SA Power Networks

Supporting document 5.15

LV Transformer Monitoring Business Case

2020-25 Revised Regulatory Proposal

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SA Power Networks

LV transformer monitoring business case

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SA Power Networks
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Contents

Summary

This business case recommends new expenditure in the 2020-2025 regulatory control period (**RCP**) to install and commission permanent remote monitoring at a sample set of approximately 1,300 multi-customer Low Voltage (**LV**) distribution transformers in the metropolitan area to improve capacity planning in the LV network.

The program requires capital expenditure (**capex**) of $5.65 million over the 2020-2025 RCP, as well as new operating costs (**opex**) in telecommunications and maintenance costs of $0.51 million over the RCP. These new operating costs are more than offset by efficiency savings delivered by the program, resulting in a net reduction in opex, after factoring in underlying growth, of $1.27 million over the RCP.

In the longer term, the permanent monitoring sites established through this program will enable the current practice of undertaking around 500 transformer load surveys each year using temporary loggers to be phased out, giving a permanent reduction in operating costs. As a consequence, over the 15-year life of the transformer monitors the program has positive net present value (**NPV**) under all sensitivity cases considered in the business case.

Context and related documents

This business case relates to the LV monitoring program in Attachment 5 – Capital expenditure; and the LV Transformer Monitoring negative step change in Attachment 6 – Operating expenditure.

The capital expenditure is in addition to 'Business as Usual' (**BAU**) expenditure on LV network maintenance which will continue through the 2020-2025 RCP, although efficiency savings delivered by the program do result in a reduction in BAU capex in the later years of the RCP.

This program is also separate to our strategic LV management program which is developing new operational capabilities to actively manage exports from small-customer Distributed Energy Resources (**DER**) such as rooftop solar and home batteries. The relationship between these programs is described in detail in Supporting Document 5.14 - DER Management Expenditure Overview.

Drivers for change

Although state-wide peak demand in South Australia is forecast to remain relatively flat over the next 15 years[1], we continue to experience localised areas of peak demand growth across the distribution network, particularly in the metropolitan area, primarily due to infill development.

One of the functions of network planning is to forecast, each year, which local LV transformers are reaching capacity so that transformer replacements or other augmentation works can be undertaken prior to the summer peak demand season. Our current method of forecasting load in the LV network relies on very limited data, however, and hence has limited accuracy.

Whenever this forecasting process fails to identify a transformer that has reached capacity, the transformer will become overloaded under summer heatwave conditions and fuses will operate, causing a loss of supply for customers in the area. During the 2018/19 summer there were around 250 such fuse operations due to overload, causing loss of supply for around 20,000 customers with an average duration of four hours per customer, predominantly at peak afternoon heatwave times.

[1] Australian Energy Market Operator's (**AEMO**'s) current forecast to 2035 for South Australia shows annual growth in peak demand of 0.1% - 0.4% for the state; refer AEMO 2019 Electricity Statement of Opportunities, August 2019, available at https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/2019-Electricity-Statement-of-Opportunities.pdf

Current practice

Although we have a supervisory control and data acquisition (**SCADA**) system to monitor many of our major high voltage (**HV**) assets such as substations, we have almost no permanent monitoring of our LV transformers. In order to forecast load growth, we conduct around 500 load surveys on individual transformers over the course of each year by installing temporary loggers to record load data over a period of one week. At the end of each one-week survey a crew returns to the site to un-install and recover the logger, and the logged data is then analysed in an effort to predict whether the transformer is likely to become overloaded under summer peak conditions.

Limitations of current practice

Our current practice has several limitations:

- As we have a limited number of temporary loggers and limited field crew to undertake survey work, surveys are spread throughout the year. This means that in most cases it is necessary to estimate summer peak demand from a limited set of measurements captured in winter, spring or autumn, where prevailing load conditions are very different. The methods used for this estimation cannot always produce an accurate forecast of summer peak demand from this data.

- The limited one-week window over which data is captured for each survey can also cause inaccuracy in the final forecasts, if the period of measurement happens to be atypical in some way.

- Network conditions can change in between when the survey is conducted and the summer peak.

- Resource limitations mean that it is only possible to survey around 500 individual transformers each year. We do not currently have a model of our LV network and because of this we do not have network planning tools able to accurately estimate performance of other transformers based on those that are surveyed.

As noted above, the limitations of this approach are evident in the significant number of unplanned customer outages that occur each summer due to un-forecast transformer overloads.

This survey-based approach to load forecasting no longer aligns with industry best practice. Most networks now use model-based approaches using data from permanent LV transformer monitors and, particularly in Victoria, smart meter data. These more modern approaches to LV network planning using permanent monitoring equipment and network models also create opportunities for synergies with other functions such as reactive investigation of customer-reported power quality problems.

The identified need

SA Power Networks is required under clause 5.2.1(a)(3) of the National Electricity Rules (**NER**) to maintain and operate its network in accordance with good electricity industry practice and relevant Australian Standards.

In addition, SA Power Networks' forecast capex and opex expenditure for the 2020-2025 RCP must comprise the forecast expenditure that SA Power Networks considers is required in order to:

- meet or manage the expected demand for standard control services over the 2020-2025 RCP;
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services; and
- maintain the quality, reliability and security of supply of standard control services (where there are no applicable regulatory obligation or requirement).

Effective capacity planning in the LV network and the proactive upgrade of overloaded transformers before they cause customer outages is a core function used to deliver standard control services and ensure continuity of supply for customers.

Options considered

In this business case we consider the costs and benefits of investing during the 2020-25 RCP to bring our LV load forecasting capability up to current industry standards. We have considered the following options:

1. **Option 1 – do nothing**: continue the current practice of rolling surveys of around 500 LV transformers each year through the 2020-25 RCP using temporary loggers. This is the baseline for the business case.
2. **Option 2 – parallel deployment of permanent monitoring:** extend our current 3-year LV transformer monitoring program. This program commenced in 2017 with a pilot rollout of 200 monitors and has a target to roll out a further 200 monitors each year in 2018 and 2019. Under this option, this program would continue in 2020-25 and be scaled up to a rate of 500 new monitors each year in order to reach a total of around 1,900 transformers (10% of target population) with permanent monitoring by the end of the period. This will establish a sufficient sample across the metropolitan area to implement a new LV load forecasting methodology. This would be based on a modern, model-based planning tool that would estimate summer peak demand across all transformers by reference to (a) the representative sample set of LV transformers with permanent monitoring and (b) customer load profiles from smart meters in the transformer area. Once the new load forecasting methodology is in place we would be able to discontinue the current practice of temporary load surveys from mid-2024 onwards, yielding a permanent reduction in the operating cost associated with the load survey program. This is essentially the option that was put forward in our Regulatory Proposal, with the costs and benefits re-modelled using updated information, including the use of a lower-cost monitoring unit than the one assumed in our original proposal.
3. **Option 3 – leverage current survey program to deploy permanent monitoring:** continue with the current rolling program of load surveys, but instead of installing a temporary logger, install a permanent LV transformer monitor at each survey site. As we undertake a little over 500 load surveys each year, we can achieve the same coverage of 1,900 transformers by the end of the 2020-25 RCP as option 2, but we can do this at a much lower cost because we are leveraging the transformer site visits and installation works that would have been undertaken anyway for load surveys, rather than running a parallel project to roll out permanent monitors. In this approach we also avoid the normal cost of returning to each survey site after one week to recover the temporary logger, and we avoid the additional administrative and project management costs associated with the rollout in option 2. In other respects, this option is the same as option 2. This is the option recommended in this business case.

4. **Option 4 – use only smart meter data to estimate transformer load**: in this option we would not install any permanent transformer monitors during the 2020-25 period, but we would seek instead to develop a new forecasting tool using only smart meter data (customer load profiles) to estimate LV transformer loads. This approach is untried in South Australia and our initial technical assessment is that, unlike options 2 and 3, it would not provide a credible replacement for current practice during the 2020-25 period, as there won't be enough customers with smart meters in most areas to enable an accurate model of transformer peak loading. As smart meter penetration builds over the 2020-25 and 2025-30 RCPs, however, this approach does have the potential to progressively reduce the number of transformer surveys required over time.

Differences between this business case and our Original Proposal

As noted above, we proposed a roll-out of permanent LV transformer monitors of similar scale and scope to option 2 in SA Power Networks 2020-25 Regulatory Proposal (**Original Proposal**). This expenditure was not approved in the Australian Energy Regulator's (**AER's**), Draft Decision for SA Power Networks Distribution Determination 2020 to 2025 (**Draft Decision**), finding that (a) we had not adequately justified why monitoring at the LV transformer is required and (b) that we did not appear to have taken into account the efficiency benefits, which would be expected to reduce business-as-usual operating costs in our Quality of Supply (**QoS**) program.

The AER also felt that the interrelationships between this program and related expenditure items in our BAU Quality of Supply capex and our strategic LV network management programs had not been taken into account. Finally, some stakeholders also questioned whether the proposed expenditure was efficient, ie whether we had identified the least-cost solution.

In the time since our Original Proposal was lodged in January 2019 we have undertaken significant further work on this project in an effort to address the above concerns, and this business case differs from our original in several areas:

- The unit cost of a permanent transformer monitor ($4,300) used in our original proposal was based on the cost of the devices we are currently rolling out in our 3-year pilot project, which commenced in 2017. In Q2 2019 we tested the market again through a formal Expression of Interest (**EOI**) process. This EOI identified five candidate products with a significantly lower price than our current product. We are currently in the process of evaluating these, but it appears likely that at least one of them will be suitable, so we have used the average price of these units ($2,500) as the basis of our revised cost estimate in this business case.

- We have proposed a new approach to rolling out permanent monitoring by leveraging the existing survey work program, as described above. This significantly reduces the cost of our preferred option (option 3) compared to the dedicated transformer monitoring rollout assumed in our Original Proposal. We have also reduced the final number of monitors slightly based on a more detailed assessment of how to target this sample set, with a focus on a representative sample of multi-customer, predominantly residential LV transformers in the metropolitan area. In combination, the lower unit cost and the more efficient rollout and installation strategy have reduced the forecast capex requirement from $18 million in our Original Proposal to $5.65 million under our preferred option.

- We have reviewed and substantially reworked and improved the financial modelling of costs and benefits used in the business case. In particular:

    - We have taken into account the impact of our strategic LV management program in reducing the incidence of customer-reported over-voltage issues in the long term. While this does not affect the core purpose of this program, which is transformer load forecasting, it does have a bearing on the calculation of one of the consequential benefits of permanent transformer monitoring, which is to avoid some of the costs associated with the reactive investigation of customer quality of supply issues. Reducing the number of customer issues through improving operational management of voltage in the LV network has the effect of reducing the value of this particular benefit over time.

- Our Original Proposal did not include any step change in Quality of Supply operating expenditure. For this business case we have re-worked our opex forecast to take into account new operating costs associated with the permanent transformer monitors, underlying growth trends, and the efficiency benefits of our preferred option. The net result is a reduction (negative step change) in opex of $1.27 million over the 2020-25 RCP, which we have included in our revised proposal.

- In addition to the opex savings, we have identified an efficiency benefit of around $0.4 million in avoided BAU QoS capex during the later years of the 2020-25 RCP, and this has been factored into that line item in our revised regulatory proposal.

- We have updated underlying opex forecasts to include trend data up to September 2019.

- We have considered a number of sensitivity cases to test the robustness of the benefits identified in the business case against errors in our assumptions.

Recommended option

A cost/benefit analysis indicates that option 3, 'leverage current survey program to deploy permanent monitoring' is the option that best promotes the NEO and reflects the expenditure criteria[2]. It delivers the best outcome of all the options considered in 15-year[3] NPV terms and, when compared to the 'do nothing' option (option 1), it also offers a number of additional benefits that have not been quantified herein. This option and the associated cost/benefit analysis are set out in detail in the remaining sections of this business case.

Features of option 3

Option 3, 'leverage current survey program to deploy permanent monitoring', includes the following elements:

- Permanent LV transformer monitors installed in place of temporary loggers during scheduled BAU load surveys through the 2020-25 period.

- Ramp up in 2020/21 followed by installation at the planned survey rate of 541 devices per annum through to 2024, for a total of 1,384 new loggers installed over the period. This will bring the total number of transformers with permanent monitoring to 1,986 including the 602 installed from 2017 to 2019, sufficient to establish a baseline sample set of 10% of our 19,856 multi-customer residential LV transformers[4].

- Development of a new model-based LV load forecasting software tool by mid-2024 and associated new load forecasting methodology. This will use year-round data captured from the sample set of permanent monitors, in combination with actual customer load profiles

[2] The capital expenditure criteria are set out in the NER 6.5.7(c) and the operating expenditure criteria are set out the NER 6.5.6(c).
[3] The 15-year time horizon for the cost/benefit analysis reflects the expected asset life of the transformer monitiors
[4] Our estimate of 10% as the minimum sample set required for a model-based approach to forecasting has been informed by advice from consultant EA Technology on similar approaches overseas; refer Original Proposal, Supporting Document 5.21, EA Technology, *LV Management Strategy*, report prepared for SA Power Networks, v1.0, December 2018.

from smart meters where available[5], to produce an annual load forecast for all metropolitan transformers. Once this is in place and the rollout of monitors is complete, the current practice of surveying more than 500 individual transformers each year can be discontinued. This will result in a permanent efficiency reduction in opex from 2024 onwards.

These elements are shown in Figure 1 below.

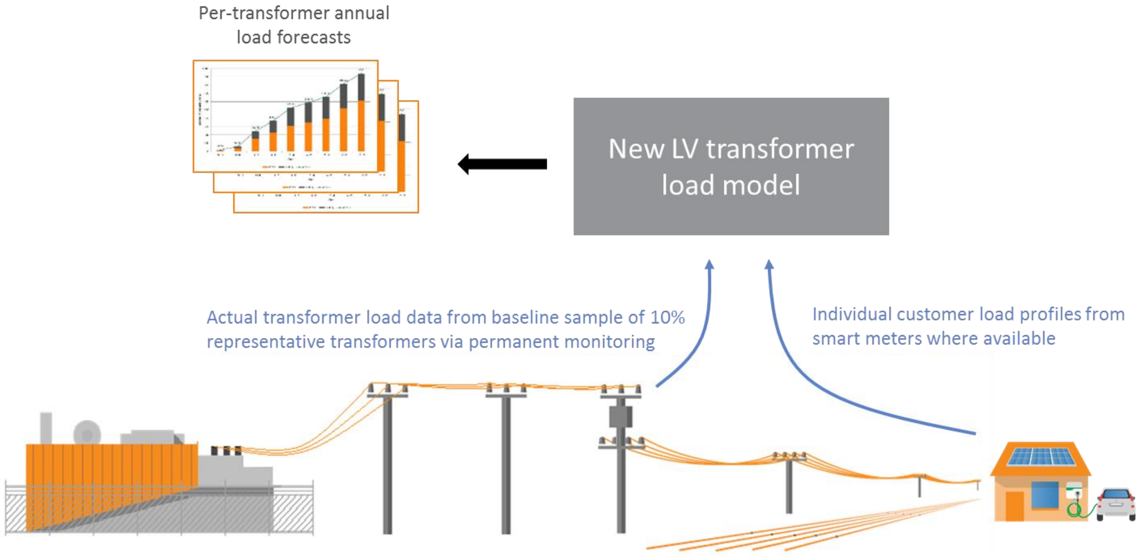

Figure 1. Components of proposed new LV transformer load forecasting method

Estimated costs

Capital expenditure

The estimated capital cost to implement option 3 is $5.65 million over the 2020-2025 RCP ($2019), as shown in the table below and the explanatory notes that follow.

Table 1: Capex costs of preferred option

Capex ($ million, $2019)

Work package	20/21	21/22	22/23	23/24	24/25	Total	Note*
Transformer monitors - materials	0.50	1.35	1.35	0.25	0.00	**3.46**	*(1)*
Transformer monitors - installation costs	0.21	0.58	0.58	0.11	0.00	**1.48**	*(2)*
Load forecasting software	0.00	0.00	0.31	0.25	0.00	**0.56**	*(3)*
Business process change	0.00	0.00	0.00	0.05	0.00	**0.05**	*(4)*
Project management	0.00	0.00	0.05	0.05	0.00	**0.10**	*(5)*
Totals	**0.71**	**1.93**	**2.29**	**0.72**	**0.00**	**5.65**	

*Refer to notes on following page.

Notes:

[5] Note that the meter data relevant to load forecasting is customer interval energy data, which we already receive from customers with smart meters as a matter of course through the normal market systems. This is not the same as the voltage data and other data that we intend to use to support our new operational systems (under our strategic LV management program), which we are required to procure separately from metering coordinators.

1. Total of 1,384 transformer monitors at average cost of $2,500 each.
2. Average installation cost per transformer monitor of $1,069.
3. Development of new model-based LV load forecasting software tool.
4. 12 weeks of effort to develop new LV planning practice based on model-based load forecasting and develop transition plan to phase out current survey program.
5. Project management is for load forecasting tool development and business process change activities only, estimate 0.25 FTE through 2022/23 and 2023/24. Project management and administrative cost associated with deployment of permanent monitors is factored into per-unit installation cost in line with current practice.
6. All costs are in $2019 including relevant business overheads.

Operating expenditure

There is an increase in operating costs associated with implementing option 3 of $0.51 million over the 2020-2025 period RCP ($2019) as shown in the table below and the explanatory notes that follow.

Table 2: Opex costs of preferred option

Opex ($ million, $2019)

Work package	20/21	21/22	22/23	23/24	24/25	Total	*Note*
Telecommunications costs	0.01	0.04	0.08	0.08	0.08	**0.30**	*(1)*
Transformer monitors - maintenance	0.01	0.03	0.05	0.05	0.05	**0.18**	*(2)*
Software maintenance costs	0.00	0.00	0.00	0.01	0.01	**0.03**	*(3)*
Totals	**0.02**	**0.07**	**0.12**	**0.15**	**0.15**	**0.51**	

Notes:

1. New telecommunications costs for permanent transformer monitors at $5 per month / $60 per annum.
2. Ongoing maintenance and repair costs for permanent transformer monitors, at 1% of capital value.
3. Hosting and maintenance costs for new LV planning software.
4. All costs are in $2019 including relevant business overheads.

Operating expenditure benefits (negative step change)

The associated increase in opex of $0.51 million over the RCP is more than offset by efficiency savings delivered by the program, resulting in a net reduction in opex (a negative step change), after factoring in underlying growth, of $1.27 million over the RCP as shown in the table below.

Table 3: Opex negative step change

Opex ($ million, $2019)

Work package	20/21	21/22	22/23	23/24	24/25	Total
Underlying QS opex increase	0.17	0.27	0.37	0.45	0.45	**1.71**
Transformer monitoring new opex	0.02	0.07	0.12	0.15	0.15	**0.51**
QS opex savings	-0.30	-0.76	-0.80	-0.81	-0.81	**-3.48**
Total (negative step change)	**-0.11**	**-0.42**	**-0.31**	**-0.22**	**-0.21**	**-1.27**

Cost estimation methodology

Specific methods used in developing and refining the cost estimates for this business case included:

- Use of standard labour costs in pricing internal and contract resources.
- Use of actual installation costs from the current LV transformer monitoring pilot program commenced in 2017, as well as the BAU load survey program.
- Market engagement through a formal EOI process in Q2 2019 to seek quotes for low-cost LV transformer monitors. This EOI identified at least five products that may be suitable, and these are currently under evaluation.
- Estimates of in-house and outsourced software development costs based on actual development costs for related software in our current Australian Renewable Energy Agency- (**ARENA**) funded trials, and the modelling done by KMPG for our strategic LV management business case.
- Industry working groups to seek industry input, share learnings and leverage other Distribution Network Service Providers' (**DNSP**'s) experience in the area of LV network monitoring, including the biannual Future Network DNSP forum that we instigated in 2018 which has been attended by all Australian DNSPs, both within and outside the National Energy Market (**NEM**).

Further details of the costs and the estimation methodology are included in Appendix A.

Estimated benefits

As shown in the table below, option 3 has an estimated positive net benefit of $4.23 million (NPV[6] to 2035) under base case assumptions, yielding a profitability index (**PI**) of 1.8.

[6] Discount rate of 2.63%

Table 4: Net costs and benefits of preferred option (NPV to 2035)

NPV ($ million)

Item	NPV to 2035
Capital cost of permanent monitors & new load forecasting systems	-5.29
New operating costs	-1.58
Efficiency benefit 1 - avoided load surveys	7.95
Efficiency benefit 2 - reduction in BAU QoS capex	2.08
Efficiency benefit 3 - avoided temporary logger installs for customer investigations	1.08
NET	**4.23**

The following sections describe how these benefits are calculated.

Benefit 1 – Avoided load surveys

In our preferred approach (option 3), the rollout of permanent transformer monitors is undertaken effectively in place of the business-as-usual process of conducting temporary load surveys, as we use each regular scheduled load survey to install a permanent monitor at the transformer instead of installing a temporary logger. The cost to attend the site and install the permanent logger is captured entirely within the new capex for the program. The original cost of the survey program, which is historically included in Quality of Supply opex, is essentially replaced with the new capex program in the 2020-25 RCP. From mid-2024 onwards this opex cost is avoided permanently with no corresponding capex, as we do not need to continue to install permanent monitors after 2024, once the sample size necessary to support model-based load forecasting has been achieved.

While the majority of this benefit manifests in avoided opex, a component relates to the reduced cost of data analysis and administration in the latter part of the 2020-25 RCP when the new load forecasting tool becomes available. These costs are historically included in BAU QoS capex, and so this portion of the benefit has been deducted from that capex line in our Revised Proposal – referred to as '**Efficiency benefit 2 – reduction in BAU QoS capex**' in the table above.

Benefit 3 – Avoided transformer loggers for customer QoS investigations

A consequential benefit of the installation of permanent, rather than temporary, logging for load surveys is that the data from the permanent loggers can also assist in investigating common customer-reported quality of supply issues such as solar inverters tripping off due to over-voltage conditions at certain times.

In the absence of any permanent monitoring in the LV network, we rely today on the installation of temporary loggers to investigate customer-reported issues. When a customer reports an issue, unless it is apparent that the customer's own wiring or equipment (eg incorrect inverter settings) are at fault, we will install temporary logging equipment at both the customer connection point and the local LV transformer for a period of one week to determine whether the issue is due to inadequate voltage regulation in the local LV network.

As we roll out permanent monitoring to progressively more LV transformers for load surveys under option 3, there is a small but increasing likelihood that any given customer enquiry will be in an area where the LV transformer already has a permanent monitor. In these cases, the normal cost to install a temporary logger at the transformer to investigate the customer's issue is avoided. This benefit increases initially with increasing customer enquiries due to the impacts of increasing rooftop solar; but decreases from 2023 onwards as our strategic LV management program begins to reduce the impact of new solar installs on the network through dynamic operational management of customer export limits.

Comparison of options

Figure 2 below compares the costs and benefits of the four options using our base-case input assumptions.

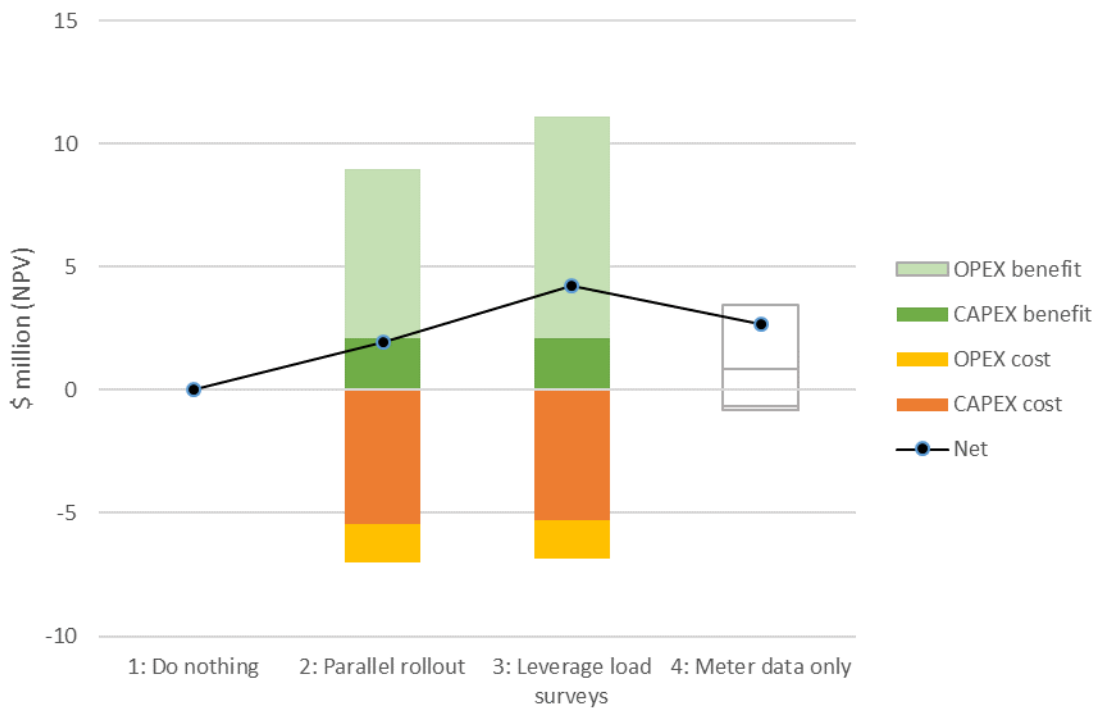

Figure 2. Cost/benefit analysis: base-case

In the figure above, option 1, 'do nothing' is considered as the baseline. The costs and benefits of the other options are presented relative to this baseline as follows:

- Capital and operating costs of each option are shown as negative values, below the horizontal axis, and capital and operating savings are shown above the axis as positive values. The line shows the net outcome.
- All figures are NPV to 2035

The chart illustrates that option 3 has the greatest positive NPV of the options considered. It is recommended over option 1, 'do nothing' because the long-term efficiency gains achieved in replacing the current practice of annual load surveys with a modern load forecasting method supported by a sample set of permanent transformer monitors and data from smart meters outweigh the capital cost of permanent monitors and the associated new software modelling tool.

In comparison, option 2, 'parallel deployment of permanent monitoring', which is broadly equivalent to the approach proposed in our original proposal but using lower cost monitoring devices, achieves the same long-term outcome as option 3 but does not benefit from the efficiency of leveraging the 2020-25 load survey program to undertake the rollout. In option 2 the normal opex cost of the annual survey program is still required until the rollout of permanent monitors is complete, whereas this cost is avoided from the beginning of the period under option 3, and so option 3 delivers a higher net benefit overall.

As noted above, we do not consider option 4, 'use only smart meter data to estimate transformer load', to be a credible option to replace our current load forecasting practice in the 2020-25 RCP, as there will be insufficient density of smart meters in the period. Estimating transformer load from meter data alone without reference to a baseline of actual transformer data is challenging at low meter densities because:

- Density of smart meters will vary by network area and customer demographic, noting that a key driver of meter replacements for the next ten years will be rooftop solar uptake;
- Transformer load estimation needs to take into account load on each phase. We cannot map a smart meter load profile to a specific phase as we do not have records of which phase each customer connects to. Permanent transformer monitoring will provide a sample set of per-phase data and enable modelling of phase imbalance;
- Because smart meter data set will tend to be dominated by solar customers during the 2020-25 RCP, load profiles for non-solar customers will tend to be under-represented.

For these reasons we could not rely only on smart meter data to forecast transformer load with the level of accuracy required to make decisions on transformer replacement in 2020-25.

Although we do not consider this a credible option, it is informative to consider the potential costs and benefits of this approach in the options analysis. Figure 2 shows how this approach would compare to our other options if we were able to develop a model using only smart meter data that could progressively replace the use of transformer surveys as meter penetration grows. The analysis suggests that this approach would deliver a poorer outcome in NPV terms than our preferred option under base-case assumptions. Compared to options 2 and 3 it would not enable the practice of temporary load surveys to be discontinued completely in 2024, and it would also not deliver the consequential benefit of avoiding the need for temporary transformer monitoring to investigate customer-reported quality of supply issues[7]. Finally, we anticipate a number of other benefits from improved network visibility at the LV transformer level that we have not sought to quantify in the cost/benefit analysis that would not be delivered under option 4; these non-quantified benefits are described in more detail below.

Sensitivity analysis

To test the options against a range of plausible future scenarios, the cost/benefit modelling was repeated for a number of sensitivity cases in which key input assumptions were varied. In constructing the sensitivity cases our approach has been:

a) to focus on credible future scenarios;

b) to consider variables most likely to affect the ranking of net economic benefits across the options under consideration; and

c) to explore changes in those input variables where there is the greatest uncertainty in the assumptions – in this case

   - the forecast long term impact of our strategic LV management program in reducing the incidence of customer-reported voltage issues from the latter part of the 2020-

[7] This kind of investigation requires a comparison of measurements taken at the transformer with measurements at the customer connection point in order to determine whether network performance is at issue, and uses a richer QoS data set at the transformer than could be derived from meter data, even at high meter densities.

25 RCP onwards through improved operational management of customer export limits, which affects some of the long-term benefits of permanent transformer monitoring; and

- the level of penetration of smart meters required in the local area to construct a transformer load forecast under option 4.

The outcome of the sensitivity analysis is shown in Figure 3 below.

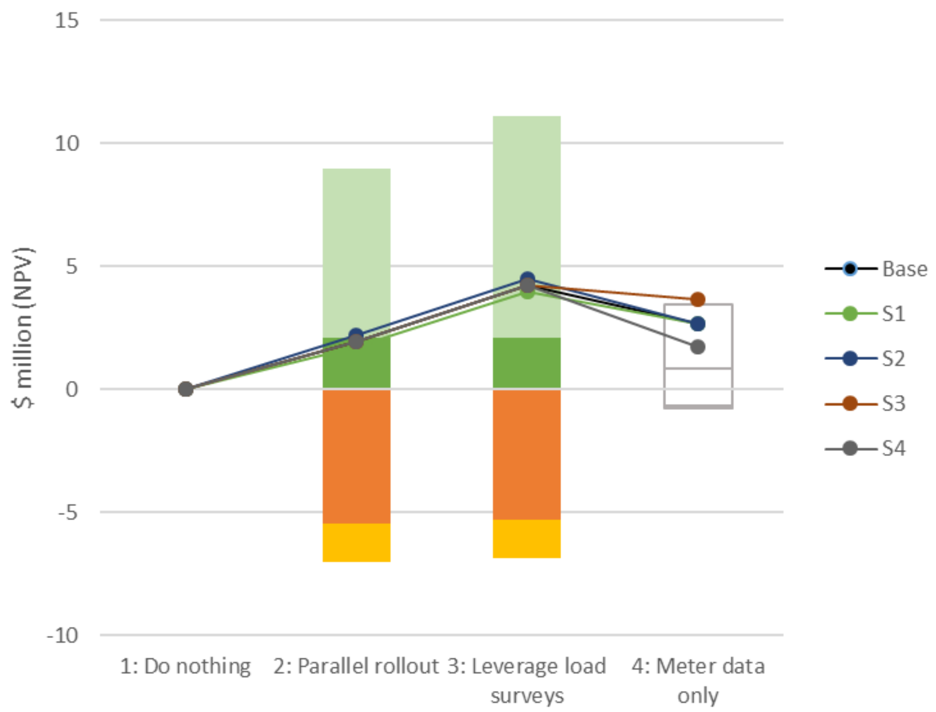

Figure 3. Cost/benefit analysis: sensitivity analysis

This analysis found that option 3 gave a net positive outcome compared to the 'do nothing' case (option 1) for all the modelled sensitivities and outperformed options 2 and 4 in all cases. The details of the specific combinations of input assumptions used in the sensitivity scenarios are included in appendix A.

Non-quantified benefits

The cost/benefit analysis presented above is based on two specific quantified benefits: the operational efficiency saving achieved by permanently discontinuing the current practice of annual temporary transformer load surveys, and the consequential benefit that having a small number of permanent transformer monitors installed in the metropolitan area will avoid the need to install temporary loggers at these transformers should customer QoS issues arise in these areas that require investigation.

We anticipate additional benefits associated with option 3 that have not been quantified, but which would strengthen the case for this as the preferred option:

- We expect that moving to a modern model-based load forecasting methodology using year-round data will improve the accuracy of our LV transformer load forecasting, reducing the number of customers affected by unplanned outages due to transformer overloads during summer heatwave conditions. We have not sought to quantify this benefit in this business case in Value of Customer Reliability (**VCR**) terms as we do not have a sufficient basis for estimating the level of improvement that may be achieved.

- Similarly, we expect that our current methodology sometimes results in the replacement of transformers or other works sooner than necessary, where the extrapolation from a 1-week load survey has over-estimated summer peak demand. Improving the accuracy of load forecasting will reduce the likelihood that work is performed that could have been deferred.

- We have taken a conservative approach to considering the interaction between this program and our strategic LV management program, insofar as we have taken into account that improved management of voltage in the LV network will, over time, reduce some of the benefits of permanent transformer monitoring, but we have not sought to quantify any upside benefits from synergies between these programs. In practice we expect to be able to use data from the permanent transformer monitors as an input to the new operational model of LV hosting capacity we are developing under the strategic LV management program, to help improve the accuracy of that model.

- Having a base of permanent LV transformer monitoring in the metropolitan area is likely to yield further efficiency benefits over time as we progressively improve legacy business processes and systems in network planning and network operations to be more data-driven, consistent with the broader direction of good industry practice. For example, we expect that functions such as upstream voltage control, outage management and scheduled maintenance in the LV network might all benefit over time from the availability of transformer data, noting that there is information we get from direct monitoring at the LV transformer level that we cannot derive either from upstream SCADA data at the substation or downstream meter data at the customer connection point (in part because we do not have a full model of the electrical characteristics of the network in between). As these opportunities are yet to be explored in detail, we have not included any assumed benefit in this business case.

Stakeholder engagement

We have undertaken a comprehensive stakeholder engagement program for our 2020-2025 Regulatory Proposal involving nearly 3,000 participants across 43 workshops and other activities around the state since the program commenced in February 2017. Our LV transformer monitoring program has been canvassed with stakeholders in a number of sessions in the context of our broader package of measures intended to improve management of our LV voltage network at both planning and operational timescales. Relevant activities have included:

- Two ‘deep dive’ workshops held in Adelaide in May 2018 to consult on our package of LV network management expenditure items, including transformer monitoring, BAU QoS capex and our strategic LV management program.

- Specific engagement with key stakeholders through SA Power Networks’ Renewables Reference Group and Customer Consultative Panel.

- Following a recommendation by the AER’s Consumer Challenge Panel (**CCP14**), we also convened a specific ‘DER Integration Working Group’ comprising a mix of senior DER industry stakeholders such as retailers and technology vendors, as well as representatives from Energy Consumers Australia, the Total Environment Centre, Clean Energy Council, the South Australian Government and AEMO. The purpose of this group was to provide a forum to seek stakeholder input to inform our strategies around LV network management and DER integration, including the proposed deployment of permanent LV transformer monitoring, and many of the stakeholders in this group made submissions to the AER in response to our

Proposal. This working group first met in August 2018 and has met six times in all, most recently in October 2019 to review and seek stakeholder feedback on this aspect of the AER's Draft Decision.

- Also following recommendations from CCP14 and AER technical advisors, we hosted a DNSP Future Network Forum in Adelaide in October 2018. Attended by all Australian DNSPs, the Energy Networks Australia and AEMO, this whole-day event provided a unique opportunity to share and align approaches to managing the transition to distributed energy across networks both within and outside the NEM. Based on the success of the Adelaide event this has now become a biannual event, with two subsequent forums held in Hobart in April 2019 and October 2019 at Energy Queensland. The most recent forum included a specific session on DNSP approaches to LV network visibility, which reinforced our understanding of the fact that we lag other networks in this regard.

- Most recently, this business case and its relationship to the other packages of work in our proposal that relate to the LV network was discussed with stakeholders in an all-day 'Focused Conversation' workshop in Adelaide on 1 November attended by representatives from the AER, SA Government, Energy and Water Ombudsman SA, SA Power Networks' Business, Community and Renewables Reference Groups and our Customer Consultative Panel.

The consistent feedback from stakeholders in these forums has been that they expect us to make prudent investments in improved network visibility, in line with the prevailing direction of the industry, where this will enable better customer outcomes.

We have also engaged, and continue to engage, actively with policymakers, regulators and market bodies such as AEMO, Australian Energy Market Commission (**AEMC**) and AER and in projects such as Open Energy Networks and the ARENA Distributed Energy Integration Program (**DEIP**) to contribute to the national debate on the actions that distribution networks need to take to support a high-DER future. Our proposed approach is consistent with recommendations of the AEMC's September 2019 *Economic Regulatory Framework Review (**ENERFR**)*, 'Integrating Distributed Energy Resources for the Grid of the Future', which identifies the following as a 'key action' for distribution businesses:

> *"Where it is cost effective, invest in new monitoring and modelling equipment to improve the visibility of loads and voltages on the part of the grid between a customer's property and the local substation so distribution businesses can better understand current and future network constraints (underway)"* [AEMC ENERFR 2019 infographic[8]]

Alignment with long-term strategy

Our preferred approach is part of a comprehensive, integrated strategy that aims to manage the changing role of the distribution network through an efficient combination of price signals (tariffs), network-side and demand-side (non-network, market-based) solutions. Our broader Future Network Strategy[9], developed in 2017, is summarised in **Error! Reference source not found.** below.

[8] AEMC, *Designing the Grid of the Future Infographic*, Electricity network economic regulatory framework review: final report, 26 September 2019
[9] SA Power Networks, *Future Network Strategy 2017-2030*, v1.0, November 2017

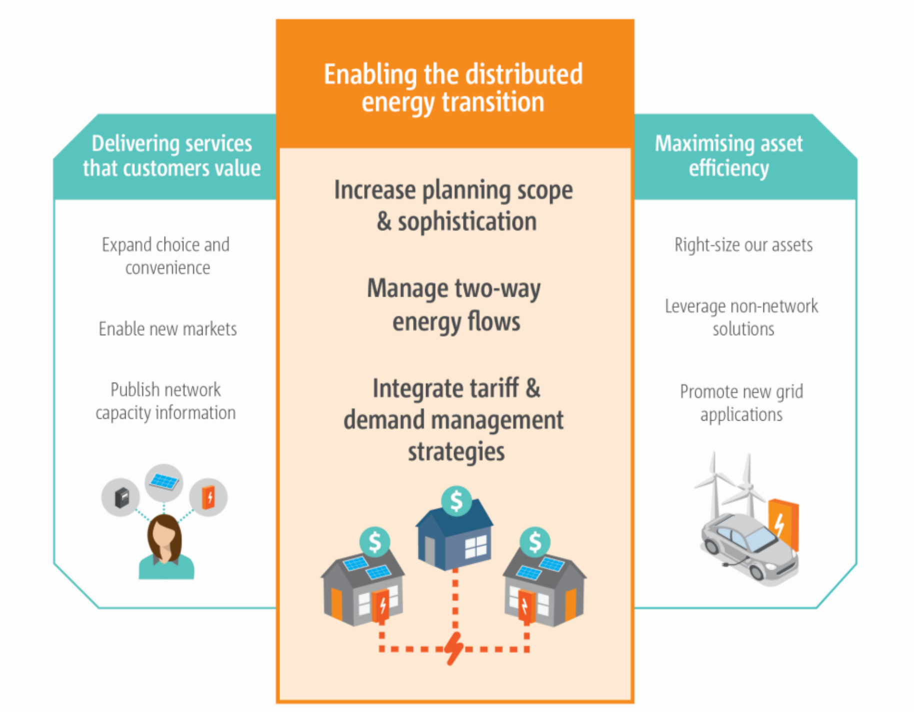

Figure 4. SA Power Networks' Future Network Strategy (2017)

As shown in the figure above, one of the core strategies identified in our Future Network Strategy is to 'Increase planning scope and sophistication'. This part of the strategy recognizes that in a changing energy system our legacy network planning processes such as load surveys will become increasingly inadequate because our network, in particular our LV network, will experience a greater range of operating conditions in future than has been the case in the past. In future, capacity planning will require us to be able to produce new forecasts that we do not currently produce:

- In the 2020-25 period it is likely that high levels of DER may cause some areas of our network to become winter peaking. Our current load forecasting method is designed only to predict summer peak demand based on temperature and other factors. Moving from a survey-based approach to a model-based approach using year-round data from permanent monitors will facilitate the development of winter peak forecasts.

- Similarly, assuming that our proposed LV voltage management strategies are effective, the primary factor that will constrain DER exports in the 2025-30 period may become the thermal capacity of the LV transformer to handle reverse power flows at peak export time. A more sophisticated network planning capability will enable us to forecast peak reverse flows in high DER areas as well as peak forward flows.

- Finally, the uptake of electric vehicles is expected to accelerate towards the end of the 2020-25 period and this could drive new pockets of localised peak demand growth in our network as well as changes in consumer load profiles. A more modern LV load forecasting tool will make it easier to manage the impact of these changes as the EV market develops.

The scope and timing of our preferred option is consistent with the roadmap set out in our 2017 Future Network Strategy and aligns with our other strategic programs.

Conclusions

This business case has considered four options for load forecasting in the LV network in the 2020-25 period. Our 15-year cost/benefit analysis indicates that option 3, leveraging our current LV transformer survey program to deploy permanent transformer monitoring at 1,384 locations will deliver greater benefits than continuing with current practice under all sensitivity cases considered in the business case. It will enable a long-term reduction in operating expenditure through the elimination of temporary load surveys and a reduction in the need to install temporary transformer loggers to investigate customer quality of supply enquiries. It will also deliver a range of other benefits that have not been quantified.

The business case recommends that option 3 be pursued at a capital cost of $5.65 million over the 2020-2025 RCP. The associated increase in opex of $0.51 million over the RCP is more than offset by efficiency savings delivered by the program, resulting in a net reduction in opex (a negative step change), after factoring in underlying growth, of $1.27 million over the RCP.

A. Supporting data

Input unit costs

An EOI was formulated and distributed in the market in early 2019 to multiple vendors with the aim to search for low cost, fit-for-purpose low voltage monitoring devices. This expression of interest uncovered five potential products with the required minimum capabilities at a lower price than the monitors currently used. The average cost of these devices was $2,500.00 per unit as can be seen in Table 5.

Table 5: Calculated average cost for LV monitor device

Manufacturer	Total Cost
Vendor 1	$4,000
Vendor 2	$2,000
Vendor 3	$2,300
Vendor 4	$1,400
Vendor 5	$2,600
Average rounded cost	$2,500

These devices are currently still under evaluation, but it is likely that at least one will be found to be suitable. On that basis our total estimated per-unit cost to procure, install and commission a LV monitoring unit on the distribution network has been revised as summarised in Table 6 below:

Table 6: Total cost of one LV monitor (installed)

LV Monitoring	Cost
Cost of single LV monitor	$2,500
Cost of installation and project management	$1,069
Network cost	$476
Total cost per unit	$4,045

This is a significant cost reduction when compared to the initial cost of LV monitoring units that were installed prior to 2019 which were used in the initial proposal.

Forecast customer quality of supply investigations

Figure 5 below shows the number of customer quality of supply enquiries received per month that were found to be attributable to over-voltage issues caused by rooftop solar PV. The figure illustrates the seasonal nature of these issues, which tend to peak in the spring months when the weather is sunny but mild, with low underlying heating or cooling load. It also shows the sharp increase in enquiries in the last three years as the penetration of rooftop PV has begun to exceed the technical limits of the low voltage network in an increasing number of areas.

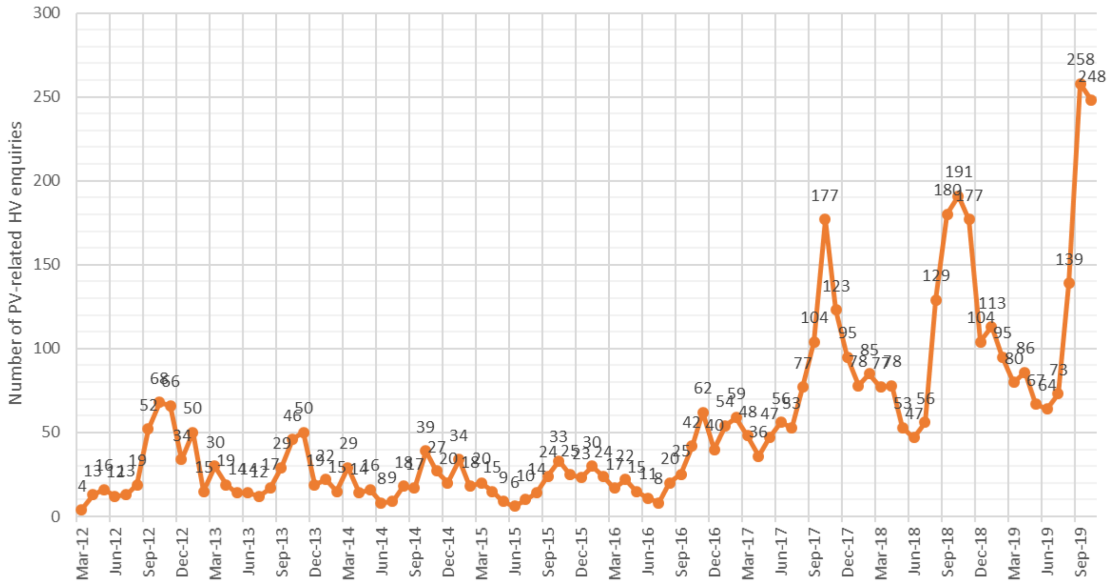

Figure 5. PV-related high voltage enquiries received per month

Figure 6 below shows the number of these enquires that resulted in follow-up work by the QoS team such as field investigation using temporary logging equipment, and our base-case future forecast. This forecast is used in calculating the opex savings arising from avoiding the need to install temporary monitors to undertake investigations in those areas that have permanent monitors installed.

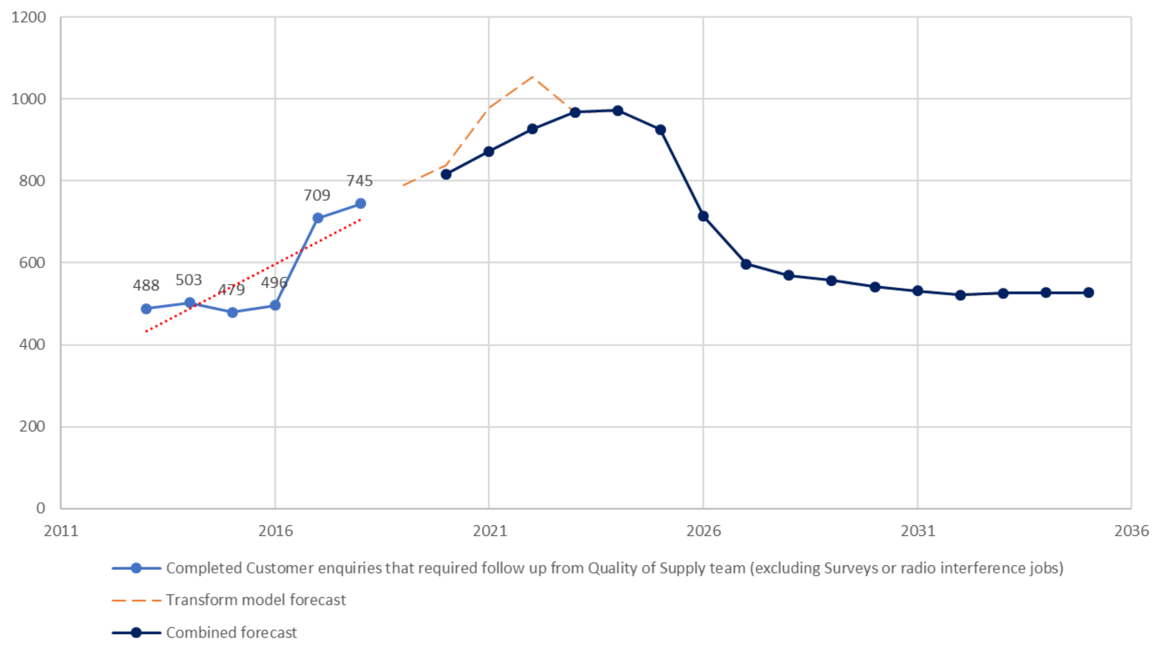

Figure 6. Number of customer enquires requiring investigation by the QoS team, trend and forecast

We have used two methods to produce the forecast:

- Simple linear extrapolation of historical trend
- A forecast based on the outputs of the EA Technology 'Transform' model. The Transform model is a statistical model that models LV network hosting capacity and can predict the number of LV circuits expected to exceed voltage regulation limits for a given penetration of DER, taking into account a range of factors. It is described in detail in our LV Management Business Case[10] and associated documents provided as part of our Original Proposal.

Our forecast is based on a blend of the linear trend in the early years of the 2020-25 RCP and the Transform model forecast thereafter. We take this approach because:

- The Transform model has 'perfect visibility' insofar as it calculates the expected prevalence of over-voltage across different LV network types based on the underlying technical characteristics of the networks and the amount of DER connected. In practice, not all actual issues will be revealed in customer enquiries, and we have no other means to detect them; hence we consider the Transform forecast to present an upper bound on the number of enquires received in the early years, and consider that historical trend to be a more reliable indicator.
- On the other hand the Transform model understands the future impact of the range of measures we are undertaking to address the rise in customer voltage issues, including our strategic LV management program (flexible export limits), the increasing percentage of Volt-VAr and Volt-Watt enabled inverters, the impact of our proposed time-of-use tariffs and so on. This is the reason for the decline in forecast enquiries towards the end of the 2020-25 RCP, as these measures begin to take effect. Hence this is our best available forecast for the period from 2024 onward.

Given the uncertainty inherent in forecasting over the long term, we have scaled these forecasts by +/- 30% in our sensitivity analysis to test the robustness of our approach against a wide range of future outcomes, as shown in Figure 7 7 below. The low extreme, S1 represents a scenario where DER impact is reduced more rapidly than expected and customer QoS investigations reduce below pre-solar levels by the end of the 2020-25 RCP. The high extreme, S2, represents a scenario where measures to reduce DER impact take longer to deliver and are less effective than expected.

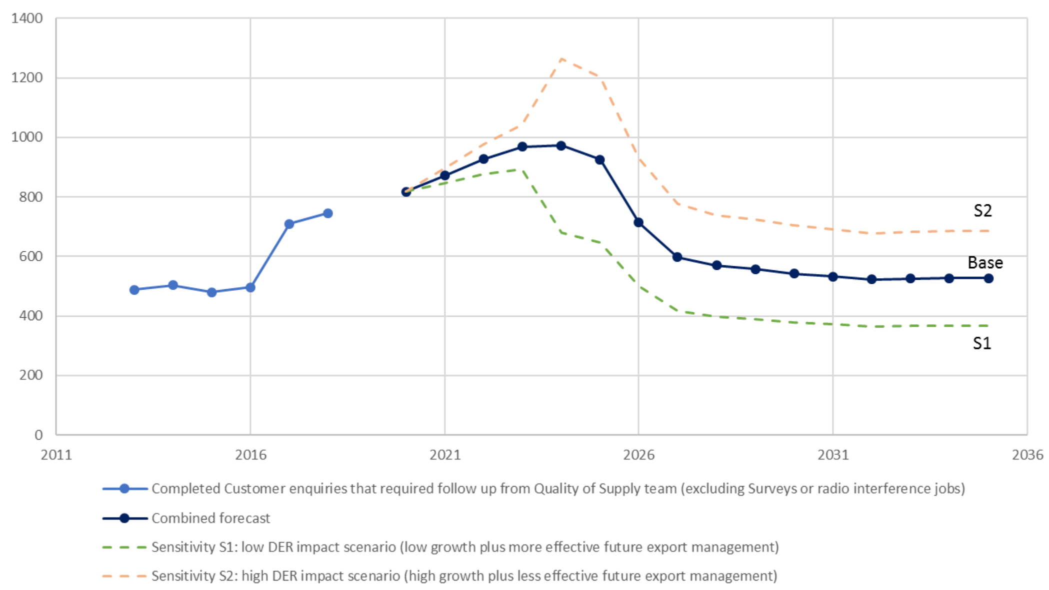

Figure 7. Forecast customer enquires requiring investigation - sensitivities

[10]Supporting Document 5.18 *LV Management Business Case*, SA Power Networks' 2020-25 Regulatory Proposal, 25 January 2019

Option 4 smart meter uptake

In our evaluation of option 4 we have sought to quantify the potential benefits of an alternative load forecasting approach that relied on smart meter data only, with no permanent transformer monitoring. Figure 88 below shows the percentage of LV transformer areas where meter penetration would be sufficient to enable such an approach, based on forecast smart meter uptake to 2035, assuming required penetration levels of 60% (sensitivity S3), 70% (base) and 80% (sensitivity S4).

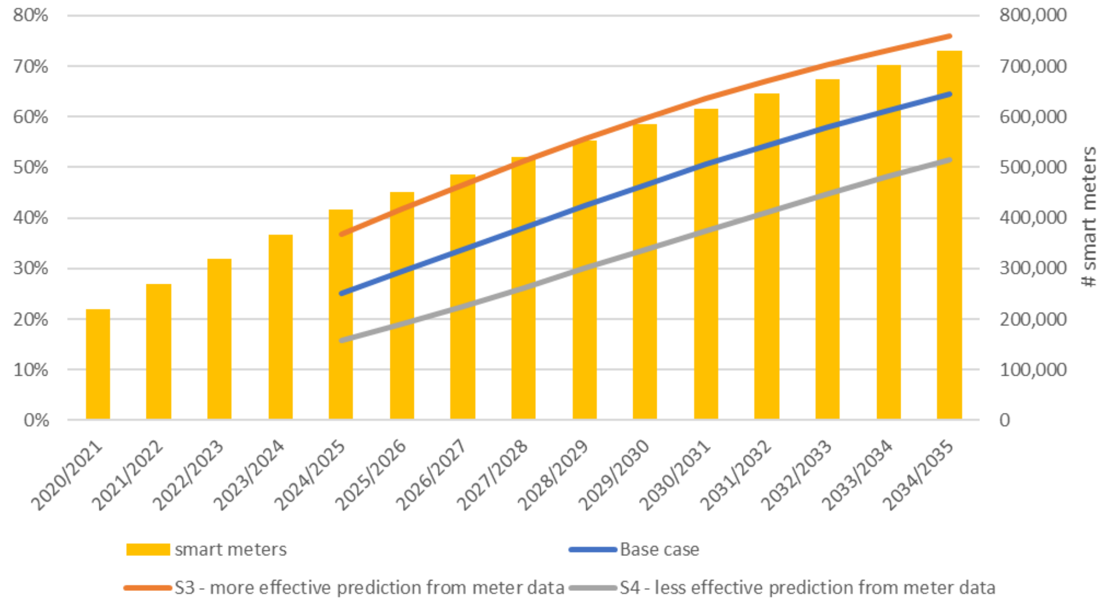

Figure 8. Option 4: percentage LV areas with sufficient meter penetration, base assumptions and sensitivity cases

Summary of sensitivity cases

S1	**Fewer customer voltage issues** – assume customer enquiries drop below trend in the early years of the 2020-25 RCP, combined with better-than-expected outcomes from measures like strategic LV management, tariffs and Volt-VAr/Volt-Watt in the longer term. This reduces the forecast of underlying customer issues and hence reduces the potential benefit of transformer monitoring.
S2	**More customer voltage issues** – assume customer enquiries escalate above trend in the early years of the 2020-25 RCP, combined with worse-than-expected outcomes from measures like strategic LV management, tariffs and Volt-VAr/Volt-Watt in the longer term. This increases the forecast of underlying customer issues and hence increases the potential benefit of transformer monitoring.
S3	**More effective prediction from meter data** – assume option 4 (load forecast using meter data only) is technically viable and can be achieved with a lower volume of meter data than the base case. This increases the benefit of option 4.
S4	**Less effective prediction from meter data** – assume option 4 (load forecast using meter data only) is technically viable but requires a higher volume of meter data than the base case. This decreases the benefit of option 4.

Base-case NPV analysis

Cost of capital (cost to borrow)	2.63%

Total Capital cost for 2020-2025 reset period ($M) $5.65

Progressive years	2020/21 1	2021/22 2	2022/23 3	2023/24 4	2024/25 5	2025/26 6	2026/27 7	2027/28 8	2028/29 9	2029/30 10	2030/31 11	2031/32 12	2032/33 13	2033/34 14	2034/35 15
Permanent LV units ($M)	$0.71	$1.93	$1.93	$0.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Software Build ($M)	$0.00	$0.00	$0.36	$0.35	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Cost ($M)	$0.71	$1.93	$2.29	$0.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Benefit ($M)	$0.28	$0.69	$0.68	$0.85	$0.89	$0.88	$0.86	$0.84	$0.84	$0.84	$0.83	$0.83	$0.83	$0.83	$0.83

Net Present Costs ($M)	$5.29
Net Present Benefits ($M)	$9.52
Net Present Value ($M)	$4.23
Profitability Index	1.80

Shortened Forms

AEMC	*Australian Energy Market Commission*
AEMO	*Australian Energy Market Operator*
AER	*Australian Energy Regulator*
ARENA	*Australian Renewable Energy Agency*
BAU	*Business as Usual*
capex	*capital expenditure*
DEIP	*Distributed Energy Integration Program*
DER	*Distributed Energy Resources*
DNSP	*Distribution Network Service Provider*
Draft Decision	*AER, Draft Decision for SA Power Networks Distribution Determination 2020 to 2025*
ENERFR	*Economic Regulatory Framework Review*
EOI	*Expression of Interest*
HV	*high voltage*
LV	*low voltage*
NEM	*National Electricity Market*
NEO	*National Energy Objective*
NER	*National Electricity Rules*
NPV	*Net Present Value*
opex	*operating expenditure*
Original Proposal	*SA Power Networks 2020-25 Regulatory Proposal*
PI	*profitability index*
QoS	*Quality of Supply*
RCP	*Regulatory Control Period*
Revised Proposal	*SA Power Networks 2020-25 Revised Regulatory Proposal*
SCADA	*Supervisory control and data acquisition*
UFLS	*Under-Frequency Load Shedding*
VCR	*Value of Customer Reliability*