NERA
ECONOMIC CONSULTING

Efficiency of Tariffs for Current and Emerging Technologies

A Report for the Australian Energy Market Commission

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Executive Summary

Throughout the 90's the prevailing story for network businesses was the need to expand network capacity in response to actual and expected rises in network maximum demand, driven in part by increasing adoption of air conditioners. This led in turn to significant investment in electricity network infrastructure to ensure that network reliability standards were maintained, and associated increases in network charges.

Since 2008, electricity consumption has fallen with associated falls in network maximum demand. This has created the current circumstance where electricity tariffs need to rise to recover the costs of the existing network assets.

Throughout the period of rising network maximum demand most consumers were faced with fixed electricity supply charges combined with flat, inclining or declining block usage tariffs. These tariff structures provided poor signals about the costs that were being caused by rising maximum demand and so likely led to inefficient expansion in network capacity.

Although air conditioners have already reached high penetration levels in Australia and therefore will have limited impact on future changes in network costs, there are new emerging technologies that are likely to impact on network costs in the future. These include solar photovoltaic systems, battery technologies and possibly the greater adoption of electric vehicles, amongst others that are currently unknown.

It is within this context that the Australian Energy Market Commission (the Commission) is examining the requirements within the National Electricity Rules (the Rules) for network businesses to implement tariffs that promote more efficient use of and investment in network infrastructure.

NERA Economic Consulting has been engaged to investigate the efficiency of tariffs charged to customers that use a number of existing and emerging technologies, including:

- air conditioners;
- solar photovoltaic systems (PVs);
- solar PVs with battery storage systems; and
- electric vehicles.

Our approach has involved investigating the efficiency of tariffs for each of these technologies for illustrative representative customers across four distribution networks.

We note that our results are dependent on the assumptions underpinning our analysis, and so are not intended to provide a projection or expectation of outcomes. In particular, it is unclear:

- how network businesses might choose to structure a more efficient tariff;
- the effect that these tariffs would have on consumption; and
- the manner in which retailers might respond to a change in network structure.

Our analysis of bill impacts is limited by these uncertainties, and is only intended to provide an indication of the potential for retail bills to change as a result of shifting to more efficient network tariffs.

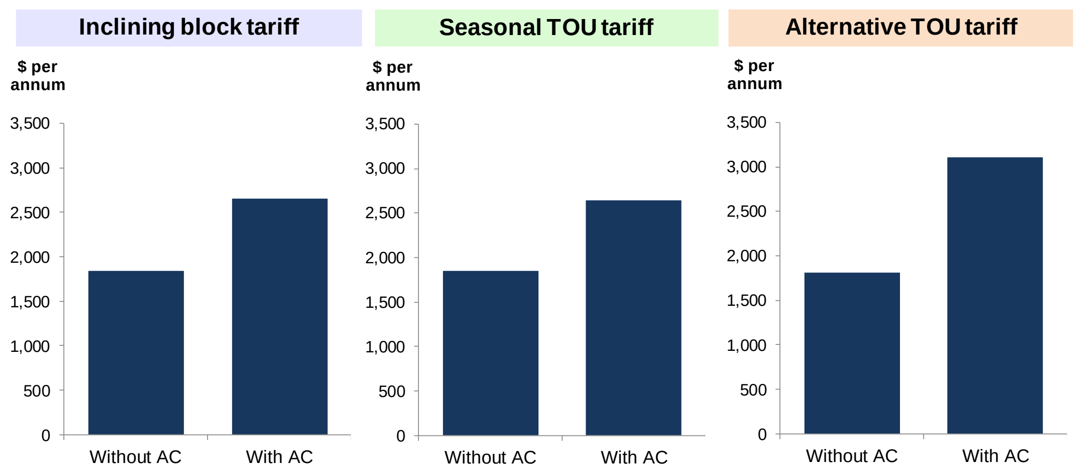
Our investigation of customers with air conditioners was focused on a representative customer within SP-Ausnet's network in Victoria. Our analysis highlights that for our illustrative representative customer:

- the implied cost of an air conditioner through higher network charges under an inclining block tariff is about one third of the estimated network costs imposed, on average, from air conditioner loads and therefore other users are bearing the remaining cost; and
- SP-Ausnet's seasonal time-of-use tariff increases the implied cost to the customer with an air conditioner, thereby reducing the remaining costs borne by other, but it still falls short of the implied network costs.

The analysis also highlights the significant contribution that air conditioner load makes to maximum network system demand.

Our case study for air-conditioners indicates that consumers with air conditioners in the case study currently pay an $800 per annum in retail bills. However, a move to a more efficient tariff would increase this differential to approximately $1300 – see Figure 1.1. Such a shift would be associated with the elimination of *any* cross-subsidy that currently exists between consumers who have or do not have an air-conditioner.

Figure 1.1
Estimated retail bills for a representative customer with and without an air-conditioner



For customers with solar PV systems we considered the implied discount resulting from avoided network charges, compared with the contribution of solar PV systems to lower coincident maximum network demand. Our illustrative assessment was undertaken drawing upon information from South Australia Power Networks, given the significant contribution that solar PV has on satisfying electricity demand in South Australia.

Our analysis highlights that for the illustrative representative customer:

- the implied benefit to customers through lower network charges if the solar PV system is north-facing is approximately 2.4 times the associated reduction in network costs; and
- the implied benefit of a west-facing solar PV system is only 12 per cent higher than the reduction in network costs.

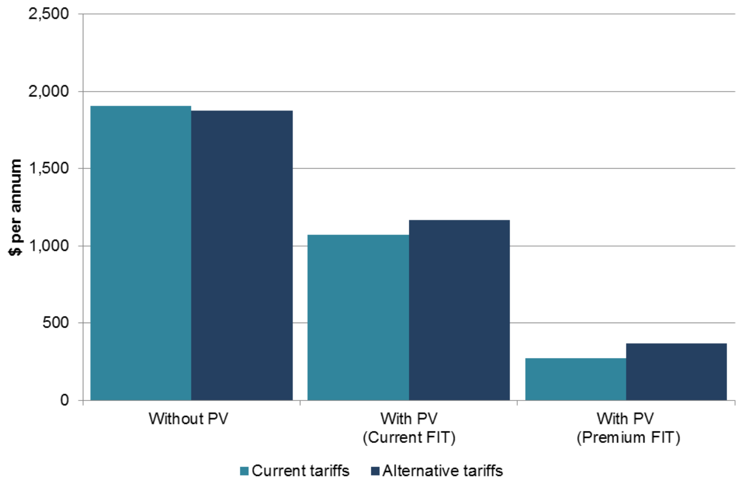
These results highlight how current tariffs in SA Power Networks area are disproportionately compensating north-facing solar PV systems as compared to west-facing solar PV systems, despite west facing solar PV systems contributing more to lowering network maximum demand.

Our PV case study suggests that under an alternative, more efficient network tariff:

- consumers without a solar PV system would see a decrease in their annual retail bill of approximately 1.6 per cent; and
- a customer with a PV system would see an increase of approximately 8.7 per cent under current feed-in tariffs – see Figure 1.2.

These results are highly dependent on the assumptions underpinning our analysis. However, they nevertheless reflect that shifting to more efficient network tariffs, and so removing the cross-subsidies that currently exist, would have a material effect on retail bills.

Figure 1.2
Estimates of retail bills under current and alternative tariffs



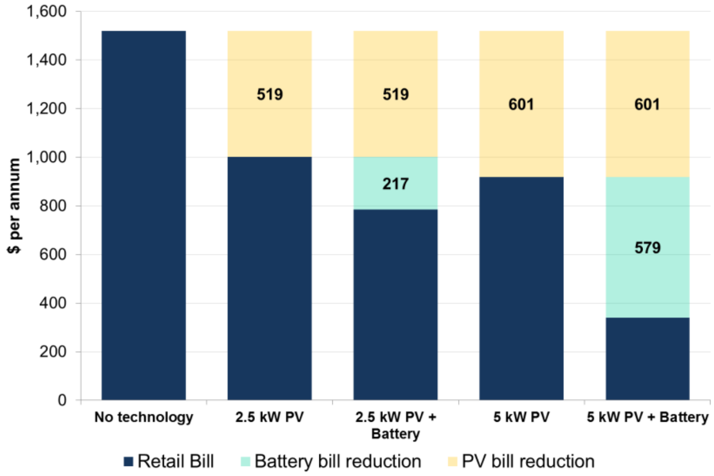
Our analysis of the effect of battery systems on distribution networks highlights:

- the need for tariffs that signal future network costs, for battery technology to be adopted (ie, peak capacity, time-of-use or critical peak tariffs); and
- the role that battery systems play in assisting customers to manage electricity tariff structures that seek to promote more efficient use of the network (ie, allows customers to avoid peak charges by using electricity stored during lower tariff periods thereby reducing network costs).

In addition, we identify the need to also ensure that the interactions between battery management systems and network tariffs do not create voltage management problems for the network business due to significant variations in the drawing of electricity from the network.

We have not examined the effect of moving to an alternative more efficient tariff for battery customers. However, a key result of this case study is the significant retail bill reductions that can potentially be achieved with solar PV and battery storage –Figure 1.3.

Figure 1.3
Estimated retail bills for battery storage plus solar PV



Finally, we investigated the potential contribution of electric vehicles to network costs, and the implied cost per kW contribution of electric vehicles to maximum network system demand. Our analysis demonstrates that under current tariffs:

- both 'smart' electric vehicles (ie, those that only charge during off-peak periods) and standard electric vehicles would pay additional network charges that exceed the costs they impose on the network; and
- there is no price signal to encourage the usage of 'smart' electric vehicles versus standard electric vehicles, despite the considerably lower network costs of the former.

These results suggest that current tariff structures would provide poor price signals for investment in, and usage of, electric vehicles. This is unsurprising, given that current tariff structures have not been designed with electric vehicles in mind. Nevertheless, our analysis indicates that were electric vehicles to emerge as a viable technology, current network tariff structures would result in poor outcomes in terms of efficiency.

Our analysis shows that, under current retail tariffs, the use of an electric vehicle leads to a significant increase in a customer's retail bill. Moreover, current retail tariffs provide little incentive to employ 'smart charging', ie, the timing of charging to avoid the network peak. Our case study demonstrates that it is possible to construct a more efficient tariff that provides an incentive to charge during off-peak periods, and that such a tariff would lead to customers with smart charge EVs receiving retail bill reductions of around $1,034 per annum versus current tariffs.

1. Introduction

The Australian Energy Market Commission (the Commission) has engaged NERA Economic Consulting (NERA) to examine the efficiency of electricity network tariffs charged to customers that use a range of existing and emerging technologies.[1] In particular, we have been asked to develop case studies considering four technologies, namely:

- air-conditioners;
- solar photovoltaic systems (PVs);
- solar PVs with battery storage systems; and
- electric vehicles.

Our report presents our analysis of the efficiency of network tariffs for these four technologies. This assessment has involved three principal tasks, namely:

- **estimating the costs** imposed on (or benefits provided to) the network by each technology relative to current network estimates of LRMC;
- **reviewing the network charges** paid by customers with each technology; and
- **evaluating the efficiency of network tariffs** and providing an illustration of the price signals implied in the tariff structures by comparing the network costs (or benefits) with the total network charges paid by customers with each technology.

In addition, this report also includes an analysis of the retail bills paid by customers with and without each of the four technologies.

1.1. Background for this study

Demand for electricity in Australia is driven by the decisions of many individual households and businesses about the quantity and timing of electricity consumption. Of principal importance are consumers' decisions to:

- purchase technologies, such as air-conditioners or PVs; and
- the manner in which they use these technologies.

In making these decisions, consumers have regard to the electricity charges (or benefits) associated with their use of the technology.

The aggregated decisions of individual consumers give rise to a system demand profile. Since the electricity network must be constructed to be able to meet this profile, the decision of a consumer to purchase and use a given technology has direct consequences for network investment and operating expenditure. To ensure an efficient outcome, the network tariffs

[1] Throughout this report, we refer to technologies that already exhibit high levels of penetration across the grid as 'existing technologies'. In contrast, technologies that have only recently started to be installed across the power system, or are still prospective, are referred to as 'emerging technologies'.

faced by consumers must reflect the costs that a technology imposes on (or the benefits that it provides to) the network.

Emergence of new technologies

In recent years, new technologies have emerged that are altering the profile of electricity usage and production across the National Electricity Market (NEM). The most notable examples are as follows:

- Since 2002, the penetration of **air conditioners** has risen consistently across Eastern Australia, so much so that heat waves are now the principal driver of maximum demand.
- **Solar PVs** have risen from negligible levels of penetration in 2009 and are now an important part of the power system. Further, there remains considerable scope for ongoing increases in the penetration of PV systems.
- **Battery storage systems** are starting to be installed by some households across the NEM. The use of battery storage in conjunction with PVs has the potential to lead to a significant change in the supply of electricity.

These new technologies are altering the manner in which electricity is consumed, and so are also affecting network costs. It follows that stark differences in electricity consumption sourced from the network can be observed between customers that use different technologies.

On that basis, existing tariff structures may fail to provide these new technologies with efficient price signals, both to inform a customer's initial decision to adopt a technology and their subsequent use of that technology. As the penetration of these technologies grows, they will, and indeed have, become more important to network outcomes.

This project also forms part of the Commission's process to address a rule change put forward by the Council of Australian Governments (COAG) Energy Council (formerly the Standing Council on Energy and Resources (SCER)) and the Independent Pricing and Regulatory Tribunal of New South Wales (IPART). The rule change is seeking changes to the rules to improve the guidance provided to distribution network service providers (DNSPs) to encourage greater use of tariff structures that promote more efficient outcomes. This report is intended to inform the Commission as it considers how to enhance the price signals sent to customers with various technologies.

1.2. Structure of the report

The remainder of this report presents our analysis in detail and is structured as follows:

- **Chapter 2** sets out our methodology for assessing the efficiency of network tariffs and describes the four case studies we have examined;
- **Chapter 3** sets out the results of our examination of efficiency of existing network tariffs and the retail bill impacts for each of the four case studies we have examined;

2. Methodology and Principal Assumptions

This chapter sets out:

- a brief description of the case studies that we have performed;
- our methodology for assessing the efficiency of network tariffs; and
- identifies the principal assumptions we have adopted in performing our analysis.

2.1. Description of case studies

We have worked with AEMC staff to develop four case studies, each of which examines a different technology in a different distribution network.

2.1.1. Case Study 1: Air conditioners in Victoria

Despite only being used for two or three months of the year, air conditioners have a considerable effect on demand for electricity. During summer heat waves households can be expected to activate their air-conditioners en masse in response to a single common signal, ie, persistent high temperatures. This effect is so significant that during summer network businesses use temperature forecasts to make hourly estimates of cooling loads.

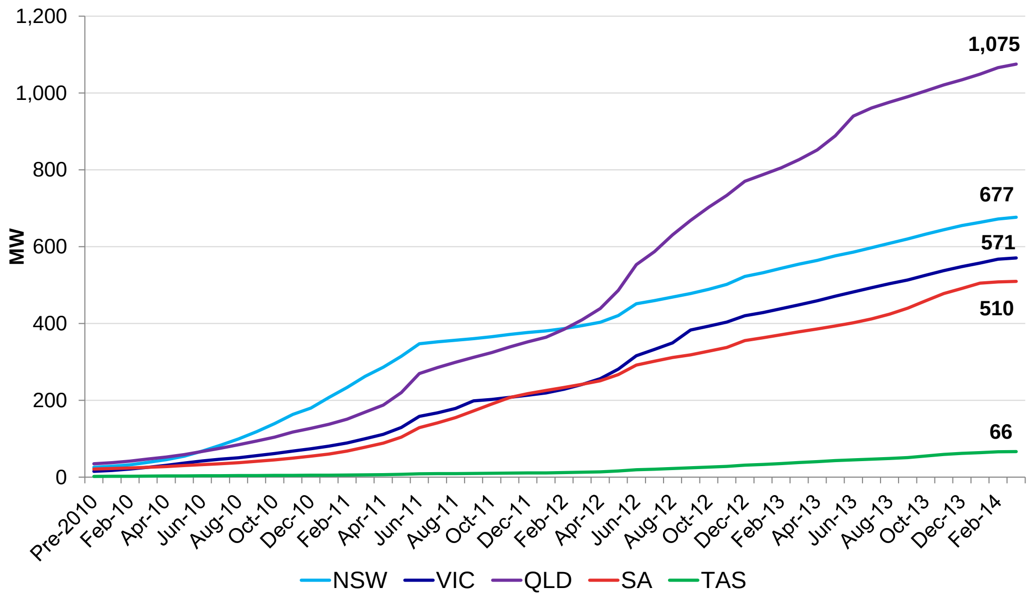
Therefore, this first case study considers the effect of air-conditioners in a network where they are prevalent and drive network investment, ie, SP-Ausnet's distribution network in Victoria.

2.1.2. Case Study 2: Solar PV in South Australia

In recent years, solar PV systems have rapidly emerged as an increasingly important part of the power system. Solar PVs reduce households' demand for grid-sourced electricity, and so reduce the load on the network in the middle of the day when these systems are generating.

The installed capacity of PVs has risen rapidly over the last four years. Figure 2.1 shows the cumulative capacity of PVs installed by state since the start of 2010.

Figure 2.1
Cumulative installed PV capacity by NEM region – January 2010 to March 2014



Source: NERA analysis of data published by the Clean Energy Regulator.

The installation of PV systems was initially driven by:

- high certificate subsidies provided by the solar credits scheme, which amplified the subsidy offered via the small-scale renewable energy scheme; and
- premium feed-in-tariff programs, such as the New South Wales solar bonus scheme.

Despite the end of premium feed-in-tariff schemes and the end of the solar credits scheme, PV systems continue to be installed at a rate of around 55 to 60 MW per month. There is now almost 3 GW of PV capacity installed across the NEM – a quantity that exceeds the capacity of Eraring power station.

Against this backdrop, our second case study focuses on the effect of PV systems installed by residential customers in South Australia Power Networks' distribution area. South Australia has the highest penetration of solar PVs of any NEM region, and so provides an excellent example of a network where PV systems are prevalent. In the context of this project, the relevant question is how these systems are affecting network outcomes, and so network costs.

2.1.3. Case Study 3: Battery storage with solar PV in Queensland

Storage can provide a solution to the availability of time-dependent sources of energy, such as run-of-river hydro, wind and solar. Storage systems and batteries can be charged during times of high output and drawn upon at times of peak demand. The challenge is that storage of energy is extremely expensive, even taking into account considerable improvements over the last decade.

However, the emergence of PV systems and an increase in the penetration of wind farms across developed economies has provided an impetus for battery development. The combination of cheap, intermittently available sources of power, and effective forms of electricity storage is so complimentary that considerable effort is being invested in storage technologies by both the public and private sectors.

The use of battery storage in conjunction with PVs has the potential to impact on the supply of electricity, and so network costs. Therefore, our third case study examines how battery storage systems may be used by residential customers in combination with PV systems. Queensland has the largest amount of installed capacity of solar PV in the NEM, and so is a relevant market to examine the potential implications of battery storage for network costs.

Battery storage presents a unique modelling challenge, since the technology profile is a function of the retail tariffs received by customers. Put another way, batteries have differing effects depending on the retail tariffs that customers pay. We describe our approach to dealing with this challenge in greater detail alongside our results for this case study.

2.1.4. Case Study 4: Electric vehicles in the Ausgrid distribution area

Electric vehicles are a potential substitute for traditional internal combustion engine vehicles. The technologies surrounding electric vehicles are still being developed, and substantial hurdles still exist to their widespread roll-out across developed countries, including:

- expense versus traditional internal combustion engine vehicles;
- performance, life-span and maintenance issues;
- the lack of infrastructure to support the effective use of the technology, ie, charging stations and service facilities; and
- the structure of existing electricity tariffs, which may not provide sufficient incentives for consumers to purchase electric vehicles.

In the event that electricity vehicles were widely adopted, the potential implications for the network would be significant. As a result, we have been asked to consider the efficiency of network tariffs for electric vehicles, and have done so by considering a residential customer in the Ausgrid distribution network.

2.2. Overview of methodology

We analyse each case study through five distinct steps. The outcome of which is an understanding of the impact of the technology on network Our methodology for this project comprises four steps:

1. Determining the change in load profile resulting from a consumer adopting each of the four technologies.
2. Assessing the effect of each technology on network charges paid by customers.
3. Assessing the effect of each technology on network costs.
4. Comparing network costs and network charges to assess efficiency, and where appropriate the development of an alternative more efficient tariff.
5. Assessing the effect of each technology on retail bills under current and alternative tariffs.

2.3. Step 1: Determining the change in load profile

In the context of electricity consumption, a technology is a device that consumes or produces electricity. Put another way, technologies *alter* a consumer's level and profile of consumption.

The change in the consumer's load profile is directly related to the costs that they impose on the network. Indeed, to some extent the specific type of technology (eg, air conditioner, dishwasher) may be an unhelpful concept when thinking about network costs. The more useful concept is that technologies have *characteristics* that give rise to specific types of changes in customers load profiles. As a result, the same technologies tend to give rise to the same network costs.

The first step in our methodology has therefore been to determine the change in load profile associated with each technology. This has involved:

- establishing 'base-case' load profiles for each representative customer profile;
- calculating the load (or potentially generation) profile associated with each technology, which we term the 'technology load profile'; and
- combining each base case load profile with each technology load profile.

In developing these profiles, we have been informed by data sets that have been provided by each of the four DNSPs that form the subject of the case studies.

2.3.1. Base case customer load profiles

To examine how a technology affects customer network and retail bills, it is necessary to assume a 'base case' customer profile, to which a technology can be 'added'. Typically, this type of analysis considers a single profile that is developed to be representative of a larger class of customers.

We have adopted this approach for the purposes of estimating network bills and retail bills. In particular, we have adopted:

- **Case Study 1: Air conditioners in SP-Ausnet's distribution area** – the representative customer load profile is based on an average profile constructed from a sample of 200 customers on the inclining block network tariff.[2]
- **Case Study 2: PV Systems in South Australia –** in the absence of individual customer load profiles, we have assumed a 5 MWh per annum customer with a load profile matching the aggregate residential load profile provided by SAPN, which includes an adjustment for solar generation based on SAPN's estimates of solar contribution to load.
- **Case Study 3: Battery systems in Energex's network –** due to the low penetration of interval meters in Energex's network, it is necessary to use of net-system load profile data.

[2] This data was provided by SP-Ausnet for the period from 2010 until April 2014 – the longest period for which reliable metering data was available.

We have assumed that this profile is scaled so that the representative customer has 5 MWh per annum of consumption.

- **Case Study 4: Electric Vehicles in Ausgrid's network** – the representative customer load profile is based on an average profile constructed from a sample of 200 customers on the EA025 network tariff.[3]

An important aspect of our analysis has been to consider the implications of variation in the consumption profiles of *similar* customers for a potential change in network tariff structures. In illustrating the potential implications on customers of a shift to more efficient tariffs, where possible we have examined the consumption profiles of representative samples of individual customers in each distribution network.

2.3.2. Load profiles associated with each technology

Each of the four technologies we have considered has required a different process to determine its load profile. For example, air conditioner consumption is driven by changes in ambient temperature, and so we have had to examine the responsiveness of customers to that variable.

Given that we have adopted a tailored approach to each case study, we have therefore described the assumptions underpinning the development of each technology load profile in the context of presenting our results.

2.3.3. Combining customer and technology load profiles

Having developed the customer and technology load profiles, it is a straightforward process to combine them. In the case of solar PV and battery storage systems, the technology load profile may act to *reduce* consumption, and is therefore associated with a network benefit rather than a network cost.

2.4. Step 2: Assessing the effect of each technology on network charges paid by customers

The second step in our methodology has been to estimate the effect of each technology on network charges paid by customers for current tariffs. The calculation of network charges has been straightforward, and involved:

- identifying the relevant network tariffs for each case study, and collating the associated data; and
- calculating the fixed and variable components of network charges for the base consumption profile with and without each of the technologies.

A summary of the network tariffs that we have used in our case studies is set out in Table 2.1.

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[3] This data was provided by Ausgrid for the period from January 2009 until January 2014 – a period of 5 years. We note that the interval data by definition excludes customers on standard inclining block tariffs since, by definition, these customers are on time-of-use tariffs. We have identified where this is relevant to our analysis and findings throughout this report.

Table 2.1
Current network tariffs adopted for case studies

	All- Day Tariff (Tariff code)	Time of Use Tariff (Tariff code)
SP AusNet	Small Residential Single Rate (NEE11)	Small Residential Interval Meter TOU (NSP11)
SA Power Networks	Low Voltage Residential Single Rate (MRSR)	N/A
Energex	Residential Flat (8400)	Residential TOU (8900)
Ausgrid	Residential Inclining Block (EA010)	Residential TOU (EA025)

2.5. Step 3: Assessing the effect of technologies on network costs

The third step of the process is to identify the network costs or benefits associated with each of the four technologies. The relevant network cost is the incremental increase in network costs incurred as a consequence of increasing the use of the relevant technology, ie, the LRMC of network services for customers with those technologies.

In practice, estimating the network cost of a given technology on the network has involved:

- estimating the effect of the technology on the annual system maximum demand; and
- multiplying the contribution of the technology to the system peak (in kW per annum) by the most recent estimates of LRMC for that network.

A crucial assumption in our analysis has been that the principal driver of network costs is the requirement for capacity, whether it be defined in terms of:

- a requirement to provide sufficient capacity to meet maximum demand[4]; or
- a requirement to supply a level of capacity at some level of reliability.

The significance of capacity as a driver of network can also be seen in the prominence of this parameter in network planning processes, and this was supported by information provided by DNSPs. We note that DNSPs provided anecdotal evidence that there are also benefits and costs associated with technologies altering:

- the *cumulative stress* placed upon a network, ie, the over-loading of components over extended periods; and

4 The interval over which maximum demand is defined is relevant. In general, comments from network businesses were that maximum demand tends to be forecast on a 30 minute of 15 minute interval basis. In contrast, maximum demand in the generation sector is often examined on a 5 minute interval basis. The different may reflect the nature of network infrastructure.

- voltage stability in localised parts of the network – a feature that was identified by South Australia Power Networks as an emerging issue in areas of its network where there is a high penetration of PV systems.

Notwithstanding the anecdotal evidence provided, network businesses were not able to provide information that quantified the extent of these other drivers of network costs. As a result, we have restricted our analysis to an examination of how technologies influence capacity and reliability requirements.

2.6. Step 4: Assessment of efficiency and development of alternative tariffs

Having estimated both the network costs and the charges paid by customers with and without specific technologies, the final step is a comparison of these two sets of results. In general, a tariff provides an efficient price signal to the technology where the additional network charges associated with the technology are equal to the costs imposed by that technology on the network.

Informed by this assessment of efficiency, we have been asked to comment on how distribution tariffs could be improved to better reflect the effect of each technology on network costs. To this end, for each case study we have provided an illustrative example of how tariff structures might be altered to provide price signals that promote efficient use of the technology with respect to network costs.

As part of this analysis, we have examined the change in customer bills associated with a shift from the current to the alternative tariff. We note that this analysis is not intended to provide a forecast or projection of customer impact of increasing efficiency. Instead, the objective of our analysis is to illustrate the potential implications of changing the basis of charging (eg, from usage based charges to critical peak charges) for customers.

We have used various alternative tariffs for each case study. The tariffs used are as follows:

- Case study 1 – A modified version of SP-Ausnet’s seasonal time-of-use tariff;
- Case study 2 – a ‘sharp’ peak time-of-use tariff has been calculated that ensures the networks charges reflect the incremental contribution to maximum demand and so, LRMC;
- Case study 3 – no alternative tariff calculated; and
- Case study 4 – modified TOU charge that recovers the same revenue and with the TOU periods shifted to cover high demand events later in the day.

2.7. Step 5: Assessment of retail bills

As part of this study, we have been asked to calculate retail bills for customers, both with and without each of the subject technologies under current retail tariffs. This has included an adjustment for any feed-in-tariffs for which a customer is eligible. Table 2.2 sets out the retail tariff assumptions that we have used to perform this retail bill analysis.

Table 2.2
Retail tariff assumptions for customer bill assessment

	All- Day Tariff	Time of Use Tariff
Case study 1	Origin Energy Residential Peak	Origin Energy Residential TOU
Case study 2	Origin Energy 110 Qtly Domestic Light/Power	N/A
Case study 3	Regulated Queensland All-Day Tariff (Tariff 11)	Regulated Queensland All-Day Tariff (Tariff 12)
Case study 4	Energy Australia Domestic All Time	Energy Australia PowerSmart Home

3. Case Study Results

This section sets out the results of our examination of efficiency of existing network tariffs for each of the four case studies we have examined. For each case study, we describe:

- our process for developing the technology load profile;
- our estimate of network charges for customers with and without the technology;
- our estimate of network costs (or benefits) associated with the technology;
- our assessment of the efficiency of existing network tariffs; and
- an examination of an alternative tariff structure that might better promote efficiency.

3.1. Case Study 1 – Air conditioners

Case Study 1 analyses the impact of air conditioners in the SP-Ausnet distribution region in Victoria. Table 3.1 summaries the key assumptions used in the case study.

Table 3.1
Summary of air conditioning case study assumptions

Assumption	Description
Load profile	- Based on sample of 391 customers
	- Calculated as cooling response of customer sample
Technology	5kW air conditioning system
Network tariffs	2013/14 – inclining block and TOU
Retail tariffs	All-day tariff - Origin Energy Residential Peak
	TOU tariff - Origin Energy Residential TOU
Alternative tariff	Seasonal TOU

Key Findings

Case Study 1 – Air conditioners

- Air conditioners are significant contributors to maximum demand in the SP-Ausnet distribution area.
- The current TOU tariff does not impose a sufficient cost on air conditioner users to ensure the impact on their bill is aligned with incremental network costs and therefore other users are bearing these costs.
- Although more efficient than the standard TOU tariff, the seasonal TOU still does not accurately reflect the incremental network costs incurred due to air conditioners.
- A more efficient alternative tariff requires the vast majority of charges to be incurred during peak times.

3.1.1. Step 1 – Load profile of air-conditioners

The load profile was created using a sample of 391 customers in the SP Ausnet distribution region. The profile was estimated in an indirect manner by assuming that the air conditioning load is equal to the cooling response of the consumers, ie, the changes in consumption observed during periods of high temperatures. We note that due to data availability, we have used the daily maximum temperature rather than the daily average temperature.

The assumption underpinning this methodology is that all increases in load due to increases in temperature are due to air conditioners. A margin of error will be introduced to the extent that consumers vary their consumption in response to high temperature in any other way, for example, other methods of cooling, such as fans. We expect that any such bias will not alter the findings of the analysis.

The process of calculating the cooling response using the sample of customer data involved the following steps:

- **Step 1:** Aggregate all customer consumption data to form a single demand profile
- **Step 2:** Find the maximum temperature for each day in the sample
- **Step 3:** Find the average consumption for each level of temperature
- **Step 4:** Identify the temperature level with the minimum level of consumption, ie, the point where cooling load is assumed to be zero
- **Step 5:** For each temperature level, calculate the air conditioner profile, as the maximum of the consumption for that level minus the consumption for the minimum consumption level and zero.

Figure 3.1 shows a decomposition of the total consumption profile into the air conditioning consumption and the remaining residual consumption. The figure shows that as expected the maximum air conditioning consumption is typically during the mid-afternoon. Also, there is notable alignment of the peak air conditioning consumption and the ‘peak time’ as defined by a SP Ausnet TOU tariff.

Figure 3.1
Air conditioning load and residual by time of day - weekday

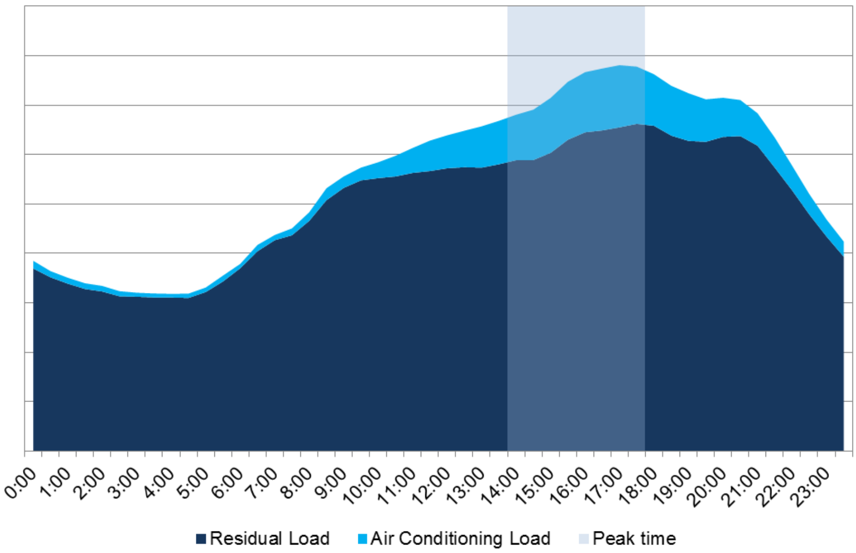
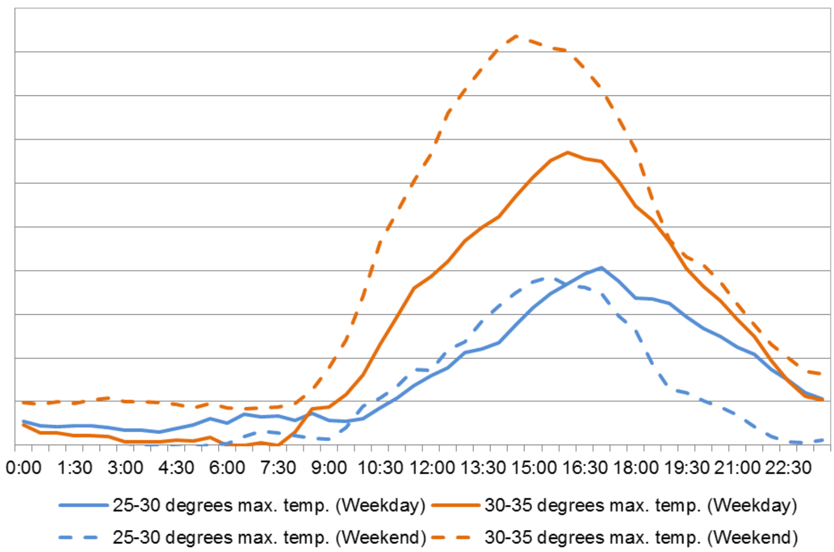


Figure 3.2 show the variation in the air conditioner load profile with maximum daily temperature. The profile shows a noticeable increase in the profile with increases in temperature, an effect that is more pronounced on weekday as opposed to weekends.

Figure 3.2
Load profile changes with temperature - Weekday and Weekend

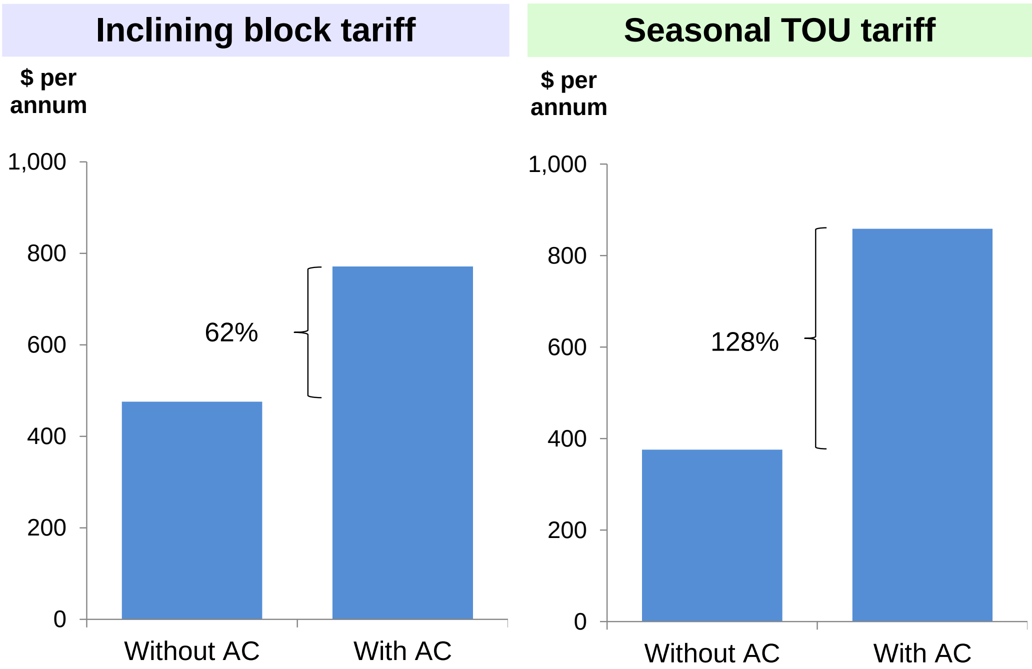


3.1.2. Step 2 – Estimate network charges

Figure 3.3 sets out the effect of using an air conditioner on a customer's network bill for SP Ausnet's inclining block and seasonal time-of-use tariffs. We observe that:

- customers without an air conditioner receive a discount of around 20 per cent on their network bill by moving to the seasonal TOU tariff; and
- the 5 kW air-conditioners increases a customer's network bill markedly for both tariffs, but the increase is far greater for the seasonal TOU tariff.

Figure 3.3
Effect of air-conditioner adoption on a customer's network charges

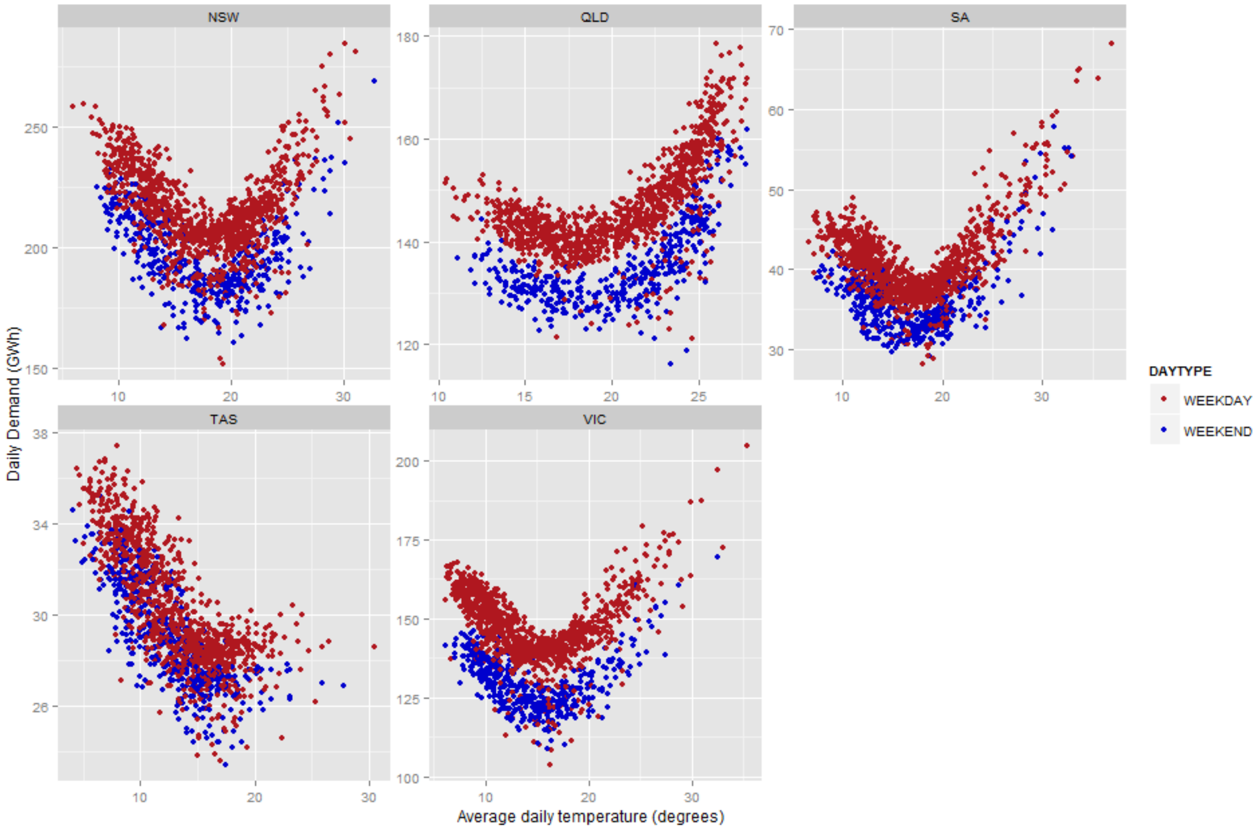


Our analysis indicates that the seasonal time-of-use tariff is well targeted to cooling loads during peak periods, and so provides a better signal to customers using an air conditioner than the standard inclining block tariff.

3.1.3. Step 3 – Estimate network costs

The effect of air conditioners on system loads is well-established. Figure 3.4 plots average daily demand versus daily average temperature for each region in the NEM. Points are coloured depending on whether the day was a working day (red) or a weekend (blue). The relationship between demand and temperature is clear – once the average daily temperature moves away from the zone between 17 and 20 degrees Celsius, heating and cooling loads come online. For the purposes of this study, we are interested in the cooling response – ie, the increase in loads that occurs for temperatures exceeding 20 degrees.

Figure 3.4
Relationship between temperature and demand – NEM regions

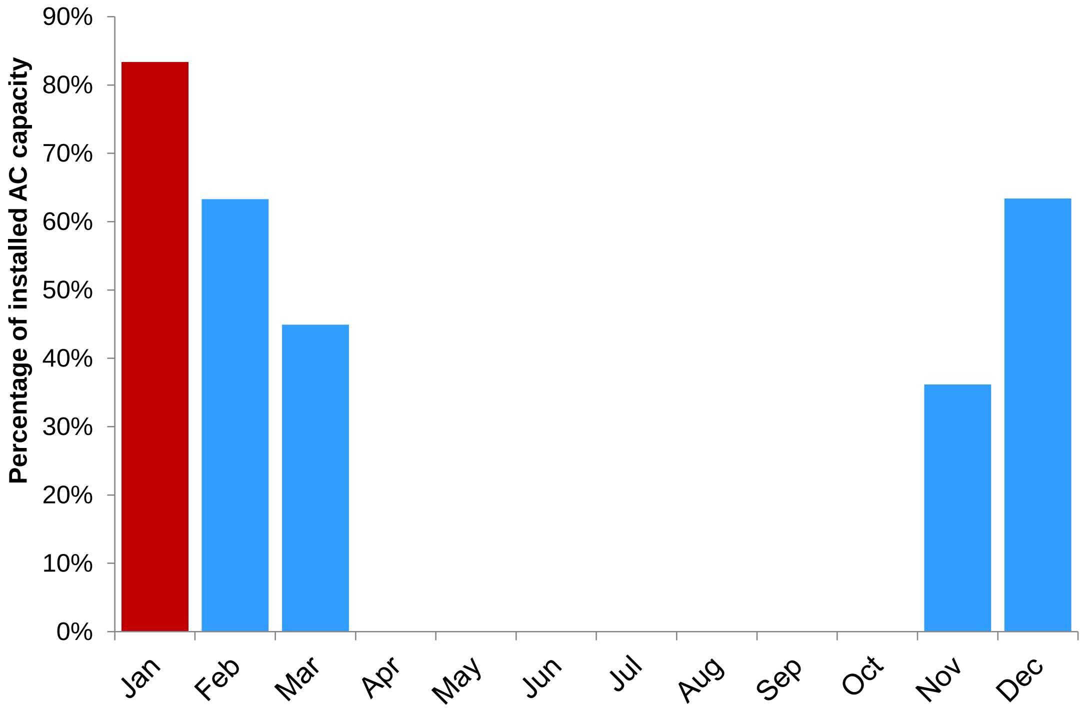


The strong relationship between daily demand and temperature would suggest that air conditioners contribute strongly to the system peak, and indeed this is borne out by our analysis for this case study.

Contribution of air-conditioners to maximum demand

Figure 3.5 shows the contribution of our estimated air conditioner load profile to monthly maximum demand in the SP-Ausnet distribution area in 2013 – annual maximum demand which occurred in January is marked in red.

Figure 3.5
Air conditioners have a high contribution to maximum demand



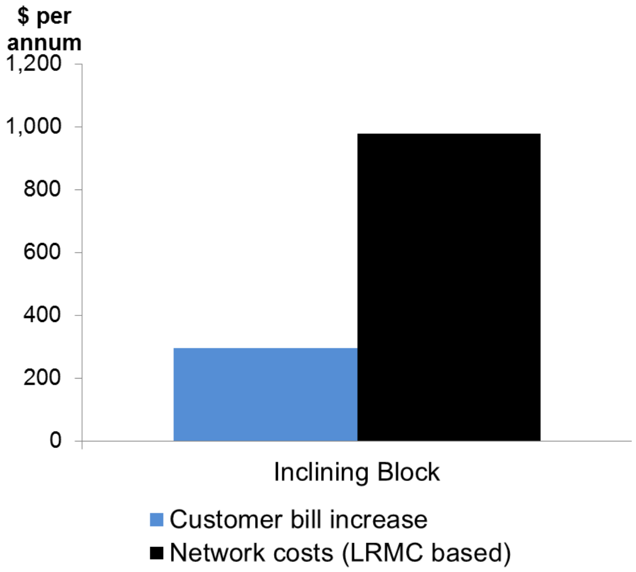
Our estimates indicate that the air conditioner load profile contributes around 84 per cent of its installed capacity to the system maximum demand, which typically occurs in January. For example, we estimate that a 5 kW air conditioner can be expected to contribute around 4.2 kW to maximum demand.

We note again that the load profile we have created for an air conditioner is an average profile across SP-Ausnet's customer base. Some customers may not turn on their air conditioners at the peak time, and some may be consuming at a level exceeding our estimate. However, in our opinion our analysis provides a helpful insight into the average costs imposed by an air conditioner on the system.

3.1.4. Step 4 – Assessment of efficiency

Figure 3.6 compares the increase in a customer's network bill with an LRMC-based estimate of the network costs associated with the additional maximum demand imposed on the network by a 5 kW air conditioner, ie, 4.2 kW. SP-Ausnet does not publish its estimates of LRMC, and so for the purposes of this analysis we have adopted the average of available LRMC estimates (ie, $235 per kW per annum) across all distribution networks in the NEM.

Figure 3.6
Air conditioners impose costs on the network that exceed the costs to the consumer



This analysis indicates that the network costs associated with air conditioners exceed the additional network charges paid by the consumer for using the technology. In particular, the inclining block tariff provides a price signal of around $296, which is a third of the additional network costs.

Of relevance is that our analysis is based on an estimate of LRMC that is not specific to SP-Ausnet's network, and so the estimate of network costs may not be applicable. However, in order for the inclining block tariff to be providing an efficient price signal for the use of air conditioners, LRMC would have to be $71 per kW per annum – a value that is relatively low.

3.1.5. Alternative tariffs for air conditioners

We have been asked to comment on how distribution tariffs could be improved to better reflect the effect of each technology on network costs.

For this case study, we have considered whether SP-Ausnet's seasonal TOU tariff might provide a better price signal to promote efficient use of the technology with respect to network costs and examined their effect on customers.

The seasonal TOU tariff that SP-Ausnet has developed provides an improved signal to customers in terms of increasing the customer cost associated with consuming electricity during peak times, be it in summer or winter. Figure 3.7 compares the following two charts:

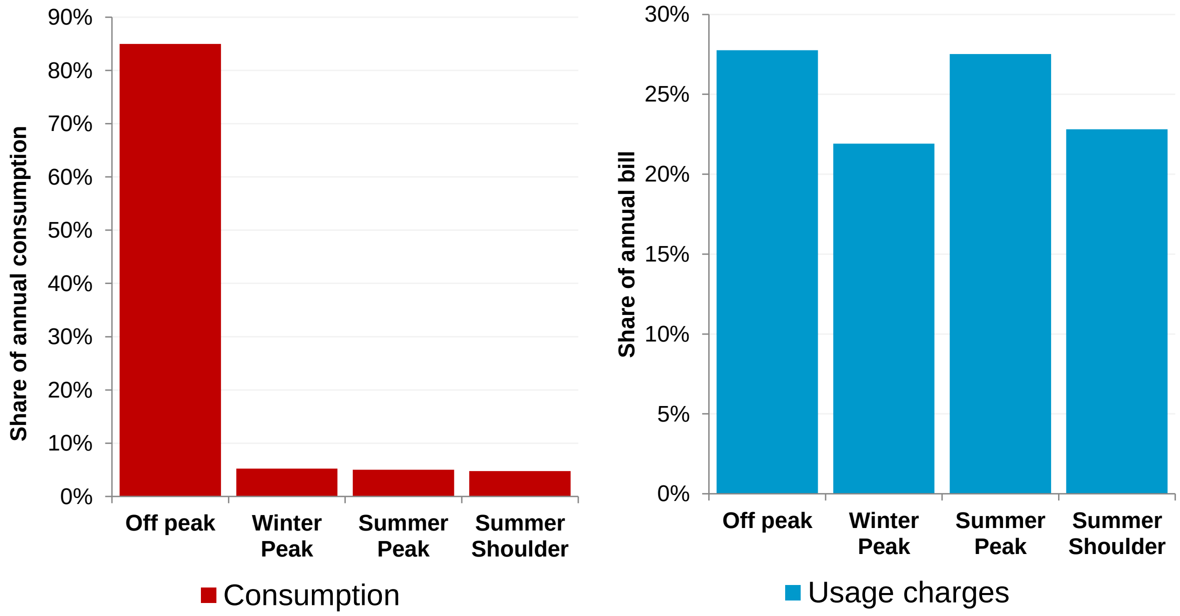
- a decomposition of **consumption** by all customers in the sample set provided by SP-Ausnet into the four different time periods of the seasonal TOU tariff (ie, off-peak, winter peak, summer peak, summer shoulder); and
- a decomposition of the **usage charges** that would be collected were those customers on a seasonal TOU tariff.

The winter peak, summer peak, and summer shoulder periods account for 73 per cent of usage charges, but represent only 15 per cent of total consumption. As a result, the seasonal TOU tariff:

- raises prices for electricity at times when there is a higher network cost associated with that consumption; and
- lowers costs at off-peak times to encourage optimal utilisation of network assets.

It follows that the seasonal TOU tariff is likely to better promote efficiency than the existing inclining block structure.

Figure 3.7
Seasonal TOU tariff places significantly greater weight on consumption at peak times

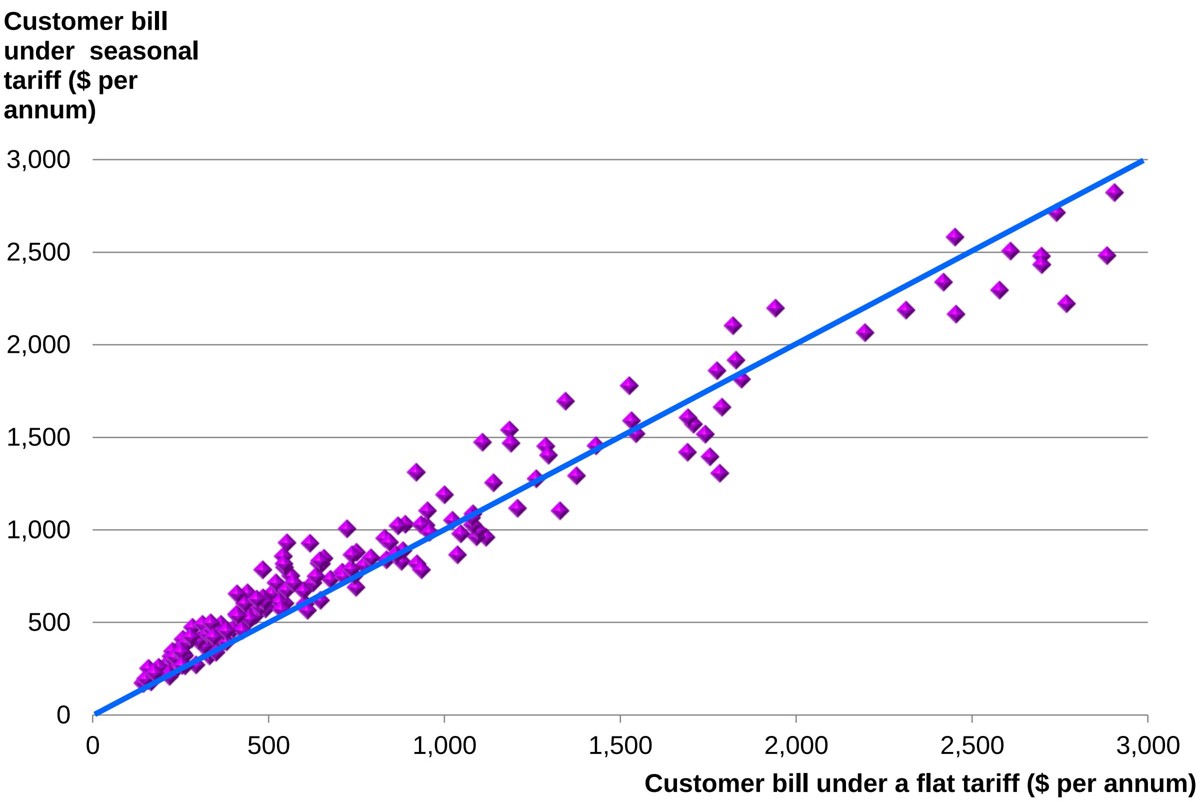


Customer impact of a shift to the seasonal TOU tariff

We have been asked to consider how shifting customers to different tariffs might affect particular customers. Almost none of SP-Ausnet's residential customers are on the seasonal TOU tariff, and an immediate question is how such a shift might affect those customers. We have used the consumption data provided to us by SP-Ausnet to compare the effect of such a shift.

Figure 3.8 compares customer network bills under the seasonal TOU tariff with those under the current inclining block tariff based on their 2013 consumption. The blue line indicates the points where customer network bills under both sets of tariffs are equal. Points above the line represent customers who have higher bills on the seasonal TOU tariff; points below the line represent customers who have higher bills on the current inclining block tariff.

Figure 3.8
Customers' network bills under a seasonal TOU are similar to bills under the current inclining block tariff



Source: Analysis is based on customer usage data for 2013 provided by SP Ausnet.

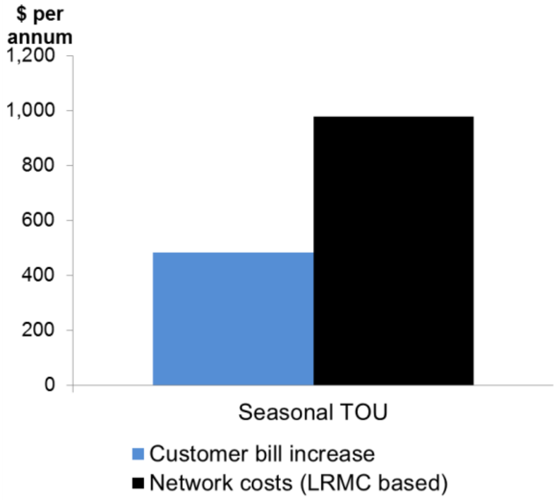
We note the following:

- customers with smaller bills (ie, under $1000 per annum) tend to receive higher bills on the seasonal TOU tariff\; and
- in general the bills are relatively similar to one another, as demonstrated by the fact that most points lie close to blue line.

This analysis necessarily assumes that when customers shift to the seasonal TOU tariff their consumption profile remains unchanged. In reality, the additional price signal at peak times would likely lead customers to reduce their consumption at these times. Our analysis would therefore tend to overestimate the impact on customers of shifting to the seasonal TOU.

Figure 3.9 shows a comparison between the increase in a customer bill associated with using the technology versus the incremental impact on network costs. Clearly, despite the increases in tariff rates during peak times under the seasonal TOU, alignment is still not achieved between bill impacts and the impacts on network costs.

Figure 3.9
Customer bill increase versus incremental network costs - Seasonal TOU

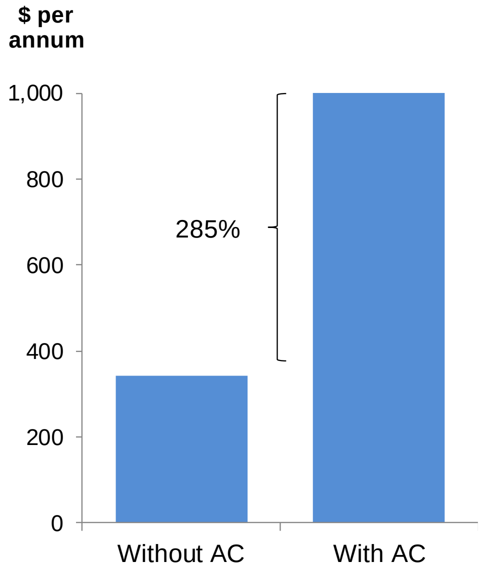


A modified TOU tariff

In order to address the inefficiency of the current TOU and seasonal TOU tariffs, we have investigated tariff structures that are potentially more efficient in the price signals provided to air-conditioners. To do this, we maintained the current seasonal TOU period definitions and altered the tariff rates for each period (ie, summer peak, winter peak, summer shoulder and off-peak).

To achieve the required customer bill increase to reflect the impact of air conditioning usage on network costs, a tariff rate of $1.57 during the summer peak is required, with all other periods have tariff rates of zero. Figure 3.10 shows the relative network bills under the modified TOU tariff for a customer with and without an air conditioner. The result is differential between the bills of around $680.

Figure 3.10
Network bill for a customer with and without air conditioning under modified TOU tariff



However, we note that our analysis indicates that such a tariff is unlikely to maintain revenue neutrality. Indeed, in order to maintain revenue neutrality an even more pronounced peak charge is required to distinguish further between the amounts charged to customers with air conditioners and those without air conditioners.

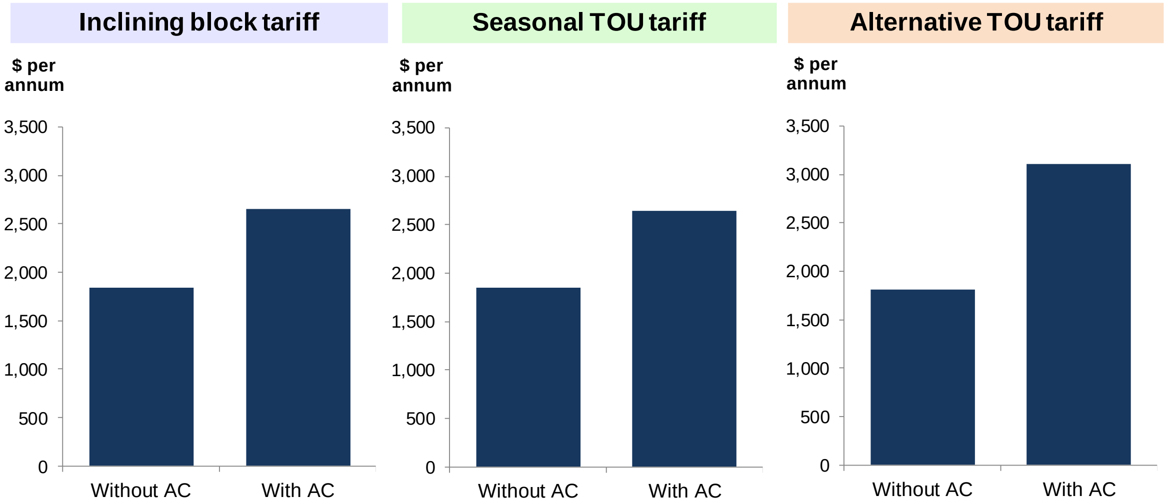
3.1.6. Retail bills under current and alternative tariffs

Figure 3.11 shows retail bills for a representative customer in the SP-Ausnet distribution area. Under all three tariff set assumptions the representative customer pays significantly more when they have an air conditioner. Our results show that:

- assuming an inclining block tariff, the estimated bill increases from $1,840 to $2,651 – an increase of 44 per cent;
- assuming a TOU tariff, the estimated bill increases from $1,846 to $2,643 – an increase of 43 per cent; and
- assuming the alternative more efficient TOU tariff, the estimated bill increases from $1,813 to $3,105 – an increase of 71 per cent.[5]

[5] Note that the difference in retail bills between consumers with and without an air conditioner is larger than the increase in network costs because the increase in consumption between consumers with and without an air conditioner also leads to increases in generation and other costs.

Figure 3.11
Estimated retail bills for a representative customer with and without an air-conditioner



3.2. Case Study 2 – PV Systems

Case Study 2 analyses the impact of PV systems in the SAPN distribution region in South Australia. Table 3.2 summaries the key assumptions used in the case study.

Table 3.2
Summary of PV system case study assumptions

Assumption	Description
Load profile	- Data from the System Advisory Model from the National Renewable Energy Laboratory, US - Both north facing and west facing profiles used
Technology	2.5kW PV system
Network tariffs	Low Voltage Residential Single Rate (MRSR)
Retail tariffs	Origin Energy 110 Qtly Domestic Light/Power
Alternative tariff	‘Sharp’ peak tariff as calculated by NERA

Key Findings
Case Study 2 – PV systems

- Our analysis highlights the impact that tariff design has in the roll out of new technologies.
- The discount received by solar PV customers under the current ToU tariffs outweighs the benefits they provide to the grid and therefore these discounts are being subsidised by other customers.
- The current tariff designs have incentivised the installation of north-facing solar PV systems and that given current penetration levels, the installation of a west-facing system would lead to a greater reduction in network costs.
- Retail bills under the proposed alternative more efficient tariff would lead to higher bills for customers with PV systems and lower bills for customers without.

3.2.1. Load profile of PV systems

Perhaps surprisingly, PV systems exhibit considerable variation in output depending upon their location, and from one day to the next. The output of a PV system is a function of a number of factors including ambient temperature, wind speed and the level of solar irradiance.

We estimated historical hourly generation from PV systems in South Australia using temperature and solar irradiance data for a typical meteorological year.[6] Using this data we have created solar traces for Adelaide for two PV orientations, namely:

- north facing, ie, the orientation that maximises total *energy* output of the PV system; and
- west facing, ie, the orientation that maximises output during the system peak in South Australia.

We have then scaled these traces based on the installed capacity of the PV system.[7]

3.2.2. Estimate of network charges for PV customers

Figure 3.12 presents our estimates of the network charges under the standard inclining block network tariff for:

- a customer without a PV system;
- a customer with a north-facing PV system; and

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6 Estimates of generation from PVs have been developed using the System Advisory Model (SAM), as developed by the National Renewable Energy Laboratory – a United States government-funded research body.

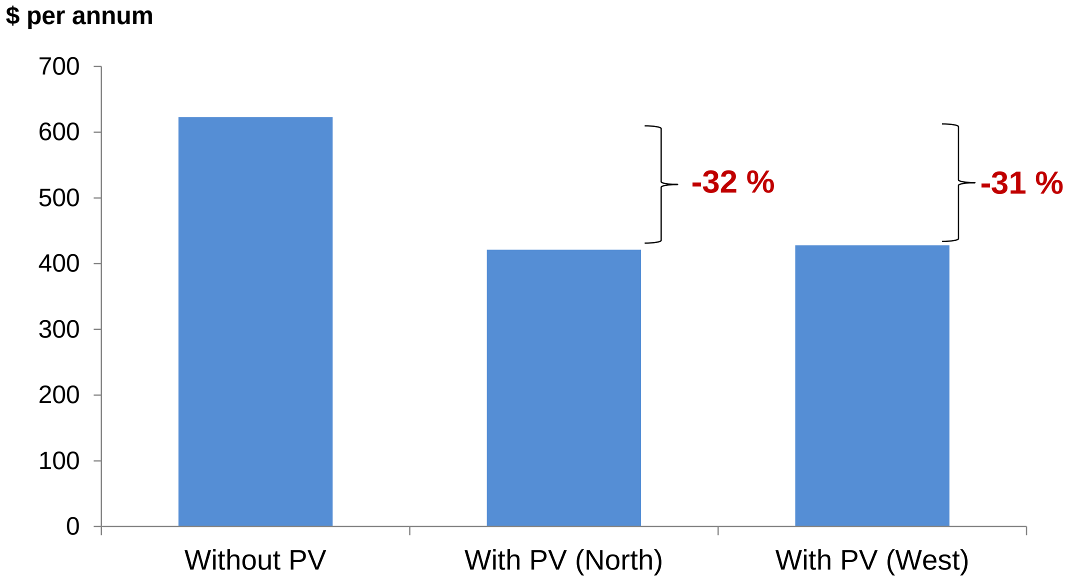
7 We note that the relative size of the PV system does not affect our assessment of efficiency.

- a customer with a west-facing PV system.

Both the north-facing and the west-facing PV system result in a substantial reduction in the customer's network bill, although the reduction from the north-facing system is slightly greater.

Of interest is that the west-facing system earns a similar bill reduction, despite generating 15 per cent less energy than the north-facing system. The reason for this outcome is that the west-facing system has a lower export ratio – ie, more of the energy it generates is consumed by the household.

Figure 3.12
Under standard tariffs, PVs reduce a customer's network bill



3.2.3. Estimate of network benefits provided by PVs

The network benefits provided by PVs are a function of their output and the system profile of demand. In networks where the system peak occurs at times when PV output is high, it can be expected that PVs may have a considerable effect on system demand. In contrast, if the system peak tends to occur at a time when PV output is low, there may be few network benefits from PV systems.

Figure 3.13 compares the system demand profile on the maximum demand day for the South Australia region of the NEM in 2014 (shown in blue) with our estimated north-facing PV output profile (shown in red). Figure 3.14 provides the same analysis for the west-facing PV output profile.

Figure 3.13
Output from a North-oriented PV is relatively low during the system peak

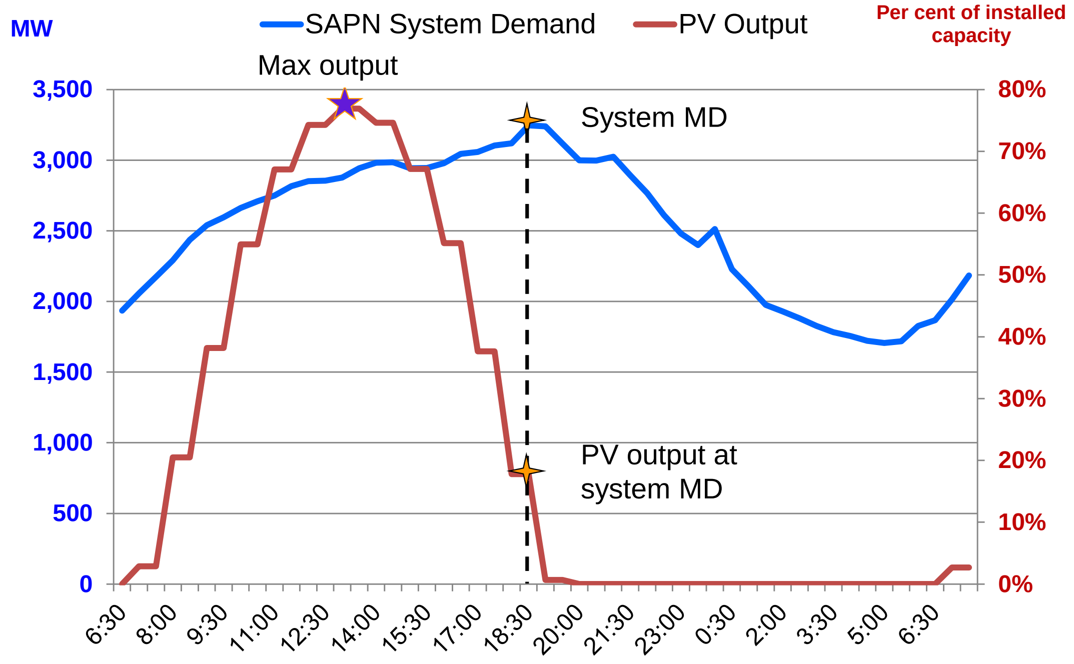
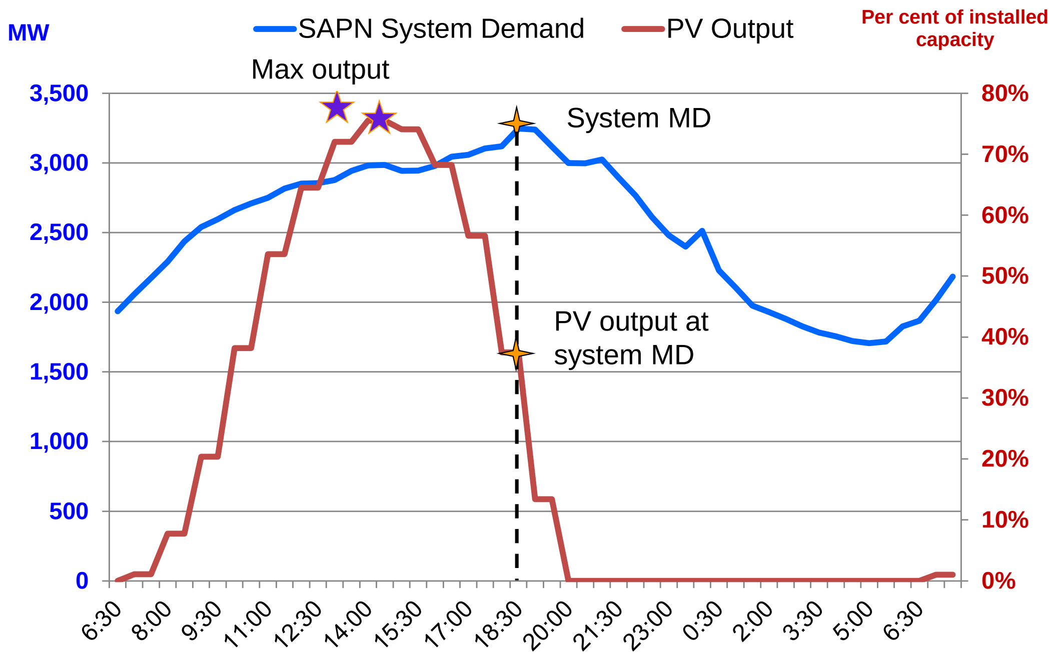


Figure 3.14
Output from a West-oriented PV is higher during the system peak



We observe that:

- the system maximum demand in 2014 occurred in the half hour ending 6:30 pm (AEST);
- output from the north-facing system peaks in the half-hour ending 1 pm (AEST), but is only 18 per cent of the system installed capacity during the system peak; and
- output from the west-facing system peaks in the half-hour ending 2 pm (AEST), and is 38 per cent of the system installed capacity during the system peak.

We note that this analysis has been performed based on the most recently available data for the system load, ie, the summer of 2014. This is consistent with our analysis assessing the efficiency of *current tariffs* given the *current state of the network*.

That said, we recognise that solar PV systems have contributed to a shift in maximum demand over a number of years, such that the system peak in South Australia is now later in the day, as solar PV output diminishes. This highlights the dynamic relationship between solar PV investment, output and changes in network maximum demand.

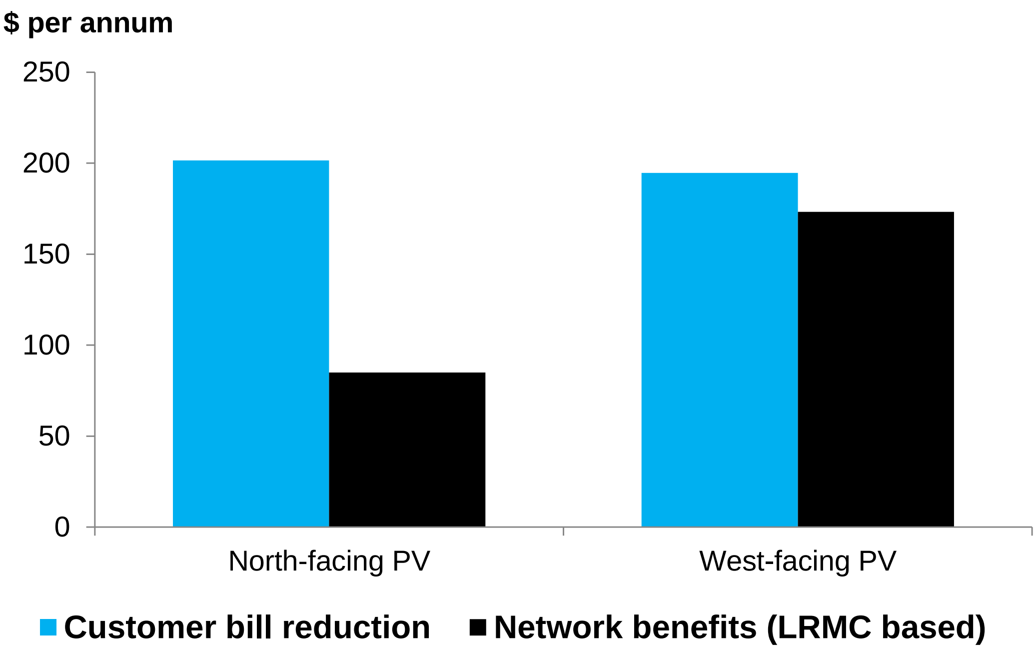
In addition, our analysis of the benefits of PV is based on the contribution they make to system wide maximum demand. It follows that the actual benefits might be larger for systems installed in locations where demand is nearing the local network capacity. Similarly the benefits might be lower for those parts of the network where capacity is relatively unconstrained given prevailing network capacity and consumption conditions. This highlights the importance of evaluating the benefits of solar PV systems to networks at a localised level.

3.2.4. Assessment of efficiency

Figure 3.15 compares the network with the customer benefits of installing PV systems with an LRMC-based estimate of the network benefits of installing those systems. We have estimated the network benefits by multiplying the generation of the PV system at the time of maximum demand by an estimate of LRMC based on SAPN's 2013/14 LV Residential figure.[8] Put another way, we have estimated the contribution of PV systems to reducing the system maximum demand, and then multiplied this value by the network LRMC.

8 We have used a value of $150 which is approximately equal to SAPN's estimate of low voltage residential customers of $156 per kVA per annum.

Figure 3.15
Customer bills reductions for North-facing PVs exceed the network benefits



We note the following:

- our estimated network bill reduction for a customer with a north-facing PV systems is around 2.4 times greater than the associated network benefits;
- in contrast, the network bill reduction for a customer with a west facing PV system is only 12 per cent greater than the associated network benefits; and
- the benefits of the west-facing PV system exceed those of the north-facing PV system, yet the north-facing system receives a greater customer benefit.

Our analysis suggests that current network tariffs are providing a price signal to PV systems that exceeds the benefits of those systems to the network. Moreover, the price signal encourages customers to use PVs in a manner that is sub-optimal for the network, ie, by orienting their PV to the north and not the west.

3.2.5. Alternative tariffs for PV systems

By definition, a flat usage based tariff cannot provide a price signal that distinguishes between consumption at different times of the day. The alternative tariff that we have developed for this case study is a time-of-use tariff that provides a strong price signal in the hours surrounding the evening peak on week days, and a weak price signal at all other times. Hereafter we refer to this as a 'sharp peak TOU'.

We have set the level of the alternative tariff by assuming that:

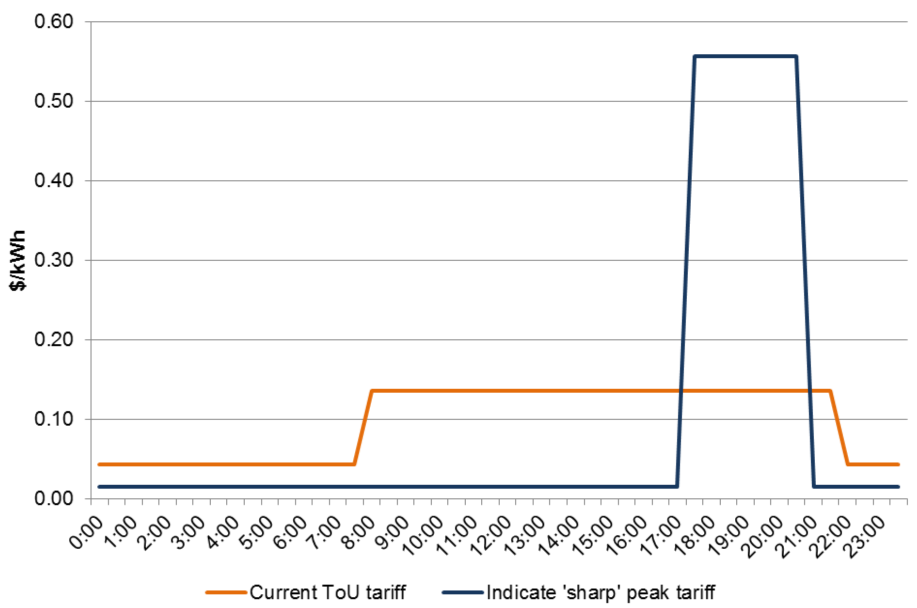
- customers in the tariff class are either representative customers with PVs or without PVs, with a breakdown of 25 per cent PV customers, 75 per cent non-PV customers;

- a sharper peak time period applies, ie, 1.5 hours either side of peak system demand;
- the new tariffs must recover the same revenue as the old tariffs (ie, there is no demand response to changes in price); and
- the fixed supply charge is held constant.

The new tariff scheme is then calculated by determining the set of peak and off-peak charges that ensure the same revenue is recovered and that the difference in the bill under the tariffs is equal to the marginal impact of a solar PV system on the grid, ie, the network LRMC multiplied by the reduction in peak demand resulting from PV. This calculation assumes no change in consumption in response to the change in tariff.

Figure 3.16 shows the resulting indicative 'sharp' peak tariff from this process. The tariff during the peak period is significantly higher than the peak period tariff under the current ToU tariff.

Figure 3.16
Current ToU tariff and indicate 'sharp' peak alternative tariff - Weekday

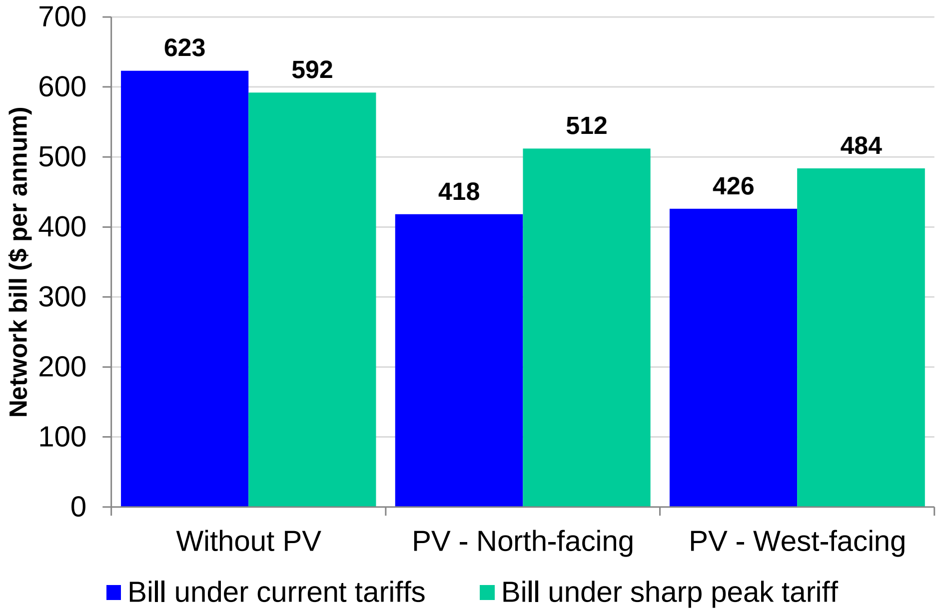


Customer impact of a shift to the narrow-peak TOU tariff

Figure 3.17 presents our estimates of the customer bill impact of shifting to the narrow-peak TOU tariff. In particular, we estimate that:

- a customer without a PV would receive a network bill reduction of around $30 per annum;
- a customer with a North-facing PV would experience a bill increase of $94 per annum; and
- a customer with a West-facing PV would experience a bill increase of $58 per annum.

Figure 3.17
The sharp-peak TOU tariff lessens the difference in customer bills



A shift to the sharp-peak tariff decreases bills for customers without PVs and increases bills for customer with PVs. However, the customers with a west-facing PV system experience a smaller reduction due to their higher PV output at peak times. Moreover, under the alternative tariff, customers receive the greatest benefits from orienting their PV systems westwards.

We recognise that our analysis represents a significant simplification of the problem of providing price signals to customers to optimally invest in solar PV systems. In particular, our analysis has necessarily not captured the varying effects on different types of customers. For example, a customer who consumes a large proportion of their energy during the sharp peak is likely to experience a significant bill increase on this tariff.

Nevertheless, in our opinion this case study illustrates that in South Australia current usage tariffs are failing to provide customers with a price signal that promotes efficient usage of energy, and efficient investment in PV systems.

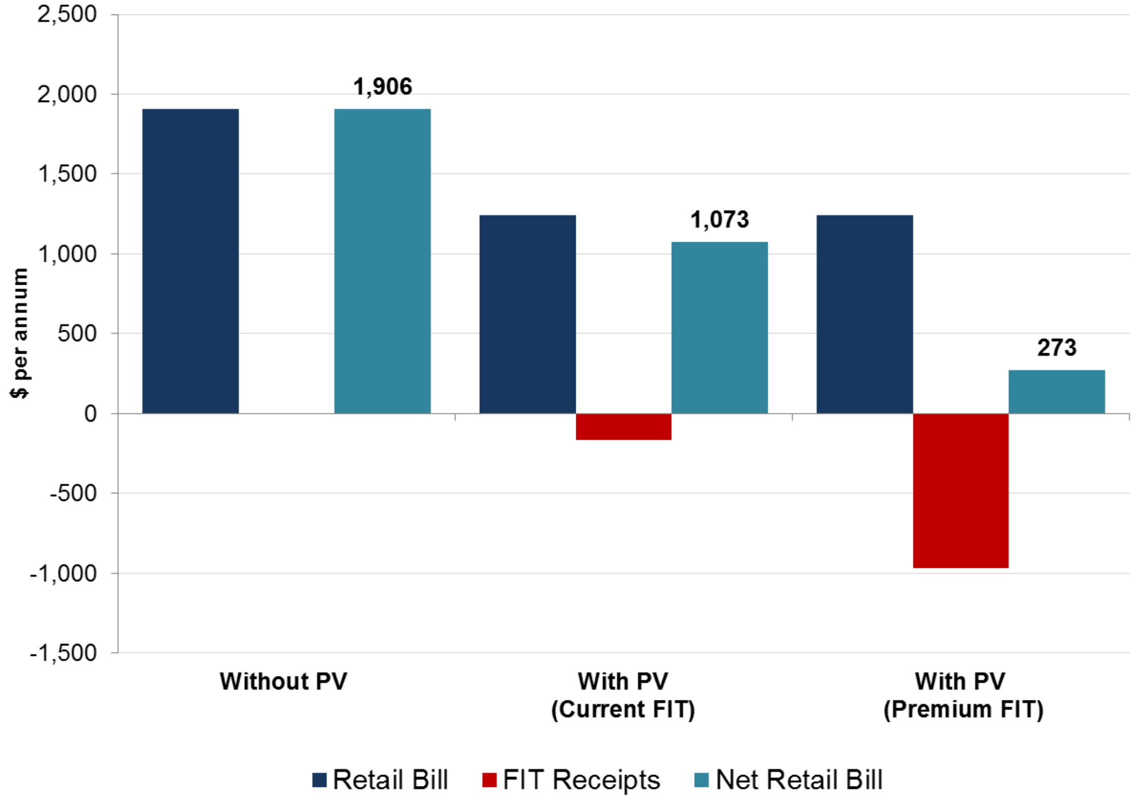
3.2.6. Retail bills under current and alternative tariffs

Figure 3.18 shows the retail bills, including feed-in-tariffs for a representative customer with and without a PV system. In each case the net retail bill is the retail bill less the receipts from the feed-in-tariffs.

In the case without the PV generator, there are no FIT receipts and the retail bill is estimated to be $1,906. In the case where the representative customer has a PV installed and received FIT receipts according to the current FIT scheme the retail bill falls relative to the case without the PV system to a value of $1,240, a drop of approximately 35 per cent. In addition the FIT in this scenario reduces the net retail bill by a further $167, leading to a drop in the net retail bill of approximately 44 per cent.

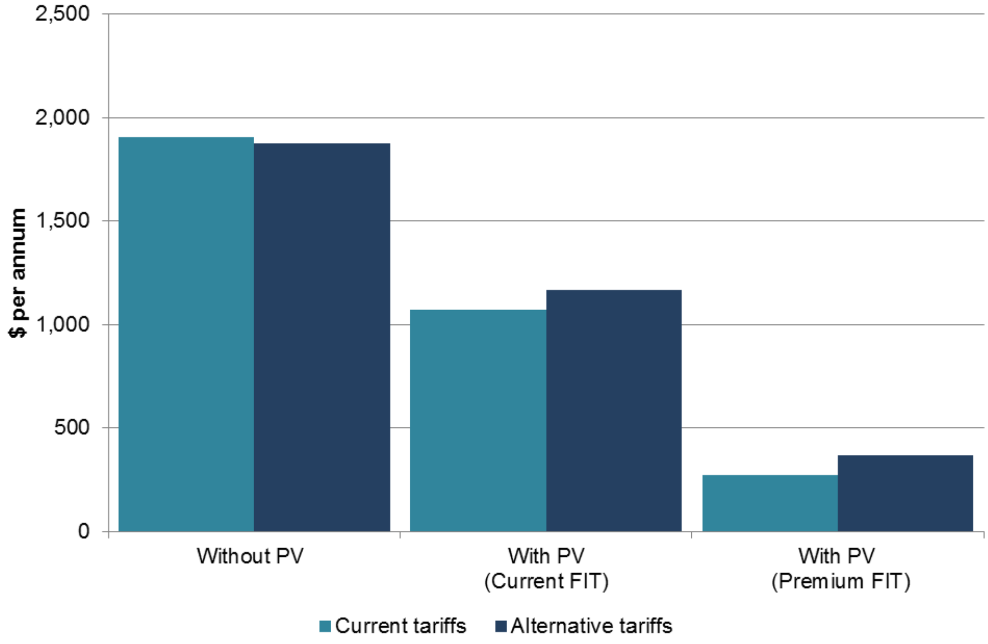
In the case of a representative customer with a PV system under a premium FIT there is an almost six-fold increase in the FIT receipts which lead to annual bill of $273, a reduction relative to the representative customer with no PV system of 86 per cent.

Figure 3.18
Estimated retail bills for a representative customer with and without a PV system



To understand the impact of the more a more efficient tariff, Figure 3.19 shows the impact of a move to the tariff on retail bills. Driven by the changes in underlying network costs, the retail bill would decrease for a customer without a PV system, by approximately 1.6%, and increase for a customer with a PV system, by 8.7% under a current FIT and 34.3% under a premium FIT.

Figure 3.19
Estimates of retail bills under current and alternative tariffs



3.3. Case Study 3 – Battery storage in combination with PV

At the moment, the prevalence of inclining block tariffs in most jurisdictions means that batteries on their own offer no benefit to a customer – there is no reason to store energy for later extraction if prices do not vary throughout the day.

However, batteries can allow households with PV systems to store excess energy generated during the day which can be used in the evening. Households who do not receive a premium FIT can therefore use batteries to increase the amount of energy that their PV system generates.

For the purposes of this case study, we have therefore restricted our analysis to cases where batteries are augmenting a PV system. However, we recognise that the use of batteries as a stand-alone technology is likely to become increasingly relevant in the future.

Case Study 3 analyses the impact of solar PV systems with battery storage in the Energex distribution region in Queensland. Table 3.3 summaries the key assumptions used in the case study.

Table 3.3
Summary of solar PV system with battery storage case study assumptions

Assumption	Description
Load profile	- Data from the System Advisory Model from the National Renewable Energy Laboratory, US
Technology	Two configurations used: 1) 2.5kW PV system and 4kWh battery and 2) 5kW PV system and 8 kWh battery
Network tariffs	All-day tariff - Residential Flat (8400)
	TOU tariff - Residential TOU (8900)
Retail tariffs	All-day tariff - Regulated Queensland All-Day Tariff (Tariff 11)
	TOU tariff - Regulated Queensland All-Day Tariff (Tariff 12)
Alternative tariff	N/A

Key Findings

Case Study 3 – Battery storage with a PV system

- Designing tariffs to reflect the operational characteristics of battery storage is complex and requires deeper consideration.
- Current tariffs are not well suited to efficiently managing a significant penetration of battery storage
- Significant retail bill savings are possible through the use of battery storage with solar PV, however the magnitude of these savings is highly dependent on the operation of the battery.

3.3.1. Load profile of battery storage systems

Battery systems provide an interesting modelling challenge. A battery load profile is itself a function of the retail tariffs paid by the household, and battery owners can be expected to use batteries to minimise their total retail bill.

We have developed a model to solve for the half-hourly operational profile that minimises a customer's retail bill subject to the following constraints:

- the battery has a maximum storage capacity – ie, 4 kWh;
- the battery can be fully charged/depleted in 1 hour; and
- customers cannot feed energy generated from the battery back into the grid.

The final assumption is an important simplification, since it avoids excessive gaming of tariffs by battery owners. Nevertheless, we will demonstrate that even with this assumption batteries may present challenges for network businesses.

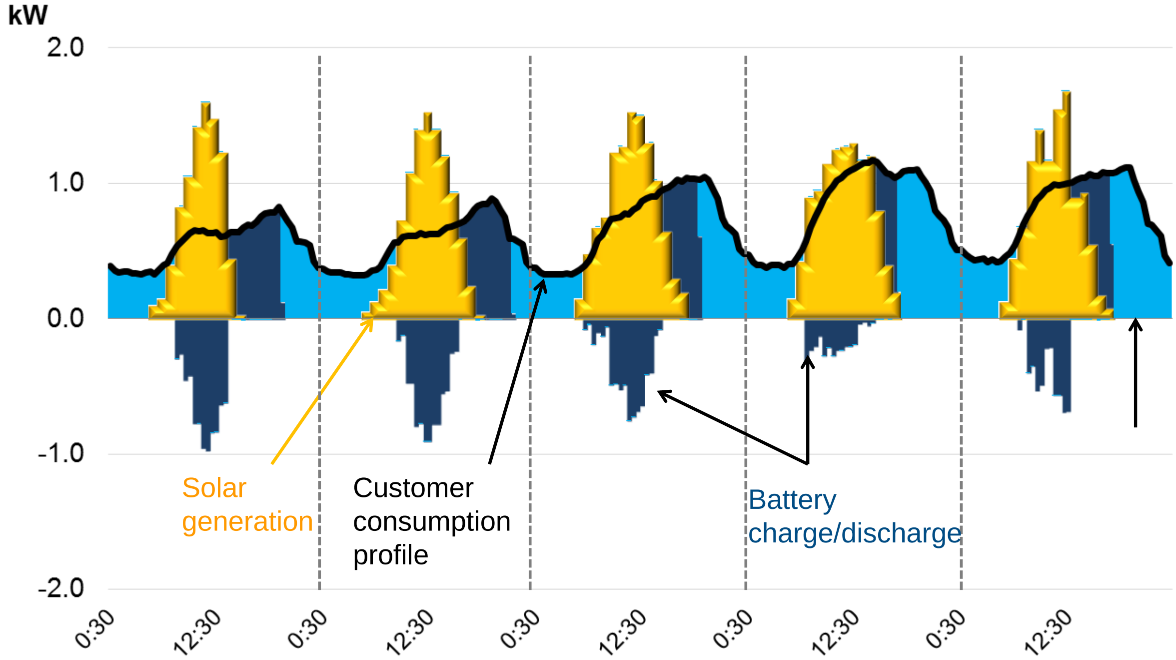
Our analysis assumes a 2.5 kW PV system, which is a moderate sized PV for a standard household. We adopted the same process to generate solar traces as for the PV case study,[9] but for this study we have only considered a north facing PV system.

We have also performed a sensitivity examining the effect of 'oversizing' a PV system. In this case, the exact same customer doubles the size of their PV system (from 2.5 kW to 5 kW) and their battery (from 4 kWh to 8kWh) and ultimately draws very little energy from the grid.

The half-hourly operational profile of the battery generally follows the pattern shown in Figure 3.20. In simple terms, the battery stores excess energy generated in the middle of the day, which it then discharges during the peak period.

[9] The typical meteorological year data was for Brisbane Airport, sourced from the Bureau of Meteorology.

Figure 3.20
Batteries store excess energy from PVs for subsequent extraction at peak periods



Note: Assumes a 2.5 kW PV with 4kWh of storage; battery can charge/be discharged entirely in 1 hour.

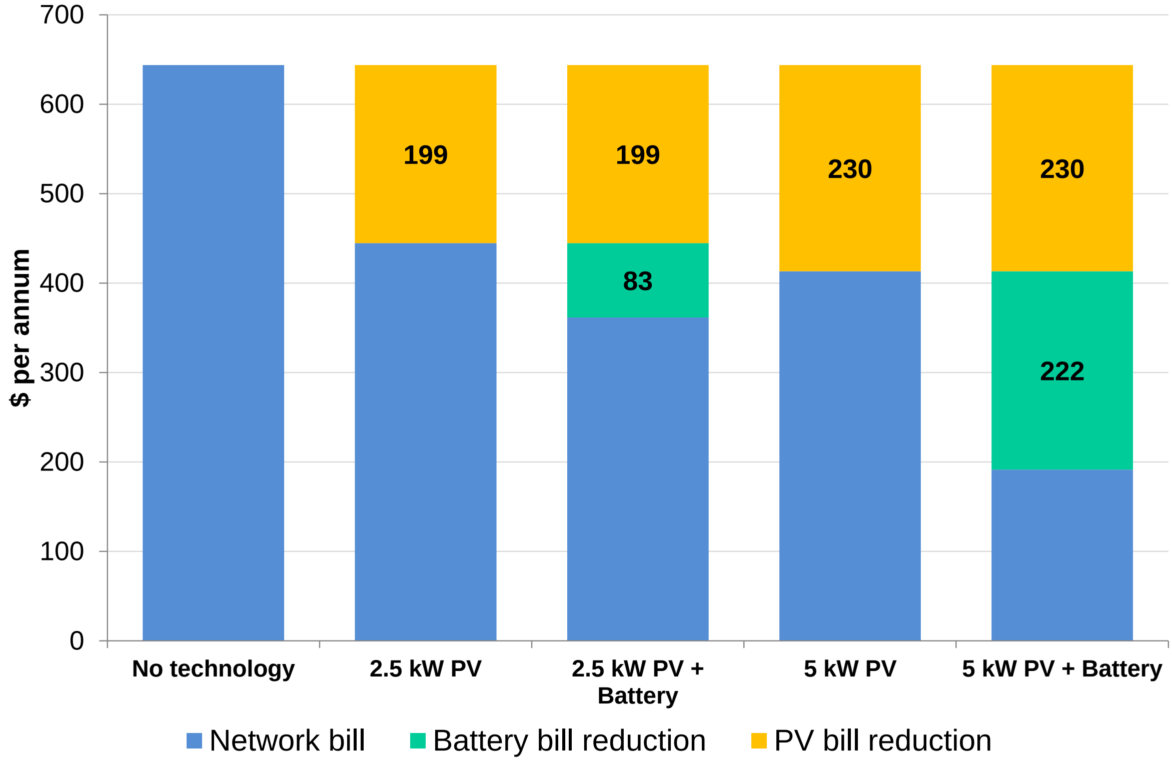
3.3.2. Estimate of network charges

Using our battery output model, we have estimated network charges for five separate cases:

- **no technology** – the base case representative customer with no PV or battery system;
- **2.5 kW PV** – a customer with a 2.5 kW PV system but no battery;
- **2.5 kW PV + Battery** – a customer with a 2.5 kW PV system and a 4 kWh battery;
- **5 kW PV** – a customer with a 5 kW PV system but no battery; and
- **5 kW PV + Battery** – a customer with a 5 kW PV system and an 8 kWh battery.

Figure 3.21 sets out our results for each of the five cases, and indicates the component of the bill reduction accounted for by the PV system versus the battery.

Figure 3.21
Battery and PV systems provide substantial network bill reductions



Note: This analysis excludes the effect of feed-in-tariffs.

We note the following:

- the 2.5 kW PV system provides a 31 per cent reduction in the customer's network bill;
- the installation of a 4 kWh battery provides an additional 13 per cent reduction when used in combination with the PV system;
- the 5 kW PV system results in only a marginal decrease in the customer's bill over and above the 2.5 kW PV system, mainly because most of the additional energy is fed back into the grid; and
- the 8 kWh battery system together with the 5 kW PV increases the customer benefits derived from the battery, because the customer can store the large quantities of excess energy generated during the day for extraction at peak times.

3.3.3. Estimate of network benefits

The potential of batteries to reduce loads at peak times offers the promise of significant network benefits. However, it is important to note that battery systems will be programmed to respond to retail tariffs and not to network requirements. Put another way, battery owners will (sensibly) operate their batteries to maximise their own welfare rather than to reduce future network costs.

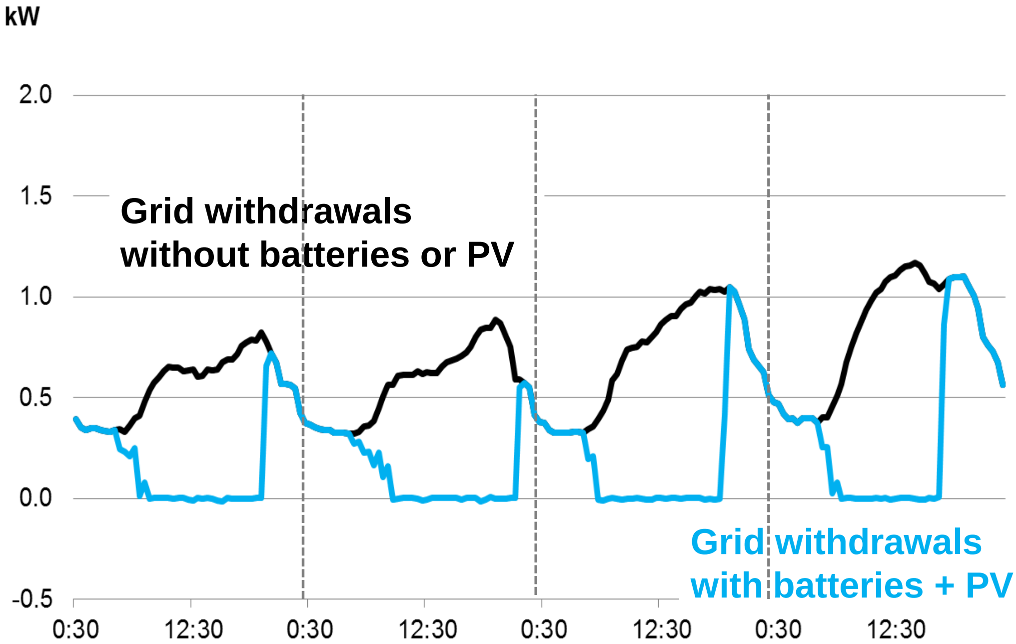
The benefit of battery technology is it allows a customer to manage the bill risks arising from tariff structures that provide better signals about the network costs imposed from electricity use during particular times of the day or year (ie, coincident with maximum system demand). The benefit of this technology is therefore related to the value customers place in having flexibility about the time of electricity consumption, compared to the costs of the battery systems.

We have not, however, explicitly estimated the benefits of PVs and batteries to the grid. In our opinion, such an estimate is misleading and open to misinterpretation, because it fails to recognise that the battery systems are responding to the price signals provided to the customer through prevailing tariff structures. Rather, we describe the potential effect of PV with battery storage on the load profile under current tariffs. This analysis allows us to understand the potential impact of an increasing penetration of batteries and provide some insight into factors that need to be considered when designing tariffs for use with battery storage.

To illustrate the effect of a solar PV system and battery storage on the load profile of a consumer the remainder of this section looks at grid withdrawals and battery charge and discharge assuming the current flat and ToU tariffs and a 2.5 kW PV system with 4kWh of battery storage.

Figure 3.22 shows the effect that the combination of battery and PV systems can have on a customer’s load profile under a flat tariff structure. In this example, we can see that a customer’s consumption can be lessened considerably through the use of a battery system. Indeed, we note that with a sufficiently large PV and battery system, it is possible to reduce consumption from the grid to zero – ie, to ‘go off grid’.

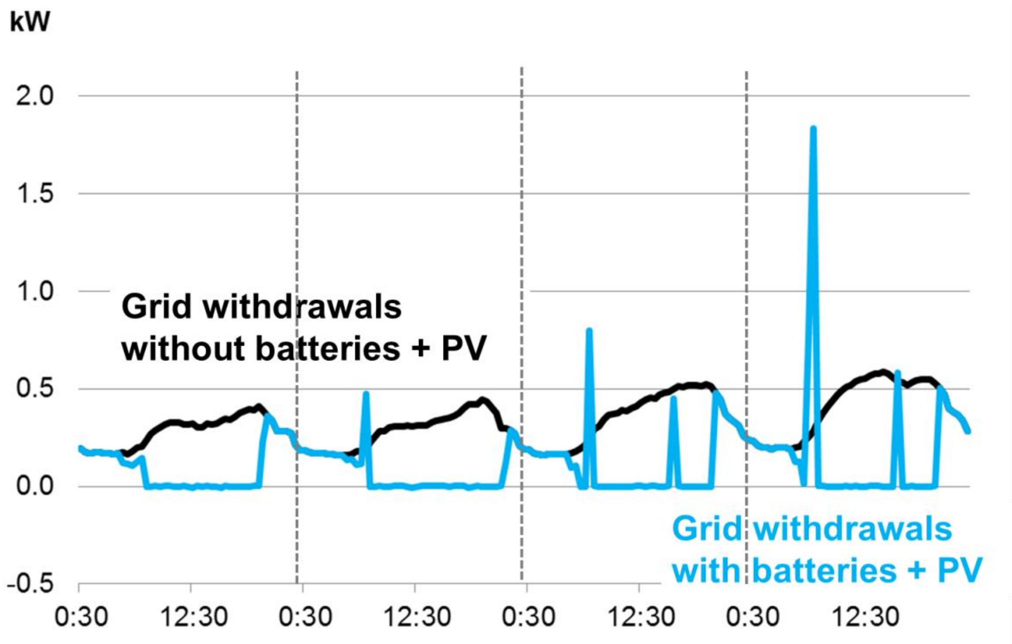
Figure 3.22
Batteries together with PVs have the potential to lessen demand at peak times



The analysis indicates that for the simple case of a flat tariff, the behavior of the battery system is relatively stable and has the potential to achieve reliable reductions in peak demand. However, the resulting behavior of the battery system can be potentially more unpredictable when subject to other tariff structures.

Figure 3.23 shows an indicative consumption under a TOU tariff for a consumer with the same battery storage and a solar PV system and the same set of parameters. The introduction of step changes in tariff rates means that the charge and discharge patterns of the battery can be highly variable as it tries and 'game' the changes in the tariffs. In the example shown, the sharp changes in tariffs between the off-peak, shoulder and peak periods means that the battery attempts to withdraw from the grid in the period immediately preceding a tariff increase.

Figure 3.23
Grid withdrawals w/ and w/o battery storage - ToU tariff



This phenomenon is a function of the technical assumptions made in conducting the analysis; nevertheless the analysis highlights the potential impact of battery storage when exposed to tariffs that are not designs for their use. In order to mitigate these potential issues, with large penetration of battery storage technical constraints will likely need to be placed on battery operation to ensure that they operate in the interests of the broader grid.

3.3.4. Assessment of efficiency

Given that batteries have the ability to response to price signals in a real-time manner, the price signals that they are exposed to need to be designed accordingly. In the context of batteries the question of efficiency is not around the level and structure of tariffs, but rather around the mechanism by which the incentives to which batteries are subject to change with varying system conditions. Given the ability of battery storage to react to prices in real time, a static set of prices will never provide an efficient incentive to consumers; rather a framework for the calculation of prices needs to be developed.

Given the potential for perverse outcomes with the large scale use of battery storage a potential solution to the question of efficiency may only be reached through some form of regulated or centralized approach to battery operation.

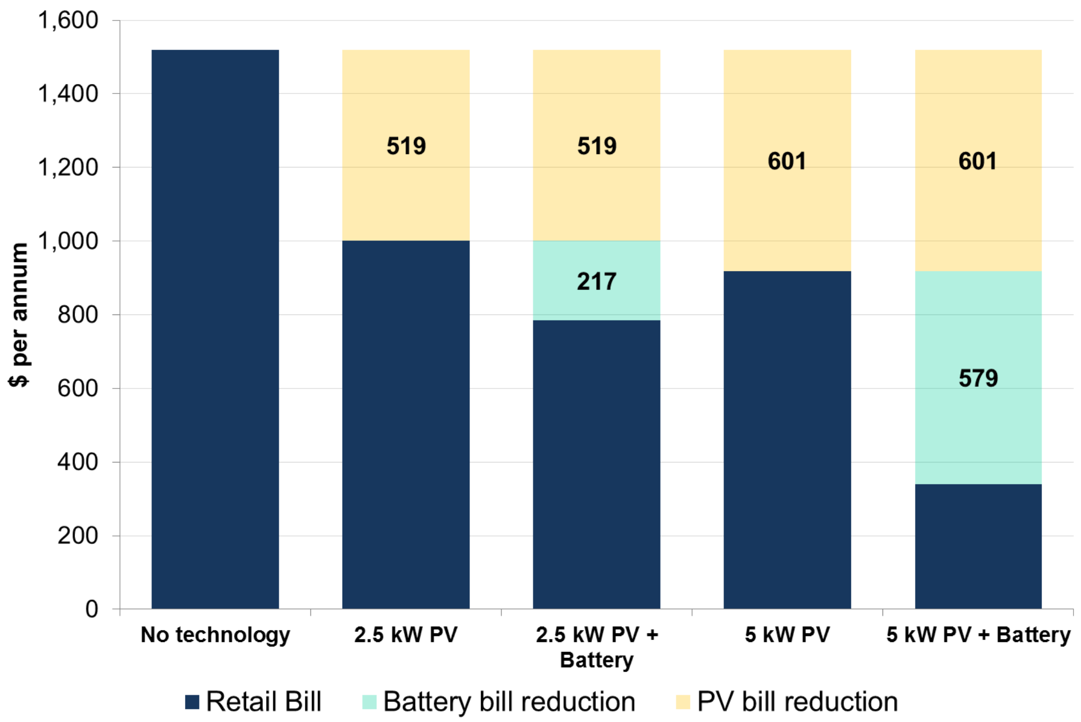
3.3.5. Retail bills under current and alternative tariffs

Figure 3.24 shows the estimated retail bills for a representative customer in the Energex distribution region subject to an inclining block tariff using a range of battery and solar PV technologies.

Assuming the representative customer has a 2.5kW system, the PV system alone results in a saving of $519 and the addition of battery storage gives an additional reduction of $217. The combination of these two factors gives a total reduction relative to the case of no technology of 48 per cent.

Assuming the representative customer has a 5kW PV system, the PV system alone results in a saving of $601 and the addition of battery storage gives an additional reduction of $579. The combination of these two factors gives a total reduction relative to the case of no technology of 78 per cent.

Figure 3.24
Estimated retail bills for the battery storage plus PV case study



3.4. Case Study 4 – Electric vehicles

Case Study 4 analyses the impact of electric vehicles in the Ausgrid distribution region in New South Wales. Table 3.4 summaries the key assumptions used in the case study.

Table 3.4
Summary of electric vehicle case study assumptions

Assumption	Description
Load profile	Based on AEMO NTNDP electric vehicle profile
Technology	Consumption of 7.3MWh per annum
Network tariffs	All-day tariff - Residential Inclining Block (EA010)
	TOU tariff - Residential TOU (EA025)
Retail tariffs	All-day tariff - Energy Australia Domestic All Time
	TOU tariff - Energy Australia PowerSmart Home
Alternative tariff	Modified TOU as calculated by NERA

Key Findings
Case Study 4 – Electric Vehicle

- Current tariffs do not align the bill impact associated with charging an electric vehicle with the network costs incurred.
- A more efficient tariff would have a higher tariff rate during peak times and an adjustment of the peak period until later in the day.
- Under an alternative more efficient tariff and relative to an inclining block tariff, customers without an electric vehicle and those that charge their electric vehicle in a ‘standard’ way would see a minor bill increase while those who charge during off-peak time would see a significant bill decrease.

3.4.1. Load profile of electric vehicles

The load profile of electric vehicles depends on the technology type of the electric vehicle. Standard electric vehicles commence charging the moment the user plugs the vehicle into the socket. ‘Smart’ electric vehicles are programmed to charge during off-peak periods, ie, a system is installed that allows for the timing of charging to be controlled.

We have used electric vehicle load profiles developed by the AEMO to develop two load profiles for electric vehicles for Sydney, namely:

- a standard electric vehicle consumption profile where charging commences when the user arrives home; and
- a 'smart' electric vehicle consumption profile where charging occurs during off-peak periods from 11 pm to 6 am.

3.4.2. Estimate of network charges

Figures 3.25 and 3.26 present our estimates of the network charge under an all-day inclining block tariff and TOU tariff. [10] We have estimated network charges for three separate cases:

- **no electric vehicle**– a base case representative customer that consumes around 7.2 MWh a year and does not have an electric vehicle;
- **standard electric vehicle** – a base case representative customer that also has a standard electric vehicle and consumes an additional 7.3 MWh a year (14.5 MWh a year in total); and
- **smart electric vehicle** – a base case representative customer that also has a smart electric vehicle and consumes an additional 7.3 MWh a year (14.5 MWh a year in total).

The increase in the network charge for the two electric vehicle types varies significantly depending on the current network tariff of the customer. The base case representative customer pays:

- an additional network charge of $1,392 under an all-day inclining block tariff, regardless of the electric vehicle type; and
- an additional network charge of $836 under a TOU tariff with a standard electric vehicle, significantly more than the $192 increase in network charge with a 'smart' electric vehicle.

[10] We have used the Network Use Of System (NUOS) charge for the purposes of calculating network charges for Sydney. We have adopted this approach because of the declining block nature of all day DUOS tariff, which does not charge for block 3 usage, meant a customer may only pay a minor increase in DUOS charges even if their consumption has increase substantially because of electricity vehicles.

Figure 3.25
Network bill impact of EV adoption – Inclining block tariffs

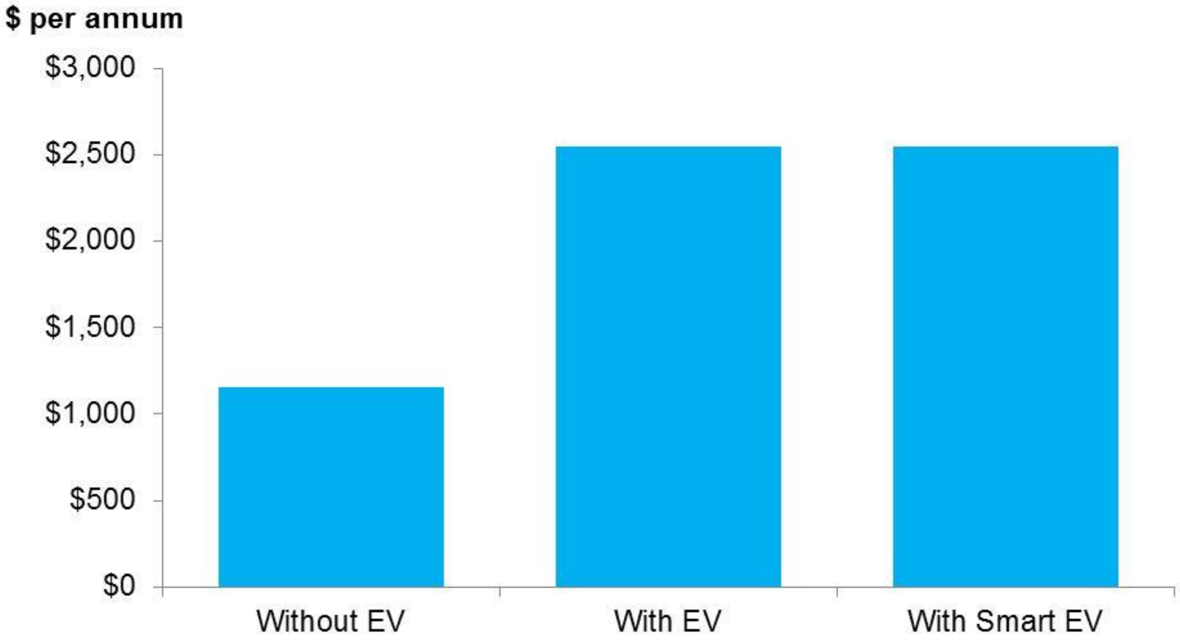
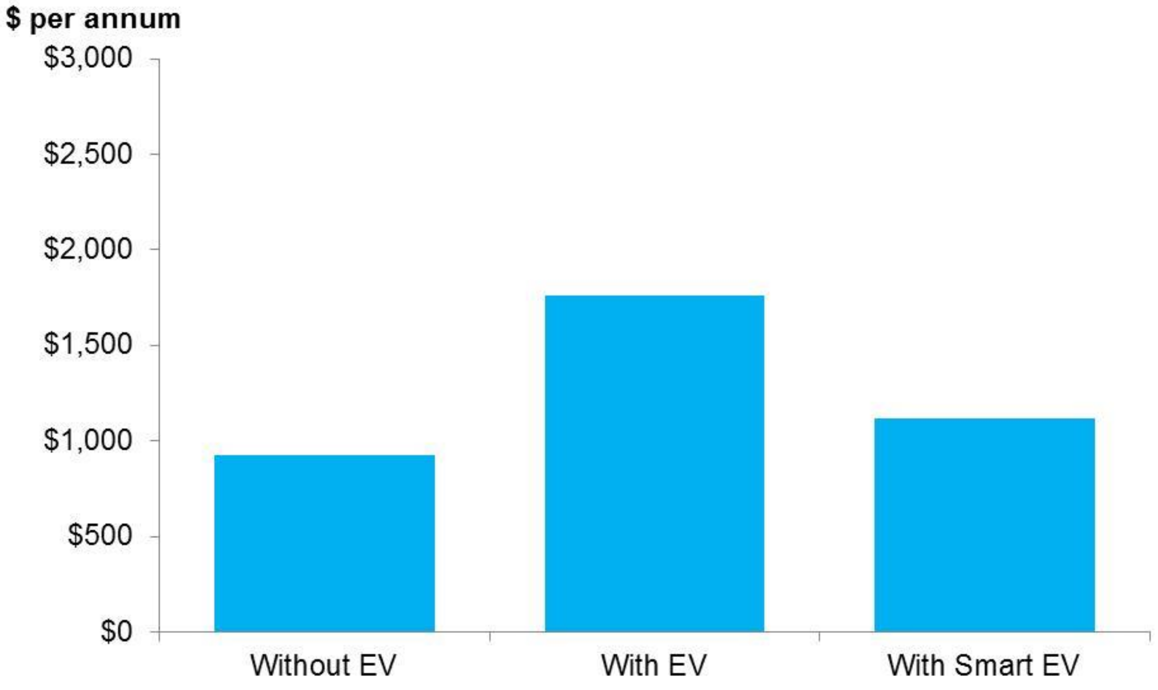


Figure 3.26
Network bill impact of EV adoption – Time-of-use tariffs



3.4.3. Estimated network costs of electric vehicles

The effect that electric vehicles have on network costs depends on when electric vehicles commence charging and so the type of electric vehicle.

Figure 3.27 shows the load profile of a standard electric vehicle and the timing of max demand at different bulk supply points. In general, most bulk supply points experience peak demand between 4 pm and 8 pm. Our analysis shows that a standard electric vehicle's electricity consumption tends to ramp up or peak around this time, and so can significantly contribute to maximum demand and network costs.

Figure 3.27
EV consumption peaks close to maximum demand at many BSPs

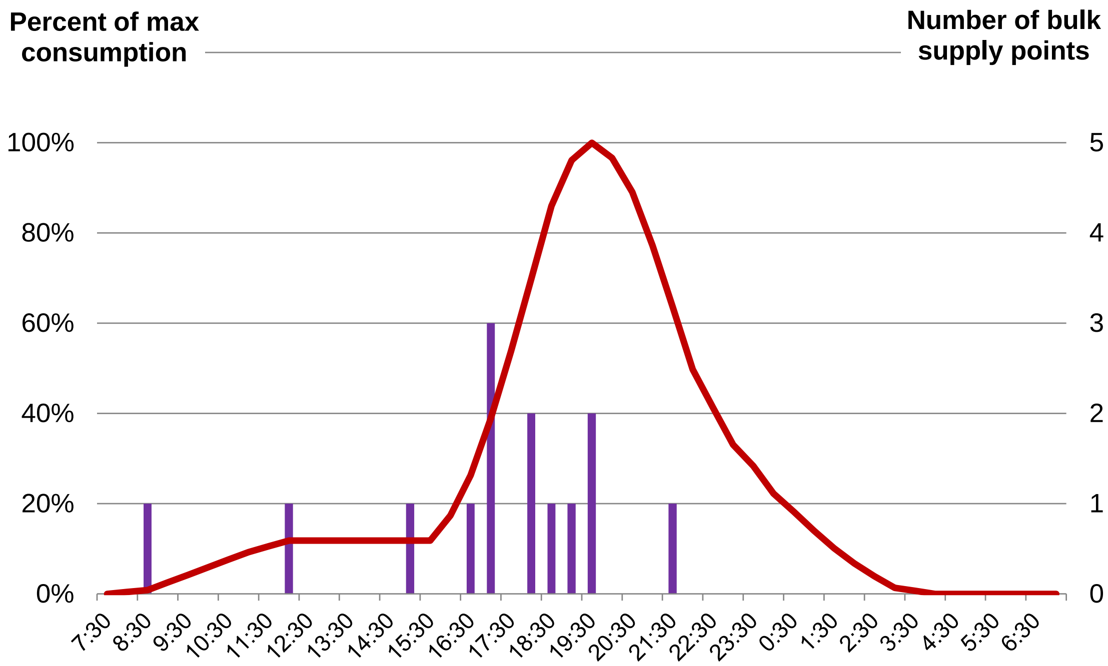
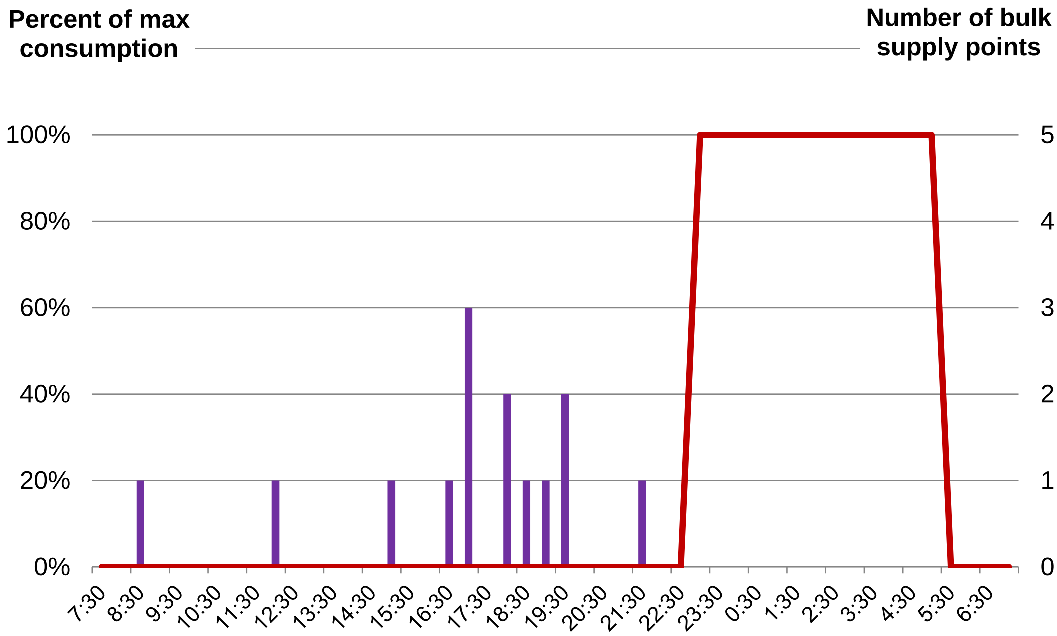


Figure 3.28 shows the load profile of a 'smart' electric vehicle and the timing of max demand at different bulk supply points. 'Smart' electric vehicles are programmed to charge during off-peak periods. Consequently, the network costs of 'smart' electric vehicles are essentially zero on the basis of maximum demand

Figure 3.28
'Smart' EVs can be programmed to avoid bulk supply point max demand



3.4.4. Assessment of efficiency

Figure 3.29 compares the increase in a customer's network bill with an LRMC-based estimate on a per kW basis. The network cost is calculated based on a 1.4 kW electric vehicle's contribution to network max demand, which we have estimated to be zero kW for a 'smart' electric vehicle and 1.3 kW for a standard electric vehicle.[11] We then compare this with an estimated LRMC of $160 for the Ausgrid network.

We note that:

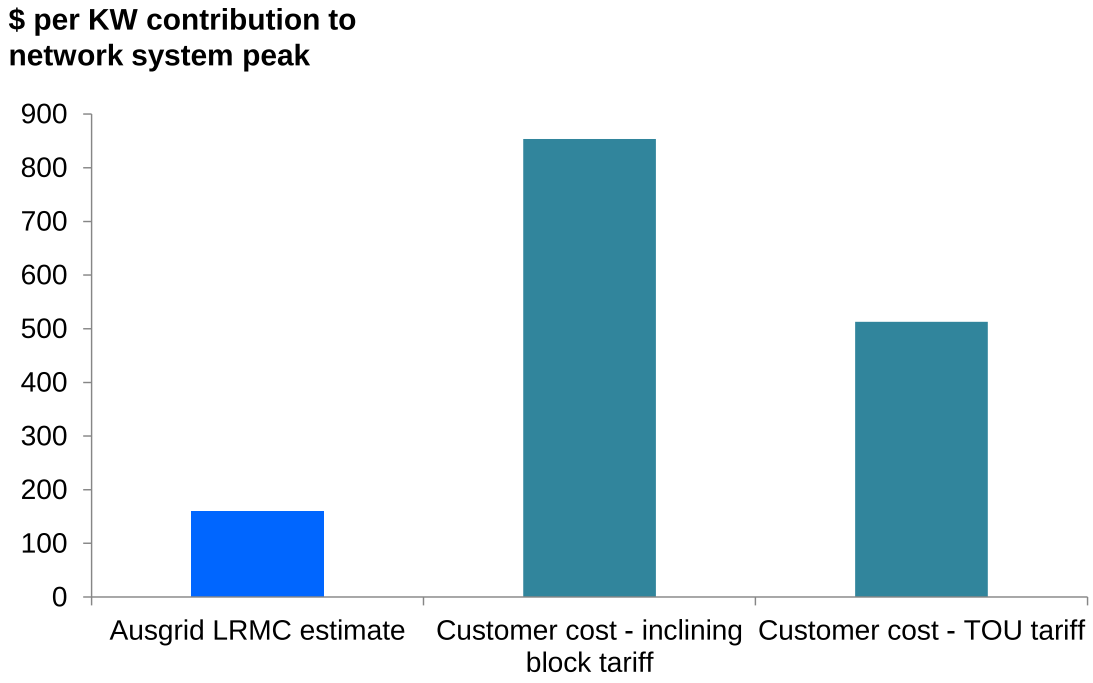
- while standard electric vehicles commence charging around or when the network is at its maximum demand, customers pay a high network charge because of electric vehicles have a high capacity factor;
- a customer could pay significantly more under an inclining tariff, particularly if most of the additional usage falls into the third pricing block;
- an inclining block tariff does not provide a signal to customers to adopt 'smart' electric vehicles';
- 'smart' electric vehicles contribute practically nothing to maximum system network demand; and

[11] For the purpose of assessing efficiency, we have selected one of the bulk supply points that resembles a typical residential load and estimated how electric vehicle contribute to maximum demand.

- under TOU tariffs, consumers are provided with a price signal to adopt 'smart' electric vehicles.

We note that the lower customer cost for TOU tariffs is partly attributable to discounting of the TOU tariffs by Ausgrid.

Figure 3.29
Standard EVs pay a network charge that significantly exceeds their network cost

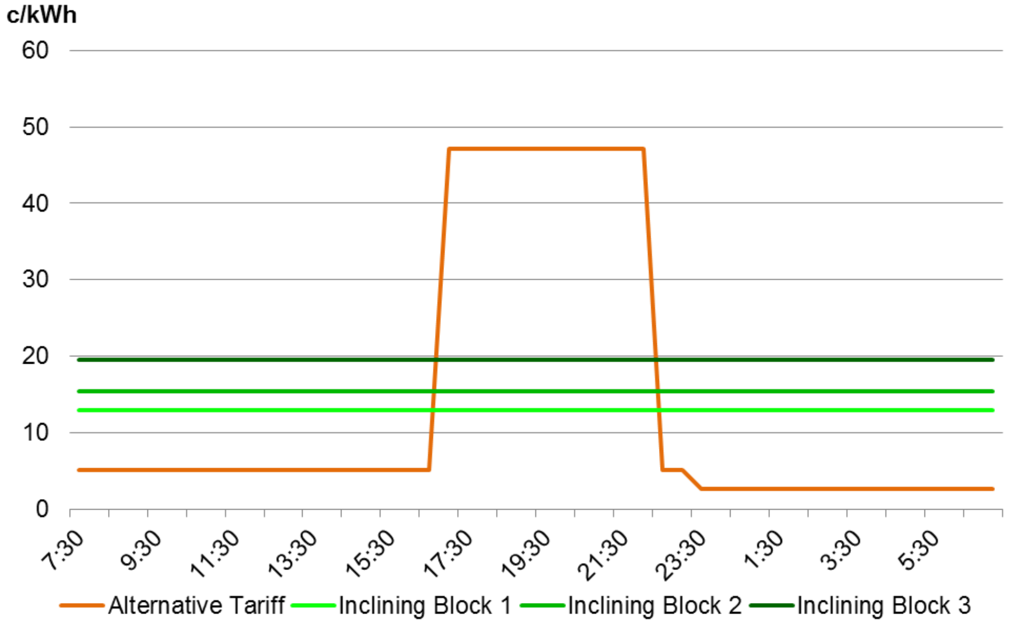


3.4.5. Alternative tariffs for electric vehicles

The current inclining block tariff does not provide a price signal to customers to adopt a 'smart' electric vehicle or charge during the off-peak. Figure 3.30 shows the alternative tariff that we have designed. The alternative tariff is based the existing time-of-use tariff with a few minor modifications, comprising of:

- adjusting peak tariffs so that the alternative tariff recovers the same amount as existing inclining block tariffs; and
- redefining peak and shoulder periods to cover some of the high demand events later in the day.

Figure 3.30
Alternative tariffs to encourage the uptake of 'smart' EVs or charging during off-peak

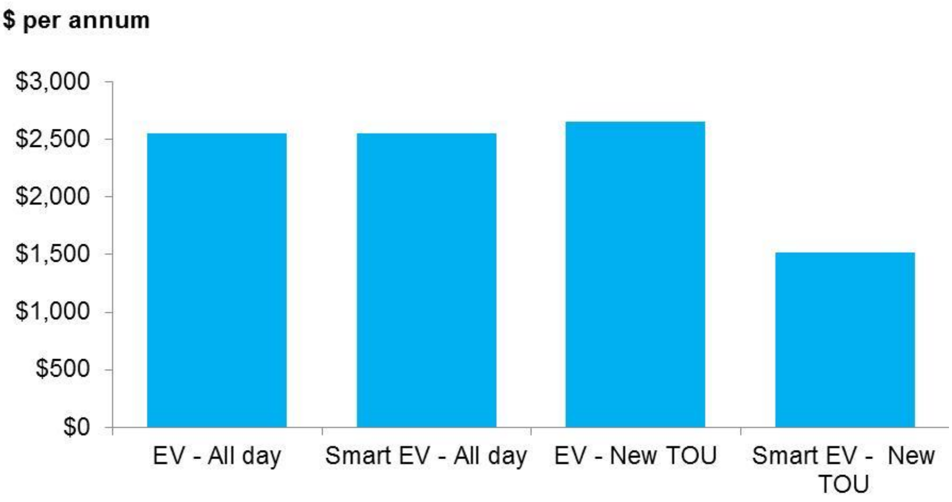


Customer impact of a shift to the new Time-of-Use Tariff

Figure 3.31 presents our estimates of the customer bill impact of customers with EV shifting to the new TOU tariff. In particular, we estimate that, shifting from the inclining block tariff:

- a customer with a standard EV would experience a bill increase of $107 per annum; and
- a customer with a smart EV would experience a bill reduction of $1,034 per annum versus the all-day tariff.

Figure 3.31
Alternative tariffs to encourage the uptake of 'smart' EVs



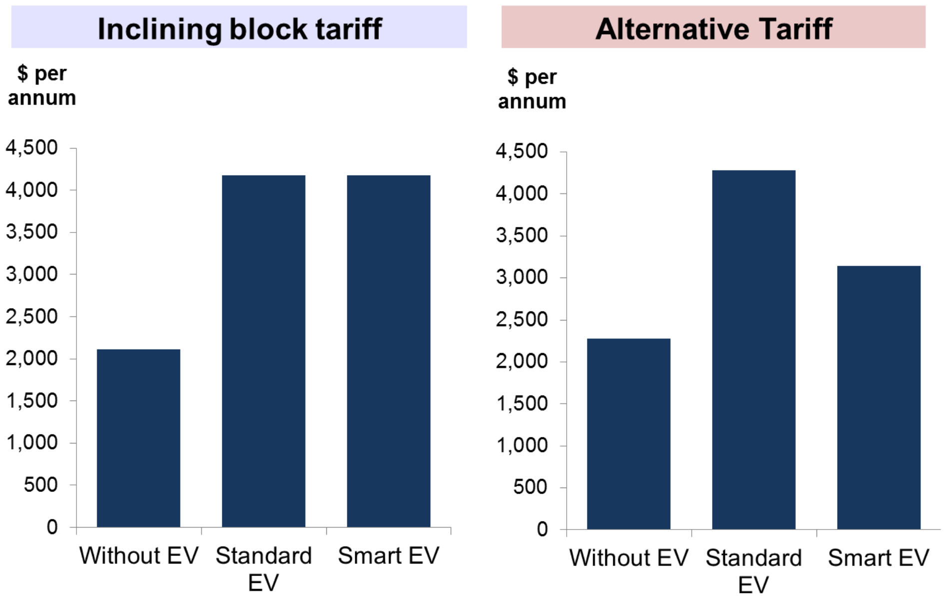
3.4.6. Retail bills under current and alternative tariffs

Figure 3.32 shows the estimated retail bills for a representative customer with an electricity vehicle under an inclining block tariff and the alternative TOU tariff. The expected revenue under these two tariffs is identical and the bills have been estimated assuming a standard profile of electricity vehicle charging as well as a 'smart' approach to EV charging which involves charging during off-peak times.

Assuming an inclining block tariff, the retail bill for a representative customer without an electric vehicle is estimated to be $2,111 and with the addition of an electric vehicle with both a standard and smart charging pattern, the retail bill is estimated to be $4,176.

Assuming the alternative TOU tariff, the retail bill for a representative customer without an electric vehicle is estimated to be $2,277[12]. With the addition of an electric vehicle with a standard charging pattern the retail bill is estimated to be $4,283. The retail bill assuming the addition of an electric vehicle with smart charging is $3,142.

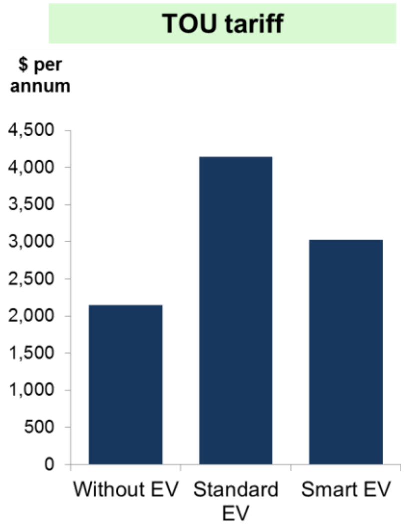
Figure 3.32
Estimated retail bills under inclining block and alternative tariff



Assuming a TOU tariff, the retail bill for a representative customer without an electric vehicle is estimated to be $2,146. With the addition of an electric vehicle with a standard charging pattern the retail bill is estimated to be $4,145. The retail bill assuming the addition of an electric vehicle with smart charging is $3,021, a value which is significantly lower than standard charging due to the lower tariff for off-peak times under a TOU tariff relative to an inclining block tariff.

12 Note that the difference in retail bills for a consumer without an electric vehicle between the inclining block tariff and alternative tariff is due to the difference in fixed charges assumed between the two scenarios. The fixed charge for the alternative tariff is based on the fixed charge for the standard TOU tariff.

Figure 3.33
Estimated retail bills under TOU tariff



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