MANAGING THE RISK OF INSTRUMENT TRANSFORMER FAILURE

Project Assessment Conclusions Report

7 January 2020

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Executive Summary

This report is the final stage of an investigation into the most economic option to address the risk of instrument transformer failure

This Project Assessment Conclusions Report (PACR) is the final step in the application of the Regulatory Investment Test for Transmission (RIT-T) to investigate options to address the risk of instrument transformer failure across the South Australian electricity transmission network.

Instrument transformers are a major component of the electrical protection system that ensures electrical faults are cleared within designated times, as specified in the National Electricity Rules (NER).[1] If an instrument transformer fails explosively, it can cause unpredictable damage resulting in harm to people, potential substation failure and consequential involuntary load curtailment for customers.

An initial report was released in October 2019 identifying a proposed solution

A Project Specification Consultation Report (PSCR) for this RIT-T was published on 8 October 2019 and outlined how there is only one technically and economically feasible option, which is to replace the end-of-life instrument transformers with a capital cost of approximately $12 million.

Other options considered included the replacement of entire substations at a capital cost of approximately $20 to $40 million per substation, which is significantly more costly than the proposed solution and therefore economically infeasible (even where replacing multiple instrument transformers at the same substation).

The PSCR assessed different timings of this replacement option and concluded that replacing the identified assets as soon as practicable is the preferred option primarily on account of avoided unserved energy.

The PSCR also explained why network support solutions are not expected to have a feasible role to play in addressing the identified need on account of the unique and specific role that instrument transformers play in the transmission of electricity and their relatively low replacement cost.

No submissions were received on the PSCR.

This report maintains the initial conclusion that replacing the identified instrument transformers as soon as possible is the preferred option[2]

The preferred option that has been identified is Option 1, i.e. replacing 179 instrument transformers between 2020 and 2023. The estimated capital cost of this option is approximately $12 million, which equates to approximately $66,600 for each of the new instrument transformers planned to be replaced.

We have undertaken a thorough sensitivity testing exercise to investigate the robustness of the RIT-T assessment to underlying assumptions about each of the key variables. For all sensitivity tests undertaken, the preferred option remains replacing the identified assets in the next four years.

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1 S5.1a.8 of the NER outlines the requirements regarding fault clearance times, including the specific maximum permitted fault clearance times.

2 The preferred option is defined as the option that maximises net market benefits under the RIT-T framework.

Next steps

ElectraNet intends to commence work on replacing the identified instrument transformers in early 2020.

There are 19 substations where instrument transformers are planned to be replaced and we are planning to have all assets removed or replaced by June 2023.

Further details in relation to this project can be obtained from:

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Glossary of Terms

Term	Description
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ETC	Electricity Transmission Code
NPV	Net Present Value
NEM	National Electricity Market
NER, Rules	National Electricity Rules
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PV	Present value
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer Reliability

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1. Introduction

This Project Assessment Conclusions Report (PACR) represents the final step in the application of the RIT-T to address the risk of instrument transformer failure at certain substations in the South Australian transmission network.

A Project Specification Consultation Report (PSCR) was released on 8 October 2019 that described the identified need we are seeking to address, set out the technical characteristics that a network support option would be required to deliver and outlined the credible option we consider addresses the identified need. The PSCR also set-out an economic assessment, along with a draft conclusion on the preferred option, as well as how ElectraNet was intending to apply the NER exemption from preparing a Project Assessment Draft Report (PADR) for this RIT-T.[3]

No submissions were received on the PSCR.

1.1 Why we consider this RIT-T is necessary

Changes to the National Electricity Rules (NER) in July 2017 extended the application of the RIT-T to replacement capital expenditure on 18 September 2017.[4]

Accordingly, we have undertaken this RIT-T to consult on proposed expenditure related to replacing instrument transformers, as none of the exemptions listed in NER clause 5.16.3(a) apply.

The credible option discussed in this PSCR has not been foreshadowed in AEMO's National Transmission Network Development Plan (NTNDP) or Integrated System Plan (ISP) as these assets do not have a material impact on the main transmission flow paths between the NEM regions.

1.2 Next steps

ElectraNet intends to commence work on replacing the identified assets in early 2020.

There are 19 substations where instrument transformers are planned to be replaced. We are planning to have all assets removed or replaced by June 2023.

Further details in relation to this project can be obtained from:

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3 In accordance with NER clause 5.16.4(z1).

4 The application of the RIT-T to replacement expenditure ('repex') commenced on 18 September 2017, however, all repex projects that were 'committed' by 30 January 2018 are exempt. See paragraph 18 of the AER's RIT-T for the definition of a 'committed project'. While the planning process for replacing the identified instrument transformers was well-advanced by 30 January 2018, the project was not yet 'committed'. Accordingly, we have subsequently undertaken this RIT-T to consult on its proposed expenditure related to replace the identified instrument transformers.

2. The identified need for this RIT-T is to ensure reliable and safe supply of electricity to South Australia

This section outlines the identified need for this RIT-T, as well as the assumptions underpinning it. It first provides some background on the identified instrument transformers and their role in the wider transmission of electricity in South Australia.

2.1 Background to the identified need

'Instrument transformers' is a general term used to refer to current and voltage devices that change currents and voltages from one magnitude to another or perform an isolating function, i.e., isolate the utilisation current or voltage from the supply voltage for safety to both the operator and the end device in use. Instrument transformers are designed specifically for use with electrical equipment falling into the broad category of devices commonly called instruments such as voltmeters, ammeters and wattmeters, etc.[5]

Instrument transformers are a major component of the electrical protection system that ensures faults are cleared within designated times, as stipulated by the National Electricity Rules (NER).[6] In addition, if an instrument transformer fails explosively it can cause unpredictable damage resulting in potential substation failure and consequential involuntary load curtailment for consumers.

Instrument transformers situated at the Torrens Island B substation are illustrated Figure 1.

Figure 1 - Endurance 275 kV post current transformers at Torrens Island B

5 GE, *Instrument Transformer Basic Technical Information and Application*, p. 3 – available at: https://www.gegridsolutions.com/products/manuals/ITITechInfo.pdf

6 S5.1a.8 of the NER outlines the requirements regarding fault clearance times, including the specific maximum permitted fault clearance times.

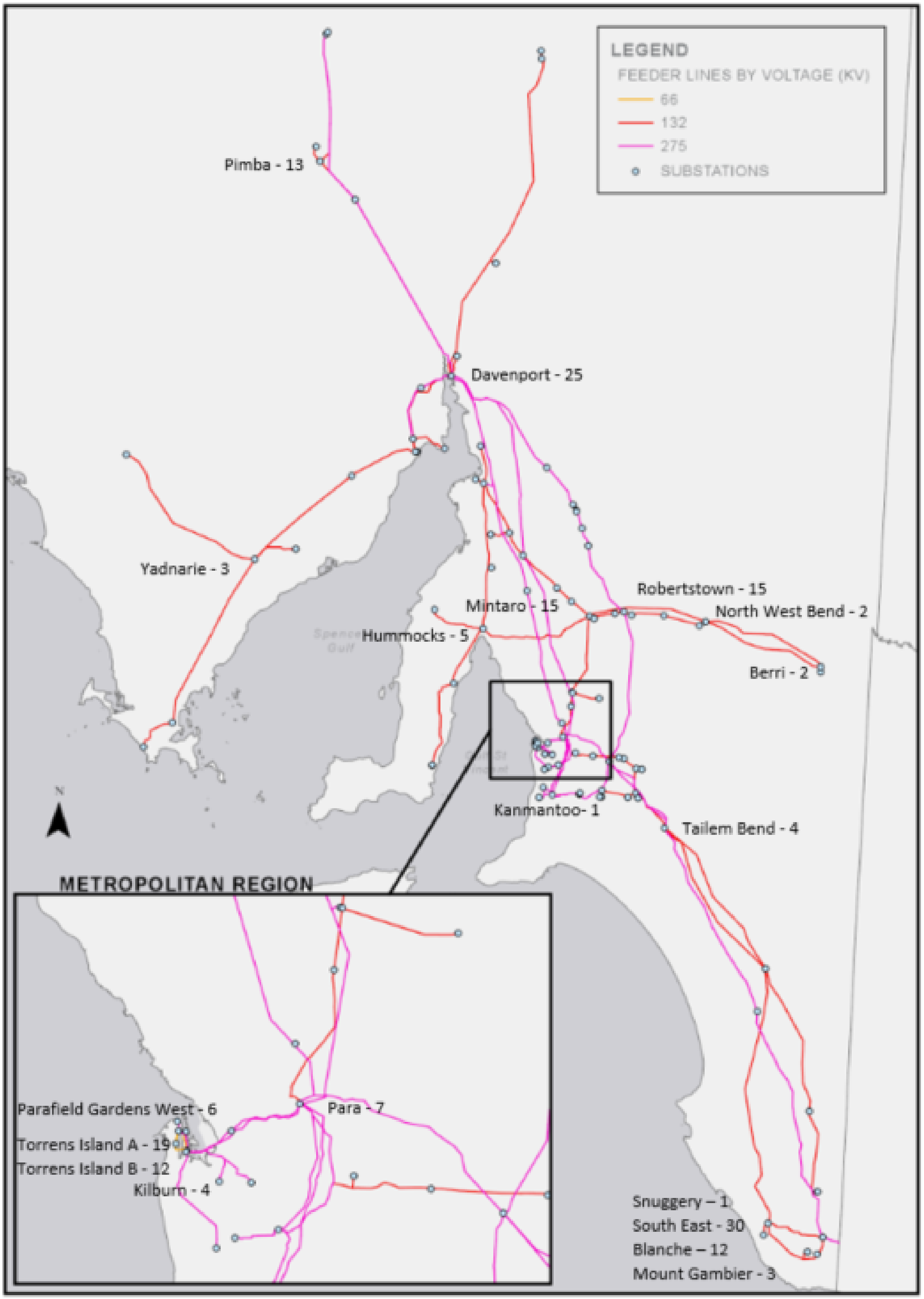
Instrument transformers are essential to the task of transmitting electricity, without them the transmission network could not perform safely and efficiently.

Across our transmission network, we have identified 179 instrument transformers for replacement based on their age and condition. In particular, we have identified:

- 124 Current Transformers;
- 46 Capacitor Voltage Transformers; and
- 9 Voltage Transformers.

The distribution of the 19 substations where instrument transformers are planned to be replaced is illustrated in Figure 2. Specifically, it shows the number of existing transformers identified for replacement at each substation.

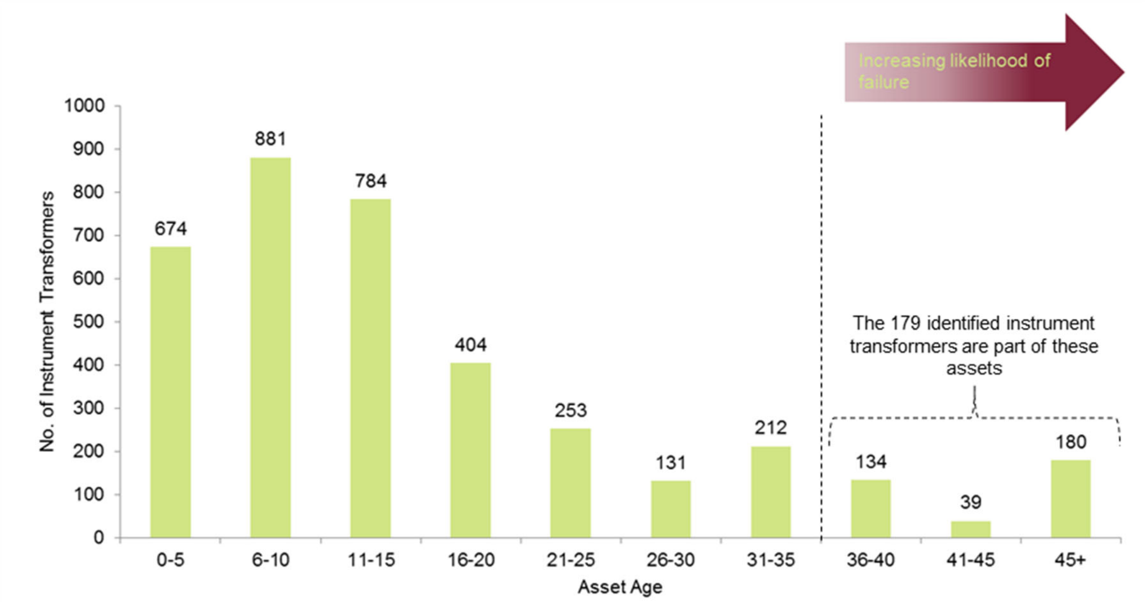
Figure 2 - Location of the instrument transformers that are being replaced



The instrument transformers to be replaced have a standard life[7] of 44.8 years and are now mostly aged between 36 and 58 years. These instrument transformers are planned to be replaced one for one with new instrument transformers with the same technical capacity.

If the replacement program is not implemented, it is expected that these assets may fail explosively at an increasing rate going forward. A failure can cause unpredictable damage to the substation, involuntary load shedding and possible personal injuries. Further, if the replacement program is not implemented there will be an increased cost to replace the assets upon failure in a reactive fashion.

Figure 3 - Age profile of instrument transformers and increasing level of failure



The existing porcelain instrument transformers have much higher likely consequences when an explosive failure occurs, compared to the polymer instrument transformers that are replacing them.

When a porcelain instrument transformer explodes, there is the possibility of considerable damage caused to other substation assets, resulting in a high likelihood of an outage and, if the substation is attended at the time, significant safety risks. The avoidance of explosive failure and decreased likelihood of adverse consequences from an explosive failure will create cost savings across these two areas during the delivery of the program (compared to a 'replace on failure' strategy, which is assumed under the base case in this RIT-T assessment).

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7 The AER considers that repex involves replacing an asset or asset component with its modern equivalent where the asset has reached the end of its *economic* life, which takes into account the age, condition, technology and operating environment of an existing asset (see: AER, *ElectraNet transmission determination 2018 to 2023*, Attachment 6 – Capital expenditure, Draft Decision, October 2017, p. 42.). We present here the standard technical lives of the instrument transformers for context and note that the assessment of replacing the identified transformers, both in the Revenue Proposal and this RIT-T, is consistent with the concept of economic life; ie, the expenditure decision is primarily based on the existing asset's inability to efficiently maintain its service performance requirement.

In March 2017, there was an explosive failure of an instrument transformer at the Torrens Island switchyard that placed the South Australian electricity network at significant risk. Specifically, while there was a localised outage, the only reason there was not a significant loss of load at the time was due to the voltage levels at South East substation being within the lower limits, so the Heywood Interconnector could continue to be connected.

The explosive failure at the Torrens Island switchyard caused significant damage, disconnecting three generation units at Torrens Island Power Station and resulted in Pelican Point Power Station also tripping off due to the operation of its over current protection (that was external to the power station).

The restoration of the connection points and substation took a number of months to complete with a temporary bypass available for the less damaged connection points within two to three days.

For more information on the fault at the Torrens Island switchyard, and its effects, please refer to the AEMO incident report that was published at the time.[8]

2.2 Description of the identified need for this RIT-T

Instrument transformers are required in the operation of protection systems, which in turn are critical to the safe, reliable and secure operation of the transmission system.

As set out in the PSCR the identified need for this project is to efficiently manage the risk of failure of individual instrument transformer units that are reaching, or have passed, the end of their technical lives based on their condition.

We have assessed the condition, and timing for the ultimate replacement of instrument transformer units as part of our ongoing asset management processes. There is an increased likelihood that a number of these assets will fail in coming years given their current age, potentially resulting in unplanned unavailability to parts of the network, personal injury to substation workers and greater operating costs to ElectraNet.

We have classified this RIT-T as a ‘market benefits’ driven RIT-T as the economic assessment is not being progressed specifically to meet a mandated reliability standard but by the expected net benefits to customers.

However, the replacement program will also ensure compliance with a range of obligations under the NER and jurisdictional instruments (which is not expected to be the case under the base case). Specifically, Option 1 maintains compliance with:

- system standards and specifically the relevant fault clearance times;
- network reliability (S5.1.2):
  - when planning and operating the network we must consider a credible contingency event where the disconnection of any single generating unit or transmission line occurs and assume that the fault will be cleared in primary protection time;

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8 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Report-SA-on-3-March-2017.pdf

  - ensuring that for all lines above 66kV the line's protection system is always available, other than for short period (not greater than eight hours) whilst maintenance is carried out;

- protection systems and the fault clearance times applicable (including the fault clearance times mentioned in maintaining system security).

In addition, the *South Australian Electricity (General) Regulations 2012* (the Regulations), under the *Electricity Act 1996*, require that "*a system of maintenance must be instituted for protection and earthing systems and their components including…managed replacement programs for components approaching the end of their serviceable life*". [9] ElectraNet consider this RIT-T forms an important part of complying with this requirement and, more broadly, avoids a situation of run-to-failure for the identified assets (which would not constitute a compliant management strategy).

A full cost benefit assessment has been undertaken, comparing the risk cost reduction benefits of asset replacement options with the cost of those options.

[9] *Electricity (General) Regulations 2012 (SA)*, Schedule 3—Requirements for substations, clause 11(2).

3. Potential credible options to address the identified need

The analysis has identified that there is only one technically feasible option, which is to replace the end-of-life instrument transformers. This is because the assets play a specific and important role in enabling substations to operate and to be maintained in a timely fashion, by minimising any consequential effects on downstream customers through potential uncleared faults or explosive asset failures.

We have however investigated different assumed timings for this work in order to determine the optimal timing. This assessment is presented in section 4.5.

The option is considered to be technically and economically feasible and able to be implemented in sufficient time to meet the identified need.[10] In addition, all works are assumed to be completed in accordance with the relevant standards, with protection relays being replaced with minimal modification to fit to the substation.

The PSCR set out that we do not consider network support solutions can assist with meeting the identified need for this RIT-T, given the unique and specific role that the identified instrument transformers play in the transmission of electricity, as well as their relatively low emergency repair cost when spare components are available. Notwithstanding, the PSCR set out the required technical characteristics for a network support option for completeness, consistent with the requirements of the RIT-T.

We did not receive any submissions on the PSCR.

3.1 Option 1 – Planned replacement of instrument transformers by 2023

Option 1 involves a planned replacement of 55 Voltage Transformers and 124 Current Transformers that are aged between 36 and 58 years and have been assessed to be at end of life based on their age and/or condition. The existing porcelain instrument transformers will be replaced with polymer instrument transformers.

These replacements are planned to occur over several priority-ranked streams between 2020 and 2023. These replacements are to be performed at substation locations where no other capital projects are otherwise scheduled to undertake replacement of the identified instrument transformers from the 2018-2023 regulatory period.

All instrument transformer replacement assets are assumed to have the same signal output levels, ratios, etc. as the original assets, negating the requirement to modify any secondary system inputs. It is envisaged that minimal changes will be required with a like for like change of the instrument transformers.

The estimated total capital cost of this option is approximately $12 million. This equates to approximately $66,600 for each of the 179 total new transformers planned to be installed.

There is no incremental change in routine maintenance when the assets are replaced under Option 1 compared to the base case.

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10 In accordance with those identified in section 2.2.

It is estimated that the replacement time for an instrument transformer at site is around one week; i.e. around 3 years in total. We estimate that all instrument transformers could be replaced and commissioned by 2023 under this option.

3.2 Options considered but not progressed

We have also considered whether there are other credible options that would meet the identified need. However, the identified need to address end-of-life instrument transformers does not lend itself to any solution other than to replace the assets as the only technically and economically feasible option given the unique and specific function of these assets.

One option, for example, would be to replace the entire substation, as opposed to just the instrument transformers. However, the capital cost of this is expected to be in the order of $20-40 million per substation, which is significantly more than the option outlined above and does not provide any additional market benefits. In addition, the condition of other substation assets is such that they do not require replacing in coming years. Therefore, this is not considered to be an economically feasible option.

We do not consider that network support solutions can address, or help address, the identified need as set out in section 4 below.

4. Assessment of the credible options

This section outlines the assessment we have undertaken of the credible network option. The assessment compares the option against a base case 'do nothing' option.

For clarity, this section re-presents the underlying assessment in the PSCR. There were no material changes since the PSCR that would affect the finding that Option 1 is preferred.

4.1 Description of reasonable scenarios

The RIT-T analysis is required to incorporate a number of different reasonable scenarios, which are used to estimate expected net market benefits. The number and choice of reasonable scenarios must be appropriate to the credible options under consideration.

For a market benefits driven RIT-T such as this, the choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking of the credible options, or the sign of the net economic benefits of any of the credible options.[11]

We have developed three scenarios for this RIT-T assessment:

- a 'central' scenario reflecting our base set of key assumptions;
- a 'low benefits' scenario – reflecting a conservative set of assumptions, which represents a lower bound on reasonably expected potential market benefits that could be realised; and
- a 'high benefits' scenario – reflecting an optimistic set of assumptions, which represents an upper bound on reasonably expected potential market benefits.

The table below summarises the key assumptions making up each scenario.

Given that the low and high benefits scenarios are less likely to occur, the scenarios have been weighted accordingly; 25 per cent – low benefits scenario, 50 per cent – central benefits scenario, and 25 per cent – high benefits scenario.

[11] AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 16, p. 7.

Table 1 - Summary of the three scenarios

Key variable/parameter	Low benefits scenario	Central scenario	High benefits scenario
Capital costs	130 per cent of capital cost estimate	Base estimate	70 per cent of capital cost estimate
Commercial discount rate[12]	8.95 per cent	5.90 per cent	2.85 per cent
Avoided emergency corrective maintenance and opex	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Avoided substation damage due to explosive failure	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Reduced personal injuries from an explosive failure	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Cost of involuntary load shedding	70 per cent of base estimates	Base estimates	130 per cent of base estimates

4.2 Gross benefits for each credible option

The gross benefits estimated for Option 1 relative to the ‘do nothing’ base case in present value terms are summarised in Table 2. The gross market benefit has been calculated for each of the three scenarios as outlined in section 4.1.

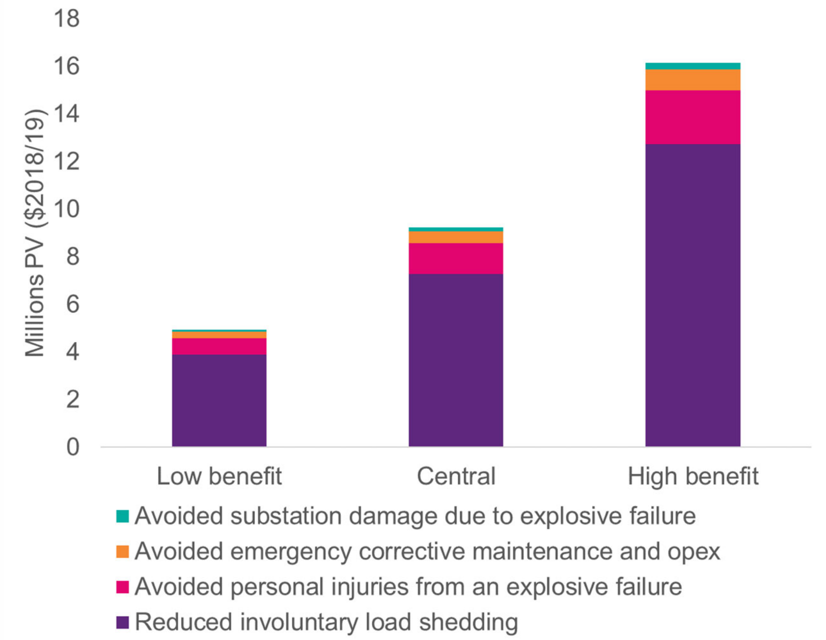
Table 2 - Estimated gross market benefit for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Planned replacement of instrument transformers by 2023	4.9	9.2	16.2

A breakdown of benefits is illustrated in Figure 4 and shows that most benefits are derived from the reduction in involuntary load shedding. There are also benefits from avoiding personal injury risks associated with lower explosive failure consequences under Option 1, as well as avoiding emergency corrective maintenance and opex.

12 Expressed on a real, pre-tax basis

Figure 4 - Breakdown of present value gross economic benefits of Option 1



As outlined in section 2.3.3, we note that, should an instrument transformer fail, there may also be wider outages than the load groups we have considered and/or planned outages for operational and capital work may have to be postponed. These additional adverse effects have not been captured in our risk cost modelling since this would require a significant modelling exercise and it is not considered material in the context of the RIT-T assessment but is expected to further increase the market benefits associated with Option 1.

4.3 Estimated costs for each credible option

The capital costs of Option 1, relative to the base case, in present value terms are summarised in Table 3.

Table 3 - Estimated capital cost for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Planned replacement of instrument transformers by 2023	-9.9	-7.3	-4.4

4.4 Net present value assessment outcomes

The net market benefit in NPV terms for Option 1 across the three scenarios, as well as on a weighted basis is summarised in Table 4. The net market benefit is the gross benefits (as set out in section 4.2) minus the cost (as outlined in section 4.3), all expressed in present value terms.

The table below shows that Option 1 provides an expected net economic benefit on a probability-weighted basis, as well as under the central and high scenarios.

While the low benefits scenario shows negative expected market benefits, this scenario is relatively unlikely because it is comprised of the lower bound of each expected net market benefit resulting in a more extreme scenario.

As outlined in Table 1, the low scenario is based on including 30 per cent higher capital costs, a commercial discount rate of 8.95 per cent and 30 per cent lower benefits (across all types of benefits).

Table 4 - Estimated net market benefit for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario	Weighted
Option 1 – Planned replacement of instrument transformers by 2023	-4.9	1.9	11.7	2.6

4.5 Sensitivity testing

We have undertaken a thorough sensitivity testing exercise to understand the robustness of the RIT-T assessment to underlying assumptions about key variables.

In particular, we have tested the optimal timing of the project, and the sensitivity of this timing to key variables.

We have then tested the sensitivity of the total net market benefit to variations in the key factors underlying the assessment, such as for example the sensitivity of the project to increases in capital costs (all sensitivities tested are examined in section 4.5.2).

4.5.1 Sensitivity testing of the assumed optimal timing for the credible option

We have estimated the optimal timing for Option 1 based on the year when the present value of the benefits exceeds the present value of the replacement project costs,[13] which is consistent with when the expected NPV is maximised. This process was undertaken for both the central set of assumptions and also a range of alternative assumptions for key variables.

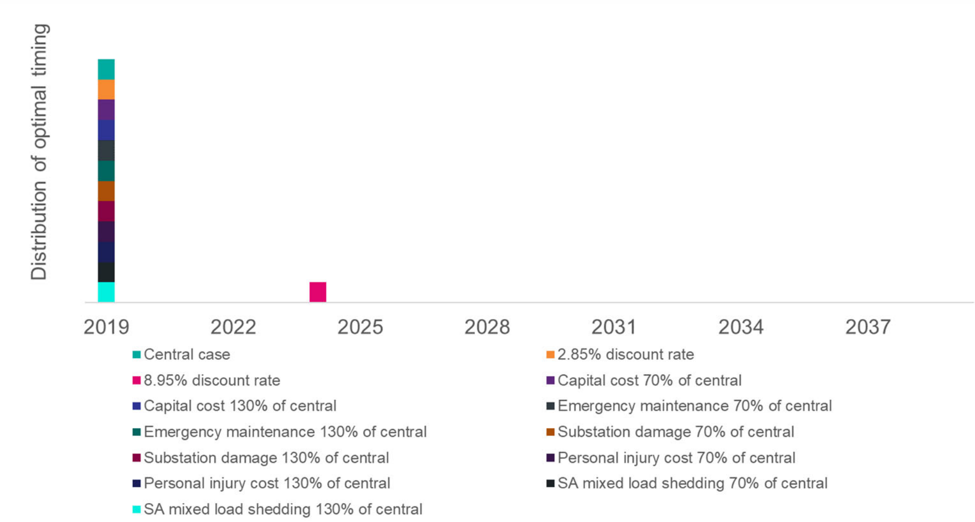
The impact on the optimal year to commence the program is outlined in Figure 5 under a range of alternative assumptions. Specifically, it shows, for each set of sensitivities/ assumptions, the year that results in the highest expected net market benefits, all else being equal.

The figure illustrates that the optimal commissioning date is as soon as possible for all except one of the sensitivities investigated. Specifically, under a high assumed commercial discount rate (of 8.95 per cent), the optimal timing is delayed until 2024. However, on balance, we consider the investment is required as soon as possible.

It is noted that the figure below shows the optimal year to *commence* the program of replacement, whilst recognising that it will take three years to complete the replacement works (i.e., the earliest all transformers can be replaced is mid-2023).

[13] We note that this approach is consistent with the AER RIT-T Guidelines (see: AER, *Regulatory Investment Test for Transmission*, Application Guidelines, December 2018, p. 21).

Figure 5 - Distribution of optimal timing for Option 1 under a range of different key assumptions



4.5.2 Sensitivity of the overall net market benefit

We have also looked at the consequences for the credible option of 'getting it wrong' if the key underlying assumptions are not accurate.

The four figures below illustrate the estimated net market benefits for each option if the four separate key assumptions in the central scenario are varied individually. Importantly, for the majority of the sensitivity tests shown below, the estimated net market benefit of Option 1 is found to be strongly positive.

The table below sets out the 'threshold' values for each of the key variables in the economic assessment, i.e. how much would each key variable need to change for Option 1 to no longer have positive net market benefits and be the preferred option.

Table 5 - Threshold values of key variables that would change preferred option

Key variable/parameter	Threshold value
Capital cost	126% of central estimate
Discount rate[14]	8.13%
Value of customer reliability	74% of central estimate
Emergency corrective maintenance, substation damage costs and personal injury costs	No limit[15]

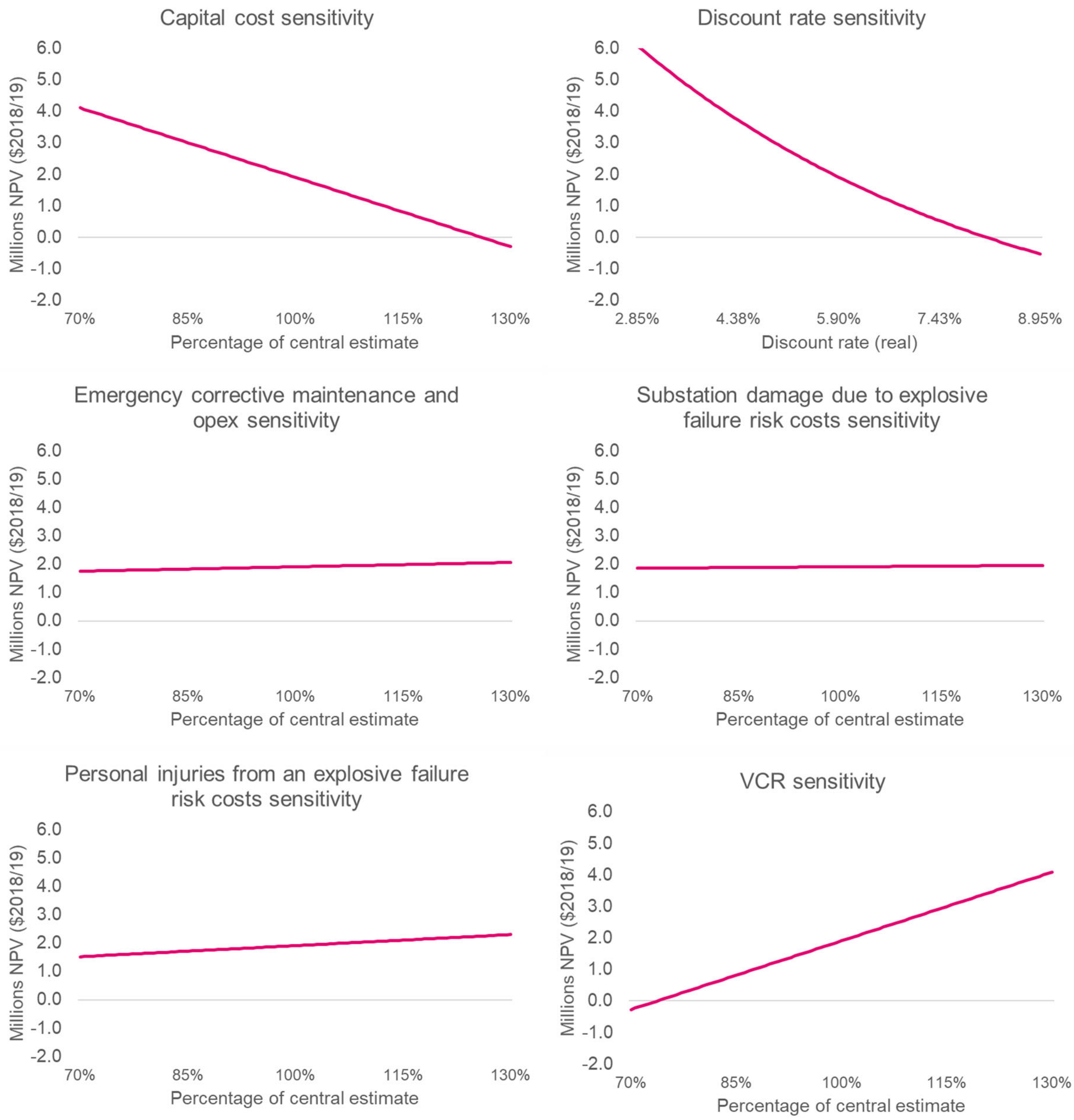
[14] Expressed on a real, pre-tax basis

[15] I.e., if any of these categories was removed completely, Option 1 would still have a positive expected net market benefit.

In addition, we find that the modelled failure rate implicit in the risk cost modelling would need to fall to approximately 79 per cent of the central estimate for there to be zero estimated net market benefits under the central scenario.

ElectraNet does not consider that any of these threshold values can be reasonably expected and, thus, considers that the expected net market benefits have been demonstrated to be robust to a range of alternate assumptions.

Figure 6 - Sensitivity testing of the NPV of net market benefits



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5. Conclusion on the preferred option

The preferred option that has been identified in this assessment to meet the identified need is Option 1, which is to replace instrument transformers between 2020 and 2023. This option is described in section 3 and is estimated to have a capital cost of $12 million.

Option 1 is the preferred option in accordance with NER clause 5.16.1(b) because it is the credible option that maximises the net present value of the net economic benefit to all those who produce, consume and transport electricity in the market. In addition, Option 1 ensures ongoing compliance with a range of obligations under the NER and jurisdictional instruments.

ElectraNet considers that the analysis undertaken and the identification of Option 1 as the preferred option satisfies the RIT-T.

ElectraNet intends to commence work on replacing the identified instrument transformers in early 2020. There are 19 substations where instrument transformers are planned to be replaced and we are planning to have all assets removed or replaced by June 2023.

APPENDICES

Appendix A Compliance checklist

This appendix sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16.4(v) of the Rules version 126.

Rules clause	Summary of requirements	Relevant section(s) in PACR
5.16.4(v)	The project assessment conclusions report must include:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	NA
5.16.4(k)	The project assessment draft report must include:	-
	(1) a description of each credible option assessed;	3
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	NA
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	3, 4, Appendix E & Appendix F
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Appendix E
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Appendix E
	(6) the identification of any class of market benefit estimated to arise outside the *region* of the *Transmission Network Service Provider* affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	NA
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	4
	(8) the identification of the proposed preferred option;	5
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a *material inter-network impact* and if the *Transmission Network Service Provider* affected by the RIT-T project has received an *augmentation technical report*, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the *regulatory investment test for transmission*.	3 & 5

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Appendix B Definitions

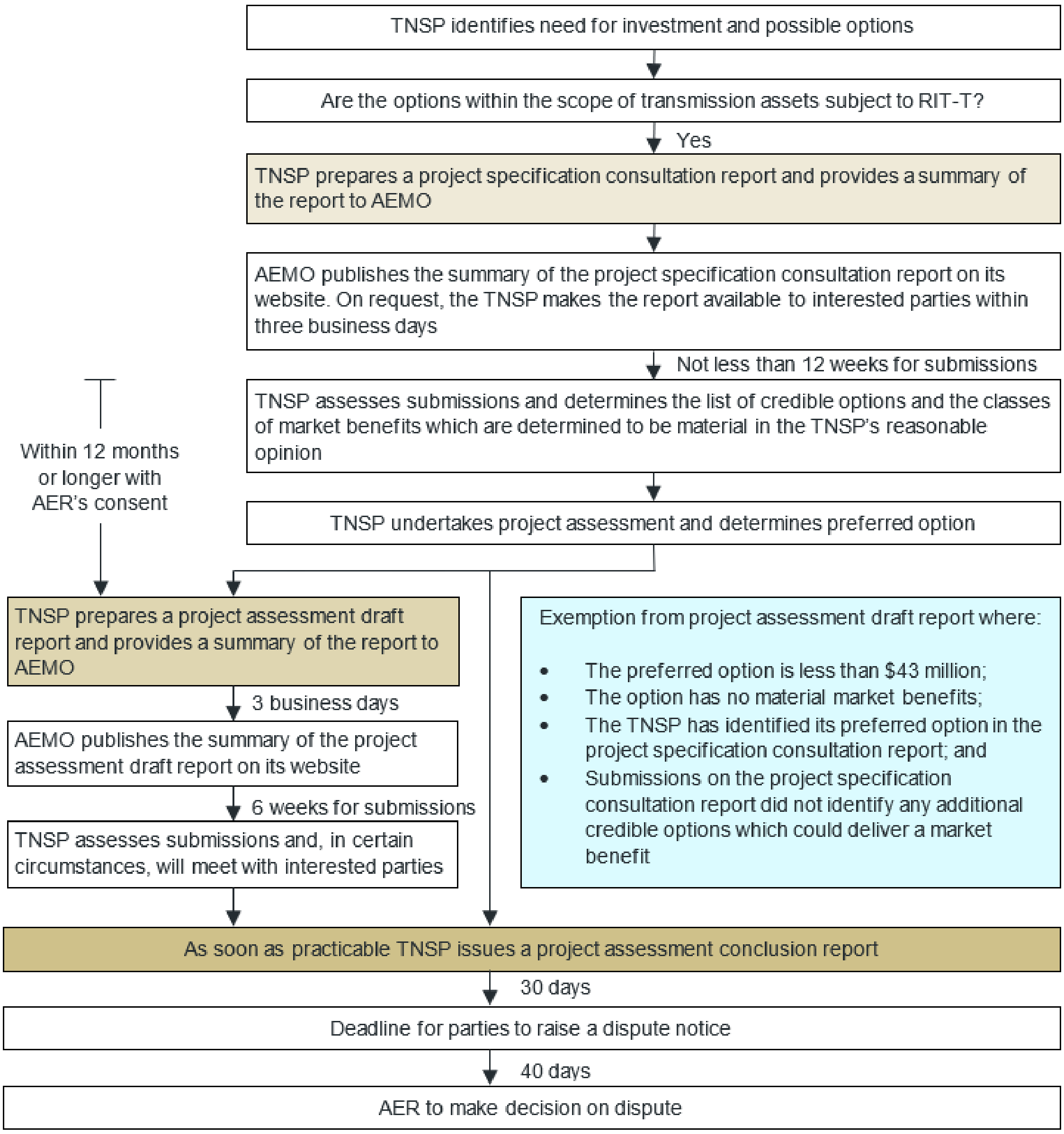
All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the NER) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.

Applicable regulatory instruments	
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, or on behalf of the transmission network service provider.
Commercially feasible	An option is commercially feasible if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options. This is taken to be synonymous with 'economically feasible'.
Costs	Costs are the present value of the direct costs of a credible option.
Credible option	A credible option is an option (or group of options) that: 1. address the identified need; 2. is (or are) commercially and technically feasible; and 3. can be implemented in sufficient time to meet the identified need.
Economically feasible	An option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need. One important exception to this Rules guidance applies where it is expected that a credible option or options are likely to deliver materially higher market benefits. In these circumstances the option may be "economically feasible" despite the higher expected cost. This is taken to be synonymous with 'commercially feasible'.
Identified need	The reason why the Transmission Network Service Provider proposes that a particular investment be undertaken in respect of its transmission network.
Market benefit	Market benefit must be: a) the present value of the benefits of a credible option calculated by: i. comparing, for each relevant reasonable scenario: A. the state of the world with the credible option in place to B. the state of the world in the base case, And ii. weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring. b) a benefit to those who consume, produce and transport electricity in the market, that is, the change in producer plus consumer surplus.
Net market benefit	Net market benefit equals the market benefit less costs.
Preferred option	The preferred option is the credible option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market compared to all other credible options. Where the identified need is for reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost).
Reasonable Scenario	Reasonable scenario means a set of variables or parameters that are not expected to change across each of the credible options or the base case.

Appendix C Process for implementing the RIT-T

For the purposes of applying the RIT-T, the NER establishes a typically three stage process, ie: (1) the PSCR; (2) the PADR; and (3) the PACR. This process is summarised in the figure below (in gold), as well as the criteria for PADR exemption that this RIT-T has applied (in blue).

Figure 7 - The RIT-T assessment and consultation process



Appendix D Assumptions underpinning the identified need

This appendix summarises the key assumptions from the risk cost modelling and other key assumptions that underpin the identified need for this RIT-T. Appendix F provides further detail on the general modelling approaches applied, including additional details on the risk cost modelling framework.

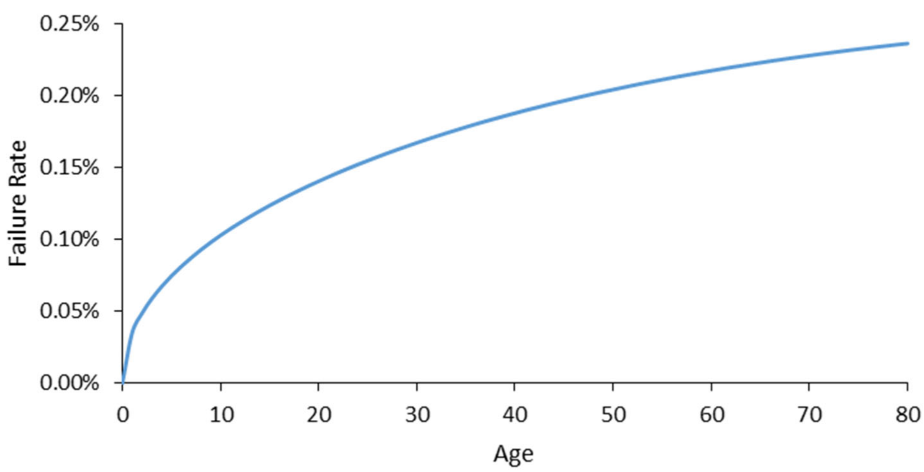
In light of the uncertainties inherent in all assumptions, we have undertaken a range of sensitivity and 'threshold' tests in order to test the robustness of the preferred option. These are outlined in section 4 above.

D1 The probability of instrument transformers failing

The probability of failure (PoF) is estimated by considering the asset's age and historical asset failure data from CIGRE's Final Report 2004 – 2007 International Enquiry on Reliability of High Voltage Equipment, Part 4 – Instrument Transformers. CIGRE is a global technical forum for large electric systems and is composed of researchers, academics, engineers, technicians, suppliers, market and system operators and other decision makers.

Figure 8 below summarises the modelled PoF for the identified instrument transformers, which shows an increase in the PoF as the assets increase in age.

Figure 8 - Weibull distribution of instrument transformer failure over age



D2 The adverse effects of instrument transformer failure

The risk cost model considers six potential failure modes for instrument transformers:

- electrical – when there is a loss of electrical connection integrity in primary and secondary components;
- electrical explosive – when the loss of electrical connection integrity in primary components results in an explosive failure;
- insulation – an internal and external dielectric failure, insulation leakage or accuracy out of tolerance;

- insulation explosive – an explosive internal and external dielectric failure or explosive insulation leakage failure;
- other – where the unit loses mechanical integrity; and
- other explosive – which is any other major failure where the unit loses mechanical integrity resulting in explosive failure.

Each of these failure modes have different characteristics and consequent likelihoods of occurring. The potential adverse consequences of an instrument transformer failure include:

- prolonged periods of unserved energy to electricity customers during the time taken to establish a temporary connection in response to an explosive failure;
- increased operating expenditure required to manage the network during an outage event;
- additional corrective maintenance costs associated with having to repair or replace the instrument transformer in an unplanned emergency;
- increased substation damage due to an explosive instrument transformer failure; and
- significant risk of fatalities if workers are present at the substation during an explosive instrument transformer failure.

D3 The likelihood and cost of consequences of an instrument transformer failure

Our risk cost model, models each of the adverse effects outlined above that could occur from an instrument transformer failure. Specifically, the risk cost model individually defines a set of assumptions for the adverse effects, which allows the 'likelihood of consequence' (LoC) and 'cost of consequence' (CoC) to be estimated for instrument transformer failures.

While the largest expected source of benefit from the planned replacement comes from avoided outages following a failure of an instrument transformer, most non-explosive failures of instrument transformers will not result in an outage, due to the presence of duplicated systems. The only non-explosive failures that will result in an outage are on single radial instrument transformers, therefore the benefits from outages relating to non-explosive failures are limited.

When there is an explosive failure of a porcelain instrument transformer, the likelihood that there will be an outage is assumed to be between 1 and a 100 per cent. This likelihood depends on several considerations including whether the substation is part of the meshed network and the distance between the location of the instrument transformer to other assets critical to supplying energy.

If the instrument transformer is instead a polymer instrument transformer the likelihood that there will be an outage is reduced to between 0.01 – 1.00 per cent. We have assumed that any outage is likely to be for 48 hours, based on the typical time to resupply the damaged substation or connection point via an alternative temporary connection. This temporary connection point would likely be in place for approximately 3 months whilst repairs are undertaken to the substation.

It is also assumed in specific instances that if there is an explosive failure of certain instrument transformers that support the interconnector there is a possibility of a wide scale outage. However, the LoC for this to occur is only when the interconnector is operating at certain limits (i.e. very unlikely).

In calculating outage costs, AEMO's estimated value of customer reliability (VCR) of a mixed load for South Australia, escalated to 2019 dollars, has been applied for all connection points when the connection point is not directly connected to a customer. When the connection point is directly connected to a customer the value of customer reliability of a direct connect load has been applied. All loads are based on the average load from the financial year 2017-18.

We note that, should an instrument transformer fail, there may also be wider outages than the load groups we have considered and/or planned outages for operational and capital work may have to be postponed.

These additional adverse effects have not been captured in our risk cost modelling since, doing so, would require a significant modelling exercise and it is not considered material in the context of the RIT-T assessment (i.e. in identifying the preferred option) but is expected to further increase the net market benefits associated with Option 1.

Unplanned outages require ElectraNet to incur further operating expenditure relating to the management of our network, including media, legal and investigation costs. These costs have been estimated using historical information and experience by the relevant internal teams at ElectraNet.

The explosive failure of an instrument transformer may in some cases cause material damage to other assets within the substation that will then require replacement or significant corrective work, resulting in additional costs. These costs have been estimated using historical information and experience by the relevant internal teams at ElectraNet.

Furthermore, we note that there is a material risk of fatality if someone is at a substation when a porcelain instrument transformer explodes. The substations where the instrument transformers are proposed to be replaced have been classified based on their size with larger substations more likely to be attended by industry workers on a regular basis and therefore have higher CoCs.

We have used the Value of Statistical Life[16], escalated to today's dollars and multiplied by a relevant disproportionate factor, in order to quantify these avoided consequences. It has also been assumed that any such events will incur additional costs such as a legal, compensation and investigation costs (which have been estimated using Safe Work Australia reports).[17] It is noted if the instrument transformer is a polymer instrument transformer the risk of fatality from an explosive failure is significantly reduced.

Overall, the costs associated with the negative consequences of an instrument transformer failure are material assumptions for the economic assessment of the project. We have therefore included a range of sensitivity tests on these as part of the economic assessment.

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[16] Department of the Prime Minister and Cabinet, *Best Practice Regulation Guidance Note Value of statistical life*, October 2018.

[17] Average Indirect Costs for work-related incidents, Australia in June 2013$, The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community: 2012-13, Safe Work Australia, p.26

Appendix E Materiality of market benefits for this RIT-T assessment

The appendix outlines the categories of market benefits prescribed in the NER and whether they are considered material for this RIT-T.[18]

Many of the expected benefits associated with Option 1 are captured in the expected costs avoided by the option (i.e., the avoided expected costs compared to the base case). As described in section 2, these include avoided risk costs.

Of these avoided costs, only unserved energy through involuntary load shedding is considered a market benefit category under the NER, as discussed further below.

E1 Avoided involuntary load shedding is the only relevant market benefit

We consider that the only relevant market benefit for this RIT-T relates to changes in involuntary load shedding. The expected unserved energy under the base case has been estimated as part of our risk cost modelling framework, which is avoided under Option 1.

The benefit associated with the reduction in unserved energy is valued using VCR, expressed in $/MWh. A VCR measure estimates the value customers place on having reliable electricity supplies. The risk cost modelling has applied a VCR value of approximately $37,000/MWh for mixed loads, which is an escalation of the value sourced from AEMO's 2014 Value of Customer Reliability Review,[19] for South Australia, and a VCR of $6,500 for direct connections. These VCR values are largely consistent with the recent AER VCR review, which we will be applying in the future.

E2 Market benefits relating to the wholesale market are not material

The Australian Energy Regulator (AER) has recognised that if the credible options considered will not have an impact on the wholesale market, then several classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[20]

Option 1 is not expected to impact on network constraints between competing generating centres and is therefore not expected to result in any change in dispatch outcomes and wholesale market prices. We note in section 2.1 that the March 2017 failure of an instrument transformer at Torrens Island did affect generators and there is a possibility of a wide scale outage from an explosive failure of some instrument transformers that support the interconnector.

However, any such market benefits relating to the wholesale market associated with Option 1 are not considered 'material' in the context of the RIT-T (since they do not affect the identified preferred option) and estimating any such market benefits would simply increase the estimated net market benefit of Option 1.

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[18] The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option – NER clause 5.16.1(c)(6). Under NER clause 5.16.4(b)(6)(iii), the PSCR should set out the classes of market benefit that the RIT-T proponent considers are not likely to be material for a particular RIT-T assessment.

[19] AEMO, *Value of Customer Reliability Review for South Australia*, September 2014, p. 31 and p. 40.

[20] AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, December 2018, p. 32.

We therefore consider that the following classes of market benefits are not material for this RIT-T assessment:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties, other than for ElectraNet (since there will be no deferral of generation investment);
- changes in ancillary services costs;
- competition benefits; and
- Renewable Energy Target (RET) penalties.

E3 Other classes of market benefits are not expected to be material

In addition to the classes of market benefits listed above, NER clause 5.16.1(c)(4) requires us to consider the following classes of market benefits in relation to each credible option:

- differences in the timing of transmission investment;
- option value; and
- changes in network losses.

We consider that none of the three classes of market benefits listed above are material for this RIT-T assessment for the reasons set out below. We do not consider that there are any other classes of market benefits, which are material for the purposes of this RIT-T assessment.

Table 6 - Reasons why non-wholesale market benefit categories are considered immaterial

Market benefit category	Reason(s) why it is considered immaterial
Differences in the timing of transmission investment	Option 1 does not affect the timing of other unrelated transmission investments (i.e. transmission investments based on a need that falls outside the scope of that described in section 2). Consequently, the market benefits associated with differences in the timing of unrelated transmission investment are not material to the RIT-T assessment.
Option value	The AER has stated that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[21] None of these conditions apply to the present assessment. The AER has also stated the view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T. Changes in future demand levels are not relevant for this RIT-T, since the need for and timing of the required investment is being driven by asset age and condition rather than future demand growth. As a result, it is not relevant to consider different future demand scenarios in undertaking the RIT-T analysis.
Changes in network losses	Given Option 1 maintains the same network capacity as current at the same location, there are not expected to be any differences in network losses.

[21] AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, December 2018, p. 95.

Appendix F Description of the modelling methodologies applied

This appendix outlines the methodologies and assumptions we have applied to undertake this RIT-T assessment.

F1 Overview of the risk cost modelling framework

We have applied an asset 'risk cost' evaluation framework to quantify the risk cost reductions associated with replacing the identified transformers that are primarily focused on mitigating risk as an input to economic evaluation and options analysis.

The 'risk cost reductions' have been calculated as the product of:

- probability of failure (PoF) of an asset, which is the probability of a failure occurring based on asset failure history information and industry data;
- likelihood of consequence (LoC), which is the likelihood of an adverse consequence of the failure event based on historical information and statistical factors and assumptions; and
- cost of consequence (CoC), which is the estimated cost of the adverse consequence based on modelled assumptions.

These three variables allow the expected risk cost benefits to be quantified and an assessment against the cost of doing so to be undertaken. Avoided risk cost values are the difference between risk costs incurred under the base case and Option 1.

The approach we continue to apply in quantifying risk was presented as part of our Revenue Proposal for the 2018-2023 regulatory control period. The AER has reported it to be consistent with good industry practice and to generally reflect reasonable inputs and assumptions.[22]

More detail on the key inputs and assumptions made for individual asset risk cost evaluations can be found in ElectraNet's asset risk cost modelling guideline.[23]

F2 The discount rate and assessment period

The RIT-T analysis has been undertaken over a 20-year period from 2019 to 2038, which considers the size, complexity and expected life of each option to provide a reasonable indication of its cost.

The new instrument transformers have asset lives of 44.8 years. We have taken a terminal value approach to incorporating capital costs in the assessment, which ensures that the capital cost of the replacement program is appropriately captured in the 20-year assessment period.

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22 AER, *ElectraNet transmission determination 2018 to 2023*, Draft Decision, Attachment 6 – Capital expenditure, October 2017, p. 4.

23 Available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/electranet-determination-2018-23/proposal#step-50979.

We have adopted a real, pre-tax discount rate of 5.9 per cent as the central assumption for the NPV analysis presented in this report, consistent with Energy Network Australia's (ENA) 2019 RIT-T Economic Assessment Handbook.[24] We consider that this is a reasonable contemporary approximation of a 'commercial' discount rate (a different concept to a regulatory WACC), consistent with the RIT-T.

The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated real, pre-tax weighted average cost of capital (WACC) be used as the lower bound discount rate in the sensitivity testing.[25]

We have therefore tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 2.85 per cent,[26] and an upper bound discount rate of 8.95 per cent (i.e. a symmetrical adjustment upward).

24 ENA, *RIT-T Economic Assessment Handbook*, 15 March 2019, p. 67.

25 AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 15, p. 7.

26 This is equal to WACC (pre-tax, real) in the latest Final Decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24/final-decision