QUEENSLAND COMPETITION AUTHORITY

Final Report

Estimating a Fair and Reasonable Solar Feed-in Tariff for Queensland

March 2013

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GLOSSARY

ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	AGL Energy Limited
APVA	Australian PV Association
ATA	Alternative Technologies Association
ASC	Australian Solar Council
Authority	Queensland Competition Authority
c/kWh	Cents per kilowatt hour
CEC	Clean Energy Council
CSO	Community Service Obligation
DCC	Directly Connected Customer
Direction	The Direction from the Minister for Energy and Water Supply pursuant to section 253AA of the *Electricity Act 1994*, directing the Authority to conduct a review into the establishment of a fair and reasonable value(s) for electricity generated from small scale solar photovoltaic (PV) generators and exported to the Queensland electricity grid (dated 7 August 2012).
DLF	Distribution Loss Factor
Draft Determination	The Authority's determination of notified prices to apply from 1 July 2013 to 30 June 2014 (acting under the 2013 Delegation)
Draft Report	The Draft Report released by the Authority on 27 November 2012 (acting under the Direction)
DUOS	Distribution Use of System
EECL	Ergon Energy Corporation Limited (distribution)
EEQ	Ergon Energy Queensland (retail)
Electricity Act	*Electricity Act 1994*
Energex	Energex Limited
EnergyAustralia	EnergyAustralia Pty Ltd
ERAA	Energy Retailers Association of Australia Ltd
ESAA	Energy Supply Association of Australia
ESCOSA	Essential Services Commission of South Australia
FRC	Full Retail Competition
GEC	Gas Electricity Certificate
GST	Goods and Services Tax
GWh	Gigawatt hours
HV	High voltage

ICC	Individually Calculated Customer
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
Issues Paper	The Issues Paper released by the Authority on 24 August 2012 (acting under the Direction)
kWh	Kilowatt hour
Large customer	A customer that consumes more than 100 MWh of electricity per year
LRET	Large-scale Renewable Energy Target
LV	Low voltage
Minister	The Minister responsible for administering the *Electricity Act 1994*, currently the Minister for Energy and Water Supply
MLF	Marginal Loss Factor
MW	MegaWatt
MWh	MegaWatt hours
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
Notified/regulated retail prices	The electricity prices that a retailer may charge its non-market customers, as defined under section 90 of the *Electricity Act 1994*
NSLP	Net System Load Profile
NSW	New South Wales
NT	Northern Territory
Origin	Origin Energy Retail Limited
PPA	Power purchase agreement
PV	Photovoltaic
QCOSS	Queensland Council of Social Service
RET	Renewable Energy Target scheme
RRN	Regional Reference Node
SA	South Australia
SBC	Solar Business Council Incorporated
SEIA	Solar Energy Industries Association Inc.
SEQ	South East Queensland
Small customer	A customer that consumes less than 100 MWh of electricity per year
SRES	Small-scale Renewable Energy Scheme
Stanwell	Stanwell Corporation Limited
STC	Small-scale Technology Certificate

STP	Small-scale Technology Percentage
Suntech	Suntech Power Australia Pty Ltd
SunWiz	Sunwiz Consulting
TCP	Transmission Connection Point
The Scheme	The Queensland Government's *Solar Bonus Scheme*
TLF	Transmission Loss Factor
TNI	Transmission Node Identifier
TOU	Time of Use
TUOS	Transmission Use of System
TRUenergy	TRUenergy Pty Ltd
UTP	The Queensland Government’s Uniform Tariff Policy
VIC	Victoria
WA	Western Australia
WACC	Weighted Average Cost of Capital
WEPC	Wholesale Energy Purchase Cost

PREAMBLE

In July 2008, the Queensland Government introduced the Solar Bonus Scheme (the Scheme) to encourage investment in renewable electricity generation. Since then, participation in the Scheme has exceeded all expectations, and the number of small-scale solar photovoltaic (PV) installations in Queensland has increased from less than 6000 in 2008-09 to over 260,000 at December 2012.

The initial Scheme was exceptionally generous, offering customers with PV installations 44 cents per kWh for their net exports of power to the network. This scheme was closed to new applications from 9 July 2012 and replaced with an interim scheme offering 8 cents per kWh which is scheduled to terminate in mid 2014. While the original scheme has closed, eligible customers will continue to receive the higher 44 cent rate until 2028.

The growth in PV installations is increasing electricity costs for all Queensland consumers. Energex and Ergon Energy expect to incur accumulated feed-in tariff payments of around $2.9 billion ($2013-14) by the end of the scheme in 2028 and these costs will flow directly through to network charges and electricity bills. The Authority estimates that the costs of the Scheme will add around $67 to the average Queenslander's annual electricity bill in 2013-14, peaking at around $276 by 2015-16 and will continue to have a significant but declining impact on customer bills until the end of the Scheme in 2028.

In August 2012, the Minister for Energy and Water Supply directed the Authority to provide recommendations on a 'fair and reasonable value' for electricity generated by small-scale solar PV generators and exported to the Queensland grid. This Final Report presents the Authority's final advice to the Government, taking into account submissions received in response to its Issues Paper and Draft Report. The Authority's recommendations provide independent advice to inform the Government's review of the current Scheme, which it will conduct by 30 June 2013.

This review is not about the benefits existing PV customers on the 44 cents per kWh scheme will receive in the future. The Government has already made clear its intention to allow eligible customers to retain access to those benefits until the scheme ends in 2028. Similarly, this review is not about the benefits PV customers on the more realistic 8 cents per kWh scheme receive into the future, though it is noted that that scheme is due to end in mid 2014.

This review is in part about the cost of some of those benefits received by PV owners and who is paying for them. It is also partly about how the impact of those costs might be controlled and more equitably shared in the future.

However, this review is largely about what might be a fair and reasonable price for new PV customers to receive for the electricity they export into the network in a new scheme which will presumably commence in mid 2014 when the current 8 cents per kWh scheme ends. To be sustainable and fair to all consumers, any new scheme must be structured so that the price received for exports of electricity reflects the true, quantifiable savings and benefits that are being achieved by the installation and on-going operation of solar PV panels.

Surprising as it may be for some consumers, there is no magic pudding when it comes to electricity prices. If one group of consumers enjoys a benefit in excess of the true savings they make, or enjoys prices below the cost of their consumption, other electricity customers have to pay the price of those excess benefits or lower prices. When those doing the paying are likely those least able to afford it and those enjoying the benefits are those likely to be most able to afford to meet their true costs, then something is truly wrong.

While the current distributor funded Scheme was successful in stimulating uptake of small-scale PV generation, the Authority considers this subsidised model is no longer appropriate. It creates significant costs for the distribution businesses which are then recovered through higher electricity prices for all customers, at a time when prices are already under increased upward pressure from a range of other cost drivers. The Authority recommends that any future feed-in tariff scheme should be funded solely by electricity retailers, based on the direct financial benefit they receive from on-selling PV exports.

The Authority's estimate of a fair and reasonable, cost-reflective value of exported PV energy for South East Queensland in 2013-14 is 7.55 cents per kWh. This is based on the direct financial benefit that a retailer would receive if it on-sold a kilowatt of exported PV electricity at a cost-reflective price. This value will always be lower than the retail price of electricity because retailers incur other costs that cannot be avoided, even when they receive the electricity itself at no financial cost.

The market for solar PV customers in South East Queensland appears quite competitive with seven retailers currently offering voluntary retailer-funded feed-in tariff premiums of up to 10 cents per kWh in addition to the statutory distributor funded feed-in tariffs of 44 and 8 cents per kWh. Some of these premiums are higher than the Authority’s best estimate of the fair and reasonable value which suggests that the Authority’s estimate is probably conservative. Given the state of competition in South East Queensland, the Authority found no persuasive reason to recommend a regulated minimum feed-in tariff for solar PV customers in this corner of the State.

However, in the Ergon Energy network area, there is little chance that competition can be relied on to deliver fair and reasonable solar feed-in tariffs in the foreseeable future. For this reason, the Authority has recommended that mandatory minimum feed-in tariff values be established. Due to the sheer scale and variability of costs across the Ergon Energy network, the value of solar PV electricity exported in regional Queensland cannot be accurately captured in a single value. The Authority has attempted to estimate six different values, for different parts of the Ergon Energy network, based on the value of avoided energy purchase costs, including network losses. These range from 7.06 cents per kWh to 14.05 cents per kWh and largely reflect the different losses incurred in supplying energy to various parts of Ergon Energy’s network from traditional sources of generation.

The Authority also examined the fair and reasonable feed-in tariffs that might apply in Ergon Energy’s isolated networks, which are not connected to the national grid, and has estimated values which might be ascribed to PV energy exported into these networks. However, the Authority considers that there are more fundamental questions to be answered before adopting a mandatory feed-in tariff scheme for these isolated networks.

Another aspect of this review involved considering options for controlling the on-going costs of the Scheme to reduce the impact that it will have on electricity bills for Queensland consumers. While there are a range of options available to the Government to achieve this, there is no single solution which will satisfy all stakeholders.

The Authority considers that the impact of the existing Scheme on electricity prices could be somewhat ameliorated by requiring electricity retailers to contribute to the ongoing costs of funding those tariffs until their statutory end dates. However, this option is not without its risks and drawbacks. If the Government chooses to take this approach, it should be careful to ensure that the mandated contribution does not overstate the benefit accruing to retailers from on-selling excess energy exported by their grid connected PV customers.

Network tariff reform is a further option to be considered as a means of more equitably sharing the costs of the Scheme. Specifically, there may be scope for distribution businesses to establish new, cost-reflective network tariffs for PV customers which ensure that these customers are charged their full fixed network costs, which are largely avoided under the present network tariff arrangements. Alternatively, they could be placed on an existing network/retail tariff (such as Tariff 12) which would reduce somewhat the hidden network subsidy they currently enjoy but also provide them with opportunities to better manage their usage by accessing time-of-use retail prices.

Key Findings

The Authority has investigated a range of matters regarding the estimation and implementation of fair and reasonable values for PV exports in Queensland. In summary, the Authority's investigation has concluded:

1. Future feed-in tariff schemes should be funded by electricity retailers, rather than regulated network businesses, to avoid cross-subsidies and the inequitable recovery of costs from those customers least able to afford them.

2. The fair and reasonable value of PV exports should be the direct financial benefit that electricity retailers receive when they on-sell exported energy from their PV customers.

3. There is no compelling evidence to support a regulated, mandatory minimum feed-in tariff for customers in the South East Queensland retail electricity market.

4. Regulated minimum retailer funded feed-in tariffs of between 7.06 and 14.05 cents per kWh should be established for customers on Ergon Energy’s National Electricity Market (NEM) connected distribution network, depending on customer location.

5. Subsidy-free feed-in tariffs cannot be implemented in the Mt Isa-Cloncurry network at this stage.

6. Further investigation is needed before mandatory feed-in tariffs are extended to Ergon Energy’s other remote isolated networks, to ensure that the potential consequences are not inconsistent with longer term strategies for efficient and reliable supply on these networks.

7. The cost of direct feed-in tariff payments under the 44 and 8 cent per kWh Schemes is expected to total $2.9 billion ($2013-14) by the end of the Scheme in 2028. When the cost impacts of the Scheme peak during 2015-16, feed-in tariff payments are expected to account for around $276 to the average residential Tariff 11 customer's annual electricity bill, or around 17% of the total bill.

8. The ongoing cost impact of the 44 cent per kWh Scheme could be controlled by introducing a mandatory contribution from retailers set at the estimated direct benefit to the retailer resulting from PV exports. The Authority estimates this measure could reduce the total costs of the Scheme by $386 million over the life of the Scheme.

9. Government could consider moving PV customers to Tariff 12 which would expose them to a more cost-reflective fixed charge than they face under current flat residential tariffs. In this regard, it would go some way to reducing the problem of PV customers avoiding a portion of the true cost of their network access due to their net consumption profile, which leads to higher average variable network charges.

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1. INTRODUCTION

On 7 August 2012, the Minister for Energy and Water Supply (the Minister) issued a Direction Notice under section 253AA of the *Electricity Act 1994* to the Queensland Competition Authority (the Authority) (see **Appendix B**). The Direction requires the Authority to investigate and report on:

(a) a fair and reasonable value for energy generated by small scale solar photovoltaic (PV) systems and exported to the Queensland electricity grid;

(b) the mechanisms by which a fair and reasonable value/values could be implemented in Queensland;

(c) a potential retailer contribution to the cost of the Queensland Solar Bonus Scheme (the Scheme) that reflects the benefit to retailers of the energy produced by small scale solar PV generators connected to the grid; and

(d) updated costs of the Scheme and any options by which to minimise or more equitably share these costs.

The Authority is to publish a Draft Report no later than November 2012 and a Final Report no later than 22 March 2013.

1.1 Direction Notice Requirements

In its investigation into the fair and reasonable value for solar PV energy, the Authority is to have regard to the following factors:

(a) there must be no consequential increase in electricity prices in Queensland or cost to the Queensland Government budget;

(b) the Council of Australian Governments (COAG) first National Principles for Feed-in Tariffs and the concept of 'fair and reasonable' value;

(c) the geographical location at which the solar PV energy is generated and value of that energy in the local network;

(d) complementarity with the carbon pricing mechanism; and

(e) consistency with the operation of a competitive Queensland electricity market.

As part of its investigation and report the Authority is also to consider:

(a) the benefit gained by electricity customers, distributors and/or retailers from electricity produced from small scale solar PV, for example in remote areas of Ergon Energy's network where high energy supply costs may be offset, or the value to the distribution business of any network investment deferral in those networks;

(b) the benefit of net versus gross metering arrangements;

(c) the Renewable Energy Buyback scheme operating in Western Australia (WA), which from 1 July 2012 offers feed-in tariff rates that vary geographically and include stringent connection requirements; and

(d) other issues the Authority deems relevant.

In its investigations into the mechanisms for implementing a fair and reasonable value for solar PV energy, the Authority is to consider and report on:

(a) implementation options within the Queensland electricity market, including a mandated ‘default minimum price’ or price range, a recommended (non-mandated) price range, or a market determined price;

(b) support for a competitive electricity market in Queensland and any specific arrangements required/ barriers to implementation in the Ergon Energy distribution area;

(c) the need for certainty for small scale solar PV owners;

(d) appropriate review mechanisms and timeframes;

(e) potential transition to a national feed-in tariff if established through COAG processes; and

(f) similar pricing and mechanisms in other jurisdictions and findings from other jurisdictional feed-in tariff reviews.

1.2 Review Process to Date

On 24 August 2012, the Authority released an Issues Paper advising interested parties of the commencement of the review. The Authority received 39 submissions in response to the Issues Paper.

On 27 November, the Authority released its Draft Report on estimating a fair and reasonable solar feed-in tariff for Queensland. The Authority received 16 submissions in response to the Draft Report. A complete list of submissions received in response to the Issues Paper and Draft Report is provided in **Appendix C**. Both reports and all submissions received are available on the Authority’s website (www.qca.org.au).

The Authority is now releasing its Final Report. This report provides the Authority's final advice to the Minister for Energy and Water Supply, to inform the Queensland Government's review of the Solar Bonus Scheme, which it will undertake by 30 June 2013. In preparing this Final Report, the Authority has taken into account the Minister's Direction, matters raised in submissions, and its own investigations.

2. BACKGROUND

2.1 The Queensland Solar Bonus Scheme

On 1 July 2008, the Queensland Government introduced the Scheme to provide eligible customers with credit for the surplus electricity generated by solar PV systems and exported into the Queensland electricity network. The Scheme is available to small residential and business customers who consume less than 100 megawatt hours (MWh) per year, with grid-connected PV systems not exceeding 5 kilowatt hours (kWh) capacity.

The Scheme was intended to provide an incentive for electricity customers to install PV systems, by providing an opportunity to recover the costs of the system by way of a feed-in tariff paid for surplus electricity their PV systems exported back to the distribution network.

How the Scheme works

Participants in the Scheme are paid the prescribed feed-in tariff for each kWh of electricity exported back into the network when a PV system is generating electricity surplus to the customer's immediate consumption requirements. During times when a PV system is generating less electricity than the customer's consumption, the balance of electricity demanded is drawn from the network, supplied by the customer's electricity retailer.

On 9 July 2012, the Queensland Government reduced the feed-in tariff under the Scheme from 44 cents per kWh to 8 cents per kWh. Existing participants will continue to receive the 44 cents per kWh feed-in tariff for electricity exports until 2028, provided they maintain their eligibility for the Scheme. Eligible customers who joined the Scheme after 9 July 2012 will receive 8 cents per kWh until 30 June 2014.

Metering and billing

Customers participating in the Scheme require specialised meters connected between the network, the premises and the PV system. These meters are capable of recording the volume of electricity being drawn from the network (imports) and the volume of electricity fed back into the network (exports). This is known as a 'net' metering arrangement. This is distinct from a 'gross' metering arrangement where the meter separately records the total amount of electricity consumed and the total amount generated by the PV system.

At the end of each billing period, the customer's meter is read to determine the total amounts of surplus electricity exported to and imported from, the network. The distribution business provides this data to the retailer, which then calculates the amount of the 'solar bonus' by multiplying the number of kWh exported by the rate of the feed-in tariff. This amount is then deducted from the customer's consumption charge for imported electricity and is reflected on the retail bill.

If the value of the customer’s exports exceeds the value of energy consumed, the excess amount is applied as a credit to the customer's retail account. If the customer's solar bonus payments exceed their network imported consumption costs over a 12-month period, the customer may request payment of the balance, rather than retaining a credit.

Who pays the feed-in tariff?

The current Scheme is funded by the distribution network businesses, Energex and Ergon Energy. This means the electricity distribution business is currently liable to pay the amount of the feed-in tariff which is then credited to the PV customer by the retailer. As distribution network charges are regulated, the costs incurred by the distribution business in funding the current Scheme are recovered through higher network charges for all customers. Under the existing arrangements, electricity retailers in Queensland are not required to contribute to the costs of the Scheme, nor are they required to pay for the electricity generated by their grid connected PV customers. This means that retailers are potentially receiving a windfall gain equal to the value of the avoided costs of sourcing that electricity through the National Electricity Market (NEM).

The current (distribution-funded) Scheme is distinct from a retailer-funded scheme, where the feed-in tariff amount is credited to the customer's quarterly consumption charge directly by the retailer, with no financial flows from the distributor to the retailer. Unlike a distribution-funded scheme, a retailer-funded scheme does not rely on subsidisation through network charges, and therefore is not funded by spreading the cost across all network customers.

Voluntary retailer tariff premiums

While retailer contributions to the Scheme are not currently mandatory, there are a number of electricity retailers in Queensland offering a discount, or premium tariff, to customers who export surplus PV electricity, in addition to the feed-in tariff funded by the distributor. The Authority understands that some retailers are offering this additional premium tariff at a rate of up to 10 cents per kWh for net exported electricity.

However, these tariff premiums should be interpreted carefully as they may be accompanied by additional contract terms and conditions potentially affecting the real net value to the customer of the tariff offer.

2.2 Outcomes of the Scheme

As at the end of December 2012, the total installed PV capacity in Queensland was estimated at 763.9 MW, up from 9.5 MW in the first year of the Scheme. Over the same period, the number of participants in the Scheme grew from under 6,000 to over 260,000, with a significant number of additional, eligible connection applications pending. As a result, Queensland has the largest rooftop solar generating capacity of any state in Australia.

Table 2.1: Growth in PV installations in Queensland since 2008

	2008-09	*2009-10*	*2010-11*	*2011-12*	*2012-13 (Q1 & Q2)*	*Total*
Number of PV installations	5,926	24,514	66,355	97,042	68,624	262,461
Capacity Installed (MW)	9.5	42.9	159.5	293.4	258.6	763.9
Energy exported (GWh)	1.4	10.6	52.1	214.4	231.2	509.7
Solar bonus payments ($m)	0.6	4.7	22.9	94.3	101.6	224.1

Source: Queensland Department of Energy and Water Supply (February 2013)

Note: Totals may not add due to rounding

2.3 Reasons for this review

As mentioned above, in July 2012 the Queensland Government reduced the solar feed-in tariff from 44 cents per kWh to 8 cents per kWh for new applicants.

The Government noted that the 44 cents per kWh rate was set in 2008 when solar PV prices were substantially higher (around $6,000 per 1.5 kilowatt system installed, with rebates).

The installed price of solar panels (inclusive of rebates) has decreased significantly since 2008. The Authority understands that a 1.5 kilowatt solar PV system can now be installed for under $2500 in South East Queensland.

In making its decision to reduce the feed-in tariff, the Government also noted the Scheme's impact on electricity costs for all Queenslanders. In particular, the Government noted that participation in the Scheme had surpassed expectations and, as a consequence, is now resulting in higher than expected feed-in tariff costs for Energex and Ergon Energy. These higher costs are beginning to be passed through in the electricity bills of all customers, impacting on affordability for all Queenslanders.

This raises concerns about the equity of the Scheme because electricity customers who may not be able to afford (or who choose not to invest in) a solar PV installation are forced to pay the feed-in tariff to those customers who choose to install solar panels, without receiving any benefit in return.

In light of the reduction in PV system costs and the impact on electricity affordability, the Government considered it timely to reassess the feed-in tariff rate to ensure it remains appropriate. The Minister’s letter to the Authority notes that the 8 cent tariff will be reviewed by 1 July 2013, and is legislated to end on 1 July 2014. The outcomes of the Authority's review of a fair and reasonable value for PV energy will be considered by the Government in its review of the 8 cents per kWh feed-in tariff.

2.4 Developments in other jurisdictions

The review of the Queensland feed-in tariff rate comes at a time when many similar schemes across Australia are subject to review and change. The current state of feed-in tariffs across Australia is summarised in Table 2.2 below.

New South Wales (NSW)

The NSW Solar Bonus Scheme, which was funded by distributors, was closed to new applications in April 2011, subject to review by the Independent Pricing and Regulatory Tribunal (IPART). In its May 2012 report, IPART recommended that feed-in tariff payments should be funded by retailers, not distributors, but that they should not be mandatory. In June 2012, IPART recommended a benchmark tariff range of 7.7 to 12.9 cents per kWh for a fair and reasonable market-determined feed-in tariff (funded by retailers) during 2012-13. IPART stated that the benchmark range would help customers understand the value of their exported energy and help them find the most competitive market offerings.

South Australia (SA)

SA’s distributor-funded feed-in tariff scheme is being incrementally reduced from 44 cents per kWh to 16 cents per kWh and will be closed to all new applicants from 30 September 2013. This scheme runs parallel to a compulsory retailer funded feed-in tariff premium, which was set by the Essential Services Commission of South Australia (ESCOSA) in January 2012. The minimum retailer premium applies for three years, starting at 7.1 cents per kWh in 2011-12, increasing to 11.2 cents per kWh in 2013-14.

Western Australia (WA)

In May 2011, the WA distributor-funded feed-in tariff was reduced from 44 cents per kWh to 20 cents per kWh, before the scheme was closed to new applicants on 31 July 2011. Customers in WA still have access to the Renewable Energy Buyback Scheme (REBS) which mandates that a buyback rate be paid by retailers to net exporters of PV generated electricity. The buyback rates are set by the retailer and approved by the Public Utilities Office. The rates offered by Horizon Power are set on a locational basis and reflect the cost of electricity generation to each town in its network area. These buyback rates currently range from 10 cents per kWh to 50 cents per kWh and are reviewed annually. Customers on Synergy's distribution network can also access a REBS with a buyback rate of 8.4094 cents per kWh for residential customers.

Australian Capital Territory (ACT)

In the ACT, the distributor-funded feed-in tariff scheme for small and medium scale systems reached its legislated total capacity target of 30 MW and was closed to new applications on 13 July 2011. New PV customers may still be eligible for ActewAGL's '1 for 1' buyback offer for net energy exports. This is a voluntary tariff offer where ActewAGL pays customers a feed-in tariff for net exports, at a rate equivalent to the customer's own energy consumption tariff.

Victoria (VIC)

The feed-in tariff arrangements applying in VIC were reviewed by the Victorian Competition and Efficiency Commission (VCEC) in 2012, which reported to the Victorian Treasurer on 27 July 2012. In its Final Report, VCEC recommended closing the transitional distribution-funded feed-in tariff scheme by December 2013, with a move to a competitively determined, retailer-funded feed-in tariff by December 2015.

On 3 September 2012, the Victorian Government announced that the Standard Feed-in Tariff (SFiT) and Transitional Feed-in Tariff (TFiT) would be closed to new applicants from 1 January 2013. A new feed-in tariff was implemented which offers a minimum 8 cents per kWh for net PV exports during 2013. Feed-in tariff rates for subsequent years will be updated annually until 2016 by the Essential Services Commission.

Table 2.2: Current jurisdictional feed-in tariff arrangements

State	Distributor contribution (c/kWh)	Retailer contribution (c/kWh)	Metering basis
ACT	50.05 - 30.16c, nil from 14 July 2011	1:1 at customer's consumption tariff (voluntary offer)	Gross
NSW	60c, 20c , nil from April 2011	7.7c contribution to existing scheme 7.7-12.9c from July 2012 (voluntary)	Gross Net
SA	44c, 16c, nil from 30 September 2016 Nil from 1 Oct 2013	9.8c for 2012-13	Net
Tasmania	nil	1:1 at customer's consumption tariff (22.64c)	Net
Northern Territory	1:1 at customers consumption tariff 18.48c - 31.7c	nil	Gross
VIC	60c, 25c from 1 January 2012 8c from 1 January 2013	6-8c - voluntary market offers	Net
Queensland	44c, 8c, nil from 1 July 2014	4-10c - voluntary market offers	Net
WA	60c, 40c, nil from August 2011	Various location-based tariffs Horizon Power - 10c - 50c Synergy - 8.4094 c	Net

Note: Information current at 8 March 2013

3. DEFINING A 'FAIR AND REASONABLE' VALUE FOR PV EXPORTS

3.1 Introduction

In establishing a fair and reasonable value for energy generated from small-scale solar PV generators and exported into the Queensland electricity grid, the terms of reference require that the Authority should have regard to the following:

(a) the COAG's first National Principle for feed-in tariffs and the concept of fair and reasonable value;

(b) there must be no consequential increase in electricity prices in Queensland or cost to the Queensland Government budget;

(c) the benefit gained by electricity customers, distributors and/or retailers from electricity produced by small scale solar PV customers; and

(d) other issues the Authority deems relevant.

3.2 Defining Fair and Reasonable

In its Draft Report, the Authority considered that a fair and reasonable feed-in tariff should be subsidy free, due to the requirement that it must not result in an increase in electricity prices in Queensland, or require funding from the Queensland Government budget. On this basis, the Authority was of the view that that any future feed-in tariff for Queensland should be funded by electricity retailers rather than distribution businesses. This is because distributor-funded schemes necessarily involve subsidies, funded through higher electricity network charges.

The Authority also suggested that a fair and reasonable value for feed-in tariffs that is consistent with COAG's first National Principles may be interpreted as the value to retailers from electricity exported to the grid by small scale solar PV customers.

The Authority discussed costs and benefits which PV generation might offer to distributors and customers and suggested that:

(a) network costs or benefits, whichever they might be, should not be included in a fair and reasonable value for a feed-in tariff, given that impacts on network expenditure requirements should be reflected in regulated network charges approved by the Australian Energy Regulator (AER), which retailers then pass through to customers;

(b) any benefits of PV generation on network loss factors should also be excluded from the feed-in tariff because they would be captured in the network loss factors which apply to wholesale energy purchases from the NEM, and would therefore be shared across all network customers; and

(c) the timing and volume of solar PV exports will influence the timing and volume of electricity that is drawn from the NEM, which in turn may affect wholesale electricity prices and therefore retail electricity prices for customers generally.

3.3 Approaches in Other Jurisdictions

Recent reviews of feed-in tariff arrangements by ESCOSA[1], IPART[2] and VCEC[3] considered this issue and concluded that 'fair and reasonable' value of PV exports should be interpreted as the direct financial benefit to the electricity retailer when it on-sells exported PV electricity. In each case, these reviews generally concluded that the value of the benefit to the retailer should be represented by the value of costs that retailers avoid when on-selling PV energy.

3.4 Submissions

In response to the Issues Paper, the Solar Energy Industries Association (SEIA) suggested that the fair and reasonable value be set at 80% of the retail billing price, which would allow the retailers to recover a margin of 20%. Suntech suggested a similar approach whereby the value is set at between 70 and 80% of the consumption charge. A number of stakeholders, including Energex, also encouraged the Authority to develop a feed-in tariff which captures the value of the exported energy at the time of day it is generated.

A number of submissions, particularly from PV owners, suggested that a fair and reasonable feed-in tariff should be based on (or at least have regard to) the 'payback period' of the capital cost of a PV system to ensure an adequate return for their investments and allow recovery of costs for PV investors. In contrast, TRUenergy argued that setting a feed-in tariff based on a payback period would risk sending a misplaced signal to potential PV customers that this form of generation is more desirable in the market than it may actually be.

Some stakeholders further suggested that the fair and reasonable value should be at least equal to the retail price, or equivalent 'GreenPower' tariffs[4].

Many stakeholders put forward arguments for the inclusion of network costs and benefits in the value of the feed-in tariff. Common suggestions were that PV generation can allow investment deferrals by reducing demand peaks at certain times of the day. The Clean Energy Council suggested that PV exports have an impact on network loss factors and this should be returned to the PV customer. It also suggested that not apportioning the contribution to improved loss factors directly to the PV customers would effectively mean that PV customers were subsidising non-PV customers.

In contrast, TRUenergy stated that if the benefit of avoided losses were applied only to PV customers, this would disadvantage the local non-PV customers. It considered that the benefit of reduced losses is dependent on the presence of equivalent or larger loads in the vicinity, so the customers responsible for those loads should also share in any benefit, which would be impossible to administer.

Infinity Solar submitted that the feed-in tariff should reflect the benefits of reduced network congestion as well as quality and reliability improvements created by PV generation. In contrast, the Alternative Technologies Association (ATA) submitted that whilst any benefits of investment deferral at the residential level should not be included in the fair and reasonable value, it suggested that the potential benefit would be greater in commercial and industrial load centres and that this should be included in the feed-in tariff.

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[1] ESCOSA, *2012 Determination of Solar Feed-in Tariff Premium, Final Price Determination*, January 2012
[2] IPART, *Setting a Fair and Reasonable Value for Electricity Generated by Small-scale Solar PV Units in NSW, Final Report*, March 2012.
[3] VCEC, *Inquiry into Distributed Generation*, Final Report, July 2012
[4] H. Paull, G. Bell and A. Wilson

In contrast, AGL supported the Authority's position of not including network costs and benefits, changes in loss factors, time of exports and the merit order effect in the estimated value, which is consistent with the approaches taken by IPART and ESCOSA.

Energex suggested that small-scale PV exports are unlikely to provide significant benefits in terms of deferred network investment and that there is a potential for increased investment costs to accommodate exported electricity while maintaining service delivery standards. Energex noted that these costs are likely to emerge in residential areas where PV generation occurs at times of light network load and has little or no impact on network loads during the evening peak consumption period.

Similarly, Ergon Energy stated that PV exports are unlikely to lead to significant network cost savings, pointing out a range of technical challenges it faces as a result of increased PV generation on its network, including voltage rises and imbalances, system stability issues and the potential for reverse flows in the high voltage network.

Notwithstanding the comments above, both Energex and Ergon Energy stated that it would be difficult to accurately estimate network costs and benefits and that they are best addressed through the relevant regulatory frameworks and not the feed-in tariff. TRUenergy also considered that network benefits from PV exports would be very difficult to determine and may be small or offset by PV-related costs. TRUenergy also agreed that any such impacts should be reviewed by the AER and included in network charges.

Energex stated that PV exports are likely to result in reduced transmission and distribution losses but noted that any improvement should be reflected in the loss factors used in the market settlement process. Through this process, any reduction in system-wide losses will be accounted for by the Australian Energy Market Operator (AEMO) when setting the loss factors to be applied to wholesale electricity purchases from the NEM. Energex argued that accurately quantifying the impact on losses would require considerable cost and effort.

A number of solar industry and advocacy groups submitted that the impact of PV generation on wholesale energy prices should be considered as a component in valuing PV exports[5]. The Clean Energy Council suggested that ignoring this benefit would be short-changing solar PV owners and would not be fair and reasonable.

Submissions from solar interests and industry groups suggested that a broad range of costs and benefits associated with solar PV, including environmental and social benefits, and deferral of investment in new power stations, should be reflected in the fair and reasonable feed-in tariff. Infinity Solar submitted that PV energy has a range of other benefits including, increasing owner's awareness and influencing usage behaviours, improving asset values and resale values. It noted that these factors cannot be easily quantified but should still be considered.

In response to the Draft Report, stakeholders including AGL, Origin Energy, EnergyAustralia, Master Electricians Association, National Generator's Forum and the Queensland Council of Social Service (QCOSS) generally supported the Authority's interpretation the fair and reasonable value.

QCOSS submitted that setting the retailer-funded feed-in tariff at a rate any higher than the direct financial benefit to retailers would likely result in retailers increasing electricity prices for all customers to cover costs that exceed the benefit they receive. QCOSS suggested that this would be inequitable for customers without solar PV as they would face higher

[5] ATA, Australian PV Association, Australian Solar Council, Clean Energy Council and SunWiz.

electricity prices without receiving the benefit of payment for any installed solar PV generated and exported to the grid.

QCOSS also stated that, given the significant detriment already created for consumers through higher electricity prices, it is important that further detriment to consumers is avoided, particularly for those currently unable to install a solar PV. QCOSS argued that the fair and reasonable feed-in tariff value should be set at a level which ensures that whoever pays the feed-in tariff is not forced to incur costs in excess of the direct financial benefit they receive.

3.5 The Authority's Position

As discussed in Chapter 2, the existing statutory Scheme is funded entirely by distribution businesses, which in turn recover these costs through higher network charges for all customers. These higher network charges in turn increase electricity prices in Queensland. As a result, the Authority considers that a distributor-funded solar PV feed-in tariff is inconsistent with the terms of reference. Similarly, the terms of reference preclude a taxpayer funded scheme, as this would require funding from the Queensland Government budget.

For these reasons, the Authority considers that feed-in tariffs, whether mandated or not, should be funded by electricity retailers, not regulated electricity distribution businesses.

Due to the subsidy arrangements which apply to Ergon Energy, the matter of budget neutrality and subsequent impact on electricity prices becomes more complex. These issues are addressed in Chapter 6.

Defining 'Fair and Reasonable'

The first national COAG principle establishes that the payment for PV exports should be

> *at least equal to the value of that energy in the relevant electricity market and the relevant electricity network it feeds into, taking into account the time of day during which the energy is exported...*

To define a fair and reasonable value for PV exports, it is worth examining the elements of this statement separately.

Value in the relevant electricity market

It is important to draw a distinction between the value of exported PV energy in the retail electricity market and its equivalent value in the wholesale spot market. The Authority considers that the relevant market in this case is the retail electricity market, not the wholesale electricity market. Small residential PV exporters are not direct participants in the wholesale market and their exported energy only has realisable financial value in the presence of the retailer as an intermediary. Without the retailer acting as an intermediary, there is no market or mechanism for small PV customers to on-sell excess PV electricity, nor any means of accurately valuing it. Therefore, the relevant market should be the retail market. On this basis, it follows that the starting point for valuing PV exports should be the value that the retailer ascribes to any exported PV energy that it can on-sell to its customers.

The Authority notes submissions arguing that the fair and reasonable value should be set close to, or at, the same level as the retail consumption charge. However, valuing PV exports on this basis would be inconsistent with the concept of value in the retail market. This is because when retailers purchase electricity from the wholesale market, or on-sells exported PV to customers, they incur a range of costs that they cannot avoid.

If the relevant market for the purpose of determining a fair and reasonable feed-in tariff is the retail electricity market, then the value of PV exports in the retail market is the benefit that the retailer derives from on-selling PV exports generated by its customers. The financial benefit to the retailer is therefore the retail price it can charge for selling each unit of PV energy, less the costs it cannot avoid when on-selling that unit of energy. On this basis, a feed-in tariff which is equal to, or close to, the retail price would significantly overstate the true value of that energy in the retail market as it ignores the fact that retailers face other costs.

The Authority understands that there may be other costs and benefits created by solar PV generation, including social and environmental factors, as suggested by some stakeholders. However, the Authority considers that the value of PV exports should, as far as possible, reflect the explicit value of that electricity in the relevant market, in this case, the retail electricity market. Assessing the extent to which the value of retail electricity captures all positive (and negative) externalities of its production and delivery is beyond the scope of the Authority's review. Further, it is questionable that feed-in tariff policy is the right vehicle to address these complex externalities and the Authority would suggest that these matters are best handled directly by other policy responses.

The requirement to consider the value in the relevant market also removes the option of basing the feed-in tariff on a payback period estimate, as suggested by some stakeholders. The return of investment to the PV owner is separate from the value to retailers of the energy generated and exported by the PV owner. Whilst an individual owner's payback period for their PV installation may be sensitive to the rate of the feed-in tariff, the value of the electricity it exports into the retail market is not. Given this, it would not be appropriate to derive a fair and reasonable feed-in tariff using the payback period approach.

Value in the relevant electricity network

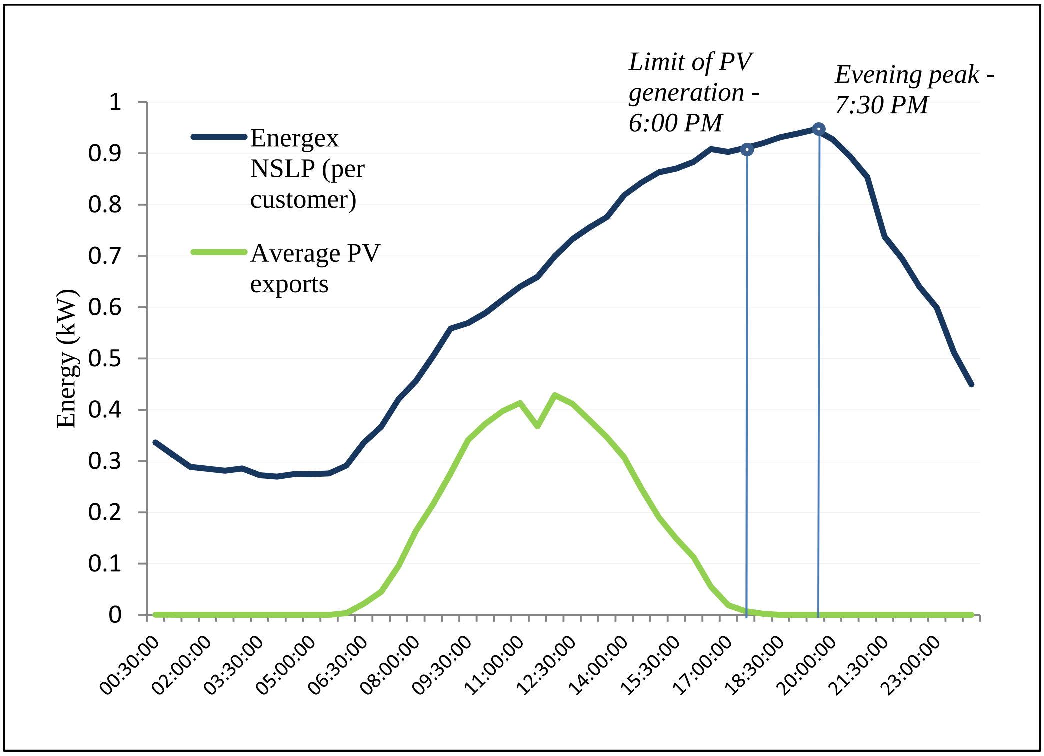
It is also important to consider that the value of electricity in the retail market will differ depending on the costs of delivering that energy to the relevant network. These costs relate to network infrastructure and maintenance costs, the impact of energy losses incurred when transporting electricity over long distances and the potential for cost savings (and cost increases) which PV might bring to the network.

Network costs and benefits

Establishing the network costs and benefits arising from installation of PV generation is clearly not straightforward. There is evidence that increased PV penetration can reduce costs in some circumstances and increase costs in others. The most persuasive information before the Authority tends to suggest that the latter impact may be more significant, at least in aggregate terms. This issue is discussed further in Chapter 6.

With regard to the benefit of reduced peak demand due to PV generation, the Authority considers that this is currently unlikely to be of significant impact in Queensland. Some submissions correctly noted that the greatest impact would likely be in areas dominated by daytime commercial loads, which coincide with the typical generation profile of PV installations. However, networks are designed and built to handle the highest peaks, which typically occur outside of this time. Figure 3.1 shows an average PV net export profile for a sample of customers in South East Queensland on the highest peak demand day during 2011-12, charted against the Energex net system load profile (NSLP) of that same day. As this illustrates, the impact of PV generation diminishes prior to the onset of the highest evening residential peak, which the network is built to withstand.

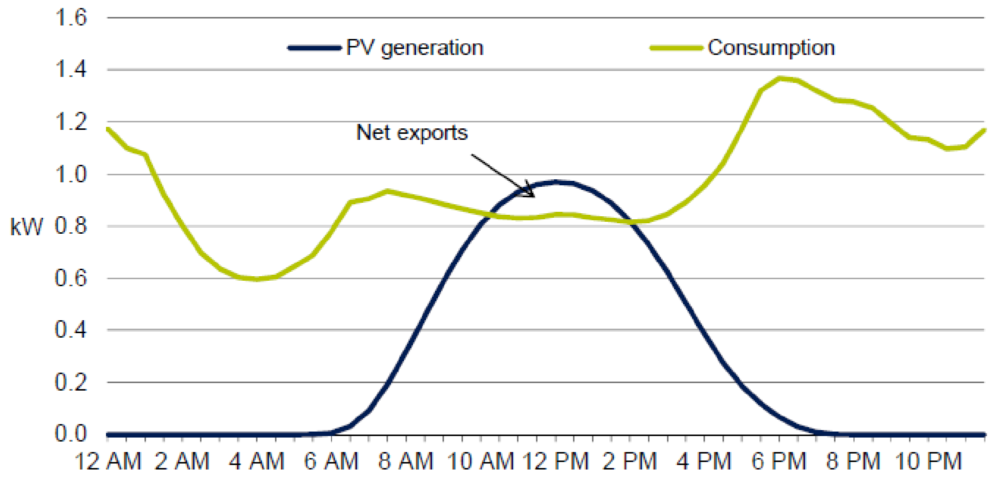
Figure 3.1: PV Exports and Peak Demand - 9 January 2012



Note: PV profile reflects the net exports of a small sample of PV installations in a localised area. However, the shape of the export profile is a reasonable estimation of the generation profile on this day.

These findings are consistent with the findings of other feed-in tariff reviews. In its most recent determination of fair and reasonable feed-in tariffs for NSW, IPART concluded that PV exports are unlikely to create value for distributors because any benefits that arise are likely to be location- and time-specific and that these benefits are likely to be small or offset by system-wide cost increases as a result of the uptake of small-scale PV generators. The relationship between the peaks in PV exports and electricity consumption in NSW, shown in Figure 3.2, is similar to the sample for Queensland shown above.

Figure 3.2: PV Generation, Exports and Peak Demand in NSW



Source: IPART.

Similarly, in its recent Final Report on its review into the design, efficiency and effectiveness of feed-in tariff schemes in Victoria, VCEC was of the view that the value of any network benefits should be returned to distributed generators, but acknowledged that this value cannot be efficiently captured through existing feed-in tariffs because it is highly location specific[6].

Whilst it appears unlikely that PV generation has so far had a material impact on peak demand in Queensland, this could become a more realistic proposition with greater penetration of electricity storage technologies. Storage would provide flexibility to use solar PV energy in ways that maximise its economic value to customers and networks.

Regardless of the net impact of PV on network costs, the Authority retains the view it put forward in its Draft Report, that any network costs and benefits should be captured in the AER's revenue determination process for Energex and Ergon Energy. Through this process, any increase or decrease in efficient network expenditures attributable to PV generation will be reflected in future network tariffs and shared among all customers. This view was supported in submissions by Energex and Ergon Energy, as well as ESCOSA in its most recent determination of a fair and reasonable feed-in tariff for South Australia. For the reasons outlined, the Authority has decided not to include any allowance for network cost impacts in its estimate of the fair and reasonable feed-in tariff.

Benefit of improved loss factors

A benefit of PV exports may arise from changes in network loss factors due to electricity being consumed in close proximity to where it is generated (by PV customers). This concept should be distinguished from the benefit to retailers of not having to purchase a certain amount of additional energy to overcome losses on energy purchased from the NEM when they receive PV exports from customers - this issue is addressed in Chapter 4.

The Authority acknowledges that increased small-scale PV generation is likely to have some impact on system-wide network losses over time. However, the Authority agrees with

[6] VCEC, *Power from the People: Inquiry into Distributed Generation. Final Report*, July 2012 p. 85

Energex and TRUenergy that it is not necessary or appropriate to directly estimate this in the fair and reasonable value for two reasons.

Firstly, any reduction in network loss factors attributable purely to residential PV generation is likely to be small and prohibitively complex to calculate with accuracy. This is because the benefits will be highly variable and location specific. Furthermore, the value of the benefit is likely to be very small and outweighed by the costs of determining it.

Secondly, and more importantly, any reduction in system wide losses will be accounted for by the AEMO when setting the loss factors to be applied to wholesale electricity purchases from the NEM. The Authority agrees with Energex that this is the most appropriate way to capture the value of this benefit and ensure that it is shared amongst all network customers. In fact, attempting to quantify the benefit of reduced loss factors, and returning it to PV customers through a feed-in tariff, would mean that the benefit was actually double-counted and would result in an overstated feed-in value for PV exports.

The Authority's proposed treatment of loss factors is consistent with the approaches adopted recently by IPART, ESCOSA and VCEC.

Taking account of the time of the exports

The spot price of electricity in the NEM is dynamic and responds to changes in supply and demand on a half-hourly basis throughout the day. However, there are a number of reasons why this inter-temporal variation in price is not relevant to establishing the value of PV in the Queensland retail electricity market.

In Queensland, retailers' electricity purchases for all small retail customers on both the Energex and Ergon Energy distribution networks are settled by AEMO against the relevant NSLP, regardless of whether or not they have interval meters installed. This is because the majority of interval meters for small customers in Queensland are not equipped with communications capabilities and must be manually read on a quarterly basis as simple accumulation meters.

This means that it is not possible to identify each individual customer's consumption (or PV exports) for each half-hour settlement period. To address this issue, AEMO calculates an aggregate consumption profile (the NSLP) which is used to calculate each retailer's wholesale electricity purchase liabilities for the settlement period. More details on how retailers' energy costs are settled against the NSLP are provided in the Authority's Final Determination on Regulated Retail Electricity Prices for 2012-13.

The result of this metrology and settlement process is a weighted average price for each 24-hour period, calculated as a function of aggregate half-hourly consumption and the corresponding half-hourly pool price. The retailer then pays AEMO this price for each unit of electricity it buys for its customers, irrespective of the time of day at which it was actually consumed.

On this basis, the financial value of avoided energy purchase costs due to PV exports is the same, regardless of the time the electricity was generated and exported. As a result, it is not possible to take account of the time at which PV exports occur in determining the fair and reasonable feed-in tariff, as suggested in some submissions.

Benefit of lower wholesale electricity prices

The Authority understands that increased PV generation is likely to have placed some downward pressure on wholesale spot prices at certain times of the day, as suggested by a number of stakeholders.

When solar PV units are exporting to the network, they displace a portion of the dispatched NEM generation required to meet demand at the regional reference node. This does not manifest as an increase in supply in the generation market itself (it is actually a reduction in demand) but the result is a lower spot price paid in the market. This effect is apparent in many markets, not just the NEM, and is a natural market outcome when suppliers of a homogeneous product are price-takers in a competitive market facing fairly predictable and inelastic demand.

In the case of net-metered solar PV generation, much of the impact on wholesale prices is likely a result of lower network demand due to self-consumption of PV power, not from additional supply exported to the network. By consuming PV electricity generated onsite, customers demand less from the NEM generation market, which typically results in a lower wholesale market price. However, this market response does not discriminate between a network demand reduction caused by self-consumption of PV, energy efficiency measures, load-shedding, or other demand curtailment activities. Each of these measures will similarly reduce demand for electricity from the NEM and force down the wholesale electricity price to some extent.

While the Authority does not dispute the potential for PV exports to influence the wholesale electricity price, it does not accept that any associated reduction should be returned to PV owners through a feed-in tariff, as some stakeholders have argued.

While the impact on wholesale prices may be in some part attributable to PV generation, the Authority notes that it would be difficult to distinguish between the self-consumption of PV electricity and any other demand management practices which reduce metered network consumption.

More importantly, the Authority does not consider there is a sound economic argument to support this proposal. The benefit of lower wholesale electricity prices is a consequence of competition in the market and should accrue to all participants. It follows then that, to return the benefit of lower prices solely to PV generators would require a subsidy from other participants. If this was funded by retailers, it would increase electricity prices for all other customers, which would be inconsistent with a key requirement under the terms of reference for this review. Specifically, that there should be no consequential increase in electricity prices in Queensland.

The Authority's view is shared by a number of regulators including IPART, ESCOSA and most recently by VCEC.

Conclusion

For the reasons discussed, the Authority considers that the term 'fair and reasonable' value should be interpreted as the value of the direct financial benefit to retailers from on-selling electricity exported by PV customers to the network.

This is generally consistent with the interpretation adopted by IPART in its most recent determination to set the upper end of the feed-in tariff range for NSW, the VCEC's definition of the term fair and reasonable in its Final Report and the definition of fair and reasonable value that ESCOSA was required to calculate in its most recent determination.

4. ESTIMATING THE FAIR AND REASONABLE VALUE OF PV EXPORTS TO THE RETAILER

As discussed in Chapter 3, the Authority considers that the fair and reasonable value of PV exports should be interpreted as the sum of direct financial benefits which accrue to a retailer when it on-sells energy exported by its grid-connected PV customers.

In order to estimate the fair and reasonable export value, it is necessary to assess each of the costs that a retailer incurs in providing retail services and determine whether a retailer avoids them when on-selling PV energy.

While there are various ways to calculate the costs that contribute to the retail price of electricity, the Authority's Draft Report adopted the cost estimates determined in setting notified prices, on the basis that these are the Authority’s best estimates of the retail costs of supplying electricity. There was general support for this proposed approach in submissions, but some stakeholders suggested various modifications to the calculation of specific cost components.

The process of estimating the value of PV exports in the Ergon Energy network is complicated by the Government’s subsidisation of retail electricity prices in regional Queensland. This is considered separately in section 4.11 below.

4.1 Approaches in other Jurisdictions

New South Wales (NSW)

In its 2012 review into solar feed-in tariffs for NSW, IPART estimated a benchmark range for the fair and reasonable value of PV exports, based on two approaches[7]. Firstly, it estimated the direct financial benefit accruing to retailers when they on-sell PV exports, based on the actual costs of the Standard Retailers in NSW. IPART examined those costs that could be avoided when PV exports are on-sold, and concluded that retailers can avoid some electricity purchase costs, a portion of losses and NEM fees when on-selling PV exports.

Secondly, IPART estimated the value of exported PV energy in the wholesale market based on the price that energy would have attracted if it was sold in the NEM at the time it was exported. This was done with reference to historical half-hourly PV generation profiles and historical half-hourly NEM spot prices.

In June 2012, IPART estimated that the direct financial benefit to retailers from on-selling exported PV electricity was between 10.3 and 12.9 cents per kWh. Using the second approach, IPART estimated the expected value of PV exports in the wholesale market to be between 7.7 and 9.9 cents per kWh. Based on these values, IPART recommended a voluntary benchmark feed-in tariff range of 7.7 to 12.9 cents per kWh (represented by the lowest and highest estimates from each estimation method)[8].

South Australia

In South Australia, ESCOSA also valued PV exports by estimating the value to the retailer, based on the direct costs avoided when it on-sells PV electricity[9]. Similar to IPART,

[7] IPART, *Setting a Fair and Reasonable Value for Electricity Generated by Small-scale Solar PV Units in NSW, Final Report*, March 2012.
[8] IPART, *Solar Feed-in Tariffs, Retailer Contribution and Benchmark Range for 1 July 2012 to 30 June 2013*. June 2012.
[9] ESCOSA, *2012 Determination of Solar Feed-in Tariff Premium - Final Price Determination*. January 2012.

ESCOSA concluded that energy purchase costs, some losses and NEM fees are avoided when PV exports are on-sold by retailers. Based on this approach, ESCOSA estimated the value of PV exports to the retailer to be 7.1 cents per kWh in 2011-12 and 9.8 cents per kWh in 2012-13.

Australian Capital Territory

The Independent Competition and Regulatory Commission (ICRC) determined a premium tariff rate of 39 cents per kWh to apply under the *Electricity Feed-in (Renewable Energy Premium) Act 2008* during 2011-12[10]. This rate was derived using an approach which allows customers with systems up to 5kW capacity to earn a return on their investment commensurate to the risk-free government bond rate. As discussed in Chapter 3, such an approach would not be suitable for this review, as the Authority has been tasked with estimating a subsidy-free feed-in tariff rate, rather than a premium rate, as was required of the ICRC.

Victoria

In September 2012, VCEC recommended that the Victorian Government replace the existing SFiT scheme (SFiT) with a new scheme requiring retailers to offer a minimum 'efficient and fair' price for small renewable generation exports, based on the wholesale price of electricity, adjusted for the effect of reduced losses[11]. VCEC recommended that a minimum efficient and fair market price for 2013 would be in the range of 6 to 8 cents per kWh.

The Victorian Government accepted the recommendations of VCEC, but chose to set the new minimum standard feed-in tariff rate at the upper end of that range (8 cents per kWh).

4.2 Benchmark Retail Electricity Price for On-sold PV Exports

Estimating the value to retailers of PV exports requires first that the retail price at which exported PV electricity can reasonably be on-sold be established. From this starting point the value of PV exports to the retailer is estimated by subtracting the costs that the retailer cannot avoid when it on-sells exported PV electricity. The steps in this process are discussed in this Chapter and the result can be seen in Table 4.6.

Relevant Tariff Class

For the Draft Report, the Authority used a cost-reflective Tariff 11 for 2012-13 as the basis for estimating the benefit to the retailer. While this was not the actual Tariff 11 for 2012-13 (which was frozen by the Government at the 2011-12 level, adjusted for the effect of carbon pricing), it was the appropriate benchmark to use for the purposes of the Draft Report.

The current Scheme is only available to small customers, the majority of whom will be supplied under Tariff 11 or a market contract rate below the regulated price. The consumption by these customers is settled at a weighted average wholesale electricity price, based on the NSLP, which captures only residential and small business consumption. Consumption of large customers, controlled loads and unmetered supplies are 'netted off' to produce the NSLP. The benefit to the retailer from on-selling PV exports arises from a reduction in the amount of electricity it must purchase from the NEM. In other words, the benefit is the reduction in the retailer's share of load settled against the NSLP for residential and small business customers.

[10] Independent Competition and Regulatory Commission, *Final Report, Electricity Feed-in Renewable Energy Premium: Determination of Premium Rate 2011-12*, March 2011.
[11] VCEC, *Inquiry into Distributed Generation, Final Report*, July 2012

While it is true that PV exports may be on-sold at prices other than Tariff 11 and that PV customers themselves may be supplied through market contracts, this has no bearing on the financial benefit to the retailer due to the way that AEMO derives the NSLP and settles the retailers' energy purchase cost liabilities in Queensland. The outcome of this settlement process is that the retailer faces the same averaged wholesale energy purchase price for all consumption within the NSLP, regardless of the actual prices it charges its individual customers.

Use of Cost-Reflective Tariff

The Authority maintains that the appropriate benchmark on-sell price for PV exports should reflect a best estimate of the efficient cost of supplying the residential and small business NSLP. For this Final Report, this is reasonably represented by the proposed cost-reflective Tariff 11 for 2013-14, not the proposed transitional Tariff 11[12]. This is because the additional revenue retailers would receive through the transitional Tariff 11 during 2013-14 is essentially compensation for the under-recovery they are incurring on the fixed charge component, which has been held artificially low during 2012-13. For this reason, it would not be appropriate to calculate the benefit to the retailer based on the transitional Tariff 11.

For this Final Report, the Authority has used the proposed cost-reflective residential Tariff 11 as the assumed retail on-sell price for PV exports, updated to reflect the findings of the Authority's 2013-14 draft price determination.

4.3 Wholesale Energy Costs in South East Queensland

Wholesale energy costs are those costs that AEMO charges a retailer for electricity purchased from the NEM. When on-selling energy from PV exports, wholesale energy costs are the most significant costs that are avoided by the retailer.

Estimating the value of electricity purchased from the NEM is a complex exercise, but one which the Authority conducts each year for the purpose of setting notified prices for regulated retail electricity tariffs. For small residential customers, the Authority currently bases its wholesale energy cost estimate on the cost of supplying the Energex NLSP.

In the Draft Report, the Authority suggested it would be reasonable to use the wholesale energy cost estimate that it used to determine notified prices for small customers as the value of the avoided wholesale energy cost component (before losses) in the feed-in tariff estimate.

Submissions

Sunwiz and the Clean Energy Council argued that using the NSLP does not capture the premium value of energy at the time it is exported. AGL suggested that the use of the NSLP to estimate the value of PV exports is only relevant as long as PV customers' imports and exports are settled on accumulation data.

Stanwell considered that the method used by the Authority to calculate notified prices provided a cost-reflective, unbiased estimate of energy purchase costs and was a suitable basis for estimating the fair and reasonable value of the feed-in tariff. Similarly, Infinity Solar submitted that using the cost estimates from notified prices is the most efficient method for determining the feed-in tariff.

Origin stated that it does not object in principle to using notified prices as the basis of cost estimates for a fair and reasonable value or benchmark, should that form of regulation apply,

[12] See the Authority's Draft Determination on notified prices for 2013-14 for further information on proposed transitional tariffs.

notwithstanding its concerns regarding the treatment of the retail margin (discussed in section 4.9).

In response to the Draft Report, Ergon Energy reiterated its view that while retailers with PV customers would need to purchase less wholesale electricity from the market, they may incur higher hedging costs given the intermittent nature of PV electricity generation. Ergon Energy argued that this could mean that retailers are more exposed to high and unhedged pool prices, and would potentially need to purchase additional hedging products to manage that risk. Ergon Energy suggested that the impact of PV should be viewed from a kWh capacity perspective rather than the kWh volume perspective (based on 0.4% of energy provided by PV). Ergon Energy stated that comparing actual peak capacity usage numbers to the total PV capacity in the network, the solar PV capacity represents around 10% of the actual peak capacity usage, and argued that this highlights the potential impact and risks, and financial derivatives needed to manage the intermittent PV generation profile.

The basis of Ergon Energy's argument is that hedging costs may increase due to the peakier load profile arising from increasing solar PV penetration. Ergon Energy argued that it may need to purchase financial caps to support solar generated electricity when cloud cover, or other factors, reduce solar PV generation during times of high pool prices. In other words, for a given hedging position, an unexpected loss of PV generation capacity may leave it under-hedged and exposed to high spot prices. In contrast, the Australian Solar Council suggested that PV exports have reduced volatility in the wholesale market, which should have the effect of reducing the retailers’ risk. In response to the Draft Report, the Department of Energy and Water Supply (DEWS) suggested that the Authority consider the matter of fair and reasonable feed-in tariffs and complementarity with the carbon pricing mechanism.

The Authority's Position

Use of the NSLP to estimate wholesale electricity costs

The Authority notes the issues raised by SunWiz, Clean Energy Council and AGL regarding the limitations of the NSLP. However, given the existing metrology procedures in Queensland, the Authority considers that the NSLP remains the most appropriate means of assigning a market value to PV exports using the Authority's 'benefit to retailer' approach. As discussed in Chapter 3, for most residential consumption, the retailer is charged according to its share of the NSLP in the local network area rather than the individual consumption pattern of each household that it services. As such, the benefit to the retailer is the amount by which the PV exports reduce its share of the NSLP. This does not necessarily reflect the spot prices that the exports might have attracted if they were sold in the NEM at the time of generation. On this basis, the financial benefit to the retailer of the avoided energy purchase costs due to PV exporting is the same, regardless of the time the electricity was generated or exported.

With the further introduction of remotely-read interval meters and changes to the existing metrology procedures in Queensland, there may be more flexibility to isolate or 'peel off' the PV export volumes from the NSLP. This would be necessary before AEMO could bill retailers based on the time that they purchase energy from the NEM, and the value of PV exports could be linked to the wholesale pool price throughout the day.

Impact of PV generation on retail hedging costs

The Authority does not consider there is a strong argument that PV generation materially impacts hedging costs, as suggested by Ergon Energy, because it is not clear that the volume risk a retailer faces from intermittent PV generation is any different to the volume risk associated with other demand management activities or consumption variability more generally. To the extent that a retailer underestimates the volume of electricity it must buy from the NEM, it may be under-hedged and exposed to the spot price. However, this will be the case regardless of what caused consumption to be underestimated. In any event, the Authority considers that a prudent retailers' hedging strategy would take account of all factors contributing to variability in consumption, including the intermittent nature of PV generation.

The Authority also notes Ergon Energy's statement that PV exports represent only around 0.4% of the total energy delivered on its network. Given that this represents a small contribution to total energy requirements, it is not clear that Ergon Energy's hedging strategy and associated hedging costs would be materially influenced by the variability of PV exports. While other retailers may receive a greater share of their electricity requirements from PV customers, no retailers other than Ergon Energy raised hedging costs as a specific issue.

The Authority does not consider Ergon Energy's submission in response to the Draft Report, provides any more compelling input on this matter. Regardless of the volume of PV generation as a proportion of total energy delivered on Ergon Energy's network, the fact remains that the Authority has not been presented with any evidence to value the alleged cost impact, nor any proposal for how this might be captured when calculating a fair and reasonable feed-in tariff.

The issue of hedging cost impacts raised by Ergon Energy was also addressed in some detail by ESCOSA in its January 2012 solar feed-in tariff determination[13]. ESCOSA found that there was no reason to conclude, all else being equal, that solar PV increases a retailer's hedging costs. Based on these considerations, the Authority maintains its Draft Report position not to adjust the fair and reasonable value of PV exports to account for any additional hedging costs associated with PV exports, above those already implicit in the estimated wholesale energy purchase cost (WEPC).

Prudential capital allowance

Since preparing its Draft Report, the Authority has refined the WEPC calculation to include an allowance of $0.631 per MWh for the cost of meeting prudential requirements imposed by AEMO. The reasons for this amendment are discussed in the Authority's Draft Determination for 2013-14 notified prices and ACIL Tasman's report[14].

The Authority considers that this cost is not avoided when a retailer on-sells electricity from its PV customers and has excluded it from the estimated fair and reasonable value.

Complementarity with the carbon pricing mechanism

The terms of reference require the Authority to have regard to 'complementarity' with the carbon pricing mechanism when investigating fair and reasonable feed-in tariffs. The WEPC estimates used by the Authority have been calculated by ACIL Tasman inclusive of the carbon price and as such, the carbon price is implicit in the calculation of the financial benefit to the retailer.

However, when considering whether a feed-in tariff scheme is 'complementary' to the carbon pricing mechanism, the Authority has also considered whether it is appropriate to estimate

[13] ESCOSA, *2012 Determination of Solar Feed-in Tariff Premium - Final Price Determination*. January 2012. pp 37-40.

[14] ACIL Tasman, *Estimated Energy Costs for Use in 2013-14 electricity retail tariffs - draft report*, February 2013.

the benefit to the retailer based on an estimated WEPC which is inclusive of carbon price impacts.

The Authority's fair and reasonable value for solar PV energy is represented by the financial benefit to the retailer, which is based on the costs that the retailer avoids due to PV exports. As the main avoided cost is the cost of energy purchases from the NEM (which is predominantly supplied by carbon intensive generation sources) it is reasonable that the avoided cost of energy should include the estimated impact of the carbon price. In the absence of PV exports, a retailer would need to source additional electricity from the NEM at a price which would invariably include some reflection of the carbon price.

The Authority considers there are no major impediments to the operation of a fair and reasonable, retailer-funded feed-in tariff scheme created by the current carbon pricing mechanism. Specifically, should the carbon price change, or the mechanism be removed altogether, the Authority's approach to estimating the fair and reasonable value of PV exports would reflect that change.

The Authority's Position

The Authority considers that an appropriate estimate of the avoided wholesale energy costs in South East Queensland is provided by the WEPC estimates developed by ACIL Tasman for the Authority's 2013-14 Draft Determination of notified prices[15]. On this basis, for 2013-14, the estimated financial benefit to the retailer of avoided wholesale energy costs, before losses, is 6.859 cents per kWh.

Table 4.1: Wholesale energy cost allowance (before losses) for South East Queensland

Settlement class	*c/kWh*
Energex NSLP and unmetered supply	6.859

Source: ACIL Tasman, Estimated Energy Costs for Use in 2013-14 electricity retail tariffs - draft report, February 2013

4.4 Network Costs

4.4.1 Direct Network Costs

Network charges represent around 50% of regulated retail tariffs. The Authority calculates notified prices for small customers using Energex's network charges.

Excess energy exported by PV customers is ultimately used by other customers on the network and will therefore register as metered consumption. As retailers are charged a variable network charge according to metered energy consumption, any PV exports that a retailer on-sells will still attract the full variable network charge. As such, network costs are unavoidable when a retailer on-sells PV exports and should therefore be excluded from the estimated export value.

4.4.2 Indirect Network Costs

As discussed in Chapter 3, the Authority considers that if there are any indirect network costs or benefits associated with PV generation such as deferral of investment expenditures, these should be reflected in network prices and therefore should not be separately estimated

[15] Further details of the Authority's approach to estimating wholesale energy purchase costs can be found in its *Draft Determination: Regulated Retail Electricity Prices 2013-14*, February 2013.

in calculating the fair and reasonable value of PV exports. Under the Authority's approach to determining notified prices (which are the basis of the estimated benefit to the retailer) actual network charges are passed through in full and therefore any change in network costs is reflected in the notified prices. It follows then, that it is neither necessary or appropriate to reflect network cost impacts in the estimated retailer benefit as they should already be accounted for.

The Authority's Position

The Authority considers that network charges are unavoidable when a retailer on-sells exported PV electricity and should be excluded from the estimated benefit to the retailer. As foreshadowed in the Draft Report, the Authority has updated the estimates of network charges using the indicative variable charge for Energex's flat residential network tariff for 2013-14 as set out in Table 4.2 below.

Table 4.2: Energex variable network charge for residential customers in 2013-14

Network tariff	*Variable rate c/kwh*
Residential Flat 8400 (SAC Non-Demand)	12.593

Source: Energex, Indicative 2013-14 SAC Network Tariffs. 11 January 2013.

4.5 Green Scheme Costs

Green schemes include the Renewable Energy Target (RET) scheme and the Queensland Gas Scheme.

Under the RET scheme, retailers face costs for all purchases of energy from a grid with greater than 100MW of installed capacity. This would include the vast majority of PV exports in Queensland. As a result, RET scheme costs are unavoidable when a retailer on-sells PV exports and should be excluded from a feed-in tariff.

Under the Queensland Gas Scheme, retailers face costs according to gross energy sales to customers. Costs related to the Queensland Gas Scheme are also unavoidable when a retailer on-sells PV exports and should be excluded from a feed-in tariff.

Submissions

The Clean Energy Council suggested that there is some 'double counting of green fees' arising from PV exports and stated that 'green scheme' costs should not be levied on retailers when they on-sell exported PV energy. Although it did not elaborate, the issue raised by Clean Energy Council seems to relate to the fact that electricity retailers are liable for green scheme fees on small-scale PV exports that they purchase, which some may consider is inconsistent with the intent of renewable energy schemes. SunWiz suggested that Queensland Gas Scheme charges are levied on gross electricity imports and argued that the scheme should be changed to apply only to net consumption.

In response to the Draft Report, the Clean Energy Council submitted that the assumed small-scale technology certificate (STC) price of $40 used in calculating notified prices has not eventuated, resulting in actual costs of RET compliance which are around 25% lower than the Authority's estimates. The Clean Energy Council argued that therefore, only 75% of the calculated costs are unavoidable for the purposes of calculating the fair and reasonable value.

The Authority's Position

The Authority understands that some green scheme costs, including the Queensland Gas Scheme, are levied on gross energy sales, which means that retailers do not avoid these cost when they on-sell exported PV energy. The Authority notes the concerns raised by the Clean Energy Council and SunWiz regarding the way in which some green scheme fees may be levied, but the manner in which these schemes are applied is outside the scope of the Authority's review.

The Authority is therefore of the view that the green scheme costs are not avoided when retailers on-sell PV exports and has excluded them from the estimation of the fair and reasonable value. The applicable costs used in the draft determination for 2013-14 notified prices are set out in Table 4.3 below.

In regard to the Clean Energy Council's concerns about the assumed price of STC, the Authority notes that its Draft Determination on notified prices for 2013-14 proposes a cost pass-through mechanism to adjust notified prices between tariff years and correct for any material over or under recovery of costs associated with purchasing STC. Should the Authority have a role in calculating the fair and reasonable value of PV exports in future years, then this pass-through mechanism would ensure that the estimated benefit to the retailer reflects the actual STC costs incurred by retailers, over time. The Authority's proposed pass-through mechanism is discussed in detail in the Draft Determination[16].

Table 4.3: Green scheme costs for 2013-14

Cost component	*c/kWh*
Gas Electricity Certificates	0.060
LRET	0.413
SRES	0.529
Total	**1.002**

Source: ACIL Tasman, Estimated Energy Costs for Use in 2013-14 electricity retail tariffs - draft report, February 2013

Note: Totals may not add due to rounding

4.6 NEM Participation Fees and Ancillary Services Charges

NEM participation fees are levied on retailers by AEMO to cover the costs of operating the national electricity market and ancillary services charges cover the costs of the services used by AEMO to manage power system safety, security and reliability.

In the Draft Report, the Authority suggested that retailers avoid these costs when on-selling their customers' exported PV energy and therefore these costs should be included in the fair and reasonable value of PV exports.

Submissions

TRUenergy suggested that in fact these costs are not avoidable as that they will be reallocated via usage charge increases to all customers. TRUenergy also suggested that the

[16] QCA, *Draft Determination: Regulated Retail Electricity Prices 2013-14*. February 2013. pp 56-64

intermittent nature of PV generation is more likely to increase the costs for ancillary services required to stabilise system frequency and voltage support, which are directly related to the degree of generation and demand variability.

The Authority's Position

The Authority understands that NEM participation fees and ancillary services fees are paid based on net energy purchased and measured by AEMO at the regional reference node. It follows then that retailers avoid NEM and ancillary services fees at a rate which is proportional to avoided wholesale energy purchases resulting from PV exports.

To the extent that AEMO might adjust its fees in response to a declining revenue base, as suggested by TRUenergy, the Authority considers it would not be reasonable to attribute this to the impact of solar PV generation alone, as there are a range of other demand side responses contributing to decreasing network consumption.

Regardless of any effect that reduced network consumption may have on AEMO's market charges, the Authority's annual calculation of notified prices includes updated AEMO fees and charges. Therefore, by using the notified price as the basis for estimating a fair and reasonable feed-in tariff, any annual adjustments to AEMO charges will be captured in the Authority's calculations.

As foreshadowed in the Draft Report, the Authority has updated NEM and ancillary services fees as used in the Authority's Draft Determination of notified prices for 2013-14, as set out in Table 4.4 below.

Table 4.4: NEM participation and ancillary services fees for 2013-14

	c/kWh
NEM fees	0.039
Ancillary services fees	0.031
Total	**0.070**

Source: ACIL Tasman, Estimated Energy Costs for Use in 2013-14 electricity retail tariffs - draft report, February 2013

4.7 Energy Losses

In delivering energy from a generator to a consumer, some electricity is lost through the transmission and distribution networks, as heat, due to the resistance of the conductors. The consequence of this is that retailers must purchase enough electricity from the NEM to supply the demand of their customers, plus an additional amount to compensate for the electricity lost during delivery.

One of the benefits of distributed generation, including solar PV, is that it reduces the need to transport energy long distances and therefore bypasses transmission losses. On this basis, it is likely that transmission losses can be avoided when a retailer on-sells PV exports and the value of the avoided losses should therefore be included in a feed-in tariff based on the benefits to retailers.

Distribution losses occur when transporting electricity through the lower voltage distribution network. In the Draft Report, the Authority suggested that electricity from distributed generation, including solar PV, would also likely avoid a proportion of distribution losses.

In setting notified prices, the Authority applies AER approved loss factors from Energex's network area to its cost estimates to account for losses.

Submissions

ATA submitted that the value of avoided losses needs to take account of the time at which solar exports are occurring. It stated that exports often occur at times when the network is under heavy load so customers may benefit from lower losses.

Ergon Energy submitted that it would be very difficult to accurately estimate the value of avoided losses due to PV generation in its network area and the overall impact would likely be small as solar PV only accounts for around 0.4% of energy delivered across its network. To illustrate, Ergon Energy estimated that if the total energy requirement in its network area was supplied from within the distribution network (rather than the transmission network), the estimated reduction in distribution losses would be only 0.02%[17].

Energex agreed that PV exports are likely to result in some reduction in transmission and distribution losses. However, Energex noted there would be considerable cost and effort required to accurately quantify avoided distribution losses attributable to PV for the purposes of inclusion in a feed-in tariff value.

The Authority's Position

The Authority considers that retailers avoid transmission losses when they on-sell PV exports supplied into the distribution networks and that this should be factored into the fair and reasonable value of PV exports as a reduced energy purchase requirement.

The Authority considers that it is likely that PV exports would be consumed close to where they are supplied into the distribution network and that it therefore seems reasonable to conclude that avoided distribution losses associated with PV exports would be low. However, as noted in submissions, estimating the impact of PV exports on distribution losses would be a costly and complex exercise. The Authority considers that the benefits of isolating the reduction in losses attributable only to PV would be outweighed by the cost of the exercise. For these reasons, the Authority proposes to assume that retailers avoid the full extent of distribution losses associated with the distribution loss factors the Authority uses to calculate notified prices.

The Authority notes ATA's submission and agrees that actual losses may vary at different times of the day and when the network is subject to different loads. However, the loss factor applied to wholesale energy purchases is a fixed value established at the regional reference node and applied to all retailers. Therefore, the value of actual losses during the time of PV generation has no bearing on the benefit to the retailer.

To estimate the value of avoided losses accruing to the retailer, the Authority has used the loss factors for Energex as used in its Draft Determination on notified prices for 2013-14, as set out in Table 4.5. These loss factors reflect the transmission losses and AER approved distribution loss factors sourced from AEMO.

[17] Ergon Energy, *Submission on the Issues Paper - Estimating a Fair and Reasonable Solar Feed-In Tariff for Queensland*. 19 September 2012. p.8

Table 4.5: Energy loss factors in South East Queensland

Settlement class	*Transmission Losses*	*Distribution Losses*	***Total Losses***
Energex NSLP	1.0%	6.2 %	**7.2 %**

Source: ACIL Tasman, Estimated Energy Costs for Use in 2013-14 electricity retail tariffs - draft report, February 2013

4.8 Retail Operating Costs

Retail operating costs relate to the cost of the services provided by an electricity retailer to its customers. These typically include customer administration costs (including call centres), corporate overheads, billing and revenue collection, IT systems, regulatory compliance and costs associated with marketing, advertising and sales overheads.

The treatment of retail operating costs is somewhat secondary to this feed-in tariff review, as under its current approach to setting notified prices, the Authority accounts for these costs with a per customer allowance. While retailers cannot avoid these costs when on-selling PV exports, they do not factor into the calculation of the feed-in tariff because they are accounted for in the fixed charge of a retail tariff rather than the variable charge.

Submissions

In response to the Issues Paper, TRUenergy submitted that it incurs a higher proportion of fixed operating costs for its PV customers, noting that it and other retailers maintain dedicated teams to manage their PV customers. TRUenergy suggested that the higher cost of serving its PV customers is attributed to extra handling time in processing connections, billing complexity, extra complexity in answering customer queries and complications associated with supporting various legacy feed-in tariff schemes.

Ergon Energy also submitted that retailers will forego a margin as a result of reduced energy sales, as well as incurring additional costs to manage PV customer accounts.

In response to the Draft Report, EnergyAustralia[18] considered that the Authority's estimate was broadly in line with its expectations of a fair and reasonable feed-in tariff. However, it disagreed with the Authority's findings on the level of retail operating costs associated with solar PV. EnergyAustralia stated that solar PV customers are amongst its highest cost to serve customers.

The Authority's Position

In its 2012 Final Determination, ESCOSA considered whether PV customers impose higher operating costs on retailers and argued that within every customer group there will be customers who require additional support from their retailer, not just PV customers[19]. The Authority shares this view and notes that its approach to retail operating costs for notified prices for small customers is based on estimating an average cost per customer within each class. It follows then that, while the cost of serving an individual customer may be higher or lower than the average, the retailer would not be financially disadvantaged on average.

[18] TRUenergy was rebranded as EnergyAustralia in October 2012.

[19] ESCOSA, *2012 Determination of Solar Feed-in Tariff Premium -Final Price Determination*, January 2012. p.43

The Authority is also inclined to agree with the argument put forward by IPART in its 2012 Final Determination that the cost to serve PV customers would fall over time as customers become more informed[20].

For these reasons the Authority maintains its position not to adjust its estimate of the fair and reasonable feed-in tariff to reflect higher retail operating costs for PV customers.

4.9 Retail margin and headroom

The Authority currently applies a 5.7% retail margin and 5% headroom to all cost components in setting notified prices. The retail margin represents the compensation to investors for committing capital to a business and for accepting risks associated with providing retail electricity services. Headroom is an allowance added to regulated retail tariffs to support the current level of competition in the market.

In its Issues Paper, the Authority suggested a number of ways that it could treat the margin and headroom allowances when considering the feed-in tariff including:

(a) passing the full value of the margin and the headroom to the PV customer to reflect the risks it may face in terms of return on investment;

(b) allowing retailers to retain the full value of the margin and headroom on the basis that they face additional risk in servicing PV customers; or

(c) sharing of the margin and headroom between the PV customer and the retailer.

The Authority considered these options in its Draft Report and concluded that it was not appropriate for the value of the margin associated with avoided costs to be returned to the PV customer.

This conclusion was based on the fact that, while PV exports may provide a direct financial benefit for retailers through the avoidance of some costs, it is unlikely that there is a commensurate reduction in risk faced by retailers with PV exporting customers. Indeed, there are arguments that increasing the volume of PV exports may actually increase some risks faced by retailers. While the Authority did not endorse this view, it concluded that, on balance, the risks faced by retailers are unlikely to be reduced as a direct result of PV exports.

Submissions

TRUenergy submitted that headroom should not be included in the value of the feed-in tariff as PV customers tend to be more costly for retailers compared to non-PV customers. TRUenergy also stated that it would be inappropriate to share the headroom allowance as PV exporters are not involved in competing for customers.

AGL shared a similar view stating that, when a customer receives a market contract rate and the head room allowance has been used to deliver that competitive offer, then the retailer does not 'avoid' this cost. AGL also said that sharing the headroom and margin allowance is not appropriate because it attributes a greater value to PV than energy generated from other sources which are available at the same time.

TRUenergy noted that financing and capital risks faced by retailers are not faced by PV customers so there is no justification for sharing of the margin component. Origin stated that

[20] IPART, *Setting a Fair and Reasonable Value for Electricity Generated by Small-Scale Solar PV Units in NSW, Final Report*, March 2012. p.51

sharing the retail margin could perversely incentivise retailers to not offer feed-in tariff products if the retail margin is lower for PV customers than other customers. Origin also argued that sharing the margin would reduce the flexibility afforded to retailers when determining feed-in tariff offers.

In contrast, the Clean Energy Council and the Solar Business Council argued that returning the margin and headroom to PV customers would reflect the risk borne by customers in buying a PV unit, as well as the reduced risk faced by retailers from lower electricity price volatility. Some submissions also suggested that the margin and headroom should be shared to reflect the investment risk or the 'return on investment' expected by owners of PV systems.

The Authority's Position

The Authority disagrees with the proposal by the Clean Energy Council and the Solar Business Council that risks borne by PV customers should be accounted for in setting the feed-in tariff because, as discussed in Chapter 3, the Authority considers the feed-in tariff value should reflect the value that PV exports represent to retailers.

The key issue is whether the retailer should retain the value of the margin that is associated with the costs that it can avoid. In theory, to the extent that those costs are avoided, the margin associated with them also forms part of the direct financial benefit to the retailer in the market.

However, the margin represents a premium to retailers to reflect risks, many of which are not avoided by the on-sale of PV electricity. In addition to the risks unique to the NEM, retailers also face general commercial risks in operating a business including credit default, financing and regulatory risks. These are broad business-wide risks which would not be reduced as a direct result of on-selling PV exports.

In a similar way, the headroom allowance within the notified price is not an explicit component of benefit to the retailer which is directly attributable to PV exports, rather it is a means of promoting competition in the market. The retailer is entitled to a headroom allowance on every kWh of energy it sells at the notified price, including that sourced from PV customers. On this basis, it is not appropriate to consider headroom an avoidable cost when estimating the benefit to the retailer.

Retailers have argued against including margin and headroom in the fair and reasonable value on the basis that it will jeopardise competition and dissuade retailers from accepting new solar PV customers. While the Authority is not convinced this would necessarily occur in practice, it is mindful of the role that the margin and headroom play in supporting competition in the retail market and accounting for commercial risks.

The Authority therefore remains of the view expressed in the Draft Report that the fair and reasonable PV export value should not include the value of margin and headroom on avoided cost components. This acknowledges that the risks faced by retailers are not avoided when they on-sell PV exports.

4.10 Fair and Reasonable Value of PV Exports in South East Queensland

Based on the Authority's analysis, it is likely that the value of PV exports to a retailer in South East Queensland, selling exported electricity at the draft determination cost-reflective Tariff 11 price for 2013-14, would be approximately 7.55 cents per kWh. The calculation of this value is illustrated in Table 4.6 below.

As foreshadowed in the Draft Report, the Authority has used the updated cost data from the Authority's February 2013 Draft Determination of 2012-13 notified prices as inputs for estimating the financial benefit to retailers for this Final Report.

Table 4.6: Estimated Fair and Reasonable Value PV Exports in SEQ (2013-14)

Cost Component	*Retail Cost (c/kWh)*	*Unavoidable Costs (c/kWh)*
Wholesale electricity costs	6.859	-
Green scheme costs	1.002	1.002
NEM and ancillary services fees	0.070	-
Prudential capital	0.063	0.063
Subtotal	*7.994*	*1.065*
Plus losses (7.2%)[1]	0.624	-
Plus network costs	12.593	12.593
Plus margin (5.7%)	1.209	1.209[2]
Subtotal	*22.421*	*14.867*
Plus headroom (5%)	1.121	1.121[2]
TOTAL (excl. GST)[3]	**23.541**	**15.988**
Less unavoidable costs	(15.988)	n/a
Direct Financial Benefit to the Retailer	**7.553 c/kWh**	

Note: Totals may not add due to rounding
1. Calculation of loss factors are discussed in detail in Appendix D.
2. As discussed in section 4.8, the full amounts of retail margin and headroom are considered unavoidable.
3. Estimated retail price is based on 2013-14 cost reflective residential tariff.

4.11 Value of PV Exports in the Ergon Energy Distribution Area

Estimating feed-in tariffs in the Ergon Energy region is complicated by the application of the Queensland Government's Uniform Tariff Policy (UTP). This is because, under the UTP, the notified price that applies across all of Queensland reflects the costs of supply in the Energex network area only. In reality, retailers supplying customers in Ergon Energy's network area will incur different (in aggregate higher) costs than those in Energex's network area.

On this basis, the Authority considers the value of PV exports to Ergon Energy (retail) would be more appropriately estimated using a bottom-up approach based on the costs that it avoids when it on-sells exported PV electricity.

Submissions

Ergon Energy[21] suggested that using the cost estimates from the notified prices is not a reasonable method for determining the feed-in tariff as it assumes that the retailer would avoid all of the elements that make up that cost estimate. Ergon Energy added that developing geographical based feed-in tariffs would require the Authority to consider

[21] EECL and EEQ.

substituting Energex's network costs with its own where appropriate, as well as reconsidering the value of the other avoided cost components.

TRUenergy submitted that, while it does not actively market to customers in the Ergon Energy network area, it considers the fair and reasonable value for Ergon Energy customers should reflect the value to retailers of PV exports in the Energex area alone. The Clean Energy Council suggested that the principles for determining and implementing the fair and reasonable value should be broadly the same for Energex and Ergon Energy, however, the actual values paid may legitimately differ.

The Australian Solar Council and the Solar Business Council Inc. supported broad geographical based feed-in tariffs provided they are not so complex as to impose significant administration costs. Similarly, Alternative Technologies Association pointed to the system in Western Australia where feed-in tariffs vary regionally based on losses and suggested a similar approach would be logical in Queensland.

In contrast, Ergon Energy argued that different feed-in tariffs for different areas will be more complex to administer and may impose additional costs on both the retailer and the distribution business. It stated that if more tariffs are introduced, it would need to update its billing systems and tariff codes.

Ergon Energy supported establishing a fair and reasonable value for energy exported by small-scale solar PV systems exported into its isolated community networks, valued at the energy cost allowed for in the regulated retail price determination. Ergon Energy agreed with the Authority's methodology for calculating loss factors for the feed-in tariffs.

Ergon Energy noted that small-scale PV generation on these networks may have benefits in some cases, including savings of diesel fuel consumption, environmental benefits and the potential to delay upgrades to its power stations in a small number of communities which have daytime peak loads. However, Ergon Energy also noted that there are a range of technical limitations which constrain the amount of uncontrolled PV that can be installed on these networks and the benefits that can be realised from PV generation.

In response to the Draft Report, DEWS suggested that the methodology used to estimate the fair and reasonable value for the Mt Isa-Cloncurry network may understate the actual value of PV exports. DEWS suggested that the Authority gather actual generation data and recalculate the fair value for this location using that pricing data.

DEWS also rejected the Authority's conclusion that Ergon Energy was best placed to develop appropriate feed-in tariffs for its isolated networks, pointing to the REBS administered by Horizon Power in Western Australia as a successful example. DEWS requested that the Authority estimate a fair and reasonable value (or a representative range) for Ergon Energy's other isolated networks, arguing that the Authority's position was inconsistent with its conclusion that feed-in tariffs should be regulated in the Ergon Energy area due to the lack of competition. DEWS agreed that there is little competitive drive for Ergon Energy to develop products in this market for its NEM and non-NEM customers and argued that that feed-in tariffs should also be mandated for these isolated networks.

Approaches in Other Jurisdictions

In Western Australia, Horizon Power applies feed-in tariffs set on a locational basis which reflect the avoided costs of generation fuel and capacity costs relevant to each location. These buyback rates currently range from 10 cents per kWh in towns where the cost of supplying electricity is lower, to 50 cents per kWh where these costs are higher. Horizon Power reviews the buyback rates annually.

The Authority's Position

Estimating the fair and reasonable value

The Authority has concluded that wholesale energy purchase costs, some network losses and NEM and ancillary services fees are avoided by the retailer when it on-sells PV electricity. These costs will form the basis of the estimated value of PV exports to Ergon Energy (retail).

The Authority notes Ergon Energy's suggestion that its own network costs should be substituted for Energex's when estimating geographical based values. However, as the Authority is estimating the value of PV exports on the basis of avoided costs (rather than a benefit to the retailer based on the notified price), network costs have no bearing on the calculation.

Wholesale energy costs

The Authority has estimated the value of Ergon Energy's avoided wholesale energy costs using the weighted energy cost estimates developed by ACIL Tasman for the Authority's 2013-14 notified prices Draft Determination[22]. The wholesale energy cost estimate is based on the Ergon Energy NSLP. For 2013-14, the estimated value of avoided wholesale energy costs at the regional reference node (before losses) is 6.333 cents per kWh.

Table 4.7: Wholesale energy cost allowance for 2013-14 (before losses)

Settlement class	***c/kWh***
Ergon Energy NSLP	6.333

Source: ACIL Tasman, Estimated energy costs for use in 2013-14 electricity retail tariffs- Draft Report, February 2013

NEM participation fees and ancillary services fees

As discussed in section 4.5, the Authority considers that retailers avoid NEM and ancillary services fees at a rate which is proportional to avoided wholesale energy purchases resulting from PV exports. To estimate PV export values for Ergon Energy, the Authority proposes to use the NEM and ancillary services fees used in calculating draft notified prices for 2013-14, as set out in Table 4.8 below.

Table 4.8: NEM participation and ancillary services fees for 2013-14

	c/kWh
NEM fees	0.039
Ancillary services fees	0.031
Total	**0.070**

Source: ACIL Tasman, Estimated energy costs for use in 2013-14 electricity retail tariffs- Draft Report, February 2013

[22] Further details of the Authority's approach to estimating wholesale energy purchase costs can be found in its *Draft Determination: Regulated Retail Electricity Prices 2013-14*, February 2013.

Energy losses

As discussed in section 4.6, the Authority considers it reasonable to assume that all transmission or distribution losses are avoided when on-selling PV exports. The Authority proposes to estimate the value of avoided losses by analysing the relevant marginal loss factors for 2012-13 as published by AEMO, and average distribution loss factors published by Ergon Energy.

In section 4.7, the Authority concluded it is reasonable to use a single network loss factor to value avoided losses across the entire Energex network area. However, in the case of Ergon Energy, the Authority considers there is an opportunity to improve on that approach to better reflect the value of PV at different locations on the network.

The Authority has estimated seven loss factors which capture the regional variation in transmission and distribution losses across the Ergon Energy network, as illustrated in Table 4.9. The calculation of these loss factors is explained in **Appendix D**.

Table 4.9: Load weighted average loss factors for Ergon Energy

Transmission Region	*East Zone*	*West Zone*	*Mt Isa*
T_1	9.341%	41.337%	
T_2	18.664%	49.351%	7.90 %
T_3	22.679%	54.431%	

Sources: QCA analysis; AEMO, List of Regional Boundaries and Marginal Loss Factors for the 2012-13 Financial Year. 12 June 2012; Ergon Energy, Network Tariff Guide of Standard Control Services 1 July 2012 to 30 June 2013. 9 July 2012.

4.12 Value of PV in Ergon Energy's Isolated Networks

Ergon Energy is responsible for providing electricity to customers in 39 remote and isolated communities across Queensland, which are not connected to national grid and NEM. These networks are located throughout Western Queensland, Gulf of Carpentaria, Cape York, Torres Strait islands, Palm Island and the Mornington Islands. Customers on these networks are excluded by legislation from choosing their electricity retailer and may only purchase electricity from Ergon Energy on a standard contract at the notified price.

Ergon Energy uses a range of technologies (including some renewable generation) to supply electricity to these networks. However, the majority of power is produced by Ergon Energy owned diesel generators[23]. Given this, the use of more renewable generation such as PV may provide opportunities for savings on fuel costs and upgrades to diesel generation capacity, particularly in communities that have daytime peak loads.

In the Draft Report, the Authority agreed with Ergon Energy's suggestion that the value of PV in its isolated networks should be set to ensure a benefit for the customer and a reduction in the cost to operate the isolated systems, and that the value should capture issues unique to these isolated systems. These networks have different characteristics, load profiles, cost structures and technical limitations which will determine the ability of solar PV to provide useful economic benefits. The Authority also acknowledged that there are a range of technical limitations which constrain the amount of uncontrolled solar PV that can be installed on these networks.

[23] Ergon Energy, *Network Management Plan, 2012-13 to 2016-17*, p.27.

The Authority concluded that the most efficient outcomes for these networks are unlikely to arise through regulation of feed-in tariffs. It concluded that mandating minimum feed-in tariffs for these networks could hinder Ergon Energy's efforts to realise cost savings and efficiencies using renewable generation by providing signals which may not necessarily encourage the most efficient investment for the circumstances.

The Authority considered that Ergon Energy (retail and distribution businesses) were best placed to formulate effective programs, including feed-in tariffs, where there is a net benefit for these networks and customers. The Authority did not consider it appropriate to estimate the value of fair and reasonable feed-in tariffs for PV customers in Ergon Energy’s isolated networks and recommended that Ergon Energy should not be subject to a minimum mandatory feed-in tariff for its remote and isolated networks at this stage.

In the Draft Report, the Authority considered it possible to estimate a value for PV exports for the Mt Isa-Cloncurry network, as a specific distribution loss factor was available for this network. However, the Authority's value was based on the Ergon Energy NSLP wholesale price estimates at the regional reference node, not the actual cost of supply in the Mt Isa network. The Authority indicated that it would consult with Ergon Energy to develop a more accurate value of PV exports for the Final Report.

The Authority's Position

In response to suggestions offered by DEWS, the Authority revisited the issues surrounding fair and reasonable feed-in tariffs for Ergon Energy's isolated networks. The Authority sought additional information from Ergon Energy to inform its considerations including generation costs, network capacities as well as opportunities and limitations for PV generation within its isolated networks.

The key considerations in estimating fair and reasonable PV export values for these networks are broadly the same as those for any other network system. However, the nature of these networks requires that some factors be given more weight than might otherwise be the case. The most important distinction is the relatively small size of these networks, which makes them more sensitive to incremental changes in uncontrolled intermittent generation than larger networks. The Authority has factored this into its considerations.

Ergon Energy's isolated networks are predominantly supplied by diesel engine powered generators, with some wind, solar and geo-thermal installations. Table 4.10 lists the current inventory of remote generators by generation source/fuel type.

Table 4.10: Ergon Energy's Isolated Network Power Stations

Power Station	*Fuel/Energy Source*
Aurukun, Badu Island, Bamaga, Boigu Island, Burketown, Camooweal, Coconut Island, Coen, Darnley Island, Dauan Island, Doomadgee, Gunana Township, Hammond Island, Kowanyama, Kubin Community, Lockhart River, Mabuig Island, Mapoon, Murray Island, Palm Island, Pormpuraaw, Saibai Island, Stephen Island, Warraber Island, Wasaga Township, Yam Island, Yorke Island	Diesel
Bedourie, Boulia, Jundah	Diesel and Bio-Diesel
Birdsville	Diesel, Bio-Diesel and Geothermal
Thursday Island	Diesel, Wind
Windorah	Diesel, Bio-Diesel and Solar

Source: Ergon Energy (12 February 2013)

Avoided costs due to PV exports

For the reasons discussed in section 4.11, estimating feed-in tariffs using the financial benefit to the retailer approach is not appropriate for Ergon Energy's isolated networks. Rather, the fair and reasonable values should be developed using a bottom-up approach based on the costs that are avoided when PV electricity is exported to its networks.

Ergon Energy advised that the most significant saving due to PV generation would be from avoided costs of diesel to fuel its generators and suggested that any feed-in tariff for these networks should only reflect this cost. Ergon Energy provided the Authority with its average diesel fuel costs associated with generating power for these networks on a confidential basis.

The Authority engaged ACIL Tasman to review Ergon Energy's estimated costs and to prepare its own estimates of the likely value of avoided costs due to PV generation on these networks. ACIL concluded that the information submitted by Ergon Energy appeared generally consistent with its own estimates.

The Authority is inclined to agree with Ergon Energy's suggestion that diesel costs are the primary potential cost saving due to PV generation on isolated networks. Diesel fuel costs are the most identifiable and quantifiable direct costs associated with supplying electricity on these isolated networks and are clearly related to the volume of electricity generated.

However, diesel generators have certain technical characteristics which affect the actual change in fuel consumption when PV output reduces load on the generator. While it appeals to common sense that reducing the loading on a diesel generator would reduce the amount of diesel fuel used, the relationship is not simple or linear. Ergon Energy noted that the change in the efficiency of diesel generators depends on many factors and is difficult to accurately determine, but engine efficiency tends to deteriorate at lower engine loads. Ergon Energy also advised that, when PV systems are generating on these networks, the amount of diesel required to generate each kWh of electricity could actually increase, not decrease.

As a result, Ergon Energy's average diesel fuel cost is unlikely to reflect the true marginal value of avoided fuel costs for each kWh of displaced diesel generation. However, without a detailed examination of diesel generator efficiencies, the average cost of diesel fuel per kWh of generated electricity is the best available estimate of the potential avoided costs.

The Authority considers that the potential for cost savings, other than avoided diesel fuel costs, are negligible. Specifically:

(a) opportunities to defer or avoid network investment due to PV are unlikely, except on the very few networks which have a daytime peak load. As a result, there are very few cases where the costs of upgrading power stations and associated facilities can be reduced by adding uncontrolled PV to the network. In fact, PV generation may actually increase costs for Ergon Energy and these costs may be significant due to the more sensitive nature of these isolated networks to uncontrolled PV generation;

(b) the reduced load on diesel generators is unlikely to have any measurable impact on maintenance costs as the 'run-hours' of the generator are not typically reduced due to PV. Ergon Energy advised that there is therefore little, if any, change to diesel generator maintenance requirements and associated costs; and

(c) the value of avoided losses is likely to be minimal due to the small size of these networks.

For these reasons, the Authority agrees with Ergon Energy that the value attributed to PV exports for these isolated networks should be based only on the estimated value of avoided diesel fuel costs, in the absence of better data.

Napranum isolated network

The Napranum isolated network, near Wiepa, is supplied by a power station which is owned and operated by Rio Tinto. The Authority understands that the power station uses diesel engine generators.

Rio Tinto periodically invoices Ergon Energy for electricity supplied and these costs are recovered through the current community service obligation payment. Ergon Energy provided the Authority with the current prices paid to Rio Tinto including diesel fuel, generation asset cost and network cost components on a confidential basis.

The Authority has reviewed Ergon Energy's Napranum costs and finds that, while the values differ somewhat from those associated with its other isolated networks, on balance, there would be little benefit from setting a specific feed-in tariff just for the Napranum network, which supplies less than 300 customers.

Conclusion on isolated networks (including Napranum)

The actual costs incurred by Ergon Energy are confidential, they cannot be explicitly used as estimates of the fair and reasonable value. Based on its review of Ergon Energy's confidential cost information and the estimates provided by ACIL Tasman, the Authority estimates the potential economic value of PV exports in these isolated networks (excluding Mt Isa-Cloncurry) would be between 28 and 33 cents per kWh.

For the reasons discussed in this chapter, the Authority does not recommend that mandatory minimum feed-in tariffs be implemented in these networks at this stage. However, if the Government is inclined to do so, the Authority would suggest that the mandated values be set conservatively to avoid over-estimating any cost savings. This could be achieved by adopting Ergon Energy’s suggestion in response to the Issues Paper, and set the fair and reasonable value for these networks at the wholesale energy purchase cost allowance at the regional reference node. For its Draft Determination of notified prices for 2013-14, the Authority has estimated this at 6.333 cents per kWh for Ergon Energy. To minimise administrative costs, the Authority also considers that a single value should apply to all of these networks, if a mandated feed-in tariff is applied.

Mt Isa-Cloncurry isolated network

Ergon Energy's Mt Isa-Cloncurry isolated network is significantly larger than the other remote networks and features different generation arrangements. To supply its customers on this network, Ergon Energy currently purchases electricity from Mica Creek Power Station under a Power Purchase Agreement (PPA) with Stanwell Corporation.

While the terms of the PPA are confidential, the Authority understands that, under the current agreement, Ergon Energy would not avoid any energy purchase costs as a result of PV generation offsetting some portion of its physical energy purchase requirements.

The Authority engaged ACIL Tasman to provide an independent estimate of Ergon Energy's likely energy purchase costs for the Mt Isa-Cloncurry network. Based on the current supply arrangements, ACIL modelled the total energy purchase cost for 2013-14 at $141.65 per MWh of electricity generated.

While it would be possible to implement a retailer-funded feed-in tariff for Mt Isa-Cloncurry customers, it clearly cannot be based on the benefit to the retailer of PV exports, or the value of avoided costs. Under the prevailing energy supply contracts, implementing a fair and reasonable feed-in tariff for this system would require a subsidy and an increase to the community service obligation (CSO) - outcomes which conflict with the terms of reference and the COAG National Principles. On this basis, the Authority considers that a feed-in tariff should not be mandated in the Mt Isa-Cloncurry network at this stage.

However, should the Government decide to implement a subsidised, mandatory feed-in tariff for customers on the Mt Isa-Cloncurry network, the Authority suggests that the tariff be set conservatively to reflect only the wholesale energy purchase cost allowance for Ergon Energy's NEM connected network of 6.333 cent per kWh. Doing so would ensure that PV customers receive some (albeit subsidised) value for their exports, while minimising the increase to the CSO. Applying a single feed-in tariff across all isolated networks (including Mt Isa-Cloncurry) also maintains administrative simplicity, should the Government decide to mandate a minimum value.

Ergon Energy advised that the Mt Isa-Cloncurry network could accommodate additional PV installations for the foreseeable future, subject to any localised network constraints.

Other considerations for feed-in tariff policy for isolated networks

Under the terms of reference, the Authority is also to consider any specific arrangements required, or barriers to implementation of, fair and reasonable feed-in tariffs in the Ergon Energy distribution area. There are a number of important factors relevant to these isolated networks which will have implications for the ongoing scope for solar PV. The Authority considers these are relevant considerations when deciding if, and how, feed-in tariffs for uncontrolled small-scale PV should feature in these networks in the future.

Ability of the networks to accommodate PV generation

Ergon Energy advised that all customer PV applications on isolated networks need to be assessed to ensure that they will not have an adverse effect on electricity supply to the customer and neighbouring properties, or even the entire isolated network. This is necessary as these isolated networks have finite capacity to host uncontrolled PV generation, some of which have already been reached, or are close to it.

For example, three isolated networks (Birdsville, Doomadgee and Windorah) have already reached their maximum hosting capacity for uncontrolled intermittent generation, with a number of other sites expected to reach their capacity after the connection of only one or two additional small PV systems.

Another limitation arises due to the tendency for solar PV output to change rapidly according to sunlight conditions. When cloud cover causes the sudden drop off of PV generation, the existing (non-solar) generators must respond, or 'ramp-up' quickly to cover the shortfall in generation. As a result, Ergon Energy must set limits on the amount of intermittent generation that can be reliably supported on each network, including the size of individual customer installations.

Diesel generators also require a minimum loading to be placed on them to ensure the engine is not damaged. As the operation of uncontrolled solar PV in these networks requires the diesel generators to run in parallel, the minimum loading on the diesel engines must be considered when considering how much uncontrolled solar PV can be accommodated on a particular network. Ergon Energy noted that the minimum loading required on diesel generators to avoid long term engine damage is typically 30-40% of the generator's rated capacity, depending on the type of diesel engine.

In the Authority's view, these technical limitations need to be considered when determining feed-in tariff policy for these isolated networks. To the extent that feed-in tariffs incentivise the uptake of PV capacity, and cause the network constraints to be exceeded sooner than might otherwise be the case (and bringing forward investment expenditure), then these factors should be considered when determining the form of regulation and the value of any feed-in tariff.

In theory, these technical limits should act as a natural barrier to further PV installations that may trigger an incremental increase in capital for network upgrades. However, whether or not this works in practice would need to be considered in the context of other drivers of capex, of which, growth in PV installations would be only one.

Most of these technical limitations can probably be overcome at a cost. Therefore deciding to accept (or even encourage) growth in small-scale PV installations on isolated networks where constraints exist, requires the careful consideration of the resulting costs and benefits. It may be the case that introducing or expanding small-scale PV generation is not the most desirable option for these networks and their customers. These issues need to be examined before new incentives are introduced. Doing so will avoid the risk of entrenching inefficient solutions, or creating problems and costs in the future.

Metering requirements

A significant number of Ergon Energy's isolated networks deliver electricity to customers through card-operated meters, which operate on a pre-paid basis. Ergon Energy is currently unable to provide feed-in tariffs to customers with these meters, as they are supplied under arrangements which do not involve an account with Ergon Energy. Only PV customers with manually read meters and an account with Ergon Energy, can currently be paid for electricity exports.

Many of the isolated networks have some mix of customers with card meters and those with manually read meters billed by Ergon Energy. This raises a potential equity concern within these communities as some customers may be able to access a feed-in tariff, while others may not, simply due to the billing and metering arrangement they have.

Ergon Energy has also advised that, due to the remoteness of many of these networks, the costs to send technicians to site to install appropriate metering could be very significant, particularly in cases where access is only by aircraft. It is also likely that these same costs would be faced by solar panel installers. In this sense, these costs are likely to represent a further significant barrier to uptake of PV, regardless of whether a fair and reasonable feed-in tariff is available.

It is not clear how, or if, these issues could be resolved without incurring a higher CSO. Nonetheless, the Authority notes the issue for the Government's consideration in formulating its policy on feed-in tariffs for these networks.

Overcoming technical constraints

The Authority notes that the success of the REBS, operated by Horizon Power in WA, is in some part due to the use of generation management technologies. These systems are used to smooth out the impacts of intermittent PV outputs by using short-term onsite battery storage at the PV customers' premises. This ensures that, when the level of PV generation suddenly drops (for example due to cloud cover), the customer's immediate load is met by onsite batteries until such time as the main diesel power station can 'ramp-up' to cover the drop in generation. While this type of technology can address the problems of intermittent generation, it cannot resolve losses in fuel efficiency due to reduced loading of diesel generators.

The Authority understands that generation management technologies remain quite costly and must be funded by the solar PV customer, representing a significant additional cost on top of the PV panels and inverters. If the Government and Ergon Energy consider that small-scale PV with generation management is an efficient, ongoing solution in these isolated networks, they could consider policies that make these technologies more affordable for customers, reducing barriers to increased uptake.

Ergon Energy noted that there are a number of other technologies which could be considered to enable better management and consequently greater penetration of intermittent generation which may provide more economically viable solutions, including centralised control and storage. These technologies would allow Ergon Energy to remotely control intermittent generation using the main power station's control systems. This would allow control of actual generation, dispatching and ramping capabilities of intermittent generators, and their outputs to accommodate better integration of PV into these isolated networks. However, implementing these technologies would require additional capital and operating expenditure, and would need to be subject to rigorous cost-benefit analysis by Ergon Energy.

The effect of these costs and benefits on the size of the CSO will be a key consideration for Government. Any measures that increase Ergon Energy's network costs will, all else constant, increase the CSO paid to Ergon Energy (distribution) by the Queensland Government.

In summary, there are a range of potential barriers to the uptake of small-scale PV in these isolated networks, at least some of which can be removed at a cost. Careful consideration needs to be given to the role that small-scale PV can play in these isolated networks in the future, after examining the possibilities for PV to bring efficiencies and ultimately benefits to customers.

However, such an investigation of detailed costs and benefits is well beyond the scope of the Authority's terms of reference. In any event, these considerations are already fundamental components of Ergon Energy's management and development strategies for these networks, including its 'Isolated Systems Strategy'.

As part of this strategy, Ergon Energy investigates renewable energy generation options where these are economically viable and sets a long term target of zero diesel fuel use on its isolated networks, due to the rising and volatile costs of diesel. Ergon Energy has stated that distributed generation (including small-scale customer owned PV) is one means of moving towards the zero diesel use target, subject to the total amount being within technical limits and the price paid for the generation output results in an economically viable solution.

It is internal analysis and planning such as this that will reveal the most appropriate way of integrating small-scale PV into these networks, and the economic value that should be attributed to its output.

Horizon Power REBS

The Authority acknowledges the similarities between Ergon Energy and Horizon Power in the challenges they face in providing reliable and cost efficient power supply solutions to remote and isolated networks. The REBS scheme appears to be a considered and effective example of how intermittent, uncontrolled generation can be efficiently integrated into remote systems. Ergon Energy is no doubt well aware of the scheme and abreast of its relevance to its own circumstances.

The information available regarding the REBS scheme suggests that the process of developing and implementing efficient feed-in tariffs on Horizons remote and isolated networks is not straightforward. It requires detailed assessments of the costs of supply, technical knowledge of each networks' characteristics, capacities and constraints as well as consideration of complementary technologies to manage the output of PV systems on small networks.

Ergon Energy appears quite active and successful in delivering efficient and reliable renewable generation to its isolated networks. For example it has invested in wind generation on Thursday Island, geothermal generation in Birdsville and solar farms in Windorah and Doomadgee communities. Ergon Energy has also investigated and implemented generation management technologies in some cases to enable the more reliable integration of renewable generation sources with traditional diesel generators.

Given the complexities involved, the Authority considers that Ergon Energy is best placed to manage these isolated networks. The Horizon Power REBS scheme was largely developed and implemented by Horizon Power as the vertically integrated energy supplier, not an independent economic regulator subject to asymmetric information limitations. The Authority understands that the success of the Horizon Power REBS scheme is in no small part due to the fact that it was developed by the business itself with access to the detailed knowledge of the network's capacities and limitations, as well as technical understanding of the most effective and efficient solutions for deploying intermittent generation in unique network situations. There appears to be no reason why Ergon Energy should not be capable of producing similarly successful outcomes once provided with sufficient incentives to do so.

The Authority's Final Position

After further considering this issue, the Authority remains of the view that Ergon Energy is best placed to develop and implement renewable energy solutions, including feed-in tariffs where appropriate, for these unique isolated networks and should be encouraged by the Government to continue its work program in this field.

Notwithstanding these views, the Authority has considered information provided by Ergon Energy and ACIL Tasman to attempt to estimate the economic value of PV exports in these isolated networks, for the Government's consideration. However, the Authority's view is that feed-in tariffs should not be mandated in Ergon Energy's isolated networks at this stage. The Authority has a number of concerns which have lead it to form this view. Specifically:

(a) the estimated value of avoided diesel costs may not actually be realised in practice under a feed-in tariff scheme for these networks due to technical and efficiency characteristics of the diesel generators;

(b) the Authority understands that small-scale PV generation on the Mt Isa-Cloncurry network provides no financial benefit to Ergon Energy under the terms of its current power purchase agreements;

(c) mandatory feed-in tariffs may incentivise uptake of PV installations, which could drive a step change in the amount of intermittent capacity on these networks, and potentially increase the costs and problems that come along with it;

(d) incentivising further installation of uncontrolled PV generation may drive outcomes which conflict with Ergon Energy's plans to implement the most efficient electricity supply solutions for these networks; and

(e) there is a potential equity issue within some of these isolated networks due to metering, whereby it is not possible to provide feed-in tariffs to customers with card meters.

The most efficient outcomes for these networks are unlikely to arise through regulation of feed-in tariffs at this stage. Mandating minimum feed-in tariffs for these networks could hinder Ergon Energy's efforts to realise cost savings and efficiencies using renewable generation by providing signals which may not necessarily encourage the most efficient investment for the circumstances.

4.13 Final Position on Fair and Reasonable Value of PV exports in Ergon Energy’s Distribution Area

Based on the Authority's analysis, it is likely that the value of PV exports to a retailer in Ergon Energy’s distribution area would range between 7.06 cents and 14.05 cents per kWh, depending on the location of the PV generation. The calculation of these values is illustrated in Table 4.10 below.

As for the value calculated for South East Queensland, the values in Table 4.10, the Authority has used values from its Draft Determination on notified retail prices for 2013-14 to update the fair and reasonable estimated feed-in tariffs presented in its 2012 Draft Report.

With regard to Ergon Energy's isolated networks (other than Mt Isa-Cloncurry), the potential value of avoided costs associated with PV generation may be between 28 and 33 cents per kWh. However as the noted, the Authority is concerned that these values may not be representative of actual avoided costs and recommends feed-in tariffs not be mandated at this stage. If the Government decides to mandate a feed-in tariff for customers on Ergon Energy's isolated networks, the Authority suggests that a single value be applied, set at the estimated wholesale energy purchase cost (at the regional reference node) used in its Draft Determination on notified prices for 2013-14.

Table 4.10: Estimated values of PV exports in Ergon Energy Networks (2013-14)

Avoided cost component	***East Zone (c/kWh)***			***West Zone (c/kWh)***		
	T_1	**T_2**	**T_3**	**T_1**	**T_2**	**T_3**
Wholesale energy purchases	6.333			6.333		
NEM fees	0.039			0.039		
Ancillary services fees	0.040			0.040		
Subtotal	**6.403**			**6.403**		
Plus network losses % (transmission and distribution)	1.0934	1.1866	1.2268	1.4134	1.4935	1.5443
Value of network losses (c/kWh)	0.660	1.469	1.878	4.513	6.240	7.649
Value of avoided costs (c/kWh)	**7.064**	**7.873**	**8.282**	**10.917**	**12.644**	**14.053**

Note: Totals may not add due to rounding

5. IMPLEMENTING A FAIR AND REASONABLE SOLAR FEED-IN TARIFF

The terms of the Direction require the Authority to consider and report on three options for implementing the fair and reasonable value of a feed-in tariff for the Queensland market. The options included:

(a) mandating a 'default minimum price' or price range;

(b) recommending a price range; and

(c) letting the market set a voluntary feed-in tariff.

In its Draft Report, the Authority suggested that each of these options might be appropriate in certain circumstances, for example:

(a) where competition in the market is insufficient to compel retailers to voluntarily offer a fair and reasonable feed-in tariff, a mandatory feed-in tariff would need to be established;

(b) where the market is more competitive a more light-handed form of regulation, such as publishing a non-mandatory recommended price range, may be appropriate; and

(c) where there is a healthy level of competition in the market it may be appropriate to allow retailers to voluntarily offer a feed-in tariff without regulatory intervention or guidance.

The Authority concluded that the market in South East Queensland is sufficiently competitive to support market determined, retailer funded feed-in tariffs which are fair and reasonable. However, the Authority considered that this is unlikely to occur in the Ergon Energy network area, and therefore recommended a set of mandatory minimum feed-in tariff values be established.

Submissions

Retailers such as AGL, Ergon Energy, EnergyAustralia, National Generators Forum and Origin Energy, in addition to associations such as the Energy Supply Association of Australia (ESAA) and the Energy Retailers Association of Australia (ERAA), argued that a market determined feed-in tariff was the most appropriate form of regulation for South East Queensland. They argued that there was already a range of voluntary feed-in tariff offers available to customers, which retailers felt was indicative of a competitive market operating effectively without regulation. AGL also noted that imposing a mandatory value that was set too high would lead to retailers avoiding solar PV customers, thereby reducing competition.

Retailers also highlighted that voluntary tariffs allow them to be more adaptive to changes in technology and market developments. Retailers and retailer associations also felt that a mandated feed-in tariff would represent an extension of regulation over the Queensland electricity market, increasing regulatory risk for retailers.

Solar PV customers, renewable energy associations (the Australian PV Association, the Alternative Technology Association, the Clean Energy Council, the Solar Energy Industries Association, the Solar Business Council and Sunwiz Consulting), as well as Infinity Solar and Stanwell argued for a mandatory minimum feed-in tariff to be set. It was argued by some that only a mandated feed-in tariff could take into account factors such as reduced network losses and environmental and health benefits which are not directly captured by retailers.

Solar PV customers and installers such as Infinity Solar argued that the certainty of a mandatory minimum was vital for the uptake of solar PV installations. In addition, the Solar Business Council expressed concern that individual customers did not have the power to negotiate with retailers.

The Clean Energy Council, Sunwiz and customers argued that vertically integrated retailers that owned generation assets faced different incentives to non-integrated retailers. In particular, it was suggested that vertically integrated retailers would be less likely to offer fair and reasonable feed-in tariff rates, as solar PV generation reduced the profitability of their generation assets. The Clean Energy Council also argued that a mandatory feed-in tariff was necessary to prevent 'market capture' by these vertically integrated retailers.

The Clean Energy Council further argued that the introduction of voluntary feed-in tariffs in NSW "has not been successful", on the basis that not all retailers were offering voluntary feed-in tariffs.

QCOSS and the Queensland Consumers Association argued that some level of regulation, such as a non-mandatory benchmark range, would be appropriate in areas with sufficient competition.

Energex and Ergon Energy suggested that a light-handed regulatory approach should be considered. Energex was in favour of a benchmark approach unless a time-of-use methodology is adopted, in which case Energex stated that a more heavy-handed approach may be required to ensure time of use pricing signals are passed on. Ergon Energy was in favour of market competition without regulatory intervention.

Infinity Solar, the ESAA, Energex and Ergon Energy suggested that competition in the Ergon Energy distribution area was not mature and that regulatory intervention would be necessary. In addition, renewable energy associations that advocated mandatory tariffs in the Energex distribution area also advocated mandatory tariffs in the Ergon Energy distribution area. The ESAA suggested that if the Authority recommended a voluntary feed-in tariff for Ergon Energy it would have to satisfy itself that any voluntary feed-in tariff would be consistent with a competitive outcome.

Ergon Energy suggested that it could calculate a voluntary feed-in tariff rate which the Authority could compare to competitive outcomes. Ergon Energy also highlighted the effect on its CSO if any regulated feed-in tariff was set too high.

In response to the Draft Report, the Queensland Consumer's Association agreed that feed-in tariffs should be mandatory and set annually for the Ergon Energy distribution area, while DEWS suggested that the mandated feed-in tariffs should be extended to remote and isolated networks, due to lack of competition existing in these areas.

5.1 Form of Regulation in South East Queensland

As discussed above, the form of regulation appropriate for implementing a fair and reasonable feed-in tariff will depend on the level of competition in the retail electricity market in Queensland.

The extent of competition in the Queensland electricity market, as revealed by the proportion of customers on market contracts, is also relevant because in order for a customer to receive a feed-in tariff while on the regulated retail tariff, the customer would have to sign a separate PPA. PPAs are used widely in the large scale generation market. However, the cost of drawing up suitable PPAs makes them cost prohibitive for small-scale generation, such as solar PV. As a result almost all solar PV customers are on market contracts.

Retail Electricity Market Depth

As discussed in the Issues Paper, for most small customers (those consuming less than 100MWh per year), the option to choose their electricity retailer became available with the introduction of Full Retail Competition (FRC) on 1 July 2007. Retail competition for larger customers (those consuming more than 100 MWh per year) began to open up in 1998.

The retail electricity market in South East Queensland has developed considerably since the introduction of FRC. As at 30 June 2012, there were 18 retailers operating in Queensland, 12 servicing small customers and 16 servicing large customers. The Authority publishes statistics on the number of market and non-market customers on a quarterly basis. The June 2012 figures show that, in total, over two thirds (69%) of South East Queensland customers are currently on a market contract. This indicates that a majority of customers have opted for market contracts, which is consistent with a competitive retail electricity market.

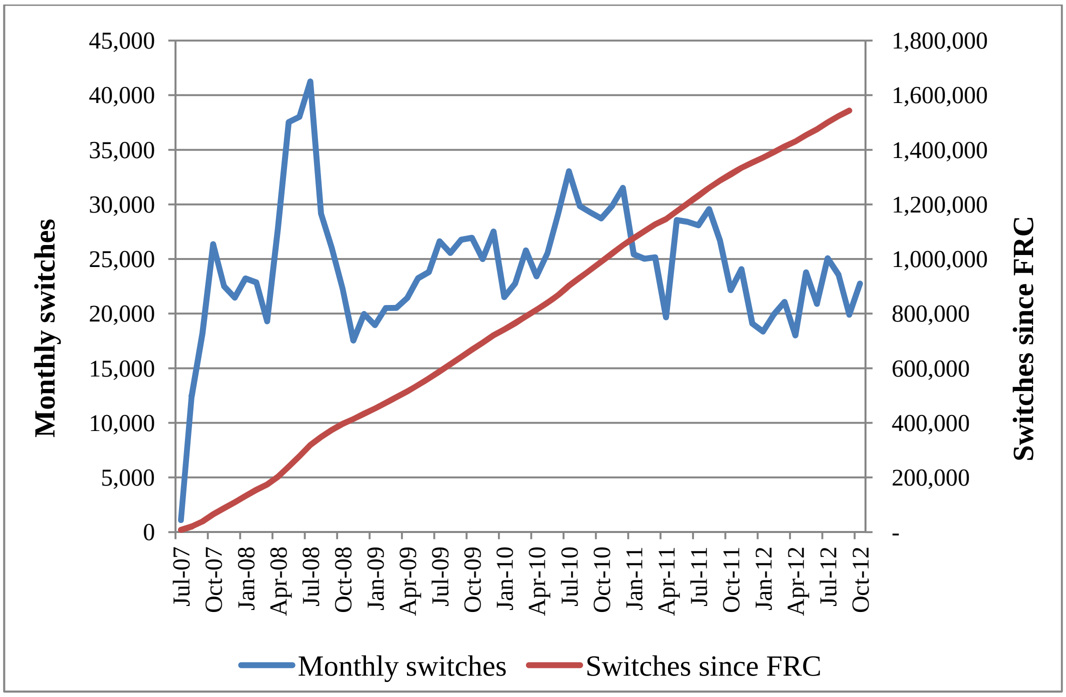
While the Authority does not have access to information on the market offers available to business customers, there are currently over 50 supply offers available to residential customers. These market offers provide customers with a range of contractual terms and conditions combined with potential savings and other incentives.

Customer Switching Activity

The rate of customer switching is often used to measure the level of activity in an electricity market. While not always the case, a high switching rate typically suggests that retailers are actively marketing in a region and that they are offering customers sufficient savings to incentivise them to switch retailers.

Since FRC commenced in Queensland, the level of customer switching activity has been relatively high. Figure 5.1 shows monthly and total customer switches in Queensland since 2007. While there was considerable volatility in the switching rate over the initial 18 months of FRC, customer activity has typically stayed within the range of 20,000 to 30,000 customer switches per month in more recent years. In comparison to other markets around the world, the level of customer switching activity in South East Queensland is particularly high.

Figure 5.1: Retail customer switching activity in Queensland



Source: AEMO Retail Transfer Statistical Data, July 2007 – October 2012 (Code M57B)

Based on the information available, the Authority currently considers there is a reasonable level of competition in the South East Queensland retail electricity market.

Competition in the Solar Feed-in Tariff Market

In section 4.10, the Authority established its estimate of a fair and reasonable feed-in tariff value of 7.55 c/kWh, based on the direct financial benefit to retailers, using the data and methodology from the 2013-14 price review (see Table 4.6). This figure enables the Authority to determine if the additional feed-in tariffs offered on a voluntary basis by retailers can be considered fair and reasonable.

Table 5.1 shows the range of feed-in tariffs currently available in South East Queensland. While not every retailer in Queensland currently offers a premium solar PV feed-in tariff, the retailers in Table 5.1 account for an overwhelming majority of market customers in South East Queensland.

The table highlights that most retailers are currently offering up to 10 cents per kWh to solar PV customers on a voluntary basis. Given that customers are free, within contractual limits, to transfer to the retailer of their choice, solar PV customers in South East Queensland can currently access voluntary feed-in tariffs that exceed the fair and reasonable feed-in tariff estimate calculated by the Authority in Chapter 4.

Table 5.1: Current voluntary feed-in tariff offers in South East Queensland

Retailer	*Voluntary Feed-in Tariff (c/kWh)*
AGL	8
Click Energy	10
Diamond Energy	4
EnergyAustralia (formerly TRUenergy)	8
Lumo Energy	6
Origin Energy	6
Powerdirect	6

Source: QCA analysis. Offers current as at 8 March 2013

Authority's Position

Based on the preceding analysis the Authority concludes that:

(a) there are a significant number of customers participating in the competitive electricity market in South East Queensland;

(b) the South East Queensland market is currently producing a variety of market offers from a number of retailers;

(c) customers have access to a variety of market offers that feature a voluntary feed-in tariff from different retailers; and

(d) customers currently have access to market offers that exceed the fair and reasonable value of PV exports estimated by the Authority in section 4.10.

In light of these findings, the Authority considers market competition to be currently delivering fair and reasonable feed in tariff values without regulatory intervention.

As such, the Authority does not consider it necessary or desirable to impose any mandated value for the feed-in tariff in South East Queensland market.

The Authority has considered suggestions to recommend a benchmark range for fair and reasonable feed-in tariffs. However, the Authority is concerned that publishing a benchmark indicative range could dilute the benefits of competition by not providing an incentive for retailers to avoid revealing their efficient costs. It is likely that the lower bounds of a benchmark range, if published by the Authority, would effectively be viewed by retailers as a minimum obligation and would offer voluntary tariffs no higher than that level, regardless of their individual financial capacity to make more generous offers. There appears to be some evidence of this in NSW, where a number of retailers adjusted their voluntary feed-in tariff offers to reflect the lower bound of the IPART's 2012-13 benchmark range after it was published.

In New South Wales, IPART found that a fair and reasonable feed-in tariff for customers who are not eligible for the Solar Bonus Scheme was in the range of 7.7 to 12.9 cents per kilowatt hour for electricity exported to the grid in 2012-13. At the time of writing, half of retailers catering for solar PV in NSW are offering voluntary feed-in tariffs at lower bounds of the fair and reasonable range, and only one retailer is making feed-in tariff offers above this level.

Recent research[24] has highlighted the effect of regulated benchmarks or prices. Any benchmark figure published by an institution such as the Authority would become a focal point within the local market, and affect the behaviour of retailers and consumers.

Publishing a benchmark range with an upper bound would also significantly reduce any incentive for a retailer to make a feed-in tariff offer above the upper bound, as consumers would consider that to be a 'maximum' fair and reasonable value, as judged by the Authority.

The Authority recommends that the market be allowed to continue determining appropriate feed-in tariff rates. To ensure the market continues to provide a fair and reasonable feed-in tariff to customers, the Authority recommends the solar PV market outcomes be reviewed by 30 June 2014.

5.2 Form of Regulation in the Ergon Energy Distribution Area

Competition in the Queensland electricity retail market has not developed uniformly. While all retailers are licensed to operate across the State, each retailer will choose the locations in which it is prepared to make offers for supply and the types of customers it is seeking to attract. Due to the Queensland Government's UTP, retailers are not inclined to offer market contracts to customers in the Ergon Energy distribution area. This is because Ergon Energy distribution costs and charges are significantly higher than those in South East Queensland, but retailers are required to honour the same notified prices charged in the south-east corner. To compensate for the difference between costs and the uniform regulated retail tariff, the retail arm of Ergon Energy (Ergon Energy Queensland) receives a subsidy from the state government. Without access to this subsidy, other retailers are currently unable to offer competitive market contracts to customers in the Ergon Energy distribution area.

As at the end of June 2012, approximately 68% of small customers in South East Queensland were supplied through competitive market contracts. In contrast, outside South East Queensland, less than 1% of small customers were supplied through market contracts. The Authority is not aware of any market contracts generally available to residential customers in Ergon Energy's distribution area.

Also, Ergon Energy (retail) is only able to supply customers on regulated retail tariffs. As noted earlier, this does not allow Ergon Energy to offer a feed-in tariff to customers without signing a PPA, which is cost prohibitive for most small residential PV installations. Even if this were not the case, the demonstrable lack of competition outside of South East Queensland means there is little competitive incentive for Ergon Energy to offer a fair and reasonable feed-in tariff.

Finally, the Authority is not aware of any retailers offering a voluntary feed-in tariffs in Ergon Energy's distribution area.

Authority's Position

Despite supporting regulatory intervention in areas lacking competition in the retail electricity market, Ergon Energy suggested that it could offer a voluntary feed-in tariff rate in its distribution area. However, the Authority considers that the lack of competitive pressure makes it unlikely that Ergon Energy would necessarily offer a fair and reasonable

[24] Yarrow, G, *Report on the impact of maintaining price regulation*. Regulatory Policy Institute, Oxford, UK January 2008

feed-in tariff value. The Authority remains of the view that the best way to ensure Ergon Energy's PV customers (or potential PV customers) receive a fair and reasonable value for their PV exports is to make the feed-in tariffs presented in Table 4.10 mandatory. This approach was supported by Infinity Solar, the ESAA, Energex, Ergon Energy, EnergyAustralia and QCOSS as well as those advocating mandatory feed-in tariffs state-wide.

In order to ensure a smooth transition to the fair and reasonable tariffs, Ergon Energy (retail) could be required to provide fair and reasonable feed-in tariffs to the following customers:

(a) existing customers who remain eligible for, and are receiving the 8 cent per kWh feed-in tariff under section 44A of the *Electricity Act 1994*, after this scheme is closed;

(b) customers who connect an eligible solar PV installation after the date on which the existing 8 cent per kWh distributor-funded scheme is closed for new and existing customers; and

(c) existing customers who become ineligible for the existing 44 cent per kWh feed-in tariff in the future.

Ergon Energy (retail) should not be required to provide the mandated fair and reasonable feed-in tariffs to those customers who receive, and remain eligible for, the 44 cent per kWh distributor-funded feed-in tariff because these customers are already more than adequately compensated for their PV exports.

These eligibility arrangements will ensure that PV customers continue to receive the feed-in tariffs they are currently entitled to, without further adding to the costs of the existing Scheme and placing more pressure on electricity prices, as required by the Direction Notice. However, to ensure that feed-in tariffs do not become a barrier to entry for other retailers wishing to compete in the Ergon Energy distribution area, the feed-in tariff rates calculated for the Ergon Energy distribution area should only apply to Ergon Energy (retail).

As discussed in Chapter 4, the Authority maintains its position that minimum mandatory feed-in tariffs should not be implemented for Ergon Energy's isolated networks at this stage.

5.3 Metering Arrangements

Feed-in tariffs can be applied in one of two ways, based on the way that solar PV generation output is measured. Each metering arrangement has a different set of implications and incentives which need to be considered.

Under a net metering arrangement, the output of the customer's PV system is first used to meet their own immediate consumption needs at any point in time (while it is generating), with any shortfall imported from the network and charged at the normal retail price. If the generation output of the PV system exceeds the customer's immediate requirements, any excess electricity is fed back into the network and registers on the customer's meter as exported energy. When the customer is billed, the retailer credits the value of the exported surplus electricity against the total consumption charge for electricity imported from the network.

Under the alternate gross metering arrangement, the customer exports all of the energy generated by their PV system back into the network, and imports all of the energy they consume from the network. At the end of the billing period, the total amount of exported electricity is multiplied by the feed-in tariff rate and then credited to the customer's retail account to offset the cost of imported electricity which is charged at the customers' prevailing retail price.

Submissions

The majority of submissions, including those from retailers, clean energy associations, PV associations, customer groups and the distributors strongly opposed a move to gross metering. These stakeholders generally argued that gross metering unfairly forces PV customers to sell all of their PV energy at a low rate and draw all of their consumption from the network at a higher retail price.

Submissions from the Australian Solar Council, Energex, Ergon Energy, Infinity Solar, the Solar Business Council, Suntech, Sunwiz, and some solar PV customers also argued that gross metering does not provide appropriate incentives to modify consumption behaviour.

AGL, Energex, Ergon Energy, TRUenergy and Origin Energy suggested that it would be preferable to address any cross-subsidies between solar PV and non-solar PV customers that might arise due to less-than-cost-reflective network charges by improving the cost reflectivity of the network charges, rather than by adopting a gross metering arrangement.

In contrast, Stanwell Corporation supported gross metering on the basis that it would ensure that all customers paid a network charge for all of their consumption (fixed and variable components), regardless of whether they were exporting PV generated power to the grid.

A submission from an individual customer, Mr Trevor Berrill, also supported gross metering, on the basis that it could provide useful information, including the total volume of energy generated by PV units (separate from energy consumption), that cannot be easily recorded under net metering.

Energex and Ergon Energy suggested that net metering is more efficient and provided more customer choice than gross metering. The distributors also suggested that the introduction of gross metering would require additional metering for some consumers and impose significant additional costs on distribution businesses.

In response to the Draft Report, the Queensland Consumer's Association supported the Authority's preference for net metering but expressed reservations about retailers being allowed to offer gross metered tariffs, arguing that this would introduce extra complexity and difficulties for consumers when comparing retailer offers.

The Authority's Position

Many submissions which strongly rejected the option of gross metering incorrectly assumed that the outcomes of this review would apply retrospectively to customers on the existing net-metered feed-in tariffs. The purpose of this review is to advise the Minister on a fair and reasonable feed-in tariff value for Queensland customers, and the mechanisms through which such a tariff could be implemented.

The Authority discussed the option of gross metering in order to highlight that PV customers on a net metered tariff are able to avoid a disproportionate amount of network costs by minimising their reliance on grid-sourced electricity. Whilst they still pay a daily fixed network charge, their liability for volume based network charges may be significantly lower than other customers in the same consumption tariff class. This raises a potential concern because, generally, the network charge components are not cost-reflective. That is to say, the variable network charges tend to overstate the true cost of each customer's use of the network, while fixed components tend to significantly understate the true value of the assets required to service each customer.

Implementing a gross metered feed-in tariff for new participants would be one way to alleviate inequities arising from sharing of the under-recovered network charges resulting from the net metering arrangement. However, the Authority agrees with comments made in submissions from distributors and retailers, that it would be preferable to improve the cost-reflectivity of network charges in order to eliminate the cross-subsidies between solar PV and non-solar PV customers. This solution would come at the cost of much higher fixed network charges for all customers which, when viewed from other perspectives, might also be seen as imposing a high cost on those least able to afford it. An alternative might be to introduce a new network charge for customers with PV installations which is designed to recover the actual fixed costs: these customers network connection, which they are not paying under the current network charging arrangements, when they reduce their consumption from the network.

The Authority also notes that net metering is currently the dominant metering approach in Australia and its retention in Queensland would likely assist in any transition to a national feed-in tariff scheme, should one be introduced in the future.

Based on these considerations, the Authority is inclined to prefer a net metering arrangement. However, the Authority considers that retailers should not be precluded from offering gross metered feed-in tariffs, should they so choose. The Authority notes the concerns raised by the Queensland Consumers Association, however it considers that retailers should not be constrained from offering innovative feed-in tariff products to promote competition among retailers, including offering a choice of metering options to customers.

5.4 Other Issues

Some submissions raised other issues in relation to implementing a fair and reasonable feed-in tariff that have not been addressed above.

Administration Costs of Multiple Feed-in Tariffs in Ergon Energy's Distribution Area

As discussed in Chapter 4, the Authority considers there is scope to apply some broad geographically sensitive feed-in tariffs across the Ergon Energy supply area. However, doing so raises some implementation issues identified in submissions.

The Australian Solar Council and the Solar Business Council Inc. supported broad geographical based feed-in tariffs provided they are not so complex that they would impose significant administration costs. Similarly, ATA pointed to the system in Western Australia where feed-in tariffs vary regionally based on losses and suggested a similar approach would be logical in Queensland.

In contrast, Ergon Energy argued that different feed-in tariffs for different areas will be more complex to administer and may impose additional costs on both the retailer and the distribution business. It claimed that if more tariffs are introduced, it would need to update its billing systems and tariff codes.

Approaches in Other Jurisdictions

In Western Australia, solar PV customers are offered feed-in tariffs through the REBS, which requires retailers to offer a buyback rate to net exporters of renewable generated electricity. The buyback rates and terms and conditions are set by the retailer and approved by the Public Utilities Office.

Horizon Power is the incumbent electricity supplier to Western Australian customers outside of the South West Interconnected System (SWIS)[25]. Horizon Power's network area covers 2.2 million square kilometres and services around 100,000 residential customers across the Kimberley, Pilbara, Gascoyne, Mid West and Southern Goldfields regions. Horizon Power also manages and delivers electricity to 36 isolated systems in remote and regional areas.

Horizon Power applies feed-in tariffs set on a locational basis which reflect the avoided costs of generation fuel and capacity costs relevant to each location. These buyback rates currently range from 10 cents per kWh in towns where the cost of supplying electricity is lower, to 50 cents per kWh where these costs are higher. Horizon Power reviews the buyback rates annually.

The Authority's Position

While Ergon Energy suggested that administering multiple feed-in tariffs set on a locational basis would be complex and require billing system upgrades, it was not clear on the significance of those costs. However, given Horizon Power is able to administer numerous feed-in tariffs across WA, the Authority assumes that the cost to Ergon Energy of administering a small number of different feed-in tariffs would not be unreasonable.

The Authority has nonetheless been mindful of the cost of implementation and has developed its proposed feed-in tariffs based on existing Ergon Energy pricing zones and loss factors, as currently used to determine the allocation of its network charges. On this basis, the Authority considers that implementing the regional feed-in tariffs presented in Table 4.10 should not be excessively complex or costly for Ergon Energy.

Obligation to Connect PV Customers

The Clean Energy Council submitted that it was aware of some PV customers being refused a solar PV export connection to the distribution network. It argued there should be an enshrined 'right to connect' for customers wishing to install grid-connected PV systems.

The Authority considers there are several problems with this proposal. Firstly, any move to oblige a distributor to connect PV customers could significantly impede the distributor’s ability to run its network in the most efficient way and could have potentially serious negative implications for the network and electricity prices. This is because network operators must observe a range of standards and limitations when modifying the network and there may be sound reasons why some connections should not be made. Network businesses are best placed to make those decisions and should not be restricted from refusing individual PV connections where there are negative consequences for the safety, reliability or efficiency of the network. Furthermore, imposing a right to connect would likely interfere with the regulation of the distribution businesses, which would be inconsistent with the COAG National Principles.

For these reasons the Authority considers there should not be any enshrined right to connect for PV installations.

[25] Horizon Power is owned by the WA State Government and is a vertically integrated generator, network service provider and retailer.

Eligibility of Commercial Customers

The Clean Energy Council argued that it is not fair or reasonable that commercial customers are excluded from accessing the existing Scheme. It argued that there are a significant number of commercial customers who are currently prevented, or de-incentivised by the lack of a right to connect or minimum mandatory feed-in tariff.

While the current review is not about access to the current Scheme, as the Authority is recommending that retailer-funded feed-in tariffs in South East Queensland not be regulated, if retailers choose to develop fair and reasonable feed-in tariffs for customers other than residential customers, they should not be restricted from doing so. Given that statistics indicate the proportion of commercial customers on market contracts is larger than for residential customers, the Authority considers it likely that there is a healthy level of competition for commercial customers in South East Queensland. On this basis, it is likely that retailers would also make voluntary feed-in tariff offers to commercial customers.

Eligibility of Other Technologies

A number of stakeholders, including Energex, submitted that the feed-in tariff should be made available to other types of renewable sources such as wind, fuel cells and energy storage, and should not be limited to small scale solar PV. It was also suggested that time-varying tariff rates and different rates for different technologies could be developed.

While the terms of reference for this investigation specify that the Authority is to advise on a feed-in tariff for solar PV generation only, the Authority sees no reason why retailers could not develop fair and reasonable feed-in tariffs for other technologies.

5.5 Processes for Ongoing Review

In its Issues Paper, the Authority presented the following options to ensure that any mandatory fair and reasonable value remained appropriate over time:

(a) an annual review of the value(s), to apply for the following 12-month period;

(b) a multi-year review which establishes a fixed value or values for two or more years; or

(c) a multi-year review which establishes a variable value or values for two or more years, updated at defined intervals, or as necessary.

Submissions

Submissions provided mixed support for the annual and multi-year review options. Those that favoured a multi-year approach generally argued that this approach would provide certainty for customers and retailers. However, stakeholders that favoured this option also suggested the need for a mechanism to allow a flexible review of the benchmark value in response to material changes in circumstances affecting the value.

The Authority's Position

In its Draft Report, the Authority noted that reviewing the value annually is likely to be the most administratively costly option. However, it would allow the fair and reasonable value to be updated to reflect unforseen changes in underlying determinants in a timelier manner than under a multi-year review.

At present, the Authority reviews and sets regulated retail electricity prices on an annual basis. There does not appear to be any reason why feed-in tariffs would need to be reviewed more frequently than notified retail prices. On the same basis, the Authority does not consider that there would be any need for a mechanism to 're-open' the value between annual reviews. More frequent reviews would likely impose unnecessary additional administrative costs on all parties, while less frequent reviews would risk values falling out of touch with the market.

For these reasons, the Authority considers that the benchmark value should be updated on an annual basis, concurrent with the Authority's review of notified retail electricity prices. This would represent an efficient approach to ongoing review of feed-in tariff arrangements, as the Authority can apply its prevailing methodology and most recent available data, consistent with that used for setting notified prices.

5.6 Supporting Arrangements for Market-based Feed-in Tariffs

While not raised in the Issues Paper, several stakeholders suggested that introducing voluntary feed-in tariffs may require the implementation of measures to ensure that customers are able to make informed choices about feed-in tariffs. This may include monitoring of the market for a period of time to ensure that competition continues to provide customers with access to fair and reasonable feed-in tariff offers.

Submissions

The Queensland Consumers Association and the QCOSS emphasised the need for customers to be informed if they were to participate in the market, and cited anecdotal evidence that many solar PV customers are not well informed regarding the benefits of solar PV installations and electricity market offers generally.

QCOSS were concerned that there is currently no independent comparison tool for solar feed-in tariffs where customers could access clear and comparable information on market offers with a feed-in tariff component, such as an online price comparison tool. The Clean Energy Council also highlighted the importance of transparency, stating that in NSW, where voluntary feed-in tariffs were implemented, that solar feed-in tariff information had been removed from the MyEnergyOffers website, placing consumers in a “weak” negotiating position. However, this appears to be incorrect and, at the time of writing, information on solar feed-in tariffs was clearly available on the 'MyEnergyOffers' website[26], and has been since before the release of the Authority’s Issues Paper in August 2012.

To enable consumers to make informed choices, QCOSS and the Queensland Consumers Association recommended the Authority establish a minimum regulated solar feed-in tariff, subject to future review.

Ergon Energy suggested that voluntary feed-in tariff offers could be monitored and compared by the Authority, and regulatory intervention could be considered were the market not to deliver fair and reasonable feed-in tariffs.

QCOSS noted that there is currently no independent price comparison tool that enables Queensland solar PV customers to compare market offers with a solar feed-in tariff component. QCOSS noted that implementation of the National Energy Customer Framework (NECF) in Queensland would enable solar PV customers to access the AER’s Energy Made Easy website, which provides an independent online price comparison resource including information on offers for solar PV customers. QCOSS suggested that an alternative would be for the Authority to incorporate solar PV offers into their existing price comparison tool.

[26] http://www.myenergyoffers.nsw.gov.au/useful-information/solar-feed-in-tariffs.aspx

The Authority's Position

The Authority agrees with submissions highlighting the importance of enabling customers to make informed choices if they are to benefit from competition in the market for solar PV customers. Informed choice requires that customers not only understand the terms and conditions of a market offer they are considering, but also how that market offer compares to others in the marketplace.

Current information requirements in the Electricity Industry Code (the Code) for non-solar PV customers provide the ability for customers to make informed choices and have supported the development of competition in the residential electricity market. These provisions could be extended to cover solar PV customers.

The Authority notes that, as Queensland is currently committed to the implementation of the NECF. Should it be implemented, the NECF includes appropriate information disclosure requirements that cover solar PV feed-in tariffs.

5.7 Statutory Implementation

As discussed in section 5.2, Ergon Energy (retail) is precluded from offering retail electricity on terms other than gazetted notified prices. The drafting of section 90(1) of the Electricity *Act 1994* would also seem to preclude Ergon Energy from offering a feed-in tariff to customers without entering into a PPA.

Should the Government accept the Authority's recommendation to mandate minimum feed-in tariffs for Ergon Energy customers, it is more than likely that some supporting legislative changes may be necessary.

6. PROJECTED COST OF THE SOLAR BONUS SCHEME

Although the feed-in tariff under the Scheme has been reduced from 44 cents per kWh to 8 cents per kWh for new customers, there remain a significant number of PV customers who will continue to receive the old rate until the end of the Scheme in 2028. This means the Scheme will continue to have an impact on electricity prices for some time.

As part of its review, the Authority has been asked to report updated projected costs of the current Scheme. To estimate these costs, the Authority requested information from Energex and Ergon Energy. The Authority has also considered how these costs might impact retail electricity prices.

6.1 Solar Bonus Scheme Costs Incurred by Distributors

As discussed in Chapter 2, the Scheme is currently funded by the distributors. The majority of the costs arise from feed-in tariff payments by the distributors to solar PV customers for energy exported to the grid. In addition, the distributors incur infrastructure and administrative costs as a result of connecting solar PV customers.

As shown in Table 6.1, feed-in tariff payments are expected to cost Energex and Ergon Energy $239 million in 2012-13, increasing to $275 million in 2013-14, before slowly tapering-off as a result of customers becoming ineligible for the scheme. In nominal dollars, payments are expected to cost in the order of $3.4 billion by the close of the 44 c/kWh scheme in 2028 ($3.0 billion in real terms, once adjusted for changes to the consumer price index (CPI) over the period).

More than 99% of these costs reflect payments of the 44 cents per kWh feed-in tariff which was closed to new applicants on 9 July 2012, with the 8 cents per kWh feed-in tariff making only a minor contribution to date.

Installed capacity on the Scheme is forecast to peak at 1,098MW in 2013, which is roughly 130 times the capacity originally proposed[27]. While capacity eligible for the Scheme is expected to taper off in a similar way to feed-in tariff payments, Energex expects that non-Scheme PV will continue to grow beyond 2013-14. Energex forecasts that by 2021, 1,280 MW of PV capacity will be installed on its network, 790MW of which will not be related to the Scheme. While non-Scheme capacity will not impact on feed-in tariff costs, it will impact infrastructure costs and amplify the effect of in-house consumption on network tariffs.

[27] Section 52 of the *Clean Energy Act 2008* (which created the Scheme at section 44 of the *Electricity Act 1994*) originally prescribed that a review of the provisions be conducted at either 10 years after commencement, or when eligible installed solar generation capacity reached 8 MW, whichever came first.

Table 6.1: Feed-in Tariff Costs for 44c/kWh and 8c/kWh Schemes ($m, nominal)[a]

Distributor	*2010-11*	*2011-12*	*2012-13*	*2013-14*	*2014-15*	*2015-16*	*2016-17*	*2017-18*	*2018-19*	*2019-20*
Energex	19.4	73.9	168.7	191.2	181.4	174.2	167.2	160.5	154.1	147.9
Ergon Energy	6.5	27.0	69.7	83.5	64.7	61.7	58.9	56.2	53.6	51.1
Total	**25.9**	**100.9**	**238.5**	**274.7**	**246.1**	**235.9**	**226.1**	**216.7**	**207.7**	**199.0**
44 c/kWh installed capacity	212.0	504.4	938.9	910.6	869.8	831.0	793.9	758.6	724.9	692.7
8 c/kWh installed capacity (MWh)	0.0	0.0	59.2	187.7	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Capacity (MWh)	**212.0**	**504.4**	**998.0**	**1098.3**	**869.8**	**831.0**	**793.9**	**758.6**	**724.9**	**692.7**

Source: Energex and Ergon Energy

a. Costs are presented to 2019-20 - the end of the next distribution regulatory period. The patterns established by the last year of the table will continue through to 2028. – see also Figure 6.1.

Infrastructure and Administrative Costs

While less significant than feed-in tariff payments, the distributors also incur a considerable level of infrastructure and administrative costs as a result of the Scheme. Infrastructure costs include additional metering and connection equipment at the customer’s meter box and the costs of upgrading local networks to ensure they are capable of dealing with PV exports. Administrative costs include increased call-centre operations, upgrading and checking billing systems, and assessing and actioning customer applications.

Energex and Ergon Energy provided infrastructure and administration costs in terms of the contribution these costs make to the revenue the AER allows the distributors to recover from distribution charges. As administration costs are operating expenditures that are reflected one-for-one in the distributors’ allowed revenue, the administration costs presented in Table 6.2 reflect the actual costs expected to be incurred by the distributors in each year. In contrast, because infrastructure costs represent capital expenditure that would be added to the distributors’ asset bases, the values shown in Table 6.2 reflect the regulated return on and return of these assets that the distributors are allowed to receive, not the full amount of the capital expenditure in the year it is incurred.

To estimate administration and infrastructure costs, Energex used an activity based costing (ABC) exercise which captures activities undertaken and the resources used, to determine the average cost per solar PV system installed. The annual infrastructure and administration costs were derived by multiplying the average cost per system by the forecast number of systems. Energex estimates administrative cost per system for 2011-12 at $27 (escalated by CPI for future years).

Energex also estimated infrastructure capital costs from the ABC process (including system assessment, cost of meters and meter installation costs) are then converted into an annual revenue requirement using the AER's post-tax revenue model methodology. The infrastructure cost per system for 2011-12 was estimated by Energex at $210 (escalated by CPI for future years). Energex latest forecast for 2012-13 is lower than that provided for the Draft Report.

Ergon Energy uses a similar approach to estimating administrative costs based on resources (specifically labour) used in specific activities. For example, where an employee spends 10% of their working time on a particular activity then 10% of that employee's salary would be factored into the calculation of the administrative costs. Ergon Energy has not included other overhead costs such as IT items or property, as the need for these would exist even without the Scheme. Ergon Energy's estimated infrastructure costs include network augmentation costs and metering costs. Ergon Energy advised that its network augmentation costs were estimated by modelling the verified impacts of PV systems on a range of network configurations, forecast PV installations and forecast number of constrained networks. To forecast metering costs, Ergon Energy multiplied the estimated unit cost of an inverter energy system meter by the forecast number of PV connections in each year.

While some of these costs have been covered by the capital and operational expenditure allowances in the AER’s original determination, the Authority is of the view that is it reasonable to include them in an analysis of the costs of the Scheme.

Table 6.2: Infrastructure and administration costs ($ million, nominal)[a]

	2010-11	*2011-12*	*2012-13*	*2013-14*	*2014-15*	*2015-16*	*2016-17*	*2017-18*	*2018-19*	*2019 -20*
Energex										
Administration	2.3	2.1	2.5	0.6	0.6	0.6	0.6	0.6	0.6	0.5
Infrastructure[b]	1.4	3.3	3.4	5.7	6.3	6.0	6.5	7.0	7.4	7.9
Total	**3.7**	**5.4**	**5.9**	**6.3**	**6.9**	**6.6**	**7.1**	**7.6**	**8.0**	**8.4**
Ergon Energy										
Administration	2.7	4.8	4.9	4.0	1.6	0.4	0.0	0.0	0.0	0.0
Infrastructure[b]	0.6	2.8	7.8	12.6	13.5	12.7	12.3	12.0	11.6	11.3
Total	**3.3**	**7.6**	**12.7**	**16.6**	**15.1**	**13.1**	**12.3**	**12.0**	**11.6**	**11.3**

Source: Energex, Ergon Energy and the Authority’s analysis

a. Costs are presented to 2019-20 - the end of the next distribution regulatory period. The patterns established by the last year of the table will continue through to 2028.

b. return on and return of assets

6.2 Differences from Draft Report Cost Projections

The forecast cost impacts of the Scheme have increased significantly from those presented in the Authority’s Draft Report, most notably for Energex. This has occurred for a number of reasons. Firstly, since providing forecasts for the Authority's Draft Report in September 2012, Energex has noticed that a higher than expected number connection applications being followed through by customers. Energex previously anticipated that around 25-30% of applications received during the weeks leading up to 10 July 2012 would not actually be installed. Based on its recent experience, Energex now expects that only 10-20% will not go through with the installation, which has increased the number of systems eligible for the 44 cent payments (and 8 cent payments should they become ineligible for the 44 cent rate in the future).

Secondly, Energex has noted that the average size of systems being installed (measured by inverter capacity) is higher than previously observed. While Energex's forecasts for the Draft Report assumed an average system size of 2.6 kW, the average installation size observed in December 2012 was 4.5 kW and the expected average installation size by June

2013 is forecast to be approximately 3.1 kW. This increase in average system size increases generation output and, all other things constant, the volume of exports eligible for the 44 cent rate which increases total expected feed-in tariff payments. Energex has also observed similar increases in average inverter capacity for installations eligible for the 8 cent rate.

Finally, Energex's forecast of the rate at which customers become ineligible for the Scheme due to change of address, has decreased from 6% to 4%, based on recent experience. The effect of this is that more customer are expected to remain eligible for the Scheme for longer, which has increased forecast feed-in tariff payments compared to those presented in the Draft Report.

While Ergon Energy's forecast Scheme costs have not increased by as much as Energex's, it has observed a higher rate of installations eligible for the 44 cent Scheme than it previously modelled, which is driving higher expected energy exports and direct feed-in tariff payments. In contrast, Ergon Energy has revised down its forecast payments at the 8 cent rate due to the number of applications and installations being significantly lower than previously expected.

6.3 Impact of the Solar Bonus Scheme on the Distributors' Prices

Energex and Ergon Energy provided estimates of how the costs presented above are likely to flow through into distribution prices over the period to 2017-18.

Feed-in Tariff Payments

The AER approves the amount of revenue to be raised by the distributors on a five-yearly basis (the regulatory period). The costs associated with feed-in tariff payments for 2012-13 to 2014-15 (the last year of the current regulatory period) presented in Table 6.1 are significantly higher than the level of costs that the AER approved for inclusion in the distributors' annual revenue for each of these years. However, the AER will allow the distributors to recoup any extra costs such as these but, for administrative reasons, there is a two-year lag between when the distributors incur the costs and when they can recover those costs via higher distribution prices. This means that distribution prices for any given year of the current AER regulatory period do not reflect the costs the distributors have actually incurred in making feed-in tariff payments. Rather, they reflect the level of costs that were forecast at the time the current AER regulatory period commenced.

For the next AER regulatory period, which starts in 2015-16, Energex and Ergon Energy should be able to more accurately forecast feed-in tariff costs, given the maturity of the Scheme. As a result, the distributors' prices in 2015-16 and 2016-17 will likely reflect something close to the actual costs being incurred on feed-in tariff payments during those years. However, these will then be inflated by the significant catch-up of extra costs that the distributors did not recoup via distribution charges in 2013-14 and 2014-15.

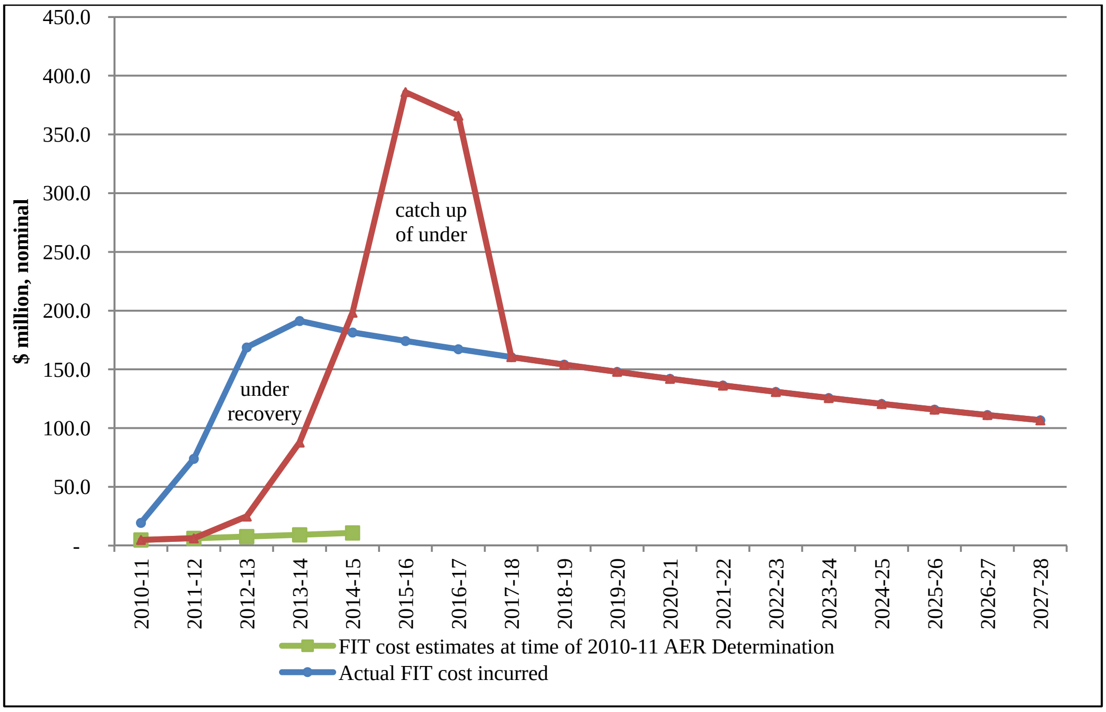
In its submission on the Draft Report, DEWS noted that the National Electricity Rules (NER) may provide some flexibility to allow this catch-up to be spread over a number of years. The Authority understands that Energex is considering applying to the AER to smooth the recovery of expected pass-through amounts over the next five-year regulatory control period[28]. There is no indication if Ergon Energy will do likewise.

As any potential smoothing of cost pass-through amounts is yet to be considered or confirmed by the AER, the Authority can only proceed on the basis of usual practice to date and assume that the distributors will recoup the under-recovery from 2013-14 and 2014-15 in

[28] Energex, Response to request for information - Review of solar feed-in tariffs. 25 January 2013. p.3

2015-16 and 2016-17 respectively. The impact of this catch-up of PV costs on Energex's revenue is shown in Figure 6.1. Should these costs eventually be smoothed over time, the cost impacts will differ to the profiles depicted in this figure, but the costs will not disappear.

Figure 6.1: Energex feed-in tariff payments and impacts on network revenue



Source: Energex and the Authority's analysis

With more accurate estimates of feed-in tariff costs accounted for in distribution prices from 2015-16, the prospect of further significant under-recovery of actual costs diminishes. As a result, revenue from network charges is likely to more closely reflect actual costs incurred on feed-in tariffs from 2017-18.

Infrastructure and Administrative Costs

The Authority understands that neither of the distributors' revenue allowances for the current AER regulatory period included explicit allowances for infrastructure and administration costs associated with PV generation. While the distributors may be entitled to recoup some of these costs via the AER's cost pass-through arrangements, neither have indicated an intention to do so. As a result, unlike the situation with feed-in tariff payments described above, there is not expected to be a doubling-up of network price impacts associated with infrastructure and administration costs in 2015-16 and 2016-17 due to earlier under-recovery of costs. In this instance, while the costs have still been incurred, the distributors have, presumably, put off other previously approved operating and capital expenditure projects in order to absorb these new costs.

In-house Consumption of PV Energy

Under the Scheme, the feed-in tariff is applied as a net tariff (on excess energy exported to the grid) rather than a gross tariff (on total energy generated). This means that PV customers avoid paying the variable network charges associated with energy they would have purchased from the grid if they did not produce their own energy.

Both distributors have network charges that rely on recovering a significant portion of fixed network costs via the variable volume component of the network charge. If the network costs were allocated to the fixed and volume charge components strictly on the basis of how those costs are incurred, the resulting network charges would be predominantly a flat fixed charge (reflecting the fact that the majority of network costs are fixed). While PV customers on a net feed-in tariff are charged for their access to the network on this basis (and hence no longer pay volume based network charges on their total use) they will not be meeting the true costs of retaining their network connection. In this case, the distributors will either under-recover their allowed network revenue (such under-recovery then being distributed to all network customers as higher prices in later years) or have to reduce their consumption forecasts which will also lead to higher unit prices for all customers.

There are good reasons why the networks would charge customers non-cost reflective fixed and variable price components. Primary among these are the necessity to have a substantial variable charge component in order to pass price signals to customers about the cost of their use of the network. But, under a net feed-in tariff arrangement, the apparent cost savings for customers with PV installations are exaggerated and the apparent but unreal cost savings are passed on to all customers in the form of higher prices.

As the Queensland Government noted in its submission, in-house PV consumption is not recorded under net metering arrangements which makes it difficult for the distributors to accurately determine the quantum (and impact) of in-house consumption in Queensland. The task is made even more difficult by the on-going demand reductions stemming from low economic growth and other forms of demand management as outlined above. Given the lack of metering data, each distributor has assumed that a typical PV customer on the 44 cent per kWh scheme would consume 60% of their PV generation and export 40%. Energex has based this assumption on research by IPART (which has access to the necessary metering data because of the gross scheme that operates in NSW) and has verified it with its own calculations based on the installed PV capacity and net exports for which it is liable to pay feed-in tariff payments. Energex estimates that in-house consumption would be higher under the 8 cent per kWh scheme (80% of generation) because there is more incentive to offset consumption and less incentive to over-invest in PV units under the less favourable feed-in tariff.

While the cost of feed-in tariff payments will decrease over time, and the bulk of infrastructure and administrations costs will be incurred in the early years of the Scheme, Energex expects that in-house consumption will continue to grow into the future as more customers invest in PV panels. Since the close of the 44 cents per kWh feed-in tariff, Energex has continued to experience high levels of PV applications and expects to receive around 13,000 applications per annum in forthcoming years. Ergon Energy also expects that in-house consumption will increase over the next couple of years after which it assumes it will remain constant. As such, the impacts of in-house consumption on network tariffs are expected to continue to grow into the future.

Energex has estimated that in-house consumption will reduce total distributed consumption by up to 1051.7 GWh per year over the period to 2017-18 as a result of the increasing number of PV owners consuming their own generation, and that this will increase network prices by up to 4.6% per year. Similarly, Ergon Energy has estimated that in-house consumption will reduce total distributed consumption by up to 288 GWh per year over the period to 2017-18, and that this will lead to network price increases of up to 2% per annum.

Total Distribution Price Impacts

Table 6.3 summarises the three main sources of distribution price impacts discussed above.

Table 6.3: Contribution of Solar Bonus Scheme to distribution prices (% increase)[a]

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019 -20
Energex										
Feed-in tariff payments	0.4%	0.5%	1.7%	5.2%	10.9%	24.9%	23.1%	8.8%	8.2%	7.7%
Infrastructure & admin	0.3%	0.4%	0.4%	0.4%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%
In-house consumption	0.4%	1.2%	2.7%	3.6%	3.9%	4.2%	4.4%	4.6%	4.8%	4.8%
Total	**1.1%**	**2.2%**	**4.8%**	**9.17%**	**15.1%**	**29.5%**	**27.8%**	**13.8%**	**13.4%**	**12.9%**
Ergon Energy										
Feed-in tariff payments	0.2%	0.3%	0.6%	2.0%	4.7%	8.6%	7.0%	3.0%	2.8%	2.6%
Infrastructure & admin	0.3%	0.6%	0.9%	1.0%	0.9%	0.7%	0.7%	0.6%	0.6%	0.6%
In-house consumption	0.1%	0.6%	1.7%	2.0%	1.5%	1.4%	1.3%	1.2%	1.2%	1.1%
Total	**0.7%**	**1.5%**	**3.2%**	**5.04%**	**7.0%**	**10.7%**	**9.0%**	**4.9%**	**4.5%**	**4.2%**

Source: Energex and Ergon Energy and the Authority's analysis

a. costs are presented to 2019-20 - the end of the next distribution regulatory period. The patterns established by the last year of the table will continue through to 2028.

6.4 Impact of Solar Bonus Scheme Costs on Retail Electricity Prices

Wholesale Energy Costs

In response to the Draft Report, DEWS considered that the calculation of a fair and reasonable value for PV exports is separate from the calculation of Scheme costs. DEWS suggested that there are retail side benefits from solar PV that were acknowledged by the Authority, but excluded from its calculations of a fair and reasonable value. As an example, DEWS suggested that, to the extent that solar PV is a contributing factor in lower persistent wholesale energy costs in the NEM, the financial benefit should be realised in future retail price setting which would offset some of the network price increases. DEWS suggested that the Authority should consider quantifying, or estimating, this benefit of the Scheme to allow a balanced consideration of the Scheme's net electricity pricing impacts.

As discussed in Chapters 3 and 4, the Authority does not consider it appropriate, or necessary, to consider the apparent price suppressing effect of PV generation when estimating fair and reasonable feed-in tariffs. The Authority noted that this effect (also described as the merit order effect) is not purely a consequence of PV generation - it may be observed as a result of a number of influences from both the demand and supply side, for example, the entry of other forms of low marginal cost generation.

Similarly, the Authority considers that while a short-run suppression of wholesale electricity prices may be in some part attributable to additional low marginal cost PV generation, it is not appropriate to consider that as a specific benefit offsetting the costs of the Scheme without looking at the long-run implications. In the long run, the suppression of wholesale prices by subsidised PV generation is likely to diminish. This is because, while PV and other renewables have a very low marginal cost of generation, they have a much higher average cost due to the relatively high capital cost. All else being equal, this would be expected to increase electricity prices in the long-run, not decrease them.

On this basis the Authority does not accept that the price suppressing effect of PV should be considered when estimating the ongoing costs of the Scheme. To do so would require equal attention be given to the potential long-run price effects, which the Authority considers would require a much more significant and detailed study than that envisaged by the terms of reference.

Network Costs

As a rule of thumb, network costs typically account for around 50% of a retail bill. As a result, the retail electricity bills of customers in the Energex and Ergon Energy distribution areas could be expected to increase by around half the network price impacts shown in Table 6.3 as a result of the costs of the Scheme.

One exception to this is for small customers (those consuming less than 100MWh a year) on regulated retail tariffs in Ergon Energy's distribution area, who will face increases associated with the Energex distribution area. This is because the UTP results in all small customers, regardless of their location, having access to regulated retail prices based on the cost of supply in Energex's distribution area (discussed in Chapter 5).

The Authority has calculated more accurate estimates of the expected impact of the Scheme on retail electricity prices for residential customers based on its Draft Determination cost-reflective Tariff 11 price for 2013-14 (Table 6.4 and Figure 6.2). The 9.2% increase in Energex's distribution prices in 2013-14 is estimated to add around $67 to the annual bill of a typical residential customer (one consuming around 4,818kWh on Tariff 11). Assuming all other costs are held constant at 2013-14 levels, this cost is expected to increase to around $276 (16.6%) in 2015-16, before tapering off in future years.

These retail price impacts are significantly higher than those the Authority calculated in the (solar) Draft Report and reflect Energex's feed-in tariff updates. They still reflect Energex's plan to recoup costs associated with the scheme across all customers. As noted above, there may be some opportunity for Energex to spread the 2015-16 and 2016-17 cost pass-through impacts over a number of years, in which case the cost impacts will differ to the profiles depicted in figure 6.2.

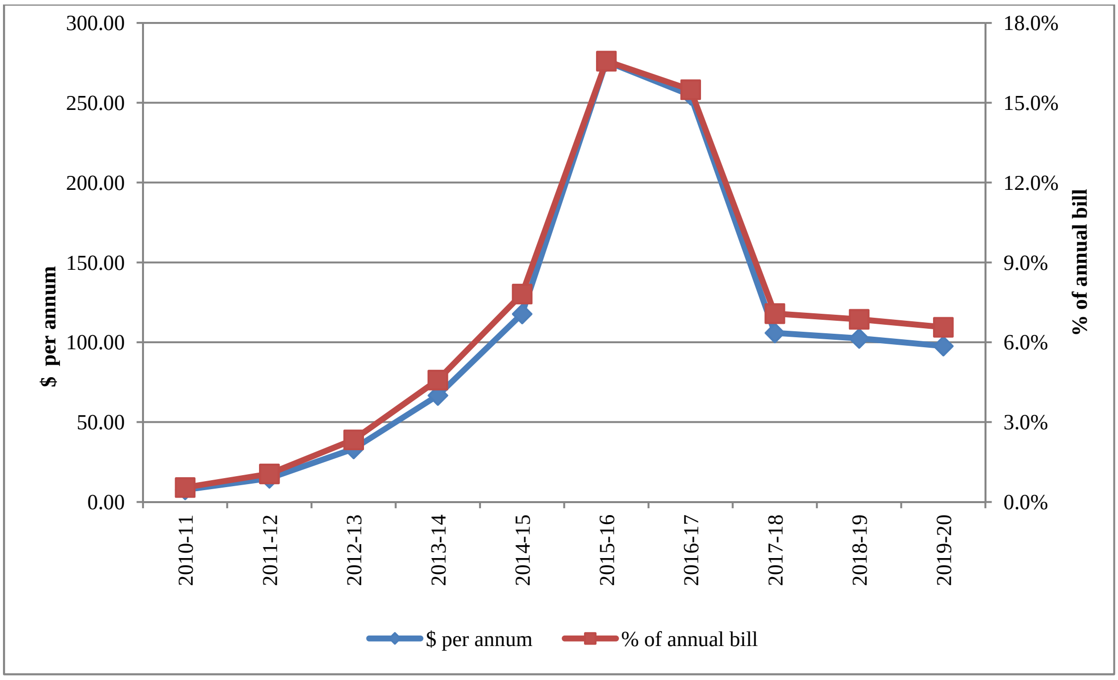
Table 6.4: Impact of Solar Bonus Scheme on Tariff 11 holding other costs constant[a] ($ nominal)

		2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Energex price change	%	*1.1%*	*2.2%*	*4.8%*	*9.2%*	*15.1%*	*29.5%*	*27.8%*	*13.8%*	*13.4%*	*12.9%*
Typical annual T11 impact	$	7.60	14.84	33.24	66.73	117.78	275.90	254.72	105.88	102.42	97.65
% of Annual T11 bill	%	*0.5%*	*1.1%*	*2.3%*	*4.6%*	*7.8%*	*16.6%*	*15.5%*	*7.1%*	*6.9%*	*6.6%*

Source: Energex and the Authority's analysis

a Costs are presented to 2019-20 - the end of the next distribution regulatory period. The patterns established by the last year of the table will continue through to 2028 – See also Figure 6.2

Figure 6.2: Indicative impact of Solar Bonus Scheme on the typical Tariff 11 customer's bill (other costs held constant at 2013-14 levels)*



Source: Energex and the Authority's analysis

**Costs are presented to 2019-20 - the end of the next distribution regulatory period. The patterns established by the last year of the table will continue through to 2028.*

7. MANAGING THE ON-GOING COSTS OF THE SOLAR BONUS SCHEME

The Authority has been asked to investigate options for minimising, or more equitably sharing, the on-going costs of the Scheme, including a potential retailer contribution.

As discussed in Chapter 2, the existing Scheme is a distributor-funded scheme, the costs of which are ultimately borne by electricity customers via higher network charges, and therefore higher retail electricity prices. This raises concerns about the equity of the Scheme for non-PV customers.

In addition, as discussed in Chapter 3, it is clear that retailers are likely to derive some financial benefit from their customers' PV energy exports. As a result, it would seem that requiring retailers to contribute to the future costs of the existing Scheme is one reasonable way to reduce the on-going impact of the Scheme on network charges and customers' electricity bills.

In the Draft Report, the Authority considered that the on-going costs of the Scheme could potentially be reduced by requiring retailers to make a contribution to the distributor-funded 44 cent feed-in tariff payments. The Authority also suggested that more cost-reflective network charges for PV customers would improve the equity of the current funding arrangement.

7.1 Approaches in Other Jurisdictions

For its 2012 review of solar feed-in tariffs, IPART[29] recommended that NSW retailers be required to contribute 7.7 cents per kWh to the costs of the existing distributor-funded scheme in NSW[30]. The value recommended by IPART represents the lower end of the estimated benchmark range for the fair and reasonable value of PV, as discussed in Chapter 3.

7.2 Submissions

Retailers generally did not support a mandatory contribution from retailers to the distributor-funded Scheme. Origin argued that imposing such costs would be to the detriment of consumers and would create additional costs and reduce competition. EnergyAustralia also suggested that mandating a retailer contribution could increase the on-going costs of the Scheme due to higher inefficiencies related to the less centralised method of cost recovery.

The ERAA submitted that a mandatory retailer contribution, above what is commercially viable, would increase the risks faced by retailers. AGL also noted that voluntary premiums may be withdrawn should a mandatory retailer contribution be implemented, pointing to the outcomes of the mandatory contribution in NSW which saw retailers adjust their voluntary premiums accordingly.

The National Generators Forum (NGF) supported a retailer contribution to fund the Scheme as it would reduce the excessive payments to householders with PV panels, thereby reducing the burden on others without PV panels. The NGF submitted that the present pricing approach of access to the network for customers with PV panels is inefficient as the sunk network costs are not recovered from these customers. The NGF suggested that, in effect, there is a wealth transfer from those without PV panels to those with PV panels.

[29] IPART, *Setting a Fair and Reasonable Value for Electricity Generated by Small-scale Solar PV Units in NSW, Final Report*, March 2012.
[30] IPART, *Solar Feed-in Tariffs, Retailer Contribution and Benchmark Range for 1 July 2012 to 30 June 2013*. June 2012.

While Origin did not support a mandatory retailer contribution to the Scheme, should this approach be adopted, Origin supported the Authority's position that this be set lower than the benchmark estimate of a fair and reasonable FIT. NGF and AGL also agreed with this conservative approach to setting a mandatory retailer contribution.

The ESAA considered that retailers should not be required to contribute to the costs of the feed-in tariff Scheme, which it argued was a policy decision made against the advice of the energy industry. However, the ESAA stated that if the Government chose to make retailers fund a portion of the costs, it should allow time for existing contracts to end before changes are made, and only require retailers to contribute to the cost of the Scheme for their customers on the current 44 cent per kWh and 8 cent per kWh feed-in tariffs.

TRUenergy suggested that any retailer contribution should be simple and straightforward and should not exceed the real value to the retailer of the PV exports. TRUenergy submitted that it would be helpful if the Authority and Government played a part in creating awareness of the reasons for introducing a cost sharing arrangement as customers will likely be confused when voluntary retailer FITs are withdrawn (or reduced).

Consumer groups were generally in favour of a retailer contribution to the distributor-funded Scheme. QCOSS supported this approach but noted that it would be likely to impact on retailers' willingness to continue to offer voluntary premiums. While QCOSS noted that this would not be an ideal outcome for some customers, it considered the 44 cent per kWh tariff is sufficiently generous to accommodate this outcome and that the overall benefit of reducing electricity price increases for all customers would outweigh the negative impact to individual PV customers. QCOSS suggested that the retailer contribution be set at a level to ensure that PV customers do not become less desirable to retailers and therefore disadvantaged in the market.

Queensland Consumers Association also raised concerns that the withdrawal of voluntary premiums could have significant impacts on customers whose investment decisions may have assumed the continuation of such premiums. Queensland Consumers Association suggested that any retailer contribution should be phased in over a number of years to minimise the impact of the likely withdrawal of voluntary premiums.

The Master Electricians Association noted that, if a retailer contribution is adopted, voluntary feed-in tariffs will be reduced. However, it concluded that the overall benefit for all Queensland consumers, in terms of reducing electricity price rises, would outweigh any negative impact on these individual customers.

Mr PG Atherton raised concerns with the impact of solar PV on electricity costs for other consumers and suggested that costs could be distributed more equitably by requiring solar PV customers to pay a substantial annual grid connection fee, based on the capacity of their system. Mr Atherton considered that this policy would spread the capital costs across all customers in a much fairer manner.

Energex suggested that an equitable funding arrangement would include a contribution from electricity retailers as well as recognition that solar PV customers should not be exempt from appropriate network charges. However, Energex suggested that feed-in tariffs should not attempt to correct or compensate for other market arrangements that may distort customer behaviour and/or cost allocation to various market participants and customers. Energex also suggested that the retailer contribution should be linked to the Authority's estimation of the fair and reasonable value of PV exports and would reduce the distributor funded feed-in tariff payments that need to be recovered through higher network charges, which would reduce the cost impact of the Scheme on non-PV customers. Energex suggested that while a mandatory retailer contribution would likely result in voluntary premiums being withdrawn, it argued that this should not be a consideration in the Authority's deliberations as this represents part of the risk that customers accept when they choose to invest in solar PV.

Ergon Energy was also of the view that it is reasonable that retailers contribute to the on-going costs of the Scheme. However, Ergon Energy suggested that the amount of the contribution should be established on a voluntary basis. Ergon Energy also suggested that introducing a combination of kWh tariffs and basic kW tariffs (preferably kVa), and having tariffs with capacity charging for import and export as well as an energy charge, could provide a fairer reflection of costs incurred for use of the network, import and export, and the volume of electricity consumed.

In response to the Draft Report, DEWS requested that the Authority examine other options for managing the ongoing costs of the Scheme, in addition to the retailer contribution. DEWS suggested that, while the 44 cent rate is locked-in under legislation to 2028, there may be some flexibility to minimise costs by influencing or better managing how solar PV customers utilise their solar energy. DEWS suggested that the Authority consider the possibility of spreading the costs of the Scheme over a wider cost base to ease the per unit impact, or potentially implementing a cap on the volume of exports that may be eligible for the feed-in tariff, among other cost control options.

7.3 Options for Equitable Sharing of Ongoing Scheme Costs

As discussed in Chapter 3, putting aside the extremely generous 44 cent per kWh feed-in tariff offered to PV customers under the existing scheme which the Government has committed to maintaining, the Authority considers that the existing distributor funded Scheme is flawed, principally because:

(a) the financial benefit retailers receive from exported PV energy is not recognised; and

(b) it imposes the cost of the Scheme on all customers inequitably (via higher average network charges).

Retailer Contribution to Feed-in Tariff Payments

The main cost impact of the Scheme – the value of direct feed-in tariff payments made by the distributors – could be reduced by addressing the first flaw of the Scheme noted above and requiring electricity retailers to make a contribution to the feed-in tariff payments that recognises the benefit they currently obtain from the on selling of exported PV generated power.

Looking forward, the Authority concluded in Chapter 5 that whether, and how much, retailers other than Ergon Energy Queensland choose to pay for PV exports should be left to market participants to decide and not be mandated. Adopting the same approach here will not reduce the costs of the current 44 cent per kWh scheme. Voluntary contributions on offer from retailers under the current Scheme do not reduce the cost of the direct payments made by the distributors or reduce the consequent burden being placed on all other network customers. The current voluntary contributions by retailers simply make an excessively generous scheme even more generous for PV customers.

Mandating a retailer contribution to the current Scheme would go some way to addressing the inequities inherent in the current Scheme. However, as noted by the ESAA, and others it would be forcing all retailers to mitigate the costs of the flawed distribution funded scheme at the expense of consumers.

The Authority agrees with a number of stakeholders that, if a retailer contribution to the existing Scheme is mandated, it is likely that there would be a corresponding reduction in any voluntary market offerings. While the Authority acknowledges that this would reduce the benefits accruing to PV customers, it would also reduce the burden being placed on those unable, or unwilling, to invest in PV panels. Existing PV customers have been assured that they will continue to be entitled to the generous 44 cents per kWh for a further 15 years. This view was shared by QCOSS and Master Electricians Association which considered that the benefits for all customers of reduced pressure on network prices will outweigh the unfavourable outcomes for some individual customers. Similarly, customers receiving the 8 cent per kWh tariff are also being adequately compensated, at a rate that is above the fair and reasonable value estimated by the Authority. However, in any event, the 8 cent per kWh tariff is due to be withdrawn on 30 June 2014.

The Authority considers that if retailers are required to contribute to the costs of the current Scheme, the value of that contribution should be set below the fair and reasonable values the Authority estimated in Chapter 4. This is because setting a mandated contribution too high could adversely affect competition and discourage retailers from offering services to new PV customers. It might also encourage retailers to increase prices to recover the additional costs of the required contribution. Neither outcome would be desirable, or consistent with the terms of reference or the principles established by COAG.

As discussed in Chapters 4 and 5, there are additional problems to consider in the Ergon Energy distribution area. Mandating a feed-in tariff for second tier retailers in the Ergon Energy network area could create a barrier to entry in an area where competition is already very limited. On this basis, the Authority suggests that retailers in the Ergon Energy network area, other than Ergon Energy Queensland, be exempt from making mandatory contributions to the existing Scheme, should the Government take this course of action.

Based on the considerations above, the Authority has estimated the value that might be attached to a mandatory retailer contribution based on wholesale energy purchase costs at regional reference nodes (RRNs) (see Table 7.1). These are likely to be conservative valuations of a possible retailer contribution as they represent the value to the retailer prior to any other avoided costs, network losses, margin or head room. The values in Table 7.1 have been updated to reflect ACIL Tasman's estimates used in the draft determination on notified prices for 2013-14.

Table 7.1: Potential retailer contributions to existing Scheme (2013-14)

	c/kWh
South East Queensland Retailers	6.859
Ergon Energy Queensland	6.333

Source: ACIL Tasman, Estimated Energy Costs for Use in 2013-14 electricity retail tariffs - draft report, February 2013

Impact on Electricity Prices

Currently, the Queensland distribution businesses incur the cost of direct feed-in tariff payments under the Scheme. These costs are then recovered through higher distribution network charges. The cost impacts of direct feed-in tariff payments are discussed in detail in Chapter 6.

The Authority has examined these costs and calculated the potential cost savings from mandating the estimated retailer contributions noted in Table 7.1. These estimates do not represent projections made by the distribution businesses, rather they are an estimate of the potential savings to each distributor from lower net feed-in tariff payments, after the retailer contribution.

To estimate the potential cost savings, the Authority calculated the value of the retailer contributions as a proportion of the 44 and 8 cent per kWh feed-in tariff payments, and applied this as a weighted average to the total projected costs of direct feed-in tariff payments, as advised by the distributors. This is a simple approach but provides a reasonable estimate of the savings to be made by the distribution business.

Based on the Authority's analysis, retailer contributions to the existing 44 and 8 cent per kWh feed-in tariffs could reduce the distributors' annual costs of direct feed-in tariff payments by $41.8 million in 2013-14, with the potential savings declining by around 10% in 2014-15, and around 4% each year thereafter. By the end of the 44 cents per kWh Scheme in 2028, retailer contributions could provide total savings of around $ 447 million. These potential cost savings are set out in Table 7.2.

Table 7.2: Potential reduction in feed-in tariff costs for 44c/kWh and 8c/kWh Schemes from retailer contributions ($m, nominal)

Distributor	*2012-13*	*2013-14*	*2014-15*	*2015-16*	*2016-17*	*2017-18*	*2018-19*	*2019-20*	*2020-28*	***Total***
Energex	168.73	191.23	181.44	174.18	167.21	160.52	154.10	147.94	989.22	2427.87
Ergon Energy	69.74	83.49	64.70	61.70	58.90	56.20	53.60	51.10	332.62	865.58
Total	238.47	274.72	246.14	235.88	226.11	216.72	207.70	199.04	1321.84	3293.45
Potential cost saving	**n/a**	**41.83**	**37.60**	**36.03**	**34.54**	**33.11**	**31.74**	**30.42**	**202.08**	**447.35**

Source: Energex and Ergon Energy
Note: Totals may not add due to rounding. 'Total' column includes costs of $126.8 million incurred between 2010-11 and 2011-12, not shown on this table.

To the extent that the distribution businesses would face lower feed-in tariff payments under a retailer contribution arrangement, the Authority expects that distribution network charges would be lower than they might otherwise be, which would reduce the impact of the Scheme on retail prices.

The Authority estimates that the retailer contributions presented above could reduce the typical residential customer's annual retail bill by up to $50.10 as shown in Table 7.3.

Table 7.3: Impact of Solar Bonus Scheme on Tariff 11 holding other costs constant* ($m, nominal)

	2012-13	***2013-14***	***2014-15***	***2015-16***	***2016-17***	***2017-18***	*2018-19*	*2019-20*
Typical annual T11 bill impact ($)	33.24	66.73	117.78	275.90	254.72	105.88	102.42	97.65
Estimated annual impact after retailer contribution ($)	n/a**	n/a**	n/a**	225.80	209.80	93.84	91.30	87.39
Potential annual saving of retailer contribution on average customer bill ($)	n/a**	n/a**	n/a**	**$50.10**	**$44.92**	**$12.05**	**$11.11**	**$10.26**

* *Costs are presented to 2019-20 - the end of the next distribution regulatory period. The patterns established by the last year of the table will continue through to 2028.*

** *Savings on customer retail bills will not occur until 2015-16 because, prior to this, any retailer contribution will simply reduce the amount of cost under-recovered by Energex.*

Source: Energex and the Authority's analysis

The estimated impacts of a retailer contribution set out in tables 7.2 and 7.3 are notably higher than those estimated in the Authority's Draft Report. This is because the projected costs of the Scheme have been revised upwards by Energex and Ergon Energy in light of new information about the number of new installations and the generating capacity of those installations (see Chapter 6). The estimated amount of retailer contributions has increased commensurately with this increase in total forecast costs. Secondly, the Authority's energy purchase cost estimates taken from the 2013-14 draft determination (on which the retailer contribution amounts are based), are higher than those used in the Draft Report, while the feed-in tariff rates have remained constant in nominal terms. This means the potential per kWh impact of a retailer contribution is relatively higher than that modelled for the Draft Report.

7.4 Other options for managing the ongoing costs of the Scheme

Tariffs and Allocation of Costs

Cost-reflective network tariffs

In its Draft Report, the Authority raised the issue of network tariff structures and how their lack of cost-reflectivity was driving much of the inequity arising from the current Scheme.

The Authority suggested that this flaw could be addressed in part through improved network charges for PV customers. In particular, more cost reflective (fixed and variable) network prices could reduce the extent to which other customers must pay for the network costs PV customers avoid as a result of in-house PV power consumption (as discussed in 6). Similarly, more cost-reflective network prices could reflect other costs of the Scheme, such as administration and infrastructure costs specific to PV installations.

In response, the Clean Energy Council, Queensland Consumers Association, DEWS and a number of individual customers did not support this approach.

DEWS also suggested that, because customers can manipulate their exports to some extent, levying a fixed charge on 44 cent feed-in tariff customers may create an incentive to recover any additional fixed charge by maximising their exports through load shifting. DEWS suggested that this could increase the total cost passed through to electricity customers because the unit cost of the feed-in tariff is higher than the network distribution use of system (DUOS) charge avoided per kilowatt hour from in-house consumption. DEWS stated that this may also place more stress on the network at critical peak times. DEWS was also concerned that the recovery of network costs (such as remediation costs) from solar PV owners would be inconsistent with the Authority's treatment of network costs and benefits and, at a minimum, any fixed charge should be net of the network benefits the Scheme creates.

In contrast, the ESAA considered that the Authority had raised a valid point regarding network tariffs, noting there is merit in giving further consideration to the appropriateness of distribution network charges more broadly. ESAA noted that, over time, the increased penetration of distributed generation (particularly solar PV), coupled with anticipated improvements in network utilisation through time-of-use pricing, may necessitate revisions to current network tariff structures to ensure that costs are equitably recovered from all customers. AGL and Origin Energy also supported a move to more cost-reflective network pricing over time in order to send appropriate signals to customers. AGL noted that any specific PV charge would need to be fully passed through to customers which would require the development of new retail tariffs.

Ergon Energy stated that it is currently undertaking a review of its network tariff strategy and will investigate innovative network (tariff) structures as part of this review. However Ergon Energy and DEWS noted that network businesses are subject to clause 6.18.4(b)(4) of the NER. In simple terms, this clause requires that retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile[31].

The Authority accepts that this requirement, and the limitations suggested by DEWS, may constrain the network business's attempts to implement more efficient network access prices for PV customers specifically. Nevertheless, the Authority would encourage the distributors to seriously consider tariffs for PV customers in the context of broader network tariff reform programs, as Queensland moves to more cost reflective retail pricing during the next three years.

Time-of-use pricing for solar PV customers

In response to the Draft Report, DEWS submitted that encouraging more in-home consumption of PV electricity (rather than encouraging exporting) may provide a better total cost outcome than options to incorporate avoided DUOS charges into pricing for PV customers and suggested that this would effectively reduce the per kWh variable network charge. DEWS suggested that, assuming PV customers are on Tariff 11, the cost to the network of in-house consumption is lost revenue of 10.2 cents per kWh, which represents the variable charge avoided by PV customers. On his basis, DEWS suggested that each kWh of solar energy used in the home, rather than exported, avoids a net cost to the network of 33.8 cents per kWh (being the difference between the avoided feed-in tariff payment and the avoided variable network charge).

The Authority agrees that time-of-use (TOU) retail pricing (for example, Tariff 12) could potentially incentivise greater in-house consumption of PV generation by some customers and remove incentives to maximise the amount of exported energy, therefore saving some costs. However, the conditions needed to achieve this do not appear to be present at this stage. The potential for cost savings from implementing this option depends on:

[31] NER, Clause 6.18.4(b)(4)

(a) the customer's ability to modify their consumption profile by shifting loads from peak periods into PV generating times; and

(b) the power of the incentive for customers to do so.

A customer's ability to shift loads will depend on many practical and lifestyle factors. Some customers will be able to quite easily modify consumption patterns, while others may have requirements which do not allow them to significantly change their usage patterns. To the extent that a customer has an inflexible consumption profile, mandating that they be billed on a TOU basis could produce undesirable and inequitable outcomes.

For those customers who are flexible enough to modify their consumption profile, the next issue is their willingness to do so. This will largely depend on the strength of the economic incentive to shift loads, that is, the price differential between the peak TOU rate and the off-peak TOU rate, and the value that the individual customer attaches to it.

However, the 44 cent per kWh feed-in tariff is a premium rate, which works against the incentives of current TOU retail pricing structures. As the 44 cent per kWh tariff is higher than the Authority's draft 2013-14 residential peak rate for Tariff 12, PV customers on this tariff would still face a financial incentive to export as much energy as possible, rather than shift more consumption into PV generating times.

In fact, as the Tariff 12 shoulder rate (7am to 4pm) of 22.591 cents per kWh (excluding GST) is lower than the flat residential Tariff 11 consumption rate of 23.541 cents per kWh, moving existing 44 cent PV customers from Tariff 11 to Tariff 12 would actually increase the customer's net benefit per kWh of exporting PV energy during daylight hours. To illustrate, a PV customer on Tariff 11 exporting electricity at 44 cent per kWh and buying it back sometime later at 23.541 cents would realise a net benefit of 20.5 cents per kWh. The same customer on Tariff 12, exporting during the day and consuming during the shoulder period at 22.591 cents, would realise a net benefit of 21.4 cents per kWh. Even if the customer exports during the day and consumes at the current peak rate of 30.974 cents, they are still better off by 13 cents per kWh exported[32].

This illustrates that in order for TOU pricing to encourage changes in PV customers' consumption patterns, the peak and shoulder TOU rates for these customers would need to be set above 44 cents per kWh, which is significantly higher than current cost reflective level. This is unlikely to be a sensible solution, particularly given the ongoing transition to greater cost-reflectivity of retail tariffs.

However, TOU pricing would expose PV customers to a more cost reflective fixed charge than they face under current flat residential tariffs. In this regard, it would go some way to reducing the problem of PV customers avoiding a portion of the true cost of their network access due to their net consumption profile, which leads to higher average variable network charges.

Based on current tariff structures, applying TOU pricing to PV customers is unlikely to reduce the costs of direct feed-in tariff payments. The Authority notes that mandating that PV customers to shift to a TOU tariff at this stage could be seen as treating PV customers less favourably than some other small customers, and would need to be considered against the NER requirements at clause 6.18.4(b)(4).

[32] The incentive to defer consumption to the off-peak period (10pm to 7am) is the same as faced by non-PV customers on TOU tariffs. This is because, with the possible exception of the hours between dawn and 7am, the PV customer does not face the opportunity cost of exporting at a rate higher than the prevailing consumption rate during this period.

Increasing the cost recovery base

In response to the Draft Report, DEWS suggested that the Authority should consider whether there is an argument for sharing the feed-in tariff costs across a broader base of network tariff classes, to reduce the per-unit price impact.

The Authority understands that Energex and Ergon Energy's latest projections (as presented in Chapter 6) are based on spreading the feed-in tariff costs across the broadest possible base (all customers, including large customers) therefore it is not clear how the impact could be further diluted through cost allocation. As a result of broadening the base to include large customers, the impact on small customers is decreased, but only by shifting that part of the cost burden onto large customers.

This raises a potential equity issue, as the Scheme is only available to small customers. Requiring large customers to bear some of the costs of the Scheme could be considered inequitable. However, the Authority understands that this allocation of costs is acceptable under the current regulatory arrangements for Energex and Ergon Energy, and the cross-subsidisation of costs in this manner is commonplace in regulated network pricing given the current lack of cost reflectivity. It might also be justified in light of the Authority's view that some other benefits of solar PV exports (such as reduced loss factors and lower wholesale energy prices) should be shared among all electricity consumers.

Ultimately, the issue of how these costs are recovered through regulated network charges is a matter for the distribution businesses, subject to approval by the AER under the requirements of the NER. Notwithstanding the fact that the current distributor funding arrangement is fundamentally flawed, sharing the costs of the Scheme across the broadest customer base is one way to minimise its impact on residential customers. However, the benefit of reduced costs for residential customers needs to be weighed against the added cost burden assumed by large customers.

Limiting the volume of PV exports eligible for feed-in tariff

As suggested by DEWS, another means of reducing ongoing 44 cent feed-in tariff payments would be to cap the volume of exports which may be eligible for the payment. This limit could be calculated over a defined period, for example daily, quarterly or annually. When a customer's PV exports reach the defined export cap, any additional metered exports would not attract the 44 cent feed-in tariff and instead attract no payment, or possibly some other value less than 44 cents per kWh.

To implement this measure, Government would first need to determine the level of the export cap. To provide cost savings relative to the projected costs of the Scheme, the export cap would need to be set below the average, per customer export volume implied in the distributors' cost projections. The relationship between volume of exports and the total feed-in tariff payment is linear (in nominal terms), so to achieve a 10% reduction in projected direct feed-in tariff payments in any given period would require an export cap set at 10% of the average per customer exports, with a zero feed-in tariff for all subsequent exports exceeding the cap[33].

An alternate approach might be some form of 'declining-block' cap, whereby exports attract the 44 cent per kWh tariff up to a defined cap, after which additional exports attract a reduced feed-in tariff rate, for example 8 cents per kWh (rather than zero). Various

[33] Importantly, this assumes that all feed-in tariff costs are recovered through network revenues in the year they are actually incurred. As discussed in the next section, this correlation is lost when actual costs exceed forecasts for any given year.

permutations of export cap values and subsequent declining blocks for excess exports could be modelled and would provide different potential cost savings.

These solutions would also reduce the incentives for customers to focus on exporting as much energy as possible at the premium 44 cent rate, and use more energy in-house. Importantly, it would also weaken the incentive for customers to significantly expand their existing systems purely with the intention of profiting from the generous 44 cent feed-in tariff, which was certainly not the intent of the Scheme in the first place.

However, this is really a decision for Government as it has indicated its intention to keep the Scheme and introducing an export cap arrangement could be seen as a fundamental change to the benefits available to existing Scheme participants.

Transferring feed-in tariff payment liabilities to Government

While outside of the Minister’s Direction and not strictly a direct cost saving measure, the Government could consider transferring the liability to pay feed-in tariffs under the 44 cent per kWh Scheme from the distributors to the Queensland Government, to improve the equity of how those costs are recovered from customers.

Shifting the obligation to pay direct feed-in tariff payments from the network businesses to the Government changes who ultimately pays for feed-in tariff costs. Recent analysis reveals that the funding of the current Scheme is highly regressive, that is, the incidence of the cost impacts of the Scheme are inversely correlated to income[34]. In fact, this analysis found that the implied tax rate for low income households is 3.4 times higher than those households in the highest income bracket[35]. If paid by Government, the costs of the Scheme would be funded by state taxes, not through regulated network charges which apply indiscriminately to all electricity consumers, regardless of their income or capacity to pay. This could moderate the regressive nature of the current Scheme. However, in doing so, it would shift the burden to those who pay state taxes (land tax, payroll tax, royalties and duties) which may in turn raise further questions of equity depending on the ultimate incidence of those taxes.

The Authority notes that moving the existing Scheme to a Government funded model would also bring it into closer accord with the COAG National Principles, which state that:

> *...any jurisdictional or cooperative decision to legislate rights for small renewable customers to receive more than the value of their energy must:*
>
> *c) give explicit consideration to compensation from public funds or specific levies rather than cross-subsidised by energy distributors or retailers; and*
>
> *d) not impose a disproportionate burden on other energy consumers without small renewable generation.*

The Authority's Position

With the exception of a mandatory contribution from retailers and more appropriate tariff structures, there is no other clear solution for minimising the ongoing costs of the Scheme, while producing outcomes that are consistent with both the terms of reference and the COAG National Principles.

[34] Nelson, T., Simshauser, P. and Nelson, J. *Queensland solar feed-in tariffs and the merit order effect: Economic benefit, or regressive taxation and wealth transfers?* Economic Analysis and Policy, Vol. 42 No. 3, December 2012.
[35] *ibid.*

While a cap on eligible exports would be an effective cost control measure, this could be argued to be a fundamental change to the benefits available to existing Scheme participants. That said, if the Government was to open to changing the Scheme in such fundamental way, the simplest approach to minimising ongoing costs would be to directly reduce the existing statutory feed-in tariff rate.

Of the options discussed in this Chapter, the Authority considers the most realistic approach would be a mandatory retailer contribution to the distributor funded 44 cent per kWh direct feed-in tariff costs, with the contribution set at the estimated wholesale energy cost and reviewed annually as part of the determination process for notified prices, coupled with a requirement for PV customers to move to Tariff 12.

The Government could also consider the merits of moving the funding liability (in whole or in part) for the Scheme from electricity consumers to the general taxpayer as this may be a less regressive funding model.

APPENDIX A: MINISTERIAL DIRECTION AND COVERING LETTER

QUEENSLAND GOVERNMENT

Office of the Minister for Energy and Water Supply

QLD COMPETITION AUTHORITY
13 AUG 2012
DATE RECEIVED

Ref: EWS/001493
MC11288

Level 13 Mineral House
41 George Street Brisbane 4000
PO Box 15456 City East
Queensland 4002 Australia
Telephone +61 7 3896 3691
Facsimile +61 7 3012 9115
Email energy&water@ministerial.qld.gov.au

7 August 2012

Mr Brian Parmenter
Chairman
Queensland Competition Authority
GPO Box 2257
Brisbane Qld 4001

Dear Mr Parmenter

I refer to the Government's recent decision to change the Queensland Solar Bonus Scheme (the Scheme) to reduce the credit amount for electricity produced by small photovoltaic (PV) generators (known as the feed-in tariff) from 44 cents to 8 cents per kilowatt hour (c/kWh) for new customers of the Scheme from 10 July 2012.

As part of this decision, the Government announced its intention to task the Queensland Competition Authority (QCA) with investigating a fair and reasonable value for exported energy from small scale solar PV system in Queensland.

I now direct the QCA to conduct an investigation into the establishment of a fair and reasonable value for electricity generated from small scale solar PV generators and exported to the Queensland electricity grid, as well as the mechanisms for its implementation. This direction is authorised under section 253AA of the *Electricity Act 1994*.

I attach my direction and the Terms of Reference which impose conditions on the QCA when undertaking the directed function. Consistent with the Terms of Reference, the Authority is required to undertake an open consultation process with all relevant parties and consider all submissions received within the consultation period.

The Authority must publish an issues paper no later than September 2012, its draft report by late November 2012, and its final report by 22 March 2013. The Government will give consideration to the QCA recommendations in a further review of the Scheme by 30 June 2013.

/2

-2-

Background

The Solar Bonus Scheme was established in 2008 with the aims of making solar power more affordable for Queenslanders, stimulating the solar power industry and encouraging energy efficiency. The Scheme pays eligible households and other small customers for the surplus electricity generated from solar PV panel systems, which is exported to the Queensland electricity grid. The cost of the feed-in tariff (FiT) is passed through to the electricity bills of Queensland electricity consumers.

Exponential growth in customer connections to the Scheme has escalated its costs well in excess of the allowances in the Queensland Distribution Determination 2010-11 to 2014-15. At the end of June 2012, approximately 504 MW of solar photovoltaic (PV) capacity had been connected to Queensland networks and around 190,000 small electricity customers are participating in the scheme.

Changes were recently made that reduce the FiT to limit the long-term cost of the Scheme and its associated impact on electricity bills. From 10 July 2012, new customers who are eligible for the Scheme will receive a FiT of 8 c/kWh, which will be legislated to end on 1 July 2014.

All Australian States and Territories with solar FiT schemes in place have reviewed their premium FiT schemes and subsequently reduced, capped, or withdrawn them following concerns regarding the high rate of growth of the industry and scheme costs. In 2011 and 2012, South Australian, New South Wales and Victorian Governments respectively tasked the Essential Services Commission of South Australia, the Independent Pricing and Regulatory Tribunal, and the Victorian Competition and Efficiency Commission to determine fair and reasonable FiT rates for household solar PV generation in their respective jurisdictions.

In a communiqué of 8 June 2012, Australia, State and Territory Energy and Resource Ministers announced that the Standing Council on Energy and Resources (SCER) was considering the merits and options for developing guidelines for a consistent national approach to fair and reasonable FiT for micro-renewable generation, including solar PV. SCER has tasked officials to prepare advice on options to achieve a consistent national framework for determining 'fair and reasonable' tariffs that jurisdictions may adopt. The framework would provide guidance to what constitutes a minimum tariff that may be offered by retailers to ensure a 'fair and reasonable' return to micro-generation owners for electricity supplied into the grid. The advice will also cover possible options to implement a national framework.

If you have any questions about my advice to you, Mr Benn Barr, General Manager, Energy Sector Reform of the Department of Energy and Water Supply will be pleased to assist you and can be contacted on telephone 3225 8305.

Yours sincerely

[redacted]

Mark McArdle MP
Minister for Energy and Water Supply

Att

ELECTRICITY ACT 1994
Section 253AA

As the Minister for Energy and Water Supply, pursuant to section 253AA of the *Electricity Act 1994*, I hereby direct the Queensland Competition Authority (the Authority) to conduct review into the establishment of a fair and reasonable value(s) for electricity generated from small scale solar photovoltaic (PV) generators and exported to the Queensland electricity grid, in accordance with the following Terms of Reference.

Terms of Reference

1) Matters to be considered

The Authority is to investigate and report to Government on:

a. a fair and reasonable value for energy generated by small scale solar PV systems and exported to the Queensland electricity grid;
b. the mechanisms by which a fair and reasonable value/values could be implemented in Queensland;
c. a retailer contribution to the cost of the Scheme that reflects the benefit to retailers of the energy produced by small scale solar PV generators connected to the grid; and
d. updated costs of the Scheme and any options by which to minimise or more equitably share these costs.

For the purposes of these Terms of Reference a small scale solar PV system is defined as solar PV embedded generators which complies with the Australian Standard AS4777, with an inverter with ratings up to 10 kilovolt-ampere (kVA) for single phase units, or up to 30 kVA for three-phase units. The Queensland electricity grid encompasses the Queensland distribution networks of Energex, Ergon Energy and Essential Energy.

In its investigations into (a) the QCA should have regard to the following factors:

- there must be no consequential increase in electricity prices in Queensland or cost to the Queensland Government budget;
- the Council of Australian Governments (COAG) First National Principle for Feed-in Tariffs, and concept of 'fair and reasonable' value;
- the geographical location at which the solar PV energy is generated and value of that energy in the local network;
- complementarity with the carbon pricing mechanism; and
- consistency with the operation of a competitive Queensland electricity market.

As part of its investigation and report, the Authority is also to consider:

- the benefit gained by electricity customers, electricity distributors and/or electricity retailers from electricity produced from small scale solar PV, for example in remote areas of the Ergon Energy network where high energy supply costs may be offset, or the value to the distribution business of any network investment deferral in those networks;
- the benefit of net versus gross metering arrangements;
- the renewable buyback Scheme operated by Horizon Power in Western Australia, which from 1 July 2012 offers feed-in tariff rates that vary geographically and include stringent connection requirements; and
- other issues the Authority deems relevant.

In its investigations into (b), the QCA is to consider and report on:

- implementation options within the Queensland electricity market, including:

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  - as a mandated 'default minimum price' or price range;
  - as set by the market;
  - as a recommended price range.
- support for a competitive electricity market in Queensland, and any specific arrangements required / barriers to implementation in the Ergon Energy distribution area;
- the need for certainty for small scale solar PV owners;
- appropriate review mechanisms and timeframes;
- potential transition to a national feed-in tariff if established through COAG processes; and
- similar pricing and mechanisms in other jurisdictions and findings from other jurisdictional feed-in tariff reviews.

2) Consultation

The QCA should consult with stakeholders, and consider submissions, within the timetable for investigating a fair and reasonable FiT and publishing the issues paper, draft and final reports. The Authority must make its reports available to the public.

3) Timing

a) *Issues Paper*

The Authority must publish an issues paper outlining the issues associated with its investigation no later than September 2012.

b) *Draft Report*

The Authority must publish a draft report on its investigation into a fair and reasonable value for electricity generated from small scale solar PV generators no later than November 2012.

The Authority must publish a written notice inviting submissions about the draft report. The notice must state a period (the *consultation period*) during which anyone can make written submissions to the Authority about issues relevant to the draft report. The Authority must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

c) *Final Report*

The Authority must publish a final report on its investigation into a fair and reasonable value for electricity generated from small scale solar PV generators no later than 22 March 2013.

MARK McARDLE

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APPENDIX B: COAG'S NATIONAL PRINCIPLES FOR FEED-IN TARIFF SCHEMES

COUNCIL OF AUSTRALIAN GOVERNMENTS MEETING

CANBERRA

29 November 2008

National Principles for Feed-in Tariff Schemes

Micro renewable generation to receive fair and reasonable value for exported energy

1. That Governments agree that residential and small business consumers with small renewables (small renewable consumers) should have the right to export energy to the electricity grid and require market participants to provide payment for that export which is at least equal to the value of that energy in the relevant electricity market and the relevant electricity network it feeds in to, taking into account the time of day during which energy is exported.

Any premium rate to be jurisdictionally determined, transitional and considered for public funding

2. That any jurisdictional or cooperative decisions to legislate rights for small renewable consumers to receive more than the value of their energy must:
   a) be a transitional measure (noting that a national emissions trading system will provide increasing support for low emissions technologies), with clearly defined time limits and review thresholds;
   b) for any new measures, or during any reviews of existing measures, undertake analysis to establish the benefits and costs of any subsidy against the objectives of that subsidy (taking into account other complementary measures in place to support small renewable consumers);
   c) give explicit consideration to compensation from public funds or specific levies rather than cross-subsidised by energy distributors or retailers; and
   d) not impose a disproportionate burden on other energy consumers without small renewable generation.

MCE to continue to advance fair treatment of small renewables

3. That the Ministerial Council on Energy (MCE) should continue to implement the regulatory arrangements for small renewable customers, consistent with the objectives of the relevant electricity legislation, whereby the:
    a) terms and conditions for PV customers should be incorporated into the regulation of the minimum terms and conditions for retail contracts such that they are no less favourable than the terms and conditions for customers without small renewables;
    b) connection arrangements for small renewables customers should be standardised and simplified to recognise the market power imbalance between small renewable customers and networks; and
    c) assignment of tariffs to small renewable consumers should be on the basis that they are treated no less favourably than customers without small renewables but with a similar load on the network.

FiT policy to be consistent with previous COAG agreements (particularly the Australian Energy Market Agreement)

4. That the arrangements for PV consumers by the MCE and jurisdictions:
    a) should not deter competition for their business from electricity retailers in jurisdictions where there is full retail contestability and innovation in the tariff offerings available to PV customers;
    b) in relation to jurisdictions in the National Electricity Market, should not interfere with the regulation of distribution tariffs or operation of the national electricity market under the National Electricity Law or duplicate the regulatory arrangements that are part of that Law;
    c) should be subject to independent regulatory oversight according to clear principles; and
    d) should be consistent with implementation of other intergovernmental agreements relating to energy, competition policy or climate change.

APPENDIX C: STAKEHOLDER SUBMISSIONS

The Authority received 39 formal submissions on the Issues Paper and 16 formal submissions on the Draft Report. Submissions can be viewed on the Authority's website at www.qca.org.au.

Table C.1: Submissions in response to the Issues Paper

Stakeholder submissions	
AGL Energy Limited	D. Maddock
Australian PV Association	S. Muneshi
Australian Solar Council	Origin Energy
Alternative Technologies Association	Queensland Consumers Association
P.G. Atherton	QCOSS
B. Bartlett	S. Robertson
S. Beames	D. Rogers
T. Berrill	J & T Russo
I. Brimblecombe	G. Sanders
R.J Campbell	K. Smith
F & J Cipriani	Solar Business Council Inc
Clean Energy Council	Solar Energy Industries Association
Energex Limited	R. Sproxton
Energy Retailers Association of Australia	Stanwell Corporation Limited
Energy Supply Association of Australia	Suntech Power Australia Pty Ltd
Ergon Energy	SunWiz Consulting
I.H & C Herbert	The Solar Guys
R & G Hussey	T. Miles
Infinity Solar	TRUenergy Pty Ltd
L & S Jones	

Table C.2: Submissions in response to the Draft Report

Stakeholder submissions	
AGL Energy Limited	Origin Energy
G. Bell	H. Paull
Clean Energy Council	Queensland Consumers Association
EnergyAustralia	QCOSS
Energy Supply Association of Australia	Springers Solar
Ergon Energy	A. Wilson
Master Electricians Australia	National Generators Forum
T. Miles	Department of Energy and Water Supply (Qld Govt)

APPENDIX D: CALCULATION OF LOSS FACTORS AND AVOIDED LOSSES

Ergon Energy Network Area

In Chapter 4, the Authority used a single network loss factor to value avoided losses from PV exports across the entire Energex network area. However, given the scale and diversity of the Ergon Energy network, there is an opportunity to improve on that approach to better reflect the value of PV at different locations on its network.

The Authority estimated six different feed-in tariffs for Ergon Energy which attempt to capture the value of avoided energy purchase costs by using the marginal loss factors and distribution loss factors for different areas of the Ergon Energy network. The methodology draws on the existing ways in which Ergon Energy considers network losses for the purposes of applying its network charges to individual customers.

How Ergon Energy Accounts for Network Losses

Network pricing zones

For the purposes of distribution network pricing, Ergon Energy divides its network into three pricing zones based on broad geographical regions - East, West and a third zone which covers the isolated Mt Isa-Cloncurry network. These zones are broadly based on local government boundaries, with some exceptions where individual network feeders are not wholly situated within those boundaries. For the reasons discussed in Chapter 4, the Authority has not recommended a mandatory minimum fair and reasonable feed-in tariff for the Mt Isa-Cloncurry network area.

These zones are used to reflect the differences in costs of supplying electricity between the more densely populated Eastern coastal regions of Queensland (east of the Great Dividing Range), and the more sparsely populated regions of Western Queensland (west of the Great Dividing Range) which have much longer distribution feeders and more remote loads.

According to Ergon Energy, the East zone accounts for around 90% of its customer base, while the West zone accounts for 8%. The Mt Isa zone represents 2% of total customers in the Ergon Energy network area[36]. Table D.1 shows the general locations that fall within each pricing zone.

[36] Ergon Energy, *Network Management Plan-Part A: Electricity Supply for Regional Queensland 2012-13 to 2016-17*. p.12,15

Table D.1: Ergon Energy Network Pricing Zones

Zone	*Included areas*	*Other areas and exceptions*
East Zone *Regional Councils*	Bundaberg, Cassowary Coast, Fraser Coast. Gladstone, Mackay, North Burnett, Rockhampton, South Burnett, Southern Downs, Toowoomba, Whitsunday, Townsville City Council	Cairns –excluding areas north of Daintree River; Gympie – Ergon Energy area only; Isaac – excluding areas of Moranbah Township; Western Downs - Dalby Township and Wambo district; Central Highlands – excluding Emerald and areas west of Emerald; Tablelands – excluding Herberton and Mareeba areas not supplied by east distribution system
Shire Councils	Banana, Burdekin, Hinchinbrook, Cherbourg, Woorabinda, Yarrabah	
West Zone *Regional Councils*	Barcaldine, Blackall-Tambo, Charters Towers, Longreach, Maranoa	Barcoo – NEM connected areas only; Cairns – North of Daintree River only; Goondiwindi (Ergon Energy area only); Isaac – west of Moranbah township only; Western Downs – excluding Dalby township and Wambo District; Central Highlands – Emerald and areas west of Emerald; Tablelands – Herberton and Mareeba areas not supplied by east distribution system
Shire Councils	Balonne, Bulloo, Carpentaria, Cook, Croydon, Etheridge, Flinders, Hope Vale, McKinlay, Murweh, Paroo, Quilpie, Richmond, Winton, Wujal Wujal	
Mt Isa Zone *Shire Councils*	Cloncurry Shire Council, Mount Isa City Council	Areas of Burke and Boulia Shire Councils supplied by the Mt Isa system

Source: Ergon Energy, Network Tariff Guide of Standard Control Services 1 July 2012 to 30 June 2013. 9 July 2012.

Transmission regions

Ergon Energy also divides its network area into three transmission use of system (TUOS) regions which reflect the different costs incurred by delivering high-voltage electricity over the transmission network in regional Queensland. These regions are used for allocating TUOS charges to customers.

The Authority understands that the three TOUS regions are broadly defined by distance from the regional reference node in order to reflect the impact of losses. Given the linear orientation of Powerlink's 275 kV transmission network in regional Queensland, losses would be expected to become more significant as latitude decreases. The TUOS regions are not relevant to the Mt Isa pricing zone as it is an isolated distribution system and is not supplied by Powerlink's transmission network.

Calculating transmission losses

Transmission losses are reflected in marginal loss factors measured at each transmission connection point (TCP) on the Powerlink transmission network. These marginal loss factors reveal the average losses incurred when transporting electricity from the regional reference node to each TCP[37].

The Authority's methodology for estimating transmission losses involves determining which TCPs align with each TUOS region and pricing zone, before calculating a volume-weighted average marginal loss factor for each TUOS region and network pricing zone, based on historical load data for the TCPs.

Allocating TCPs to TUOS regions and pricing zones

To allocate TCPs to the relevant TUOS regions, the Authority referred to the list of TCPs published in Ergon Energy's network tariff guide for 2012-13. This lists each TCP, its transmission node identifier, and the TUOS region it relates to[38].

Each TCP was then allocated to either the East or West pricing zone using a high-level mapping approach to reconcile the geographical location of each TCP with Ergon Energy's published zone map and zone definitions[39].

Marginal loss factors

The Authority then examined the 2012-13 marginal loss factors for each relevant TCP in the Ergon Energy area, as published by AEMO[40]. From this point, a load-weighted average marginal loss factor for the group of TCP's in each of Ergon Energy's three TUOS regions was calculated, for both the East and West pricing zones, as set out in Table D.2.

The Authority did not have information about TCP's in TUOS region three of the West pricing zone. In the absence of these data, the estimated transmission losses in the West zone-TUOS region three have been proxied by the estimated marginal loss factor for East zone-TUOS region three.

As noted, the design of the transmission network means that the magnitude of losses will tend to be inversely proportional to the latitude of the relevant transmission connection point. On this basis it seems reasonable to assume that average marginal losses for TCPs in TUOS region three will be similar regardless of the pricing zone in which they are physically located. However, the Authority understands there may be some exceptions to this, particularly if TCPs are located on lower voltage transmission lines (132/110 kV) which extend laterally from the main 275 kV backbone.

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[37] The Queensland regional reference node is Powerlink's South Pine 275kV bulk supply point, located in the northern Brisbane suburb of Brendale.
[38] See Ergon Energy, *Network Tariff Guide for Standard Control Services, 1 July 2012 to 30 June 2013*. 9 July 2012. p 34.
[39] See Ergon Energy, *Network Tariff Guide for Standard Control Services, 1 July 2012 to 30 June 2013*. 9 July 2012. pp. 14-15.
[40] AEMO, *List of Regional Boundaries and Marginal Loss Factors for the 2012-13 Financial Year*. 12 June 2012.

Table D.2: Load-Weighted average marginal loss factors for Ergon Energy

TUOS Region	*East Zone*	*West Zone*
T_1	1.0143	1.0415
T_2	1.1008	1.1006
T_3	1.1380	1.1380

Sources: QCA analysis; AEMO, List of Regional Boundaries and Marginal Loss Factors for the 2012-13 Financial Year. 12 June 2012; Ergon Energy, Network Tariff Guide of Standard Control Services 1 July 2012 to 30 June 2013. 9 July 2012.

Calculating distribution losses

The next step is to identify the relevant distribution losses that are incurred in each network pricing zone.

Distribution losses are predominately a function of distance between the load and the point where the distribution network joins the TCP. The impact of these losses is reflected in average distribution loss factors at different points on the distribution network, which are used to calculate DUOS and TUOS charges for Ergon Energy's distribution customers. The size and complexity of Ergon Energy's distribution network gives rise to a number of loss factors at different network levels across its area. These distribution loss factors are approved annually by the AER and are available in Ergon Energy's 2012-13 network tariff guide. The approved average distribution loss factors for each network pricing zone are set out in Table D.3 below.

Table D.3: Ergon Energy distribution loss factors (2012-13)

Network level	*East Zone*	*West Zone*
Sub transmission Bus	1.007	1.044
Sub-transmission Line	1.016	1.091
22/11 kV Bus	1.018	1.097
22/11 kV Line	1.038	1.133
Low Voltage (LV) Bus	1.077	1.185
Low Voltage (LV) Line	1.078	1.357

Source: Ergon Energy, Network Tariff Guide of Standard Control Services 1 July 2012 to 30 June 2013. 9 July 2012.

These values illustrate the significant difference in average losses across the distribution network area, between the TCPs and the customer. For standard small residential customers (represented at the 'LV Line' network level) in the East zone, about 7.8% of electricity is lost over the network. In contrast, the average energy lost when supplying customers in the West zone is estimated at 35.7%.

As distribution loss factors for 2013-14 will not be published by AEMO until 1 April 2013, the Authority has used the published 2012-13 values as the best available estimates of loss factors to apply for this Final Report.

Calculating combined network losses

From this point it is possible to determine the total average losses between the regional reference node and the solar PV customer.

To derive the total network losses, a combined loss factor for each TUOS region and pricing zone is calculated, as the product of the load-weighted average marginal loss factors (see Table D.2) and Ergon Energy's published average distribution loss factors for each pricing zone, at the LV line level (see Table D.3). The LV line level was selected, as it represents the network level at which most small-scale solar PV customers are connected. The estimated combined loss factors are set out in Table D.4.

Table D.4: Average combined loss factors for Ergon Energy (2012-13)

TUOS Region	*East Zone*	*West Zone*
T_1	1.0934	1.4134
T_2	1.1866	1.4935
T_3	1.2268	1.5443

Sources: QCA analysis; AEMO, List of Regional Boundaries and Marginal Loss Factors for the 2012-13 Financial Year. 12 June 2012; Ergon Energy, Network Tariff Guide of Standard Control Services 1 July 2012 to 30 June 2013. 9 July 2012.

Application of Losses to Wholesale Energy Purchase Cost Estimates

Ergon Energy network area

The Authority applied the six combined loss factors in Table D.4 to the wholesale energy purchase cost estimates at the regional reference node. This returns the total avoided wholesale energy purchase costs per kWh, including the value of avoided transmission and distribution losses between the node and the solar PV customer, for each pricing zone. This is derived using the following formula:

$$Value\ of\ Losses_{T_n}^{Z} = \frac{WEPC_{RNN}}{\{1 - (MLF_{T_n} * DLF_Z)\}}$$

Where:

T_n	is the Ergon Energy TUOS region (1,2 or 3)
Z	is the Ergon Energy network pricing zone (East or West)
$WEPCR_{NN}$	is the wholesale energy purchase cost at the regional reference node, including NEM and ancillary services fees
MLF	is the weighted average marginal loss factor calculated by the Authority
DLF	is the average distribution loss factor at the LV Line network level

This calculation produces six discrete values of avoided energy purchase costs for different geographical areas which vary depending on the degree of transmission and distribution losses incurred in supplying electricity at the low voltage network level. The calculation of these values for each pricing zone for 2013-14 is set out in Tables D.5 and D.6.

Table D.5: East Pricing Zone - Avoided wholesale energy purchase costs

East Pricing Zone	*TUOS Region 1*	*TUOS Region 2*	*TUOS Region 3*
Load-weighted average marginal loss factor (from Table D.2)	1.0143	1.1008	1.1380
Ergon Energy average distribution loss factor (from Table D.3)	1.078	1.078	1.078
Total average combined loss factor	1.0934	1.866	1.2268
WEPC (c/kWh)	6.333	6.333	6.333
Plus NEM and ancillary services fees (c/kWh)	0.071	0.071	0.071
$WEPC_{RNN}$ (c/kWh)	6.404	6.404	6.404
Losses (%)	9.341	18.664	22.679
Value of losses (c/kWh)	0.660	1.469	1.878
Total avoided energy purchase costs (c/kWh)	**7.064**	**7.873**	**8.282**

Table D.6: West Pricing Zone - Avoided wholesale energy purchase costs

West Pricing Zone	*TUOS Region 1*	*TUOS Region 2*	*TUOS Region 3*
Load-weighted average marginal loss factor (from Table D.2)	1.0415	1.1006	1.1380
Ergon Energy average distribution loss factor (from Table D.3)	1.357	1.357	1.357
Total average combined loss factor	1.4134	1.4935	1.5443
WEPC (c/kWh)	6.333	6.333	6.333
Plus NEM and ancillary services fees (c/kWh)	0.071	0.071	0.071
$WEPC_{RNN}$ (c/kWh)	6.404	6.404	6.404
Losses (%)	41.337	49.351	54.431
Value of losses (c/kWh)	4.513	6.240	7.649
Total avoided energy purchase costs (c/kWh)	**10.917**	**12.644**	**14.053**

Energex network area

To estimate the value of avoided losses accruing to the retailer, the Authority used the loss factors for Energex as used in its draft determination on notified prices for 2013-14, set out in Table D.8. These loss factors reflect the transmission losses and AER approved distribution loss factors for 2012-13. The total combined loss factor is calculated as the product of transmission losses and distribution losses.

Table D.8: Loss factors for Energex network area - 2012-13

Settlement class	*Transmission Loss Factor*	*Distribution Loss Factor*	***Combined Loss Factor***
Energex NSLP	1.010	1.062	**1.072**

Source: ACIL Tasman, Estimated energy costs for use in 2013-14 electricity retail tariffs- Draft Report, February 2013

Due to the different methodology used to calculate the value of PV in the Energex area, this loss combined factor is not used to directly estimate the value of avoided losses from on-selling of PV exports. Rather, the loss factor is applied to the total (avoidable and unavoidable) wholesale energy purchase costs at the regional reference node, based on the Authority's draft cost reflective residential tariff for 2013-14. The loss factor is applied using the following equation, consistent with ACIL Tasman's approach to calculating losses for the Authority's Draft Determination on notified prices for 2013-14[41].

$$WEPC = \frac{WEPC_{RNN}}{(1 - CLF)}$$

Where:

WEPC is the total wholesale energy purchase cost, including the value of transmission and distribution losses

$WEPCR_{NN}$ is the total wholesale energy purchase cost at the regional reference node, including NEM and ancillary services fees, and green scheme costs

CLF is the combined loss factor reflecting transmission and distribution losses between the regional reference node and the customer

As illustrated in Table D.9 below (from Chapter 4), the direct financial benefit to the South East Queensland retailer from on-selling PV exports is calculated as the difference between the assumed on-selling retail price and the sum of unavoidable costs. In this sense, the value of avoided losses is indirectly implied in the calculation of the direct financial benefit to the retailer of PV exports.

[41] ACIL Tasman, *Estimated energy costs for use in 2013-14 electricity retail tariffs- Draft Report*, February 2013.

Table D.9: Estimated fair and reasonable value PV exports in SEQ (2013-14)

Cost Component	*Retail Cost (c/kWh)*	*Unavoidable Costs (c/kWh)*
Wholesale electricity costs	6.859	-
Green Scheme costs	1.002	1.002
NEM and ancillary services fees	0.070	-
Prudential Capital	0.063	0.063
Subtotal	*7.994*	1.065
Plus losses (7.2%)[1]	0.624	-
Plus network costs	12.593	12.593
Plus margin (5.7%)	1.209	1.209[2]
Subtotal	*22.421*	14.867
Plus head room (5%)	1.121	1.121[2]
TOTAL (excl. GST)[3]	**23.541**	**15.988**
Less unavoidable costs	(15.988)	n/a
Direct Financial Benefit to the Retailer	**7.553 c/kWh**	

Note: Totals may not add due to rounding
1. Calculation of loss factors are discussed in detail in Appendix D.
2. As discussed in section 4.8, the full amounts of retail margin and head room are considered unavoidable.
3. Estimated retail price is based on 2013-14 cost reflective residential tariff.