AUSTRALIAN PV INSTITUTE

*APVI Submission to the Queensland Productivity Commission Draft Report: **Electricity Pricing Inquiry** Feb 2016*

11 March 2016

Summary of APVI Response

The QCA Draft Report for the Electricity Pricing Inquiry makes a valuable contribution to the energy debate at a time of change when more rational debate is needed. However, while supporting a number of the Draft Report's recommendations, the APVI believes there are a number of improvements that could be made.

Monopoly status of networks

Given the increased competition being faced by networks, they should no longer be considered 'natural monopolies' but as 'partial monopolies'. Although there is still a clear need for regulation to place a cap on prices, the current revenue cap also places a floor on prices. It therefore restricts the extent to which competition can reduce the costs that monopolies impose on customers.

The revenue cap can be decreased by actions that reduce the size of the Regulated Asset Base (RAB), using methods that do not necessarily involve artificially writing down the RAB. Despite this, the Draft Report does not make any specific recommendations for policies, programs or procedures to place downward pressure on the size of the network (which could reduce its rate of expansion, or even in certain locations, reduce its size during future refurbishment).

Cost-reflective tariffs

Despite emphasising the importance of cost-reflective tariff design, the QPC appears to make no efforts to ensure that the networks' cost-reflective tariffs are in fact cost-reflective. In the body of this submission we show that neither Energex's nor Ergon's demand charge-based tariffs are anything like cost-reflective.

One consequence of this is that batteries, and similar load control devices, are most likely to be programmed to operate in such a way that they will do little to reduce network peaks. The current demand-charge tariffs could, at the same time, result in significant dead weight losses for customers.

Renewable Energy Target's impact on customer bills

Assessing the impact of policies such as the RET is more complicated that simply adding the LGC price to household bills. The combination of LGC costs and the merit order effect result in more transfers than costs, and even the QPC's own modelling shows a QRET would result in an average of only 0.5% increase to customer bills, which (i) pales into insignificance compared to the 87% increase in the last 10 years, and (ii) still results in a net decrease over the forward period.

Comparing abatement costs of the QRET to the ERF

The Draft Report makes the mistake of assuming that a certificate price is the same as the cost of abatement. In the body of this submission we show that the actual additional abatement driven by the Emissions Reduction Fund (ERF) is much less than claimed by the Commonwealth Government, and as a result the cost of abatement is significantly higher. In contrast, the amount of renewable energy generated under a RET is readily measureable and would not have occurred otherwise. As a result, the abatement driven by a RET is much more measurable and certain.

PV's ability to reduce demand peaks

The Draft Report sometimes states that PV does reduce demand peaks and sometimes states that it doesn't. There is a significant amount of well-documented evidence provided by network operators that PV reduces network demand peaks – both at the feeder and system-wide level. This is documented in the body of our submission. For example, at a system-wide level, the peak for Qld for 2015/16 to date was on Tues 2 Feb and PV reduced it from 9,576MW to 9,062, a reduction of 5.36%.

Of course, the problem is that the degree to which PV may reduce demand peaks is uncertain. If true cost-reflective tariffs were implemented (that is, tariffs which really did reflect the cost of network augmentation, as discussed in the Section 'Cost-reflective Tariffs'), then PV systems would only be rewarded to the extent that they really did reduce demand peaks. As a result, much of the debate around the degree to which PV reduces demand peaks would be unnecessary.

Data availability and analysis

The QPC clearly understands the importance of data collection and analysis. We endorse the importance of tariff studies, not only regarding their impacts on customers, but also regarding their impacts on network demand peaks.

We strongly advise that the data collected by networks be made available to the public. In addition to the public interest groups, the Australian universities and research centres host many very smart paid researchers, as well as students undertaking 4th year theses, Masters and PhDs. They are capable of undertaking very detailed and rigorous analysis, often for free.

General points

Recommendation 11: Rather than simply recommending against Government intervention to achieve a 3GW PV target for Qld, the QCA should look for opportunities to link this target to its many other recommendations concerning vulnerable customers and the concession framework, and thus achieve both outcomes.

Recommendation 36: The QCA could consider supporting online calculators, such as the one recently funded by the National Farmers Federation and NSW Farmers, to facilitate customer understanding of new technologies and tariffs.

Recommendation 38: The APVI supports this recommendation and believes that, in addition to energy efficiency and demand side management, solar PV, wind and batteries should be supported.

Recommendation 41 to 43: The APVI supports these recommendations. The trend to more locally-based service provision has the potential to offer lower cost and more sustainable options to large portions of Queensland.

Recommendation 54: The APVI supports this recommendation. In addition, the Queensland Government should investigate ways to overcome the split incentive problem that inhibits uptake of energy efficiency and demand management technologies, as well as solar PV and batteries when homes and other buildings are not owner-occupied.

Modelling: Beware of placing too much emphasis on modelled scenarios. Considering the transformational change that has occurred in the Australian electricity sector over the last 20 years, projections that 96.6% of the Qld large-scale generation mix will be based on coal and gas-fired generation in future should be treated with great caution.

The ACIL Allen report, that the Draft Report often refers to, should be made available to the public so that the underlying modelling assumptions can be better understood.

The Solar Bonus Scheme: The Draft Report recommends that the SBS be terminated early, however the Qld government has already ruled this option out, and so we have not taken the time to analyse the impact of this recommendation.

Monopoly Status of Networks

A number of times the Draft Report refers to networks as 'natural monopolies', but also acknowledges they are being exposed to greater competitive pressures. For example:

> *"Because the network businesses are natural monopolies, they are not exposed to the same competitive pressures as the generation and retail businesses. Instead, the network businesses are regulated by the AER, which sets an upper limit (a cap) on the amount of annual revenue each business can earn through regulated prices"* (page 64)

Competition comes from both new technologies and business models. For example:

> *"Network businesses are facing competition from new technologies, such as advanced metering, solar PV and batteries."* (page x)

> *"Evidence shows emerging competition from new retail and technology business models"* (page 62)

> *"Competition from emerging regulated products and services (such as solar PV and batteries) has the potential to erode network usage and challenge existing pricing arrangements"* (page 68)

> *"All the network business indicated that the right balance in regulation is important as they are increasingly exposed to competition from unregulated service providers"* (page 73)

Regulation is applied to natural monopolies to ensure they don't abuse their monopoly power and behave contrary to the public interest. In other words, it is to ensure that prices are kept low, with the aim of regulation being to act as a form of 'shadow competition', and ideally achieve prices that would occur in a purely competitive environment.

Given that a natural monopoly is defined as a business where the barriers to entry are too high for alternatives to compete, it is clear that networks can no longer be considered to be pure natural monopolies. It is more accurate to refer to them as 'partial monopolies' or that they have a 'residual role'. They do still retain some monopoly power because: (i) there will still be a significant number of customers who, for various reasons, cannot access the alternatives, (ii) even for most customers who do use one or more alternatives, they will still be reliant on networks to some extent and (iii) there will be benefits in preventing the duplication of expensive network assets.

There is still a need for regulation to place a cap on prices. However, revenue cap regulation, in its current form, also acts as a floor, and so ensures that the networks maintain their revenue stream, irrespective of what happens with demand. The revenue cap therefore restricts the extent to which competition can reduce the costs that monopolies impose on customers. John Stuart Mill would be turning in his grave.

The retail market provides a good corollary. Having some competition amongst some retailers does not necessarily remove the need for a regulated retail price offering, but it does mean that customers should have choice over what they pay and too whom.

We understand this is the realm of the AER, and that the QPC does not control the nature of the revenue cap regulation that networks are subjected to. However, as the QPC makes clear, there is a need for increased competition and a need to ensure that *"the regulatory framework does not impede the efficient deployment of the technologies [advanced metering, solar PV and batteries]"* (QPC, 2016, page x). The aim of this competition is of course to place downward pressure on prices. However, in the context of revenue cap regulation, costs imposed on customers can only reduce in absolute terms if the size of the revenue cap is decreased.

The AER has, with varying degrees of success, reduced networks' revenue cap by focusing on more efficient capital expenditure (the capex incentive guideline, specifically the Capital Expenditure Sharing Scheme) and on how the RAB is used to calculate their Maximum Allowable Revenue (MAR) (the rate of return guideline). However, there is also the potential to reduce the RAB. As the QPC states:

> *"There may be a strong case for a write-down of the RAB, if it can be demonstrated that electricity assets are no longer being used. Where particular assets have become stranded, for example due to obsolescence, oversizing or inappropriate location, it would not be appropriate for electricity users to continue paying for them."* (page 83)

Then, despite the QPC's Draft Recommendation 16 that "Distribution businesses should continue to minimise or defer network capital expenditure by pursuing both tariff and non-tariff demand management programs…", the QPC does not go on to make any specific recommendations for policies, programs or procedures to reduce the size of the network. In fact, throughout the Draft Report, there seems to be an underlying assumption that the size of the networks will simply increase over time, despite the growing evidence that distributed generation, batteries and demand side management are likely to reduce load peaks, and that the "*key challenge for the electricity sector* [having arguably overcapitalised on network infrastructure] *is to find ways to better use this infrastructure*" (page viii).

Even if it is the case that networks do increase in size over time, in order to drive increased competition to achieve least costs for customers, the policies put in place should be capable of doing so whether networks increase or decrease. This does not need to involve artificially writing down the networks' RAB.

For example, more emphasis could be placed on enhancing mechanisms such as the Regulatory Investment Test for Distribution (RIT-D). Although this is a national scheme, it highlights the type of approach and improvements the QPC could explore.

The RIT-D requires DNSPs to consider and assess all credible options before they make an investment decision to address an identified network need. However, there would seem to be some key limitations with current RIT-D arrangements. In particular it does not need to be applied where the project is related only to the refurbishment or replacement of existing assets – and so cannot be used to decrease the size of the network. In addition:

- it only identifies large opportunities to avoid large (>$5 million) network investments, so would exclude a significant proportion of distribution network investment
- the initial decision regarding whether a non-network option should be considered lies with the DNSP
- its effectiveness is very much reliant on non-network stakeholders being actively engaged,
- despite the better regulation reforms and recent downgrades in DNSPs Weighted Average Cost of Capital (WACCs), strong incentives remain for DNSPs to prefer CAPEX over OPEX
- there is no process for non-network solutions to be tested in advance, and
- it includes only economic impacts.

The 2014 Distribution Annual Planning Reports for distributors operating in the Australian National Electricity Market listed some 330 committed or proposed network augmentation projects, and only some 35 proposed RIT-D projects. Of these projects, where either RIT-D or the previous Regulator Test were applied, only 1 resulted in a non-network option, and this was a diesel generator.

Cost-Reflective Tariffs

The Draft Report emphasises the importance of cost-reflective tariff design. It states that electricity tariffs should:

> *"send the right price signals to customers about the costs of permanent connection to the network and about the cost of using the network at peak periods"* (page x)

and that

> *"…. cost-reflective pricing is intended to ensure fairer prices that reflect customer's individual impact on the network, and remove cross-subsidies that see some consumers paying more than their fair share of costs."* (page xiii)

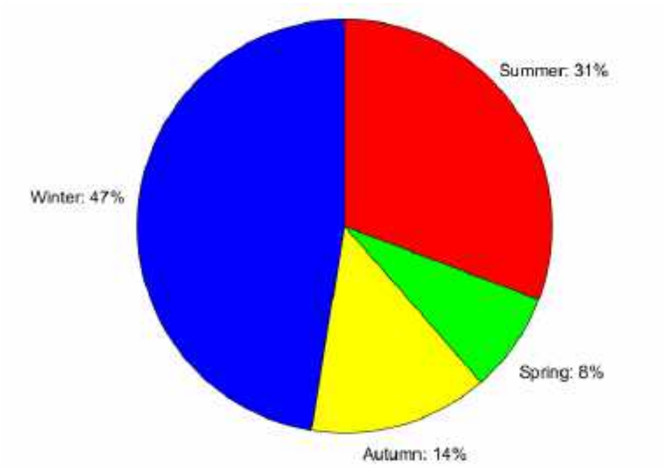
It also highlights

> *"the need for effective price signals for network use to avoid the need for costly infrastructure to meet peak demand, and to ensure all customers are being charged fairly for their use of the infrastructure"* (page 68)

Recommendation 53 states that:

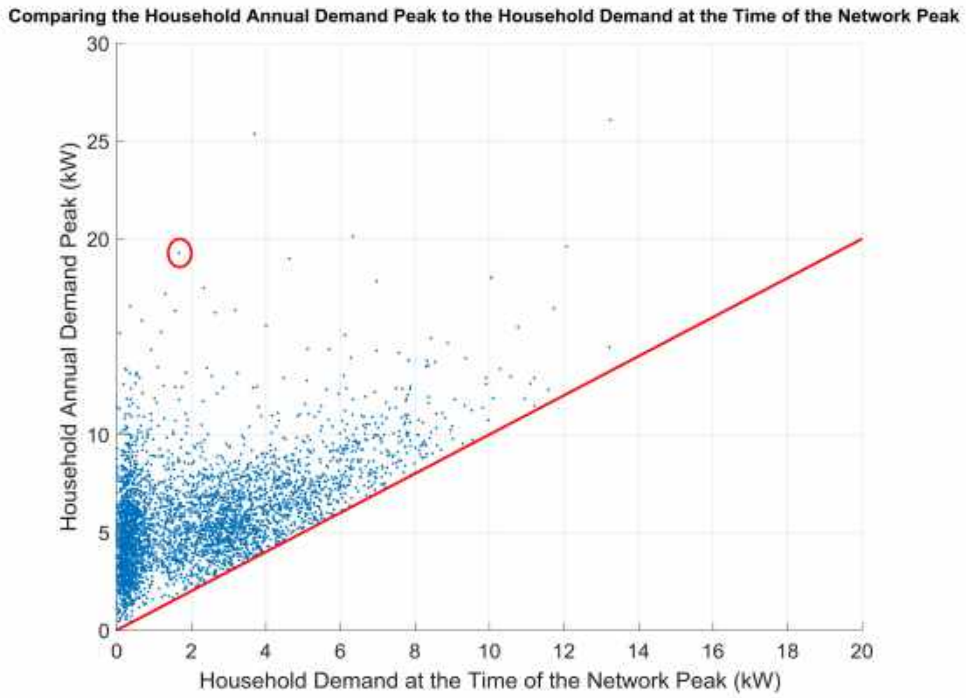
> *"The Queensland Government should establish a working group involving distribution and retail businesses and relevant customer representatives to:*
>
> *- develop new tools to help customers understand the costs and benefits of demand tariffs;*
> *- identify customers vulnerable to the impacts of tariff reform; and*
> *- investigate the requirement for support."*

We wholeheartedly agree with all these statements. Unfortunately the cost-reflective tariffs currently being proposed by Ergon and Energex are not cost-reflective. We have analysed Ergon's and Energex's tariffs proposed for 2016/17 using the load data from 3,876 households from the Smart Grid Smart City database for 2013. Their aggregated load profile, which is a proxy for the load profile of the network that serves them, peaks in summer at 6pm on Fri 18 Jan. As shown in the chart below, about half of the individual houses actually peak in winter, with only 31% peaking in summer.



The following chart then compares each household's annual demand peak with each household's demand at the time of the network peak (which is what causes the network peak). All the households above the red line have an annual peak that is greater than their demand during the network's annual peak. For example, the red circled point has an annual peak of 19.3kW but was contributing only 1.7 kW during the network peak.

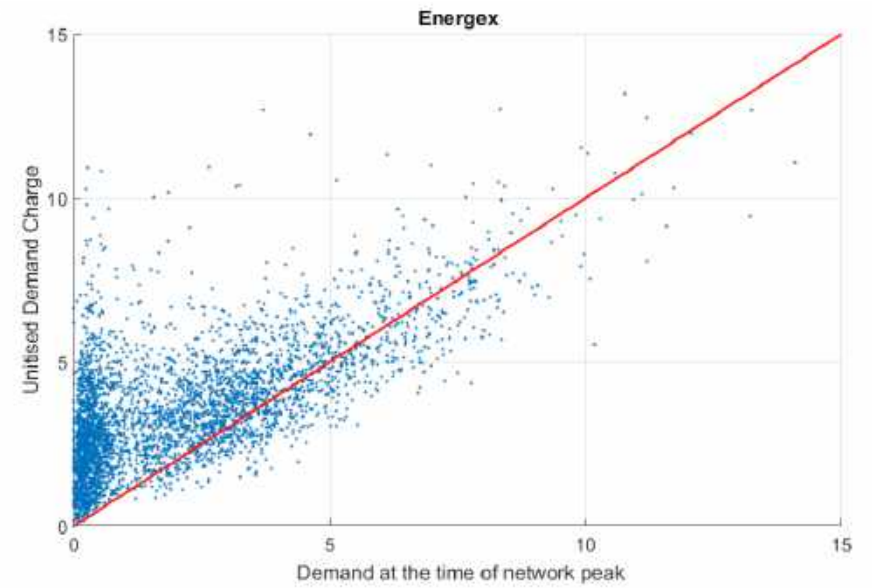
This means that charging a household based on their annual demand peak would not only result in them being charged too much, but would also mean they are charged for network augmentation at times when their demand is not affecting the cost of augmentation. This is a clear 'dead weight loss' – meaning that consumers are paying more than they should for a given good or service and so are consuming less than their optimum. In short, consumers would be incentivised to reduce demand at the wrong time and hence have limited impact on reducing network expenditure.

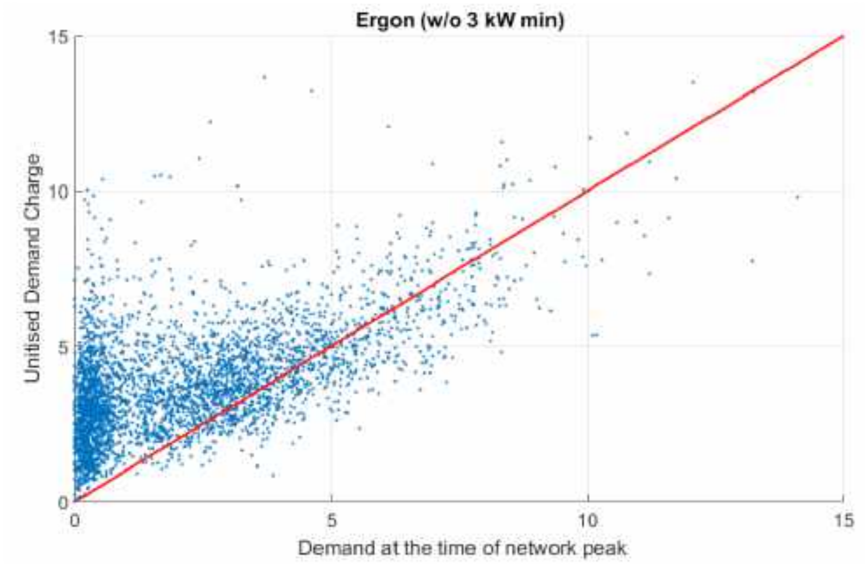


The charts below are the same as the chart above except that, instead of using each household's annual demand peak, they use Energex's 'Residential Demand Tariff' and Ergon's 'Seasonal Time of Use Demand Residential Tariff'. The distribution network component of these tariffs has been 'unitised' – meaning that the monthly demand charges have been converted to an equivalent kW value.[1]

It can be seen that, in addition to most houses being charged more than they should be (generally those who are less responsible for the network peak), now some of the households (generally those who are more responsible for the network peak) would be charged less than they should be. The correlation between payments under the demand charge and responsibility for the network peak is very low, at 66% (Energex) and 60% (Ergon).

[1] So for Energex, the demand charge was taken to be $1/kW and the total annual charge was divided by 3 to obtain an average 'per peak' charge. For Ergon, a similar process was followed except that the summer peaks were given a higher weighting because of the higher summer demand charge.



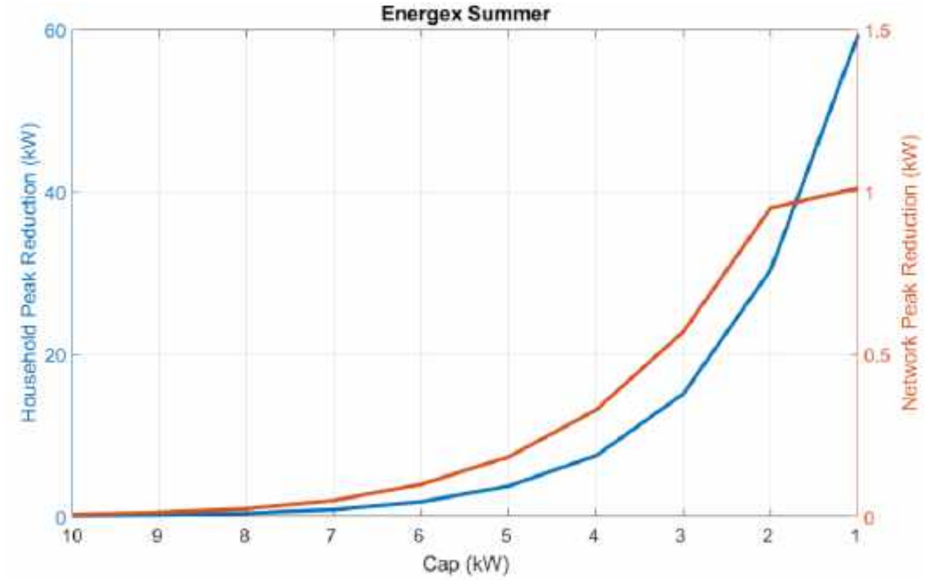


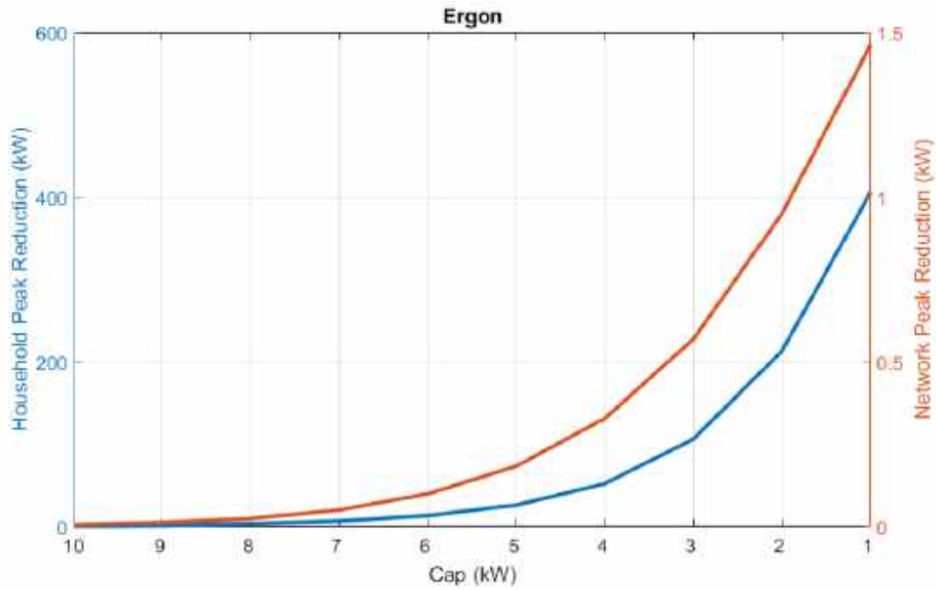
This has an important implication for networks. If a demand charge is applied over a considerable period of time, households have a stronger incentive to install load control devices such as batteries – rather than just undertake behavioural responses. This in particular applies to demand tariffs such as Ergon's, but also to a lesser extent to Energex's. Batteries are likely to be programmed to limit a household's peaks throughout the demand charge period, but not to minimise demand at the time of the network peak. As a result, although they may reduce a customer's bills, they may not be particularly effective at reducing the network's annual peak (or peaks). If a customer cannot afford a battery, they may choose some other form of control, such as having their grid connection capacity capped at a certain level. However, as stated above, this would mean their demand was being restricted when it is not affecting the cost of augmentation, resulting in a significant dead weight loss.

One way to quantify this dead weight loss is to calculate the reduction in the customers' peaks that is required to obtain a certain reduction in the network peak. The following charts show this analysis for Energex's 'Residential Demand Tariff' and Ergon's 'Seasonal Time of Use Demand Residential Tariff'. The left hand y axis shows the total reduction in average customer demand caused by it being capped at certain kW levels (x axis). The right hand y axis shows the corresponding reduction in the network peak – averaged per customer. The network calculations allow for the fact that, as one peak is reduced, another will become the peak, and so it must be reduced as well. Thus, the total peak reduction equals the old peak minus the new peak (which is most likely on a different day).

It can be seen that, for Energex, a reduction of 1kW in the network annual peak requires a net annual reduction of about 40kW by the average customer - a significant dead weight loss, that would be avoided if the demand charge was based on the household's demand at the time of the network peak. This chart assumes that the cap is only applied during the summer months, when Energex's demand charge applies. For Ergon, because the demand charge is applied all year, a 1kW reduction in the network annual peak requires a net annual reduction of about 200kW by the average customer.

This is of course why the $/kW charge applied through the demand tariffs is so much lower than the network LRMC. However this only addresses the symptom, not the problem, which is that the demand charge targets customer peaks not the network peak.





Thus, the APVI agrees with Draft Recommendations 51 to 53 and would also like to see the government allocate resources to assess whether such tariffs are actually cost-reflective. Of course, as discussed in the AEMC's Rule Determination 'National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014', in addition to cost-reflectivity, fairness is an important criterion when designing tariffs. Fairness applies not only to allocation of the short-term costs (LRMC) to those most responsible for them, but also allocation of historical responsibility. This is a very complex topic, with significant equity implications, but the QPC Draft Report doesn't seem to mention it at all.

The Renewable Energy Target's impact on customer bills

At first pass it makes sense to assume that a RET would increase customer bills. This is because renewable energy generation must be more expensive than conventional generation, otherwise, why would it require a RET? Thus, a RET will increase bills.

However, in practice, it is not so simple. Modelling undertaken by ROAM Consulting for the RET Review in 2014 indicated that:

(i) Yes, despite the impact of the merit order effect (MOE) in reducing wholesale prices, in the short term (out to 2017/18) the RET does increase customers' bills (because of the cost of LGCs).

(ii) However, from 2017/18 onwards the net impact of the MOE and the LGC price is to decrease customer bills. This occurs essentially because a) the LGC price applies only to the renewable energy electricity, whereas the MOE applies to all electricity bought through the wholesale market, and b) the MOE decreases income for gas-fired generators, which is of course a transfer, not a cost.

Although this is only one modelling study, it does show that assessing the impact of policies such as the RET is more complicated that simply adding the LGC price to household bills.

Indeed, Figure 33 on page 56 of the Draft Report confirms this trend, with an initial increase in customer bills followed by a decrease. Commercial prices are in fact predicted to be 0.7% lower because of a QRET, and the 0.5% increase for household prices and a 0.3% increase for industry pales into insignificance compared to the 87% increase in the last 10 years (82% of which was due to network costs, in turn primarily driven by increased uptake of air conditioners). In addition, having increased renewable energy in the mix will significantly reduce the impact of the carbon price that will almost certainly be re-introduced into the Qld economy in time. Designing policy based on the assumption that a carbon price will not be introduced is a very high risk strategy indeed.

Comparing the cost of abatement due to a QRET to the ERF

Page 58 of the Draft Report refers to the Emissions Reduction Fund (ERF) achieving an average abatement price of $13.95. This is not correct. The $13.95 refers to the certificate price, which in a baseline and credit scheme such as the ERF is very different to the abatement price.

Because the effectiveness of baseline and credit schemes in reducing emissions relies on estimates of what would have happened in the scheme's absence, they include measures to improve their 'additionality'. However, all the ERF's additionality requirements (the newness requirement, the regulatory additionality requirement, the government program requirement), focus on ensuring the abatement *activities* would not have occurred otherwise, not on ensuring that the abatement itself is additional.

The ‘ERF-abatement’ provided through the Landfill & waste methodologies, which created 35.9% of the ACCUs (Australian Carbon Credit Units) in the first ERF auction, is particularly problematic. For a significant number of such projects, which have existed for some time and so have already received support through previous schemes, such as the NSW Greenhouse Gas Reduction Scheme (GGAS)[2] and Greenhouse Friendly, the above additionality requirements have been waived. Even where the newness requirement is in place, it is still possible for projects to already be in operation before the ERF auction.

As a result, such projects will be credited with reducing emissions as a result of the ERF auction - even where they do not need to reduce emissions after the ERF auction any more than they were before it. They can in fact provide less abatement after the ERF auction than they were before, and still be credited with providing additional emission reductions.

Of the plants that were previously supported by GGAS, most were operating at least as early as 2006, and all were operating well before the ERF started. Many of them were operating well before 2006: for example Lucas Heights 2 was built in 1998, and created just under a third of the LFG certificates in the first auction. Similarly, the plants that were previously supported by Greenhouse Friendly were operating as early as 2002 and 2003.

The above examples are just a subset of the landfill gas plant that created certificates under the ERF. It is impossible to determine the full extent of this problem because of a lack of information provided about the projects credited with ACCUs. In particular: (i) often a number of projects are grouped together and so the number of ACCUs generated by particular plant is unknown; and (ii) some projects may be creating ACCUs as ‘recommencing projects’ or ‘upgrade projects’, in which case their abatement may be additional, but this information is not provided.

The projects registered in the first ERF auction as ‘Sequestration’ activities contributed 63.1% of the contracted ACCUs, and all appear to be for activities that are yet to happen. Therefore it is not possible at this stage to determine how effective they will be. However, 46.6% of the total ACCUs are from Avoided Deforestation, and the degree to which they have actually reduced emissions is entirely dependent on the assumption that, had it not been for the ERF, the associated forests would have been cleared, which is impossible to determine. Further, recent reports of land clearing in Qld indicate they are accelerating and will dwarf the ‘abatement’ claimed in the ERF. Clearly, there is an obvious risk that the areas opting to claim abatement under the ERF will be those that were not going to be cleared anyway, and vice versa.

In summary, it appears likely that a significant proportion of the ERF abatement activities are unlikely to reduce emissions below what they would have been in the absence of the ERF. This means that the actual cost of abatement is much higher than reported by the government, and the ERF is unlikely to be suitable for meeting more stringent emissions targets in the future.

In contrast, although a Renewable Energy Target is also a baseline and credit scheme, the amount of renewable energy generated is readily measureable and would not have occurred otherwise. As a result, the abatement driven by a RET is much more certain. This is surely one of the reasons that jurisdictions such as the ACT already has its own RET.

[2] The scheme was originally called the Greenhouse Gas Abatement Scheme and has retained the original acronym.

The ability of PV to reduce demand peaks

The Draft Report states that ACIL Allen assume rooftop PV will reduce peak demand by only 1.4% in 2015-16 and 2.1% over the longer term. In fact, the peak for Qld for 2015/16 to date was on Tues 2 Feb and PV reduced it from 9,576MW to 9,062, a reduction of 5.36%.[3]

The Draft Report also states "While average consumption has fallen with the uptake of roof-top solar PV, there is no evidence that peak demand has decreased." (page 75) It is not clear whether it refers to peak demand at the feeder level or system-wide level.

In fact, there is a significant amount of well-documented evidence that PV can reduce network demand peaks. According to data provided by Ausgrid, the amount of PV capacity available on different distribution network peaks has been shown to vary from 11.8% to 48.5% of rated capacity.[4] An assessment of the correlation between PV output and state-wide demand peaks (transmission networks) in NSW, Queensland, Victoria and South Australia over the summers of 2011/12 and 2012/13, showed PV output at between 21% and 58% of its rated capacity (Burke, 2014).[5]

In addition, information provided by distribution network service providers (DNSPs) in their Distribution Annual Planning Reports (DAPRs) has shown that PV does in fact reduce network demand peaks. For example:

Ergon DAPR 2014 Ergon state that PV has reduced their system-wide annual demand peak and annual load factors. In part due to PV, "Ergon Energy has revised downwards its system-wide maximum demand from previous forecast estimates".

Energex DAPR 2014 "Solar PV has also had a small but increasing influence in summer day peak system demand. Importantly, in comparison with prior years, decline in peak demand has resulted in network limitations being deferred and this is reflected in the analysis contained in Volume 2. It has also resulted in reduced capital expenditure."

Ausgrid DAPR 2014 "The historical load data includes the impact of downstream embedded generation that was generating at the time of peak, consequently, the forecast includes the impact of small scale generation (such as rooftop solar installations)". The impact of PV during the annual peak is incorporated into all their Sub-transmission Substation and Zone Substation load forecasts in their DAPR.

Endeavour Energy DAPR 2014 "Endeavour Energy continues to monitor the impacts of solar panels which, in some areas, have materially reduced demand. Areas with demand that peaks later in the afternoon or evening have little effect from PV generation on peak demand. What it does do is to reduce the duration of the peak and reduce the thermal heating of some parts of the network during the day".

Essential Energy DAPR 2014 The impact of PV during the annual peak is incorporated into all their Sub-transmission Substation and Zone Substation load forecasts in their DAPR.

United Energy DAPR 2014 "Hence the level of uptake of micro-generators has a downward influence on UE's growth in maximum demand. UE incorporates the uptake of micro-generators into the maximum demand forecast. During the 2013-14 summer, the UE network had approximately 87

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[3] From http://pv-map.apvi.org.au/live.

[4] Calculated from Ausgrid, 2011, 'Effect of small solar Photovoltaic (PV) systems on network peak demand', Research Paper, *Ausgrid*, Oct 2011. From http://www.ausgrid.com.au/Common/About-us/Newsroom/Discussions/~/media/Files/About%20Us/Newsroom/Discussions/Solar%20PV%20Research%20Paper.ashx

[5] Burke, K. B., 2014, 'The reliability of distributed solar in critical peak demand: A capital value assessment', *Renewable Energy*, 68, p103–110.

MW of installed roof-top solar photovoltaic panels connected to the system. It is assessed that the contribution of this generation to reducing the UE maximum demand was approximately 13 MW".

Jemena DAPR 2014 Their model used to forecast maximum demand incorporates the impact of PV, which decreases peak demand forecasts to levels below what they otherwise would be.

Of course, the problem is that the degree to which PV may reduce demand peaks is uncertain. If cost-reflective tariffs were implemented (that really did reflect the cost of network augmentation, as discussed in the Section 'Cost-reflective Tariffs'), then PV systems would only be rewarded to the extent that they really did reduce demand peaks. As a result, much of the debate around the degree to which PV reduces demand peaks would be unnecessary.

Data Availability and Analysis

The QPC clearly understands the importance of data collection and analysis. They recommended that: "the Government prioritise data collection to better understand impacts on customers, and in particular to identify impacts on vulnerable customers" (QPC, 2016, page xiii), and that "The Queensland Government should improve the dataset used to determine the impacts of network tariff reform on customers…" (QPC, 2016, page xviii). It also cites examples where Energex and Ergon will be undertaking studies on their new demand charge tariffs.

We strongly endorse the importance of tariff studies, not only regarding their impacts on customers, but also regarding their impacts on network demand peaks. As detailed in the Section 'Cost-Reflective Tariffs', the demand charge tariffs currently being promoted by DNSPs are highly unlikely to be cost-reflective, and could drive the uptake of technologies and practices that will have much less impact on network demand peaks than hoped.

We strongly advise that the data collected by networks be made available to the public. In addition to the public interest groups, the Australian universities and research centres host many very smart paid researchers as well as students undertaking 4th year theses, Masters and PhDs. They are capable of undertaking very detailed and rigorous analysis, often for free.

General Points

Recommendation 11

Rather than simply recommending against Government intervention to achieve a 3GW PV target for Qld, the QCA should look for opportunities to link this target to its many other recommendations concerning vulnerable customers and the concession framework (including Recommendations 24, 28, 29, 30, 36, 38, 39, 45, 47, 50, 51). Many of the changes underway are in response to PV and other distributed energy opportunities, which disadvantaged consumers may not have the opportunity to access. The 3GW target (as well as energy efficiency and demand management options) could usefully be implemented via programs targeting vulnerable and low income households, including those in public housing. This would have the added benefit of making these customers more self-sufficient and reducing ongoing electricity support payments.

Recommendation 36

The QCA could consider supporting online calculators such as the one recently funded by the National Farmers Federation and NSW Farmers.

See http://www.aginnovators.org.au/content/solar-pv-battery-financial-analysis-calculator

Although this was designed to help customers determine the financial impacts of solar PV and batteries, it can also be used without these technologies. It should also be possible to add in the effects of different types of energy efficiency and demand side management.

Recommendation 38

The APVI supports this recommendation and believes that, in addition to energy efficiency and demand side management, solar PV, wind and batteries should be supported.

Recommendations 41 to 43

The APVI supports these recommendations. The trend to more locally based service provisions has the potential to provide lower cost and more sustainable options to large portions of Queensland. Locally based renewable energy supply will hasten the transition away from fossil fuels, while reducing the need for long networks will improve reliability and safety for consumers in the wake of increasing extreme weather events such as cyclones and bushfires. Establishing transparent processes and facilitating third party access will serve to overcome some of the shortcomings of the RIT-D.

Recommendation 54

The APVI supports this recommendation. In addition, the Queensland Government should investigate ways to overcome the split incentive problem that inhibits uptake of energy efficiency and demand management technologies, as well as solar PV and batteries.

Modelling in general

Beware of placing too much emphasis on modelled scenarios. The only certainly regarding modelling of any kind is that it will be wrong. This is not to say modelling is not valuable. It is both valuable and necessary. However, considering the transformational change that has occurred in the Australian electricity sector over the last 20 years, projections that 96.6% of the Qld large-scale generation mix will be based on coal and gas-fired generation in future should be treated with great caution.

Modelling showing reduced network costs over time

Pages 13 and 14 of the Draft Report show the network component of retail tariffs decreasing, presumably because of depreciation. The ACIL Allen report, that the Draft Report often refers to, should be made available to the public so that these effects and the underlying modelling assumptions can be better understood.

Attachment A: Background on the APVI

The APVI is an independent Institute comprising companies, government agencies, individuals, universities and research institutions with an interest in solar photovoltaic electricity. In addition to Australian activities, we provide the structure through which Australia participates in the International Energy Agency (IEA) PVPS (Photovoltaic Power Systems) and SHC (Solar Heating and Cooling) programmes, which in turn are made up of a number of activities concerning PV and solar system performance and implementation. Further information is available from www.apvi.org.au.

APVI Objective

The objective of the APVI is to support the increased development and use of PV via research, analysis and information.

APVI subscription provides:

Information

- Australian PV data and information
- Standards impacting on PV applications
- Up to date information on new PV developments around the world (research, product development, policy, marketing strategies) as well as issues arising
- Access to PV sites and PV data from around the world
- International experiences with strategies, standards, technologies and policies

Networking

- Opportunity to participate in Australian and international projects, with associated shared knowledge and understanding
- Access to Australian and international PV networks (PV industry, government, researchers) which can be invaluable in business, research or policy development or information exchange generally
- Opportunity to meet regularly and discuss specific issues which are of local, as well as international interest. This provides opportunities for joint work, reduces duplication of effort and keeps everyone up to date on current issues.

Marketing Australian Products and Expertise

- Opportunities for Australian input (and hence influence on) PV guidelines and standards development. This ensures both that Australian products are not excluded from international markets and that Australian product developers are aware of likely international guidelines.
- Using the information and networks detailed above to promote Australian products and expertise.
- Working with international network partners to further develop products and services.
- Using the network to enter into new markets and open new business opportunities in Australia.

The International Energy Agency Programmes

PV Power Systems (IEA PVPS)

- **Mission:** *To enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems*
- **Focus** (26 countries, 5 associates)
  - PV technology development
  - Competitive PV markets
  - Environmentally & economically sustainable PV industry
  - Policy recommendations and strategies
  - Neutral and unbiased information

Australia currently participates in:

PVPS Task 1: Information Dissemination

PVPS Task 9: PV Services for Regional Development

PVPS Task 13: PV System Performance

PVPS Task 14: High Penetration PV in Electricity Grids.

Solar Heating & Cooling (IEA SHC)

- **Mission:** *International collaboration to fulfil the vision of solar thermal energy meeting 50% of low temperature heating and cooling demand by 2050*
- **Focus** (21 countries, 2 associates)
  - Components
  - Systems
  - Integration into energy system
  - Design and planning tools
  - Training and capacity building

Current Australian participation:

- SHC Task 51 – PV in Urban Environments
- SHC Task 48 – Quality Assurance Support Measures for Solar Cooling Systems
- SHC Task 47 – Solar renovation of non-residential buildings
- SHC Task 46 - Solar Resource Assessment and Forecasting
- SHC Task 43 - Solar Rating & Certification Procedures
- SHC Task 42 - Compact Thermal Energy Storage
- SHC Task 40 - Net Zero Energy Solar Buildings

For further information on the Australian PV Association visit: **www.apvi.org.au**

For further information on the IEA PVPS Programmes visit **www.iea-pvps.org and www.iea-shc.org**