2018 Solar Feed-in Tariff Review

A FINAL REPORT PREPARED FOR IPART

March 2018

2018 Solar Feed-in Tariff Review

2018 Solar Feed-in Tariff Review

Figures

1 Introduction

The Independent Pricing and Regulatory Tribunal (IPART) has been asked by the NSW Government to recommend a voluntary benchmark range ("benchmark range") for solar feed-in tariffs (FiTs). IPART has been undertaking this task for around six years, and over this time a methodology has been developed in consultation with stakeholders.

For this 2018 review, IPART has been asked to recommend a benchmark range for the next three years. As part of this review process, IPART will release an issues paper that invites comments from stakeholders on possible improvements to our methodology.

1.1 IPART's Terms of Reference

The Terms of Reference to IPART require IPART to determine:

- The voluntary benchmark range for solar feed-in tariffs paid by retailers for electricity produced by complying generators supplied to the distribution network.
- Time dependent benchmark ranges paid by retailers for electricity produced by complying generators and supplied to the distribution network during different times of the day.

1.2 Frontier Economics' engagement

Frontier Economics has been engaged by IPART to provide expert advice to ensure that the methodology used to determine the solar FiT benchmark range over the next three years is robust. Specifically, we have been engaged to:

- Review the existing methodology for the solar feed-in tariff benchmark range to determine whether it captures all relevant values for solar PV exports to the grid, given the NSW Government's terms of reference.
  - For example, are there any network benefits that should be incorporated?
- Undertake analysis, and make recommendations on key elements of the methodology including:
  - the appropriateness of a 5% contract premium
  - the appropriateness of a 40-day averaging period for futures prices
  - the solar premium modelling approach which uses only historical data, and can be sensitive to historical spot price volatility around the middle of the day that may not be representative of the future (for example, could a

forward-looking view of spot price volatility be incorporated in the methodology)

- whether there is sufficient half-hourly PV export data from the Essential Energy and Endeavour Energy network areas to include these in the analysis
- how best to incorporate time-varying benchmark ranges as required by the terms of reference
- any other areas where the consultant considers the methodology could be improved.

1.3 Structure of report

This report is structured as follows:

- Section 2 provides a brief overview of IPART's current methodology.
- Section 3 summarises the key issues to be addressed in the report.
- Section 4 discusses the approach to estimating solar FiTs.
- Section 5 considers the approach for forecasting patterns of solar PV exports.
- Sections 6 through 9 consider various potential components of the FiT.
- Section 10 discusses the structure of solar FiTs.

2 Overview of IPART's existing methodology

IPART has been recommending a voluntary benchmark range for solar feed-in tariffs (FiT) for the last six years.

Over this time IPART's methodology has been relatively consistent. IPART's methodology for recommending the voluntary benchmark range is based on the fact that retailers financially benefit by on-selling electricity which has been exported to the grid by customers with solar PV. This financial benefit is gained because retailers avoid paying several of the cost components typically associated with supplying electricity to their customers.

At a high level, IPART calculates the financial benefit to retailers on the basis of the following four components:

- the forecast average wholesale electricity price in NSW
- the 'premium' that solar electricity earns over the average wholesale price
- the loss factor applicable to NSW, and
- NEM fees and charges.

The first two of these four components are estimated and the remaining two can be collected from publicly available sources.

2.1 Forecasting average wholesale electricity prices

To forecast the average wholesale electricity price, IPART use daily prices for NSW base load electricity contracts for the coming financial year. Spot prices are inferred from these futures prices by:

- taking a 40-day trading average of the ASX contract price for the coming year, and
- removing an assumed contract premium of 5 per cent to convert contract prices to expected spot prices.

This provides a forecast of the average spot price for the coming year.

2.2 Solar premiums

The solar premium is the ratio of **annual solar PV export-weighted electricity price** to the **annual time-weighted electricity price:**

- The annual solar PV export-weighted electricity price is the average electricity price across the year when the half-hourly electricity prices are weighted by how much electricity is exported from solar PV panels in each half-hour.

- The annual time-weighted electricity price is the arithmetic average of the half-hourly electricity price across the year.

Simply put, the solar premium captures how much solar PV export occurs, on average, at high or low price times. A flat solar PV export profile results in the output-weighted price being equal to the time-weighted price, and a solar premium of one. Solar PV exports tending to occur at higher-price times will increase the output-weighted price, but not the time-weighted price. This will result in a solar premium greater than one. Solar PV exports tending to occur at lower-price times will decrease the output-weighted price, but not the time-weighted price. This will result in a solar premium less than zero.

2.2.1 Data

In IPART's most recent review[1] of the solar FiT, for 2017/18, they calculated the solar premium using historical half-hourly solar PV export data and historical half-hourly spot prices for NSW from 2009/10 to 2015/16.

The information IPART used for solar PV exports came solely from customers in Ausgrid's network area. This was because there were a large number of customers who had time-of-use meters in Ausgrid's network area whereas the other network areas – Endeavour Energy and Essential Energy – did not, and therefore could not provide sufficient data seeing as most of their customers were still on accumulation meters.

The current sample which IPART obtains from Ausgrid is a random sample of business and residential customers that have solar PV.

2.2.2 Modelling methodology

IPART uses a Monte Carlo simulation process to estimate the solar premium. This involves the following three step process.

Aggregation

This step involves creating aggregate half-hourly profiles for each meter class and year of data. These profiles are created by summing half-hourly solar PV exports of each sampled customer for each half-hour. Once these profiles are created, they are normalised to 1 GWh. Normalisation is done to allow for easier comparability; it does not interfere with the correlation between spot prices and solar PV exports, which means that it does not affect the calculation of the solar premium.

[1] IPART, *Solar feed-in tariffs – Benchmark range 2017-18*, Final Report, June 2017

Simulation

The Monte Carlo simulation is run by creating 5,000 synthetic years from the historical data. Each year consists of 365 days, and the half-hourly solar PV export and spot price data for each day is extracted from a pool of comparable historical days. A comparable historical day is defined as any day with the same name within the same quarter. So in creating a synthetic Monday in January, a comparable day would be any Monday within the first quarter.

Calculation and generation of solar premiums

After running the simulation, IPART calculates 5,000 solar premiums, and then generates a distribution. The distribution is then used for summary statistics such as the median, 25^{th} and 75^{th} percentile.

IPART uses the 25^{th} percentile solar premium as opposed to the median. This decision is based on the view that the high prices seen during the middle of the day in 2009/10 and 2010/11 will not be representative of future years.

2.2.3 Avoided losses

Solar PV exports have the added benefit to retailers of being generated and exported close to where electricity is consumed. Conversely, centralised utility-scale electricity needs to be transported long distances through both transmission and distribution networks. There are losses associated with the transport of electricity, which for the aforementioned reason, solar PV exports largely avoid.

IPART accounts for avoided losses by grossing up solar PV exports to the NSW regional reference node using an estimated loss factor. This estimated loss factor is calculated as *MLF x DLF*, where:

- The MLF measures the transmission line losses between the Regional Reference Node and each bulk supply connection point for the coming financial year, weighted by actual energy consumption at each connection point, excluding industrial customers.
- The DLF measures the distribution loss factors for small customers for the coming financial year, weighted by customers' actual consumption.

2.2.4 Avoided NEM fees and ancillary charges

Retailers pay NEM fees which are in part, based on the amount of electricity purchased. If retailers are able to on-sell solar PV exports, they reduce the amount of electricity they need to purchase in the NEM, and as such avoid some of these fees. IPART's estimates of the NEM fees and ancillary charges are based on information from AEMO.

3 Key issues to be addressed

In assessing IPART's existing methodology for determining a benchmark range for the solar FiT, there are a number of issues that we need to address.

To begin, we need to consider the appropriate method for determining a benchmark range for the solar FiT, where the benchmark range should result in no increases in retail electricity prices. There are a number of approaches that could be used. We consider these approaches in **Section 4**.

There are then a number of issues of implementation that we need to consider.

First, we need to consider the methodology for assessing when solar PV exports will tend to occur. The reason that the timing of solar PV exports is important is that the value of the supply of electricity varies according to when it is supplied: wholesale prices can vary enormously from half-hour to half-hour and the benefit of the supply of electricity in managing demand on the transmission or distribution network depends on electricity being available when demand is highest. We discuss the approach to determining when solar PV exports will occur in **Section 5**.

Second, we need to consider the value of the solar PV exports. There are a number of potential sources of value of solar PV exports in the electricity supply chain:

- Since the electricity exported from solar PV panels is used in place of electricity supplied from the wholesale electricity market, solar PV exports have a wholesale market value. The wholesale market value of solar PV exports is discussed in **Section 6**.
- Since the electricity exported from solar PV panels is supplied within the distribution network, solar PV exports potentially have a value to the electricity network by reducing the need for network investment. However, solar PV exports potentially also impose costs on the electricity network where additional investment is required to manage the volume of solar PV exports. The effect of solar PV exports on the network, and what this implies for the benchmark range for the solar FiT, is discussed in **Section 7**.
- In addition to the potential value of solar PV exports to the wholesale electricity market and to electricity networks, there are a number of other potential sources of value of solar PV exports which have been proposed or considered. We consider these other potential sources of value in **Section 8** and **Section 9**.

Third, we need to consider some issues about the way that the benchmark solar FiT should be structured. For instance, should solar FiTs differ by the time of day or the season? These issues are discussed in **Section 10**.

4 Approach

There are a number of different approaches that can be taken to estimating the benchmark range for the solar FiT.

In its previous reviews, IPART has had regard to two approaches.

First, as discussed in Section 2, IPART has previously estimated the benchmark solar FiT using an approach that estimates the financial benefit of solar exports to retailers. The logic of this approach is that in a competitive retail market it would be expected that retailers would be driven by competition to offer a FiT to their customers that reflected the financial benefit that they receive as a result of their customers' solar PV exports.

Second, IPART has also previously had regard to an approach which estimates the wholesale market value of solar PV exports. The logic of this approach is that it represents the payment that solar PV exports would receive if they were treated in the same way that exports from centralised generation were. This approach does not reflect existing market arrangements, but does provide an indication of the value of solar PV exports to the wholesale market.

A third approach is to estimate the net economic benefits of solar PV exports and base the benchmark FiT on those net economic benefits that are best recovered through the FiT on solar PV exports. Again, this approach does not reflect existing market arrangements, but it does provide a useful way of thinking about the underlying economic benefits of solar PV exports.

4.1 Our recommendation

In our view, setting the benchmark solar FiT using an approach that estimates the financial benefit of solar exports to retailers is likely to best meet IPART's Terms of Reference.

IPART's Terms of Reference require that, in conducting its investigation, IPART is to consider the following key parameters:

- there should be no resulting increases in retailer electricity prices, and
- the benchmark range should operate in such a way as to support a competitive electricity market in NSW.

In our view, setting the benchmark solar FiT using an approach that estimates the financial benefit of solar exports to retailers is consistent with each of these parameters. This approach would be expected to provide FiTs that avoid retailers needing to seek some external source of funding to cover the costs of FiTs (which would potentially lead to increases in retail electricity prices) and would be expected to result in FiTs that are consistent with those that would occur in a competitive market.

Other approaches to setting the FiT may not be consistent with these parameters.

For instance, consider what would happen if an alternative approach resulted in a benchmark range for the solar FiT that is higher than suggested by the financial benefit approach. In this case, assuming that retailers offer FiTs consistent with the benchmark, the FiT payments that retailers would make would mean that retailers would expect to make a financial loss by making those payments. If retailers expect to make a financial loss by making FiT payments, there are a number of potential outcomes:

- Retailers could decide not to supply customers with solar PV panels, in order to avoid the expected financial loss of making FiT payments. This would reduce competition for customers that have solar PV panels.
- Ultimately, however, it is likely that retailers could attempt to recover these financial losses by increasing the retail electricity price to customers that have solar PV panels. This would be a response consistent with competitive markets: since all retailers would expect to make a financial loss by making FiT payments, retailers would only be interested in supplying a customer with solar PV panels if the retail price was sufficiently high enough to compensate for this loss. Competition would not prevent this behaviour since all retailers would expect the same financial loss by making FiT payments. However, if a retailer also tried to charge that higher retail price to a customer that did not have solar PV panels the retailer would be uncompetitive.
- These financial losses could be funded externally. For instance, the subsidised payments under the previous Solar Bonus Scheme were funded through an increase in network tariffs. However, this ultimately had the effect of increasing electricity prices.

In the alternative, consider what would happen if an alternative approach resulted in a benchmark FiT that is lower than suggested by the financial benefit approach. In this case, assuming that retailers offer FiTs consistent with the benchmark, the FiT payments that retailers would make would mean that retailers would expect to make a financial gain by making those payments. If retailers expect to make a financial gain by making FiT payments, there are a number of potential outcomes:

- Retailers would likely be attracted to supply customers with solar PV panels, and competition for these customers could increase.
- Ultimately, however, this competition is likely to lead to retailers competing for these customers by offering lower retail electricity prices. This would be a response consistent with competitive markets: since all retailers would expect to make a financial gain by making FiT payments, retailers would be prepared to discount retail prices until this financial gain has been competed away.

In short, taking the existing financial arrangements that retailers face as given, setting FiTs based on the financial benefit approach is most likely to result in FiTs and retail prices that are competitive and to ensure a competitive retail market.

4.2 The rest of this report

While our view is that setting the benchmark solar FiT using an approach that estimates the financial benefit of solar exports to retailers is likely to best meet IPART's Terms of Reference, we nevertheless also have regard to the net economic benefits of solar PV exports in the sections that follow. The reason for this is that we think it is useful to understand whether the financial benefit of solar exports to retailers differs from the net economic benefits of solar PV exports and, if so, to what extent.

5 Estimating patterns of solar PV exports

In this section we consider the approach to determining the patterns of solar PV exports.

As discussed in Section 2, IPART's current approach is to use historical patterns of half-hour solar PV exports (and half-hourly wholesale electricity prices) as the basis for estimating future patterns of half-hourly solar PV exports. Specifically, IPART uses historical half-hourly prices over the period since 2009/10 as an input into the Monte Carlo simulation of the solar premium.

Our view is that the use of historical data on patterns of solar PV exports (and system prices) remains the best basis for estimating solar premiums. The alternative – making use of modelling of solar PV exports and system prices – is unlikely to capture the range of factors that drive price volatility as well as relying on historical data.

This section considers the key questions underlying this approach: should an aggregate shape be used and is the data provided by Essential Energy suitable for use in estimating the solar premium.

Of course there is another fundamental question: over what period should historical half-hourly wholesale electricity prices be used in determining the solar premium? Our view is that, at the moment, it is likely that changes over time in the patterns of system prices will be a bigger driver of changes in the value of solar PV exports and, therefore, the decision of the period to use historical data should really be driven by consideration of historical system prices. We discuss this in Section 6. However, if battery adoption becomes more widespread over coming years, then patterns of exports for customers with solar PV panels (and batteries) could become very different. If this is the case, the approach to using historical data to estimate patterns of solar PV exports may need to be reconsidered.

5.1 Use of an aggregate shape

IPART's approach is based on aggregating the solar PV exports from all of the customers within the sample group provided by distribution businesses. The result is that the benchmark range of the solar FiT should be thought of as a FiT that represents the value of solar PV exports for an average customer.

Our view is that this is a sensible approach. There is no doubt that different patterns of solar PV exports (associated with the different customers) will have different values. But this does not imply that the benchmark FiT should be tailored to different types of customers. The reason is that the different value of solar PV is driven by differences in the timing of exports and this can change from year to year even for individual customers.

However, if battery adoption becomes more widespread over coming years this may mean that adopting a different value of solar PV for customers with and without batteries makes economic sense. If patterns of exports are sufficiently different, and consistently different, between customers with and without batteries, and if these differences imply a different value of solar PV, then incentives can be improved by adopting a different value of solar PV for customers with and without batteries.

5.2 Use of Essential Energy data and Endeavour Energy data

IPART has provided us with data on solar exports provided by Essential Energy and Endeavour Energy. We understand that this data represents the solar exports from a random sample of solar customers.

We have reviewed the data from Endeavour Energy and on the basis of this review consider that there may be some issues with the data provided. We understand that IPART is discussing these issues with Endeavour Energy. We have also reviewed the data from Essential Energy. This data does not have the same immediately apparent issues as the data from Endeavour Energy, but it is notable that the data from Essential Energy does have a large number of customers with total exports that are significantly higher than in the other network areas. This might be because patterns of consumption differ between the network areas, or it could be because there are some gross-metered customers included in the data from Essential Energy. We understand that IPART is discussing these issues with Essential Energy.

Assuming that the questions about the data provided by Endeavour Energy and Essential Energy can be resolved, the only real issue that we foresee with the data provided by Endeavour Energy and Essential Energy is that the data is for a shorter period of time than the data available from Ausgrid. Depending on the historical period over which IPART decides to calculate the wholesale market value of solar PV, this may mean that the data provided by Endeavour Energy and Essential Energy does not cover enough historical years. This would increase the risk that the data that is available from Endeavour Energy and Essential Energy represents an outlier; whether this is the case will not be apparent until more years of data are available.

In principle, this need not preclude making use of the Essential Energy and Endeavour Energy data: if a relationship in the aggregate shape of solar PV exports for Essential Energy's and Endeavour Energy's sample of customers and Ausgrid's sample of customers can be established, this relationship could be used to infer what the aggregate shape for Essential Energy's and Endeavour Energy's sample of customers would be based on Ausgrid's longer data series. However, our review of the data highlights material differences in patterns of solar PV exports between the network areas. This makes it difficult to establish a relationship that can be used to infer solar PV exports in Essential Energy's area and Endeavour Energy's area, and suggests that waiting until more data is available is likely a better approach.

If data from Essential Energy's and Endeavour Energy's solar customers can be used, it does raise the question of whether this data should be:

- used to calculate a specific wholesale market value for each distribution network, which would be used only in setting a benchmark range for solar FiTs in the relevant distribution area; or
- combined with data from other distribution networks to calculate a wholesale market value for all NSW distribution networks, which would be used in setting a benchmark range for solar FiTs in all NSW distribution networks.

Our view is that the first of these approaches would provide the most efficient price signals. To the extent that patterns of solar PV exports are different in different network areas – which may be a result of different weather patterns, different decisions about the typical size of a solar PV system or different patterns of typical electricity consumption – then setting a benchmark range for solar FiTs in each distribution network provides better signals to customers about the value of the solar PV that they are likely to export. We also note that setting a benchmark range for solar FiTs in each distribution network would be consistent with the approach that retailers tend to take in setting retail electricity tariffs (with different retail tariffs in different distribution areas) and that IPART has previously adopted in regulating retail electricity tariffs. IPART's regulated retail tariffs differed by network area to take account of, among other things, different patterns of typical electricity consumption across distribution networks, and the effect that these different patterns of consumption would have on retailer's costs of supplying wholesale electricity.

6 Estimating the wholesale market value of solar PV exports

In this section we consider the wholesale market value of solar PV exports.

The wholesale market value of solar PV exports is a key component of the financial benefit of solar exports to retailers. The reason is that when a retailer's customer generates electricity from solar PV the retailer's sales to its customers are reduced only to the extent that the customer's *imports of electricity* are reduced, but the retailer's purchases of electricity from the wholesale market are reduced to the extent of the customer's *generation of electricity*. This difference – which amounts to the customer's solar PV exports – can be valued according to the wholesale electricity price.

The wholesale market value of solar PV exports also represents an economic benefit of solar PV. Exports of solar PV (and, indeed, generation of solar PV that is consumed behind the meter) displace electricity generated and sold on the wholesale market. There are costs associated with the electricity generated and sold on the wholesale market, which are reflected in wholesale prices. This means that the wholesale market value of solar PV exports represents an economic benefit.

The wholesale market value of solar PV exports is determined as the average wholesale electricity price at times when solar PV is exporting. We have discussed the approach to estimating when solar PV is exporting in Section 5. This section focuses on estimating wholesale electricity prices at those times. We discuss the approach to estimating future patterns of half-hourly electricity prices in two stages:

- Forecasting of future average wholesale electricity prices.
- Forecasting patterns of future wholesale electricity prices.

6.1 Forecasting future average wholesale electricity prices

As discussed in Section 2, IPART's current approach is to make use of futures contract prices from ASX Energy to estimate the average annual spot price for future years. Spot prices are inferred from these futures prices by:

- taking a 40-day trading average of the ASX contract price for the coming year, and
- removing an assumed contract premium of 5 per cent to convert contract prices to expected spot prices.

This section considers each of the three key elements of this calculation: the use of ASX Energy contract prices, the averaging of prices over a 40-day period and the assumption that contract prices include a contract premium of 5 per cent.

ASX Energy prices

In our view, ASX Energy prices remain the best public source of short-term forecasts of wholesale electricity prices that retailers are likely to face. For this reason, we recommend that IPART continue to use ASX Energy prices for the purpose of estimating the wholesale market value of solar PV exports.

However, given that IPART's review is for the three financial years from 2018/19 to 2020/21, it is worth bearing in mind certain limitations with the use of ASX Energy contract prices.

First, ASX Energy quarterly contracts tend to trade with reasonable frequency for around two years prior to the contract quarter. So, for instance, ASX Energy's NSW base quarterly contracts for Q1 and Q2 in 2021 have not yet begun to trade (although a 'default' price is published by ASX Energy). This means that ASX Energy prices can reasonably be used to determine the wholesale market value of solar PV exports for a year or two, but could not currently be used reliably to determine the wholesale market value of solar PV exports for three years.

Second, it is unclear what effect the introduction of the National Energy Guarantee (NEG) would have on trade in ASX Energy contracts. The NEG would place an obligation on retailers to meet their load obligations with a portfolio of resources which include a minimum amount of flexible dispatchable capacity, and an emissions level consistent with Australia's international emissions reduction commitments. If retailers are to use contracts to achieve their obligations under the reliability guarantee and emissions guarantee it would seem that retailers will need to be able to identify the generator with which they are contracting. This is not how ASX Energy contracts work; ASX Energy contracts are derivatives contracts in which contract counterparties are not identified and in which no emissions level or generation type is specified. If the NEG proceeds it would seem that either ASX Energy contracts would need to change so that retailers can use these contracts to meet their obligations under the NEG, or that trade in ASX Energy contracts will diminish or cease.

Averaging prices over a 40-day period

ASX Energy contracts trade for a number of years prior to the contract quarter. This means that the price of these contracts that is used to infer future spot prices could be based on the most recent price published by ASX Energy, or an average price over a period of time.

Generally speaking, our view is that the most recent price published by ASX Energy will provide the best information about future spot prices and also that economic decisions by retailers should be based on current market prices. However, given that trade of ASX Energy contracts can be intermittent (with contracts often not trading every day) it makes sense to average prices over a period of time, such as 40 days.

Retailers have argued that ASX Energy contract prices be averaged over a much longer period of time – such as two years – to reflect the fact that retailers will tend to buy contracts over time. Our view is that making economic decisions on the basis of historic costs is inefficient and that competition will drive retailers to make economic decisions based on current market prices. In the current circumstances – where contract prices have been increasing materially over time – making economic decisions based on average contract prices over a two year period will result in retailers pricing their electricity supply below the value of their contracts. As AGL has noted in its recent submission to the Independent Competition and Regulatory Commission, this would result in wholesale electricity costs set below market costs.[2]

Contract premium

In prior work in which we have inferred spot electricity prices from wholesale electricity prices (or vice versa) we have assumed that the contract premium is 5 per cent.

Unfortunately, observing contract premiums is essentially impossible. The reason is that the contract premium is the difference between expected spot prices and contract prices; expected spot prices cannot be observed, only spot price outcomes can. Nevertheless, by comparing contract prices with spot price outcomes some information about contract premiums can be inferred. Our most recent analysis of the contract premium, undertaken during 2017, continues to suggest that a 5 per cent contract premium is a reasonable assumption. This recent analysis examined the relationship between historical contract prices and historical spot price across the NEM, and for the full historical period for which contract prices have been published. As would be expected, there has been substantial variation in the relationship between contract prices and spot prices over time and in different regions of the NEM. Nevertheless, this analysis suggested that, on average, a 5 per cent contract premium is a reasonable assumption.

2 AGL, *Draft Report – Standing offer prices for supply of electricity to small electricity customers from 1 July 2017*, Letter to the ICRC, 30 April 2017.

6.2 Forecasting future patterns of wholesale electricity prices

Prices for ASX Energy contracts provide a useful estimate of annual average wholesale electricity prices (or quarterly average electricity prices) but do not provide information about the half-hourly patterns of wholesale electricity prices. It is these half-hourly patterns of wholesale electricity prices that are crucial to the wholesale market value of solar PV exports.

As discussed in Section 2, IPART's current approach is to use historical patterns of half-hourly wholesale electricity prices (and half-hourly solar PV exports) as the basis for estimating future patterns of half-hourly prices. Specifically, IPART uses historical half-hourly prices over the period since 2009/10 as an input into the Monte Carlo simulation of the solar premium.

Our view is that the use of historical data on patterns of system prices (and solar PV exports) remains the best basis for estimating solar premiums. The alternative – making use of modelling of solar PV exports and system prices – is unlikely to capture the range of factors that drive price volatility as well as relying on historical data.

This section considers the key questions underlying this approach: are historical half-hourly wholesale electricity prices a useful guide to future half-hourly prices; if so, over what period should historical half-hourly wholesale electricity prices be used in determining the solar premium?

Because patterns in half-hourly wholesale electricity prices will be affected by system demand, we first examine changing patterns in system demand before turning to examine changing patterns in wholesale electricity prices.

6.2.1 Changing patterns in system demand

Strong uptake of solar PV will cause demand for utility-scale electricity to fall. This is because households with solar PV generate their own electricity to meet part, or all, of their consumption, and export any excess generation into the grid. Whether solar PV generation is consumed behind the meter or exported into the grid it will displace electricity supplied by utility-scale generation. This reduction in system demand would be expected to cause a reduction in wholesale electricity prices.

Historical demand

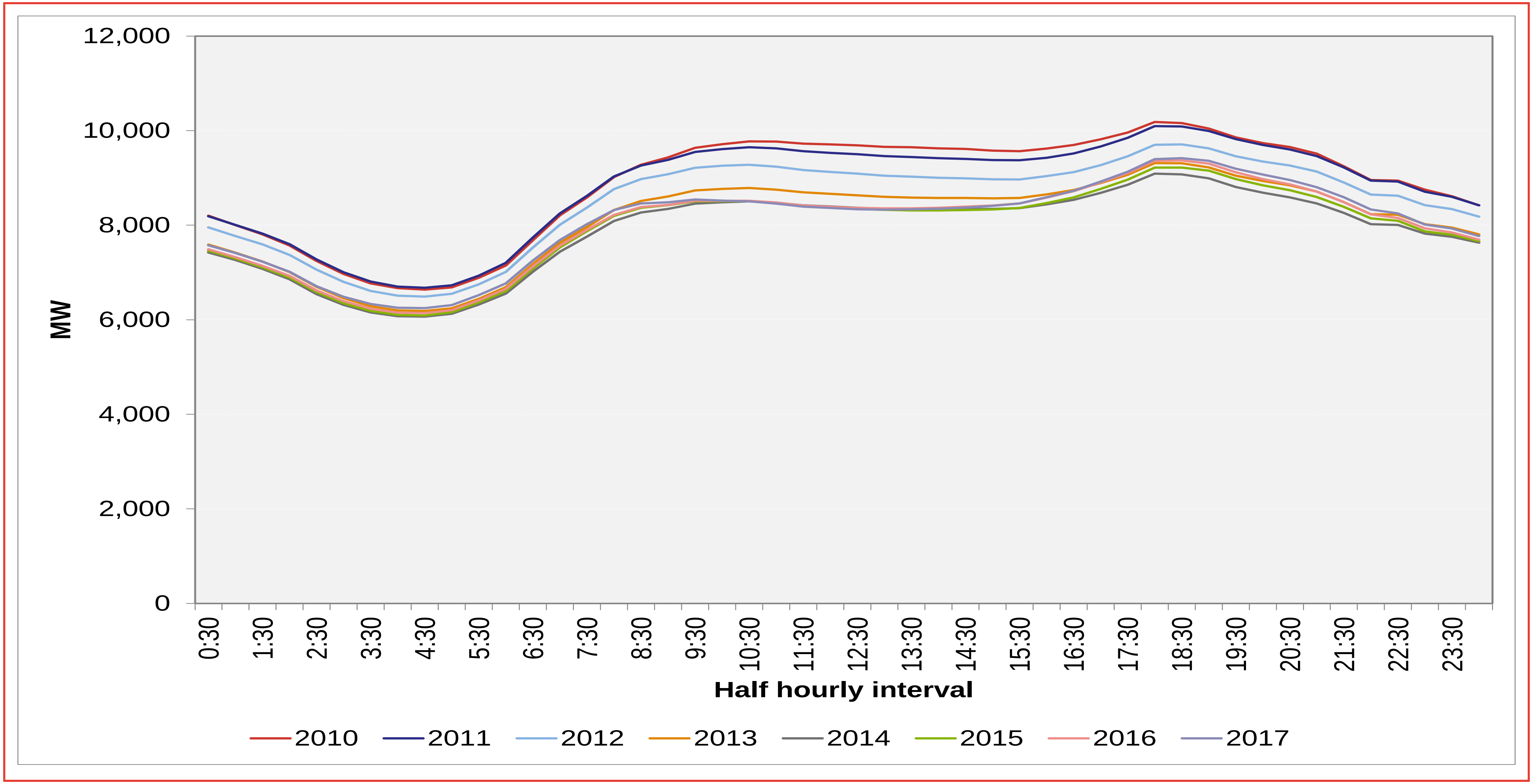
To begin, we analyse historical half-hourly NSW system demand, for financial years 2009/10 through to 2016/17. We are looking for evidence that there has been a reduction in system demand in the middle of the day, when solar PV exports are at their highest. An indication of this is provided by looking at the average shape of daily system demand for these financial years. This is shown in Figure 1. The same information is shown in Figure 2 on a normalised basis (that is, controlling for differences in total annual demand) to more clearly highlight changes in the typical pattern of daily demand.

Figure 1 and Figure 2 make it clear that there has been a reduction in demand during periods of solar PV generation over the period 2009/10 to 2016/17. In particular, careful observation of Figure 2 reveals that there have been relative reductions in system demand in the middle of the day in each year from 2009/10 to 2016/17.

A similar picture is provided if we look at the same normalised average daily shapes, but this time for each month of the year. This is shown in Figure 3. A similar pattern is observable in Figure 3 – demand during the middle of the day, when solar PV is generating, has tended to fall over time. However, this pattern is not as consistent. In particular, recent hot summers have resulted in higher demand during the afternoon in summer months. However, even during these recent summers, the data suggests that the time of peak demand has tended to move later in the afternoon than it has previously been. This is not the case in winter. The reason is that peak demand in winter occurs after sunset, when solar PV generation has no effect.

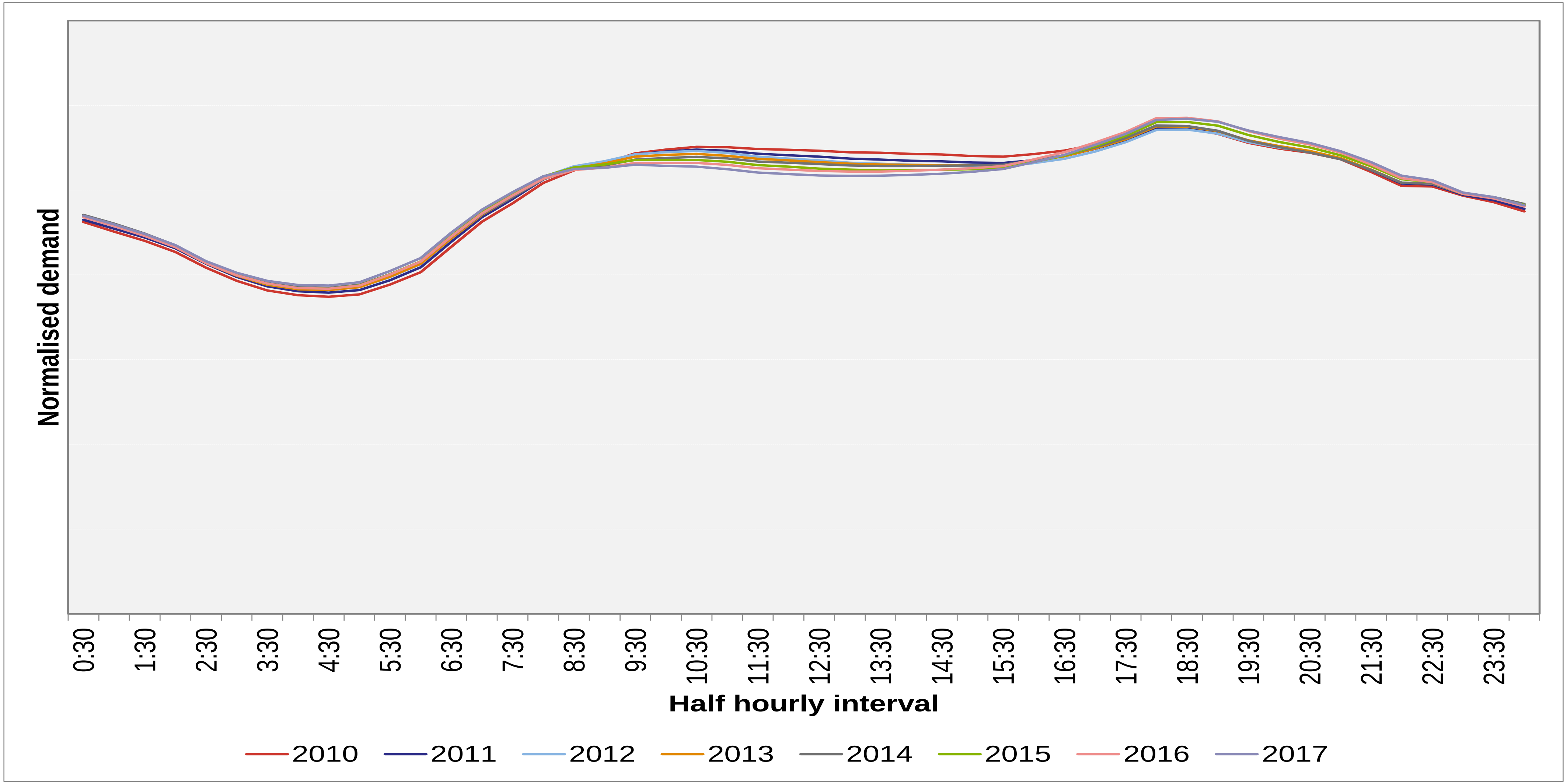
Taken together, the data indicates that system demand is, in general, becoming relatively lower during the middle of the day and that peak demand during summer months is moving later in the afternoon. However, the data also indicates that these trends are not uniform and that other drivers of demand outcomes – including weather conditions – can still result in relatively higher demand during hot summer afternoons.

Figure 1: Average daily demand shape in NSW for 2009/10 to 2016/17



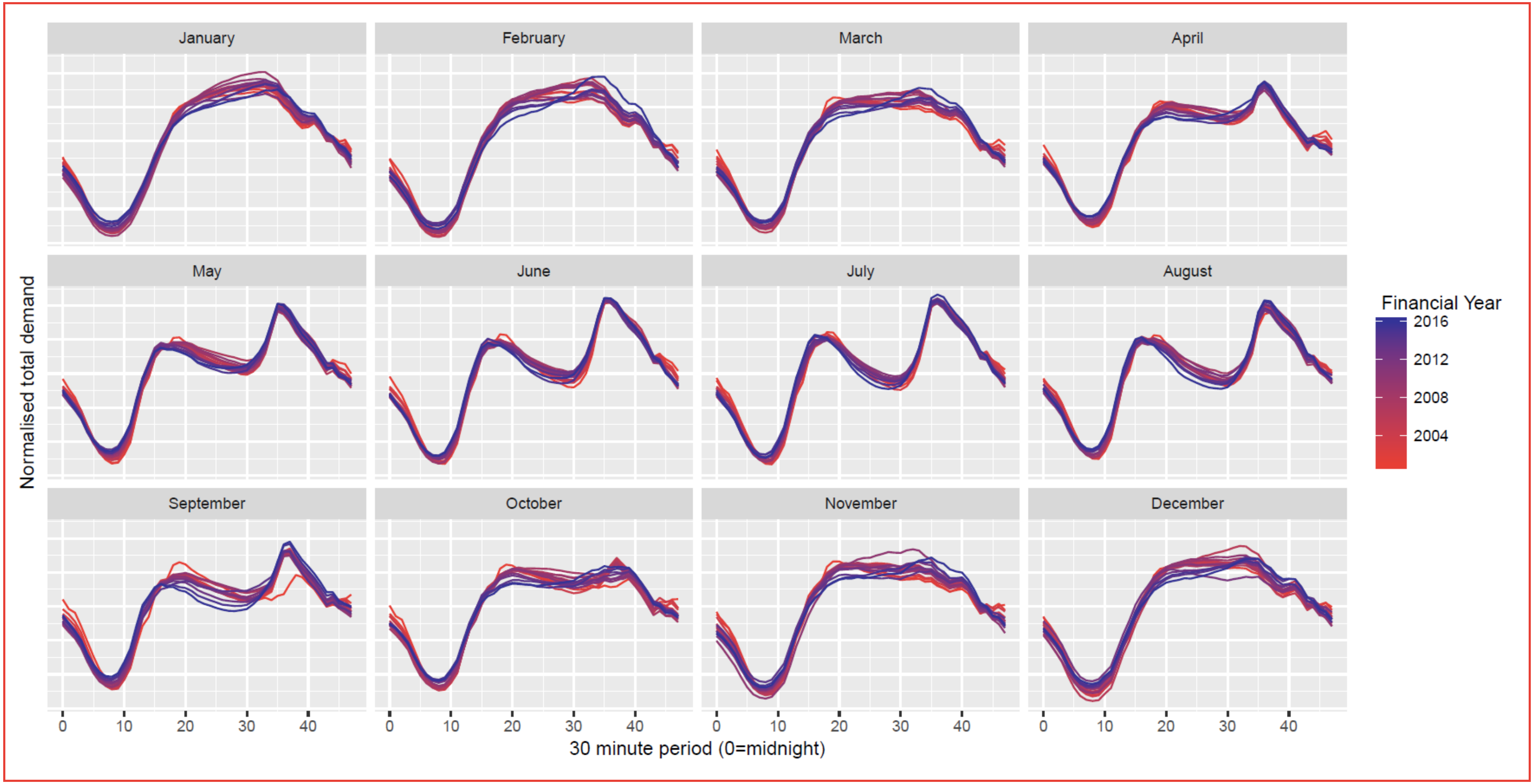
Source: AEMO data, Frontier Economics analysis

Figure 2: Normalised average daily demand shape in NSW for 2009/10 to 2016/17



Source: AEMO data, Frontier Economics analysis

Figure 3: Normalised average daily demand shape in NSW for 2009/10 to 2016/17 – by month

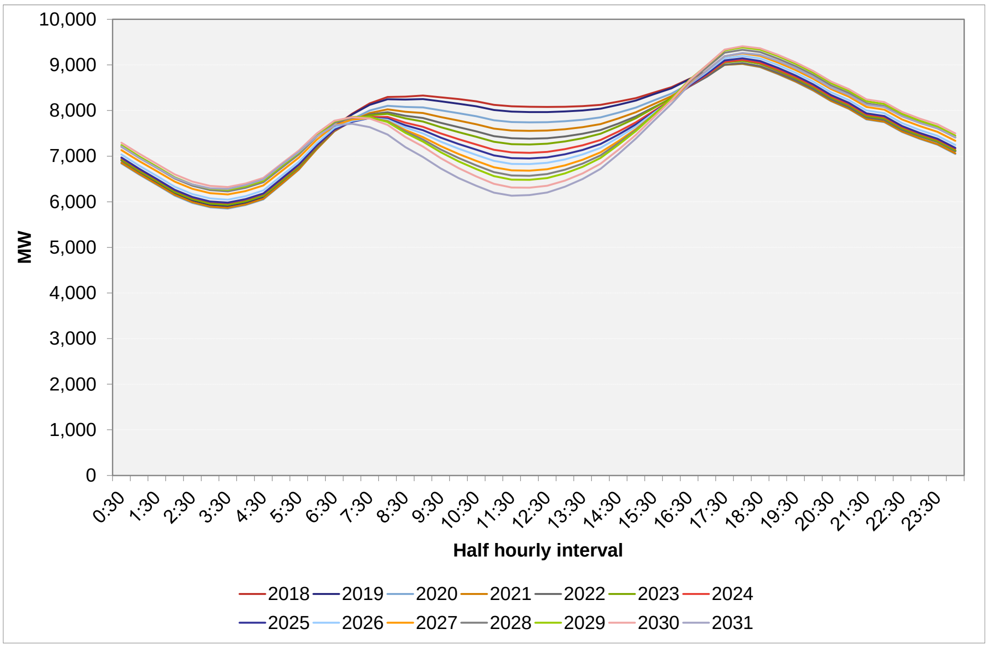


Source: AEMO data, Frontier Economics analysis

Forecast demand

The changing patterns of system demand that have been caused by rooftop solar PV are forecast to continue. AEMO's forecasting of electricity demand suggests that there will be continued uptake of rooftop solar PV, and that this will continue to change patterns of system demand. Figure 4 shows that AEMO's forecasts suggest that system demand during the middle of the day will continue to fall, even as system demand during other parts of the day will increase. This would be expected to have an ongoing effect on pricing outcomes.

Figure 4: Forecast average daily demand shape in NSW for 2017/18 to 2030/31



Source: AEMO data, Frontier Economics analysis

6.2.2 Changing patterns in system prices

Ultimately, when calculating the solar premium, we are interested in patterns in system prices rather than patterns in system demand. The historical data suggests that just as patterns of system demand have been changing – with lower demand during the day and peak demand occurring later in summer – so patterns in system prices have been changing.

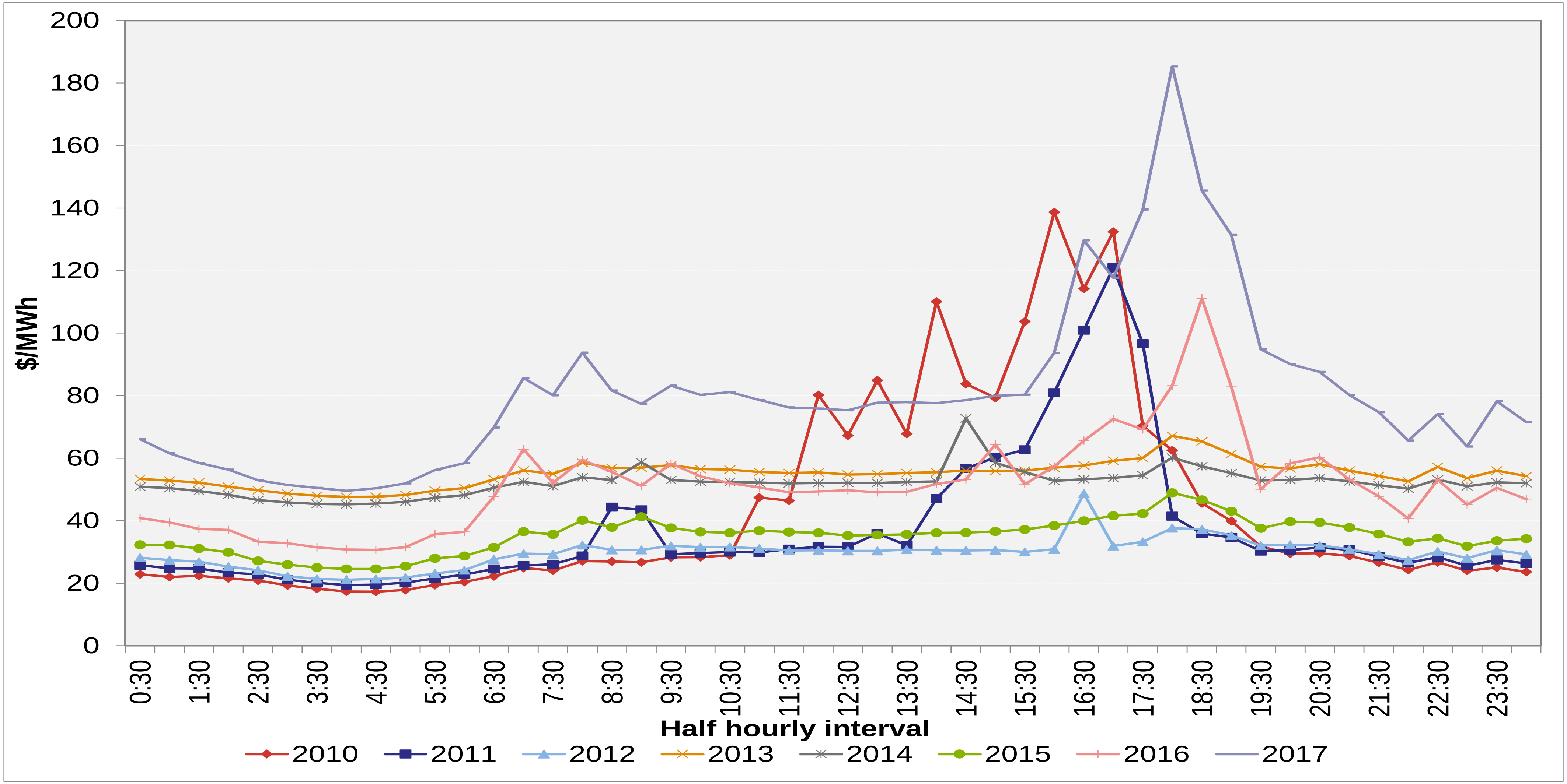
An indication of this is provided by looking at the average shape of historical daily system prices. This is shown in Figure 5 for the years 2009/10 to 2016/17. The same information is shown in Figure 6 on a normalised basis (that is, controlling for differences in average annual prices) to more clearly highlight changes in the typical pattern of daily prices. Figure 6 also labels the time of the highest average price for each year.

Trends over time in the pattern of system prices are less clear than trends over time in the pattern of system demand. This is not surprising; system prices are driven as much by changes in the supply and availability of generation and transmission infrastructure as by changes in patterns of demand. Nevertheless, a few things are apparent from Figure 5 and Figure 6:

- Prices were quite volatile during 2009/10 and 2010/11. These financial years were characterised by relatively low average prices overnight and during the morning, and significantly higher average prices during the afternoon.
- Prices were much more stable for the next four years, from 2011/12 to 2014/15. During these years average prices tended to be a little higher during the afternoon and evening, but there was far less volatility.
- Price during 2015/16 and 2016/17 have become more volatile (and higher on average). However, the evidence suggests that, on average, higher prices tend to occur later in the day in 2015/16 and 2016/17 than in 2009/10 and 2010/11.

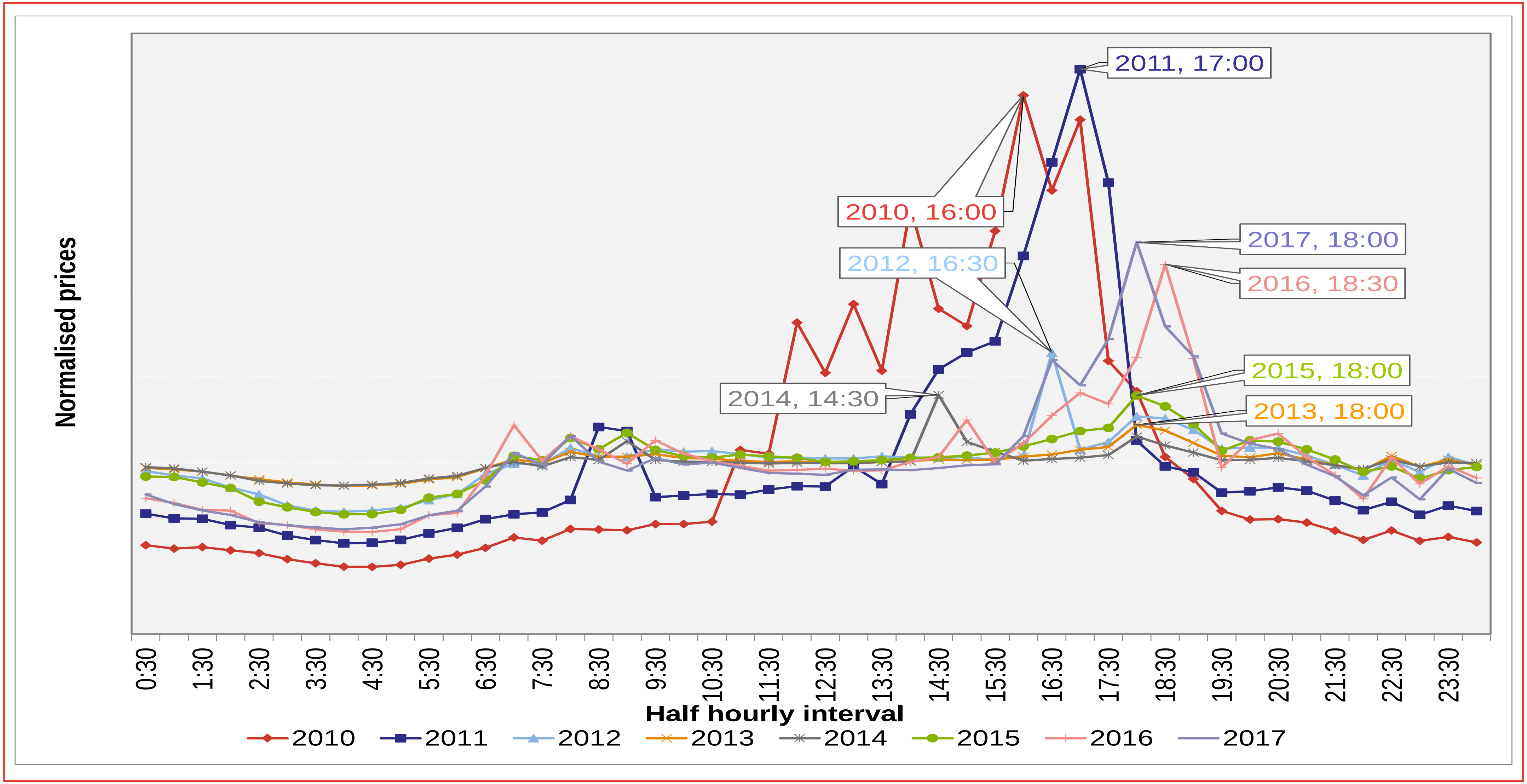
These changes in the patterns of prices are somewhat clearer to see in Figure 6 than in Figure 5, because the quite material differences in average annual prices have been normalised in Figure 6.

Figure 5: Average daily price shape in NSW for 2009/10 to 2016/17 ($ nominal)



Source: AEMO data, Frontier Economics analysis

Figure 6: Normalised average daily price shape in NSW for 2009/10 to 2016/17 ($ nominal)



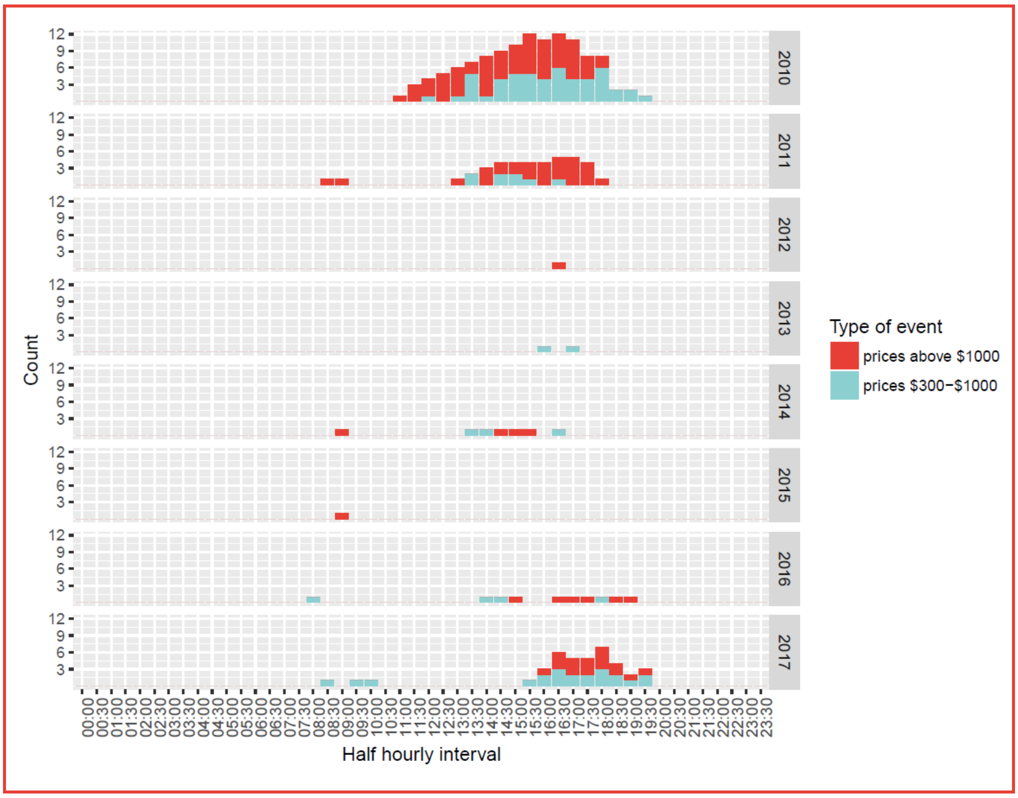
Source: AEMO data, Frontier Economics analysis

Another way of investigating trends in patterns of system prices is to look at the timing of high price events. Figure 7 shows the number of high price events in each year from 2009/10 to 2016/17, by time of day that they occurred. Figure 7 separately shows the number of prices between $300/MWh and $1,000/MWh and prices above $1,000/MWh up to the market price cap (which is currently $14,200/MWh).

Figure 7 shows similar trends in prices to Figure 5 and Figure 6:

- There were a significant number of high price events during 2009/10 and 2010/11. These high price events tended to occur during the afternoon, typically between noon and 5:30PM.
- There were very few high price events from 2011/12 to 2014/15.
- The number of high price events increased again in 2015/16 and 2016/17. However, the timing of these high price events – particularly in 2016/17 – has shifted. These tended to occur later in the afternoon and evening, typically from 3:30PM to 7:30PM.

Figure 7: High price events in NSW for 2009/10 to 2016/17



Source: AEMO data, Frontier Economics analysis

6.3 Conclusion and recommendation

In our view, the most recent data suggests that data from 2009/10 and 2010/11 should be excluded from consideration when calculating the solar premium.

There have now been six more recent years during which the patterns of high prices during the day that occurred in 2009/10 and 2010/11 have not recurred.

Furthermore, we have now seen quite different patterns of high prices occur in both 2015/16 and 2016/17. Without the historical data for these two most recent years, there remained the question of what pricing patterns would occur once the excess supply and low prices that we saw over the period 2011/12 to 2014/15 came to an end. One possibility was that we would see a return to high prices occurring predominantly in the early afternoon. However, this has not been the case. Rather, what we have seen in recent years (particularly since the closure of Hazelwood power station) is higher prices occurring later in the afternoon. Given the significant changes in patterns of demand since 2009/10, this is not surprising.

The other question that needs to be considered is whether data from the lower-priced years of 2011/12 to 2014/15 should also be excluded from consideration when calculating the solar premium. This is more difficult to answer. Current market expectations (as evidenced by ASX Energy contract prices) suggest that the market is expecting a continuation of higher prices in NSW, at least for the next few years. This would suggest that prices next year will be more like prices in 2015/16 and 2016/17 and the analysis should be confined to these years. However, there is also considerable volatility in solar PV export and price outcomes from year to year, and confining the analysis to too few years is undesirable.

On balance, our view is that the calculation of the solar premium should certainly include data from 2015/16 and 2016/17. Furthermore, our view is that the historical solar premium for 2013/14 and 2014/15 should be calculated and compared with the historical solar premium for 2015/16 and 2016/17. As long as the historical solar premium from these earlier years does not diverge too far from the historical solar premium for 2015/16 and 2016/17 our view is that 2013/14 and 2014/15 should also be included in the analysis. If the historical solar premium for 2013/14 and 2014/15 does diverge from the historical solar premium for 2015/16 and 2016/17, these earlier years could still be included in the analysis, but consideration should be given to setting the benchmark range for the solar FiT using something other than the 50th percentile.

This is not to say that we will not see instances of high prices during the day (like we saw in 2009/10 and 2010/11) in future. Instances of high prices in the NEM are often driven by unexpected outages of transmission lines or generation plant, and are not only driven by periods of high demand. This can result in high prices occurring at any time of day. However, given the nature of these outages, the likelihood of these occurring and causing high prices in any particular year, and the timing of this if it does occur, is impossible to predict. In our view, the fact that there is always a degree of uncertainty about the timing of high price events in the NEM does not suggest that justify including data from 2009/10 and 2010/11 when calculating the solar premium because the patterns of prices in these years appear to have been driven largely by patterns of demand which have since changed rather than by this uncertainty about the timing of high price events.

7 The effect of solar PV exports on the network

In this section we consider whether there is a network value of solar PV exports.

Importantly, even if it is the case that there is a network value of solar PV exports, this network value will not be reflected in the financial benefit of solar exports to retailers under the current arrangements for metering and charging for use of the transmission and distribution networks. The reason is that when a retailer's customer generates electricity from solar PV the retailer's sales to its customers are reduced to the extent that the customer's *imports of electricity* are reduced, and the retailer's payment for use of the network for this customer is also reduced to the extent that the customer's *imports of electricity* are reduced. This is due to current metering and charging arrangements, under which a retailer makes payments to the distribution network for "Network Use of System" (NUOS) charges. NUOS charges are made up of "Transmission Use of System" (TUOS) charges and "Distribution Use of System" (DUOS) charges; the distribution network keeps payments for DUOS charges and passes payments for TUOS charges through to the transmission network. Unlike with wholesale market metering and settlement arrangements, therefore, there is no financial benefit to retailers as a result of avoided transmission or distribution network charges.

In this section, however, we investigate the separate question of whether solar PV exports provide an economic benefit to the transmission or distribution network. And, if it can be established that solar PV exports do provide an economic benefit, does this suggest that the financial benefit approach should be amended so that such economic benefit can be reflected in the benchmark solar FiT recommended by IPART.

7.1 Do solar PV exports provide network benefits?

Potential benefits to the electricity network

The most likely source of benefit to electricity networks from solar PV exports is the ability to avoid or defer investments required to meet peak demand.[3] In order for solar PV exports to enable networks to avoid or defer investments to meet peak demand it would need to be the case that solar PV exports occur at times,

3 The recent review by the Essential Services Commission (ESC) into the network value of distribution generation also identified other potential sources of network value but ultimately concluded that the main source of value is through reducing network congestion.

See: Essential Services Commission, *The Network Value of Distribution Generation*, Distribution Generation Inquiry Stage 2 Final Report, February 2017.

and in places, where the exported electricity contributes to meeting peak demand and enables the deferral of an investment that would otherwise need to occur.

First we consider whether solar PV exports are likely to occur at times of peak demand.

The analysis of system demand we presented in Section 6 indicates that, across the network as a whole, the time of peak demand in summer is late in the afternoon – around 5:00PM to 6:00PM – and the time of peak demand in winter is in the early evening – around 6:00PM to 7:00PM. This indicates that, across the network as a whole, solar PV exports are likely to make a small contribution (relative to their capacity) to meeting peak demand in summer, and are likely to make no contribution to meeting peak demand in winter.

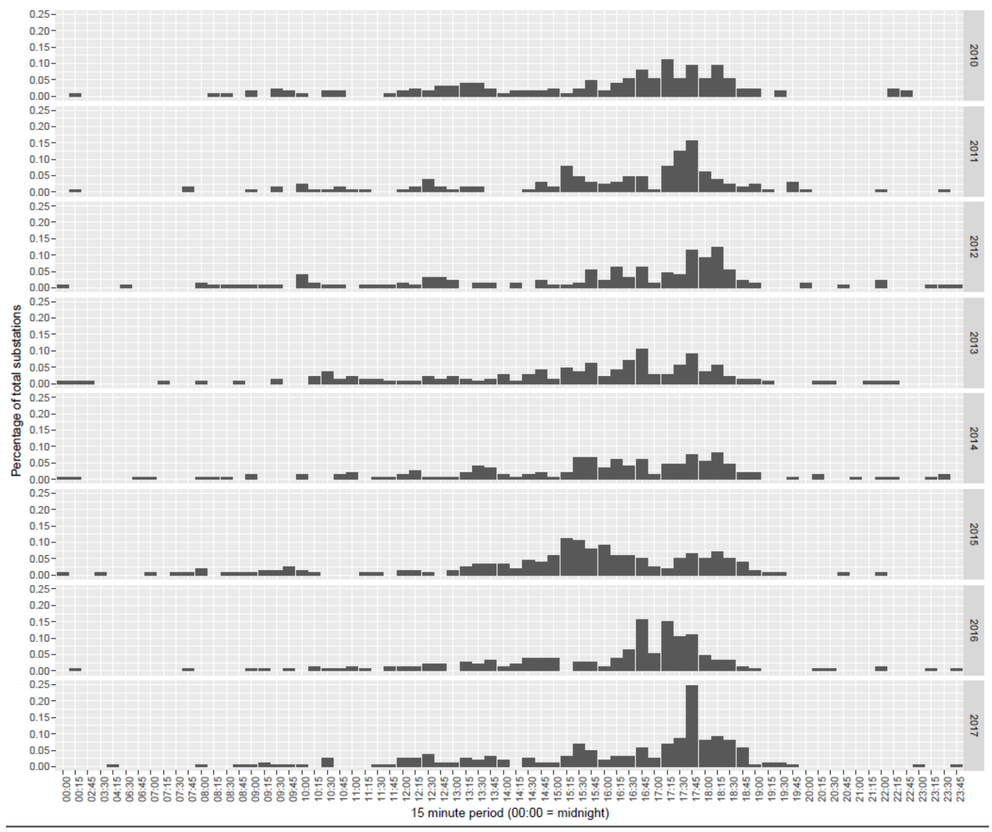
Of course demand-related investments in the transmission and distribution network are driven by the need for additional capacity in specific locations in the network. As a result, patterns of system level demand don't provide the full story, particularly for distribution networks.

For distribution networks, an additional source of data is half-hourly data on zone substations within a distribution network. For the purposes of illustration we have considered the zone substation data for Endeavour Energy's distribution network area. For each zone substation we have calculated the time of peak demand for each year from 2009/10 to 2016/17, and we have counted the proportion of zone substations that have peak demand in each 15 minute period of the day. This data is represented in Figure 8. A few things are apparent from this zone substation data, which are generally consistent with the analysis of system demand presented in Section 6:

- The timing of peak demand is quite dispersed. A few zone substations tend to have peak demand during the morning, a number have peak demand during working hours and the bulk have peak demand in the afternoon or evening.
- Over time a greater proportion of zone substations have peak demand that occurs after 5:00PM. This trend is particularly apparent over the last few years, and presumably reflects the effect of rooftop solar PV in those zone substations that supply electricity to parts of the network where a large number of residential customers have rooftop solar PV.

This data suggests that the extent of the contribution of solar PV exports to meeting peak demand on the distribution network is likely to depend very much on the location of the solar PV within the network, and that over time the number of areas of the network within which solar PV does materially contribute to meeting peak demand is likely to decrease.

Figure 8: Time of peak demand for Endeavour Energy substations



Source: AEMO data, Frontier Economics analysis

Even in areas of the network in which solar PV exports do occur at times of peak demand, this does not necessarily imply that the solar PV exports will materially reduce network costs. The reason is that many parts of the transmission and distribution networks have ample spare capacity, so that even if solar PV exports do contribute to reducing peak demand this may not result in any material cost saving from avoided or deferred investment.

Potential costs to the electricity network

Solar PV exports may also impose costs on the electricity network, particularly distribution networks. These costs could include the costs of reinforcing the network in order to handle bi-directional flows of electricity or to handle the volume of solar PV exports.

As with the potential benefits of solar PV exports to the electricity network, these potential costs will depend on the timing of exports and the location of rooftop solar PV within the network.

Conclusion on costs and benefits

Ultimately, whether solar PV exports provide benefits to the electricity network, or impose costs on the electricity network, depends very much on the location of solar PV within the network. In some locations a typical solar PV export profile may assist in managing peak demand and reduce costs either for the transmission network or the distribution network, while in other locations a typical solar PV export profile may require additional investment by the distribution network to handle the export flows.

This is the same conclusion reached by the Essential Services Commission (ESC) in its recent review into the network value of distributed generation. The ESC concluded that "the value of the grid services that distributed generation can provides is … variable – between locations, across times, and between years".[4] Similarly, in its report on the Distribution Market Model, the Australian Energy Market Commission (AEMC) concluded that distributed generation can provide network benefits, but as the extent of installation of distributed generation on the network increases it may impose costs as a result of impacts on the stability of the network.[5]

7.2 Should network benefits and costs be reflected in IPART's benchmark FiT?

As discussed previously, any network value of solar PV exports will not be reflected in the financial benefit of solar exports to retailers under the current arrangements. This would mean that reflecting any financial benefit of solar PV exports in IPART's benchmark range of the solar FiT would tend to cause retailers to seek some external source of funding to cover the costs of FiTs (which would potentially lead to increases in retail electricity prices) and would not be expected to result in FiTs that are consistent with those that would occur in a competitive market.

Additionally, there are good reasons to think that network businesses are better placed to reflect the network costs or benefits of solar PV exports in network tariffs. Network businesses – particularly distribution businesses – will be aware of the locational and temporal effects of solar PV exports on their network and will be better placed to design network tariffs that reflect these locational and temporal effects. Setting FiTs using the same Network + Retail approach to tariff regulation that has been applied for retail electricity tariffs (under which network businesses set the Network component of electricity tariffs subject to the existing regulatory

---

4 Essential Services Commission, *The Network Value of Distribution Generation*, Distribution Generation Inquiry Stage 2 Final Report, February 2017, page XXII.

5 AEMC, *Distribution Market Model*, Final Report, 22 August 2017, page 55.

arrangements and IPART set the Retail component of electricity tariffs) would promote more efficient price signals: transmission and distribution networks would be able to send price signals reflecting any network effects of solar PV exports through network tariffs, while IPART's benchmark range of the solar FiT can provide price signals reflecting the wholesale market value (and other relevant values) of solar PV exports.

The view that IPART's benchmark range of the solar FiT should not include network value is consistent with the conclusions of the ESC:[6]

> If a broad-based network value feed-in tariff (FiT) was calculated with sufficient granularity to reflect the underlying network value it would be disproportionately complex and costly to implement. If it were made simple enough to implement, it would be inadequately reflective of value and could lead to payments to distributed generators who were not providing benefits, while at the same time, not sufficiently rewarding those who were.

It is also consistent with the AEMC's view:[7]

> [recognising the network benefits of distributed energy sources] would need to occur on a localised basis, based on information at that particular part of the network i.e. a one size fits all solution will not work. This is consistent with the Commission's recent final determination on the *Local generation network credits* rule change request, where the AEMC concluded that the impact of distributed energy resources on networks depends on where the generator connects to the network, as well as the time of generation. Therefore, any payments associated with this need to be specific and depend on those factors.

The AEMC concluded that it will consider the arrangements for distribution network access and connection charging for distributed energy resources through the 2018 *Electricity Network Economic Regulatory Framework Review*.

7.3 One-to-one FiTs

On occasion it has been suggested that FiTs should be set at the same level as retail tariffs (presumably this would mean that FiTs would reflect the variable component of retail tariffs).

It should be clear from the rest of this report that our view is that FiTs should not be set at the level of the variable component of current retail tariffs. The reason is that the variable component of current retail tariffs includes a variable component of network tariffs (among other things). As we suggest in the rest of this report, including this component for network tariffs (and other variable costs) in FiTs would not be consistent with the approach of setting FiTs based on the financial

---

6 Essential Services Commission, *The Network Value of Distribution Generation*, Distribution Generation Inquiry Stage 2 Final Report, February 2017, page XXII.

7 AEMC, *Distribution Market Model*, Final Report, 22 August 2017, page 55.

benefit of solar exports to retailers and it would also not reflect the economic value of solar FiTs.

This is not to say that there is not some logic to the idea that FiTs should be set at the same level as the variable component of retail tariffs. However, the economic logic of this is that the variable component of retail tariffs should be much lower, only reflecting variable costs of supplying electricity to retail customers. Since network costs are predominantly fixed, this would suggest that the variable component of retail tariffs also should not include a component for network tariffs. In any case, this logic can be taken too far: since solar exports and retail imports occur at different times of the day and year, the wholesale market value of these would be expected to be different in any case.

8 Other supply chain costs

In this section we consider each of the other elements of the cost of supplying electricity – network losses, market fees and ancillary services charges and the costs of arranging retail supply.

8.1 Network losses

There are losses associated with the transportation of electricity from where it is generated to where it is consumed. These losses occur as a result of electrical resistance and the heating of conductors. This means that for the average customer, when they consume a kWh of electricity this requires the generation of more than a kWh of electricity.

The installation of solar PV panels by a small customer does have implications for the extent of losses on the electricity network. By generating electricity close to where it is consumed, rather than far from where it is consumed as is the case for centralised generation, solar PV exports reduce the losses associated with the transport of electricity.

These avoided network losses are a component of the financial benefit of solar exports to retailers and also represent an economic benefit of solar PV exports. Avoided network losses are a component of the financial benefit of solar exports, for the same reason that wholesale energy costs are a component of the financial benefit: when a retailer's customer generates electricity from solar PV the retailer's sales to its customers are reduced only to the extent that the customer's *imports of electricity* are reduced, but the retailer's purchases of electricity from the wholesale market are reduced to the extent of the customer's *generation of electricity*, including avoided losses.

For this reason, our view is that it is appropriate for avoided losses to be included in FiTs.

Avoided network losses also represent a real economic benefit of solar PV exports, because the losses on the electricity network are a real cost associated with the supply of electricity.

8.2 Market fees and ancillary services charges

Market fees and ancillary services charges are fees charged by AEMO to recover the costs of operating the electricity market.

There are a number of different categories of market fees. These are variously charged to market customers (including retailers), generators, market network service providers and/or intending market participants. Similarly, there are a number of different categories of ancillary services, and the payments for these are variously recovered from all market participants, market customers and/or generators.

Avoided market fees and ancillary services charges are a component of the financial benefit of solar exports, for the same reason that wholesale energy costs are a component of the financial benefit: when a retailer's customer generates electricity from solar PV the retailer's sales to its customers (and therefore its recovery of market fees and ancillary services charges from its customers) are reduced only to the extent that the customer's *imports of electricity* are reduced, but the retailer's purchases of electricity from the wholesale market (and therefore its payment of market fees and ancillary services charges to AEMO) are reduced to the extent of the customer's *generation of electricity*, including avoided losses.

For this reason, our view is that it is appropriate for market fees and ancillary services charges to be included in FiTs.

Assuming that charges for market fees and ancillary services charges are cost-reflective, avoided market fees and ancillary services charges would also represent a real economic benefit of solar PV exports. However, if these fees are not cost-reflective (for instance, because the costs of operating the market are largely fixed even though they are recovered through variable charges) then solar PV exports may provide no economic benefit due to avoided costs of operating the market.

8.3 Costs of arranging retail supply

The costs of arranging retail supply include retail operating costs and the retail margin.

There is no clear evidence that the costs of arranging retail supply are affected by solar PV exports. Retailers have suggested that the costs of managing customers with solar PV customers are higher, but we are not aware that evidence to support this has been provided. Generally, the retail operating costs and the retail margin are thought to depend principally on how many customers are supplied, rather than on the amount of electricity that is supplied. While retailers' practices vary, these costs are also often recovered through fixed charges.

For this reason, our view is that avoided retail operating costs and retail margin should not be included in FiTs. However, if retailers can provide evidence that retail operating costs are higher for customers with FiTs our view is that it would be consistent with our recommended approach to account for this in FiTs.

9 Other sources of value from solar PV exports

This section considers a number of other sources of value from solar PV exports that have been considered in other reviews or proposed by stakeholders.

9.1 Value from reduced wholesale electricity prices

As part of previous regulatory reviews of solar FiTs, a number of stakeholders have suggested that solar PV panels provide a wholesale market benefit by lowering the wholesale spot price for electricity. This has been referred to as the 'merit order effect' because solar PV panels change the point on the supply curve (known as the merit order) at which demand and supply intersect and, therefore, lower the price for electricity.

The proposition that installation of solar PV panels lowers electricity prices is entirely consistent with both economic principles and the design of the NEM: lower demand means that demand can be met at a lower price. As discussed in Section 6, there is also evidence that the installation of solar PV panels that has already occurred in NSW and other NEM regions has resulted in lower wholesale electricity prices.

The question is whether the 'benefit' of this reduction in electricity prices should accrue to customers that install solar PV panels by increasing the FiT that these customers receive. In our view, this would be inconsistent with the way that markets work as this would simply represent a transfer of value from all electricity customers to those that install solar PV panels and would be administratively very complex.

The 'merit order effect' is not unique to the electricity market and is not unique to the installation of solar PV panels. In all competitive markets, the entry of new sellers or new buyers can affect the market price, and new sellers and new buyers will face the *post-entry* price. However, not only do new sellers (or new buyers) not have access to the pre-entry price for their own sales (or purchases), but they certainly do not face a transfer from existing sellers (or to existing buyers) to account for the effect that entry has on the price that existing sellers receive (and buyers pay).

In economic terms, any reduction in the electricity price caused by the installation of solar PV panels results in a transfer from electricity producers to electricity consumers: at a lower price, consumer surplus increases but producer surplus decreases. To include this increase in consumer surplus in the FiT would simply be a subsequent transfer from these existing consumers to those that install solar PV panels.

We note that this transfer is not required for solar PV customers to receive a market value for the electricity they produce: solar PV customers will receive that market value as long as they receive a FiT that reflects forecast post-entry electricity wholesale prices (as discussed above). We also note that there is no equivalent transfer associated with any other investment in the electricity industry: those that invest in large-scale generation do not receive a transfer from consumers to reflect the lower wholesale electricity price that their investment causes; neither do those customers that increase load (for instance, by installing air conditioning) have to compensate other consumers to reflect the higher wholesale electricity price that their investment causes.

Finally, giving effect to a mechanism that includes the increase in consumer surplus in the FiT would be administratively complex. It would involve levying an additional charge on all electricity customers and transferring this revenue to solar customers through the FiT. Calculating the additional charge to levy would be difficult now and would become increasingly difficult over time because it would effectively involve dispatching the market twice – once with solar PV installations and once without solar PV installations. However, forecasting the wholesale electricity price without solar PV installations would become increasingly speculative over time as the market adjusts to the installed capacity of solar PV.

For these reasons, our view is that the 'merit order' effect should not be accounted for in determining FiTs.

9.2 Value of avoided externalities associated with centralised generation

The Essential Services Commission's report on the energy value of distribution generation,[8] suggests that there are environmental and social benefits associated with electricity produced by solar PV. The Essential Service Commission (ESC) considered a number of potential environmental and social benefits including: avoided pollution, avoided resource consumption and extraction, job creation, increased choice and competition and enhanced wellbeing.

Ultimately, the ESC concluded that the only area of environmental or social benefit that could be quantified with reasonable confidence is reduced emissions of greenhouse gases. The ESC identified a method for calculating the volume of greenhouse gas abatement but did not seek to place a value on this volume of abatement. The ESC noted that the monetary value of abatement is a matter for Government policy.

8 ESC, *The Energy Value of Distributed Generation*, Distributed Generation Inquiry Stage 1 Final Report, August 2016.

Our view is that there is not a strong case for environmental or social benefits to be separately accounted for in determining a benchmark FiT. We deal with potential environmental benefits and potential social benefits separately in the sections that follow.

Potential environmental benefits

The potential environmental benefits discussed by the ESC included avoided pollution and reduced resource consumptions and extraction. These benefits are in fact environmental detriments associated with generation from utility-scale power stations, particularly coal-fired power stations.

It may be that some of these environmental detriments are externalities associated with generation from utility-scale power stations. An externality occurs where a person's economic welfare is affected by outcomes caused by another economic agent, and these outcomes are caused without consideration of their effects on others. For instance, pollution caused by a power station can impact the rest of society, but there may be no price that reflects this pollution. Externalities are one cause of market failures; the absence of a price on the externality means that the market cannot be relied upon to produce efficient quantities.

Policy intervention can be used to address the market failure associated with externalities. However, in our view, environmental detriments associated with generation from utility-scale power stations should not be reflected in the FiT. There are three reasons for this.

First, to justify reflecting an environmental detriment from utility-scale power stations in a FiT it would need to be established that the environmental detriment is, in fact, an externality. However, in many cases the effect of the environmental detriment associated with generation from utility-scale power stations is already taken into account in the power station owner's decisions. This occurs where there is a price attached to the environmental detriment. An example of this is the water consumption of coal-fired power stations. Where power stations are required to purchase the water that they use, and the price they pay reflects the scarcity value of that water, the power station owner's decisions will already reflect the scarcity value of that water. Furthermore, because the power station owner's decisions will reflect the scarcity value of water, this scarcity value will also be reflected in the wholesale electricity prices that determine the wholesale market value of solar PV exports. In this case – in other words, assuming that prices for water reflect its scarcity value – adding a separate component to the FiT to reflect the scarcity value of water would result in double-counting the scarcity value of water, potentially leading to inefficient decisions about the installation of solar PV panels or the export of electricity from solar PV panels.

Second, in many cases steps have already been taken to address any externality associated with generation from utility-scale power stations. There are a number of ways that policy makers can seek to rectify the market failure caused by externalities, including taxes or subsidies to create a price signal that 'internalises' the externality, and various forms of regulation to limit activities that impose external costs. An example of this is the air, land and water pollution associated with coal-fired power stations. Regulations such as standards and limits are already in place, with the intention of addressing the inefficiency associated with the external costs of pollution. The fact that pollution continues does not necessarily reflect the fact that such regulations are failing to adequately address the externalities associated with coal-fired power stations; rather, it could reflect the fact that generation from coal-fired power stations is efficient even if these external costs are internalised. In this case – in other words, assuming that existing regulations are an appropriate response to the external costs of pollution from utility-scale power stations – adding a separate component to the FiT to reflect the external costs of pollution would result in double-counting these external costs, potentially leading to inefficient decisions about the installation of solar PV panels or the export of electricity from solar PV panels.

We would note that the Renewable Energy Target is one of the policy mechanisms that reduces greenhouse gas emissions. Both large-scale and small-scale renewable generation is able to generate additional revenues under the Renewable Energy Target: large-scale renewable generation is able to create and sell Large-scale Generation Certificates (LGCs) and small-scale renewable generation is able to create and sell Small-scale Technology Certificates (STC)s. It seems clear to us that the Renewable Energy Target is intended, at least in part, to address the externalities associated with centralised generation using coal and gas, and that the prices for LGCs and STCs are intended to internalise the benefits that renewable generation provides. In this case, adding a separate component to the FiT to reflect the benefit that renewable generation would double-count that benefit.

Finally, even if it could be established that there are external costs associated with generation from utility-scale power stations, and that existing regulatory mechanisms do not adequately address these external costs, there remains a question about whether including these external costs in the FiT available to customers that install solar PV panels is an appropriate policy response. If these external costs could be reflected in the FiT available to these customers, more efficient decisions on investment and operation of solar PV panels or investment and operation of utility-scale power stations may be expected. However, this would only address these external costs for a small part of the market; other sources of generation, such as cleaner coal-fired power stations or cleaner gas-fired power stations, or utility-scale renewable power stations, will not receive the same incentive. For this reason, there are almost certainly better policy options to address these external costs that result in outcomes that are more broadly efficient. And these other policy options are likely to result in changes to outcomes in the wholesale electricity market, including changes to wholesale electricity prices. In this case, separately reflecting these avoided external costs in the FiT that customers who install solar PV panels receive runs the risk of double-counting, leading to inefficient decisions.

For these reasons, we do not see merit in including a separate amount to reflect the avoided environmental detriment of generation from utility-scale power stations in the FiT.

Potential social benefits

The potential social benefits discussed by the ESC included job creation and increased choice and competition. The ESC ultimately concluded that these potential social benefits do not warrant inclusion in a FiT.

Our view is that it is unclear that these represent economic benefits of solar PV exports. In relation to job creation, for instance, it is not clear that solar PV exports (or solar PV generation generally) results in more jobs than the alternative. In any case, even if solar PV exports do result in job creation, this is not a financial benefit to retailers, so requiring retailers to reflect the value of this job creation in FiTs will result in the detrimental consequences discussed in Section 4.

10 Structure of benchmark solar FiT

The previous sections of this report have considered the appropriate benchmark range for FiTs, based on the financial benefit to retailers of solar exports.

A related question is how the FiT should be structured. IPART's Terms of Reference require IPART to investigate and report on time dependent benchmark ranges for FiTs. This section considers the case for time dependent benchmark ranges for FiTs and also considers the relationship between FiTs and retail tariffs.

It is clear from the analysis of the wholesale market value of solar PV exports in Section 6 that the value of solar PV exports depends on the wholesale electricity price at the time of export.

This suggests that there can be a case for time-varying FiTs. FiTs could be set to vary for different periods of time during the day or for different times of the year; for instance, a 'peak' FiT during the afternoon – say from 3:00PM to 5:00PM – would likely be higher than a flat annual FiT (and would also imply a lower 'off-peak' FiT for the rest of the day). Similarly, since wholesale prices during the window from 3:00PM to 5:00PM tend to be higher in summer than in winter, a 'seasonal peak' FiT for summer afternoons would likely he higher still.

In thinking about the case for time-varying FiTs it is worth considering the benefit of sending these time-varying price signals. Having a higher peak FiT would potentially provide signals for efficient outcomes if the higher peak FiT encouraged greater solar PV exports during these high priced times. There are essentially three ways that this could occur:

- customers could install larger solar PV systems in order to be able to export more during the afternoon,
- customers could orient their solar PV systems to the west rather than the north, in order to increase generation in the afternoon, and/or
- customers could reduce their electricity use in the afternoon, in order to be able to export more of the electricity generated.

It is not clear how likely the first two of these are. Installing a larger solar PV system will increase the cost of the system, and while the customer will receive a higher 'peak' FiT the customer will also receive a lower 'off-peak' FiT, so the economics regarding system size may not change. And changing the orientation of a solar PV system may not be practical given the customer's roof space.

In regard to the third of these it is worth noting that the FiT is only one of the price signals that customers receive about the time of day that they use electricity. The other price signal is, of course, the retail price that they face. In thinking about the case for time-varying FiTs to encourage changes in the way that customers use electricity, therefore, it is worth thinking about whether these price signals are consistent with the price signals that are provided by retail prices. Estimating ToU

FiTs using the same time periods as are used for ToU retail tariffs would provide this consistency.

FRONTIER ECONOMICS
BRISBANE | MELBOURNE | SINGAPORE | SYDNEY
Frontier Economics Pty Ltd 395 Collins Street Melbourne Victoria 3000
Tel: +61 (0)3 9620 4488 Fax: +61 (0)3 9620 4499 www.frontier-economics.com.au
ACN: 087 553 124 ABN: 13 087 553 124