# Smart Meter Data Acquisition and LV Monitor

## Business Case

17 January 2024

Part of Energy Queensland

# CONTENTS

## List of Tables

## List of Figures

# 1 SUMMARY

<table>
<tr><th>Title</th><th>Smart Meter Data Acquisition and LV Monitor Installation</th></tr>
<tr><td>DNSP</td><td>Ergon Energy Network</td></tr>
<tr><td>Expenditure category</td><td>☐ Replacement ☒ Augmentation ☐ Connections ☐ Tools and Equipment<br>☐ ICT ☐ Property ☐ Fleet ☒ Opex Step Change</td></tr>
<tr><td>Identified need<br><em>(select all applicable)</em></td><td>☐ Legislation ☐ Regulatory compliance<br>☒ Reliability ☒ CECV ☒ Safety ☐ Environment ☒ Financial<br>☒ Other<br><br>This case addresses several needs - the need to improve outage response times, the need to provide a safe network and the need to reduce where possible, the cost of replacing network assets. The rollout of smart meters across our networks provides us with the opportunity to obtain power quality data for our LV networks. The benefits that will flow from this include:<ul><li>Reliability – improved reliability from identifying and responding more quickly for service line and distribution transformer failures.</li><li>CECV – better visibility allows us to set less conservative operating envelopes for export.</li><li>Safety – obtaining data will allow us to determine broken neutrals on our LV service lines.</li><li>Financial – monitoring our LV service population will allow us to time our replacements more effectively, reducing replacement costs.</li></ul></td></tr>
<tr><td>Summary of preferred option</td><td>Option 2 is the preferred option. This option acquires a mixture of near real-time and 6-hour delivered data from Smart Meters for our Overhead service population, and obtain near real-time data for 25% of our underground service population</td></tr>
<tr><td>Expenditure</td><td>
<table>
<tr><th>Year</th><th>2025-26</th><th>2026-27</th><th>2027-28</th><th>2028-29</th><th>2029-30</th><th>2025-30</th></tr>
<tr><td>$m, direct 2022-23 Opex</td><td>0.9</td><td>1.1</td><td>1.3</td><td>1.5</td><td>1.6</td><td><strong>6.4</strong></td></tr>
<tr><td>$m, direct 2022-23 Capex</td><td>1.9</td><td>1.9</td><td>2.0</td><td>2.0</td><td>1.8</td><td><strong>9.5</strong></td></tr>
<tr><td>$m, direct 2022-23 Totex</td><td>2.8</td><td>3.0</td><td>3.2</td><td>3.4</td><td>3.4</td><td><strong>15.9</strong></td></tr>
</table>
</td></tr>
<tr><td>Benefits</td><td>This investment has been assessed over a 15-year horizon, with the net benefits over this period estimated at $554.4m.</td></tr>
<tr><td>Consumer engagement</td><td>This investment was discussed with our Reset Reference Group, and the business case has been shared with them prior to the submission of the Regulatory Proposal.</td></tr>
</table>

# 2 BACKGROUND

Acquiring smart meter data have a large range of network and customer benefits, including increased understanding of our network from data to make informed network planning and investment decisions, better ability to enable DER integration, and an ability to better detect electricity theft. In terms of improvement in managing our physical assets, the benefits are largely attributable to an improvement in safety and reliability of our overhead service line and distribution transformer populations. The following sections provide an outline of these asset populations, their condition, and their asset performance.

## 2.1 Asset Population

### 2.1.1 Service Lines

Ergon Energy overhead services provide a connection for electricity between the Ergon Energy overhead low voltage (LV) mains line and designated points of connection owned by individual customers. These overhead services are considered low-cost assets and are typically managed based on population, using regular inspections and systematic performance reviews to identify and address any issues or concerns. Ergon Energy currently manages approximately 440,000 services as detailed in Figure 1.

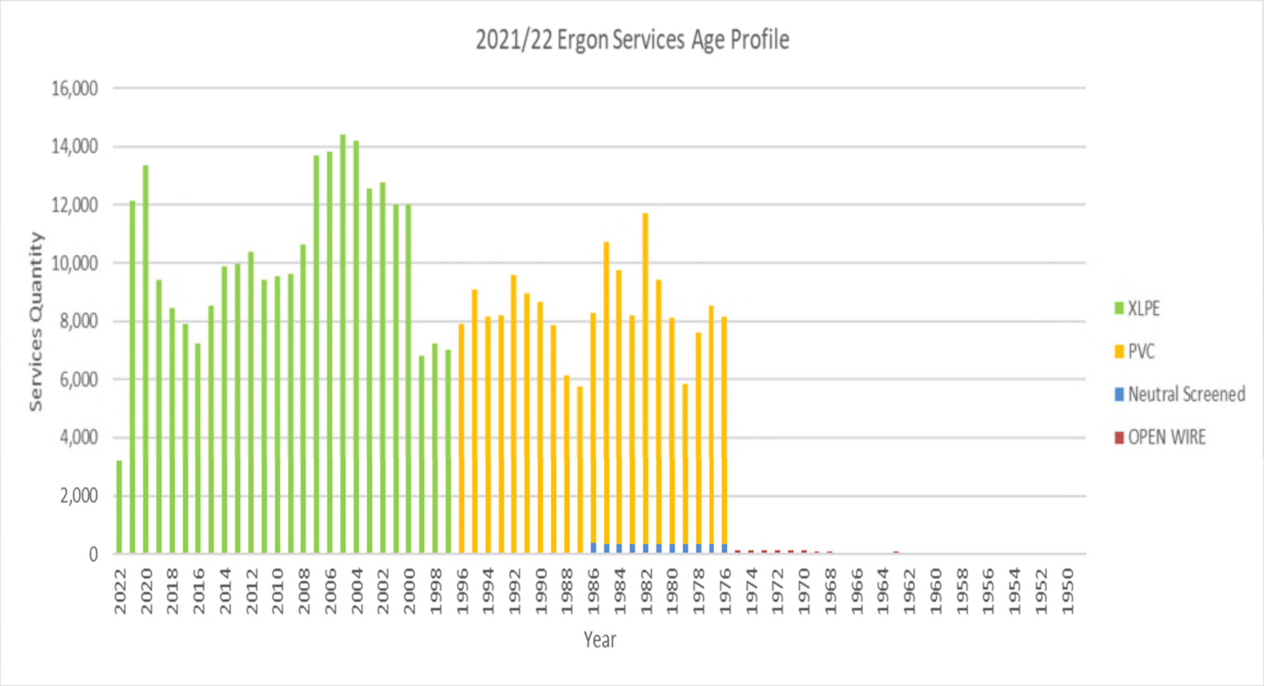

**Figure 1 – Service Line Age Profile**

Further demonstrating the need to focus on our management of service line assets, during this period, our technical regulator the Electrical Safety Office issued us with:

- 10 improvements notices related to our service line assets.
- Notice to give information and produce documents to the regulator under Section 122C of the Electrical Safety Act 2022 regarding the management of Entity Neutrals, as well as a follow up notice.

### 2.1.2 Distribution Transformers

Ergon Energy's Distribution Transformer asset class population consists of Ground and Kiosk Mounted Transformers, Pole Mounted Transformers, Distribution Regulators, SWER Isolation Transformers, Pole-Mounted Reactors, Substation Earthing Transformers and Substation Service Transformers.

The Distribution Transformer asset class provide capabilities to complete a variety of functions including voltage conversion, voltage regulation, reactive load management and earthing. Transformers, regulators, and reactors are essential components of electrical networks as they allow for the use of cost-effective infrastructure to achieve efficient transportation of electricity across large distances. An age profile of all distribution transformer assets is shown in Figure 2. This age profile distribution reflects that we have 7,215 assets are over 50 years, and 54 assets are over 70 years across the asset class.

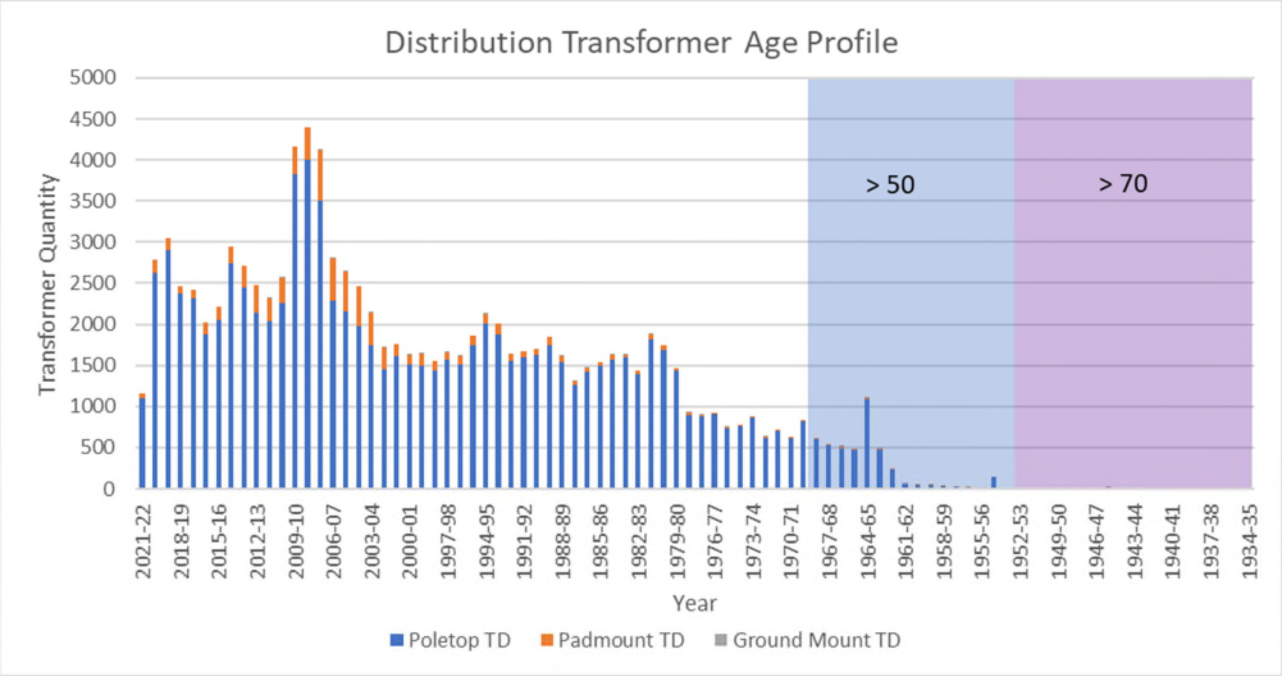

**Figure 2 – Distribution Transformer Age Profile**

### 2.1.3 Smart Meters and LV Monitors

Ergon Energy currently has an extremely limited data acquisition capability on our LV networks, and virtually no network visibility beyond the distribution transformer. This lack of network data has historically been due to a lack of technology to be able to detect the sorts of issues that would provide benefit to customers. With both the Australian Energy Market Commission and the Queensland Energy and Jobs Plan committing to a high penetration of smart meters, there is now the capability available to monitor our LV network through acquiring metering data.

The AEMC has recently undertaken a review into the roll-out of smart meters, and the consequential access to the smart meter data for DNSPs. Their recommendation is that DNSPs would be able to gain access to basic smart meter data for free, with advanced smart meter data to be negotiated. In addition to the roll-out of smart meters, communications and monitoring equipment advances in recent years mean we are now able to have the technology to install devices on our LV network to provide the same data as a smart meter.

We have had early discussions with Metering Providers to determine the costs and delivery parameters of data that is acquired from smart meters. For the purposes of this business case, we have assumed that daily or 6-hour delivery of data would constitute basic data, with near real-time delivery of data being advanced data. As such, we have assumed the following costs:

- Daily delivery of data - $0 / meter / annum
- 6-hour delivery of data - $0 / meter / annum

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

# 3 IDENTIFIED NEED

The identified need is to improve our visibility of our LV networks.

The opportunities that this data acquisition offer our customers comes from us being able to proactively manage our network, with the Reliability, Safety Export and Financial benefit streams from an effective visibility strategy flowing to customers. The opportunities for this investment include:

- **LV service in-service faults:** LV visibility for a single service cable allows us to respond to faults on our LV service cables more quickly, which reduces the safety and reliability issues that arise from faulty service lines.
- **Distribution Transformer in-service faults:** Widespread LV visibility coverage (where we don't already have a transformer monitor) allows us to respond to faults on our distribution transformers given we can more easily and quickly identify an outage to an area. This will reduce the reliability issues following a distribution transformer outage.
- **DER integration:** Live data on our network will enable us to better manage our dynamic operating envelopes, decreasing the level of curtailment across our network and better targeting investment in increasing capacity.
- **Service line replacement deferral:** by having a more active monitoring of our service lines, we will be able to defer the proactive replacement of the service line we are monitoring.
- **Grid planning improvements:** increased availability of power quality data on our network allows us to understand loads and export requirements for these networks, informing better demand and energy forecasts at the LV level, in turn reducing the future labour requirements in our forecasting and planning teams.
- **Electricity theft:** power quality data down to the household level allows us to identify where customers have bypassed the meter and therefore paying a reduced network charge.

## 3.1 Discussions with customers

We discussed our approach to Smart Meter Data Acquisition with our Reset Reference Group to guide the way we considered the benefits that flowed to customers from this investment. Their feedback was clearly that we should invest based on the highest cost benefit option, without bias to technology or timing of costs. To this end, we have undertaken a cost benefit analysis and sensitivity analysis to determine which of the options we have considered maximises the benefits to our customers and the community.

## 3.2 Counterfactual analysis

### 3.2.1 Summary

The counterfactual for this business case is based on not acquiring any smart meter data or establishing any more LV monitoring devices. There are already 20,000 LV monitoring devices across the Ergon Energy network.

In understanding the risks and calculating the benefits attributable to a more active monitoring capability of our network, we have split some of our risk costs into a “per service” framework by age, which means that we have calculated the existing risk level for a single service cable or distribution transformer of each age from 1 to 60. This simplifies the understanding of the benefits of a single monitoring device where the benefit will be attributable to a single asset.

We have then modelled those benefits that can be attributed to monitoring capability at scale, such as distribution transformer reliability and DER integration at more of a system level, with the benefits of this capability being shared across our network, rather than only by the single service line asset.

### 3.2.2 Costs

The counterfactual case has no costs associated with it given there is no investment in data acquisition.

### 3.2.3 Risks

**Service line Safety and Reliability risk costs**

To simplify the analysis, we have provided an assessment of the risk cost of the counterfactual has been determined as the NPV of the 15-year horizon across the range of the age of our service cables. That is, we have calculated the present value of the risk cost in the safety and reliability for a single service aged 1 to 60. The following assumptions have been utilised in developing the per service line risk costs:

- **Probability of Failure (PoF):** as part of our Service Lines Replacement business case, we calculated a Weibull distribution to represent the PoF for a service line. This incorporates both service failures and service defects. The parameters of this are beta of 3.7 and gamma (characteristic life) of 37. Figure 3 shows our actual failure data and the associated modelled Weibull distribution.
- **Likelihood of Consequence (LoC) - Reliability:** 100% of defects and failures result in a network outage. The assumptions around these outages are:
    - 4-hour outage for a service failure
    - 1-hour outage for a service defect
    - 1kW average consumption for a service line
    - VCR rate of $48.18 / kWh, which is the Queensland average
- **LoC – Safety:** utilising historic data and industry experience we have determined the LoC following a failure or defect for service lines to be:
    - 0.02% of service failures result in a fatality
    - 0.0003% of service defects result in a fatality

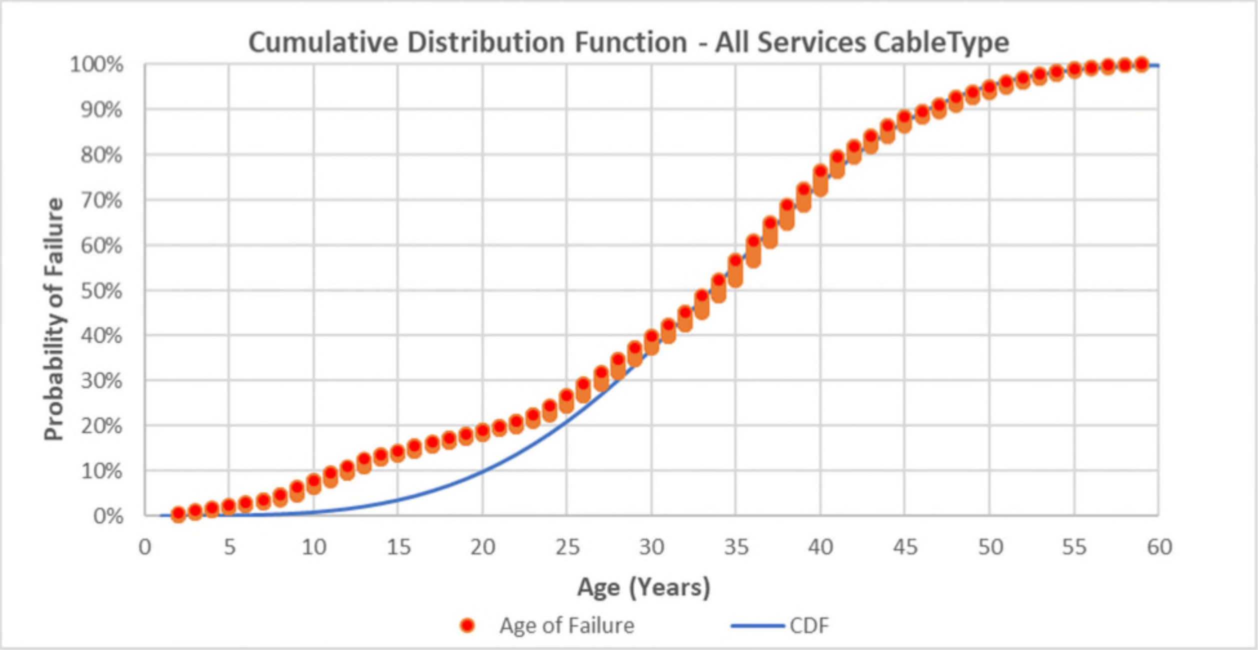

**Figure 3 – Service Line Failure and Defect Weibull Distribution**

As can be seen from Figure 3, our Weibull distribution tends to underestimate the PoF for a service line below 30 years but provides a very accurate representation of failure above this age. We have utilised this curve in assessing the counterfactual risk associated with our service cable failures.

### Service line replacement deferral risk cost

Active monitoring of LV services will allow us to have a lower volume proactive replacement program for our service lines assets. To simplify the analysis for this business case, rather than factoring in our entire replacement program as a cost and then factoring in these reduced costs as a benefit, Figure 4 shows the present value of a two-year deferral of a service line replacement over time. This factors in a replacement value of $1,000 / service and a cost of capital of 3.5%.

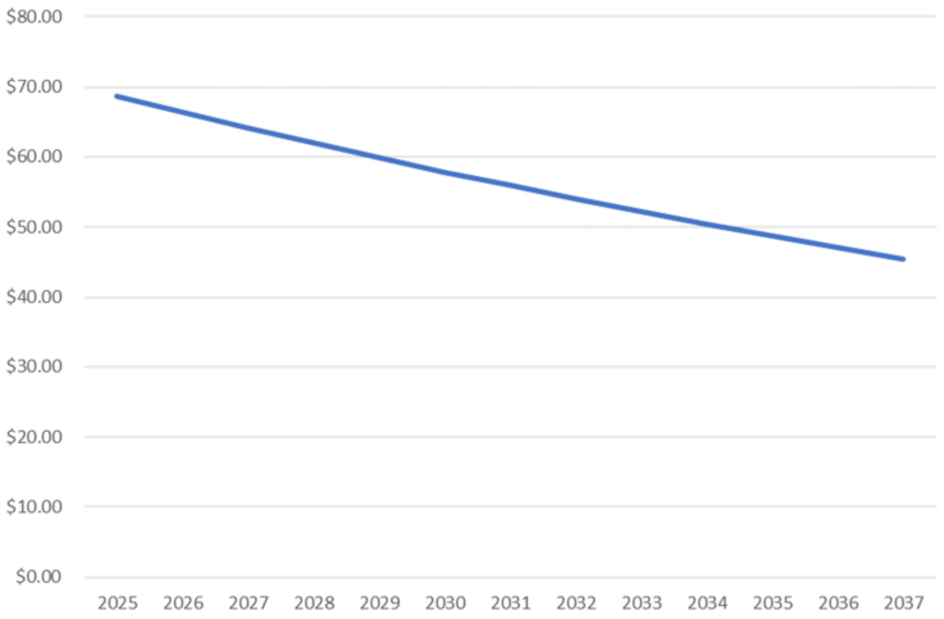

**Figure 4 – Present Value of a Two-Year Deferral of a service line replacement**

Figure 4 demonstrates that over the next 10 years, a two-year deferral of a service cable replacement represents between $40 - $70 in risk cost.

### Distribution Transformer Reliability risk costs

Broader visibility on our LV network also gives us the capability to respond to an outage of a distribution transformer faster. As such, below is the modelling of the total reliability risk associated with our distribution transformers. We haven't modelled the safety risk associated with transformers given that smart meter data and LV monitors don't provide a safety benefit related to distribution transformers.

- **Probability of Failure (PoF):** as part of our Distribution Transformer Replacement business case, we calculated a Weibull distribution to represent the PoF for a distribution transformer. The parameters of this are beta of 2.3 and gamma (characteristic life) of 32. Figure 5 shows our actual failure data and the associated modelled Weibull distribution.
- **Likelihood of Consequence (LoC) - Reliability:** 100% of failures result in a network outage. It is important to note that for networks with no or limited visibility, we require customers to notify us of asset failures resulting in outages. As such, the timeframe for restoration is dependent on the level of information that customers can provide, and the volume of customer calls so that we can determine where the fault in the network is. The assumptions around these outages are:
    - 4-hour outage for a transformer failure.
    - 100kW average consumption for a distribution transformer
    - VCR rate of $48.18 / kWh

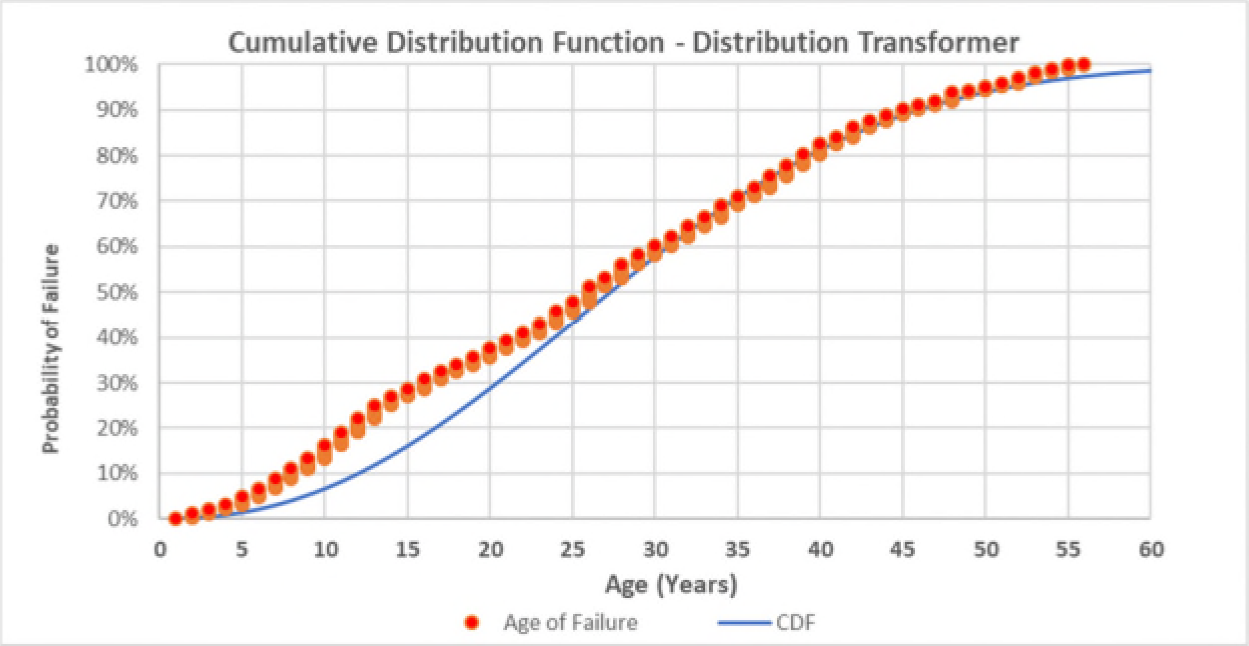

**Figure 5 – Distribution Transformer Weibull Distribution**

As can be seen from Figure 5, our Weibull distribution tends to underestimate the PoF for a service line below 30 years but provides a very accurate representation of failure above this age. We have utilised this curve in assessing the counterfactual risk associated with our transformer failures.

### DER Integration risk costs

The benefits of access to live data have been calculated, with a detailed explanation contained in our DER Integration Strategy. In simple terms, better data for our LV network visibility would allow us to better set dynamic operating envelopes and increase the export that customers can utilise on our network, as well as ensuring our investments in increasing hosting capacity for DER are more efficient than would otherwise be the case. As part of the Strategy, we calculated that the difference between a DoE with access to sufficient live data and a more basic DoE has a present value of $6.8m in benefits.

### Grid planning and forecasting functionality

Our current limited visibility on LV networks makes forecasting minimum and maximum demands and energy use on our networks difficult. As a result, our planning and forecasting teams require much more effort to correctly forecast this demand and coming up with the associated projects and programs to respond to any identified needs. As our network becomes more complex and load flows in both directions at different times of the day, network data will become more valuable, and increasing the data capture across our network will result in a lower level of effort than would have otherwise been the case. Although we aren't forecasting that data capture would reduce our current planning and forecasting effort, we are forecasting that there will be a reduction in the level of effort required in the planning and forecasting areas than otherwise would have been the case.

### Electricity theft

With limited data on our LV networks, electricity theft is difficult for us to detect. Greater visibility of the customer connection arrangement and power quality data at their premises will enable us to determine where this may be occurring. The current rate of theft is difficult for us to determine.

However, we have estimated that full visibility would be able to prevent theft from 40 customers / year.

# 4 OPTIONS ANALYSIS

## 4.1 Option 1 – Overhead Service Lines 6-hour data capture

This option focuses on acquiring data about overhead service lines to capture the safety and reliability benefits, as well as a deferral of service lines replacement. This option will also result in an improvement in our distribution transformer failure response. This option results in data being captured for around 40% of our customers services.

### 4.1.1 Assumptions

The following assumptions have been factored into the analysis:

- **Data acquisition timeframe –** this option assumes 6-hour data is captured from smart meters.
- **Ratio of data capture** – this option assumes that we capture the smart meter data that is available for our overhead network and complement this with LV monitoring for those areas where we are unable to source smart meter data.
- **Service line safety improvement** – using 6-hour data will prevent 70% of the safety incidents on our LV service lines. This is difficult to quantify and has been determined through engineering judgement.
- **Service line reliability improvement** – using 6-hour data will prevent around 10% of the customer outages related to service line failures through being able to respond earlier to faults. This is low due to the lag in data reaching our network operations centre from 6-hour data.
- **Distribution transformer reliability improvement** –
  - We have around 27,000 transformers that are pole-mounted that will have their reliability improved should they fail in service. This is equal to all pole-mounted transformers above 60kVA in size.
  - Using 6-hour data will prevent around 1% of the customer outages related to transformer failures. This translates to a 30-minute saving in outage for 10% of the cases where the data collection corresponds to the time the fault occurs.
  - We have utilised the existing age profile of our distribution transformer population in combination with the Weibull distribution to determine the benefits attributable.
- **DER Integration** – no benefits are factored into this analysis for DER integration as the approach only considers 6-hour data, which does not provide a material uplift in capacity for export.
- **Service line replacement deferral** – we have factored in a present value benefit of $20 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 80 hours of effort in planning the network at $112 / hour.
- **Electricity Theft** – we have estimated a reduction of theft from 10 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh.

- **Investment horizon** – this has been assumed to be 15 years to compare options involving more LV monitors, which have an asset life expectation of 15 years.

### 4.1.2 Costs

The cost of this option once the final uptake is at scale is:

- Smart meter data acquisition - $0m / year

[redacted]

- Establishing 12,300 LV monitors at $770 / monitor. These will cover the areas where we expect won't receive smart meter early enough through the rollout.
- Data analytics for LV monitors of $10 / year, which begins to be accrued after 5 years.

### 4.1.3 Benefits

A summary of the benefits attributable to our LV monitoring capability are listed in Table 2.

**Table 2 Benefits overview for Option 1**

| Benefit Type | Benefit Description | Value |
|---|---|---|
| Service line safety and reliability | Improvement in fault and defect detection to improve safety and reliability of our network. | **$39.7m / year** |
| Distribution transformer reliability | Improvement in network reliability for customers due to greater visibility throughout our network. | **$1.4m / year** |
| Service line replacement deferral | Ability to defer the replacement of a service line by two years. | **$2.1m / year** |
| DER Integration | Ability to orchestrate DER more accurately on our network | **No benefit** |
| Grid Planning uplift | Ability to better plan the network through access to LV data. | **$9k / year** |
| Theft | Ability to detect when a customer has by-passed the meter | **$12k / year** |

The yearly benefits cashflow is shown in Figure 6.

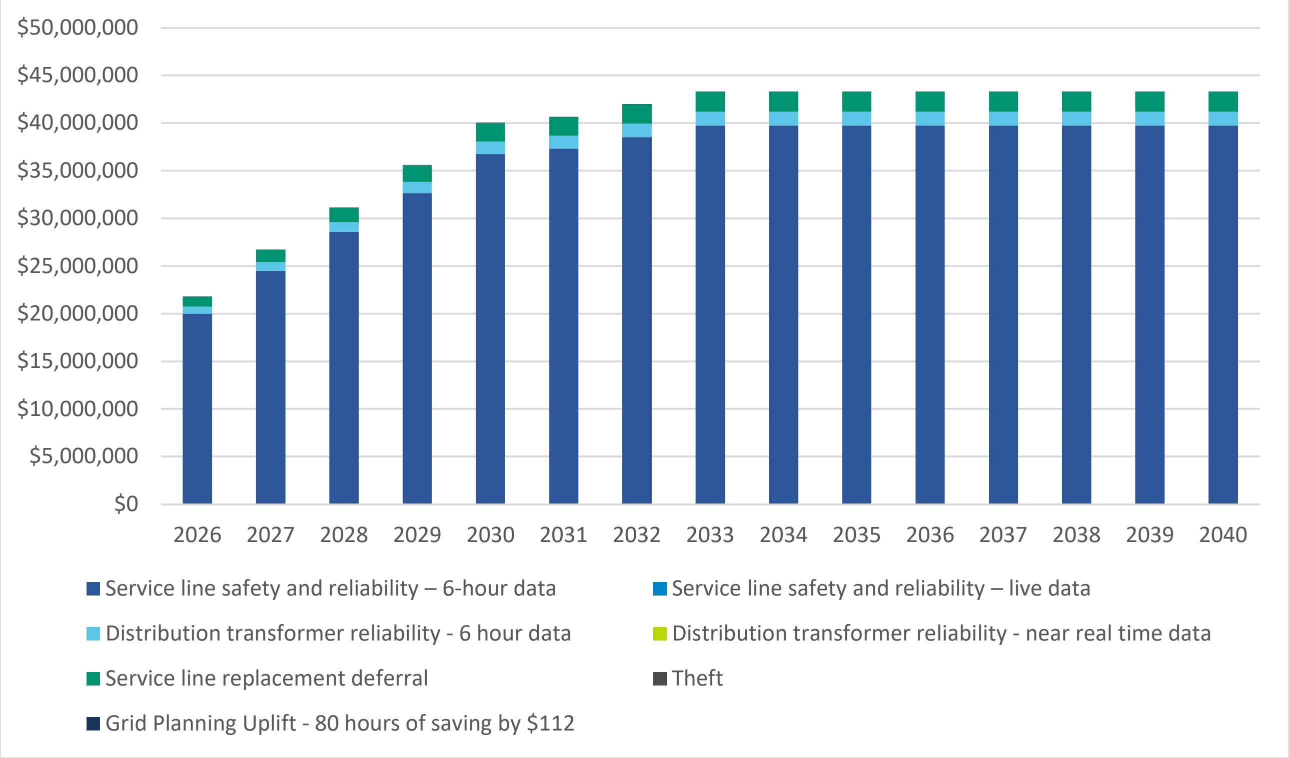

**Figure 6 – Benefits Cashflows for Option 1**

## 4.2 Option 2 – OH Services and 25% of Underground Services

This option acquires a mixture of data for overhead and underground service lines to capture the safety and reliability benefits, as well as a deferral of service lines replacement. This option will also result in an improvement in our distribution transformer failure response. To capture the benefits associated with DER integration, this option captures 25% of our overhead network and 25% of our underground network as live data, from either smart meters or LV monitors to enable highly efficient operating envelopes to be produced. This option results in data being captured for around 60% of our LV network.

### 4.2.1 Assumptions

- **Data acquisition timeframe –** this option assumes live data is utilised for 25% of our OH service lines, 25% of our UG service cables, with the data for the remaining OH services being captured in 6-hour windows.
- **Ratio of data capture** – this option assumes that we capture the smart meter that is available for our overhead network and complement this with LV monitoring for those areas where we are unable to source smart meter data.
- **Service line safety improvement** – using live data will prevent 90% of the safety incidents on our LV service lines. For those with 6-hour data capture, 70% of our incidents will be captured. This is likely understating the number of incidents that we would capture as a result of this capability.
- **Service line reliability improvement** – using live data will reduce 100% of our reliability incidents by 1 hour, while those with 6-hour data will prevent around 10% of the customer

outages related to service line failures through being able to respond earlier to faults. This is low due to the lag in data reaching our network operations centre from 6-hour data.

- **Distribution transformer reliability improvement** –
  - We have around 27,000 transformers that are pole-mounted and 7,000 that are ground mounted that are above 60kVA in size. These are the transformers that will have their reliability improved should they fail in service. This is equal to all pole-mounted transformers above 60kVA in size.
  - Using a near real-time data capture will prevent around 15% of the customer outages related to transformer failures on all the 34,000 transformers identified above. This translates to a 30-minute saving on all outages where live data has been captured. This assumes a mixture of live data across all transformers in our network.
  - We have utilised the age profile of our distribution transformer population to determine the benefits attributable.
- **DER Integration** – the benefits of the uplift described in our DER Integration Strategy from the basic DoE to the highly accurate DoE have been attributed to this business case. The resultant improvement is entirely attributable to obtaining the critical mass of 25% of live data.
- **Service line and cable replacement deferral** – we have factored in a present value benefit of $20 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 160 hours of effort in planning the network at $112 / hour.
- **Electricity Theft** – we have estimated a reduction of theft from 20 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh
- **Investment horizon** – this has been assumed to be 15 years to compare options involving more LV monitors, which have an asset life expectation of 15 years.

### 4.2.2 Costs

The cost of this program is:

- 6-hourly smart meter data acquisition - $0m / year

[redacted]

- Establishing 12,300 LV monitors at $770 / monitor. These will cover the areas where we expect won't receive smart meter early enough through the rollout.
- Data analytics for LV monitors of $10 / year, which begins to be accrued after 5 years.

### 4.2.3 Benefits

A summary of the benefits attributable to our LV monitoring capability are list below. These are summarised to yearly figures as the final uptake rate in 2030 as we achieve close to full penetration of smart meters.

**Table 3 Benefits overview for Option 2**

| Benefit Type | Benefit Description | Value |
|---|---|---|
| Service line safety and reliability – 6-hour data | Improvement in fault and defect detection to improve safety and reliability of our network. | **$29.8m / year** |
| Service line safety and reliability – live data | Improvement in fault and defect detection to improve safety and reliability of our network. | **$25.9m / year** |
| Distribution transformer reliability | Improvement in network reliability for customers due to greater visibility throughout our network. | **$5.5m / year** |
| Service line replacement deferral | Ability to defer the replacement of a service line by two years. | **$2.1m / year** |
| DER Integration | Ability to orchestrate DER more accurately on our network | **Present value of $6.8m** |
| Grid Planning uplift | Ability to better plan the network through access to LV data. | **$18k / year** |
| Theft | Ability to detect when a customer has by-passed the meter | **$24k / year** |

The yearly benefits cashflow is shown in Figure 7.

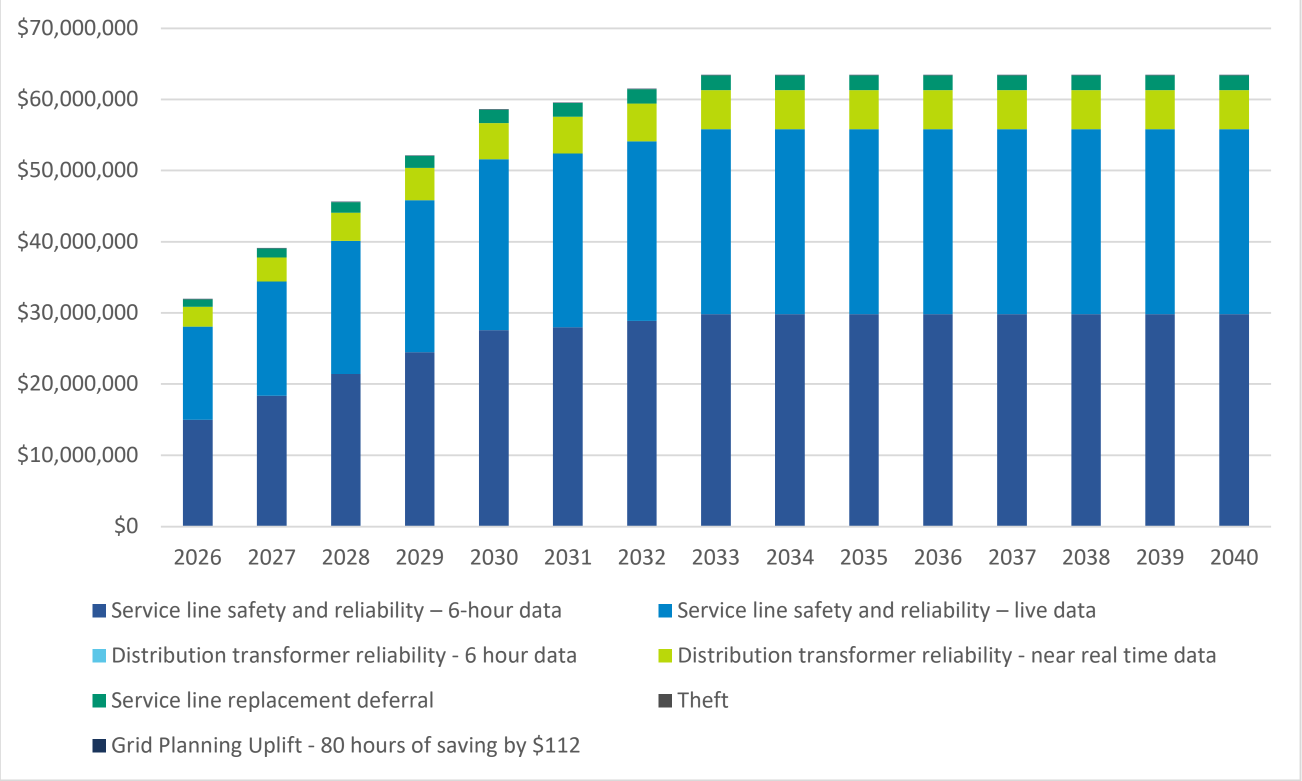

**Figure 7 – Options 2 Benefits Cashflow**

## 4.3 Option 3 – OH Services only with a mixture of near real-time and 6-hour data capture

This option acquires data for overhead service lines only, in capturing the safety and reliability benefits, as well as a deferral of service lines replacement. This option will also result in an improvement in our distribution transformer failure response. To capture the benefits associated with DER integration, this option requires 25% of our overhead network, from either smart meters or LV monitors to enable highly efficient operating envelopes to be produced. This option results in data capture for around 40% of our overhead service lines.

### 4.3.1 Assumptions

- **Data acquisition timeframe –** this option assumes near real-time data is utilised for 25% of our OH service lines with data for the remaining OH services being captured in 6-hour windows.
- **Ratio of data capture** – this option assumes that we capture the smart meter that is available for our overhead network and complement this with LV monitoring for those areas where we are unable to source smart meter data.
- **Service line safety improvement** – using live data will prevent 90% of the safety incidents on our LV service lines. For those with 6-hour data capture, 70% of our incidents will be captured. This is likely understating the number of incidents that we would capture as a result of this capability.
- **Service line reliability improvement** – using live data will reduce 100% of our reliability incidents by 1 hour, while those with 6-hour data will prevent around 10% of the customer outages related to service line failures through being able to respond earlier to faults. This is low due to the lag in data reaching our network operations centre from 6-hour data.
- **Distribution transformer reliability improvement** –
  - We have around 27,000 transformers that are pole-mounted that will have their reliability improved should they fail in service. This is equal to all pole-mounted transformers above 60kVA in size.
  - Using a near real-time data capture will prevent around 15% of the customer outages related to transformer failures on 27,000 transformers identified above. This translates to a 30-minute saving on all outages where live data has been captured. This assumes a mixture of live data across all transformers in our network.
  - We have utilised the age profile of our distribution transformer population to determine the benefits attributable.
- **DER Integration** – the benefits of the uplift described in our DER Integration Strategy from the basic DoE to the highly accurate DoE have been attributed to this business case. The resultant improvement is entirely attributable to obtaining the critical mass of 25% of live data, but only for our overhead networks which equates to 40% of our network.
- **Service line and cable replacement deferral** – we have factored in a present value benefit of $20 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 80 hours of effort in planning the network at $112 / hour.

- **Electricity Theft** – we have estimated a reduction of theft from 10 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh
- **Investment horizon** – this has been assumed to be 15 years to compare options involving more LV monitors, which have an asset life expectation of 15 years.

### 4.3.2 Costs

The cost of this program is:

- 6-hourly smart meter data acquisition - $0 / year

[redacted]

- Establishing 12,300 LV monitors at $770 / monitor. These will cover the areas where we expect won't receive smart meter early enough through the rollout.
- Data analytics for LV monitors of $10 / year, which begins to be accrued after 5 years.

### 4.3.3 Benefits

A summary of the benefits attributable to our LV monitoring capability are list below. These are summarised to yearly figures as the final uptake rate in 2030 as we achieve close to full penetration of smart meters.

**Table 4 Benefits overview for Option 3**

| Benefit Type | Benefit Description | Value |
|---|---|---|
| Service line safety and reliability – 6-hour data | Improvement in fault and defect detection to improve safety and reliability of our network. | **$29.8m / year** |
| Service line safety and reliability – live data | Improvement in fault and defect detection to improve safety and reliability of our network. | **$25.9m / year** |
| Distribution transformer reliability | Improvement in network reliability for customers due to greater visibility throughout our network. | **$4.3m / year** |
| Service line replacement deferral | Ability to defer the replacement of a service line by two years. | **$2.1m / year** |
| DER Integration | Ability to orchestrate DER more accurately on our network | **Present value of $3.4m** |
| Grid Planning uplift | Ability to better plan the network through access to LV data. | **$9k / year** |
| Theft | Ability to detect when a customer has by-passed the meter | **$12k / year** |

The yearly benefits cashflow is shown in Figure 8

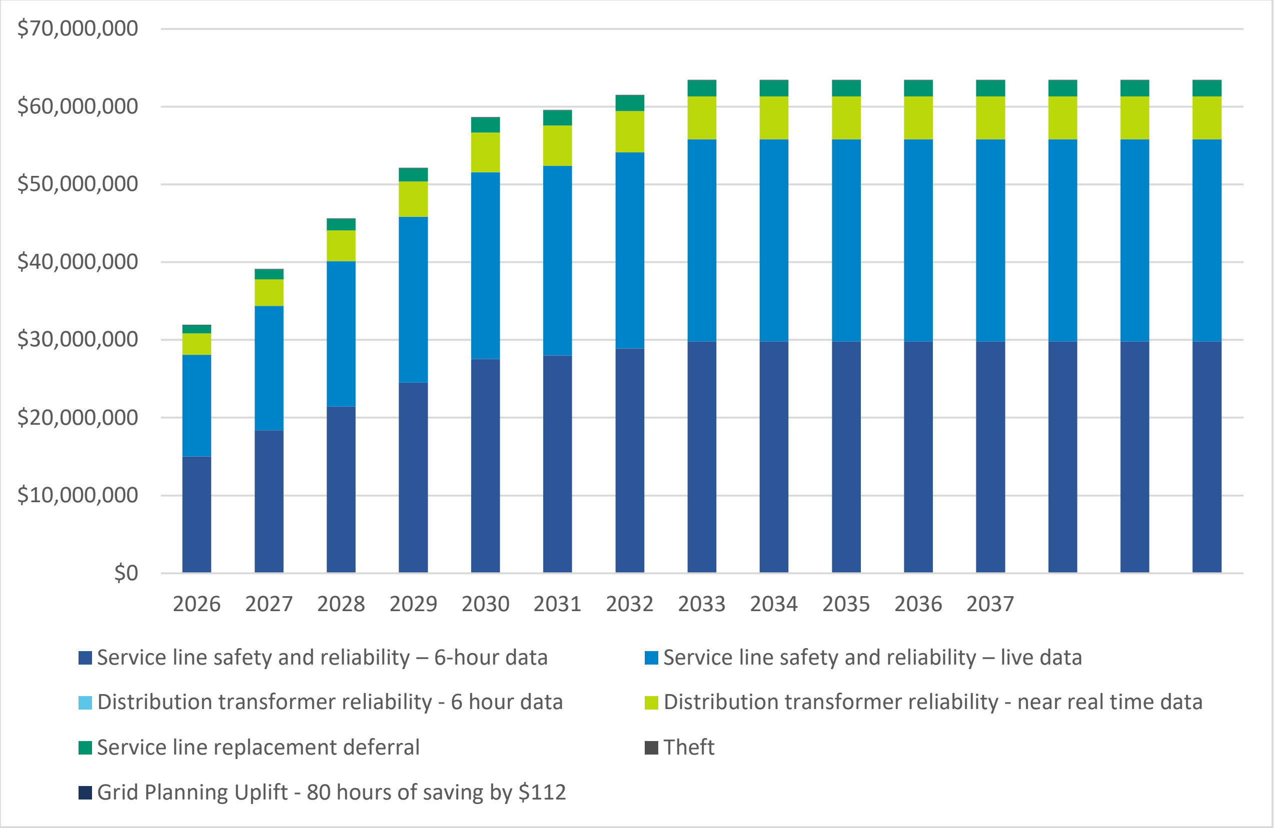

**Figure 8 – Option 3 Benefits Cashflow**

## 4.4 Option 4 – All services, with capture of live data for 25%

This option acquires data for overhead and underground service lines. This captures the safety and reliability benefits, as well as a deferral of service lines replacement, while also resulting in an improvement in our distribution transformer failure response for both overhead and underground areas with the acquisition of near real-time data. This also captures the benefits associated with DER integration to enable highly efficient operating envelopes to be produced. This option results in data being captured for around 80-90% of our services.

### 4.4.1 Assumptions

- **Data acquisition timeframe –** this option assumes near real-time data is utilised for 25% of our OH and UG service lines, with the remaining services captured in a 6-hour window.
- **Ratio of data capture** – this option assumes that we capture the smart meter that is available for our overhead and underground network and complement this with LV monitoring for those areas where we are unable to source smart meter data.
- **Service line safety improvement** – using live data will prevent 90% of the safety incidents on our LV service lines. For those with 6-hour data capture, 70% of our incidents will be captured. This is likely understating the number of incidents that we would capture as a result of this capability.
- **Service line reliability improvement** – using live data will reduce 100% of our reliability incidents by 1 hour for service line failure, while those with 6-hour data will prevent around 10% of the customer outages related to service line failures through being able to respond earlier to faults. This is low due to the lag in data reaching our network operations centre from 6-hour data.
- **Distribution transformer reliability improvement** –
    - We have factored in an improvement in the failure response to all 34,000 transformers in our network above 60kVA.
    - We have utilised the age profile of our distribution transformer population to determine the benefits attributable.
- **DER Integration** – the benefits of the uplift described in our DER Integration Strategy from the basic DoE to the highly accurate DoE have been attributed to this business case. The resultant improvement is entirely attributable to obtaining the critical mass of 25% of live data for both our overhead and underground networks.
- **Service line and cable replacement deferral** – we have factored in a present value benefit of $20 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 360 hours of effort in planning the network at $112 / hour.
- **Electricity Theft** – we have estimated a reduction of theft from 40 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh
- **Investment horizon** – this has been assumed to be 15 years to compare options involving more LV monitors, which have an asset life expectation of 15 years.

### 4.4.2 Costs

The cost of this program is:

- 6-hourly smart meter data acquisition - $0m / year

[redacted]

- Establishing 12,300 LV monitors at $770 / monitor. These will cover the areas where we expect won't receive smart meter early enough through the rollout.
- Data analytics for LV monitors of $10 / year, which begins to be accrued after 5 years.

### 4.4.3 Benefits

A summary of the benefits attributable to our LV monitoring capability are list below. These are summarised to yearly figures as the final uptake rate in 2030 as we achieve close to full penetration of smart meters.

**Table 5 Benefits overview for Option 4**

| Benefit Type | Benefit Description | Value |
|---|---|---|
| Service line safety and reliability – 6-hour data | Improvement in fault and defect detection to improve safety and reliability of our network. | **$29.8m / year** |
| Service line safety and reliability – live data | Improvement in fault and defect detection to improve safety and reliability of our network. | **$25.9 / year** |
| Distribution transformer reliability | Improvement in network reliability for customers due to greater visibility throughout our network. | **$5.5m / year** |
| Service line replacement deferral | Ability to defer the replacement of a service line by two years. | **$2.1m / year** |
| DER Integration | Ability to orchestrate DER more accurately on our network | **Present value of $6.8m** |
| Grid Planning uplift | Ability to better plan the network through access to LV data. | **$35k / year** |
| Theft | Ability to detect when a customer has by-passed the meter | **$48k / year** |

The yearly benefits cashflow is shown in Figure 9.

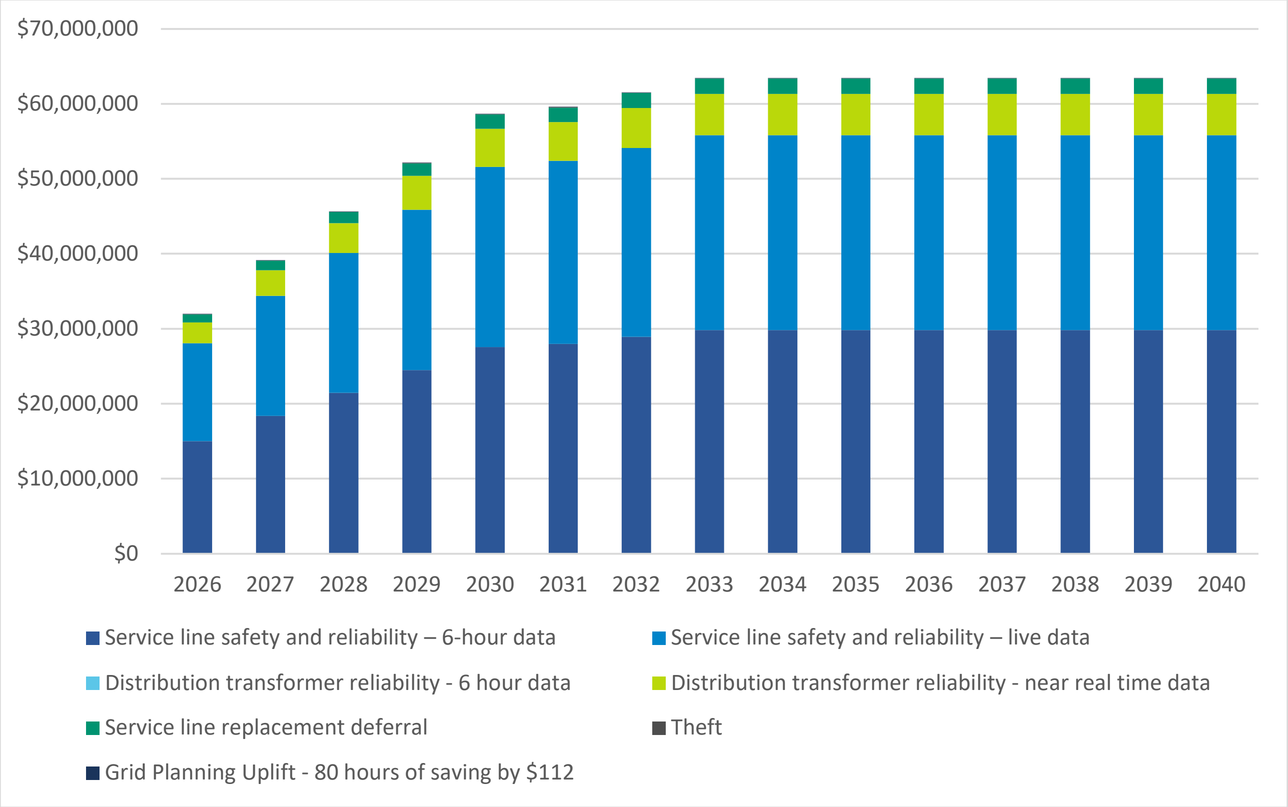

**Figure 9 – Option 4 Benefits Cashflow**

## 4.5 Economic Analysis

### 4.5.1 Cost summary 2025-30

Table 6 shows the costs for each option for the 2025-2030 period, 2022/23 $. These have been broken up into Opex and Capex to ensure the step change value can be separately reported from the capex implications of the program.

**Table 6 Cost summary 2025-30 2022/23 $m**

| Option | Expenditure Type | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | Total 2025-30 |
|---|---|---|---|---|---|---|---|
| Option 1 | Opex | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | **0.7** |
| | Capex | 1.9 | 1.9 | 2.0 | 2.0 | 1.8 | **9.5** |
| Option 2 | Opex | 0.9 | 1.1 | 1.3 | 1.5 | 1.6 | **6.4** |
| | Capex | 1.9 | 1.9 | 2.0 | 2.0 | 1.8 | **9.5** |
| Option 3 | Opex | 0.6 | 0.7 | 0.8 | 0.9 | 1.0 | **4.1** |
| | Capex | 1.9 | 1.9 | 2.0 | 2.0 | 1.8 | **9.5** |
| Option 4 | Opex | 1.0 | 1.2 | 1.3 | 1.5 | 1.7 | **6.7** |
| | Capex | 1.9 | 1.9 | 2.0 | 2.0 | 1.8 | **9.5** |

### 4.5.2 NPV analysis

The NPV of all options has been calculated, with the results shown in Table 7.

**Table 7 NPV analysis $m**

| Option | Net Present Value | Present Value of Costs | Present Value of Benefits |
|---|---|---|---|
| Option 1 | 377.9 | 17.6 | 395.6 |
| Option 2 | 554.4 | 32.0 | 586.4 |
| Option 3 | 545.6 | 26.3 | 571.9 |
| Option 4 | 554.3 | 32.5 | 586.8 |

As can be seen from Table 7, Option 2 maximises the value to our customers, with benefits of obtaining greater visibility on our network outweighing the costs associated with obtaining it. Option 4 is the next best option. However, the extra benefits from acquiring data for all customer services begins to have a diminishing return, meaning that the balance of obtaining overhead service lines data for safety and reliability benefits, combined with underground areas for distribution transformer reliability provides the most balanced outcome.

## 5 RECOMMENDATION

Consistent with the cost benefit analysis of acquiring data for our LV network, Option 2 is the recommended option. This includes obtaining all data for overhead services, with 25% being near real-time, and obtaining 25% of data for our underground networks.

**Table 8 Options Analysis Scorecard**

| Criteria | Option 1 – 6-hour data for OH | Option 2 – Mixture of data for OH and 25% for underground | Option 3 – Mixture of 6-hour and near real-time data for OH | Option 4 – All customer data, 25% near real-time |
|---|---|---|---|---|
| **Net Present Value** | $377.9m | $554.4m | $545.6m | $554.3m |
| **Investment cost (TCO)**** | $10.2m | $15.8m | $13.7m | $16.2m |
| **Detailed analysis –** Benefits | Provides an improvement in safety and reliability for our OH services network. | Provides safety benefits for our OH services network.<br>Provides reliability benefits for our services and transformer network across all our network. | Provides safety benefits for our OH network.<br>Provides reliability benefits to our OH network. | Provides the highest overall benefits to customers. |
| **Detailed analysis –** Risks | Does not provide any reliability benefits for transformer failures. | Provides slightly less grid planning visibility than option 4. | Does not provide any benefits for our customers connected to the underground networks. | Provides the most benefits to our customers. |

# APPENDICES

## Appendix 1: Alignment with the National Electricity Rules

**Table 9 Recommended Option's Alignment with the National Electricity Rules**

| NER capital expenditure objectives | Rationale |
|---|---|
| A building block proposal must include the total forecast capital expenditure which the DNSP considers is required in order to achieve each of the following (the capital expenditure objectives): | |
| **6.5.7 (a) (1)**<br>meet or manage the expected demand for standard control services over that period | This business case seeks to meet our obligations to provide a safe and reliable network and improve our ability to respond to asset failures. |
| **6.5.7 (a) (2)**<br>comply with all applicable regulatory obligations or requirements associated with the provision of standard control services; | We have a regulatory obligation to operate our network safely and undertake expenditure that is proportionate to the risk involved. We have demonstrated a positive cost-benefit analysis for this expenditure. |
| **6.5.7 (a) (3)**<br>to the extent that there is no applicable regulatory obligation or requirement in relation to:<br>(i) the quality, reliability or security of supply of standard control services; or<br>(ii) the reliability or security of the distribution system through the supply of standard control services,<br>to the relevant extent:<br>(iii) maintain the quality, reliability and security of supply of standard control services; and<br>(iv) maintain the reliability and security of the distribution system through the supply of standard control services | This business case is supported by positive cost benefit analysis. |
| **6.5.7 (a) (4)**<br>maintain the safety of the distribution system through the supply of standard control services. | This business case proposes the use of smart meter data to detect asset failures that could result in public safety issues. |
| **NER capital expenditure criteria** | **Rationale** |
| The AER must be satisfied that the forecast capital expenditure reflects each of the following: | |
| **6.5.7 (c) (1) (i)**<br>the efficient costs of achieving the capital expenditure objectives | The costs of this initiative are proportionate to the risks we have identified. |
| **6.5.7 (c) (1) (ii)**<br>the costs that a prudent operator would require to achieve the capital expenditure objectives | This business case has a positive cost-benefit analysis, demonstrating prudency. |
| **6.5.7 (c) (1) (iii)**<br>a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives | The costs associated with this initiative have been worked through with suppliers of data and analytics tools. |

# Appendix 2: Reconciliation Table

**Table 10 Reconciliation**

| Expenditure | DNSP | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2025-30 |
|---|---|---|---|---|---|---|---|
| Opex in business case<br>$m, direct 2022-23 | Ergon | 0.9 | 1.1 | 1.3 | 1.5 | 1.6 | **6.4** |
| Capex in business case<br>$m, direct 2022-23 | Ergon | 1.9 | 1.9 | 2.0 | 2.0 | 1.8 | **9.5** |