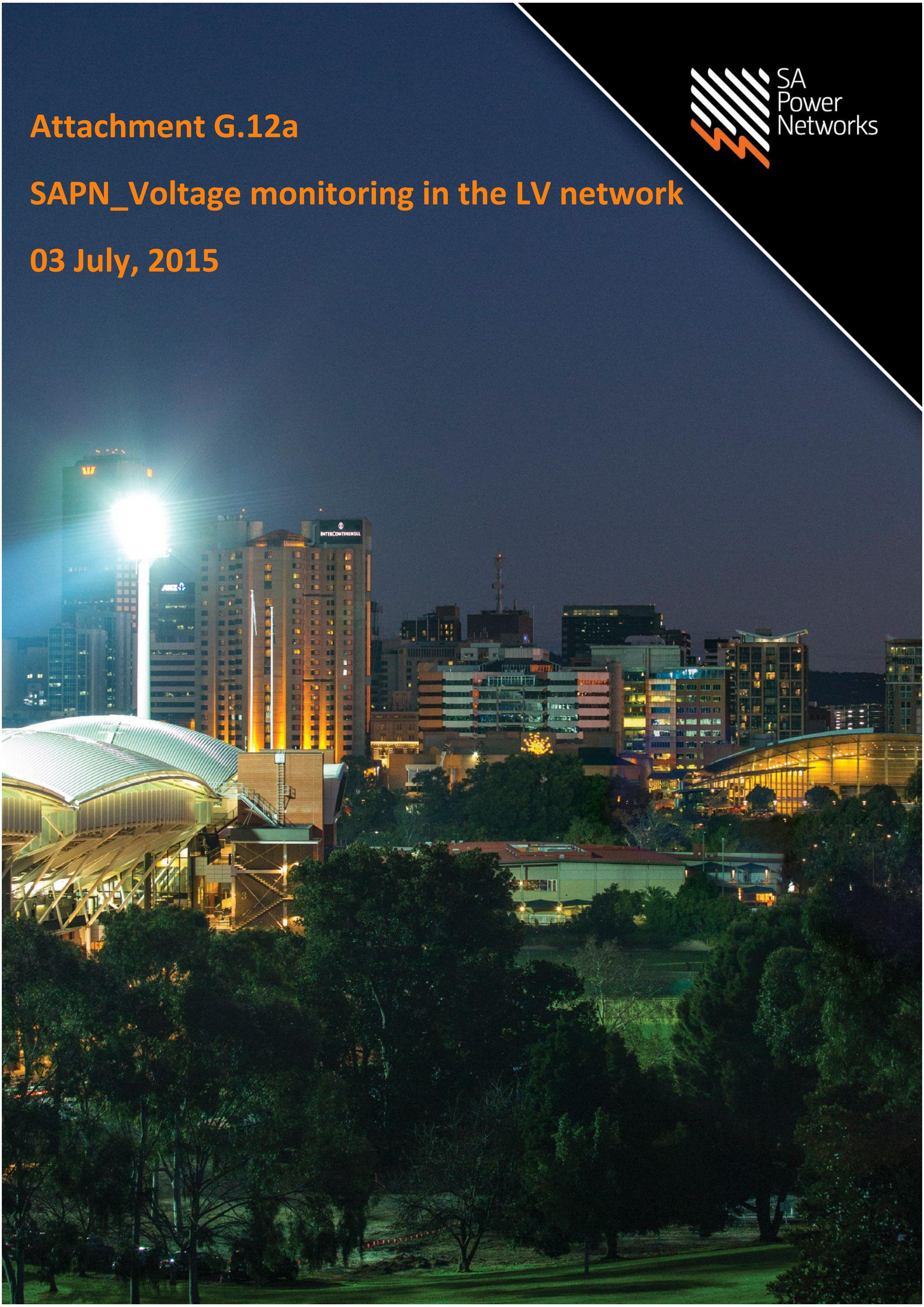
Attachment G.12a

SAPN_Voltage monitoring in the LV network

03 July, 2015



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1 INTRODUCTION

In our original regulatory proposal (Original Proposal) for the 2015-2020 Regulatory Control Period (RCP) SA Power Networks proposed new capital and operating expenditure to deploy local voltage monitoring across older areas of our Low Voltage (LV) network in order to manage an emerging problem with voltage regulation due to high penetrations of rooftop solar PV. In its Preliminary Determination, the AER did not approve this expenditure.

This document sets out our response to this aspect of the AER's Preliminary Determination, and provides further detail in support of our Revised Proposal in relation to voltage monitoring in the LV network.

2 DRIVERS OF CHANGE

SA Power Networks has a regulated requirement[1] to maintain supply voltage at customer premises at between 216V and 253V, the range specified in AS60038. Historically, this has been achieved without any active monitoring of voltage in the LV network; in a one-way distribution network, voltage at the customer premises can normally be estimated to the required accuracy from known voltage at a major upstream network asset like a substation. We have so far employed a reactive approach to managing occasional customer power quality issues, in which we deploy temporary local monitoring in the LV network in areas where customers have raised complaints about power quality, and this has served us well.

In the last four years, however, there has been a fundamental change in our operating environment. Since 2010 more than 170,000 customers have connected small-scale intermittent generators, in the form of rooftop solar PV systems, to the LV network. As a consequence we now have unprecedented two-way energy flows in the LV network, for which it was never designed (refer Appendix E). This is causing significant localised swings in voltage that cannot be estimated based on voltage levels at the substation.

In order to assess the potential extent of this issue, SA Power Networks engaged consultant PSC in 2014 to model the impact of increasing penetration of solar PV and other distributed energy resources on quality of supply at the customer premises[2]. The study modelled fifteen typical feeders representing a cross-section of categories of supply area including underground LV, overhead LV and SWER, and applied the findings to estimate the likelihood of future power quality issues across the broader network.

The PSC study found that across older areas of the LV network, existing network infrastructure and voltage regulation approaches limit acceptable solar PV penetration to around 25% of customers. As we enter the 2015-20 RCP the average penetration of solar PV is already more than 22% of all households, with some localised areas having penetration greater than 50%. AEMO forecasts that solar PV penetration will continue to rise significantly in South Australia over the next five years[3].

PSC's findings indicate that there are many areas of the network where, if we continue to rely on the approach that we have taken in the 2010-15 period, we will be unable to continue to meet our regulated obligation to maintain supply voltage within the range specified in AS60038 during the 2015-20 period. If we fail to maintain voltage within the range required by regulation, customers may experience visible fluctuations in supply, increased failure rate of

[1] NER, Schedule 5 and related regulation

[2] Power Systems Consulting, Impact of distributed energy resources on quality of supply, May 2014, p. 6 (Attachment 13.2 of SA Power Networks, Regulatory Proposal *2015-20*, 31 October 2014).

[3] AEMO, National Electricity Forecasting Report (NEFR), June 2015

appliances, and degraded output from solar inverters, which are required by Australian standards to shut down automatically if voltage is outside the normal range[4].

Customers surveyed by SA Power Networks in 2013 through our *TalkingPower™* consultation program strongly favoured enhancing the network to support the ongoing integration of solar PV and other new customer-side technologies[5]

If we are to continue to meet our regulated obligations while still allowing customers to connect solar PV and other embedded generation to the LV network, it is no longer prudent to rely solely on customer complaints to detect voltage issues – active monitoring at the LV network level is required.

3 OUR REGULATORY PROPOSAL

Our Original Proposal included a program of work to establish voltage monitoring at selected customer premises in older areas of the LV network. We proposed to install telecommunications modules in smart-ready meters at the time of meter replacement for a targeted subset of new and replacement meters located in urban areas with older LV network infrastructure. In so doing we could enable these meters as voltage monitors at low incremental cost, and thus efficiently establish, over time, a broad-based voltage monitoring capability across those areas of the LV network most affected by voltage variations due to solar PV[6].

This strategy relied on another aspect of our Original Proposal, being our proposal to install 'smart ready' interval meters as standard in all new and replacement situations from 2015 to support cost-reflective network tariffs. It was anticipated that approximately 15% of the new and replacement meters installed per annum would be candidates to be enabled as voltage monitors. This gave a forecast installation rate of approximately 10,000 telecommunications modules per annum over the 2015-20 RCP, which would achieve 80% coverage of target areas by 2020, with the remainder to be installed in the 2020-25 RCP.

Our LV network monitoring strategy was reflected in material cost components in the following areas of our Original Proposal:

- A $16.1 million ($2015)[7] strategic project in the augmentation category to install meter telecommunications modules for network monitoring and fund associated project costs[8]
- A CAPEX allowance for associated IT backoffice systems included as part of the 'Tariff and Metering' component of our non-recurrent IT spending forecast[9].
- A step change in SCS OPEX over the 2015-20 period included as part of the 'Demand Side Participation' (DSP) OPEX forecast[10].

[4] Refer Australian Standard AS4777.3

[5] TalkingPowerTM customer consultation workshops and online survey, SA Power Networks customer engagement initiative, 2013 – refer http://talkingpower.com.au/consultation-approach/

[6] Note that smart meters provide an efficient, low-cost platform for the broad-based monitoring required to detect voltage issues as they emerge across the network. When a problem area is identified, more sophisticated dedicated logging devices may be deployed temporarily in the area to enable detailed root-cause analysis.

[7] Note that Attachment 6 of AER's Preliminary Determination quotes a figure of $15.4 million for the cost of this project, which is the cost in $2014 and without overheads applied (p6-69)

[8] SA Power Networks' Regulatory Proposal 2015-20, section 20.6.3

[9] Ibid, section 20.8.1 and table 20.44

[10] Ibid, p257. OPEX associated with DSP was included in the "Energy Law and Regulation" OPEX step change category

4 THE AER'S PRELIMINARY DETERMINATION

In its Preliminary Determination the AER did not accept our strategic capital expenditure forecast of $16.1 (June 2015, $ million) for LV network monitoring using telecommunications modules installed in smart-ready meters.

The primary reason cited in the AER's Preliminary Determination for rejecting this aspect of our proposal was that it relied on our proposal to install smart-ready interval meters as standard over the 2015–20 RCP. The AER did not consider the installation of smart-ready meters to be prudent "*in the context of the expected market led rollout of smart meters in South Australia, and finalisation of national smart meter minimum functionality specifications*"[11]. As it did not approve the capital expenditure required to install smart-ready meters, the AER reasoned that:

> *"it is unclear whether or how many smart meters SA Power Networks will own and install in the 2015–20 regulatory control period. Irrespective of any proposed benefits from network monitoring, we consider that providing an allowance to install telecommunications modules in smart ready interval meters is not prudent without more certainty about the rollout of smart meters in South Australia".*

Elsewhere in its Preliminary Determination the AER also made a number of other observations relevant to this aspect of our proposal:

- It did not accept our forecast of the growth of solar penetration in South Australia. Instead, it determined to rely on the most recent forecasts from AEMO[12], which it considered indicated SA Power Networks' forecast number of new solar connections by over the 2015-20 period may be over-estimated by 30 percent [13].
- Although it did not agree with our solar forecasts, the AER considered that *"it is still reasonable to assume that there will be some increases in high-voltage issues associated with the increase in solar panel installations over the 2015–20 regulatory control period"*[14].

The AER did not specifically assess our forecast IT CAPEX associated with this project; rather, it took a holistic approach to assessing the overall IT portfolio. The AER did not accept the total IT capital expenditure proposed for the 2015-20 RCP, and substituted its own reduced estimate in its Preliminary Determination[15].

In terms of OPEX, the AER did not accept any step change in OPEX related to Demand Side Participation. It did not comment specifically on this component of our forecast DSP OPEX.

[11] Attachment 6 to AER Preliminary Determination, p. 6-69.
[12] AEMO, South Australian Electricity Report, August 2014
[13] Attachment 6 to AER Preliminary Determination, p. 6-46
[14] Ibid
[15] Ibid, section B.6.3

5 SA POWER NETWORKS' RESPONSE TO THE PRELIMINARY DETERMINATION

5.1 Summary

We do not agree with the AER's assessment that we will be able to meet our regulated obligation to maintain supply voltage to Australian standards in areas of high solar PV penetration in the 2015-20 period using existing approaches that rely on customers to report voltage irregularities. Recent evidence suggests that voltage issues are already emerging, and moreover that the extent of these issues is significantly greater than is revealed by the number of customer complaints.

While PSC's modelling suggests that it will be possible to correct these issues using established practices in many cases (e.g. replacement or re-tapping of distribution transformers, targeted augmentation, etc.), we are unable to undertake remedial action required to meet our regulatory obligation to maintain supply voltage to standards if we have no capability to detect the issues as they emerge. We therefore do not agree that no new expenditure is required in voltage monitoring at the LV network level.

While we still consider that smart meters will ultimately offer the most efficient platform for monitoring voltage across the LV network, we accept that the AER's rejection of our proposal to install 'smart ready' meters as standard effectively prevents us from establishing a broad-based monitoring capability based on smart meters in the 2015-20 RCP. Accordingly, we have revised our approach to LV network monitoring in our Revised Proposal.

Our response is set out in more detail in the sections that follow.

5.2 Solar forecasts

South Australia has the highest penetration of domestic rooftop solar PV of any of the NEM regions, with a total installed solar capacity across the state of more than 600 MW – enough to offset the state's entire residential demand on a mild sunny day.[16] More than 22% of residential customers have solar, and penetration in some areas of the network is much higher; as of May 2015 we now have 57 LV transformers where more than 50% of connected premises have solar PV[17].

AEMO's most recent independent forecasts show that solar penetration will continue to rise in South Australia through the 2015-20 period, increasing by approximately 70% compared to 2015 levels by 2020[18]. AEMO's forecast growth rate is slightly lower than the forecasts used in our Original Proposal.

We accept AER's Preliminary Determination to rely on AEMO's most recent forecasts, and we have adjusted our Revised Proposal accordingly.

[16] Refer Appendix E
[17] Refer Appendix D
[18] Refer 'Medium growth' scenario in AEMO's National Electricity Forecasting Report (NEFR), June 2015. See also Appendix B for further details.

5.3 PSC report

In its Preliminary Determination the AER wrote:

> *"We have carefully reviewed the findings of the PSC report and SA Power Networks' proposal. While the PSC report finds that some minimal power quality issues are likely to arise through additional growth in solar panel installations in older areas of the network, in our view the report generally finds these could be managed using generally accepted responses typical in the industry and currently adopted by SA Power Networks (e.g. retaping distribution transformers, management of float voltages, targeted augmentation)."*[19]

While we do not agree that the PSC report indicates that power quality issues are likely to be 'minimal' we do agree that the report indicates that many of these issues are likely to be able to be corrected using established mitigation methods.

We note, however, that South Australia's unique combination of occasional extreme peaks of summer demand combined with generally mild weather and very high penetration of solar PV is creating ever-widening seasonal variations in voltage that challenge established approaches[20]. Traditional methods of mitigating high voltage conditions at the LV network level such as re-tapping the high voltage connections on the distribution street transformer can correct for local voltage increases that occur when solar PV output is high but demand is low (typically mild, sunny days in spring and autumn), but can lead to low voltage conditions during periods of high load. Hence, unlike in the pre-solar past, local corrective action now needs to be combined with ongoing monitoring to ensure that voltage levels remain within the regulated range through all seasons.

Similarly, it is necessary to be able to measure voltage at the LV network level in order to manage voltage further upstream, at the HV substation, as PSC noted:

> *"HV substation voltage regulation can be used, in most instances, to overcome voltage regulation issues **provided that the voltage regulation range of the LV network is known**.*
>
> *Changes to transformer tap settings (where available) or reconductoring feeder backbones may be sufficient to enable substantial increases in acceptable DER penetration levels."*[21] (emphasis added)

We noted this in our Original Proposal, in which we wrote:

> *"The modelling indicates that in many cases power quality issues can be mitigated by relatively simple means, e.g. voltage regulation at zone substations or tap changes at transformers, **but the key element that is missing today is any visibility of actual power quality across the vast majority of the LV network**. Although we may have the means to address issues, we are effectively blind to where those issues are*

[19] Attachment 6 to AER Preliminary Determination, p 6-47. Note that this commentary was in the context of another aspect of our proposal, but it is relevant to our LV monitoring proposal.

[20] Refer Appendix E

[21] SA Power Networks Consultancy Services for Impact of Distributed Energy Resources on Quality of Supply, PSC Consulting report JA4679-4-0.1, Rev1, 12th May 2014

> *emerging until such time as customers call in to complain. Moreover, without a way to monitor power quality at the premises we have no means to close the loop and measure the effect of any remedial action to confirm that it has been successful."*[22] (emphasis added)

In summary, we agree that generally accepted responses that are currently used to correct voltage issues are likely to continue to be effective in 2015-20. At issue is the fact that the modelling suggests that our current method of *detecting* issues in the LV network, which is reliant on customers to call us to report voltage irregularities, is no longer adequate.

5.4 Recent evidence

At the time of our Original Proposal we had already commenced a small-scale trial of our proposed approach to voltage monitoring in the LV network, installing communications modules in 'smart ready' meters installed at 920 customer premises distributed uniformly within a 12 square km area in the Adelaide suburbs south of Greenhill Road. This area contains around 12,500 customer premises and was selected as it is representative of the typical suburban environment in South Australia in terms of demographic mix, housing stock, climate and solar PV penetration. Further details of the trial are provided in Appendix C.

For this trial we enabled over- and under-voltage event logging in the meters, so that each meter would log an alarm whenever supply voltage at the premises varied outside the range specified in AS60038. As at May 2015 we were able to download the first full 12 months of voltage alarm data from the meters in the trial area. We also correlated this data with customer complaints logged with our call centre in this area over the same period.

Although our analysis of the data is preliminary at this time, the data indicates[23] that:

- 180 customer premises out of the 920 equipped with monitoring in the trial area were affected by voltage variations outside the range specified in AS60038 during the 12 months from 1st May 2014 to 1st May 2015.
- These events occurred over 177 different days and comprised a mix of over-voltage and under-voltage events.
- During the same 12 month period our call centre received only 9 customer complaints regarding power quality from residents in the trial area, which contains around 12,500 customers in all.

Further details of this trial are provided in Appendix C.

This data indicates that there were quite widespread irregularities in LV network voltage in the trial area over the 12-month trial period, with one in five premises with monitoring detecting at least one voltage excursion at some point during the year. Only a small fraction of the actual voltage issues were revealed in customer complaints, however, with fewer than one in every 1,000 residents in the trial area reporting a voltage problem over the course of the year.

This is not unexpected as it can be difficult for customers to detect voltage issues, especially over-voltage issues caused by solar PV. A customer with solar PV may not be aware that their solar inverter has been automatically disconnecting from the grid for part of the day due to voltage excursions, although this may be reducing the financial benefit they receive from their solar generation.

[22] Attachment 14.3 to SA Power Networks' Regulatory Proposal 2015-20, Tariff & Metering Business Case, section 5.1

[23] The figures below exclude data from two specific events deemed to be atypical, namely one customer premises that appears to have had a specific local issue that caused a high volume of alarms for a period in 2014, and one day in January 2015 in which a grid-side overvoltage problem caused alarms at a number of premises. More details are included in Appendix C.

Although customers may not themselves be aware of voltage issues, it is clearly in their interest for us to be able to detect these issues, as there can be detrimental consequences to customers when we fail to maintain voltage within the range required by regulation.

Although our analysis of this data is preliminary at this time, the evidence from the trial supports our view that active monitoring of voltage in the LV network is required, and that continued reliance on customer complaints as our primary means to detect voltage excursions is no longer prudent nor in customers' best interests.

In the context of the AER's determination that it would be prudent to adopt a 'wait and see' approach to the issue of voltage variation in the LV network in the 2015-20 period[24], the evidence is that without some active voltage monitoring we are unable to 'see' the extent of the problem, nor measure the effectiveness of remedial measures taken to address it.

5.5 Smart meters as a future platform for voltage monitoring

The AER did not accept our proposal to install 'smart ready' interval meters as standard from 2015 to support network tariff reform[25]. This effectively prevents us from establishing a broad-based monitoring capability based on smart meters in the 2015-20 RCP as we had proposed.

We do not consider that the AER's rejection of the metering aspect of our original proposal in any way diminishes the need for us to establish a capability to monitor voltage in the LV network if we are to continue to meet our regulated obligation in relation to quality of supply in the 2015-20 RCP. Accordingly, we have revised our approach to LV network monitoring in our Revised Proposal.

We still consider that smart meters will ultimately offer the most efficient platform for monitoring voltage across the LV network. We note the AER is of the view that:

> *"under the competitive metering framework, network operators will be able to commercially negotiate with metering co-ordinators to access metering data that they wish to use for network purposes. This means that SA Power Networks does not need to own smart meters and install its own telecommunications devices to be able to access information to more effectively monitor and manage two-way power flows."*[26]

We do not disagree with this statement. In our Original Proposal we wrote:

> *"we expect, in future, to be able to access power quality data from third party meters via the proposed common market gateway, assuming a market-led smart meter rollout resulting from the metering contestability rule changes"*[27]

We note, however, that the publication in March 2015 of the AEMC's draft rule change on expanding competition in metering[28] has confirmed the timeframe for commencement of the new rules as mid 2017. On that basis we do not expect to be in a position to seek access to voltage data from third-party smart meters on a widespread basis until the 2020-25 RCP, at

[24] Attachment 6 to the AER Preliminary Determination, p6-45
[25] Ibid,, p. 6-69.
[26] Attachment 6 to AER Preliminary Determination, p. 6-69
[27] Attachment 14.3 to SA Power Networks' Regulatory Proposal 2015-20, Tariff & Metering Business Case, section 5.9
[28] AEMC Draft Rule Determination, Expanding competition in metering and related services, March 2015

which time the market will be established and the penetration of smart meters will begin to reach critical mass.

We also note that it is now apparent from the draft rule that only a rudimentary level of access to voltage data is contemplated in the proposed national minimum meter specification. Moreover, access to such data is to be left entirely at the discretion of each individual Metering Coordinator. Hence, although it remains our preferred approach, the prudence and efficiency of relying on third-party smart meters for voltage data will ultimately depend on the extent to which MCs offer access to this data, the commercial terms attached, and the extent to which the market structure facilitates long-term commercial agreements that ensure continuity of service when the MC changes at a customer site.

6 OUR REVISED PROPOSAL

6.1 Overview

In light of the AER's Preliminary Determination and greater certainty with respect to the competition in metering Rule change we now propose a staged approach to LV monitoring, in which we will deploy a smaller number of grid-side monitoring devices to targeted areas in the 2015-20 RCP, and defer expansion to more widespread monitoring until the 2020-25 RCP, by which time we hope to be able to access power quality data from third-party smart meters rolled out under the new competitive metering framework.

In determining the most effective way to target our proposed monitoring in the short term we have taken into account the AER's view that:

> *"it is more prudent to adopt a 'wait and see' approach which will allow SA Power Networks to consider the actual quantum and impact of additional solar panel installation on power quality problems, and its ability to manage these problems using existing industry standard approaches"*[29]

In our Revised Proposal we propose to deploy LV monitoring in three phases:

6.2 Phase 1 – baseline area monitoring

In phase 1 we propose to deploy grid-side monitoring devices to monitor LV distribution feeders for the 44 LV transformers located within our established trial area in the Adelaide suburbs south of Greenhill Rd. As noted earlier, this area is representative of the typical suburban environment in South Australia in terms of demographic mix, housing stock, climate and solar PV penetration.

The purpose of ongoing voltage monitoring in this area is to put into practice the AER's 'wait and see' approach. We will build on the baseline data accumulated through our trial over the last 12 months, and track "the actual quantum and impact of additional solar panel installation on power quality problems" for customers in this area as solar penetration continues to rise through the 2015-20 period. Having continuity of data will also enable us to assess the impact of new customer-side technologies, in particular battery storage, that may begin to be deployed in the latter part of the 2015-20 RCP.

Having data from both meters and grid side devices will enable us to determine the utility of voltage data from smart meters at different potential service levels (e.g. under- and over-

[29] Attachment 6 to AER Preliminary Determination, p. 6-45

voltage alarm events vs. continuous voltage logging at different sampling rates) and different meter densities (i.e. the number of meters required on each LV circuit to enable correction for anomalies caused by local variations in customer wiring[30]). This will inform our engagement with the market with the commencement of the new rules in 2017, in particular to what extent we can rely on data streams that may be provided by MCs to meet our requirements.

6.3 Phase 2 – high solar penetration areas

In phase 2 we propose to extend monitoring to 57 specific LV network areas where we have older LV network infrastructure and very high solar penetration levels (>50% penetration today). Monitoring in these areas will enable us to assess our “ability to manage these problems using existing industry standard approaches” and facilitate meeting our regulatory obligations in the 2015-20 RCP.

Specifically, deploying grid-side monitoring in these areas is required in order that we can monitor the effectiveness of current mitigation methods over time, to ensure that regulated voltage standards are maintained under all network conditions with both low and high loadings, noting the extreme seasonal variation in load in residential areas with high solar penetration[31].

6.4 Phase 3 – broad-based LV network monitoring

We will defer the broader expansion of monitoring until Phase 3, which will be undertaken in the 2020-25 RCP. At this time we hope to be able to access power quality data from third-party smart meters rolled out under the new competitive metering framework. We will have a basis of evidence from Phase 1 and Phase 2 to inform and refine our approach to Phase 3, including the specific data and services we require from third-party metering coordinators.

6.5 Summary

Our Revised Proposal to LV network monitoring differs from our Original Proposal in the following aspects:

- In our Original Proposal we proposed to deploy 50,000 smart meter telecommunications modules to establish a platform for monitoring voltage across all older areas of the LV network. In our revised proposal we have taken a staged approach, in which the establishment of broad-based LV network monitoring is deferred until the 2020-25 RCP. We now propose to deploy fewer than 500 monitoring devices in 2015-20. As a consequence our forecast capital and operating expenditure associated with these end-point monitoring devices is substantially reduced.
- Our revised approach is no longer dependent on the installation of ‘smart ready’ meters in the 2015-20 RCP. We propose to deploy stand-alone grid-side monitoring devices mounted on distribution poles at selected monitoring points along LV distribution feeders in order to facilitate monitoring for Phase 1 and Phase 2.
- Our forecast expenditure on supporting IT systems is also substantially reduced compared to our Original Proposal due to the substantially reduced scope.
- Forecast expenditure associated with integrating the LV monitoring backoffice system into operational systems (e.g. ADMS) and updating associated business processes has been deferred until Phase 3; LV monitoring will run essentially as a stand-alone system

[30] In our Original Proposal we proposed that sampling at three customer premises per LV feeder would be sufficient, if these were chosen appropriately. In our Revised Proposal we are reliant on a retailer-led smart meter deployment and hence have less capability to select the premises available for monitoring. Correlation between measurements taken at the customer premises and measurements taken grid-side will enable us to model the number of sample points required in this scenario.

[31] Refer Appendix E

for Phase 1 and Phase 2, although the SAP BI platform will be utilised for data warehousing and analytics.

- Certain items in our original expenditure forecasts were related directly to the use of smart meters for monitoring. For example, we proposed to enable additional functions in these meters such as outage detection in order to achieve consequential benefits. The related costs and benefits have been removed in our Revised Proposal.

6.6 SCS CAPEX impact

Table 1 below shows the forecast capital cost of our revised proposal to implement targeted voltage monitoring in the LV network.

CAPEX – LV monitoring	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Non-network CAPEX – IT (non-recurrent)							
Monitoring system implementation & integration	600	0	600	0	0	0	(1)
Monitoring system software licence	510	0	408	0	0	102	(2)
Monitoring system servers and hardware	175	0	175	0	0	0	
Monitoring device configuration, test and support facilities	435	435	0	0	0	0	(3)
Total non-network CAPEX - IT	**1,720**	435	1,183	0	0	102	
AUGEX Strategic – LV monitoring							
LV monitoring devices	1,152	505	647	0	0	0	(4)
Project team	363	363	0	0	0	0	(5)
Total AUGEX Strategic – LV monitoring	**1,515**	869	647	0	0	0	
Total CAPEX	**3,235**	1,304	1,830	0	0	102	(6)

Table 1 – CAPEX impact: LV monitoring

Notes:

1. Systems implementation for backoffice software to support LV monitoring in target areas using grid-side devices, and integration with SAP BW for data warehousing and analytics. Internal IT resource estimates based on Deloitte modelling.
2. Software license costs based on vendor pricing for grid-side monitoring solution to support proposed volume of monitoring devices, as well as SAP BW licence costs based on cumulative forecast data volumes (inc. increment in year 5).
3. Estimate includes cost for testing, configuration and firmware configuration management for end devices.
4. Estimate based on vendor pricing for dedicated grid-side single-circuit LV monitoring device as currently deployed in local LV transformer monitoring initiatives, plus estimated installation hardware and install cost based on data from previous installations of similar

devices on LV distribution poles. Estimates are based on volumes of 186 devices in Phase 1 and 238 devices in Phase 2, including spares and testing.

5. Project team of 3 x FTE to procure and establish systems and manage Phase 1 deployment; transition to OPEX for Phase 2. Estimate based on actual resource profile from procurement, design, deployment and operation phases of 12-month LV monitoring trial in 2013-14.
6. All estimates are in 2013/14 $.

A further breakdown of these costs is provided in the spreadsheet included in Appendix A.

6.7 SCS OPEX step change

Table 2 below shows the forecast step change in operating costs resulting from our revised proposal for targeted LV network voltage monitoring.

OPEX DSP – LV Monitoring	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Monitoring device support and configuration management	707	0	177	177	177	177	(1)
Voltage monitoring & analysis - 1xFTE	495	0	124	124	124	124	(2)
Technical field staff - monitoring network support	503	0	126	126	126	126	(3)
Monitoring server & systems IT support and maintenance	93	0	0	31	31	31	(4)
Monitoring software licences	926	149	149	209	209	209	(5)
Telecommunications costs – 3G	226	22	51	51	51	51	(6)
Total IT / systems support OPEX	**2,950**	172	626	717	717	717	(7)

Table 2 – OPEX impact: smart meter support costs

Notes:

1. 1 x FTE plus associated costs, ongoing IT systems support and configuration management
2. 1 x FTE, ongoing operation of voltage monitoring system, analysis of data and liaison with other business stakeholders
3. 1 x FTE, technical field staff, ongoing field support for Phase 1 and 2 devices (424 devices)
4. Server hardware support & maintenance based on vendor contracts
5. Software licences, combination of in-house and Software-as-a-Service, for new Phase 1 and Phase 2 grid-side monitoring, as well as re-activation of externally-hosted meter monitoring system (Software-as-a-Service) in baseline area at current vendor pricing, and data warehouse license costs.
6. 3G data costs assume 186 devices in Phase 1, 238 added in Phase 2. Estimate $10 p.m. based on carrier costs, data volumes based on historical data from transformer monitoring
7. All costs are in 2013/14 $.

A further breakdown of these costs is provided in the spreadsheet included in Appendix A.

A DETAILED BREAKDOWN OF COST ESTIMATES

Refer attached spreadsheet cost model.

B AEMO SOLAR FORECAST

The figure below shows AEMO's most recent forecast for the increase in installed capacity of rooftop solar PV in South Australia to 2030. This figure appears in AEMO's *2015 National Electricity Forecasting Report (NEFR)* published in June 2015.

Figure 29 Rooftop PV forecasts for low, medium and high consumption scenarios in South Australia

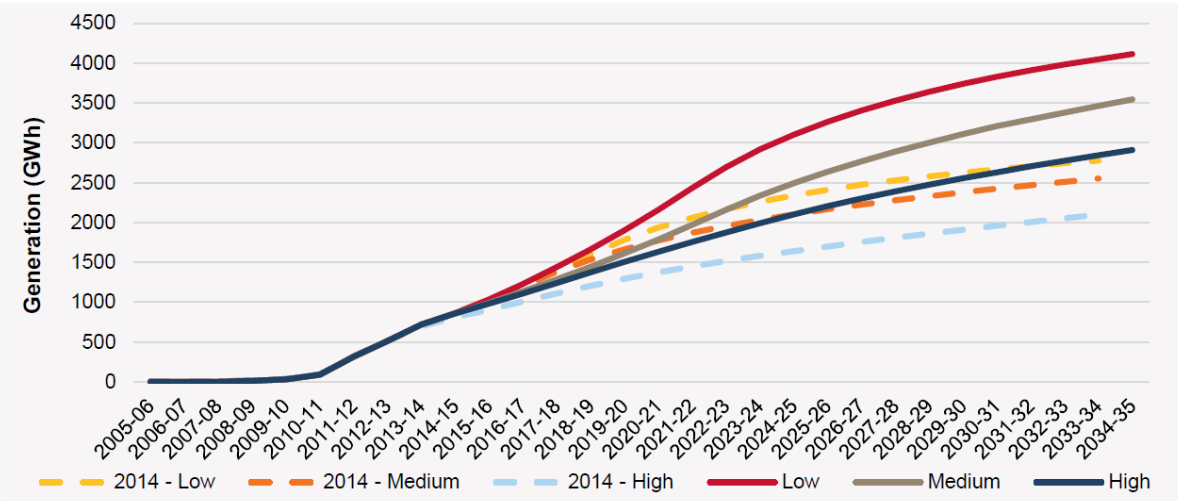

Figure 1- AEMO solar forecast for SA 2015

C SMALL SCALE LV MONITORING PILOT USING 'SMART READY' METERS

In 2013, following a competitive tender process, SA Power Networks established a smart meter trial area in the Adelaide suburbs south of Greenhill Rd. The trial area had a number of objectives:

- To test the technical feasibility of using a mesh radio network in the 900MHz band for smart meter communications when meters are installed in an ad-hoc manner to fewer than 10% of households[32], as would be the case under our proposed 'new and replacement' approach to deploying meter communications for LV monitoring.
- To establish baseline load profile data across representative customers in a number of different demographic segments, as a reference data set to analyse for customer response to cost-reflective tariffs.
- To assess the benefits of other smart meter functions, in particular the extent to which smart meters could be used as a low-cost platform for voltage monitoring.

C.1 Trial area

The trial area was established in the southern suburbs of Adelaide. Mesh network infrastructure was deployed to provide communications coverage in the area bounded by Marion Road to the west, Fullarton Rd to the east, Greenhill Road to the north and Daws Road to the south, an area of approximately 40 square km. Meters were deployed within a smaller region of approximately 12 square km located centrally within the mesh coverage area. These areas are shown in Figure 2 below.

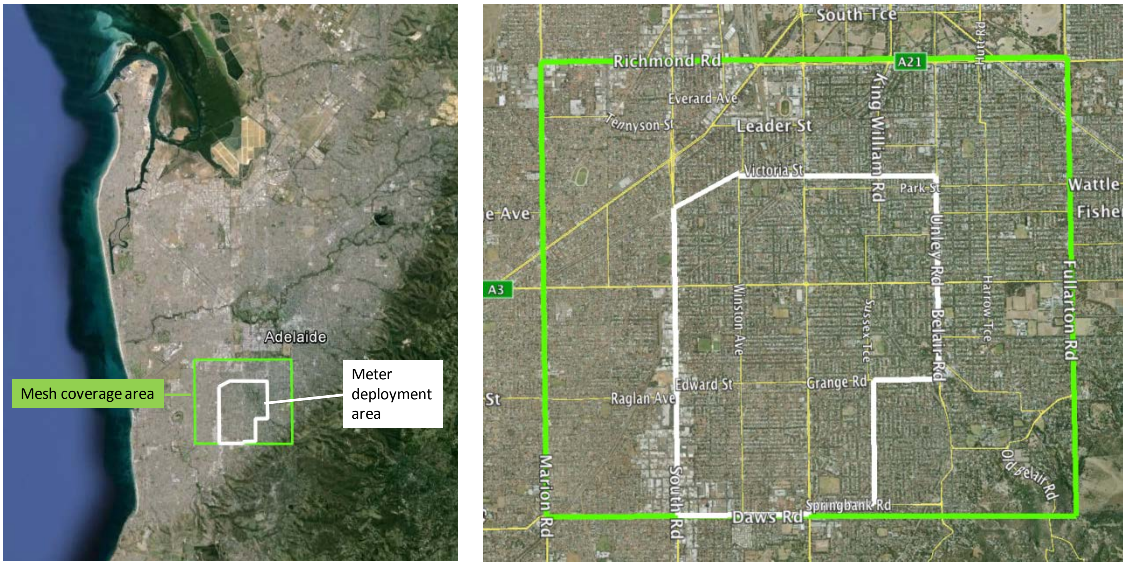

Figure 2 - Proposed trial area

The trial area comprises almost entirely flat, suburban terrain, with only a small area of undulating land in the foothills at the south eastern corner of the mesh coverage area. The majority of the area is zoned as single-storey residential housing of uniform density, with some industrial and commercial zones adjacent to the major roads. Figure 3 below is typical of residential housing within the area.

[32] Mesh radio operates at low power and relies on short range communications between meters to relay data. This has proven highly effective in Victoria in areas where every household has a smart meter, but performance in a sparse configuration in which there is a greater distance between each meter was not known.

Figure 3 - Housing within the trial area

The trial area includes around 30,000 customers, of which around 12,500 are located within the meter deployment region. Low voltage circuits in this area comprise overhead conductors supplied by 44 different pole-mounted LV distribution transformers. Solar PV penetration in this area is typical, at ~19% of customers as at May 2015.

C.2 Technical details

The meters deployed in the trial area are 'smart ready' meters from Landis & Gyr equipped with mesh radio modules from Silver Spring Networks (SSN). Backoffice software is hosted by SSN in their US data centre.

920 smart meters were deployed for the trial, of which approximately 70% are single-phase meters and 30% are 3-phase. Meters were deployed at customer premises selected in groups chosen to reflect a number of different demographic groupings, distributed sparsely and randomly through the trial area in a way that simulates an ad-hoc 'new and replacement' smart meter rollout.

Meter installation occurred between November 2013 and January 2014.

C.3 LV network voltage monitoring trial

Voltage alarm logging commenced on the 1st May 2014 and continued through to the 1st May 2015.

To limit the potential for transient alarms to be generated for meters operating close to the boundaries of the AS60038 voltage range of 216V-253V, meters were configured with extended alarm thresholds of 200V (under-voltage) and 260V (over-voltage). As a consequence, minor voltage excursions within this range were not logged.

C.4 LV network voltage monitoring – preliminary results

Voltage alarm data was downloaded from the meters in the trial area in May 2015. Figure 4 below shows a plot of the frequency of voltage alarms logged over the trial period[33].

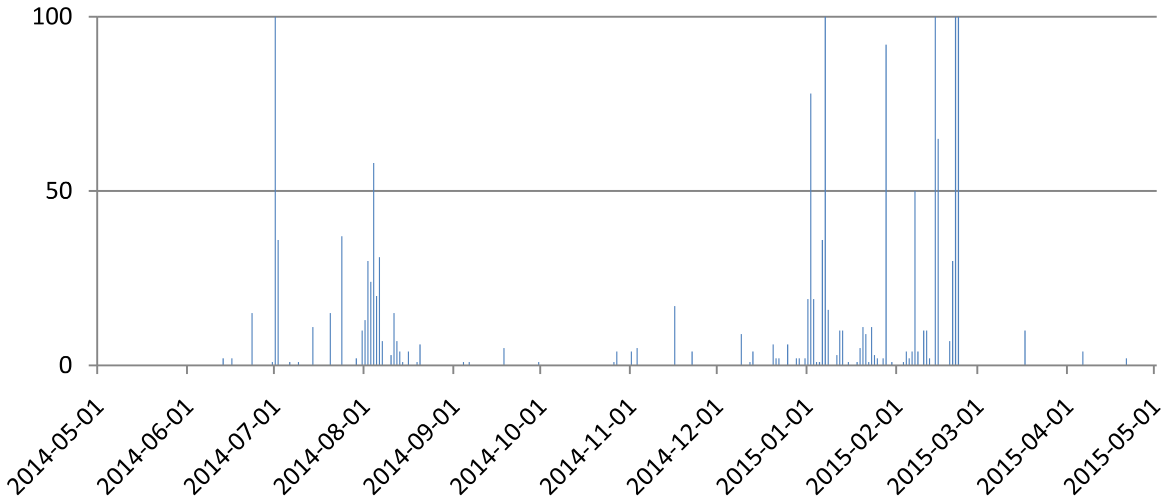

Figure 4 - Number of voltage alarms logged per day over trial period (excludes outlier events)

So far, only preliminary analysis of this data has been undertaken. The initial indications are that:

- 180 customer premises out of the 920 equipped with monitoring in the trial area generated voltage alarms indicating that supply voltage had varied beyond the extended range of 200V-260V during the 12 months from 1st May 2014 to 1st May 2015.
- These events occurred over 177 different days and comprised a mix of over-voltage and under-voltage events.
- The events appear to be seasonal in nature, with higher numbers of events occurring in winter and summer when network load is highest.

During the same 12 month period our call centre received only 9 customer complaints attributed to power quality from residents in the trial area, which contains around 12,500 customers in all. These are shown in the table below:

Notification	Created on	Description	Street	City
100709962	13.05.2014	High Voltage	Removed	Millswood
100713444	01.07.2014	Low Voltage	Removed	Millswood
100713718	07.07.2014	Low Voltage	Removed	Millswood
100713760	07.07.2014	Lights flickering	Removed	Clarence Park

[33] The raw data has been filtered to exclude data from two specific events deemed to be atypical, namely one customer premises that appears to have had a specific local issue that caused a high volume of alarms for a period in 2014, and one day in January 2015 in which a grid-side overvoltage problem caused alarms at a number of premises.

Notification	Created on	Description	Street	City
100714600	21.07.2014	Low Voltage	Removed	Cumberland Park
100719137	08.10.2014	Flickering	Removed	Millswood
100719871	17.10.2014	High Voltage	Removed	Colonel Light Gardens
100728407	25.02.2015	Flickering	Removed	Black Forest
100730794	27.03.2015	High Voltage	Removed	Clarence Gardens

Table 3 - Customer quality of supply complaints

D LV TRANSFORMERS WITH MORE THAN 50% SOLAR PENETRATION

The table below shows the 57 LV transformer areas selected for active monitoring in Phase 2 as they:

1. Are in areas with overhead LV infrastructure
2. Have more than 10 customers
3. Have more than 50% penetration of solar PV as at May 2015 (by number of connected customers).

Feeder	Transformer ID	Solar NMIs	Solar capacity (kW)	Total customers	PV penetration
SM216E	67	18	30.9	20	90%
HH403C	61	15	53.1	18	83%
GA745B	43	11	38.84	14	79%
PP03	52	12	45.25	16	75%
NL451A	29	14	46.73	19	74%
PA13	68	11	72.46	15	73%
PA26	21	13	51.88	18	72%
PL07	91	15	83.5	21	71%
MV64	28	17	32.65	24	71%
NU15	63	12	69.49	17	71%
YK17	39	14	43.11	20	70%
KA22	31	15	46.22	22	68%
PA14	52	14	58.52	21	67%
NL451A	7	14	50.47	21	67%
WHY05	8	31	137.56	47	66%
VH15	83	117	183.41	178	66%
ST21	69	11	32.68	17	65%
VH45	51	20	40.38	31	65%
WHY05	7	19	73.36	30	63%
KA22	43	13	55.78	21	62%
SA36	99	115	269.02	186	62%
MB62	1	22	75.52	36	61%
PA05	16	11	54.43	18	61%
EL23	7	11	52.5	18	61%
EL23	6	11	29.24	18	61%
GA28	30	13	29.74	22	59%
HH409A	12	14	94.88	24	58%
GA25	42	14	39.21	24	58%
LX43	13	11	43.55	19	58%
SA17	51	16	40.41	28	57%
PP03	51	17	113.79	30	57%
KA05	53	13	57.33	23	57%
VH15	92	13	42.62	23	57%
PA14	28	14	53.72	25	56%
WHY06	13	15	64.77	27	56%
MT06	14	11	48.02	20	55%
GA05	10	11	42.58	20	55%
VH22	5	11	39.77	20	55%
MV52	21	31	83.01	58	53%

Feeder	Transformer ID	Solar NMIs	Solar capacity (kW)	Total customers	PV penetration
WHY03	7	16	60.75	30	53%
PA08	6	16	59.64	30	53%
HH409D	91	16	51	30	53%
SM126C	75	11	33.25	21	52%
PP06	60	24	106.06	46	52%
AP529E	38	24	69.42	46	52%
MB24	22	12	39.64	23	52%
SM216E	60	12	28.24	23	52%
AP355A	17	13	41.79	25	52%
ST12	14	13	53.05	25	52%
VH11	7	14	43.26	27	52%
VH45	42	33	91.91	64	52%
AP125D	57	17	59.54	33	52%
PL07	98	17	59.33	33	52%
MT22	24	17	56.39	33	52%
GA25	41	18	73.86	35	51%
PA05	15	20	74.47	39	51%
MV64	35	36	98.17	71	51%

Table 4 – Phase 2 LV transformer areas

E THE TWO-WAY RESIDENTIAL NETWORK IN 2013/14

The figure below illustrates the extreme variation in daily maximum and minimum demand (kW) across the whole residential network during 2013/14[34]. It can be seen that net residential demand varied between a maximum of more than 1.7 GW during summer peak demand days, to a minimum demand that was more than 150 MW net negative (i.e. energy fed into the LV network from solar PV exceeded total demand across the residential sector) on mild, sunny days during spring and autumn.

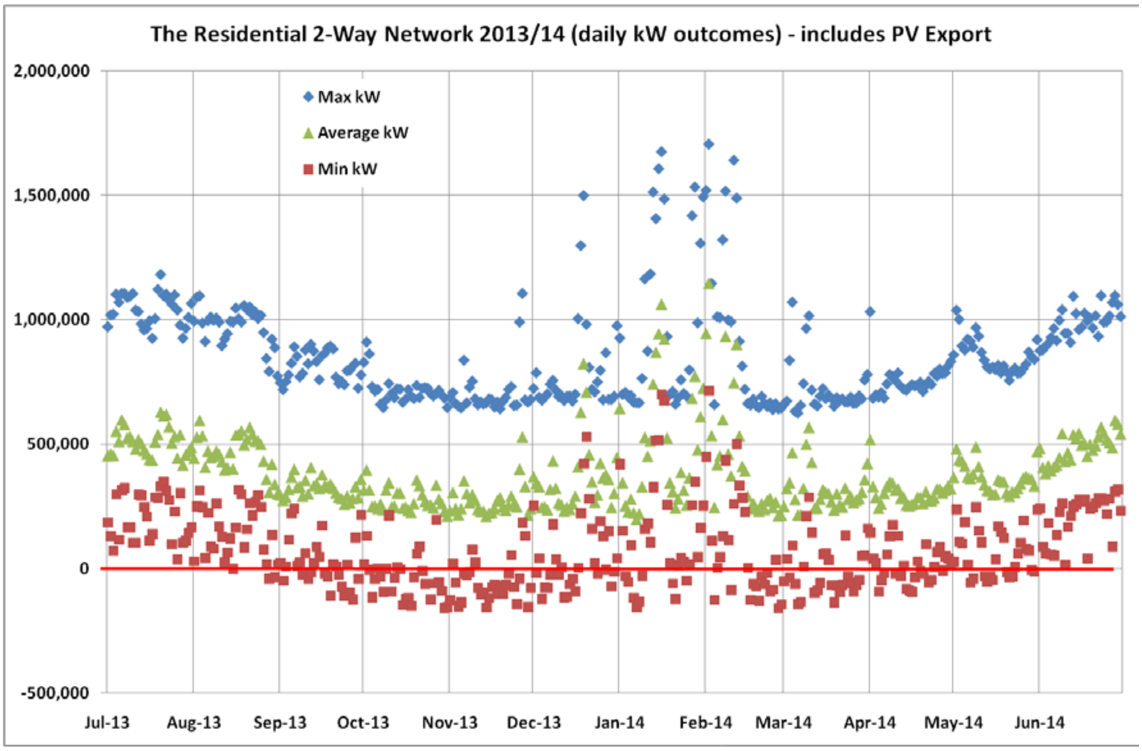

Figure 5 - 2-way energy flows in the residential network 2013/14

The following figure shows daily load profiles for the residential sector over seven consecutive days in January 2014. The figure shows that total residential demand varied over a range of +1,700 MW to -100 MW during this one week. Such extreme variations in load have arisen primarily as a consequence of the very high uptake of residential solar PV in the last four years, and present unprecedented challenges in voltage regulation in the LV network.

[34] Data estimated from representative sample of load profile meters across the residential sector

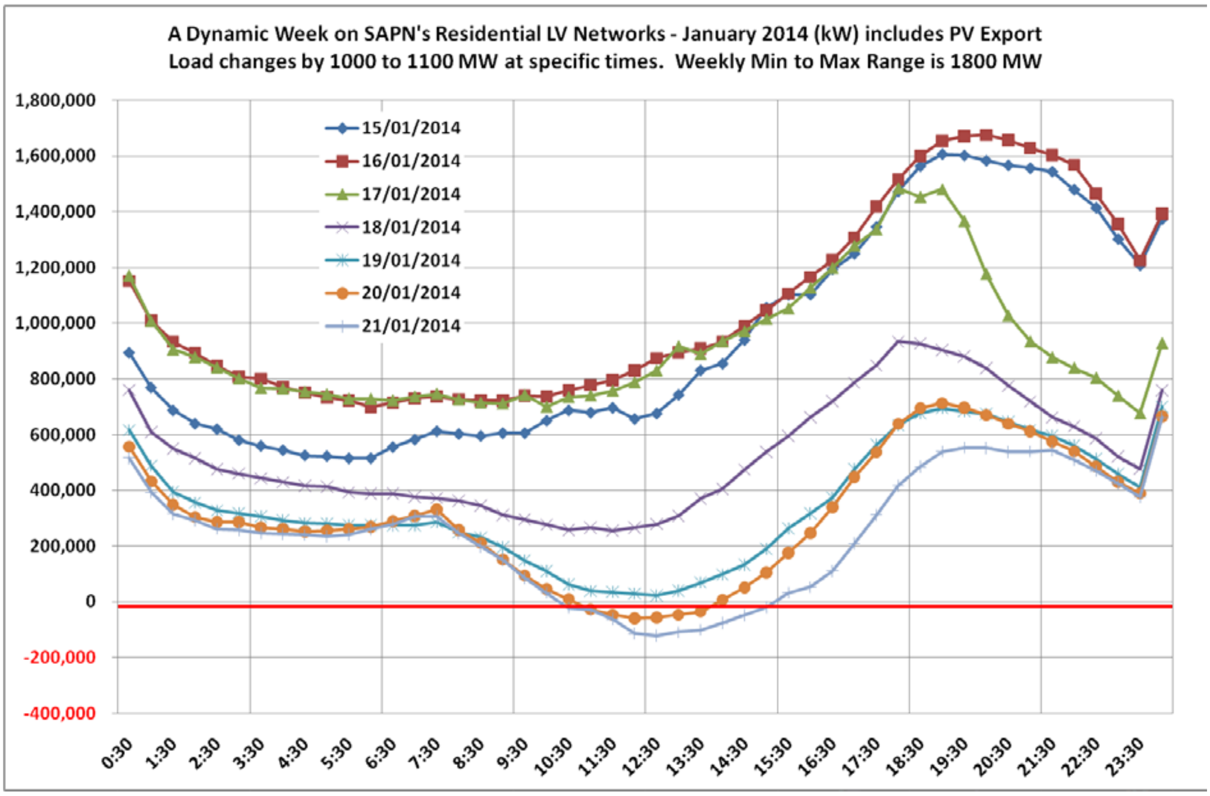

Figure 6 – daily load profiles for the residential network in January 2014