. For instance, that is why the ESB issued a consultation paper around smart charging issues and these key aspects [11]. The ESB then invited a range of stakeholder to provide feedback and submit their responses, including the Electric Vehicle Council, DNSPs, retailers and aggregators, the system operator and more. Due to space limitations, the feedback is not presented in the report [12] (e.g., The EV council clearly advocates to align with international standards such as adopting OCPP 1.6. for smart chargers [13], etc.).

EV smart chargers will also make it easier to get involved with other **innovative retail/aggregator options**, such as local-level DER services. When considering the distribution system operator (DSO) transition that is also planned [14], if a DNSP/DSO was able to acquire demand response in specific areas of the distribution network (since the plan is to reward customers for DER flexibility), this could be used to further boost EV hosting capacity. We have seen from the previous report [5], that if EV demand can be adjusted according to network usage, then it enables very high efficient utilisation of assets for improved EV hosting capacity (however, the study assumed full compliance, so in practice only a partial benefit would be seen if not all EV chargers participated). For example, project EDGE (Energy Demand and Generation Exchange) [15], which is a “*multi-year project to demonstrate an off-market, proof-of-concept DER Marketplace that efficiently operates DER to provide both wholesale and local network services within the constraints of a specific area of the power distribution grid*” [15], is part of the overall ESB DER implementation plan to reward flexible demand and DER in the market [14].

The **building standards update** also identified the potential of coordinated EVs [16]. The requirement from 2022 means that EV chargers within the buildings carpark must be able to be controlled in relation to the buildings overall demand [16], but instead of controlling in relation to distribution network assets, it is controlling EV chargers in relation to the buildings demand and connection limit. This is to prevent new buildings with EV chargers for carparking spaces from having over double the required electricity connection [16].

In terms of a wider centrally controlled network based EV management scheme (such as that seen in the previous report [5]), the Electric Vehicle Council has made it clear that currently in the short to medium term, the EV industry is *against* wide-spread involuntary EV orchestration as a solution for EV integration [13]. The ESB smart charging webinar confirmed that widespread centralized orchestration is not part of the plan for 2025. Furthermore, the Electric Vehicle Council advocates caution and to see how EV integration develops both domestically but also internationally for high EV penetrations [13].

Finally, the big push to encourage public and destination charging will of course help with EV adoption [3, 17]. But it may also help with residential EV integration within distribution networks (where most of the charging is currently predicted to occur). This is because these chargers are not used during residential LV network peak demand periods. This may mean that the charging requirements of residential EVs could be lower if public charging utilisation increases. A lower charging requirement can mean pushing the charging of the EV later into the night (ensuring it is ready for the morning). This could open the opportunity for further aggressive EV tariff options from retailers for a further discount to customers to charge their EV, which will further help manage peak demand and network costs.

Roadmap and Recommendations for EV Integration

The following recommendations are made for the integration of EVs considering early uptake of EVs (up to 20%), medium uptake (up to 40%) and high uptake (60%+). Penetration is defined as the percentage of residential customers with an EV. It should be noted that the specific years are likely going to be different from reality. Therefore, these recommendations should be taken as based around EV penetration (i.e., percentage of residential customers with an EV) rather than the potential temporal projections.

1) Early EV Uptake (e.g., next 5 years – up to 20% EVs)

The following are general recommendations for the early stages of EV uptake (e.g., the next 5 years). This closely follows the current Australian plan for EV integration which is up until 2025. The focus is on ensuring tariff reform and smart EV charging standards and adoption.

General Recommendations:

- Reinforcement where necessary for weak assets. (i.e., assets already close to their limit and that usually only cover a handful of people, such as parts of rural distribution networks where there is little room for an EV charger or two).
 - In fact, while smart charging is in its infancy, some assets will inevitably be replaced.
- All EV chargers should be smart chargers.
- Lay the regulatory groundwork for EV Mandatory Smart Charging.
- Tariff reform to reward flexibility. DNSPs should pass on cost reflective tariffs to retailers.
- Encourage smart meters with the installation of EV smart chargers.
 - Enables cost reflective tariffs from retailers.
 - Enables retailers to be charged cost reflective tariffs from DNSPs.
 - Potentially lower non-EV related peak demand which also helps with EV integration.
- Continue building public charging stations to minimize time spent charging at home.
- Encourage workplace and destination charging as much as possible.
 - Daytime charging of EVs, alignment with solar PV.
 - Lower charge length requirements for charging at home at the end of the day.
- Follow international standards to reduce costs and increase availability of options.
 - State specific requirements should also be avoided to the extent that is possible.

What if...:

- **Mandatory EV smart chargers not accepted?** (This could mean a lower uptake of off-peak charging)
 - Encourage vehicle API based control (e.g., Tesla) so smart chargers are not needed.
 - Work with stakeholders to accelerate the stand-alone monetary benefits of smart charging to encourage uptake on its own standalone merits (e.g., end of PV subsidy).
 - Tariff Reform for cost reflective tariffs.
 - Cost reflective tariffs make the adoption of smart chargers preferable.
 - Government could subsidize the \$200-\$300 additional cost of a smart charger versus a non-smart EV charger [13].
- **Cross subsidization of PV-related network reinforcement?**
 - Encourage daytime charging with cost reflective tariffs (or even a negative feed-in tariff).
 - Modify feed-in tariffs to counterbalance cross subsidization

2) Medium EV Uptake (e.g., next 10/15 years – 40% EVs)

The following are general recommendations for the medium stages of EV uptake (e.g., the next 10 years). This builds upon the current EV integration plan in Australia. Whilst the focus is still on ensuring tariff reform and smart EV charging standards and adoption, aspects such as local level distribution services and marketplaces should now be widely used by DSOs. This is because local level services offer some of the benefits that direct EV management can offer (e.g., adjustment of demand in response to network measurements), thereby increasing the efficiency of assets.

General Recommendations:

- EV smart charging should be mandatory by now for all level 2 (and +) EV chargers.
 - Retail options for off-peak EV charging, either user managed, or supplier managed.
 - Customers rewarded for demand flexibility.
 - Easy to use and public adjusted to a new way of transport.
 - Clear interoperability allowing customers to switch retailers without a new charger etc.
- Tariff reforms should continue if not reformed by now.
 - Cost reflectivity.
 - Additional market services rewarding flexibility.
 - Remove barriers of entry for new technologies and retailer options.
 - Consider allowing more than one retailer/aggregator per customer to encourage competition on specific flexibility services.
- Continue to encourage workplace, public and destination charging as much as possible to lower the length of charging required.
- Follow international standards (such as the adoption of OCPP1.6) for EV smart charging. Furthermore, additional standards should be nationwide to the extent that is possible to reduce costs and confusion.
- Push for more “prices for devices” retail tariffs. This can encourage more participation in demand response markets. It may also allow EV charging to occur even later at night than a normal TOU tariff.
 - Prices for devices may be simpler than TOU tariffs because the customer can be charged in the style of a traditional flat tariff (but at a significant discount) for handing over control to the retailer.
- Integration of local-level distribution services. Newly formed DSOs with network visibility can buy demand reduction services for asset congestion within a pre-defined area.
 - Requires retailers to help to enable DER visibility.
 - Requires significant work on standards, market frameworks, etc.

What if...:

- **Local level services are delayed?** (e.g., troubles in implementing dynamic operating envelopes, or lack of visibility of assets and/or DER)
 - Continue with cost reflective tariff reform to lower peak demand with smart charging.
 - Encourage workplace/destination/public charging to the greatest extent possible.
- **Smart charging unable to cater for users plugging into a standard 3.2kW socket?** (as seen in the AGL smart charging trial [9])
 - Work on tariff reforms whereby off-peak EV charging considerably cheaper than normal residential demand: implies wasting money if customers were to do this.
 - No incentive to try and hide EV charging demand via a method that is not metered.
 - Does it really matter since it is ~3kW instead of ~7kW? And how common will it be? As it is only half the power, it might not be a material issue, overall.
- **Cost-reflective tariffs for retailers is Opt-in and *not* Opt-out or mandatory assignment?**
 - Encourage customers to be rewarded for flexibility as much as possible, such as adopting pricing for devices whereby the customer essentially could pay a flat rate tariff but at a much lower cost to the customer due to handing over control.

3) High EV Uptake (e.g., 20+ years – 60% + EVs)

The following are general recommendations for the high stages of EV uptake (e.g., the next 20 years). At this point the medium and low EV uptake recommendations should be fully implemented. However, at this stage effectiveness of TOU based smart charging techniques might be reaching their limits without network reinforcement.

General Recommendations:

- Most EVs should be using a smart charger (or equivalent EV APIs) plus smart meter.
 - This leads to a high-cost reflective tariff adoption and customers can be rewarded for flexibility.
- DSO local-level services and marketplace for demand reduction in response to asset congestion need to be wide-spread, with also more 'prices for devices' tariffs.
 - Consider mandatory push for prices for devices tariffs to help with participation.
- Public charging, workplace charging, and destination charging should be commonplace to encourage off-peak charging.
 - Lower time needed charge EVs at home, allowing retailers to offer more aggressive tariffs.

What if...:

- **TOU based cost reflective tariffs, in combination with smart charging, may not be enough to efficiently utilize existing assets without significant scale of network augmentation/upgrade (which might be very expensive)?**
 - DSO local-level services for demand reduction in response to asset utilization measurements and estimations.
 - Prices for devices.
 - DNSPs/DSOs may consider a capacity/demand only cost reflective network tariffs to retailers.
- **Local level DSO services for demand reduction is not possible? (e.g., regulation)**
 - Consider direct management of EVs from DSOs as either:
 - A type of DSO-related control tariff (for EVs) offered by retailers (e.g., from DSO to Retailer to Customer).
 - Mandate orchestrated EV management
 - A step further than the new 2022 building regulations that require EV management within a multi-occupancy buildings' carpark relative to the total building demand. Instead of building demand, this would be in response to network demand.
 - Emergency control (e.g., Queensland 20A+ load connection rules, but re-imagined).
 - Network augmentation
 - This would be at a much lower level considering previous efforts on EV integration already in place by now: TOU and other types of tariffs would have lowered peak demand versus business-as-usual.
 - Cost reflective tariffs protect non-EV customers from unfair allocation of costs.

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1 Introduction

The adoption of electric vehicles (EVs) poses technical and economic challenges for the power grid. A large majority of charging is predicted to take place at home [3, 18-20]. Electricity distribution networks were not designed with the consideration of a high penetration of electric vehicles. Charging EVs at home can significantly increase the normal demand during the evening peak demand hours, which can lead to issues within the distribution network (such as asset congestion and voltage drop issues).

The integration of mass EV adoption into existing power systems is a complex but important task. Furthermore, the power system is much more than a set of poles and wires, and as such a wider perspective is required for the successful integration of EVs. It is clear that EV uptake will be significant in the coming decades. It is also clear from the previous stages of this project that EV integration in distribution networks could be problematic [21]. Whilst network wide-scale network reinforcement can resolve the limitations of a network's ability to host more EVs, it can come at a considerable cost for customers [4]. Therefore, it is clearly in the customers' interest to make efficient use of existing assets as much as possible by limiting the peak demand to the greatest extent that is possible.

Whilst direct EV management was shown to be an efficient method to achieve higher EV hosting capacities through maximising use of existing assets [5], the uptake of such a solution is unlikely to occur in the short to medium term. Time-of-use (TOU) tariffs were found to help EV integration; however there can be an inherent limit to their effectiveness [5]. Associated tariff reforms may be required to encourage off-peak charging behaviour and protect non-EV customers from network reinforcement costs. Furthermore, EV smart chargers are likely required to make EV charging flexibility convenient.

On the above premises, the report at hand looks towards real implementation and integration of EVs in an efficient and cost-effective manner. In particular, the report aims to provide a set of recommendations to enable integration of EVs in a manner that makes as efficient use of existing assets to protect customer bills. This is done in consideration of the Australian current plans for DER (and EV), as well as international smart charging trends seen in the United Kingdom (UK) and the United States of America (USA). The report is organised as follows: Chapter 1 contains general introductory concepts, also linked to previous parts of the project. Chapter 2 presents a brief review of UK and USA smart charging trends for EVs, Chapter 3 presents the current Australian plan for EV integration; finally, Chapter 4 presents a series of recommendations for the integration of EVs.

1.1 EV Uptake in Australia

This section summarises the trends of EV uptake in Australia.

As a part of the Australian Governments Low Emissions Technology Statement and Future Fuels and Vehicles Strategy [3, 22], the integration of EVs is a clear objective [3]. Individual Australian States have additionally set their own individual ambitious EV targets, for example [23]:

- *Queensland*: 50% of new passenger vehicle sales to be zero emission by 2030, 100% by 2036
- *South Australia*: 100% of new passenger vehicle sales to be zero emission by 2040
- *Victoria*: 50% of passenger vehicle sales being zero emission by 2040, 100% by 2050
- *New South Wales*: "Vast majority" by 2035 and 100% of new passenger vehicle sales to be zero emission by 2040, with EV buses by 2030
- *Tasmania*: 100% of government fleet to be zero emission by 2030

Each state and territory in Australia has both state and federal funding for several EV-uptake related incentives and investments [23-25], which in combination with EVs own merits, is leading it a consistent increase in EV adoption [23].

Currently it is estimated that as of March 2022, there are over 50,000 EVs in Australia [26]. The Australian EV Council's 2022 State of EVs Report [23] reported a three times increase in the sales of EVs in 2021 from 2020, with an increase from 0.78% to 2% of all vehicle sales (Figure 1-1 (a)). When looking internationally at the percentage of new sales that are EVs, most OECD economies have a higher uptake than Australia, with the current EU average at 17%, 25% in Germany and 72% in Norway [23] (Figure 1-1 (b)). In 2021, there were a total of 20,665 EV sales in 2021, up from 6900 in 2020 [27]. Although EV uptake is significantly lower than what is being seen in Europe currently [18], this trend in

Australia, and what is being seen internationally, suggests that EV uptake could increase significantly in the coming decade and beyond.

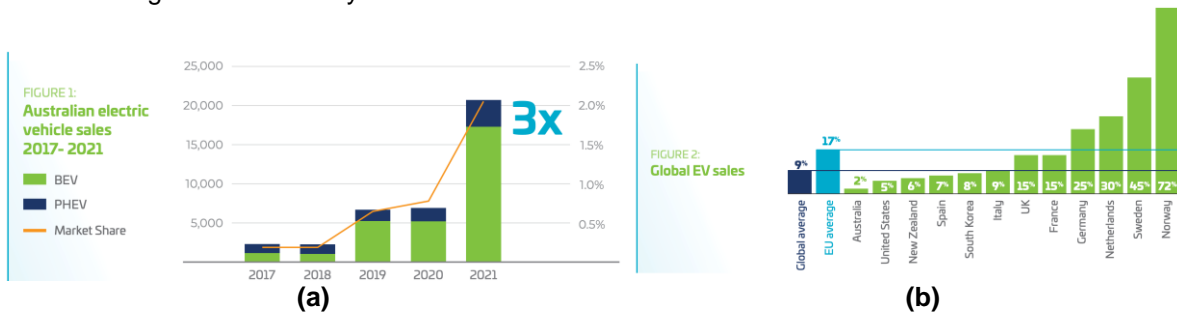


Figure 1-1. Australian EVs: (a) Australian EV Sales (b) Comparison with Global EV Sales as a Percentage of all New Vehicles Sold [23]

The Australian Energy and Market Operator (AEMO) forecast for distributed energy resources (DER) uptake [28], considering an average of the five scenarios of potential DER uptake (pessimistic to optimistic) and assuming each EV is charged by a residential 7kW charger [29] (the current trend observed, with 80% using Level 2 (7.4kW) in the EV trial Electric Nation in the UK [19]), EVs will overtake residential PV in terms of installed capacity by 2032, shown in Figure 1-2. Whilst not all will use such a charger, nor all will charge at once, it is helpful to put into context the scale of EV uptake relative to other DER types in terms of installed power capacity. Integration of roof-top solar PV is already a challenge at current levels during low-demand periods. EV integration when considering peak demand days in combination with charging during peak hours, could lead to even more serious integration issues, in particular relating to asset congestion and voltage drop issues [21].

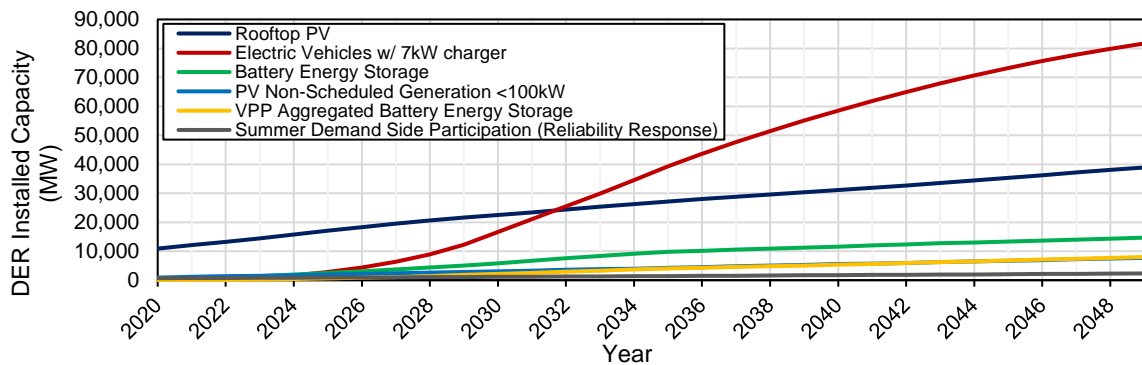


Figure 1-2. Average of AEMO Scenarios for DER Installed Capacity Forecast [29]

The uptake of EVs is a part of a larger change in household and business use of electricity and the electricity network. The integration of DER, such as EVs, residential battery storage and roof-top solar PV, among others, significantly alters both the consumption and generation of electricity. In combination with advances in automation and digital technology, DER has and will continue to create a shift in the view of how consumers interact with energy consumption, generation, networks, retailers, and the wider power system. This report aims to partially address is what the current plan for is integrating EVs in Australia and what recommendations can be made for the future.

1.2 Public EV Charging

This section presents a brief overview around some aspects related to public charging. Public charging accessibility is one of the fundamental Australian Government objectives of the both the Low Emissions Technology Statement [22] and Future Fuels and Vehicles Strategy [3]. Although public charging has not been a focus of this project (focusing on residential EV integration), it is worth highlighting some aspects. In Australia there currently are, as of January 2022, reported by the EV Council [30], 291 fast EV chargers and 1580 regular charging locations in Australia. Furthermore, it is predicted that workplace will form 6%, public 4% and destination (e.g., shopping centres etc,) 6% of total charging [18].

The availability of public charging has been identified as a key pre-cursor to enable EV uptake by helping to overcome range anxiety, provide convenience and enable cross-state and cross-country journeys. Initially utilisation of public charging may not be significant, but its presence encourages EV uptake followed by the eventual higher utilisation. Consequently, there are numerous current plans in the works to increase public charging in all Australian states and territories [3, 23]. Norway, with a population of 5.4 million, which has a very high EV adoption of 20% of the total car fleet [31] and where 72% of new car sales are EVs [23], has approximately 3,200 fast chargers (one fast charger per 1687 people!) but is reported to require approximately 5,000 [31].

Public, workplace and destination charging will undoubtedly pose issues within distribution networks. Public charging stations that employ multiple DC fast chargers, or high-power AC chargers, can quickly lead to very high-power consumptions (e.g., ten 150kW DC chargers at maximum utilisation is 1.5MW of demand) but can charge an EV very quickly (e.g., 20 minutes). Meanwhile workplace and destination chargers can be at the other end of the scale with standard Level 2 (7.4kW) chargers, or somewhere in-between.

The current trend for public, workplace and destination charging for businesses is to employ load management technology to manage charging and operate within a connection or demand/capacity tariff or connection requirement agreement (with or without a time-of-use component). This is known as *dynamic load balancing* and is often employed in fast EV charging stations by charge point operators. An example of such a product is Europe's i-charging's 'dynamicblue' chargers, which are modular, and can dynamically allocate EV charging according to a pre-defined limit (using OCPP 1.6 [32]), in response to what is currently connected [33-35].

Another example is IONITY, Europe's largest EV high powered charging network (totalling 24 countries) [36], which commonly employ load balancing. In addition, IONITY has started to install high powered batteries at some of their EV charging stations to get around connection limits [31, 37] (e.g., in Spain and the UK) where it was not possible to upgrade the network for at least several years. For example, a 500kW battery was installed alongside a 200kW LV connection to enable a higher peak combined charging power [31]. In some regions IONITY have faced delays in using battery-based techniques to mitigate connection limits due to a lack relevant regulatory and industry standards, but are working to get these resolved [31].

Any costs of such solutions in load balancing in accordance with connection limits will be absorbed by the business in the case of free charging (e.g., workplace/destination), or via the cost to charge to customers when charging at a public station.

Load balancing as a solution, for example, has been mandated in Australia by the updated building codes for 2022 for multi occupancy buildings and their carparks, whereby carparks must be able to be upgraded with charge control devices for EV charging [16]. This is where charging is limited according to the buildings spare power capacity available, after accounting for the residential buildings power consumption, therefore preventing excessively high connection requirements if all EVs are charged simultaneously at their rated power during peak demand hours [16] (further details are explained in Chapter 3.4).

Standards and interoperability have been and continue to be targeted to ensure customers can get their EV charged without much hassle and, where possible, alignment to international standards [38-40] to enable greater choice of EVs on the market for Australian customers.

1.3 At Home Charging and Distribution Networks

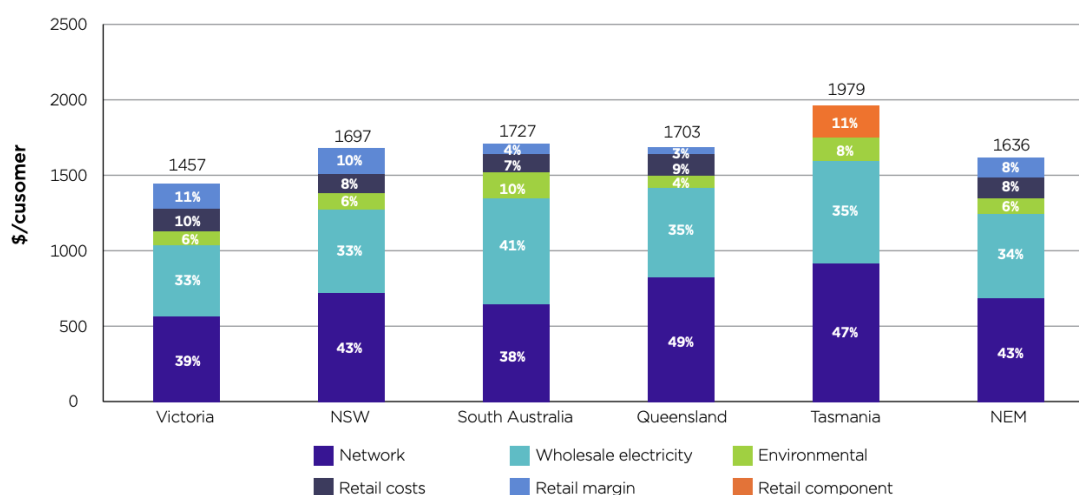
This section introduces aspects related residential charging of distribution networks. Section 1.3.1 presents what makes up residential electricity bills and the role of network costs within them, section 1.3.2 presents an explanation on EV smart charging and section 1.3.3 presents an overview of the typical residential retail tariffs that are available.

Approximately 75% to 80% [3, 18, 19] of customers charge or will charge their EV at home, whilst the estimate of the percentage of home charging is only predicted to further increase in the coming years, up to 85% by 2035 in Europe [18] for example.

Distribution networks were originally designed to cope with peak demand. Depending on the State or Territory in Australia, that design value can vary from 3 to 7kW per house (single phase) which accounts for diversity (we all use electricity at different times) and demographics (larger houses or colder places without access to gas consume more). Although distribution networks have been engineered to withstand demand growth, this does not include EVs. The trend around the world is for EVs charged at home to use the fast Level 2 chargers (around 7kW of demand). While all EVs will not be charged at the same time, they clearly are a concern for distribution companies (DNSPs), as the extra demand could easily exceed what the infrastructure has been designed for, particularly on peak demand days. These charging impacts could have a serious consequence on residential customer electricity bills if widespread network augmentation is required.

1.3.1 Electricity Bills for Residential Customers

A breakdown of residential customers costs, shown in Figure 1-3, for 2017-2018 was performed by the Australian Competition and Consumer Commission (ACCC), using retailer cost information in part of the 2018 Retail Electricity Pricing Enquiry [4, 41] as well as, but to a lesser extent, in the latest 2021 ACCC Inquiry report into the National Electricity Market (NEM) [42].



Source: ACCC analysis based on retailers' data.

Figure 1-3. Breakdown of Average Residential Bills by State for 2017-2018 excluding GST [4]

The percentage of the five individual cost components that make up a customer bills are generally equal between the six states with network and wholesale energy costs accounting for 72-79% with retail costs, retail margins and environmental costs forming the remainder [4] (*In 2021 the proportions are largely similar although the breakdown per state is not available*) [42].

Across the NEM the largest component of the overall bill paid for by residential electricity customers, according to the latest data for 2021, is the network costs, with an average of 45% in 2021 [42], an increase from 43% in 2018 where it was also the largest component.

The costs related to distribution and transmission are unavoidable for retailers and therefore customers. States and territories such as Queensland, which has the highest percentage associated with networks, employ a uniform tariff policy [43-45] to address the unique challenges of larger distances, remote areas and a lower state population density. This policy subsidises retailers to ensure the same network price for all customers regardless of location within the large state, and is funded via the Community Service Obligation payment [44].

Due to the monopolistic nature of transmission and distribution networks and the lack of competition, all networks are subject to strict regulations. The Australian Energy Regulator (AER) determines the maximum revenue from customers each year, based on [4]:

- The weighted cost of capital

- Regulatory asset base (accumulation of value of investments)
- Depreciation
- Operating costs and tax

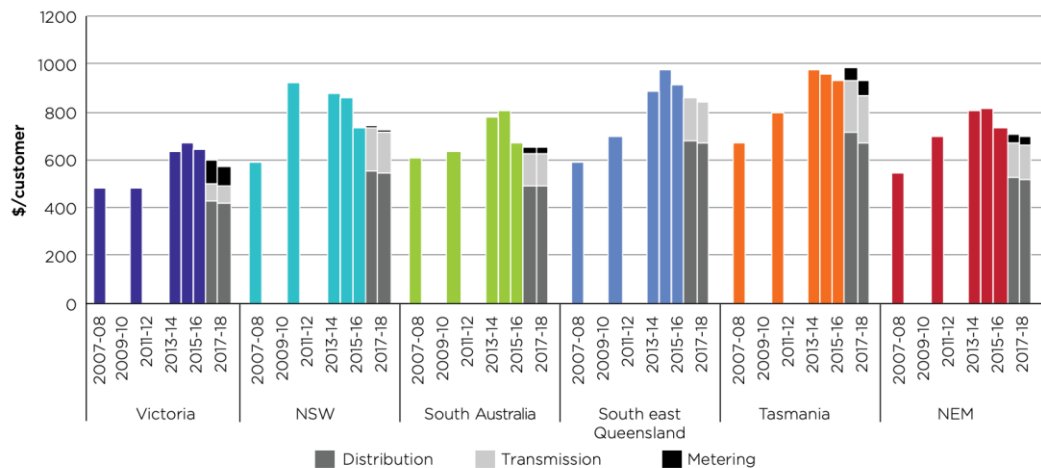
Charges to customers (via the retailers) is set by the networks based on the expected utilisation of the network; however, they cannot exceed an established *revenue* cap (no longer a price cap). It is noted by the ACCC that revenue caps provide a more stable income and prevent over-recovery of cost [4].

The costs of networks are mostly decided by the peak demand on the network (as opposed to the usage over time), so large spikes in demand drive a large part of their investment (which must be approved by regulators). In 2013 the Productivity Commission estimated that 20-30% of the network capacity in the NEM is used for less than 90 hours per year (i.e., 1% of the year) and that approximately 45% of the approved total expenditure in the distribution network, and 50% for the transmission network, is due to peak load growth [46, 47].

Network costs can, at a high level, be broken up into three different components:

1. Transmission costs
2. Distribution costs
3. Metering costs

The relative contribution of each of these to the cost stack varies between states/territories and depends on the nature of the different networks and the geography, as well as cost recovery approaches and the different policies in each state. On average across the NEM, distribution charges in 2017–18 made up between 70 percent and 80 percent of total network costs and transmission charges between 12 per cent and 25 percent [4]. Metering is generally less than 5 per cent other than in Victoria, where 17 per cent of the network costs were due to the government-mandated distributor rollout of smart meters [4]. Figure 1-4 highlights that most network costs are from distribution networks, which, when considering the geographic scale and number of assets involved in distribution, is expected. From 2008 to 2018, network costs were the largest contribution to customer bill increases.



Source: ACCC analysis based on retailers' data.

Figure 1-4. Average Network costs per customer from 2007-2008 to 2017-2018 [4]

In conclusion, it is clear that customer bills could be sensitive to increases in distribution network costs, such as network reinforcement. Given the scale of the expected EV uptake relative to other types of DER, EV integration not performed in a coordinated and planned manner that makes efficient use of existing network assets has a significant potential to cause large price rises from wide-scale network reinforcement.

1.3.2 EV Smart Charging

An EV smart charger is defined by its ability to adjust EV charging in accordance with external communication signals (be that from the customer or retailer, etc.). EV smart chargers make it very convenient to implement flexible demand, such as following a TOU tariff.

If the customer designates when to start and end EV charging on the smart charger (e.g., setting a time to start charging that relates to a tariff, or setting a maximum price per kWh), this is known as *user-managed charging*.

Another option is to hand that responsibility to an external body, such as the retailer, which can set the times for customers and ensure they are getting the best price. It can also mean that the supplier (i.e., retailer) can offer a complex tariff arrangement (such as provision of demand response, ancillary frequency services, etc), whilst shielding the customer from the associated complexities. This is also known as *supplier-managed-charging*.

Survey results that include details on customer preferences on supplier managed charging versus user managed charging can be found in the one of the previous project reports [48].

Most EV smart chargers include a manual override option should the customer urgently require charging the EV.

Another important feature of EV smart chargers is that they can measure EV related energy use (i.e., have a *sub-meter*). This means that EV charging during off-peak hours can be discounted heavily and separately from less flexible normal household demand. This requires the retailer to measure how much energy the EV was charged with and at what times, but in return the retailer can, for example, credit the energy-rate difference on the final bill.

Because of these features, it means EV demand is highly flexible, where normal household demand is less or non-flexible at all (as simulated in the previous report [5], whereby only EV charging was assumed to shift in response to TOU tariff adoption rate).

It is important to point out these features on smart chargers are optional, and customers can set the chargers up to work like a conventional charger and can pick an insurance style flat tariff accordingly (but will likely lose out on monetary savings). The point is that EV smart chargers make charging during off-peak hours extremely convenient and straightforward, and the customer could wake up to a fully charged EV (potentially having saved money in doing so).

If the customer has a connection agreement whereby the EV charger at full rated power would exceed this agreement, a smart charger is also able to throttle charging below a pre-defined limit (this can also work in this manner if there is a demand/capacity tariff). This requires appropriate metering devices to measure household demand so as to ensure net power imports are within the desired setting.

It is worth highlighting that in 2021 the government of South Australia stated that by 2024 EV chargers need to meet either OCPP1.6 V2 [32] or ANSI/CTA 2045-B (or be able to demonstrate equivalent demand response capabilities [8], essential requiring EV chargers are smart chargers). OCPP 1.6 is internationally the most widely adopted EV smart charging standard by a significant margin [9, 13, 24, 49]. This requirement for EV charging standards will come into force in 2024. A review found that 30 of 47 EV chargers investigated in Australia meet these standards [8]. Finally recent trials have found EV smart charging coordination by retailers is working as planned, for example in the AGL EV smart charging trial [9] (which also demonstrated successful coordination of EVs (i.e., Tesla) that have capable APIs and can throttle charging via external signals without a smart charger) [9]. Finally, it may be possible to retroactively upgrade an EV charger with a 'smart cable', as defined in the UK EV smart charging regulations [49].

1.3.3 Types of Tariffs

There are several types of typical tariffs offered to residential customers, which is important to clarify for the context of EV integration (i.e., smart chargers as previously explained, or the potential benefits of tariff reforms). Table 1-1 provides a summary of typical tariffs available and what they mean, with a

general categorisation of the pros and cons. Most tariffs have an additional daily supply charge. Some of these tariffs would only be available with smart meters and/or devices with submetering and appropriate retail arrangements (such as EV smart chargers following a TOU). Tariffs related to energy export, such as feed-in tariffs, are excluded.

Table 1-1. Types of Electricity Tariffs

Tariff	Pro	Con
Flat Rate Tariffs	<ul style="list-style-type: none"> → Simple to understand (also the most common type of tariff for residential customers) → Flat rate of energy (plus a daily supply charge) → Low risk and high degree of certainty of cost outcomes – relies on the retailer to balance risk 	<ul style="list-style-type: none"> → Consumers only rewarded for reducing total volume of energy usage → No incentives to help with network issues or system aspects
Time-of-Use (TOU) Tariffs	<ul style="list-style-type: none"> → Encourages energy consumption outside of peak hours, encouraging the use of cheaper wholesale energy time periods → Pre-defined TOU periods that are easy to understand (sometime with shoulder intermediate periods) → Can be combined with other types of tariffs (a common combination is with a demand tariff) → Can help with network congestion indirectly (depends on the time periods) → Can sometimes be offered as seasonal based tariff (e.g., changing the cost of energy depending on the season, other times it can be a type of demand tariff) 	<ul style="list-style-type: none"> → Can be a low penalty/reward for operating within peak period → Loss of diversity if too many customers follow the same times → potential network issues → No direct link to network capacity → Can require a new meter
Inclining Block Tariff	<ul style="list-style-type: none"> → Price will change depending on the block of energy, after a certain limit the customer will move onto the next block. Subsequent blocks increase (“incline”) the cost with usage (electricity goes up in cost, whereas gas goes down per block typically). Blocks can be across a day or a couple of days → Discourages wasteful use of electricity 	<ul style="list-style-type: none"> → No time aspect so unlikely to help with network issues nor incentivize the use of cheaper wholesale energy periods
Demand Tariffs	<ul style="list-style-type: none"> → Pay for max kW (power) → Often the demand tariff is based on measurements during peak windows and therefore can be considered a different form of a TOU tariff (e.g., if you have high peak demand during non-critical hours, that does not matter) → Sometimes there are seasonal based TOU demand tariffs whereby the demand limit changes on the season → Aimed at helping with network capacity/congestion and can provide significant network benefits → Could be combined with flat or dynamic energy tariff component (as well as TOU as mentioned) → Usually, a lower fixed supply charge 	<ul style="list-style-type: none"> → Can lead to paying a high cost for a whole month even if demand is only high for a short period during the critical period → May require an energy management system to make best use of the tariff (e.g., a smart EV charger that will throttle charging according to measured house imports) → Can require a new meter
Capacity Tariffs	<ul style="list-style-type: none"> → Pay for max kW, but is pre-agreed and not based on usage (and there is a penalty charged if exceed) → Otherwise, similar to demand tariff 	<ul style="list-style-type: none"> → Less flexible versus a demand tariff → May require an energy management system to make best use of the tariff (e.g., a smart EV charger that will throttle charging according to measured house imports) → Can require a new meter
Critical Peak Rebate/Tariff	<ul style="list-style-type: none"> → Can be a reduced demand in exchange for credit on a bill, or a cheap rate that gets expensive during critical periods → Only a few days (and minutes or hours within those days) of critical peak pricing available each year → Can be used to completely turn off a load, or it can be used to throttle demand (i.e., increase temperature setpoint) → Signal for customers to reduce demand during problematic periods only (less regular than an interruptible supply tariff) → Can be optional in exchange for high prices (i.e., if you need the demand, it can still be used, unlike interruptible supply tariffs) 	<ul style="list-style-type: none"> → Can lead to high energy cost during peak periods → In some instances, customers can be informed of critical peak a few days beforehand, which may be missed unless engaged → Can require a new meter → More common for export tariffs
Dynamic Tariff	<ul style="list-style-type: none"> → Exposure to real time energy pricing which may help promote behavior that aids system-level energy balancing 	<ul style="list-style-type: none"> → Focuses on energy/wholesale aspects and no direct network aspect → Requires high user engagement and/or an

		<p>automated system to make best use of the tariff efficiencies</p> <ul style="list-style-type: none"> → Exposure to spot price risk → Can require a new meter
Prices for Devices	<ul style="list-style-type: none"> → Retailer takes control of load that can be managed (e.g., EVs or smart appliances) in exchange for a rewarding tariff → Can be combined with other tariffs that could be normally hard to follow (such as a dynamic tariff which follows wholesale energy prices). The tariff may reduce your demand of smart devices during high spot prices for example → Exposure to additional markets that other tariff options may not offer (e.g., ancillary services) → Can be combined with export-related aspects (outside of the scope) → Four main type of demand responses that can be provided, when considering 'smart' loads that the tariff can utilize: <ol style="list-style-type: none"> 1. <u>Network demand response</u>: to manage peak demand depending on network utilization 2. <u>Wholesale demand response</u>: in response to the wholesale market – can be used to reduce prices if combined with a dynamic tariff, can also help retailers with their market positions or even defer generation capacity investments 3. <u>Ancillary services demand response</u>: used by system operator for managing system frequency (there are further subcategories for frequency-based ancillary services) 4. <u>Emergency demand response</u>: used to avoid load shedding → Retailers can group together many customers within an area and provide strong aggregate responses which would be available to markets (these are known as <i>aggregators</i>) → Could provide significant benefits to the system (and potentially the distribution network if appropriate local marketplaces are introduced) → Can either throttle devices (such as an EV charger), or can simply switch a device on/off 	<ul style="list-style-type: none"> → Requires smart devices or a home energy management system to get the most out of it (or both) → May be confusing to some customers to understand if they are getting a good deal due a potentially complex structure → Handover of control away from the customers and places trust that the retailer will get the best deal for you (<i>this could be considered a pro since getting the best deal could require a lot of effort and micro-managing depending on the tariff</i>) → Can require a new meter
Interruptible Supply Tariffs	<ul style="list-style-type: none"> → Can help with network peak demand, wholesale aspects, sometimes ancillary based system responses and a helpful emergency lever for system operators → Typically, otherwise acts like a flat rate tariff (i.e., fixed cost per unit of energy), but at a significant discount versus a normal flat rate tariff → Can sometimes be a non-binary response (such as increasing the temperature setpoint on a compatible air conditioner) → Can mean no supply charge (i.e., fixed fee for each day connected to the network) – depends on the state/territory – sometimes a reduction in supply charge → Can be offered a couple of types of load-controlled tariff, either dependent on load type or preference (e.g., one will allow greater hours of use versus the other) → Sometimes can be mandatory for certain types of loads (for example, Queensland requires this type of tariff for loads over 20A [50], or pool pumps & hot water systems also in other states) → Can provide significant cost benefits in exchange for an interruption to supply that often goes unnoticed → Some tariffs will turn off devices connected to this tariff at pre-defined periods of the day → usually aligned for network benefits → Other tariffs offer flexible demand response on request for use by DNSPs to help with issues such as network congestion 	<ul style="list-style-type: none"> → Once installed, usually there is no control of when the interruption will occur (can be controlled by the DNSP or at pre-defined times) → Requires an additional tariff since it must be combined with a primary tariff (i.e., cannot run a whole household on it) → Often there is no time related aspect of energy use of controlled load devices (i.e., is a flat rate) → Special requirements for appliances and loads connected to these tariffs. Requires additional load control equipment and can require a new meter

1.4 Key Takeaway from Previous Project Stages

This section highlights the key takeaways from the previous project stages that are relevant when considered recommendations for the integration of EVs [5, 21, 48]. Residential charging, the impact to distribution network of unmanaged EVs [21], potential solutions of EV management and time-of-use adoption for EV integration [5], residential customer insights through a survey [48], and an EV uptake consumer-focused review [20], have been the focus of the project. Section 1.4.1 highlights the impacts of unmanaged residential EV charging in distribution networks, Section 0 summarises aspects related to direct management of EVs, Section 1.4.3 presents findings from TOU profiles for EV charging, and Section 1.4.4 highlights customer acceptance of managed charging from the survey

1.4.1 Unmanaged EV Impact Analysis

Milestone 5 [21] looked at the impact that unmanaged residential EV charging could have on six Australian Integrated HV-LV feeders, with individually modelled EVs, three-phase unbalanced 24-hour time-series power flows, considering a peak demand day (worst case scenario).

EV penetration is defined as the percentage of residential customers with a single EV. Thus, to assess the unmanaged EV impacts (e.g., no TOU behaviour aspects for EV charging where most people opt for charging during the evening) for different EV penetrations, each of the six integrated HV-LV feeders considered six EV penetration steps (0%) up to a maximum of 160% in 20% steps in the EV impact analysis [21].

EV Hosting capacity is defined as the maximum amount of EVs that a given distribution network (or part of it) can host without negatively affecting its normal operation at any point in time. EV location is randomly assigned across and within the LV feeders up to the EV penetration being investigated.

Further information, such as the creation of profiles used for modelling EVs, network modelling, and other aspects can be found in the full report [21].

Rural feeders:

- Rural feeders were found to have an EV hosting capacity of up to 40% of residential customers with an EV. LV transformer utilisation issues can appear with as little as 20% EV penetration for Rural VIC and become wider at 40% for Rural NSW and TAS, including significant customer voltage drops and LV conductor issues.
- The larger number and smaller size of LV transformers typically used in rural feeders results in many congested transformers with relatively low EV penetrations. Furthermore, the length of the rural feeders and resulting higher impedances lead to lower voltages with relatively low EV penetrations.

Urban Feeders:

- Urban feeders were found to have an EV hosting capacity of up to 80% of residential customers with an EV. The first limiting factor was asset congestion (LV conductors, HV conductors or LV distribution transformers).
- While voltage issues are not significant for urban feeders until high EV penetrations, the high density of residential customers inevitably leads to a much larger peak demand even with modest EV penetrations, resulting in asset congestion.

Table 1-2 summarises the results from the EV impact assessment of unmanaged EVs, conducted as part of the previous report [21] (red indicates significant exceeding of limits, yellow indicates low breach of limits and green is within limits).

For strong feeders such as Urban NSW, EV integration for the long-term is unlikely to be a concern (i.e., 80% EV penetration). Whilst most feeders can host 20% of residential customers with an EV that is unmanaged (i.e., no TOU), the asset or voltage limitations at can occur at 40%-60% EV penetration. Meanwhile some distribution networks were found to encounter issues at 20% EV penetration, in particular, Rural VIC struggled for EV integration without any assets within the large and sparsely distributed network being negatively impacted.

This highlights that in the short term (e.g., with 2% of total car sales being EVs), while accounting for the length of time until people buy new cars and for EVs to trickle down to the second-hand market, the distribution networks may be okay. Furthermore, hosting capacity of unmanaged EVs may increase if EV charging behaviour deviates from that of Electric Nation [21]. If nothing is done to encourage off-peak charging behaviour, then by 20-40% EV hosting capacity can become quite limited for some distribution networks. This can be mitigated, however, if action is taken to enable more efficient use of existing distribution network assets and manage peak demand to the extent that is possible.

Table 1-2. EV Impact Assessment Summary

Feeder	EV Hosting Capacity							
	20%	40%	60%	80%	100%	120%	140%	160%
Rural NSW (Hazelbrook)	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond
Urban NSW (Preston)	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond
Rural TAS (Norwood)	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond
Urban TAS (West Hobart)	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond
Rural VIC (SMR8)	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond
Urban VIC (CRE21)	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond	V Cust LV TX LV Cond HV Cond

1.4.2 Direct EV Management

The report for Milestone 8 investigated the adopting the direct EV management of residential customers to increase EV hosting capacity for distribution networks [5].

The objective of the investigated EV management strategy was to mitigate thermal problems at the head of the LV feeders (i.e., LV transformer and LV conductors) and any voltage drop issues (seen by EV chargers). This is achieved through the disconnection and reconnection of chargers remotely in response to measurements available to the control decision process [51, 52]. The main focus of EV management was to assess the impact on customers (i.e., impact on charging time and how many customers are impacted) through direct management of the chargers so as to keep the network within its technical limits.

It was found that the majority of customers were relatively minimally impacted, whilst direct management of EVs, with measurements at the head of each LV feeder and at the EV charger, was able to mitigate voltage and asset congestion issues to enable up to 100% EV hosting capacity. The exception was rural VIC which was a significantly challenged feeder with small, more distributed assets, and whilst network management was successful, it was the worst performing in terms of customer impact, that is, ~80-99% for five feeders, versus 63% of customers impacted for rural VIC.

EV management highlights that if a situation arises where direct coordinated management of EVs is possible in relation to network assets, then existing assets can be used in a very efficient manner requiring minimal network augmentation (and in turn very low bill increases from network costs) by avoiding high peak demands through coordinated flexibility. Augmentation (i.e., network reinforcement) would still be required where asset congestion or voltage drops were to lead to unacceptable delays for a small minority of customers (e.g., rural VIC); however, compared to business-as-usual, it would be significantly lower. The full report is available in [5].

1.4.3 Time-of-Use Tariff Profiles

The report for Milestone 8 also investigated the benefits and challenges of time-of-use tariff profiles as strategies to increase the EV hosting capacity of existing distribution networks [5]. The objective of the investigated TOU tariff profile strategy (i.e., specific periods which relate to network peak demand whereby EV customers are discouraged to charge) was to understand how varying adoption rates of EV

customers following such TOU tariffs has an impact on the integration of residential EV charging in distribution networks.

Similarly, the study investigated potential challenges from an uncoordinated second peak (a by-product of mass adoption of the same TOU profiles and loss of diversity). To create the TOU profiles, EV demand profiles were modified to not charge during the discouraged hours (e.g., 5pm to 9pm) and to continue charging immediately after the end of the TOU tariff profile.

Because only EV demand is shifted by TOU adoption (and not residential baseline demand), it could be argued that this correlates (to some degree) with what EV smart charging behaviour could look like, whereby EV demand is flexible but normal residential demand remains largely similar. It is known that customers without incentive will opt for charging during the evening, which aligns with the network peak demand [20, 21, 48]. A smart charger, instead, makes it convenient to adjust EV charging behaviour.

It was found that TOU adoption of 20-40% could lead to an increase of EV hosting capacity of up to 20% (in some cases this meant doubling the hosting capacity!). Furthermore, augmentation for higher hosting capacities would be lower due to fewer occurrences of asset problems and a lower magnitude of problem (i.e., lower number of assets with issues and lower peak demand versus no customers following TOU).

TOU uptakes of 60% and beyond could lead to second-peak issues due to the loss of diversification over the TOU period. This highlights the need for a variety of TOU options available for customers, coordination among TOU adoption or the re-introduction of some level of diversity (i.e., randomized delay), to try to mitigate second peaks in demand. TOU adoption has clear benefits versus unmanaged EVs on the ability of distribution networks to host EVs. The full report is available in [5].

Recommendations around TOU adoption for residential EV charging [5]:

- Encourage TOU Tariffs. DNSPs should encourage TOU tariffs for EV charging, since TOU Tariffs on a per network (or state) basis can increase EV hosting capacity by 20%.
- TOU Tariffs can reduce the cost of network augmentation or other solutions. First, it can “buy time” for DNSPs and reduce present day costs since an additional 20% in EV penetration will likely take a few years at minimum. Second, it can decrease the percentage of assets that would need to be augmented (e.g., fewer LV transformers). Third, it can reduce the volume of assets to be replaced. Fourth, it can mitigate other assets problems that currently are not the limiting factor for increasing EV hosting capacity (e.g., replace LV conductors which limit hosting capacity up to a certain penetration combined with TOU tariffs that mitigate LV transformer issues, resulting in less assets that need to be augmented).
- Push TOU Tariffs as late as possible and focus on minimum demand rather than focusing on peak demand. TOU Tariffs could be further improved by targeting adoption rate during the minimum demand period for a network, instead of focusing on discouraging during the peak demand period. The results found that a second peak from TOU adoption rate can be very significant due to the removal of diversification and can cause issues. A later TOU tariff that focuses on minimum demand to avoid second peak issues would lead to residential EV charging starting at approximately 2am and beyond, with 8 hours of non-EV charging (a 4-hour delay from the latest TOU tariff considered, which was 6pm-10pm). However, on the other hand, this may lead to incomplete charging in some instances depending on how early the EV is required. It may also still have second peak issues at higher adoption rates (i.e., 60%+). Furthermore, an 8-hour TOU window may be too significant for many residential customers since present-day TOU tariffs for residential demand are typically between 4-5 hours.
- Consider a staggered TOU tariff to mitigate second peak. If a later TOU tariff is not suitable for all customers that are considering adopting the tariff, then stages of TOU tariff that start at different times (perhaps at different prices), may be highly beneficial for mitigating issues around a second peak.
- LV feeders need to be assessed to avoid false conclusions around TOU tariffs. DNSPs should consider the effects at the LV-level when considering TOU tariffs. This is because a feeder with significant non-residential demand may see a reduction of net demand across all TOU adoption rates and EV penetrations. However, within the LV feeders, the issue of a second peak will still be significant, despite at the macro HV-level the second peak is not as high as the original non-

TOU influenced peak. This, however, is less of an issue for HV-feeders with residential dominated net demands, which may experience second peak issues at the HV-level.

1.4.4 Customer Insight Survey

The report and presentation for Milestone 3 involved a customer survey of 100 EV owners and 900 non-EV owner [48, 53]. The survey covered three main objectives:

1. To characterize EV ownership and purchase intention.
2. To identify preferred locations and times for EV charging among current EV owners and potential consumers.
3. To understand consumer willingness to adopt time of use tariffs and supplier managed smart charging systems.

Full information on all of these three objectives are available in the corresponding report [48]. Some of the key takeaways from the survey in relation to EV Integration are [48, 53]:

- 16% of respondents claim they would not be able to charge an EV at home; however, this may lower in time due multi-occupancy buildings' potentially catering of EVs one day.
- Almost two thirds of the sample have Level 2 chargers installed in their residences, with no significant difference between EV and hybrid EV owners.
- Half of the EV owners use 'special tariffs' (EV specific, TOU and/or solar panels).
- Even though 82 of respondents claim to be able to set a timer to start charging their vehicles, close to 50% of the sample reported to start charging during evening peak, 30% between 17 h and 20 h or shoulder times, and 21% between 20 h and 22 h. Close to 55% of the sample reported they would start charging during evening peak when considering non-EV owners also.
- A significant majority of customers would prefer to charge their EV at work; however, less than half park their car in a private carpark during work, and only 14% of survey respondents had access to EV charging car park spots at work.

The customer survey results around supplier managed smart charging and user managed smart charging are shown in Figure 1-5. 40.4% of EV owners prefer supplier-managed charging whilst 46.2% prefer user managed charging.

When the respondents were asked directly about supplier managed charging, this increased significantly, particularly when given the option for manual override (which is possible in the UK's smart chargers, for example), with only approximately 4% of EV owners responding that they were unlikely to accept supplier-managed smart charging, shown in Figure 1-6, whilst it is 16% of non-EV owners, shown in Figure 1-7. This suggest that perhaps the ownership of an EV and the charging process help to calm any concerns around supplier-managed charging and that it may be seen as a convience.

The full information on the results from the customer survey can be found in the corresponding report and presentation [48, 53].

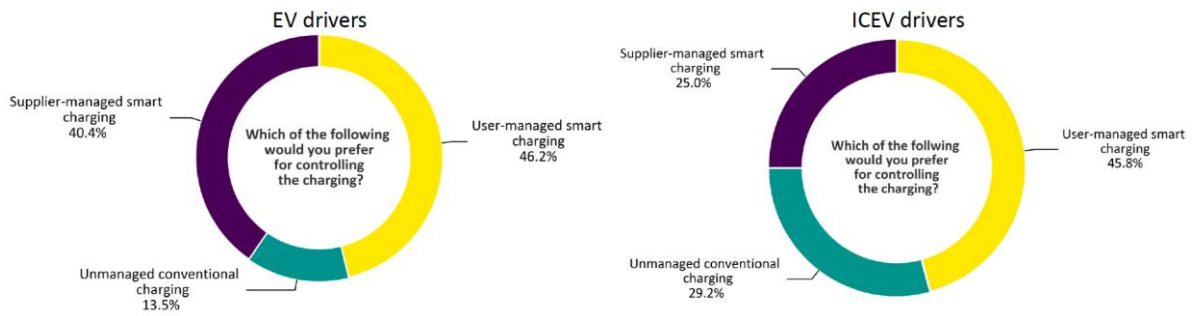


Figure 1-5. Charging preference survey result for EV and non-EV owners [48]

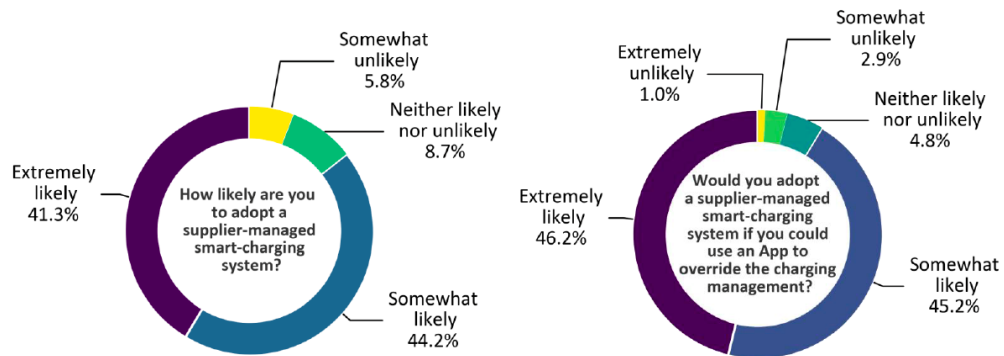


Figure 1-6. Acceptance of supplier-managed EV charging among EV owners [48]

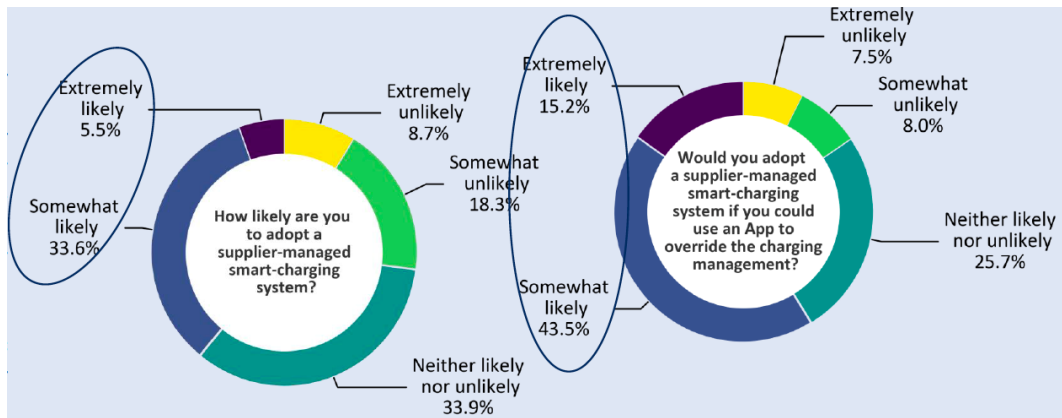


Figure 1-7. Acceptance of supplier-managed EV charging among non-EV (ICEV) owners [48]

2 International Smart Charging Review

This section presents a brief overview of recent trends for the integration of electric vehicles and EV smart charging for the UK in Section 2.1 and the USA in Section 2.2.

2.1 United Kingdom

The UK is arguably one of the leaders in terms of smart charging regulations. From the 30th of June 2022, any consumer-grade EV charger that is sold in Great Britain must be a smart charger [49]. This is supported by a framework that enables easy consumer participation (such as enticing retail offers/electricity rates for just EV charging, the ability to seamlessly switch retailer despite buying your charger through a specific retailer, etc.).

The Electric Vehicles (Smart Charge Points) Regulations 2021 is the underpinning legislation [54]. The regulations cover:

- Electric vehicle private charge points which are sold for use in a domestic or workplace environment in Great Britain.
- “Smart cables” (defined as an electrical cable which is a charge point and is able to send and receive information).

The regulations do not apply to private charge points which are:

- sold in Northern Ireland
- sold before 30 June 2022
- not intended for use within Great Britain at any time (e.g., for export)
- sold by individuals outside of the purposes of their trade, business, craft or profession (for example, second-hand sales of chargers made between private individuals)
- non-smart cables or rapid charge points
- Intended for use as public charge points (but these are likely to be subject to the UK requirements of the Alternative Fuels Infrastructure Regulations 2017 [55]).

The regulations, as stated by the UK government, “*ensure charge points have smart functionality, allowing the charging of an electric vehicle when there is less demand on the grid, or when more renewable electricity is available. The regulations also ensure that charge points meet certain device-level requirements, enabling a minimum level of access, security and information for consumers. [49]*”

The regulations state that charge points sold for the intended private charging of vehicles must meet certain device-level requirements, which include [49, 54]:

- Smart functionality, including the ability to send and receive information, the ability to respond to signals to increase the rate or time at which electricity flows through the charge point, demand side response services, and a user interface.
- Electricity supplier interoperability (i.e., retailer or aggregator), allowing the charge point to retain smart functionality even if the owner switches electricity supplier.
- Continued charging even if the charge point ceases to be connected to a communications network.
- Safety provisions, preventing the user carrying out an operation which could risk the health or safety of a person.
- A measuring system, to measure or calculate the electricity imported or exported and the time the charging lasts, with visibility to the owner of this information.
- Security requirements consistent with the existing UK cyber security standard ETSI EN 303 645.

Charge points must also [49, 54]:

- Incorporate pre-set, off peak, default charging hours and allow the owner to accept, remove or change these upon first use and subsequently.
- Allow for a randomised delay function.

These regulations came into force on the 30th of June 2022, but the security related aspects come into force on the 30th of December 2022 [49]. Whilst this delay may leave some EV chargers vulnerable, it

is likely that over-the-air updates, if not already in place, will be able to patch the chargers to updated security standards.

The chargers must follow, at a minimum, the Open Charge Point Protocol 1.6 (OCPP1.6) [32, 49, 54]. This was developed by the Open Charge Alliance (OCA), where a compliancy toolkit for self-testing by EV charger manufactures is available to enable a certification programme. The OCPP 1.6 [32] or higher is seeing very strong industry support among manufactures and can also operate alongside ISO 15118 [56], which is an international standard defining vehicle to grid (V2G) communication interfaces. Therefore OCPP 1.6 enables smart charging in the short term, but still leaves the door open in the future whereby V2G (which is out of the scope of this project), and corresponding retail offerings may become more common, i.e., they are “future proof” in a sense (most currently available UK smart chargers are not V2G capable, but OCPP 1.6 will not prevent V2G).

It is clear that with these regulations the objective is to make smart charging as seamless as possible. An important point to highlight is the default setting of pre-set off-peak charging hours. This means that even before the customer decides on their retailer and tariff options, the EV by default will avoid peak demand hours. If a customer is not engaged and sticks to an insurance style retail tariff, whereby they are just charged a flat rate for energy usage, it is possible that the charger will stay on its default setting and still charge outside peak demand hours. However, by not utilising an appropriate retail tariff the customer might lose out on monetary benefits. Furthermore, the regulations include separate metering of the EV charging and can meter how much energy is imported or exported by the EV. This enables retailers to offer tariffs with separate EV charging rates.

Giving the retailer flexibility in being able to bill customers for their EV separately allows for the freedom of retailers to offer innovative EV-focused tariffs that also benefit the network. The result is many retailers that offer tariffs whereby off-peak EV charging is considerably cheaper. In some instances, this can mean a credit on a customer electricity bill for the cheaper off-peak EV charging relative to the normal household electricity costs. Retail offerings, in combination with the default off-peak charger settings, ensure a large proportion of future EV charging will likely occur during off-peak low demand periods, either through clear financial incentives or with default actions for non-engaged customers.

One final aspect of the UK and EV integration, whilst directly outside the scope but worth highlighting for greater context, is the ongoing transition of distribution network service providers (DNSPs), known as distribution network operators (DNOs) in the UK, to a more active role of a Distribution System Operators (DSOs). The Energy Network Association (ENA) in the UK, which represents the owners and operators of licenses for the transmission and distribution of energy in the UK and Ireland, defines a DSO as follows: *“A Distribution System Operator securely operates and develops an active distribution system comprising networks, demand, generation and other flexible distributed energy resources (DER). As a neutral facilitator of an open and accessible market, it will enable competitive access to markets and optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation. A DSO enables customer to be both producers and consumers, enabling customer access to networks and markets customer choice and great customer service”* [57-59].

In Britain, there are 14 licensed DNOs (i.e., DNSPs) and are owned by six different groups that cover specific geographically defined regions. All 14 are set to transition to DSOs as part of the Open Networks Project [60, 61]. The transition from a DNO to a DSO is a complex task. Currently the 14 licensed DNOs have started to implement plans for their transition to a DSO model. Most have had engagement session with stakeholders in part to inform but also to gather their input in shaping their DSO strategy. The DNOs are working or have published their local network plan (known as RIIO-ED2) which will cover the period from 2023 to 2028 [61]. The UK regulator Ofgem is the driving force (as part of the UK governments smart systems and flexibility plan [62]) for this transition and requires DNOs to submit DSO strategies, with the overall objective of a smart and flexible energy system [63].

It is clear that mandatory EV smart chargers as well as the transition of DNOs to DSOs are all part of an overarching plan to enable and reward flexibility from distributed energy resources.

The introduction of smart chargers potentially may fall under the umbrella of DSOs in their mandate of supporting a smart and flexible energy system. How DSOs and EV smart chargers are to interact in the

UK is not finalised and may even differ between different network operators. It may be the DSO is in communication with the energy suppliers (i.e., retailers), to either procure or set limits on flexibility. Equally it could be possible that DSOs in the UK may be able to directly control of the EV smart chargers (perhaps as an emergency measure to ensure network integrity, or a mandated requirement). In either option, the introduction of smart chargers and their communication/control capabilities is clearly done in a manner with the transition to DSOs in mind (such as the mandatory OCPP 1.6 adoption which also covers V2G standard ISO 15118). Because the current UK mandated smart charging and corresponding shift of EV demand may only be effective up to a limit of EV penetration (before further actions are required to integrate EVs), DSO coordinated flexibility may be required when EV penetration reach a crucial penetration to avoid extensive and costly network reinforcement.

Whilst the transition of DNSPs (or DNOs) to DSOs is out the scope of this report, it is clear that the smart charging regulations in the UK have the transition of DNSPs (or DNOs) to DSOs clearly in mind within their specifications for EV chargers. However, whether, and how DSOs may utilise this functionality, is still to be decided in the UK. In any case, smart EV chargers and shifting charging behaviour to off-peak hours are a key method in the UK's approach for affordable EV integration.

2.2 United States of America

The Smart Electric Power Alliance (SEPA) in the USA has identified that there are 58 utilities with smart EV charging programs, totalling 71 programs [64]. This is highlighted in Figure 1-1, which breaks down the different sub proportions of EV smart charging programs.

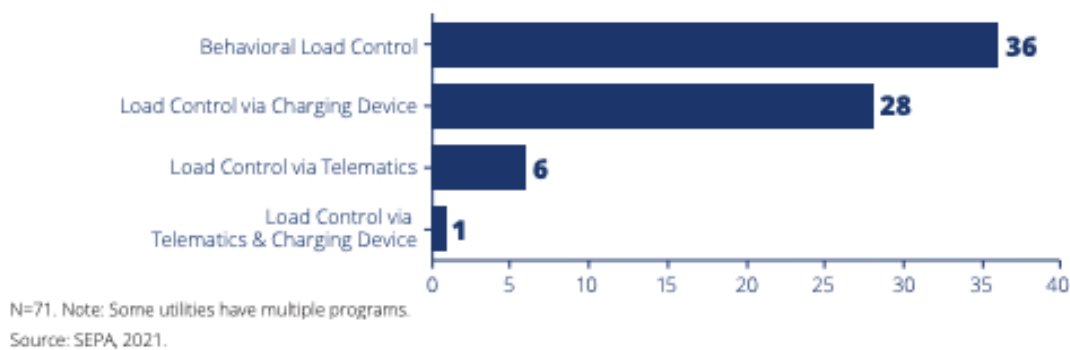


Figure 2-1. Ongoing EV Smart Charging Programs in the USA [64]

50 US distribution utilities were interviewed in August 2021, and it was found that there was overwhelming support for EV smart charging [64]:

- 19 have an EV smart charging program or have a pilot.
- Remaining 31 plan or are interested in smart charging programs.
- 67% of the 31 utilities will adopt it within the next 2 years vs less than 13% in more than 5 years.

It was recommended, for a successful EV smart charging regime, to [64]:

- Allow smart charging schemes to evolve according to the system needs.
- Consider feasibility and scale in any design (e.g., data collection and control).
- Ensure alignment and coordination.
- Make sure that the default behaviour of smart chargers should benefit both the customer and the grid.
 - Opt-out achieved much greater usage of smart charging versus opt-in.
- Implement smart chargers, if possible, via OEM telematics and EV chargers with network capabilities.
- Include customer education in marketing and recruitment of smart chargers.
- Take a holistic view of a multi-der strategy (e.g., all DER into one platform, such as aggregators).
- Allow utilities flexibility in implementing smart chargers.
- Support utility pilots to test new market mechanisms.

The US is headed toward adopting EV smart charging to help with grid integration. However, each utility has greater freedoms relative to the UK currently in how they go about implementing smart chargers (e.g., mandatory external management, user management, etc).

3 Australia's Current EV Integration Plan

This section presents a high-level overview of the current Australian plans related to EV integration. Section 3.1 highlights the various Australian energy governance bodies, Section 3.2 presents the current Australian plan for the integration of EVs, Section 3.3 briefly covers tariff reform (such as cost reflective tariffs), Section 3.4 details the updates to the Australian building codes and how it related to EV integration, whilst Section 3.5 provides a summary and conclusion to the Australian EV integration plan.

3.1 Australian Energy Governance

Firstly, it is worth highlighting and making clear the role that the various major energy bodies in Australia have. Australia's energy system is governed by a series of bodies and agencies. The National Electricity Market (NEM) began operating in 1998, and connects the east coast of Australia: Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. Western and the Northern Territory are not connected to the NEM and have their own electricity system and separate regulatory arrangements. There are over 300 registered participants in the NEM, including generators, transmission network services providers (TNSPs), distribution network service providers (DNSPs) and market customers [65].

The NEM governance structure consists of five major bodies (some states have their own versions of these institutions or only partially make use of them). The main objective of this governance structure is to enable competition, provide accountability and to support investment certainty, by separating decisions on government policy, energy regulation and the power system's operation [66]. Each market body is independent, with its own functions and decisions that it must make:

1. **Energy National Cabinet Reform Committee (ENCRC).** All the NEM market bodies are under the overall umbrella of the Energy National Cabinet Reform Committee (ENCRC) council. The ENCRC and Energy Ministers' Meeting (EMM) are ministerial forums *"for the Commonwealth, Australian states and territories, and New Zealand to work together on priority issues of national significance and key reforms in the energy sector"*. The main objective of ENCRC council and the EMM is to provide national oversight and coordination of governance and policy development for Australia's energy and resource sectors, providing national leadership in key strategic decisions and integrate these into government decision-making, and to enhance national consistency between regulatory frameworks to reduce costs and improve efficiency. Both the ENCRC and EMM are chaired by the Minister for Climate Change and Energy [66, 67].
 - a. The ENCRC and EMM work closely with Energy Consumers Australia and have ultimate national oversight of the other market institutions that are responsible for the operation of the NEM (which are listed below) [68].
 - b. The ENCRC are a subcommittee of the National Cabinet and are tasked with priorities and report the delivery of said priorities to the National Cabinet. The National Cabinet is the intergovernmental decision-making forum in which the Prime Minister, Premiers of the various states and territories and Chief Ministers meet to work collaboratively. Established in March 2020, it is chaired by the Prime Minister [69]. The Australian Energy Market Agreement (AEMA) defines how energy policy is developed through and across the various states and territories [70].
 - c. The ENCRC and corresponding EMM were formed in May 2020 following the disbanding of the Council of Australian Governments (COAG) Energy Council [68].
 - i. The COAG was the previous oversight and coordination of energy policy at a national level [67].
2. **Australian Energy Market Operator (AEMO).** The Australian Energy Market Operator (AEMO) is responsible for the management of retailer and wholesale market operation for the NEM and the Whole Energy Market (WEM) in Western Australia. Its responsibilities also include, as the system operator besides the market operator, the safe operation of the power system, maintaining power system security and, importantly, leading the design of Australia's energy system (particularly for transmission planning, such as via the Integrated System Plan [71]). In the event of an emergency, AEMO is responsible for protecting and if needs be restoring normal operation [66, 67].

- 3. Australian Energy Market Commission (AEMC).** The Australian Energy Market Commission (AEMC) is the rule maker and issuer for Australia's energy market. It amends the National Electricity Rules (NER), National Gas Rules (NGR) and the National Energy Retail Rules (NERR) which apply for the NEM. The AEMC cannot propose rule changes – it manages, consults, and decides on rule change requests that are made externally. The AEMC also provides advice to the government for improvements, and reports on competition prices and market performance [66, 67].
- a. Network Planning – The NER sets out a national framework for transmission and distribution network planning and expansion [72]. The framework involves annual planning, decision making and cost-benefit analysis of various projects. These can be split into transmission and distribution.
 - i. Transmission – AEMO is the transmission planner, and it forecasts transmission requirements over 20 years within its integrate system plan [71]
 1. Each region of the national electricity market has a jurisdictional transmission planning body responsible for their area (NSW and ACT – TransGrid, Queensland – Powerlink, South Australia – ElectraNet, Tasmania – Transend, Victoria - AEMO in its role as Victorian planner). The regional bodies take the integrated system plan from AEMO and then details specific investments required. They must prove that any investment offers economic benefits for the costs and meet reliability standards.
 - ii. Distribution – DNSPs are the organisations that own and control the hardware of the distributed energy network such as poles and wires, transformers and substations.
 1. The AEMC framework is an annual planning and reporting cycle and project assessment process for distribution networks. Within these there are three main aspects [66]:
 - a. The distribution network annual planning and reporting process (which must also include non-network options for investment).
 - b. Demand side engagement obligations.
 - c. Distribution investment project assessment (i.e., proving that the investment is good value for money in terms of costs versus benefits). The process by which a DNSP must follow to identify network investment options is known as the regulatory investment test for distribution (RIT-D).
 - b. The Reliability Panel is part of the AEMC arrangements. The panel monitors, reviews and reports on the safety and security of the system. It is comprised on people involved in the NEM, from small to large consumers, generators retailers, network businesses and the system operator AEMO. The Panel also helps to determine the standards and guidelines used by AEMO and others involved in the markets [73].
- 4. Australian Energy Regulator (AER).** The Australian Energy Regulator (AER) oversees economic regulation and enforces rules set out by the AEMC. The AER forms part of the Australian Competition and Consumer Commission (ACCC) [66, 67].
- a. The AER sets maximum prices that network owners (such as DNSPs) may charge or define the maximum revenue. They regulate DNSP and transmission operators, monitor the wholesale electricity market, monitor and enforce rules and publish information on the markets. Regulated electricity network businesses must periodically apply to the AER to assess their revenue requirements (typically, every five years), such as for the network charges which are passed onto energy retailers.
 - b. The AER enforces Retail Law for New South Wales, South Australia, Tasmania, the ACT and Queensland. In Victoria, the National Energy Retail Law does not apply, so it is replaced by the Essential Services Commission. For retailers, the AER authorises a retailer to sell energy, approves retailers' policies, manages the retailer of last resort scheme, and helps manage a price comparison website. The AER prescribes how retailers must present their prices to customers.

- c. In West Australia, for the WEM, it is known as the Economic Regulatory Authority (ERA) and in the Northern Territory the Utilities Commission fills the same role. In Queensland, the Queensland Competition Authority (QCA) reports to the AER.
5. **Energy Security Board (ESB).** The Energy Security Board (ESB) is responsible for the implementation of the outcomes from the independent review into the future security of the NEM, known as the Finkel Review [74] and was formed by the now replaced COAG [66, 67]. The ESB provides a whole-of-system perspective and oversight for energy security and reliability and is a clear voice for where the energy system should head to (alongside AEMO's integrated system plan). The ESB provides recommendations to energy ministers [75-77] and then is given a mandate by the ministers (often based on these recommendations), such as the DER Implementation plan [12, 14]. The ESB can also make rule change requests to the AEMC (despite containing the head of the AEMC) fooutlor distribution, transmission and retailer rules and regulations. The ESB has an independent chair and deputy chair, along with the heads of AEMO, the AEMC and the AER.

3.2 EV Integration Plan

Australia is in the middle of a significant energy transition. How households, business and even communities use and generate electricity is changing significantly. For example, Australia has the highest percentage of residential customers with roof-top PV in the world [78], battery energy storage is predicted to grow and when combined with advancements in technology [28], the combination is likely to lead in an alternative way customers interact with energy usage [1].

In response to these concerns, the ESB, set out a series of recommendations as part of their post 2025 market design [1, 12, 14], and the final advice to Australian government ministers to “meet the needs of the energy transition and beyond 2025” [75-77]. Within this series of recommendations, includes reforms and pathways for changes needed to markets and regulatory frameworks. In particular, reforms to enable integration of DER and including flexible demand.

Whilst EV uptake is set to significantly increase, when compared with EV uptake internationally with other markets, Australia has not reached the same EV penetration levels (unlike for roof-top solar PV, where international markets often look to Australia). Consequently, many of the recommendations were based on what has worked internationally and can be adapted to suit Australia.

As part of Australia's decarbonisation strategy to achieve net zero emissions by 2050 [79] (formed under the previous government) there were two key policies that were related to EV integration [3, 22]:

1. Technology Investment Roadmap: Low Emissions Technology Statement [22]
2. Future Fuels and Vehicles Strategy (i.e., Future Fuels Fund) [3]

The change of government during 2022 has led to new targets related to decarbonisation, such as a 43% reduction of emissions by 2030 [80]. Whilst updated further information has yet to be released, such as the “National Electric Vehicle Strategy” consultation that is due September 2022 [17, 81], the upcoming “Driving the Nation” plan, includes [17]:

- Charging stations at an average of every 150km on major roads.
- Increased funding for the existing Future Fuels and Vehicles strategy and re-named as the “Driving the Nation Fund” [82] (previously known as the Future Fuels fund [3])

Because many of these policies were developed from the ESBs advice to ministers [75-77], the plan for DER (& EV) integration spearheaded by the ESB is unlikely to change significantly. As such, the previous government's “*Technology Investment Roadmap: Low Emissions Technology Statement*” [22], and “*Future Fuels and Vehicles Strategy*” [3], are likely to be incorporated within the yet-to-be-announced “National Electric Vehicle Strategy” and “Driving the Nation Fund” [17, 82].

3.2.1 Low Emission Technology Statement Investment Roadmap

The 2021 Low Emission Technology Statement Investment Roadmap had four key ideas that were relevant for EV integration [22]:

1. Public charger availability:

- a. In July 2021, ARENA on behalf of the Australian government announced \$24.5 million of funding for round one of the future fuels fund [83]. The investment was for 403 fast charging stations focused on addressing areas across Australia that have been identified as areas without sufficient charging availability, termed “*charging blackspots*”.
- b. Further investment has been stated to be required to prepare for a rapid increase in the number of consumers choosing electric vehicles.

2. Ensuring network security and availability (i.e., networks can handle increased charging from households and business):

- a. *“As demand for vehicle charging increases, we will need to consider possible impacts on electricity grid security and reliability. The government is continuing to work directly with the states and territories and through the Energy Ministers Meeting to enable and incentivise BEV charging that will effectively and efficiently integrate BEVs into the National Electricity Market”* [22].

3. EV smart charging adoption:

- a. Because the majority of EV charging will take place at home, It was identified that *“Increased numbers of electric vehicles being charged at home at peak times could overload existing electricity networks, and require investment in distribution networks, which would be borne by all network users”* [22].
- b. *“Investment in low power smart charging infrastructure will be required to optimise grid integration of BEVs. When coordinated and managed effectively by aggregators and grid operators, BEV charging offers a new form of flexible demand that could support the security, reliability and affordability of the electricity system for all energy users. Deployment of smart chargers will minimise the need to further invest in network upgrades”* [22].

4. Interaction between transmission and distribution – Digital Grid:

- a. *“The transformation of Australia’s electricity system is making the planning, investment and operation of the grid more complex. Existing software systems and capabilities were not designed to cater for large amounts of variable renewable generation. An enhanced digital operating system is imperative for the Australian Electricity Market Operator (AEMO), together with market participants such as generators, networks and policy makers, to continue to manage a changing grid in a way that is: effective, efficient, secure and reliable”* [22].
- b. Development of a distribution system model for the system operator, to allow integration of DER within the transmission-level system simulations.

As previously mentioned, It is likely that these ideas will be incorporated into the new governments upcoming consultation on the “*National Electric Vehicle Strategy*”, (consultation paper was originally due to be released in September 2022), which aims to “*consider demand and supply-side measures – including fuel efficiency standards – to dramatically scale-up electric vehicle uptake*” [81].

3.2.2 Future Fuels and Vehicles Strategy

The second part of the previous government policy related to decarbonisation of transport and the Integration of EVs, is the aforementioned Future Fuels and Vehicles Strategy [3] (which is now known as the “*Driving the Nation Fund*” [82]). This is where most of the key policies around EV integration are set out and will likely not change significantly (for EV integration). The Future Fuels and Vehicles strategy was guided by three principles [3]:

1. Partner with the private sector to support uptake and stimulate co-investment
2. Focus on reducing barriers to the roll-out of future fuel technologies
3. Expanding consumer choice by enabling informed choices and minimising costs of integration into the grid

The fund had five priority initiatives aimed at ultimately reducing transport emissions, with a total \$250 million fund (which is now \$500 million):

1. Electric vehicle charging and hydrogen refuelling infrastructure where it is needed

- a. Includes smart charging for households and public charging availability
2. Early focus on commercial fleets
3. Improve information for motorists and fleets
4. Integrate battery electric vehicles into the electricity grid
5. Support Australian innovation and manufacturing

The government estimated \$224 million of electricity network upgrade costs can be avoided for the integration of EVs by 2030 with this plan [84]. As seen in section 1.3.1, network costs are often the largest (or single largest following whole energy costs) portion of a typical customers electricity bill.

The first point *“Electric vehicle charging and hydrogen refuelling infrastructure where it is needed”* as previously mentioned includes large investments into public charging infrastructure with the aim to encourage EV uptake by tackling range anxiety and cross-state and cross-country road trips, with EV stations built in areas with low availability. This is being continued with the change in government, with a stated public charging station every 150km on average along major routes as part of the yet-to-be-announced *“National Electric Vehicle Strategy”* [81].

The fourth point, *“Integrate battery electric vehicles into the electricity grid”* (to help to decarbonise transport), is where most aspects related to the plan for integration of EVs are set out.

In order to achieve this, The former Council of Australian Governments (COAG) Energy Council (the previous national oversight body for energy) tasked the Energy Security Board (ESB) with *“developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s”* [85]. As mentioned previously, in July 2021, the ESB provided recommendations to Australian Government Energy Ministers [75-77], (as part of the ENCRC [68]), around the redesign of National Electricity Market (NEM), *“to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least cost”* [85].

The ESB’s advice included recommendations across four general reform pathways [85]:

- strengthen signals for investment in the right mix of capacity to keep the system reliable, affordable, and secure
- deliver essential system services to maintain grid stability
- improve transmission and access arrangements to ensure timely transmission investment, incentivise better use of the network to lower costs for consumers and reduce investment uncertainty
- better enable participation of flexible demand side resources and the integration of distributed energy resources (DER).

The government’s list of priority reforms to state and territory energy ministers, included the following priorities [3]:

- ***“Exploring network tariff reform to identify additional opportunities to encourage charging behaviour and infrastructure rollout”***
- ***“Incentivising the use of smart chargers in households, including assessing regulatory options”***
- ***“Tasking the energy market bodies to partner with governments on grid integration matters”***

In October 2021, National Cabinet endorsed the final package of reforms for the Post-2025 NEM [85]. These measures include the encouragement of flexible demand to enable customers to respond to market signals.

The idea of the reforms is to incentivise charging and discharging when the system (both distribution and transmission) is at risk due to low or high demand. Furthermore, this seeks to address the third of the key principles which is to minimize the cost of integration with the grid. By deferring EV demand to peak demand hours via smart charging adoption (i.e., TOU tariff adoption for EV charging), as shown in the previous project report [5], the existing distribution networks EV hosting capacity could increase thereby deferring network reinforcement.

Many of the ideas set out in the Future Fuels and Vehicles strategy, can be found in the ESB final advice to ministers (which was approved) [75-77] and the subsequent ESB DER Implementation Plan [12, 14].

3.2.3 Energy Security Board DER Implementation Plan

This section presents a very high-level overview of the ESB DER Implementation plan, in particular the key aspects relevant for EV integration. As previously mentioned, the DER Implementation plan forms part of the ESB Post 2025 market design, which is a series of reforms to prepare Australia for the energy transition ahead with high DER uptake and the decarbonisation of the power sector.

The DER Implementation plan has two key agendas which are relevant for the Integration of EVs [1, 12]:

1. New ways to trade

- a. *“Flexible trading arrangements that will separate manageable generation and load from the uncontrollable energy supply to a home or business. This removes barriers and makes it easier for smaller players to engage with the market” [12].*
- b. *“Trader services reform that will cut red tape by creating a single universal registration category for all entities who want to do business in wholesale energy and services” [12].*
- c. *“Scheduled lite reform that will encourage smaller players like aggregators managing direct load control; or local community batteries; to voluntarily give information on decentralised generation size, availability, and operation to AEMO so it can safely and efficiently ensure supply and demand is balanced” [12].*

2. Support change with technical and process reforms [12]:

- a. *“Consumer protections that will be fit-for-purpose so consumers can safely try different products and switch providers if they want to” [12].*
- b. *“Technical settings that will change in the background out of sight, but when consumers decide to change the way they use energy they will be able to do so – simply, safely and securely” [12].*
- c. *“Evolved roles and responsibilities that will be introduced for” [12]:*
 - i. Traders (aggregators/retailers)
 - ii. Distribution networks
 - iii. The system and market operator

The overall objective of these agendas by 2025, relating to EV integration, are [1, 14, 86]:

- Reward customers for their flexibility and provide new options on how they engage with the market, including new customer protections (such as ensuring interoperability, retail frameworks and cyber security standards), whilst ensuring customers are protected
- Introduce a local network and system level services marketplace for DER from defined areas within the distribution network, in part to help with efficient DER integration and to reward flexibility [15, 87]
- Define distribution service operator (DSO) responsibilities on control, procurement, and delivery of DER (local) network services
- Allow networks continued uptake of DER in a cost-effective way and ensuring there is appropriate network visibility
- Develop the interactions between the DSO and the system operator (AEMO)
- Introduce dynamic operating envelopes for two-way energy flows & services, defined by the DSO – these define both import and export limits that will vary over time & according to network conditions
- Support energy market innovation and integration of new business models
- Provide the system operator with the visibility required for a safe and secure system
- Develop clear internationally aligned standards and ensure good interoperability
- Enable customer to engage with more than one retailer/service provider

- Enable new technologies and retailers to easily enter the market
- Reform network tariff arrangements (i.e., cost reflective tariffs to help limit the impact of network reinforcement to non-EV customers and encourage retailers to offer innovative tariffs)
- New energy data framework to make sure barriers to sharing and gaining access to data are removed, optimising consumer investments and benefits

While many of these objectives are also aimed at ensuring customers have fair and equitable access to export their DER to the grid (which is out of the scope of this project), it aims to address key issues in trying to integrate residential charging of EVs in a cost-effective manner through rewarding flexibility [86].

The DER Implementation Plan was split into three horizons, Now (2021-2022), Next (2022-2023) and Future (2023-2024), full detail of these can be found in [14], an overview of some of the relevant aspects for EV integration are listed below:

1. Now (2021-2022) “Horizon 1” [14]:

- Prioritization of standards & policies (interoperability, communications and cyber)
 - Enable active DER devices
- Further definition of DSO network responsibility (following the transition as seen in the UK)
- How to remove barriers for customers to be rewarded for flexible demand
- Ongoing Tariff Reform and test out tariff structures
- Further design of residential participation in markets (such as demand response of EV smart chargers in partnership with retailers) – flexible demand is rewarded in the market
- DER marketplace trials (Project Edge [15, 87]) – for both wholesale and local network services, within constraints of a specific area of the distribution network
- First steps of Dynamic Operating Envelopes [88] as a long-term feature for the NEM DER ecosystem
 - *“Mandatory compliance for new solar and storage by 2025” [14]*
 - Dynamic operating envelopes are often correctly associated with defining export limits (e.g., such as roof-top PV) which is out of the scope of this project. But it is also planned to define import limits which could interact with aspects such as the charging of a battery (e.g., EV). These envelopes can change in time and according to network and system conditions and will be defined by the DSO/DNSP in collaboration with the system operator [88].
- Definition of emergency responses of DER (such critical minimum load scenarios)
- Cyber security
- DER access and pricing rule changes

2. Next (2022-2023) “Horizon 2” [14]:

- Commence work on EV smart charging standards
- A fit-for-purpose regulatory framework
 - Clarification on DSO responsibilities and direct load control
 - AER to encourage new work on tariffs structures under tariff reform agendas with DNSPs
 - Tariff reform with DNSPs and new tariff structures
- Remove barriers for residential customers accessing demand response products and ensure DER demand flexibility is rewarded in the market
- Improved visibility of resources
- Development on interoperability and corresponding standards and processes for retailers and aggregators (to ensure customers have a choice of service providers)
- Dynamic operating envelopes on first networks & pilots (phased introduction of guidelines and associated regulations)
- Review of retailer authorisation process to encourage new energy related products

3. Future (2023-2024) “Horizon 3” [14]:

- Finalise policy of EV smart charging
- Completed standards process for DER Interoperability and communication standards

- Included interoperability with other types of DER beyond EV smart charging
- Customers will be able to seamlessly switch providers
- Tariff reform with more cost reflective TOU tariffs
- Retailer reform to allow more than one retailer for a single customer at a time
- Architecture to provide markets and services to effectively integrated and value DER and flexible demand (e.g., potential local level markets from the outcomes of Project EDGE trial [15])
- Introduction of Dynamic Operating Envelopes where DNPSs/DSOs publish the envelopes on what the distribution network can handle as well as consideration of wider system requirements, where retailers/aggregators apply these dynamic limits:
 - Rule change for new solar and storage to comply
 - AEMO can publish minimum load signals via markets notices for example
 - Requires frameworks and standards on how retailers/aggregators comply
- Flexible demand and DER will be rewarded in the market
 - Work is set to be well underway whereby DER will be able to respond to network congestion
- Test interactions of home energy managing systems (e.g., combine flexible EV demand using smart chargers with other devices that a residential customer could have, such as controllable air conditioning)
- Publishing of network visibility data to improve planning and locational DER investment.
 - For example, by publishing network visibility, investment into things such as EV fast charging will be more attractive to industry since there will be more certainty around network connection costs and potential network management schemes (i.e., control systems according to a defined maximum demand) or network reinforcement costs

3.2.3.1 Distributed Energy Integration Program (DEIP)

It is also worth briefly highlighting the important work of the Distributed Energy Integration Programme (DEIP) [89]. The DEIP is a collaboration of market authorities (e.g., AER, AEMC, ESB, COAG), government agencies (e.g., ARENA, CSIRO, CEFC), industry and consumer associations (e.g., Clean Energy Council, Australian Energy Council, Energy Consumers Australia), the industry association for energy networks Energy Networks Australia (ENA) as well as the system operator AEMO.

With a steering group at the helm, the forum is based around exchange of information and collaborating on DER issues, to ensure gaps in knowledge are identified, what are the required priorities and accelerate reforms through dialogue. The DEIP has four workstreams:

1. DEIP Dynamic Operating Envelopes [88]
2. DEIP Access and Pricing [90]
3. DEIP EV Working Group [91]
4. DEIP Interoperability Steering Committee (ISC) [10]

These sub-workstreams, for example the EV working group [91], involves further specific relevant stakeholders, such as individual retailers, individual DNPSs, the Electric Vehicle Council, research organisations and universities, among many others. The EV workstream aimed to [91]:

- provide a central forum for key industry and government stakeholders to collaborate and coordinate EV activities
- approach EVs from an energy sector perspective but with transport and infrastructure partners
- promote policy and regulatory development before wide scale EV adoption begins.

The EV Working Group agreed at the end of 2019 [92] to collaboratively work on four key areas [91]:

- a. EV data availability
- b. Standards development
- c. Residential tariffs and incentives
- d. High-capacity tariffs and connections

The DEIP is a clear response to the government priority of tasking the energy market bodies to partner with governments and industry on power system and DER Integration matters. This is because

communication was a clearly identified for as one of the primary government energy policies to help improve energy system efficiency and reduce costs [3].

The DIEP ensures there is dialogue between stakeholders and that information is shared to ensure that the correct conclusions are made and that decisions by one regulator for example is not done without the other relevant stakeholders being aware. As an example, parts of the ESB DER implementation plan, such as ESB policy advice for interoperability and direction on technical standards, or progress on the DER implementation plan itself, is reported to the DEIP and its members [93].

3.2.3.2 Interoperability

Going forward, consumers are likely to have access to numerous energy retailers and corresponding tariff options, with many options for customers to make use of their devices, such as their EVs via a smart EV charger. Therefore, for customers to be able to exploit their flexibility for financial benefits, and for the energy system to also encourage flexible demand, retailers need the ability to communicate with EVs or EV chargers, other devices, DNSPs/DSOs, system operator and relevant markets [24, 94, 95].

The ability for customers and retailers to interface with many types of EV smart charger, is known as interoperability. This means that if one customer buys their smart charger through the retailer, or off-the-shelf from a charging supplier, the customer is free to switch between retailers and the smart charger technology will not inhibit this.

The ESB stance on interoperability and arrangements with retailers/aggregators is as follows [11, 75-77]:

- *“Consumers should be able to share data with service providers. Interoperability should be standardised to allow data portability and sharing between consumer, aggregator, network, and market”*
- *“Consumers’ DER assets should have a level of portability between providers. These standardised communications should enable consumers to move between providers (and technology) and promote competition between providers. These standards should be minimum levels of capability while allowing providers to layer additional functionality over the top so they can offer their own innovative products and services.”*
- *“Control of and access to consumer devices should be limited to clear use cases. Control of any consumer device by a network or system operator should be limited to a set of well documented use cases that can be updated from time to time as agreed by industry.”*
- *“Consumers need to receive clear information about the compatibility of their DER assets. Device manufacturers, installers, and service providers must be transparent about any proprietary technology resulting in closed eco-systems and the consequences or limits of those closed ecosystems.”*

The Electric Vehicle Council, which is the national body representing the electric vehicle industry in Australia, highlighted (in their response to the EV smart charging consultation issue paper [24]), to the question “14. Are there any minimum technical requirements that should be considered for EVSE interoperability?”, that: *“Minimum technical requirements for EVSE, and installation of EVSE, are well covered in a variety of standards and documents. RCM marking [regulatory compliance mark (RCM)] for the hardware is required throughout Australia, and installations are required to comply with AS/NZS3000:2018, as well as local SIRs [Service & Installation Rules (SIR)] that vary state-by-state. Additional minimum technical requirements are not needed at this time [August 2022]” [13].*

The process for defining EV smart charger standards, including interoperability standards, is still ongoing as part of the ESB DER implementation plan and are not yet finalised in Australia. As highlighted in section 3.2.3, EV smart charging standards are planned to be finalised by 2024.

3.3 Tariff Reform and Retailers

As highlighted in section 1.3.1, network costs form the largest section of a typical customers electricity bill and distribution costs form the largest majority of network costs that are charged to customers (via the retailer). Furthermore, it is well understood that the investment around distribution networks is mostly driven by peak demand [46, 47].

Therefore, the costs of networks that retailers are charged by DNSPs and the interaction it has with peak demand plays a significant role in being able to integrate EVs in a cost-efficient manner. This is why the ESB in its DER implementation plan, as highlighted in section 3.2.3, for horizon 3 (2023-2024), has directly sited regulatory frameworks where by “*tariff reforms continues with more cost reflective TOU tariffs*” [14]. Tariff reforms are a key plan to go alongside the plan of encourage EV smart charging uptake, to help manage EV integration in a more cost-effective manner through encouragement of off-peak charging. Tariff reform has also become a key part of the AERs work in recent years [6, 96]. Many of the proposed tariff trials for 2022-2023 consider EV targeted specific tariffs [7].

3.3.1 Cost Reflective Tariffs

If a network requires reinforcement/augmentation though the upgrade of an asset, currently in most areas the cost is covered (or recouped) via the flat network cost charged to retailers, which is then passed onto the customer (however the retailer decides to package it).

In the context of EV integration, for example, if 20% of customers have an EV with a level 2 charger, which is charged in an unmanaged manner (i.e., alignment with peak demand, which has been shown to be a typical behaviour without a smart charger [20]), close to 100% of customers will ultimately pay for the upgrade of the distribution network to handle the higher peak demand, via an increase in the flat cost portion of their energy bill from retailers. This may be considered unfair because the customers without an EV are essentially paying for the network upgrades for the other customers with an EV. For those customers without an EV, the distribution network is already perfectly adequate for their uses and does not require an upgrade and may not buy an EV for several decades (or even a car).

Cost reflective network tariffs/pricing is the idea that the charge paid by users of the networks via a charge from the DNSP to the retailer, should reflect the underlying cost of the network in the provision of the service to the customer. The current structure for most residential customers (a flat rate usage charge with a fixed component), does not do this.

Having EV integration network related costs to be as low as possible, and fairly distributed among customers, is a key factor to improve EV integration affordability. A cost reflective network price, could help to achieve affordability for EV integration by defining:

- a. Incentives for the customer to minimize their overall peak usage on the network, in particular during peak demand periods on the network.
- b. Network charges to customers based on the impact the customer has on the current and future network costs, meaning it is more fairly distributed between customers.

Hence, a cost reflective network tariff underscores the fact that peak usage drives distribution network costs, and if the retail tariff that is passed on is fully cost reflective then it can reflect wholesale and transmission costs to some degree too. The cost reflectivity indeed links behaviour to costs.

As highlighted in Section 1.3.3, a traditional flat rate tariff is most common for residential customers. The flat rate structure provides incentives to reduce the total volume of energy used, at any time of day – there is no aspect on the time of usage. Customers who contribute more to network costs during hours of high network usage are subsidised by customers that use less.

There are three common methods that DNSPs can use to charge network costs to retailers:

1. A flat network tariff.
2. Time-of-use energy network tariff. If a customer uses more energy during peak demand periods, the network cost to the retailer increases - equally it is cheaper for the retailer if the customer uses energy outside the peak demand period. This does require measurements to calculate the costs to the retailer from the DNSP.
3. Peak demand-based network tariff. If a customer has a higher peak demand than is measured during the high demand network period, then the retailer is charged more – equally a low peak demand period during the high demand network hours means a lower charge to the retailer.

However, it may be that the retailer has opted for a cost reflective network tariff from the DNSP, but the customer still pays a non-cost reflective tariff. This is because, network tariffs from DNSPs are charged

to retailers. Some states the retailer can decide between a cost reflective or a flat rate network tariff, for residential customers.

It is up to the retailer how they package the network charge with other costs of supply, such as wholesale energy risks. Retailers are free in how this is packaged. Retail offers to customers are broadly categorized by the AER into three categories [97]:

1. **Insurance style.** The retailer faces the cost reflective network price signal but shields the end customer from the volatility. This would be in the form of a fixed daily charge and a flat kWh energy charge.
2. **Pass through offers.** The network tariff structure is reflected in the retail tariff structure (e.g., a TOU retail tariff or a demand retail tariff)
3. **Prices for devices.** The retailer will manage the customers smart devices (such as controlling an EV smart charger via OCPP 1.6 [32]), and can respond to the cost reflective network price, but is very simple for the end customers. For example, the customer could still be charged a fixed fee, but the customer gives control of the smart EV charger to the retailer which follows a TOU based profile to avoid peak demand periods. In exchange, the customer is charged a lower flat fee than a standard insurance style offer (assuming the retailer is using a cost-reflective network tariff from the DNSP in both).

Retailers are usually faced with three types of decisions around cost reflective network tariffs [4]:

- Opt-in for a cost reflective network tariff. The customer will remain on a flat network tariff unless the retailer decides to switch. The retailer is unlikely to opt-in unless the customer chooses a retail tariff that would fit well the network tariff (such as TOU).
- Opt-out for a cost reflective network tariff. All customers are on a cost reflective tariff on application date, whilst the retailer can opt-out if the customer does not want to face a cost reflective retail tariff or cannot manage the network price risk
- Mandatory assignment. Retailer faces cost reflective network charges for all customers with a suitable meter (e.g., SAPN and Energex). The retailer can pass through the signals or manage the risk themselves and offer a simpler tariff.

The AER, as discussed in a report on the “Understanding the Impact of Network tariff reform on retail offers” [97] (which followed the AER final decision on new tariff structure statements for Queensland and South Australia), met with nine retailers and energy service providers, a mixture of small medium and large. The AER asked the retailers about how they would propose retail offers to customers following a change in underlying network tariff [97]:

- Large retailers suggest they are more likely to offer insurance style retail products in response to cost reflective tariff structures.
- Medium retailers are likely to pass through underlying costs, in particular the TOU network tariff. This is because passing through network tariffs to the customer is a lower risk to the retailer.
- Many retailers considered prices for devices to be too early, citing that the technology was not widespread or developed yet. Some retailers were developing these offers, however, suggesting that this may change soon.
- Retailers generally did not want to pass through complex tariffs that directly cite network demand charges that are cost reflective as it was considered difficult to explain network demand charges to customers. Instead, even if the retailer did opt for a pass-through structure, it would be repackaged. TOU however was more likely to be directly passed through in the structure. In general retailers would not opt in for demand charges.
- Retailers would not pass-through demand-based network charges and instead opt for insurance style, or prices for devices.

The ACCC in 2018, before EVs were considered at a large scale, recommended a cost reflective network tariff in response to rising energy costs [4].

As previously mentioned, tariff reform in combination with EV smart charges it is now a clear plan for the ESB in their DER implementation plan [1, 14]. This is because a cost reflective tariff can help reward customers for their flexibility, and in exchange the networks do not need the same level of investment for network reinforcement (meaning cheaper integration of DER/EVs for customers). Not only does a

cost reflective tariff protect non-EV customers, but it can also encourage behaviour change, particularly if it is easier to alter demand through a device such as an EV smart charger (as noted in Section 1.3.2).

One disadvantage pointed out by the ACCC (in the AER EV workshop on Victorian tariff structure statement proposals) with some cost reflective tariffs mentioned is the lack of locational aspects [98]. The price signals of cost reflective network tariffs do not easily indicate the location of congestion. This is why the ACCC, in the AER EV workshop on Victorian tariff structure statement proposals, suggests that DNSPs for EV charging stations should consider or establish mechanisms for market-based dynamic locational network charges [98] (this is unlikely to apply for residential customers).

One final aspect to consider and potentially avoid is cross-subsidisation. It could be possible that if cost reflective network tariffs aimed at EVs do not consider other types of DER fully, then they could be cross subsidising integration other types of DER. For example, high levels of roof-top solar PV can also lead to asset congestion, as well as voltage rise issues. This means that network reinforcement for EVs could lead to benefits to solar-PV and that EV customers end up cross subsidising roof-top PV customers [99]. One potential solution for this could be adjustment of feed-in tariffs to compensate.

3.3.2 Smart Meters and Cost Reflective Tariff Reforms for EV Integration

There is currently a significant obstacle for widespread uptakes of such cost reflective network tariffs for retailers, which is metering.

Smart meters can record the time of electricity consumption, but accumulation meters are not able to (they only measure energy over a billing period – i.e., time between meter readings). This makes charging a cost-reflective TOU tariff significantly more challenging, both for the DNSP in their cost reflective network tariffs, but also for the retailer.

The ACCC in its 2018 retail pricing enquiry notes that the extent to which cost reflective tariffs can be rolled out is limited to customers with smart or interval meters [4]. Therefore, the ACCC considered that encouragement of smart meters is required. The rollout of smart meters is not equal across Australia; for example, it has been identified in Queensland that 80% of small customers are on accumulation meters [100], whilst most customers in Victoria do have a smart meter [4].

In Queensland and South Australia, SAPN and Energex will charge underlying network tariff structures for customers with a smart meter, because of the ability for a time-based price signal [97]. The retailer will be charged a time-of-use energy network tariff or a peak demand-based network tariff (for smart meter customers) and it is up to the retailer to decide which (i.e., mandatory assignment). Of course, the retailer can still offer insurance style flat rate tariffs to customers and balance the risk exposure of this price signal – but there is now a lower incentive for the retailer to do this since this exposes the retailer to higher risks, thereby encouraging retailers to offer more innovative tariffs.

3.3.2.1 Wholesale Energy

Another interesting point raised by the Queensland Competition Authority (QCA) (which reports to the AER, as highlighted in section 3.1) in the 2022-2023 retail price draft determination, was pointing out that AEMOs regional net system load profile (NSLP) is used by AEMO to estimate when/what time of day people use electricity by customers on accumulation meters [100]. The spot price of electricity fluctuates every 5 minutes, whilst the accumulation meters (as previously mentioned) do not record the time of power consumption. As a result, AEMO uses the NSLP to estimate the amount and timing of power consumption of customers on accumulation meters [100].

With the NSLP indicating time of usage, retailers in Queensland typical average out the daily spot price to pay for wholesale energy. This is done using the NSLP time information but in a manner to calculate an average cost [100]:

- The average daily spot price is weighted by the electricity demand according to the NSLP – this means that periods with high demand (and the corresponding spot price at that time) have a larger influence on the average spot price paid by retailers.

Because retailers therefore pay an averaged flat-rate wholesale energy cost (which is determined by the spot prices versus the volume of consumption at different prices) [100], the flat rate charged to most small customers on accumulation meters is somewhat reflective (in nature) to the costs the retailer pays. Therefore, if the appropriate framework is put into place for TOU-based wholesale energy acquisition based on smart meter data, this can significantly help in the wholesale side of TOU cost reflectivity and corresponding tariffs offered by retailers.

3.4 Building Code Update for EV Integration

As part of the Trajectory for Low Energy Buildings, all Australian state governments are now committed to ensuring new buildings can accommodate electric vehicle charging [3]. This trajectory was pushed by the COAG in 2015 and 2018 [101].

The Australian Building Codes Board considered how to ensure readiness for future installation of electric vehicle charging in the next update of the National Construction Code (NCC). Recently, building Ministers have agreed to the final changes to the 2022 edition of the NCC [16] (released on the 25th of August 2022). Under NCC Reference J1P4 (New Performance Requirement: Renewable energy and electric vehicle charging):

- *“This new Performance Requirement requires buildings to have features to support the ease of retrofit of PV, EV charging equipment and energy storage equipment. They are supported by a new set of DTS Provisions in Part J9” [16].*

Part J9 (formerly J8 Energy monitoring and onsite distributed energy resources), has three updates:

1. *“Clarifying electricity meters installed in buildings with a floor area greater than 2,500 m² for purposes of recording electricity consumption of a sole-occupancy unit are not required to provide sub-metering capability”*
2. *“Expanding where sub-metering is required to include collecting the energy data related to the use of DER such as PV, EV and battery storage systems as part of the broader energy data consumption”*
3. *“Introducing new provisions designed to make retrofit of DER equipment over the life of a building easier. These provisions require space to be left on electrical distribution boards for DER circuit breakers and for cable trays to connect distribution boards to car park spaces in Class 2 buildings. Class 2 buildings will also be required to install charge control devices to ensure EVs will only be charged when there is available electrical capacity in the building. Without this requirement, Class 2 buildings would be required to size their electricity supply to support 100% of car parking spaces being used to charge EV at times of peak demand. This would at least double the required electrical supply capacity for the building”*

Firstly, under part 2, submetering for DER is required (such as EVs) [16]. Submetering is also required for retailers to offer innovative tariffs. It may be that EV smart chargers already count as a type of submetering for these regulation requirements and therefore, separate metering may only apply to PV and battery storage if EV smart chargers are used. For example, in the UK, retailers discount your electricity bill based on a separate EV tariff and measurements from the smart EV charger. This means, for example, that retailers offer cheaper than standard tariffs for EV charging (via credits or refunds on your final bill) particularly when outside of peak demand periods (and potentially at a higher than standard rate during peak demand times). It is likely that the building will negotiate the tariff with retailers, as opposed to each EV owner directly.

Part 3 of J9 of the NCC is significant when considering EV integration. This is because Part 3 is essentially active management for large multi-occupancies residences (known as class 2). New buildings will have charge control devices that will throttle and manage charging in accordance with what is available within the connection (and will require measurement devices). It is quoted that if every carpark space supports EV charging, then at a minimum at least double the connection supply is required, if not more [16]. From the previous report, it is known that EV management is highly effective for the integration of EVs from a distribution network perspective, assuming there is monitoring at the head of low-voltage (LV) feeders [5]. Because a multi-occupancy building is much easier from a regulatory and cost standpoint to install the necessary metering devices and to control charge points, EV management is now to be implemented behind the connection point. This is similar to what charge point operators sometimes employ in public fast charging stations. This standard may be the first step to a wider acceptance of an EV management policy (once EV penetrations become significant and other

methods such as TOU-based tariff EV smart charging may reach a limit of effectiveness before network reinforcement is needed). EV management within distribution networks is a similar idea, but instead of altering charging based on measurements from the building, it is based on measurements from EV chargers and the head of the LV feeder [5].

3.5 Summary of Australia's Current Plan to Integrate Electric Vehicles

Overview of Australia's EV Integration Plan

When considering the Australian plans for DER integration, as well as smart charging trends in the UK and USA, in terms of EV integration, over the next five years, it is clear that EV smart charging is coming in Australia. This is a clear fundamental pillar around ensuring customers are encouraged and rewarded for flexible demand, in part to avoid "grid congestion", but ultimately to integrate EVs in a cost effective manner [1].

An economic consultancy firm on behalf of the ESB, estimated that that DER and flexible demand could reduce system costs for the NEM by \$6,337 million in net present value (NPV) terms to 2040 and \$13,003 million in undiscounted terms [2]. The government estimated \$224 million of electricity network upgrade costs can be avoided for the integration of EVs by 2030 with the Future Fuels and Vehicles Strategy [3].

Smart meters are being increasingly rolled out across Australia, further empowering retailers to offer innovative tariffs that can reward flexibility (beyond just EV charging). Smart meters are required for tariffs that are cost reflective, such as TOU tariffs. Cost reflective network tariffs (the charge that DNSPs place to retailers, who then decide how to pass it on) is the idea that the charge paid by users of the networks should reflect the underlying of the costs of the network in the provision of the service to the customer. If the retailer passes this cost on in some manner, then the retail tariff is cost reflective and it is also possible to have a cost reflective retail tariff that reflects other aspects of underlying costs, such as wholesale energy acquisition (e.g., dynamic tariffs). Cost reflective tariffs are not possible with an accumulation meter since the time of consumption is not known and as such is a clear barrier for cost reflective tariff reform [4]. Tariff reform is a key part of the plan for EV integration since it can help encourage customers to charge their EV outside of peak demand hours and help prevent network reinforcement. Furthermore, cost reflective tariffs aim to prevent customers subsidising the cost of network augmentation for usage which does not contribute to the need of augmentation.

An EV smart charger is defined by its ability to adjust EV charging in accordance with external communication signals (be that from the customer or retailer, etc.). EV smart chargers make it very convenient to implement flexible demand, such as following a TOU tariff. This is because an EV smart charger can be set via the customer to automatically start charging at specific times (and/or electricity price, etc.), or can be controlled externally by the retailer to get a low cost of charging - in addition to the possibility of other market services from the EV (such as demand response). Because EV smart chargers also often have submetering capabilities, retailers can offer EV specific tariffs to further incentivise flexible demand and off-peak charging. It is understood from the previous stages of the project [5], that in terms of distribution network impact on peak demand days, TOU based responses up to 40% adoption can help improve EV hosting capacity. If issues around second peaks following the end of a TOU period can be overcome (due to a loss of diversity), such as a wider range of TOU options from retailers and/or randomized delay functions, this may enable greater TOU benefits at higher TOU adoption rates.

If EV smart charging is combined with the proposed tariff reforms from DNSPs to pass on cost reflective network tariffs to retailers [6, 7], it will provide a further boost to encourage customers to be flexible in how they charge an EV. The combination of cost reflective tariffs and the convenience of smart charging is the key plan to integrate EVs in the short to medium term (in a cost-effective manner) in Australia.

EV chargers with smart functionality are required in South Australia from 2024 [8], and several trials are ongoing, including the AGL smart charging trial (including EV APIs that can adjust EV charging without a smart charger) with the Fleetcarma aggregation platform [9].

Work is ongoing on ensuring there is correct standards (i.e., communication protocols), interoperability and cyber security to ensure a smooth uptake of EV smart charging [10]. For instance, that is why the ESB issued a consultation paper around smart charging issues and these key aspects [11]. The ESB then invited a range of stakeholder to provide feedback and submit their responses, including the Electric Vehicle Council, DNSPs, retailers and aggregators, the system operator and more. Due to space limitations, the feedback is not presented in the report [12] (e.g., The EV council clearly advocates to align with international standards such as adopting OCPP 1.6. for smart chargers [13], etc.).

EV smart chargers will also make it easier to get involved with other innovate retail/aggregator options, such as local-level DER services. When considering the distribution service operator (DSO) transition that is also planned [14], if a DNSP/DSO was able to acquire demand response in specific areas of the distribution network (since the plan is to reward customers for DER flexibility), this could be used to further boost EV hosting capacity. We have seen from the previous report [5], that if EV demand can be adjusted according to network usage, then it enables very high efficient utilisation of assets for improved EV hosting capacity (although, the study assumed full compliance, so only a partial benefit would be seen if not all EV chargers participated). For example, project EDGE (Energy Demand and Generation Exchange) [15], which is a “*multi-year project to demonstrate an off-market, proof-of-concept DER Marketplace that efficiently operates DER to provide both wholesale and local network services within the constraints of a specific area of the power distribution grid*” [15], is part of the overall ESB DER implementation plan to reward flexible demand and DER in the market [14].

The building standards update identified the potential of coordinated EVs [16]. The requirement from 2022 means that EV chargers within the buildings carpark must be able to be controlled in relation to the buildings overall demand [16], but instead of controlling in relation to distribution network assets, it is controlling EV chargers in relation to the buildings demand and connection limit. This is to prevent new buildings with EV chargers for carparking spaces from having over double the required electricity connection [16].

In terms of a wider centrally controlled network based EV management scheme (such as that seen in the previous report [5]), the Electric Vehicle Council has made it clear that currently in the short to medium term, the EV industry is against wide-spread involuntary EV orchestration as a solution for EV integration [13]. The ESB smart charging webinar confirmed that widespread centralized orchestration is not part of the plan for 2025. Furthermore, the Electric Vehicle Council advocates caution and to see how EV integration develops both domestically but also internationally for high EV penetrations [13].

Finally, the big push to encourage public and destination charging will of course help with EV adoption [3, 17]. But it may also help with residential EV integration within distribution networks (where most of the charging is currently predicted to occur). This is because these chargers are not used during residential LV network peak demand periods. This may mean that the charging requirements of residential EVs could be lower if public charging utilisation increases. A lower charging requirement can mean pushing the charging of the EV later into the night (ensuring it is ready for the morning). This could open the opportunity for further aggressive EV tariff options from retailers for a further discount to customers to charge their EV, which will further help manage peak demand and network costs.

4 Roadmap and Recommendations for EV Integration

This section aims to provide a clear set of recommendations to enable integration of EVs in a cost-effective manner that makes as efficient use of existing network assets. This is done in consideration of the Australian current plans for DER (and EVs), as well as international smart charging trends seen in the UK and the USA.

The following recommendations are made for the integration of EVs considering early uptake of EVs (up to 20%), medium uptake (up to 40%) and high uptake (60%+). Penetration is defined as the percentage of residential customers with an EV. It should be noted that the years are likely going to be different from reality. Therefore, these recommendations are primarily based around EV penetration (i.e., percentage of residential customers with an EV).

1) Early EV Uptake (e.g., next 5 years – up to 20% EVs)

The following are general recommendations for the early stages of EV uptake (e.g., the next 5 years). This closely follows the current Australian plan for EV integration which is up until 2025. The focus is on ensuring tariff reform, and smart EV charging standards and adoption.

General Recommendations:

- Reinforcement where necessary for weak assets. (i.e., assets already close to their limit and that usually only cover a handful of people, such as parts of rural distribution networks where there is little room for an EV charger or two).
 - While smart charging is in its infancy, some assets will inevitably be replaced.
- All EV chargers should be smart EV chargers.
- Tariff reform to reward flexibility. DNSPs should pass on cost reflective tariffs to retailers.
- Lay the regulatory groundwork for EV Mandatory Smart Charging.
- Encourage smart meters with the installation of EV smart chargers.
 - Enables cost reflective tariffs from retailers.
 - Enables retailers to be charged cost reflective tariffs from DNSPs.
 - Potentially lower non-EV related peak demand which also helps with EV integration.
- Continue building public charging stations to minimize time spent charging at home.
- Encourage workplace and destination charging as much as possible.
 - Daytime charging of EVs, alignment with solar PV.
 - Lower charge length requirements for charging at home at the end of the day.
- Follow international standards to reduce costs and increase availability of options.
 - State specific requirements should also be avoided to the extent that is possible.

What if...:

- **Mandatory EV smart chargers not accepted?** (This could mean a lower uptake of off-peak charging)
 - Encourage vehicle API based control (e.g., Tesla) so smart chargers are not needed.
 - Work with stakeholders to accelerate the stand-alone monetary benefits of smart charging to encourage uptake on its own standalone merits (e.g., end of PV subsidy).
 - Tariff Reform for cost reflective tariffs.
 - Cost reflective tariffs make the adoption of smart chargers preferable.
 - Government could subsidize the \$200-\$300 additional cost of a smart charger versus a non-smart EV chargers [13].
- **Cross subsidization of PV-related network reinforcement?**
 - Encourage daytime charging with cost reflective tariffs (or even a negative feed-in tariff).
 - Modify feed-in tariffs to counterbalance cross subsidization

2) Medium EV Uptake (e.g., next 10/15 years – 40% EVs)

The following are general recommendations for the medium stages of EV uptake (e.g., the next 10 years). This builds upon the current EV integration plan in Australia. Whilst the focus is still on ensuring tariff reform and smart EV charging standards and adoption, aspects such as local level distribution services and marketplaces should be by now widely used by DSOs. This is because local level services offer some of the benefits that direct EV management can offer (e.g., adjustment of demand in response to network measurements), thereby increasing the efficiency of assets.

General Recommendations:

- EV smart charging should be mandatory by now for all level 2 (and +) EV chargers.
 - Retail options for off-peak EV charging, either user managed, or supplier managed.
 - Customers rewarded for demand flexibility.
 - Easy to use and public adjusted to a new way of transport.
 - Clear interoperability allowing customers to switch retailers without a new charger etc.
- Tariff reforms should continue if not reformed by now.
 - Cost reflectivity.
 - Additional market services rewarding flexibility.
 - Remove barriers of entry for new technologies and retailer options.
 - Consider allowing more than one retailer/aggregator per customer to encourage competition on specific flexibility services.
- Continue to encourage workplace, public and destination charging as much as possible to lower the length of charging required.
- Follow international standards (such as the adoption of OCPP1.6) for EV smart charging. Furthermore, additional standards should be nationwide to the extent that is possible to reduce costs and confusion.
- Push for more “prices for devices” retail tariffs. This can encourage more participation in demand response markets. It may also allow EV charging to occur even later at night than a normal TOU tariff.
 - Prices for devices may be simpler than TOU tariffs because the customer can be charged in the style of a traditional flat tariff (but at a significant discount) for handing over control to the retailer.
- Integration of local-level distribution services. Newly formed DSOs with network visibility can buy demand reduction services for asset congestion within a pre-defined area.
 - Requires retailers to help to enable DER visibility.
 - Requires significant work on standards, market frameworks, etc.

What if...:

- **Local level services are delayed?** (e.g., troubles in implementing dynamic operating envelopes, or lack of visibility of assets and/or DER)
 - Continue with cost reflective tariff reform to lower peak demand with smart charging.
 - Encourage workplace/destination/public charging to the greatest extent possible.
- **Smart charging unable to cater for users plugging into a standard 3.2kW socket?** (as seen in the AGL smart charging trial [9])
 - Work on tariff reforms whereby off-peak EV charging considerably cheaper than normal residential demand implies wasting money if customers were to do this.
 - No incentive to try and hide EV charging demand via a method that is not metered.
 - Does it matter since it's now ~3kW instead of ~7kW? How common will it be? As it is only half the power, it might not be a material issue, overall.
- **Cost-reflective tariffs for retailers is Opt-in and not Opt-out or mandatory assignment?**
 - Encourage customers to be rewarded for flexibility as much as possible, such as adopting prices for devices whereby the customer essentially could pay a flat rate tariff but at a much lower cost to the customer due to handing over control.

3) High EV Uptake (e.g., 20+ years – 60% + EVs)

The following are general recommendations for the high stages of EV uptake (e.g., the next 20 years). At this point the medium and low EV uptake recommendations should be fully implemented. However, at this stage effectiveness of TOU based smart charging techniques might be reaching their limits without network reinforcement.

General Recommendations:

- Most EVs should be using a smart charger (or equivalent EV APIs) + smart meter.
 - This leads to a high-cost reflective tariff adoption and customers can be rewarded for flexibility.
- DSO local-level services and marketplace for demand reduction in response to asset congestion needs to be wide-spread with also more ‘prices for devices’ tariffs.
 - Consider mandatory push for prices for devices tariffs to help with participation.
- Public charging, workplace charging, and destination charging should be commonplace to encourage off-peak charging.
 - Lower time needed charge EVs at home, allowing retailers to offer more aggressive tariffs.

What if...:

- **TOU based cost reflective tariffs, in combination with smart charging, may not be enough to efficiently utilize existing assets without significant scale of network augmentation/upgrade (which might be very expensive)?**
 - DSO local-level services for demand reduction in response to asset utilization measurements and estimations.
 - Prices for devices.
 - DNSPs/DSOs may consider a capacity/demand only cost reflective network tariffs to retailers.
- **Local level DSO services for demand reduction is not possible? (e.g., regulation)**
 - Consider direct management of EVs from DSOs as either:
 - A type of DSO-related control tariff (for EVs) offered by retailers (e.g., DSO → Retailer → customer).
 - Mandate orchestrated EV management
 - A step further than the new 2022 building regulations that require EV management within a multi-occupancy buildings’ carpark relative to the total building demand. Instead of building demand, this is in response to network demand.
 - Emergency control (e.g., Queensland 20A+ load connection rules, but re-imagined).
 - Network augmentation
 - This would be at a much lower level considering previous efforts on EV integration already in place by now. TOU and other types of tariffs would have lowered peak demand versus business-as-usual.
 - Cost reflective tariffs protect non-EV customers from unfair allocation of costs.

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