The fair and reasonable value of exported PV output

Supplementary report prepared for the Essential Services Commission of South Australia and updated to reflect stakeholder comments

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ACIL Tasman

Economics Policy Strategy

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)
Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra
Level 2, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney
PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Jeremy Tustin
Telephone (03) 9604 4411
Mobile 0421 053 240
Email j.tustin@aciltasman.com.au

Contributing team members

Guy Dundas
Marianne Lourey
Owen Kelp

Executive summary

The Essential Services Commission of South Australia (the Commission) is charged with protecting the long term interests of South Australian consumers with respect to the price, quality and reliability of essential services.

It has a key role in oversighting and regulating retail market competition for small energy customers in South Australia and facilitating competitive energy markets is a priority.

The Commission was recently given a new role when the South Australian Government amended section 35A of the *Electricity Act 1996* (the Act). The Commission now has the power to determine prices relating to "the feeding in of electricity into a distribution network".

The Commission is currently in the process of determining the amount that retailers should pay their customers for electricity generated by a solar photovoltaic system (PV system) and exported to the grid (exported PV output). The Commission engaged ACIL Tasman to assist by estimating the fair and reasonable value of this electricity to a retailer.

Sources of value of exported PV output to retailers

Electricity retailers in South Australia participate in the National Electricity Market (NEM), so any value they derive from exported PV output is derived through that market.

The wholesale spot price of electricity varies every half hour, but the meters used by small electricity customers in South Australia cannot measure electricity use on a half hourly basis . Therefore, the half hourly wholesale price of electricity supplied to individual customers is unknown. In the NEM it is estimated through a process known as profiling. The Australian Energy Market Operator (AEMO) uses this approach to match small customers' electricity consumption to the wholesale spot price of electricity on a half hourly basis.

The result is that the price retailers pay for electricity they supply to small customers is the wholesale spot price weighted by an aggregated measurement of the electricity usage of all small customers on a half hourly basis known as the Net System Load Profile (NSLP).

When a retailer receives exported PV output from a customer, the amount of electricity they must buy on the wholesale market is reduced and the total amount they spend on wholesale electricity reduces by the NSLP-weighted price. This is the most significant source of value to retailers from exported PV output.

When PV output is exported to the grid, it will typically be used by a customer located nearby. That customer is usually closer to the PV system than the large generators that operate in the wholesale market. Therefore, less of the exported PV output is 'lost' in the network than would be lost if the electricity came from a generator in the wholesale market. The result is that the amount of electricity retailers avoid buying due to exported PV output is more than the output itself. In South Australia the difference is approximately eight per cent on average across the network.

In addition, exported PV output reduces a retailer's total purchase of electricity from the wholesale market. In the short term, their share of the cost of operating that market, which they pay through market and ancillary service fees, is also reduced as a result. In the long term, the allocation process will take this into account.

Other impacts of PV systems

There is a potential that PV systems may have impacts on the electricity system other than those listed above. For example, exported PV output might influence:

- the cost to retailers of complying with 'green schemes'
- retailer operating costs
- network loss factors
- network augmentation costs
- contracting and risk management costs

As discussed in the report, our assessment is either that exported PV output will not influence these factors or that there is no benefit to retailers if they are influenced (or both). Therefore, we have not included them in our estimate of the value to a retailer of exported PV output.

Estimate of value to a retailer of exported PV output

Three factors make up the value to retailers of exported PV output, namely:

- reduced wholesale electricity purchase costs
- avoided losses
- reduced market and ancillary service fees.

Due to the potential impact of the Commonwealth Government's proposed carbon pricing regime (to commence on 1 July 2012), we modelled reduced wholesale electricity purchase costs under two scenarios: a Carbon scenario and a No carbon scenario.

Our estimate of the value of these factors is set out in Table ES 1.

Table ES 1 **Value of exported PV output (nominal cents per kWh)**

	2011-12	2012-13		2013-14	
	Both scenarios	Carbon scenario	No carbon scenario	Carbon scenario	No carbon scenario
Reduced wholesale electricity cost	6.4	8.9	8.1	10.2	9.0
Avoided losses	0.6	0.8	0.7	0.9	0.8
Market and ancillary service fees	0.1	0.1	0.1	0.1	0.1
Total	**7.1**	**9.8**	**9.0**	**11.2**	**9.9**

Data source: ACIL Tasman

This estimate is based on:

- a projection of the wholesale spot market price taken from *PowerMark*, our proprietary model of the NEM
- a projection of the NSLP in South Australia prepared for this purpose
- assumptions regarding market and ancillary service fees and future loss factors based on AEMO publications.

As with all projections of future events, actual prices may differ.

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1 Introduction

The Essential Services Commission of South Australia (the Commission) is charged with protecting the long term interests of South Australian consumers with respect to the price, quality and reliability of essential services.

It has a key role in oversighting and regulating retail market competition for small energy customers in South Australia and facilitating competitive energy markets is a priority.

The Commission was recently given a new role when the South Australian Government amended section 35A of the *Electricity Act 1996* (the Act).[1] The Commission now has the power to determine prices relating to "the feeding in of electricity into a distribution network".

The Commission is currently in the process of determining this price and has engaged ACIL Tasman to assist it in estimating the value of electricity generated by a solar photovoltaic system (PV system) and exported to the grid (exported PV output).

This report provides the results of our investigation and analysis of this value.

Section 2 provides an overview of the policy context surrounding the Commission's inquiry and of the task itself. As discussed in this section, the task is to estimate the value of exported PV output *to a retailer*, and so some effects of PV systems on groups other than electricity retailers are excluded from our estimate of the fair and reasonable value to a retailer of exported PV output.

Section 3 provides a discussion of the sources from which retailers may derive value from exported PV output. This includes quantified estimates of the value from each source where possible.

Section 4 provides a discussion of the impacts PV systems have, or may have, on the electricity system that do not provide a benefit to retailers.

Section 5 provides a summary of our estimate of the fair and reasonable value to a retailer of exported PV output.

1 The relevant amendment Act was proclaimed on 28 July 2011.

2 Overview

An overview of the policy context for the Commission's inquiry is provided in section 2.1. Section 2.2 then draws on that overview and other sources to define the methodology we have applied in this report.

2.1 Policy context

In 2008, the South Australian Government was the first in Australia to legislate a premium feed-in tariff for customers with PV systems. Under this scheme, small electricity customers who install PV systems on their homes are rewarded with a premium payment of 44 cents per kWh for electricity they export to the grid, approximately double the retail price of electricity.

Policy settings to support PV systems have been undergoing a period of great change in South Australia and around the country. The cost of installing PV systems has reduced in recent years and, coupled with generous Government assistance measures, uptake of these systems has grown rapidly.

At the time of writing, there were likely to be almost 70,000 PV[2] systems installed in South Australia. Therefore, customers with PV systems (PV customers) accounted for approximately 9% of all small electricity customers in South Australia.

However, as PV systems offer increasingly strong financial returns to owners even in the absence of direct subsidies, the general trend for Australian policy-makers has been to transition from a system of generous (and popular) subsidies to a sustainable policy environment that offers a fair reward to owners of PV systems for the value they deliver to the energy system, rather than a 'premium' reward through government policy.

Consistent with this trend, the South Australian Government closed the original 44 cents/kilowatt-hour (kWh) 'feed-in tariff' to new customers from 1 October 2011. That tariff has been replaced with a tariff of 16 cents per kWh. This 16 cents per kWh feed-in tariff will cease to be available to new systems from 1 October 2013 (subject to transitional arrangements).

The Government also took the view that PV customers should receive fair and reasonable compensation for the value of electricity they export to the network (exported PV output). The Government determined that customers should

2 Meter reading records indicate that approximately 58,000 systems were read in August 2011. Allowing for growth since then 70,000 is an approximation of the number of systems likely to be in place at the beginning of October 2011.

receive an amount, paid by their retailer, reflecting the fact that their retailer receives sells the exported PV output to other customers (the retailer payment).

2.2 The Commission's task

The Commission's task is to determine the amount that retailers should pay customers for exported PV output. In this section we examine the Commission's task in more detail.

The Commission's task arises from s.35A of the Act, which provides that:

> (1) The Commission may make a determination under the Essential Services Commission Act 2002 regulating prices, conditions relating to prices and price-fixing factors for—...
>
> (ba) the feeding-in of electricity into a distribution network under Division 3AB;
>
> ...
>
> (2a) In addition to the requirements of section 25(4) of the *Essential Services Commission Act 2002* , the Commission must, in acting under subsection (1)(ba), have regard to the fair and reasonable value to a retailer of electricity fed into the network by qualifying customers within the meaning of Division 3AB.
>
> ...

There are two elements of s.35A(2a) central to the analysis presented in this report. These are:

1. the electricity to be valued is only that which is exported to the grid by qualifying customers (i.e. small energy customers)[3]
2. the value to be assessed is the value to a retailer

Section 35A(2a) is clear regarding the first of these points. However, the second point requires further consideration.

There are five relevant groups of participants in the electricity market, namely:

1. electricity generators
2. network operators
3. retailers
4. PV customers

[3] For the purposes of Division 3AB of the Act, and therefore for our analysis, qualifying customers are small customers as defined in the Act. In South Australia, these are customers who consume less than 160 MWh of electricity per year regardless of whether they are business or residential customers.

5. customers that do not own PV systems (non-PV customers).

Each of these groups is potentially affected by exported PV output. However, our interpretation of the Act is that, in determining the value of the retailer payment, the Commission should exclude the impact on groups other than retailers.

In line with this interpretation, our analysis of the impact of exported PV output is split into two sections. Section 3 discusses impacts of exported PV output that relate directly to retailers. These are the basis of our estimate of the fair and reasonable value to a retailer of exported PV output.

Section 4 then discusses a number of potential effects of PV systems on other groups. These are excluded from our estimate of the fair and reasonable value to a retailer of exported PV output.

Finally, we have taken into account the fact that electricity retailers in South Australia are participants in the National Electricity Market (NEM). This means that any value they derive (or cost they incur) from exported PV output will be affected by the physical and regulatory arrangements associated with the NEM's operation. It follows that the procedures used in the NEM must be taken into account in estimating that value.

3 Sources of value to retailers

This section provides a discussion of the different ways that exported PV output affects electricity retailers.

Electricity retailers buy electricity at the wholesale level and sell it to small customers.[4] When they receive exported PV output, the amount of electricity they must buy on the wholesale electricity market is reduced. This is the most significant impact that exported PV output has on retailers. This is discussed in section 3.1.

The discussion in section 3.1 outlines the process used to settle the wholesale electricity market. This is the process used to determine the amount of electricity that customers of each participating retailer used, and thus the amount that each retailer must buy on their behalf. The way that exported PV electricity interacts with this process is central to its value to retailers.

Section 3.1 provides a worked example of how PV output affects the settlement process. The portion of PV output used in the home is discussed, as is the portion that is exported.

Projections of the value of exported PV output to a retailer are provided in section 3.1.6. Projections are made for three financial years, 2011-12, 2012-13 and 2013-14. Two alternative projections are made for the financial years 2012-13 and 2013-14, reflecting the potential introduction of a carbon price as proposed by the Commonwealth Government in its *Clean Energy Future* policy.

The implications of the hedge contracts that retailers typically use to manage price risk are discussed in section 3.2.

Exported PV output also provides value to a retailer by avoiding network losses involved in delivering electricity from remote generation sources. This is discussed in section 3.3.

Section 3.4 demonstrates that exported PV output allows retailers to avoid NEM fees and costs associated with the provision of ancillary services in the NEM. Finally, section 3.5 examines the potential effect of exported PV output on retailer operating costs and finds that any such effect is likely to be negligible.

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4 Retailers also supply large customers, but they are not eligible for the feed-in payments, which are limited to small customers and are thus not relevant to this analysis.

3.1 Reduced wholesale purchases

Wholesale electricity in the NEM is traded through a spot market. Generators sell electricity to retailers through a series of auctions run by the Australian Energy Market Operator (AEMO). The wholesale spot price of electricity is determined by those auctions on a half hourly basis.

The settlement process is used to determine the financial liability of each retailer on a daily basis. Settlement occurs weekly, four weeks in arrears, with AEMO collecting money from buyers of electricity and passing it on to generators. According to AEMO, "the settlement price for both generators and market customers is equal to the amount of energy produced or consumed multiplied by both the spot price that applies in the region of their operation and any loss factors that apply."[5]

The spot price for each NEM region is calculated at a 'regional reference node' (RRN), which is a point in the transmission network to which notionally all wholesale sales and purchases of electricity are made. The adjustment for losses mentioned above is made in relation to the RRN, and prices quoted in the NEM are prices at that node (rather than 'delivered' prices at the point of consumption).

The settlement process ensures that retailers buy electricity for their customers at the wholesale spot price that was in effect when the electricity was used. For this to happen, consumption needs to be 'matched' to the half hourly spot price.

In order to match consumption to the spot price and calculate each retailer's liability to buy electricity, AEMO must determine how much electricity each retailer's customers used in every half hour interval.

In South Australia, the vast majority of small customers have accumulation meters.[6] These record the total amount of electricity that has passed through them since they were first energised. These are read periodically to determine how much electricity passed through them since the last reading. Accumulation meters are analogous to the odometer in a car.

With accumulation meters it is impossible to determine how much electricity was used in each half hourly interval. Therefore, in South Australia it is

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5 Australian Energy Market Operator, "An Introduction to Australia's National Electricity Market", July 2010, p12, available online at [http:/www.aemo.com.au/corporate/publications.html](http://www.aemo.com.au/corporate/publications.html), accessed 26 September 2011.

6 There are some exceptions, such as the approximately 2000 interval meters in use in a Solar Cities trial site.

currently impossible to match a small customer's actual electricity use to the wholesale price at the time of that use. [7][8]

Without detailed, half hourly consumption data, an alternative approach is necessary to match the amount of energy used in a given period with the corresponding wholesale price. In the NEM, this is done using a mathematical process referred to as profiling.[9]

3.1.1 Settlement using the Net System Load Profile

Profiling is applied to the total amount of electricity sold in the NEM each day.

The starting point is all the electricity 'delivered' to the grid. Electricity used by customers with interval meters, whose consumption is known on a half hourly basis (and some ancillary loads[10]) is deducted. The residual is, by deduction, the amount of electricity that electricity retailers bought to supply small customers without interval meters.[11]

In South Australia, the profiling process also includes an adjustment, or 'peel off', for electricity used by controlled loads, most commonly electric water heaters. The controlled load peel off is calculated using sample meters and a 'controlled load profile'.[12]

The electricity that remains is deemed to have been used by small customers for general use (not controlled load). The remaining usage, which has been calculated on a half-hourly time-of-use basis, is the Net System Load Profile (NSLP).

A stylised example of the profiling process is illustrated in Figure 1 below.

Figure 1 shows the first four steps of the profiling process. The first pane shows a stylised example of electricity demand in South Australia for a single day. Demand is lower overnight than in the morning and rises to a peak in the afternoon before returning to a lower level overnight.

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7 The same is true in most other parts of the NEM.

8 It is impossible in a practical sense. It could be done if all customers had interval meters, which record electricity consumption as a series of half hourly increments for exactly this purpose. However, these are not (widely) in use in South Australia.

9 Australian Energy Market Operator "Understanding load profiles published from MSATS", August 2009, available online at http://www.aemo.com.au/electricityops/nslp.html, accessed 16 September 2011

10 For example unmetered loads such as street lighting.

11 In South Australia this is all small customers.

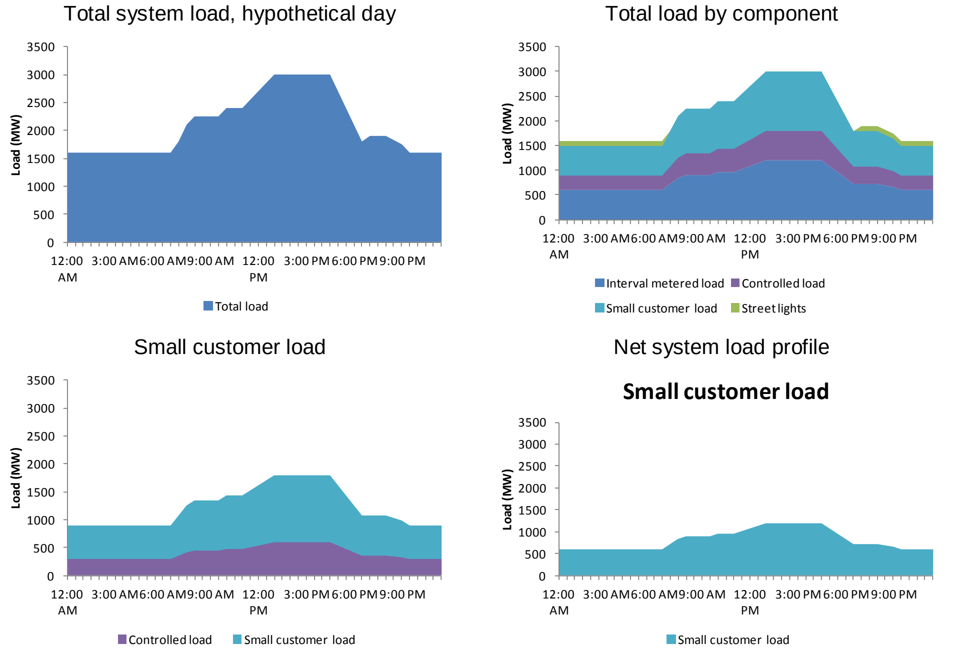
12 AEMO 2009, Op Cit

The second pane shows the same load broken into components. The commercial load category represents all customers with interval meters and the street lights category represents the various unmetered loads in the system. Controlled load (e.g. electric hot water) is shown separately from the other small customer load. The proportions of electricity used for these different purposes are illustrative; they are not intended to be indicative of actual use.

In the third pane commercial load and street lights have been removed leaving only small customer load.

Once the controlled load peel off has been done the residual is the NSLP, depicted in the fourth pane. This represents the demand for electricity of small customers other than for controlled loads such as water heating.

Figure 1 **Example of developing the NSLP for a hypothetical day**



The NSLP is then used to settle the purchase of wholesale electricity. The total quantity of electricity represented by the NSLP is allocated to individual customers and therefore individual retailers in proportion to the total amount of electricity that they consumed in the relevant period.[13] In doing this, it is assumed that each individual customer's 'load shape' is the same as the NSLP.

This is built up to determine each retailer's liability.

13 Small customers are typically billed every three months so a process is necessary to convert to daily consumption estimates.

The NSLP used in the settlement process is a robust estimate of the residual loads in the system that has been used in the NEM since January 2001. It gives an accurate picture of the electricity delivered to the grid and supplied to all small customers in aggregate on a time-of-use basis. However, it provides no information regarding how much electricity an individual customer has used or when they used it.

3.1.2 How the Net System Load Profile is used to settle the market

Once the NSLP has been calculated for a given day, two more pieces of information are used to settle the market:

- the wholesale spot price of electricity in each half hourly period
- the total amount of electricity sold to the small customers of each of the 'tier 2' retailers. In South Australia, this means all retailers other than AGL.[14]

The settlement process is illustrated in Figure 2, which shows the total system load, NSLP and wholesale spot price for 22 November 2010, and Table 1, which shows the market share of each retailer.[15][16]

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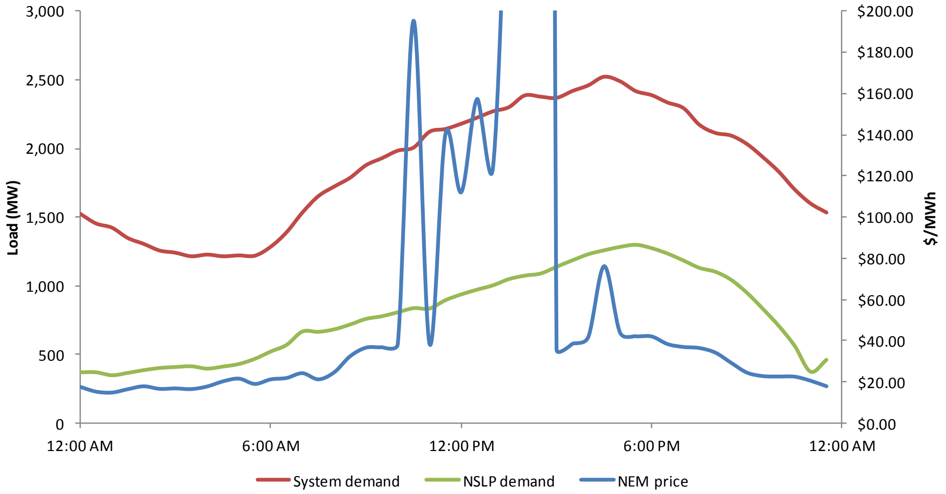
14 The liability of the tier 1 retailer, AGL in South Australia, is the remainder after the liabilities of other retailers have been netted off.

15 The data that are available publicly do not show how much of the total amount of electricity sold on the NSLP each retailer was required to buy (i.e. how much was used by each retailer's customers). For illustration purposes we have assumed that their liability on that day was the same as their market shares as the Commission reported in it's 2009/10 Annual Performance Report.

16 Between 1:30 PM and 3:00 PM on 22 November 2010 the wholesale spot price of electricity in South Australia was above $200/MWh. For ease of presentation the chart has been truncated at $200/MWh, but this obscures the price at these times. The missing prices were:

1:30 PM	$299.10
2:00 PM	$463.20
2:30 PM	$2,397.96

Figure 2 **System load, NSLP and spot price – 22 November 2010**



Data source: AEMO

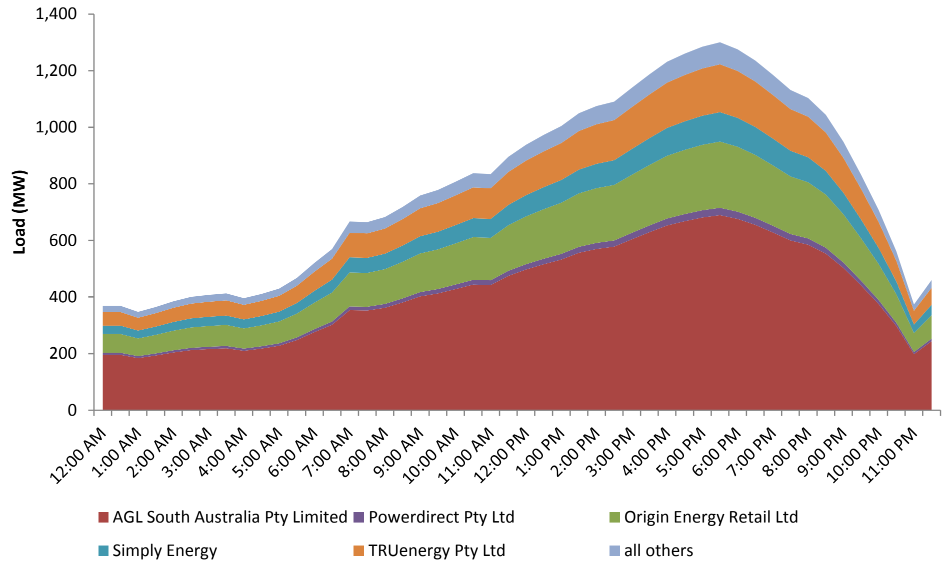
Table 1 **Retailers' market shares**

Retailer	Market share (%)
AGL	53%
Origin Energy	18%
Powerdirect	2%
Simply Energy	8%
TRUenergy	13%
All others	6%

Data source: Essential Services Commission of South Australia, Annual Performance report 2009/10, www.escosa.sa.gov.au

The market shares in Table 1 are applied to the NSLP in Figure 2 to show each retailer's 'share' of the NSLP in each half hourly interval, refer Figure 3. Each retailer's 'band' of liability is equivalent to the amount of electricity it sold all of its customers that day, allocated according to the NSLP.

Figure 3 **Retailers' estimated 'share' of NSLP on 22 November 2010**



On 22 November 2010, the total quantity of electricity sold on the basis of the NSLP was 18,944 MWh[17] and the total wholesale cost of electricity sold on the basis of the NSLP was $2,541,119.[18] The average wholesale price of electricity sold on the basis of the NSLP that day was $134.14 per MWh.

There are approximately 800,000 small customers in South Australia so the wholesale cost of electricity that day was approximately $3.18 per customer.

Table 2 shows an estimate of the cost each retailer incurred on 22 November 2010 to purchase wholesale electricity on behalf of its small customers. For example, in this illustrative example we estimate that AGL's liability for electricity sold to its small customers on 22 November 2010 was almost $1.35 million.

Table 2 **Retailers' estimated 'share' of wholesale electricity cost on 22 November 2010**

Retailer	Wholesale electricity cost ($)
AGL	$ 1,346,793
Origin Energy	$ 457,401
Powerdirect	$ 50,822
Simply Energy	$ 203,290
TRUenergy	$ 330,345
All others	$ 152,467

Data source: AEMO, ESCOSA

[17] This is the area under the green curve in Figure 2.

[18] This is the product of the blue and green curves in Figure 2.

On any given day, every electricity retailer in South Australia pays the NSLP-weighted price for every kWh of electricity they buy for small customers. Through the settlement process, the NSLP-weighted price varies daily to reflect fluctuations in the wholesale spot price and the actual timing of electricity consumption.

3.1.3 The impact of PV systems on the NSLP

As discussed in section 3.1.1, the NSLP is the residual amount of electricity demand delivered into the market after other interval metered or deemed loads have been taken into account. As electricity cannot be stored, it is also the amount of electricity that was generated for small customers in each half hourly interval.

When PV systems generate electricity, all else being equal, other generators produce less. Usually, the output of 'other generators' would fall by more than the amount of PV output because the PV systems are closer to where the electricity is used so less is lost in the network. The effect of this on the value of exported PV output is discussed in section 3.3 below.

It is important to note that, from a generator's point of view, it does not matter whether the electricity generated by the PV system is used in the home or exported. Regardless of where it is used, the output of a PV system reduces the amount of electricity generators must produce.

The output of PV systems is not taken into account explicitly in determining the NSLP. From AEMO's perspective, the electricity they generate is the same as a reduction in demand. When PV systems generate electricity, less is required from other generators and the NSLP is 'reduced' by that amount. This is illustrated in Figure 4.

The first pane of Figure 4 reproduces the NSLP from 22 November 2010.[19]

The second pane shows the hypothetical output of a 'fleet' of PV systems. For illustrative purposes, to make the effect large enough to be seen easily on the charts, this fleet of systems was assumed to generate 5,000 MWh of electricity on 22 November 2010.[20] That output was apportioned across the day in line

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19 As this is the actual data from that day it already reflects the electricity generated by PV systems that were in place then. It is used here as a starting point for illustration only.

20 This is an unrealistically large fleet of PV systems presented only for illustration purposes. Between 12:00 and 12:30 PM, the PV systems were assumed to produce 305 MWh of electricity. To do this they would need a working capacity of almost 610 MW. Assuming an average system size of 2.5 kW systems, the fleet would need to include 244,000 individual systems all working at peak output. This would be more than one system for every four small customers in South Australia, and approximately five times the number of systems in place at the time of writing.

with the solar insolation measured at North-West Bend (on the River Murray about 180 km from Adelaide) that day. This data was sourced from Renewables SA,[21] which has made insolation data available for several locations in South Australia. Of these, North-West Bend is the closest to Adelaide.

The third pane shows what the NSLP would have looked like on 22 November 2010 if the hypothetical fleet of PV systems had been in place on that day.

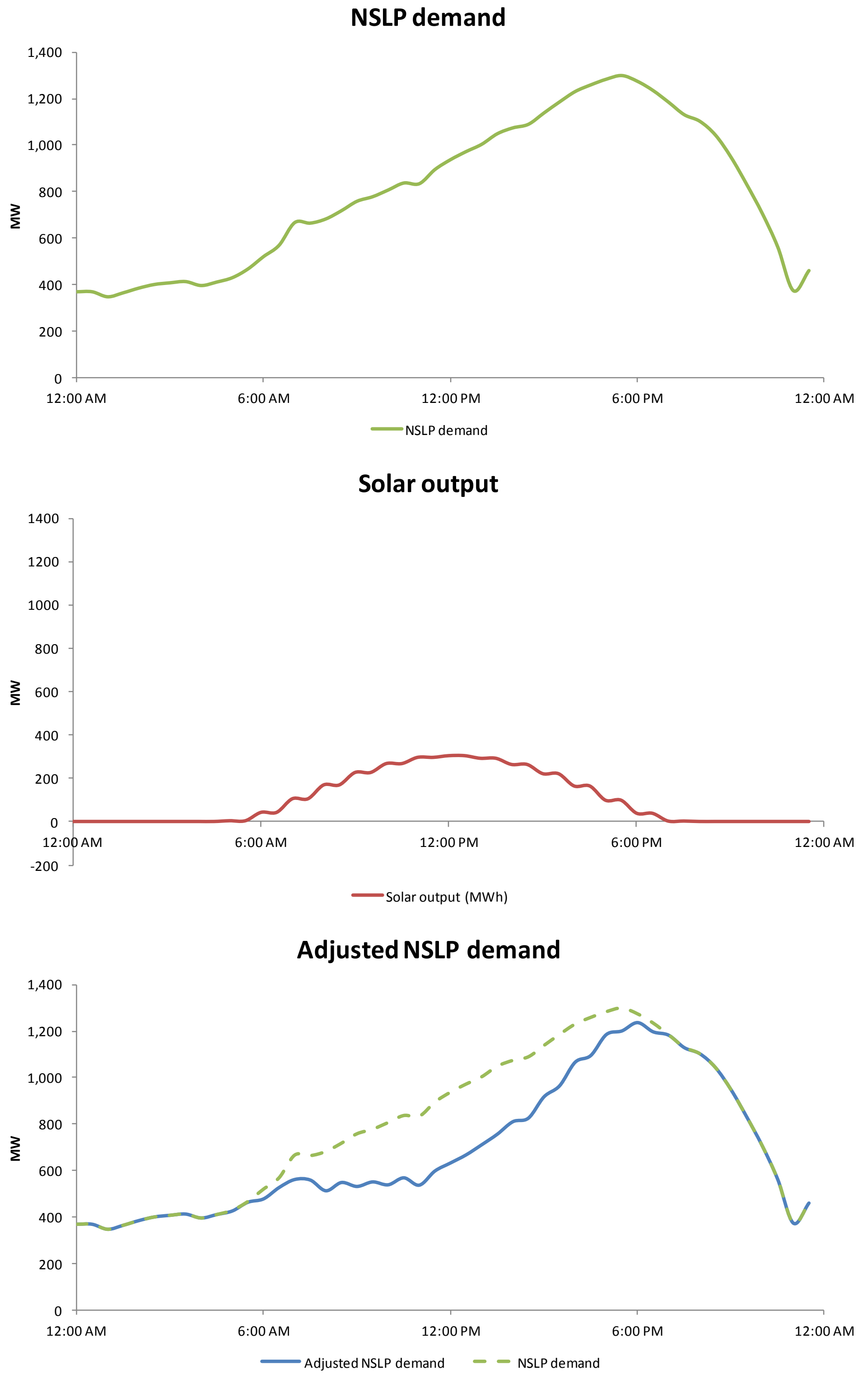
As illustrated in Figure 4, the impact of the PV systems is that the NSLP is 'lower' whenever they are generating. The difference between the NSLP with and without the PV systems is the total output of the PV systems. The area between the two curves represents 5,000 MWh.

When the NSLP is reduced in this way there are two results:

1. the NSLP-weighted price will (usually) be lower than it would have been if the PV systems were not in place, even assuming NEM prices in each half-hour period are themselves unchanged (the price effect)
2. the total amount of electricity sold on the NSLP is reduced (the volume effect).

21 http://www.renewablessa.sa.gov.au/investor-information/resources#Solar

Figure 4 **Illustrative example of the impact of PV systems on the NSLP**



Source: ACIL Tasman analysis

3.1.4 The price effect

The price effect is the mathematical result of the change in the NSLP. Assuming that spot prices themselves do not change and that they are higher during the day than overnight, the NSLP-weighted price will be decreased due to the output of PV systems.

PV systems generate during the day. The NSLP-weighted price after allowing for generation by PV systems therefore reflects a relatively higher amount of overnight electricity and a relatively lower amount of electricity during the day than the NSLP-weighted price without the PV systems.

All else being equal, the output of PV systems reduces the price that retailers pay for wholesale electricity for small customers. This affects all retailers equally and is caused by the total output of the PV systems, not (only) the quantity of electricity that is exported.

In our view, the value of the price effect will not be captured by retailers. Rather, the operation of the market will ensure that the price effect is passed through to customers. Therefore, we have excluded it from our estimate of the fair and reasonable value of exported PV output.

Retailers in South Australia operate in a competitive market. As Figure 5 shows, competition among retailers is such that all retailers offer electricity at lower prices than the regulated price determined by the Commission. All of the market offers for conventional electricity at the time of writing were below the standing contract price. The only market offers that are more expensive than the standing offer contract are environmentally friendly options, which are premium products.[22]

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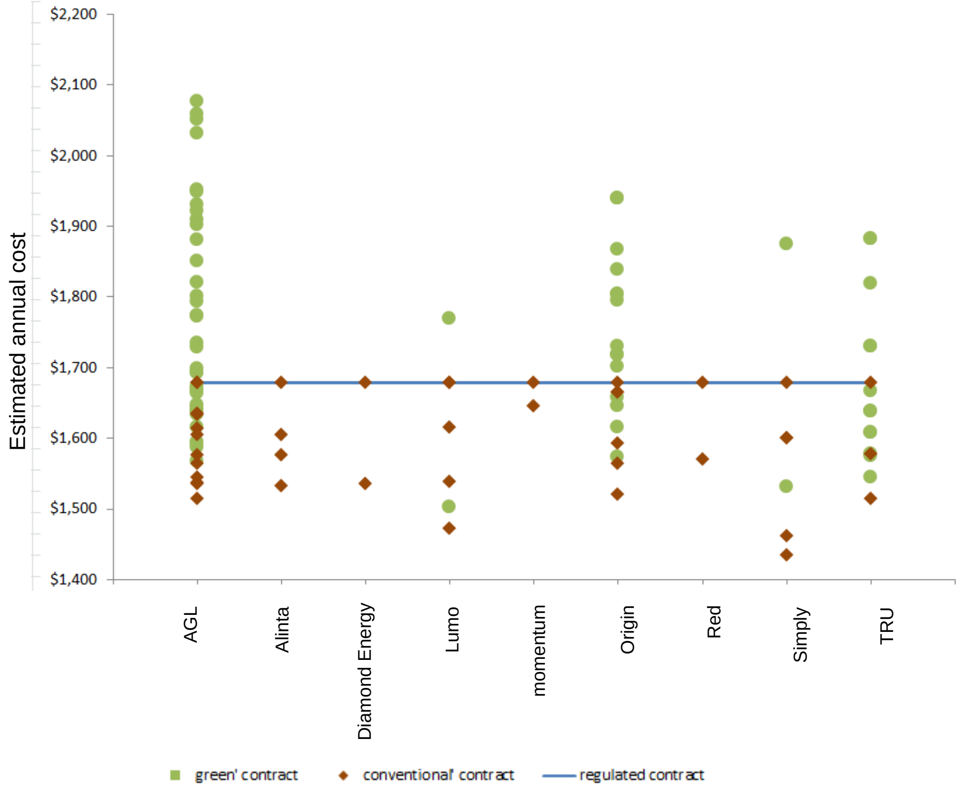
22 In June 2010 we reported to the Commission that competition in the retail electricity market in South Australia had stalled. We also reported that retailers were of the view that the Commission should increase the retail price cap and adopt the Relative Price Movement approach the Commission to adjust prices over time to increase the level of retail competition. Both of these changes have since been made. We also reported that several retailers were ready to increase their competitive activity in that market if there was a small reduction in the cost of doing business. This supports the conclusion that any reduction in cost that applied to all retailers equally would be competed away.

Figure 5 **Market offer and standing contract prices of electricity**



Note: the estimated annual cost plotted here was calculated by the Commission using its standard methodology for comparing market contract offers.

Data source: ESCOSA

The average discount to the standing contract price for market offers is five per cent, although some offers are discounted by up to 14 per cent.

These discounts are the result of competition between the retailers. In a market characterised by competition, it is reasonable to expect that retailers will pass on cost savings to their customers when they occur. Therefore it is likely that any reduction in the NSLP-weighted wholesale price of electricity will be 'competed away' from retailers to customers. Through this process, the value of the price effect is lost to retailers. This point was made by all of the retailers who made submissions to the Commission.

Given that the value of the price effect will be competed away by retailers, including it in the retailer payment would potentially be harmful to the competitive process.

Even though the benefit is 'competed away', there may be a concern that the benefit will not be allocated to the 'right' customers. Specifically, there may be a concern that PV customers cause the price effect but share its benefit with non-PV customers.

Conceptually the benefit of the price effect could be allocated to PV customers by including it in the retailer payment. If the Commission was able to estimate the value of the price effect with precision and included it in the retailer payment then PV customers would be paid more for their exported PV output as the retailer payment would be higher. To offset this, the price of electricity paid by other customers would increase.

In this scenario there would be no change in the total amount of benefit flowing to consumers from the electricity market, although the distribution of the benefit would change (towards PV customers at the expense of non-PV customers).

A more likely scenario, though, is that this redistribution itself would be costly and consumers as a group would be worse off.

Further, we note that the Act refers specifically to electricity exported to the network. Approximately two thirds of the electricity generated by PV systems that causes the price effect is used in the home.[23] Importantly, the amount of electricity that is exported while prices are high is likely to be significantly less than at other times. This is because the same increases in demand which cause the price to rise also cause in-home use of PV output to rise, reducing exported PV output.

For these reasons we have excluded the value of the price effect from our estimate of the fair and reasonable value to a retailer of exported PV output.

3.1.5 The volume effect

When PV systems generate electricity they reduce the amount of electricity that retailers must buy in two ways.

First, the PV output that is used in the home reduces the quantity that the PV customer buys from their retailer. Therefore the retailers need not buy as much to supply them. From the retailer's point of view, the PV system has the same effect as if the customer decided not to use as much electricity. The benefit of any in-home use of PV output accrues directly to the PV customer.

This part of the volume effect is not beneficial to the retailer as they neither purchase nor on-sell electricity that is consumed in the home in this manner.

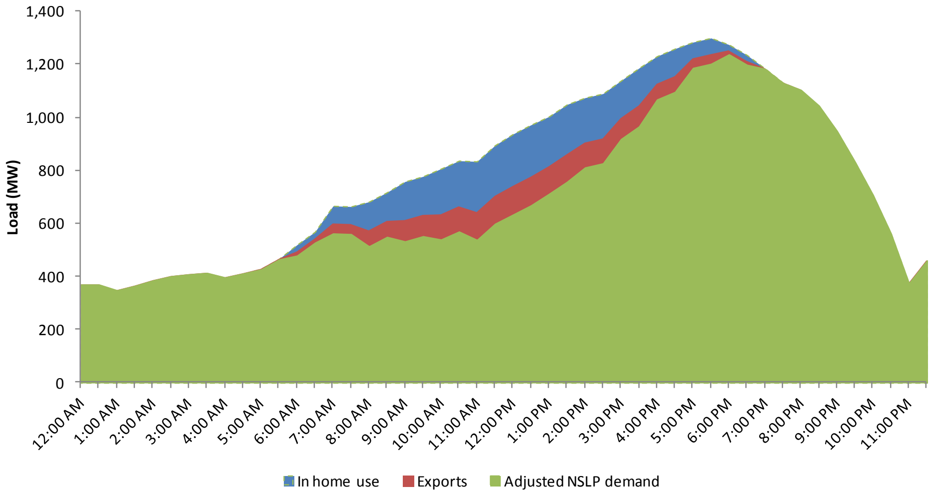
Second, the exported PV output is accounted for in calculating the retailer's 'share' of the NSLP by treating it as negative demand. Therefore, in the

23 The proportion of a PV system's output that is exported varies depending on system size and other factors. In South Australia, we estimate that the weighted average export rate is 35.8%. This has been calibrated with historical South Australian export values.

settlement process, retailers do not buy as much electricity as they would have if the PV systems had not generated electricity, as is explained below.

Continuing with the above example, the impact of the hypothetical fleet of PV systems on settlement on 22 November 2010 is summarised in Figure 6.[24]

Figure 6 **Illustrative example of the NSLP adjusted by PV output showing in-home use and exports**



In Figure 6, the (green) area under the adjusted NSLP curve is the total quantity of electricity generated by generators other than the hypothetical fleet of PV systems described above.[25]

The (red and blue) area between the original and adjusted NSLP curves is the quantity of electricity that was generated by the hypothetical fleet of systems. For illustrative purposes we have assumed that 35 per cent of this electricity was exported to the grid (red) and the remainder used in the home (blue).[26]

When the market settles, retailers will need to purchase their share of the electricity represented by the green area. Assuming that the hypothetical fleet of PV systems are spread evenly across retailers then the proportions will be the same as in Figure 3 above.

24 It is assumed that the fleet of PV systems is spread among retailers in accordance with their market shares.

25 The NSLP upon which this example is based already reflects the output of the PV systems that were in South Australia on 22 November 2010.

26 Aggregate data regarding the total quantity of exported PV output exports is available, but data regarding total production (i.e. including in-home use) is scarce. Therefore this ratio must be estimated. The estimate itself does not affect the point being illustrated.

However, there is also the electricity in the red area. Retailers will not purchase this electricity from the wholesale spot market, but they will sell it to their customers. This is true in aggregate and also for individual retailers because the electricity exported from any given customer's PV system is assigned to that customer's retailer.

Therefore, due to the volume effect, exported PV output reduces the amount of electricity that retailers must buy on the wholesale spot market to supply small customers. This point is uncontroversial. Each of the retailers that made submissions to the Commission acknowledged it.

The amount by which this is reduced is related to the quantity of *exported* PV output, although it cannot be quantified without considering network losses, which are discussed in section 3.3.

Retailers benefit from this electricity. Exported PV output reduces their need to purchase electricity from the wholesale market. The quantity that an individual retailer's 'own' customers export is captured by that retailer. The benefit is equal to the NSLP-weighted price multiplied by the amount of electricity the retailer's 'own' customers exported to the grid.

In our view, this is part of the fair and reasonable value of exported PV output to a retailer.

3.1.6 Quantifying the volume effect

In this section we provide an overview of our methodology for projecting the NSLP-weighted wholesale spot price of electricity in South Australia and our estimate for that price in 2011-12, 2012-13 and 2013-14.

This projection is based on two inputs:[27]

1. a projection of the NSLP
2. a projection of the wholesale spot price in the SA NEM region.

Our projection of the NSLP, and the methodology by which it was prepared, is set out in Appendix B.

Our projection of the wholesale spot price of electricity in South Australia was prepared using *PowerMark*, ACIL Tasman's proprietary model of the NEM.

Wholesale spot prices in the NEM will increase materially following the introduction of a carbon price as proposed by the Commonwealth Government in its *Clean Energy Future* policy. However, there is still

27 This NSLP-weighted price is expressed in per MWh terms so a forecast of the volume of exported PV output is not required.

considerable uncertainty about whether, and when, this policy will come into effect. To account for this uncertainty, we forecast the NSLP-weighted price under two scenarios:

- a Carbon scenario involving the introduction of a carbon price from 1 July 2012 starting at $23 per tonne of carbon dioxide equivalence for 2012-13
- a No carbon scenario, in which no carbon price is introduced over the projection period.

In summary, our projections of the SA NEM region load-weighted wholesale spot price of electricity are set out in Table 3.

Table 3 **Projected SA NEM region load-weighted prices 2011-12 to 2013-14, $ nominal per MWh at regional reference node**

Scenario	2011-12	2012-13	2013-14
Carbon	$53.44	$77.44	$87.05
No carbon	$53.44	$66.30	$72.83

Data source: *PowerMark* modelling

The key driver of increasing prices under the No carbon scenario is a general tightening of the supply-demand balance in response to growing demand. Recent entry of new plant has tended to suppress prices below the 'new entrant level' (the level sufficient to support investment in new plant) but ongoing demand growth in SA and other NEM regions causes prices to rise towards this level over time. By 2013-14 we project new entrant gas-fired and wind plant entering in response to the tightening supply-demand balance and firming prices.

Further, new entrant gas-fired plant is generally modelled as paying higher gas prices than incumbent gas-fired generators, reflecting expected tightness in gas contract markets.

The moderate increase due to carbon pricing on top of this underlying increase reflects the relatively low-emissions intensity of generation in the SA NEM region, which includes significant quantities of gas-fired and wind generation.

More information regarding *PowerMark* and the modelling scenarios undertaken for this analysis is in Appendix C.

The projections of the wholesale spot price of electricity and the NSLP are each a series of half hourly values, price and demand respectively, for one year blocks. These were combined to produce the projection of the NSLP-weighted prices shown in Table 4 and Figure 7.[28]

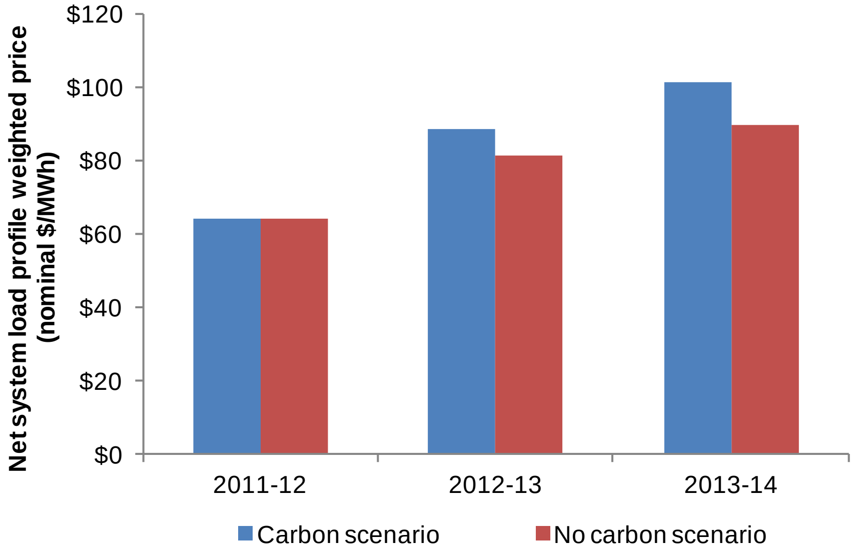
[28] The NSLP weighted price is the sumproduct of the NSLP and the wholesale price, both on a half hourly basis, divided by the sum of the NSLP.

Table 4 **Projected NSLP-weighted prices 2011-12 to 2013-14, $ nominal per MWh at regional reference node**

Scenario	2011-12	2012-13	2013-14
Carbon	$64.05	$88.91	$101.73
No carbon	$64.05	$81.46	$89.84

Data source: *PowerMark* modelling and ACIL Tasman analysis

Figure 7 **Modelled NSLP-weighted price for South Australia**



Note: All prices are presented in nominal $ per MWh at the SA NEM region regional reference node.
Source: PowerMark modelling

3.2 Why hedge contracts do not affect the value to retailers

Wholesale electricity for South Australian customers is sold into and bought through the NEM wholesale pool. That is, the wholesale electricity market operates as a gross pool. The implication is that all purchasers of wholesale electricity, including electricity retailers, must pay the NEM spot price for all electricity they purchase in any given half-hour period.

However, given the potential variability and volatility in the wholesale spot price, electricity retailers also typically enter into a variety of financial contracts to manage the risks they face in purchasing electricity from the wholesale NEM pool. While the wholesale price can increase to $12,500 per MWh, retailers generally sell this electricity to small customers at (generally) a fixed price. That price varies from retailer to retailer and the price that customers pay covers both electricity and network access. The Commission recently set the wholesale electricity component of the electricity price for small customers at $93.93 per MWh.[29,30]

It is necessary to consider whether the existence of these financial contracts affects the value of exported PV output to electricity retailers, that is, whether the NSLP-weighted wholesale spot price of electricity estimated in section 3.1.6 is the appropriate measure of value to retailers or whether it should be adjusted to take contractual positions into account.

This matter is considered in detail in Appendix A. As is shown in that appendix, a typical portfolio of contracts is designed to hedge against price risk. However, it would not limit retailers' exposure to volume risk. This means that, for a fixed contractual position[31], any variation in quantity of the electricity they purchase results in a cost (for an increase in consumption) or a saving (for a decrease in consumption) equal to the wholesale spot price. This means that where a retailer purchases a lower volume of electricity from the wholesale market due to exported PV output from its customers, it benefits by avoiding the wholesale spot price for each unit of reduced consumption.

It follows from this analysis that the fair and reasonable value of exported PV output to a retailer from avoided NSLP purchases will equal the NSLP-weighted spot price, irrespective of its contractual position.

3.3 Avoided losses

The amount of wholesale electricity displaced by exported PV output will usually be greater than the amount of that output. This is because less electricity will be lost in the network between the point of generation and the point of consumption when compared to wholesale electricity supplied by remotely-located, large-scale generators.

If wholesale electricity incurs 10% greater losses in reaching the point of consumption than exported PV output, 100 kWh of exported PV output would displace 110 kWh of wholesale electricity purchases.

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29 This was the wholesale electricity component alone. When other costs are considered the Wholesale cost of electricity is estimated at $112.89. However, $93.93 is the appropriate value to compare with the wholesale spot price.

30 This estimate is based on the long run marginal cost of electricity and another forward looking approach. One of the submissions to the Commission suggested that this should also form the basis of the retailer payment. However, while it is appropriate for efficient pricing purposes, the forward looking nature of this estimate makes it inappropriate for setting the retailer payment which must relate to the avoided cost of electricity from existing generators.

31 The question of whether exported PV output would lead a retailer to change its contract position is discussed in section 4.1.

Given this assumed loss rate, it follows that the value to a retailer of 100 kWh of exported PV output is equal to the value of 110 kWh of wholesale electricity, and therefore its per unit value to the retailer will be 10% higher.

The *PowerMark* modelling projects the wholesale electricity price at the regional reference node (RRN). Accordingly, losses between the RRN and the point of connection to the distribution network, as well as losses within the distribution network, must be taken into account.

ACIL Tasman has analysed historic transmission and distribution loss factors for the SA NEM region published by AEMO. As Table 5 shows, losses in delivering energy from the RRN to small customers in South Australia have historically been approximately eight per cent. For simplicity, we have assumed that this will not change over the projection period.

At the time of writing the Commission had not reached a conclusion as to how frequently the retailer payment would be updated. If the Commission chooses to set the retailer payment for a three year period, it would be reasonable to set it on the basis that losses will be 7.97 per cent in 2011-12 and eight per cent in 2012-13 and 2013-14.

On the other hand, if the Commission prefers to update the retailer payment on an annual basis it may prefer to do so based on the most recently published loss factor at the time.

For the purposes of this report we have assumed that losses will remain at eight per cent in 2012-13 and 2013-14. Assuming that losses remain close to the historic range, any errors introduced by this assumption will be minimal and within the error margin of the wholesale electricity price projection.

Table 5 **Historic loss factors in South Australia**

	2007-08	2008-09	2009-10	2010-11	2011-12
Low voltage customer DLF	1.0799	1.079	1.074	1.0814	1.0765
SA VTN MFL	1.0001	1.0009	1.0057	1.0003	1.003
Combined loss factor (= DLF × MLF)	1.0800	1.0800	1.0801	1.0817	1.0797
Implied losses	**8.00%**	**8.00%**	**8.01%**	**8.17%**	**7.97%**

Note: DLF means distribution loss factor. MLF means marginal loss factor and applies to the transmission network. VTN means virtual transmission node and is an aggregated representation of most consumption MLFs in the SA NEM region.

Data source: AEMO

Actual losses may be higher during the day, when PV systems are exporting, than overnight. However, the settlement process of the NSLP 'smears' the effect of loss factors across the day so that the average (published) loss factors are applied in practice. Therefore it is the published, not actual, losses that are relevant in estimating the value to retailers.

The analysis in this section is conducted on the basis that losses will remain constant over the projection period. We have not assumed that increasing penetration of PV systems will reduce loss factors over the projection period materially.

Regardless of whether this happens, any benefit from reduced (system-wide) losses will be reflected in lower electricity purchase costs for all retailers and thereby tend to be captured by consumers rather than retailers, as discussed in section 4.5.

Our estimates for the NSLP-weighted wholesale spot price of electricity in South Australia, adjusted to reflect the avoided losses, are presented in Table 6.

Table 6 **Summary results adjusted for avoided losses**

	Scenario	2011-12		2012-13		2013-14	
		$ per MWh	c per kWh	$ per MWh	c per kWh	$ per MWh	c per kWh
Energy costs before losses	Carbon	$64.05	6.4	$88.91	8.9	$101.73	10.2
	No carbon	$64.05	6.4	$81.46	8.1	$89.84	9.0
Benefit of avoided losses	Carbon	$5.55	0.6	$7.73	0.8	$8.85	0.9
	No carbon	$5.55	0.6	$7.08	0.7	$7.81	0.8
Energy costs after losses	**Carbon**	**$69.60**	**7.0**	**$96.64**	**9.7**	**$110.57**	**11.1**
	No carbon	**$69.60**	**7.0**	**$88.55**	**8.9**	**$97.65**	**9.8**

Note: All prices are presented in nominal terms. Numbers may not add due to rounding.
Data source: ACIL Tasman analysis

3.4 Market and ancillary service fees

AEMO levies two sets of fees on energy consumers in the NEM. The first covers its general operational costs (market fees). The second covers the cost of various ancillary services that are provided to ensure the reliable operation of the system (ancillary service fees).[32]

Market fees are published annually in advance and are generally levied on market customers (including retailers) on a per megawatt-hour basis.[33] AEMO's published 2011-12 fees indicate costs for market customers with a retail licence of around $0.4 per MWh, as set out in Table 7.

32 These deal with issues such as frequency control.

33 Other fees, such as for the registration of market participants, are levied on a user-pays basis, rather than on market customers specifically.

Table 7 **AEMO 2011-12 market fees**

Fee class	Rate ($ per MWh)	Paying participants
General fees	$0.12051	Market customers
Allocated fees - market customers	$0.14494	Market customers
Full Retail Contestability - electricity	$0.01573	Market customers with a retail licence
Full Retail Contestability - operations	$0.04333	Market customers with a retail licence
National Transmission Planner	$0.03681	Market customers
National Smart Metering	$0.01876	Market customers
Electricity Consumer Advocacy Panel	$0.01168	Market customers
• **Total**	• **$0.39176**	

Data source: AEMO, Electricity Revenue Requirement and Fee Schedule 2011/12, http://www.aemo.com.au/registration/0120-0031.pdf

Unlike market fees, AEMO seeks bids from market participants to provide ancillary services. Ancillary service fees are then set on a cost-recovery basis.

Ancillary service fees in South Australia are generally in the range of $0.1 per MWh to $0.2 per MWh. However, they can spike to much higher levels. For example in one week in 2010, ancillary service fees in the SA NEM region reached $35.79 per MWh.

Given this variability, we have assumed that the three year average level of ancillary service fees, which is $0.49 per MWh, reflects the likely future level of these costs.

Both market and ancillary service fees are levied on wholesale energy purchases as measured at the RRN. When a retailer acquires exported PV output from, its wholesale electricity purchases are directly reduced. Therefore, it avoids the associated market and ancillary service fees.

As these fees are levied at the RRN, similarly to avoided wholesale energy purchase costs, the effect of avoided losses actually increases the value of these avoided costs when a retailer acquires exported PV output.

With these considerations, the market fee and ancillary service fees developed for this analysis are shown in Table 8.

These reflect the current level of fees. However, AEMO's costs are mainly fixed, so as the total volume of energy each retailer buys falls the allocation process will cause the fee rates themselves to increase

We have assumed that both market fees and ancillary service fees will increase at 2.5% in nominal terms per year over the projection period.[34]

[34] As PV output increases, the volume of electricity sold on the wholesale market would decrease but the total amount of market and ancillary service fees would be unchanged.

Table 8 **Market fees and ancillary service fees**

	Scenario	2011-12		2012-13		2013-14	
		$ per MWh	c per kWh	$ per MWh	c per kWh	$ per MWh	c per kWh
Market fees	Both	$0.39	0.0	$0.40	0.0	$0.41	0.0
Ancillary service fees	Both	$0.49	0.0	$0.50	0.1	$0.51	0.1
Market fees and ancillary service fees (at RRN)	Both	$0.88	0.1	$0.90	0.1	$0.92	0.1
Market fees and ancillary service fees (after adjustment for losses)	Both	$0.96	0.1	$0.98	0.1	$1.00	0.1
Energy costs after losses	Carbon	$69.60	7.0	$96.64	9.7	$110.57	11.1
	No carbon	$69.60	7.0	$88.55	8.9	$97.65	9.8
Energy value after losses, market fees and ancillary service fees	**Carbon**	**$70.56**	**7.1**	**$97.62**	**9.8**	**$111.58**	**11.2**
	No carbon	**$70.56**	**7.1**	**$89.53**	**9.0**	**$98.65**	**9.9**

Note: All prices are presented in nominal terms

Data source: ACIL Tasman analysis

3.5 Retailer operating costs

There are other costs to being an electricity retailer than just the cost of electricity bought for customers. Retailer operating costs are the costs associated with operating the 'machinery' of being a retailer. In its 2010 retail price determination, the Commission included the following items in its assessment of retailer operating costs.[35,36]

- customer service
- sales and marketing
- revenue collection
- management and support (including corporate functions)

Therefore, conceptually, the unit price of those fees would increase. The size of this effect is likely to be immaterial, so we have not adjusted our estimate to account for it.

35 The Commission also considers the cost of meeting obligations under the Residential Energy Efficiency Scheme. These are dealt with separately in our analysis and discussed in section 4.3.

36 Essential Services Commission of South Australia, "2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination", December 2010. p A-85, available at http://www.escosa.sa.gov.au/projects/143/2010-electricity-standing-contract-price-path-inquiry.aspx, accessed 27 September 2011.

Retailer operating costs depend more on the number of customers a retailer supplies rather than the quantity of electricity it supplies them. This is reflected in the Commission's approach to estimating retailer operating costs in setting regulated retail prices, which it does on a 'per customer' basis.

The issue is whether the cost to serve a PV customer is lower, or higher, than the cost to serve a non-PV customer and whether this difference is related to the quantity of exported PV output.

In their submissions to the Commission's Issues Paper, retailers were unanimous in saying that managing relationships with PV customers is more expensive than other customers. For example Alinta Energy said that:[37]

> "PV customers are more in tune with electricity issues ...(resulting in) greater than average levels of engagement with retail providers than ... non-PV customers"

Similarly, TRUenergy said that the complexity of "quoting, service order processing, tariff changes and ongoing meter data management and billing costs for solar customers [means that] there is no doubt that the cost to serve" is higher for PV customers than others.[38]

However, it is not necessarily clear that either the PV system itself or the exported PV output makes the customers to whom Alinta refers more expensive to deal with than average. This statement appears to apply to the customers' awareness of electricity issues in general. If so, the cost to serve those customers would be higher anyway, but the *fair and value reasonable value of exported PV output would be unaffected.*

Similarly, the additional costs to which TRUenergy refers relate to the cost of serving solar customers more broadly and are not related to the value of the exported PV output itself.

Submissions from parties other than retailers did not go into detail on this issue.

The submissions give some reason to believe that the cost to serve PV customers may be higher than average. However, we note that retailers will already have established systems to manage and reconcile PV output purchased from their customers and to manage the reconciliation of credits associated with South Australia's various feed-in tariff schemes.

Only the incremental change in retailer operating costs associated with purchasing exported PV output should be considered in this context. While we

37 Alinta Energy submission, 23 September 2011, available at www.escosa.sa.gov.au

38 TRUenergy submission, 19 September 2011, available at www.escosa.sa.gov.au

have not attempted to estimate this incremental cost, our expectation is that it would be extremely small and within the reasonable error margin associated with the estimate of the energy value.

In their submissions to the Commission's Draft Decision several retailers (TRUenergy, Origin Energy and Alinta Energy) re-emphasised their view that retailer operating costs associated with servicing solar customers are higher and that these costs should be reflected in a lower value for exported PV output.

As noted in our original discussion on this issue, our view remains that the incremental cost associated with an additional unit of exported PV output is extremely small because:

- the costs associated with systems to manage the billing and other requirements of solar customers are largely fixed with minimal incremental costs associated with an additional unit of exported PV output
- such systems are necessary to manage billing of customers receiving the 44 cents/kWh feed-in tariff, which has been available since 1 July 2008
- such costs are largely independent of the share of PV output that is exported or consumed in the home, and therefore sit outside of the scope of this analysis which is to examine the value of *exported* PV output.

In summary, we remain of the view that to the extent that retailers do experience higher operating costs associated with managing solar customers or handling billing associated with feed-in tariffs, these costs are essentially unavoidable in operating as an electricity retailer in South Australia. That being the case, adjusting the fair and reasonable value of exported PV output downwards would incorrectly attribute these costs to variations in the level of exported PV output. In turn, this approach would artificially depress the value of each customer's exported PV output.

4 Sources of value (and cost) to other parties

This section provides a discussion of the impacts that exported PV output has, or may have, that do not affect retailers and therefore do not deliver value to them.

Section 4.1 deals with hedge contracts. In section 3.2 above, which also discusses these contracts, we assumed that a retailer would not reduce the volume of electricity for which they are contracted due to exported PV output. Our assessment is that the benefit accruing from this source is likely to be immaterial.

Regardless of the materiality of this impact, in section 4.1 we show that exported PV output does not affect the optimal contract position of a PV customer's 'own' retailer any differently than it affects other retailers. As with the price effect, which also affects all retailers equally, our expectation is that any benefit that might accrue to retailers from this source will be competed away in the market.

In section 4.2 we discuss network augmentation costs and the potential that exported PV output might defer these. Network costs are substantial and have been growing recently, so any cost-effective means of reducing them is worthy of consideration. However, as we discuss in section 4.2 it is unlikely that exported PV output would make any material difference to these costs and there is some evidence to suggest that it will increase them. Notwithstanding this, the market arrangements are such that retailers do not pay these costs, rather they simply pass the cost through from the electricity distributor. Therefore, regardless of the impact that exported PV output might have on network costs, the value, whether positive or negative, does not accrue to retailers.

Section 4.3 discusses 'green schemes', the various schemes that are in place in Australia to reduce the environmental impact of energy use by encouraging energy efficiency and renewable generation. As discussed in that section, exported PV output does not provide a benefit to electricity retailers by reducing their cost of complying with these schemes.

As discussed in section 3.1.4, the price effect reduces a retailers wholesale electricity cost by changing the shape of the NSLP so that is weighted less towards times when electricity prices tend to be high. This causes the NSLP-weighted price to fall.

In addition to this there is the possibility that PV output would cause the wholesale spot price of electricity itself to change. This possibility is discussed in section 4.4. Our assessment is that any benefit would be competed away by retailers in the same way as the price effect. Therefore no value would accrue to retailers even if the wholesale spot price was reduced due to exported PV output.

Finally, section 4.5 revisits network losses. In this section we consider the possibility that, in addition to the effect discussed in section 3.3 above, exported PV output might cause loss factors themselves to be adjusted. We consider this very unlikely but, even if it did occur, the benefit would accrue to retailers as a group. As with the price effect, our assessment is that this would be competed away in the market and therefore provide no value to retailers themselves.

4.1 Avoided contracting and risk management costs

In section 3.2 we established that, for a fixed contractual position, electricity retailers are exposed to the wholesale spot price of electricity when their customers change their consumption. Therefore, we concluded that the NSLP-weighted wholesale spot price of electricity was the relevant basis for estimating the fair and reasonable value to a retailer of exported PV output, irrespective of contractual positions.

In reaching that conclusion we assumed that contract positions would remain fixed. If retailers adjust their contractual positions because they receive increased exported PV output from their customers, they would also change their contracting and risk management costs.

Similarly to the discussion in section 3.1, the effect of exported PV output on the contractual positions of electricity retailers must be viewed by reference to the settlement process and the NSLP.

An electricity retailer supplying a small customer does not need to hedge itself against price risk associated with the customer's actual usage. Rather, the retailer must hedge itself against price risk associated with purchasing its share of the NSLP.

This is an important distinction. When a retailer acquires a new small customer from another retailer, its exposure to the wholesale spot price is 'filtered' through the NSLP. The incremental effect of a customer transfer on the 'acquiring' retailer is that its share of the purchase obligations derived from the NSLP increases. The increase is affected by the amount of electricity the transferring customer uses, but not by the time of use.

If the transferring customer has an existing PV system there is no price effect (that is, the shape of the NSLP will not change). Therefore, any impact on the retailer must be through the volume effect.

In this case, the acquiring retailer's exposure to the peak wholesale spot price will increase in proportion to its share of consumption in the NSLP. Therefore its optimal contracting position will be unchanged (per unit of energy purchased through the NSLP). The same is true of the retailer from which the customer has been acquired.

Similarly, if a customer installs a new PV system, whether they change retailer at the same time or not, that customer's retailer is impacted through the volume effect. As above, the volume effect does not change its optimal contracting position per unit of energy purchased through the NSLP.

In addition, the new PV system will cause all retailers' exposure to the peak wholesale spot price to change through the price effect, which may affect their optimal contracting position. This will impact all retailers equally and so no single retailer will benefit from it.

In neither case will any individual retailer receive a benefit from avoided contracting and risk management costs that is not also enjoyed by its competitors. Accordingly, any saving that does exist would be competed away and pass through to consumers.[39]

In its submission on the Commission's Draft Decision, the Australian PV Association (AVPA) noted that our argument that contractual positions are irrelevant for determining the fair and reasonable value of exported PV output assumed that contractual positions remain fixed.[40]

However, the APVA seems not to have considered the second point made above. We consider that, where contractual positions do change in response to increased exported PV output, the NSLP settlement mechanism means that no individual retailer will receive a benefit from avoided contracting and risk management costs that is not also enjoyed by its competitors. This is the essential argument as to why changes in contracting and risk management costs are not captured by retailers and therefore not relevant in determining the fair and reasonable value of exported PV output.

Alinta Energy has argued that contracting and risk management costs will increase due to increases in exported PV output, and therefore that "the price

[39] This conclusion holds with the current metering arrangements, in particular the lack of interval meters. If metering arrangements were to change this issue would need to be considered in more detail.

[40] APVA submission, December 2011, available at www.escosa.sa.gov.au

paid for output from solar PV should be a discount from the average pool price".[41]

The response to this argument is the same as in response to the APVA. It is quite possible that a retailer's average hedging cost per unit of energy sold to small customers will increase as a result of increasing exported PV output. For example, this could occur because the intermittent nature of solar PV output means that only minimal unwinding of hedge positions can occur, but increasing solar PV output reduces the total volume of electricity over which the retailer must 'smear' these hedging costs.

However, such an increase in per unit hedging costs would, through the NSLP settlement mechanism, be imposed equally on all retailers. Therefore, these costs would be borne by electricity consumers, not retailers, and are not relevant to our analysis of the fair and reasonable value of exported PV output to electricity retailers.

4.2 Network costs

The potential value that embedded generation, renewable or otherwise, can provide to electricity networks has been widely discussed.

Simply put, electricity networks are built to transfer electricity from the generator to the user. Networks have finite capacity and, in some places, they are capacity constrained, meaning that when demand is high the network comes close to, or even exceeds, its capacity. When demand exceeds capacity the network is unable to supply all of the electricity that is required and augmentation of the network is required to avoid outages.

When electricity is generated close to the load, it need not be transferred through as many components of the network. Therefore, an alternative to increasing the capacity of the network used to supply a capacity constrained area may be to 'embed' a generator in that area to bypass some components of the network that might otherwise require upgrading.

The cost of providing network infrastructure is approximately half of a typical retail bill. It has grown at a faster rate than other components of the electricity bill in recent years. Therefore any cost-effective means of deferring network investment is worthy of consideration.

Network costs for electricity consumers in the NEM states are determined through a regulatory process undertaken by the Australian Energy Regulator. This process results in a price control formula that governs prices for a five

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[41] Alinta Energy submission, 8 December 2011, available at www.escosa.sa.gov.au

year period. The network charges that arise from that formula are paid by retailers and recovered from small (and other) customers. Small customers pay for these charges on their retail bill, typically through a flat daily charge and an amount calculated on a per kWh basis.

Two issues are presented.

First, from the retailer's perspective, network charges are simply 'passed through' to network businesses. Aside from some risk management implications, the retailer is unaffected by changes in the total cost of network provision. Therefore retailers do not capture any benefit (or incur any cost) in relation to network charges by purchasing exported PV output.

The same is not true for PV customers. When they use PV output in the home, they avoid the network element of their retail bill because it is paid on a per kWh basis. Therefore, the total amount that PV customers pay for access to the network is reduced. All else being equal, this means that non-PV customers pay more for the network than PV customers. On the face of it, this may seem reasonable because PV customers also reduce their use of the network. They buy less electricity and thus less of it is transferred to them on the network.

However, the cost of network access is driven by peak demand, not electricity consumption. The cost of providing network access to an existing customer depends on their demand for electricity when demand in 'their' part of the network peaks. For small customers this usually occurs on summer afternoons, driven by air conditioning due to the high temperatures when electricity demand peaks.

It is possible that PV customers would reduce their energy use over the year, and therefore the amount they pay for network access, by more than their reduction in electricity demand at peak times. If so, they reduce the amount they pay for network access by more than their use of that network and, in doing so, receive a cross subsidy from non-PV customers whose network charges increase proportionally.

Further, for PV systems to defer network augmentation they would need to be installed in areas where the network is prone to being constrained and export electricity when those constraints bind. This implies that any payment related to network augmentation would be subject to the location, and usage, of the PV system in question and could not be averaged across all customers in any meaningful way.[42]

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[42] Doing so would also appear contrary to the Act. Specifically, section 35A(2) says that, in determining network prices, the Commission must have regard to the 'postage stamp pricing' principle, namely that network prices "should be at the same rates for all small customers regardless of their location."

In addition, South Australia's electricity network was designed for uni-directional flows. There is some evidence to suggest that PV systems actually increase network costs due to the bi-directional electricity flows associated with them.

In its submission to the Commission's Draft Decision, Tindo Solar argues that:[43]

> "As the pricing mechanism stands in relation to network charges, we believe it is reasonable PV should pay less in total for their network charges as they are using less of the network"

This argument was based on the logic that exported PV output travels a smaller distance through the distribution network than power generated by large-scale power stations, and so uses less of the network.

Tindo Solar's argument relies on the proposition that network tariffs should be levied differently in future to how they are presently. Whatever the merits of Tindo Solar's arguments or its conclusion that "there is a cross-subsidy against PV systems", it would not be appropriate to adjust estimates of the value of exported PV output on that basis.

4.3 Green schemes

'Green scheme' costs are the costs to retailers of complying with the various schemes that are in place in Australia to reduce the environmental impact of energy use, generally by encouraging energy efficiency or renewable generation.

The schemes that apply in respect of electricity consumers in South Australia are:

- the Large-scale Renewable Energy Target (LRET), a Commonwealth Government scheme that requires electricity retailers to support the development of large-scale renewable energy sources by purchasing certificates created by the generators in proportion to their electricity acquisitions on behalf of consumers
- the Small-scale Renewable Energy Scheme (SRES), a Commonwealth Government scheme that requires electricity retailers to support the development of small-scale renewable energy sources such as PV and solar water heaters by purchasing certificates created by these sources in proportion to their electricity acquisitions on behalf of consumers
- the Residential Energy Efficiency Scheme (REES), a South Australian Government scheme that requires electricity retailers to support uptake of energy efficiency opportunities by households by purchasing certificates

[43] Tindo Solar submission, 7 December 2011, available at www.escosa.sa.gov.au

that represent pre-specified energy efficiency actions, in proportion to their electricity sales.

In each case, electricity retailers are directly liable for the cost of these schemes in proportion to their wholesale electricity purchases or electricity sales. The corollary of this is that, if their share of electricity purchases or sales increase, compliance costs with these schemes increase in direct proportion.

In the case of the LRET and SRES, where liabilities are in proportion to electricity acquisitions on behalf of customers, exported PV output is treated as an acquisition by the retailer from the owner of the system and included in the total volume of that retailer's 'relevant acquisitions'. This reconciliation is similar to the settlement process by which the value of avoided wholesale purchase costs accrues to financial retailers.

ACIL Tasman has confirmed with the regulator of these schemes, the Office of the Renewable Energy Regulator (ORER), that the overall effect of ORER's treatment of relevant acquisitions is such that using exported PV output in place of wholesale electricity acquisitions does not reduce a retailer's liability for these schemes.

Therefore, avoided LRET and SRES compliance costs are not a source of financial benefit to electricity retailers from exported PV output.

The point of liability for the REES is slightly different to the LRET and SRES, being based on final sales. However, the final outcome is the same: under the REES, exported PV output is ultimately consumed at another premises and therefore liable under the REES.

Accordingly, exported PV output does not offer a financial benefit to electricity retailers through a reduction in compliance costs associated with the LRET and SRES, and is not relevant to the Commission's estimation of the retailer payment.

4.4 Reduced wholesale electricity prices

The 'price effect' discussed in section 3.1.4 considers the change in the NSLP-weighted price paid by all retailers for wholesale energy purchases made on behalf of small customers that results from an increasing level of PV generation. This occurs because PV generation tends to occur at higher priced times during the day and so reduces the NSLP-weighted price (by increasing its weighting towards overnight prices periods). This effect occurs even if NEM region prices are themselves unchanged by the advent of increased PV generation.

This section considers the case where increasing PV generation is sufficient to change NEM pricing outcomes, and whether this change would provide value to electricity retailers.

The output of PV systems in place in South Australia at the moment will undoubtedly have reduced the wholesale spot price of electricity below what it would have been had those systems not been in place. This is reflected in recent prices and therefore in projections based on demand growth from present levels.

However, changes in the wholesale spot price of electricity are not necessarily beneficial to retailers. As all retailers pay the NSLP-weighted spot price for purchases made on behalf of small customers, reductions in the spot price will pass through to all retailers equally. As with the price effect, our assessment is that these changes will accrue to customers through the competitive market.[44]

4.5 Reduced network loss factors

In general, increasing levels of PV generation (including exports) across the South Australian network result in a greater volume of electricity being generated close to the point of consumption. In turn, this would tend to result in a general reduction in the level of losses in the network as it increasingly displaces remotely generated wholesale electricity.

In practice, this would cause the loss factors AEMO uses in settling the market to change.

This effect may have already occurred to some extent, and may well occur to a greater extent in future as PV installations continue.

However, similar to the discussion in section 4.4 above, any such reduction in the loss factors in the electricity network will not provide a financial benefit to electricity retailers.

All retailers purchase wholesale electricity at the RRN of the relevant NEM region and on-sell it, after losses, to consumers. The losses attributable to each retailer are calculated using the same loss factors so all retailers face the same cost associated with losses. Therefore, all retailers face the same change in this cost whenever loss factors change.

It follows that any reduction (increase) in losses would tend to reduce (increase) electricity costs in total for consumers. It would not be captured by electricity retailers.

[44] In fact, the installations could even occur in other NEM regions as the physical interconnection of NEM regions allows for price competition between them.

5 Conclusion

In conclusion, when a retailer receives exported PV output from one of its customers it receives the following benefits:

- the amount of electricity it must buy on the wholesale spot market is reduced
- the reduction is more than the exported PV output itself because network losses are avoided
- the cost it avoids for each unit of exported PV output it receives is the NSLP-weighted price of electricity
- the cost it incurs for market and ancillary service fees is reduced

The quantity of exported PV output a retailer receives does not affect its cost of complying with green schemes nor does it affect retailer operating costs.

PV systems also cause the NSLP-weighted price to be lower than it would be if the systems were not in place. However, this benefit applies equally to all retailers in the competitive market. Any benefit that arises from this source is likely to accrue to customers, not retailers.

Similarly, any impact on the wholesale spot price of electricity is likely to accrue to customers rather than retailers.

This is also the case for changes in network loss factors. While exported PV output does avoid losses to the benefit of individual retailers, any effect that this might have on the loss factors themselves would affect all retailers. Any benefit that arises from this source is likely to accrue to customers, not retailers.

The output of PV systems is not likely to be sufficiently certain to allow retailers to alter their contract positions.

Similarly, it is unlikely to alter network augmentation costs materially and even if this did happen, any associated benefit would not accrue to the retailer.

Therefore, our estimate of the fair and reasonable value to a retailer of exported PV output is as set out in Table 9.

Table 9 **Value of exported PV output (nominal cents per kWh)**

	2011-12	2012-13		2013-14	
	Both scenarios	Carbon scenario	No carbon scenario	Carbon scenario	No carbon scenario
Reduced wholesale electricity cost	6.4	8.9	8.1	10.2	9.0
Avoided losses	0.6	0.8	0.7	0.9	0.8
Market and ancillary service fees	0.1	0.1	0.1	0.1	0.1
Total	**7.1**	**9.8**	**9.0**	**11.2**	**9.9**

Data source: ACIL Tasman

A Relationship between pool prices and hedge contracts

This appendix considers whether, for a retailer with a fixed contract position composed of typical hedge contracts used in the NEM, any change in the volume of electricity purchased from the NEM spot market delivers an electricity retailer a cost or benefit equal to the spot price relative to the situation before that change. Our conclusion is that they do.

A.1 Contracts in the NEM

The most common form of contracts used by electricity retailers are 'swaps' and 'caps' which are traded on a futures exchange operated by the Australian Securities Exchange (ASX), or private 'bilateral' equivalents of these contracts. Other, more exotic, contractual arrangements are entered into in the bilateral market. For the purpose of this analysis we consider the effect of contracts on the value of exported PV output to retailers through analysing the operation of swaps and caps.

In simple terms, these contracts operate in the following manner:

- swaps institute a series of payments between the seller and buyer of the contract to effectively fix the price of a certain volume of electricity, irrespective of spot price movements
- caps provide for payments from the seller of the contract to the buyer of the contract that effectively caps the price of electricity at a predetermined level, typically $300 per MWh, in exchange for an upfront 'premium' to enter into the contract.

The detailed operation of a swap is illustrated below through an example where:

- a retailer enters into a swap contract equivalent to a constant demand of 10 MW
- the retailer's customers consume this full 10 MW of electricity from the NEM pool at all times
- the 'strike price' of the swap is $50 per MWh, that is, the payments should operate to fix the price of electricity bought from the NEM pool at the equivalent of $50 per MWh irrespective of actual spot price movements.

Cash flows under a swap contract between the retailer, AEMO (the entity that 'settles' wholesale electricity purchases from the NEM pool) and the ASX (as the retailer's counterparty to the contract) are set out in Table A1 below. This illustrates how the effective price of the 10 MW covered by the contract is fixed at the strike price of $50 per MWh.

Table A1 **Swap contract difference payments – 10 MW contracted at $50 per MWh strike price**

Hour	NEM spot price	Payment: retailer to AEMO	Payment: retailer to ASX	Total retailer payment	Effective price for 10 MW consumed
	$ per MWh	$	$	$	$ per MWh
	A	B = A × 10 MW × 1 hr	C = (50 - A) × 10 MW × 1 hr	D = B + C	E = D ÷ (10 MW × 1 hr)
1	$1,000	$10,000	-$9,500	$500	$50
2	$50	$500	$0	$500	$50
3	$40	$400	$100	$500	$50
4	$0	$0	$500	$500	$50
6	$100	$1,000	-$500	$500	$50
...					

Note: Negative payments between the retailer and the ASX indicate a payment from the ASX to the retailer. Information presented on an hourly basis for simplicity, despite the fact that the NEM settles half-hourly.

Similarly, cash flows under a cap contract between the retailer, AEMO and the ASX are set out in Table A2 below. This illustrates how the retailer holding this cap is exposed to the spot price up to a price of $300 per MWh, but has its exposure capped at that level in the event that spot prices exceed $300 per MWh.

Table A2 **Cap contract difference payments – 10 MW contracted**

Hour	NEM spot price	Payment: retailer to AEMO	Payment: retailer to ASX	Total retailer payment	Effective price for 10 MW consumed
	$ per MWh	$	$	$	$ per MWh
	A	B = A × 10 MW × 1 hr	C = (300 - A) × 10 MW × 1 hr [if C < 0]	D = B + C	E = D ÷ (10 MW × 1 hr)
1	$1,000	$10,000	-$7,000	$3,000	$300
2	$50	$500	$0	$500	$50
3	$40	$400	$0	$400	$40
4	$0	$0	$0	$0	$0
6	$100	$1,000	$0	$1,000	$100
...					

Note: Negative payments between the retailer and the ASX indicate a payment from the ASX to the retailer. Information presented on an hourly basis for simplicity, despite the fact that the NEM settles half-hourly.

A.2 Volume risk versus price risk

The swaps and caps do not allow a retailer to avoid 'volume risk': if its customers consume more electricity at any point in time than the volume of contracts held, the retailer is fully exposed to the spot price for this uncontracted volume.

This is illustrated in the case of a swap in Table A3. The example presented below considers a situation where an electricity retailer retains 10 MW of contract cover, but its consumers use an additional (constant) 1 MW of electricity over each hour of the analysis. Table A3outlines the incremental cost of the additional consumption and demonstrates that the change in cost resulting from the additional consumption is equal to the NEM spot price.

Table A3 **Swap contract difference payments (10 MW contracted at $50 per MWh strike price) – increase in consumption**

Hour	NEM spot price	Volume of electricity consumed	Payment: retailer to AEMO	Payment: retailer to ASX	Total retailer payment	Total retailer payment for contracted 10 MW	Effective price for uncontracted 1 MW
	$ per MWh	MW	$	$	$	$	$ per MWh
	A	B	C = A × B MW × 1 hr	D = (50 - A) × 10 MW × 1 hr	E = C + D	F = $50 × 10 MW × 1 hr	G = (E – F) ÷ (1 MW × 1 hr)
1	$1,000	11	$11,000	-$9,500	$1,500	$500	$1,000
2	$50	11	$550	$0	$550	$500	$50
3	$40	11	$440	$100	$540	$500	$40
4	$0	11	$0	$500	$500	$500	$0
6	$100	11	$1,100	-$500	$600	$500	$100
...							

Note: Negative payments between the retailer and the ASX indicate a payment from the ASX to the retailer. Information presented on an hourly basis for simplicity, despite the fact that the NEM settles half-hourly.

The same logic holds in reverse when a retailer reduces its volume of wholesale purchases. Assuming the retailer’s contractual position is fixed for the time-being, if that retailer can reduce its consumption from the NEM pool it enjoys a benefit equal to the full spot price at the time of the reduced consumption. This final example is presented for completeness in Table A4.

Table A4 **Swap contract difference payments (10 MW contracted at $50 per MWh strike price) – reduction in consumption**

Hour	NEM spot price	Volume of electricity consumed	Payment: retailer to AEMO	Payment: retailer to ASX	Total retailer payment	Total retailer payment if 10 MW consumed	Effective benefit from reducing consumption by 1 MW
	$ per MWh	MW	$	$	$	$	$ per MWh
	A	B	C = A × B MW × 1 hr	D = (50 - A) × 10 MW × 1 hr	E = C + D	F = $50 × 10 MW × 1 hr	G = (F - E) ÷ (1 MW × 1 hr)
1	$1,000	9	$9,000	-$9,500	-$500	$500	$1,000
2	$50	9	$450	$0	$450	$500	$50
3	$40	9	$360	$100	$460	$500	$40
4	$0	9	$0	$500	$500	$500	$0
6	$100	9	$900	-$500	$400	$500	$100
...							

Note: Negative payments between the retailer and the ASX indicate a payment from the ASX to the retailer. Information presented on an hourly basis for simplicity, despite the fact that the NEM settles half-hourly.

This final example applies whenever a PV system exports electricity. The retailer that acquires this exported PV output has its liability for electricity purchases from the spot market reduced in a manner equivalent to a reduction in consumption, as shown in the example above.. Given a fixed contract position, the retailer reduces its payments to AEMO for purchases from the NEM pool without changing the payments it makes to or receives from its contractual counterparties (in the above examples, the ASX), and thereby receives a benefit to the value of the volume of the reduced electricity multiplied by the NEM spot price.

This analysis demonstrates that, assuming a fixed contract position composed of instruments substantially the same as ASX-traded swaps and caps, changes in the volume of electricity purchased from the NEM spot market delivers an electricity retailer a cost or benefit equal to the spot price.

B Methodology for projecting the NSLP

As outlined in section 3.1, the time-of-use profile for small customers (household and some small business loads) is calculated using a Net System Load Profile (NSLP) for settlement purposes. The NSLP is broadly the residual load once all interval metered load has been subtracted from total system load. The NSLP is used to settle wholesale market purchases made on behalf of small users where they do not have interval meters.

As discussed in section 3.1, the true value of exported PV output to an electricity retailer is determined by the effect of this output on its settlement obligations. In turn, these obligations for small customers are determined by the NSLP.

Accordingly, ACIL Tasman has used historic South Australian NSLPs to construct a projected NSLP for the years 2011-12, 2012-13 and 2013-14, and thereby to predict the NSLP-weighted price of energy in each of those years. In turn, this represents a forecast of the value of exported PV output to electricity retailers over this projection period.

B.1 Methodology

B.1.1 Treatment of controlled load

The SA NEM region includes both a NSLP and a 'controlled load' profile that is used to settle wholesale market purchases made to supply energy used by controlled load electric water heaters.

Controlled loads are typically used most intensively between 11:00 PM and 7:00 AM, when PV output is zero.

B.1.2 Relationship of historic NSLP and SA NEM region demand

ACIL Tasman has analysed the historic relationship between total NEM region load and the NSLP in South Australia as the basis of projecting the NSLP into the future on a basis consistent with the projected 'synthetic' SA NEM region loads modelled in *PowerMark*.

It is reasonable to expect a robust relationship between total SA NEM region load and the SA NSLP for several reasons:

- Non-residential loads tend to be more stable over time, such that peaks in SA NEM region load are likely to be correlated with peaks in the more volatile small-user (residential and small business) loads captured by the NSLP

- The NSLP itself is a material (approximately 40%) portion of total SA NEM region load
- The drivers of peaks in the non-NSLP load (such as air-conditioning loads in larger commercial premises on hot days) may demonstrate some correlation with the drivers of peak NSLP load (such as residential and small business air-conditional loads).

Historic SA NEM region load and SA NSLP load was analysed using data for calendar years 2008, 2009 and 2010.

However, ACIL Tasman further analysed the historic load data measured by AEMO to reflect the fact that some additional electricity consumption occurred in the period, but was not metered and recorded in the observed data set as it was supplied by small-scale PV systems. Accordingly, we derived 'underlying' profiles for both SA NEM region demand and SA NSLP demand by adding a stylised estimate of solar output in each half-hour to the observed loads (which are based on wholesale market purchases and therefore net of distributed PV generation).[45] This was necessary to account for the likelihood that increasing use of PV systems means that the regional load and NSLP will be different over the projection period than they were between 2008 and 2010.

The historic level of PV output in each hour of the calendar years 2008 to 2010 was based on a normalised 12 by 24 profile of Global Horizontal Irradiance estimated for the North-West Bend site by 3TIER for Renewables SA, as presented in Table B1.

[45] For these purposes the total output of the PV systems is required, not just the exported portion.

Table B1 **Normalised Global Horizontal Irradiance profile (W per m2)– North-West Bend, South Australia**

AEST	CST	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1:00	0:30	0	0	0	0	0	0	0	0	0	0	0	0
2:00	1:30	0	0	0	0	0	0	0	0	0	0	0	0
3:00	2:30	0	0	0	0	0	0	0	0	0	0	0	0
4:00	3:30	0	0	0	0	0	0	0	0	0	0	0	0
5:00	4:30	0	0	0	0	0	0	0	0	0	0	0	0
6:00	5:30	2.5	0	0	0	0	0	0	0	0	0.6	9.5	11.9
7:00	6:30	85.4	26.7	5.2	0	0	0	0	0	6.1	60.2	117.6	122.2
8:00	7:30	255.8	169.9	114	49.2	13.8	2.4	3.8	24.7	102.8	229.1	292.8	296.6
9:00	8:30	449.5	357.1	298.2	205.6	121.6	71.7	88.6	156.5	273.3	418	471	477.7
10:00	9:30	628.2	539.5	482.9	366.3	262.2	194.2	220.5	318.7	436.7	572.8	631.1	634.5
11:00	10:30	772.2	696.6	629.2	505.3	386.3	308.2	341.4	448.8	565.7	695.4	746.2	761.6
12:00	11:30	875.9	815.6	728.2	583.3	466.7	393.6	424.3	525.8	647.8	781.2	826.2	851.9
13:00	12:30	931.6	870.7	763.5	603.9	486.7	422.4	452.1	543.8	666.6	797	848	877.3
14:00	13:30	924.2	855.7	753.7	596	462.6	401.7	432	528.5	648.2	770.6	814.3	852.6
15:00	14:30	854.5	779.9	693.7	535.3	401.4	330.5	371.7	479.1	574.2	680.2	734.7	784.1
16:00	15:30	737.9	662.1	580.4	425	294.6	240.7	278.1	370.4	459.1	551.6	615.8	667.3
17:00	16:30	576.2	516	419.4	273.6	159.7	124.2	158.5	231	307.8	386.3	457.3	516.4
18:00	17:30	387.3	329.8	230	109.6	33.1	17.5	36	86.6	136.7	202.5	274.1	341
19:00	18:30	198.8	141.4	64	6.1	0	0	0	1.9	13.6	48.9	105.4	160
20:00	19:30	44.4	15.3	0.6	0	0	0	0	0	0	0	5.7	28.3
21:00	20:30	0	0	0	0	0	0	0	0	0	0	0	0
22:00	21:30	0	0	0	0	0	0	0	0	0	0	0	0
23:00	22:30	0	0	0	0	0	0	0	0	0	0	0	0
0:00	23:30	0	0	0	0	0	0	0	0	0	0	0	0

Note: AEST is Australian Eastern Standard Time. CST is Central Standard Time. All times represent hours ending at the time specified.
Data source: 3TIER/Renewables SA

The overall level of solar generation at any point in time was then calibrated to reflect the increasing level of PV installations over the historic period using ORER data on the historic rate of PV installation in SA.

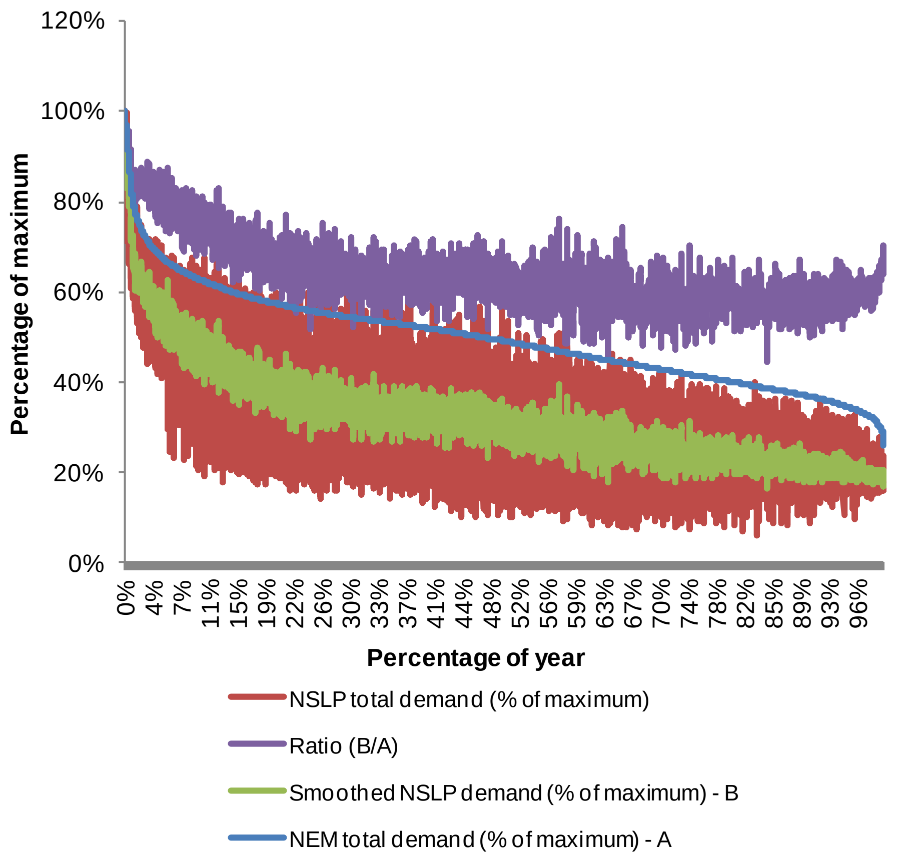
Using these underlying SA NEM region demand and SA NSLP demand profiles, ACIL Tasman derived synthetic NSLPs using the following methodology:

- match underlying historic NSLP demand with underlying historic total SA NEM region demand
- sort historic SA NEM region demand into descending order, i.e. a load duration curve
- express this load duration curve as a percentage of maximum SA NEM region demand (A) – this is the blue line shown in Figure B1 below

- express the NSLP demand for each period ordered on the basis of total SA NEM region load sorted in descending order as a percentage of maximum NSLP demand (this is the series marked in red in Figure B1 below)
- smooth this NSLP index using a simple rolling average (B) – this is the green series shown in Figure B1 below
- calculate the ratio of (A) and (B) – this is the purple series shown in Figure B1 below
- apply this ratio to the historic underlying SA NEM demand to recreate a synthetic estimate of the NSLP demand in each half hour of the historic period
- test the predictive power of this synthetic estimate of the historic NSLP when compared with observed NSLP price outcomes

This approach to estimating the synthetic NSLP demand is represented graphically in Figure B1.

Figure B1 **Derivation of synthetic NSLP – example**



Note: This example presents 2010 data only, whereas the final result averaged 2008, 2009 and 2010 outcomes.
Source: AEMO data with ACIL Tasman manipulations

The outcomes of testing the explanatory power are set out in Table B2, which shows that the estimates are consistently within 5 per cent.

Table B2 **Predictive power of synthetic NSLP derivation**

	2008	2009	2010
Observed NSLP-weighted price	$115.13	$115.80	$68.35
Predicted NSLP-weighted price	$114.46	$112.06	$66.51
Error	-0.58%	-3.23%	-2.69%

Note: NSLP-weighted prices here reflect the 'underlying' NSLP demand, i.e. adjusted to include solar generation that is netted out in developing actual NSLP data

Data source: AEMO; ACIL Tasman manipulations and analysis.

It is also relevant to note here the extremely high NSLP-weighted prices in the SA NEM region in 2008 and 2009. This result largely reflects extreme heatwave conditions in both of those years, which would not be typical of a 'normal' South Australian weather year. Accordingly, the price outcomes witnessed in those years are generally far higher than the projected NSLP price outcomes modelled here, which are based on normalised weather conditions.

Given the predictive power of this approach, the relationship can then be held constant into the future and applied to the synthetic load profiles used in *PowerMark*, in combination with the estimated maximum SA NSLP demand over time, to determine the likely NSLP demand in each hour of the projection period, that is, a synthetic estimate of the underlying (net of PV output) NSLP demand profile over the projection period.

To handle the likely future growth in the number of, and output from, PV installations in South Australia over the period to 2013-14, a stylised estimate of solar PV output for each hour was developed using ETSA estimates of future PV penetration levels, and netted out of the underlying NSLP demand profile to derive the final synthetic NSLP used to estimate price outcomes.

B.1.3 Projected NSLPs

The analysis above was used to model the 'shape' of the NSLP relative to total SA NEM region load, that is, the distribution of consumption through the year. However, it is still necessary to calibrate this shape (which is assumed to be constant) to projected values for maximum NSLP demand (i.e. the peak value of the load shape) and total NSLP consumption (i.e. the area under the load shape curve) for the projection years 2011-12, 2012-13 and 2013-14. The projected NSLPs were calibrated to the maximum demand and total energy values set out in Table B3 and Table B4 respectively.

Table B3 Projection of NSLP maximum demand

Variable	Units	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
SA summer native MD	MW	3,213	3,413	3,341				
SA summer native MD (weather corrected)	MW	3,208	3,204	3,212				
Projected SA summer MD	MW					3,230	3,290	3,370
Implied period on period growth	%				See Note below	0.5%	1.9%	2.4%
NSLP summer MD	MW	1,797	2,132	2,057				
NSLP summer MD (weather corrected)	MW	1,794	2,002	1,978				
Projected NSLP summer MD – No carbon scenario	MW					1,989	2,026	2,075
Projected NSLP summer MD – Carbon scenario	MW					1,989	2,024	2,071

Note: 2010-11 is not shown in the above table as the maximum NSLP demand for calendar year 2010 occurred in financial year 2009-10, not 2010-11. Accordingly, maximum NSLP demand for 2011-12 has been calibrated by growing 'period on period' from 2009-10 to 2011-12, i.e. over two years. All APR data reflects medium economic growth scenarios and 50% POE projections. Adjustment between No carbon and Carbon scenarios based on equivalent adjustment to SA NEM region load in *PowerMark* modelling.

Data source: AEMO; 2011 SA Annual Planning Report; ACIL Tasman manipulation.

Table B4 Projection of total NSLP electricity consumption

Variable	Units	2009-10	2010-11	2011-12	2012-13	2013-14
SA NEM region demand	GWh	14,485	14,650	14,964	15,180	15,513
Assumed solar generation	GWh	27	71	247	310	326
'Underlying' SA NEM region demand	GWh	14.512	14,721	15,211	15,490	15,839
Year on year growth	%		1.4%	3.3%	1.8%	2.3%
		2010 calendar		2011-12	2012-13	2013-14
Implied underlying 2010 SA NEM demand	GWh	14,615				
Implied period-on-period growth in underlying SA NEM demand	%			4.1%	1.8%	2.3%
SA NSLP underlying demand (historic and projected)	GWh	5,847		6,085	6,196	6,336
SA NSLP demand (historic and projected) – excluding solar generation – No carbon scenario	GWh	5,800		5,839	5,887	6,011
SA NSLP demand (historic and projected) – excluding solar generation – Carbon scenario	GWh	5,800		5,839	5,877	5,988

Note: Period on period growth for 2010 to 2011-12 captures a one and a half year period to allow for the variance between historic NSLP data, which is based on calendar years, and the projection years, which are financial years. All APR data reflects medium economic growth scenarios. 'Underlying' demand reflects metered demand, plus energy supplied from embedded solar generation. NSLP demand excluding solar reflects load as metered. Adjustment between No carbon and Carbon scenarios based on equivalent adjustment to SA NEM region load in *PowerMark* modelling.

Data source: SA Annual Planning Reports, ACIL Tasman manipulation.

This calibration involved an adjustment for embedded solar generation, as this is likely to have a material impact on the rate of growth in NSLP load. The approach adopted was to look at the growth rate in underlying SA NEM region demand implied when the forecast demand from the 2011 South Australian Annual Planning Report has an assumed level of embedded solar generation added to it. This implied underlying growth rate was then applied to the NSLP demand plus solar generation to project future levels of underlying NSLP demand. The same assumed level of embedded solar generation was then removed from the underlying NSLP demand to project the future level of NSLP load as it would be metered (i.e. net of embedded solar generation). Adjustments between the Carbon and No carbon scenarios were made consistent with those used in *PowerMark* modelling and outlined in Table C1.

In its submission on the Commission's Draft Decision, AGL notes that ACIL Tasman's methodology is 'stylised' in that does not reflect the intermittent nature of solar generation or allow for any reduction in the efficiency of PV generation under higher temperatures.[46]

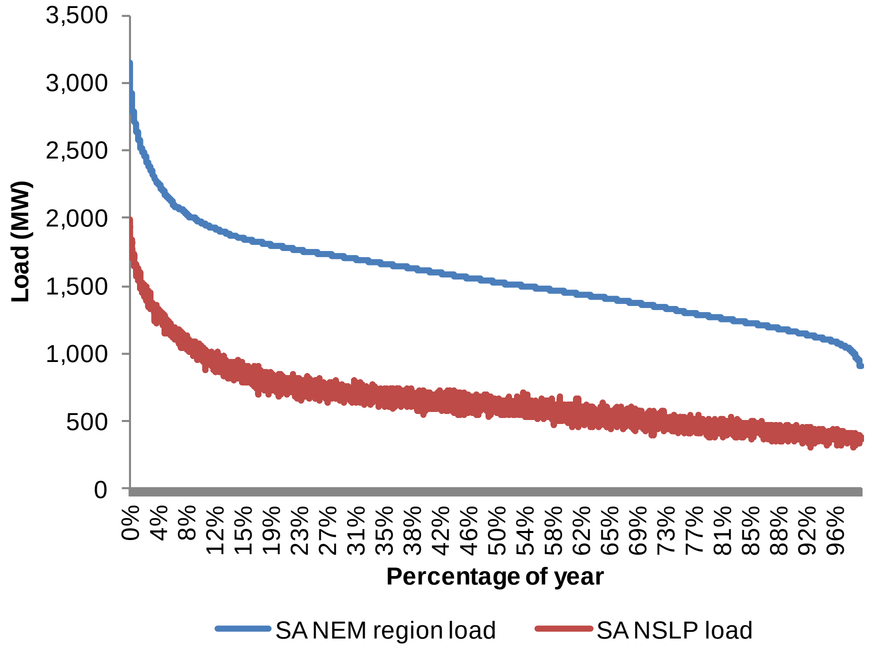
This is correct. However, such adjustments would offer only limited additional value in projecting the NSLP-weighted pool price which is the core output of this analysis. While the intermittent nature of solar output means that output in any given half hour period could be higher or lower than that modelled, the random nature of these key variables and low level of PV output in comparison to total NSLP demand means that the effect of such adjustments on the average NSLP-weighted spot price will be negligible and well within the reasonable error margin associated with the estimate of the energy value. The stylised approach adopted is appropriate to broadly capture the effect of increasing solar output in reducing the NSLP during daylight hours but not overnight, and need not seek to capture the highly uncertain impact on the NSLP in any given half hour period.

Further, it is infeasible to accurately model historic solar output in the absence of actual metered data, or to project future solar output in a way that reflects the intermittent nature of PV generation. Doing so would require data on a range of factors including system orientation, clouding and temperature that are not readily available.

46 AGL submission, 8 December 2011, available at www.escosa.sa.gov.au

Using these data, the synthetic NSLPs for the Carbon scenario for each of the three years in the projection period are shown in Figure B2, Figure B3 and Figure B4 below.[47]

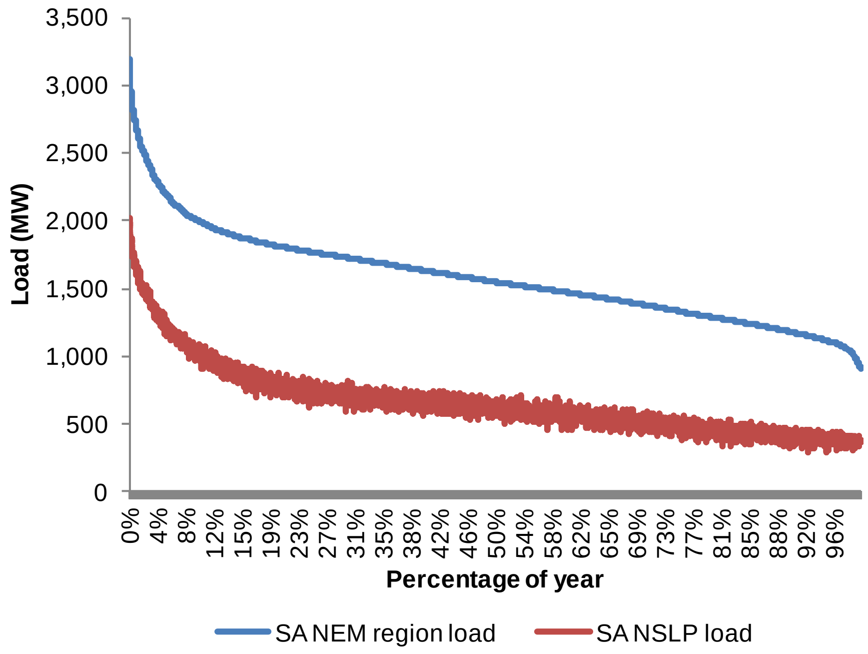
Figure B2 **2011-12 synthetic NSLP – Carbon scenario**



Source: ACIL Tasman analysis

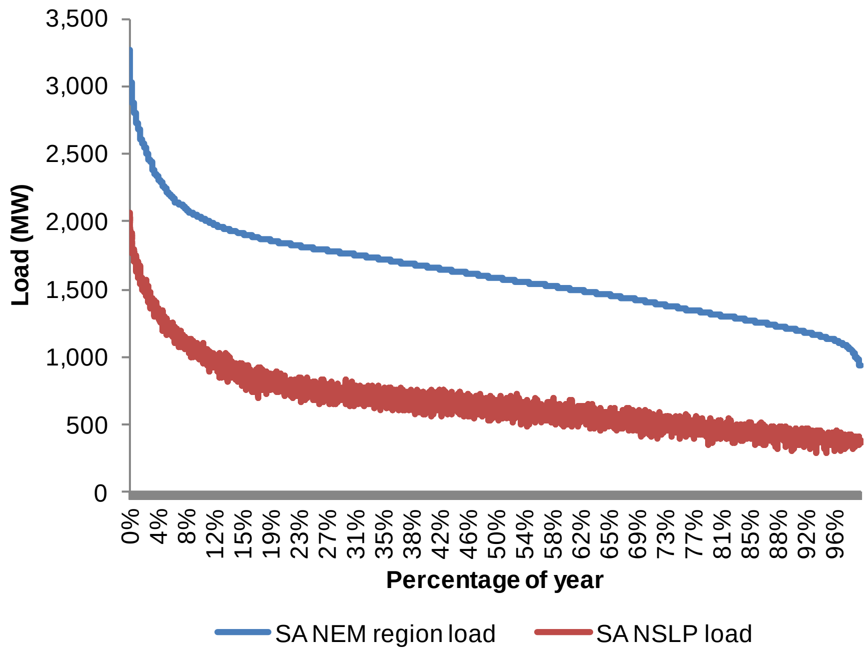
[47] These all relate to the Carbon scenario. Demand in the No carbon scenario is slightly lower, but not sufficient to warrant separate presentation of the data.

Figure B3 **2012-13 synthetic NSLP – Carbon scenario**



Source: ACIL Tasman analysis

Figure B4 **2013-14 synthetic NSLP – Carbon scenario**



Source: ACIL Tasman analysis

C PowerMark

This section provides an overview of the underlying *PowerMark* projection results for South Australia that have been used to estimate wholesale energy values over the period to 2013-14.

C.1 Basis for projections

ACIL Tasman's Energy and Resources Group has an in-depth experience of electricity market analysis in Australia, New Zealand, Singapore, Philippines and Malaysia. ACIL Tasman has been modelling and analysing the NEM since its inception and has a significant track record in advising market participants on price trends.

ACIL Tasman's electricity consulting strength is reinforced by *PowerMark*, an electricity market analysis model which simulates price formulation. *PowerMark* has been developed over the past 12 years in parallel with the development of the NEM. It is at the cutting edge in simulating market behaviour, including the exercise of market power. ACIL Tasman uses the model extensively in simulations and sensitivity analyses conducted on behalf of new entrants, banks and governments in understanding market behaviour and likely outcomes.

The projections presented herein are part of a larger NEM-wide study with a projection horizon which extends through to 2030. For the purposes of this report, only projections for South Australia have been utilised in the period 2011-12 to 2013-14. Results from two scenarios are presented:

- a Carbon scenario involving the introduction of a carbon price from 1 July 2012 starting at $23 per tonne of carbon dioxide equivalence for 2012-13
- a No carbon scenario, in which no carbon price is introduced over the projection period.

C.2 Key inputs

Key inputs into the projection include:

- NEM regional peak demand and energy
- environmental policy settings
- generator characteristics including capacity, thermal efficiency and marginal costs
- interconnector settings
- new entrant technology costs and availability.

South Australian NEM demand has been projected using the forecasts contained within the 2011 AEMO Electricity Statement of Opportunities (ESOO) with minor adjustments. Table C1 details the peak demand and energy values used for SA compared with actual outcomes from the last three years and forecasts within the 2011 SOO. Peak demand and energy values have been weather normalised and are applied to a weather-corrected half-hourly synthetic demand profile within the projection.

Table C1 **Actual and projected SA peak demand and energy**

	Actual		ACIL Tasman Carbon		ACIL Tasman No Carbon		AEMO ESOO 2011	
	Scheduled Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)
2008-09	3,331	13,505						
2009-10	3,121	13,402						
2010-11	3,385	13,517						
2011-12			3,148	13,684	3,148	13,684	3,164	13,753
2012-13			3,189	13,853	3,192	13,878	3,220	13,934
2013-14			3,263	14,155	3,270	14,208	3,300	14,267

Note: Demand and energy values presented on an 'as generated' basis for scheduled and semi-scheduled generation

Data source: AEMO data, ACIL Tasman

Carbon prices used in the Carbon scenario are $23 per tonne CO_2-e in 2012-13 and $24.15 per tonne CO_2-e in 2013-14 in nominal dollars in accordance with the Commonwealth Government's *Clean Energy Future* package. Under this scenario, both the NSW Greenhouse Gas Abatement Scheme and the Queensland Gas Scheme are assumed to cease on 30 June 2012.

The LRET has been modelled using ACIL Tasman's *RECMark* model. South Australia is projected to see some additional wind entry commissioned in 2013-14: 120 MW and 65 MW under the Carbon and No carbon scenarios, respectively.

All other projection inputs used represent ACIL Tasman's internal base case assumptions. Stochastic inputs have been conditioned such that the projection results are designed to represent median price outcomes (i.e. 50% probability of exceedence).[48]

C.3 Projected South Australian outcomes

Table C2 details actual and projected Regional Reference Prices for South Australia on a time-weighted and load-weighted basis. The modeling shows a firming of SA prices over the next few years back toward the $55 per MWh

48 It should be noted that due to the skewed distribution of potential annual price outcomes, the average outcome (i.e. the mean) is likely to be higher than median outcomes.

level on a time-weighted basis in the absence of carbon pricing. This recovery in prices is primarily driven by the trend of NEM prices from current depressed levels toward 'new entrant levels' (i.e. the level sufficient to support investment in new plant). This trend reflects the fact that recent entry of new plant (particularly wind farms in NSW, VIC and SA) has tended to suppress prices below the new entrant level. Ongoing demand growth in SA and other NEM regions tends to cause prices to rise towards this new entrant level over time, at which point investment in new plant tends to stabilise or suppress prices. In the SA NEM region we do not project new plant commencing operation until 2013-14, at which time some new wind and Open Cycle Gas Turbine (OCGT) plant enters service. Accordingly, we anticipate rising prices over this period as the supply-demand balance in the market tightens.

A further dynamic supports this trend: new entrant gas-fired plant are assumed to pay gas prices reflective of current and future gas market conditions (which is affected by the prospect of domestic gas resources being diverted to LNG production, amongst other things). These gas prices tend to be higher than the long-term contract prices paid by many incumbent gas-fired generators.

Prices are higher under the Carbon scenario as generators incorporate carbon costs into their bidding behavior. Compared with the No carbon scenario, time-weighted prices are \$14.60 per MWh and \$16.50 per MWh higher in 2012-13 and 2013-14, respectively. This implies a near-term carbon pass-through rate of between 60% and 70% for South Australia.

Table C2 **Actual and projected RRP for SA (\$ per MWh)**

	Time-weighted RRP (\$ per MWh)			Load-weighted RRP (\$ per MWh)		
	Actual	Carbon	No carbon	Actual	Carbon	No carbon
2008-09	\$50.98			\$68.58		
2009-10	\$55.31			\$82.51		
2010-11	\$32.58			\$41.97		
2011-12		\$42.49	\$42.49		\$53.44	\$53.44
2012-13		\$65.87	\$51.28		\$77.44	\$66.30
2013-14		\$72.24	\$55.77		\$87.05	\$72.83

Note: Nominal dollars

Data source: AEMO market data, ACIL Tasman PowerMark modelling

In its submission to the Commission's Draft Decision, AGL states that in its view "the implied carbon pass-through rate of 60% to 70% is too low", and notes that the "electricity industry has formed a consensus view that the impact on the pool price would be at the national carbon intensity (ACI) for the purpose of agreeing an industry standard 'pass through clause' (i.e. the AFMA pass through clause)".[49]

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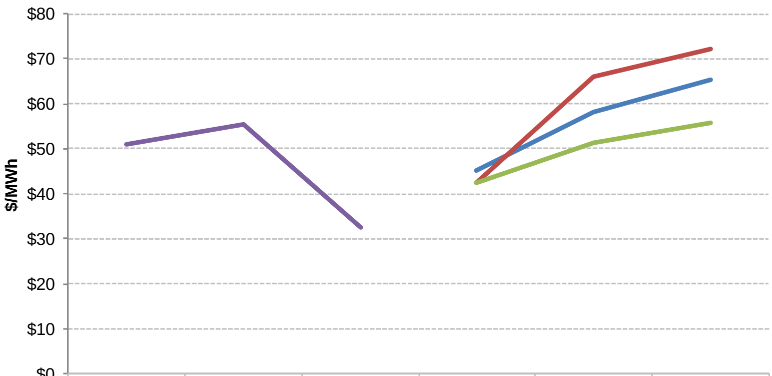
49 AGL submission, 8 December 2011, available at www.escosa.sa.gov.au

We note this opinion and concur with AGL's statement that "the impact of carbon on the pool price has been the subject of much modeling and debate". Our modeling results are one such view and reflect extensive analysis of the operation of the NEM and the proven results of ACIL Tasman's *PowerMark* model. While we note the use of a national carbon intensity measure in electricity contracts, ACIL Tasman considers that the level of carbon cost pass-through will vary between NEM regions and over time due to complex market dynamics. *PowerMark* modeling offers a credible basis for estimating such an impact in a specific region and time period as required for this analysis.

Figure C1 shows projected time-weighted RRPs compared with the last three years of actuals and current base future contract prices. At the time of the modeling the *Clean Energy Future* legislation had not passed and the futures prices for 2012-13 and 2013-14 lay in between the two scenarios. This suggests that, at that time, the futures market was still pricing in some degree of risk that explicit carbon pricing may not occur.

Figure C1 **Comparison of projected RRPs against current futures prices**



	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
Actual	$50.98	$55.31	$32.58			
D-cypha Base futures				$45.02	$58.30	$65.30
ACIL Tasman with Carbon				$42.49	$65.87	$72.24
ACIL Tasman No Carbon				$42.49	$51.28	$55.77

Note: Time-weighted annual RRP compared with Base financial year strips

Data source: AEMO market data, ACIL Tasman PowerMark modelling, d-cypha futures accessed 28 September 2011

The modeled outcome for 2011-12 sits marginally below the current futures price. This is typically what we would expect to see, with futures contracts exhibiting a small contract premium over median spot outcomes.

C.4 Generation mix

Table C3 details the actual and projected dispatch levels for South Australian generators under the Carbon scenario. Overall, the SA dispatch pattern is not projected to change materially over the period to 2013-14, with aggregate dispatch maintained at around 12,500 GWh to 13,000 GWh per annum.

Output from Northern Power Station and Pelican Point continues to dominate, accounting for over half of SA's generation. Additional contribution from wind occurs due to the completion of the Bluff wind farm (also known as Hallett stage 5) and the first full years of Lake Bonney 3 and Waterloo wind farms. Some additional new entrant wind is projected to commence operation in 2013-14, combined with a small amount of additional OCGT capacity.

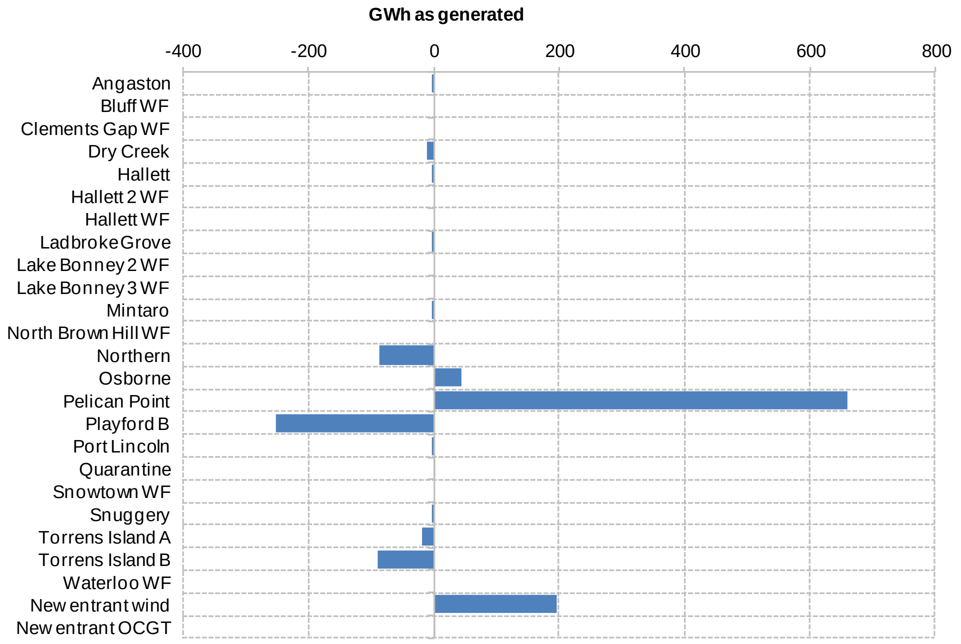
Table C3 **Actual and projected output from SA generators (GWh)**

	Actual			Projected		
Generator	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
Angaston	2	0	1	1	1	1
Bluff WF				132	170	170
Clements Gap WF	3	164	169	167	167	167
Dry Creek	6	9	2	6	7	6
Hallett	22	27	21	6	7	8
Hallett 2 WF	16	248	245	234	234	234
Hallett WF	328	336	321	312	312	312
Ladbroke Grove	192	191	138	143	135	153
Lake Bonney 2 WF	367	296	362	361	361	361
Lake Bonney 3 WF			85	93	93	93
Mintaro	4	8	3	2	3	3
North Brown Hill WF			304	445	445	445
Northern Power Station	4,219	3,546	3,943	3,933	3,943	4,057
Osborne	1,241	1,181	1,044	1,140	1,081	1,189
Pelican Point	3,289	2,979	2,939	2,779	3,271	3,037
Playford B	700	1,013	317	658	443	134
Port Lincoln	2	2	2	2	2	3
Quarantine	95	295	136	22	31	47
Snowtown WF	319	359	347	331	331	331
Snuggery	2	2	0	1	2	2
Torrens Island A	535	441	672	97	98	130
Torrens Island B	1,956	1,693	1,680	1,193	1,243	1,323
Waterloo WF			229	344	344	344
New entrant wind						406
New entrant OCGT						11
Total SA	13,298	12,792	12,958	12,402	12,724	12,966

Note: Output presented on an 'as generated' basis under the Carbon scenario
Data source: AEMO market data, ACIL Tasman PowerMark modelling

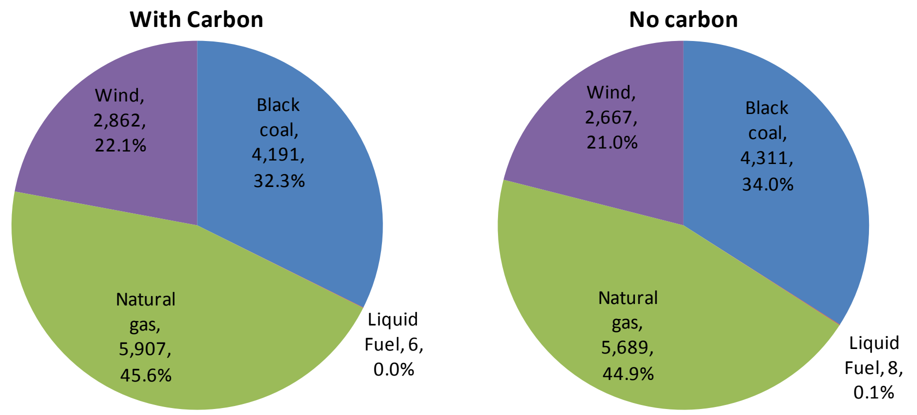
The No carbon scenario dispatch pattern is quite similar, although output from the emissions-intensive Northern and Playford power stations is slightly higher, offset by reduced output from Pelican Point and less wind generation as shown in Figure C2. Figure C3 illustrates the slight change in the fuel shares for 2013-14 as a result of the introduction of carbon pricing.

Figure C2 **Projected carbon policy impact upon SA generation volumes**



Note: Difference between aggregate dispatch volumes (2012-13 to 2013-14) relative to the No carbon case
Data source: ACIL Tasman PowerMark modelling

Figure C3 **Projected generation by fuel share for SA in 2013-14 (GWh)**



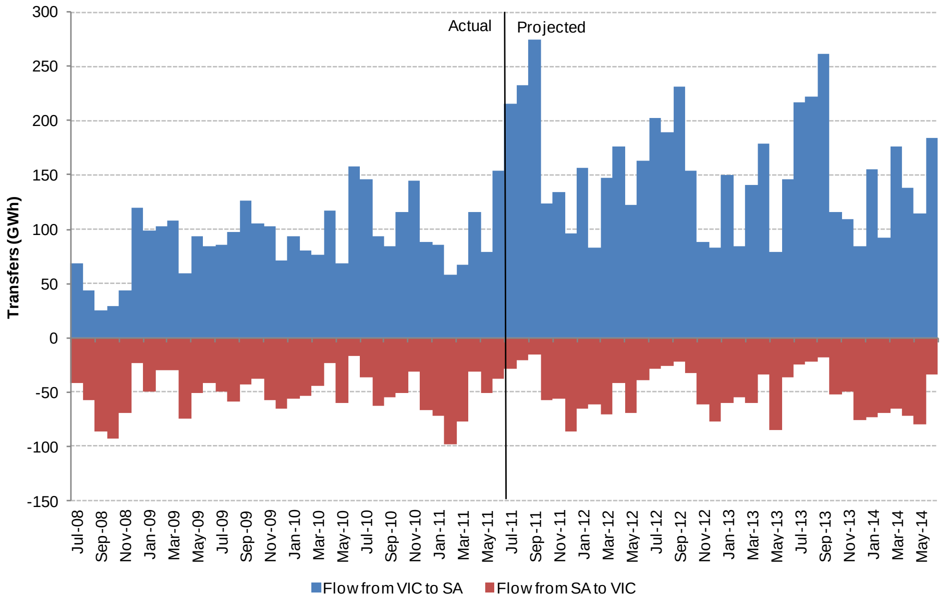
Note: Figures are GWh 'as generated' followed by the share of SA total generation for 2013-14
Data source: ACIL Tasman PowerMark modelling

C.5 Interconnectors

Figure C4 shows the monthly aggregate interconnector flows between Victoria and South Australia, with actuals over the period July 2008 to June 2011 and those projected under the Carbon scenario to June 2014. These represent the aggregate transfers across the Heywood and Murraylink interconnectors.

The projection sees increased transfers from Victoria into South Australia through 2011-12 (approximately 50% higher than 2010-11), with this trend continuing into future years. Exports from South Australia remain fairly steady compared with historical levels over the period. Summary financial year flow data is presented in Table C4.

Figure C4 **Interconnector transfers between VIC and SA**



Note: Aggregate flow on Heywood and Murraylink interconnectors. Flows from SA to VIC are shown as negatives for charting purposes.

Data source: AEMO market data, ACIL Tasman PowerMark modelling

Table C4 **Interconnector transfers between VIC and SA**

	Actual		Carbon		No carbon	
	VIC to SA (GWh)	SA to VIC (GWh)	VIC to SA (GWh)	SA to VIC (GWh)	VIC to SA (GWh)	SA to VIC (GWh)
2008-09	874	647				
2009-10	1,183	565				
2010-11	1,234	668				
2011-12			1,925	611	1,925	612
2012-13			1,730	577	1,954	624
2013-14			1,868	635	2,161	588

Note: Aggregate flow on Heywood and Murraylink interconnectors

Data source: AEMO market data, ACIL Tasman PowerMark modelling

Melbourne (Head Office)

Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455

Email melbourne@aciltasman.com.au

Brisbane

Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799

Email brisbane@aciltasman.com.au

Canberra

Level 1, 33 Ainslie Place
Canberra City ACT 2600

GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233

Email canberra@aciltasman.com.au

Perth

Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955

Email perth@aciltasman.com.au

Sydney

PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142

Email sydney@aciltasman.com.au

ACIL Tasman

ACIL Tasman Pty Ltd

www.aciltasman.com.au