# Jemena Electricity Networks (Vic) Ltd

## Heidelberg (HB) Transformer Condition Risk

RIT-D Stage 1: Non-Network Options Screening Report

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Heidelberg (HB) Transformer Condition Risk



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# EXECUTIVE SUMMARY

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The network service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

Our customers expect us to deliver a reliable electricity supply at the lowest possible cost. To do this, we must choose the most efficient solution to address emerging network issues. This means choosing the solution that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

## Identified Need

Zone substation Heidelberg (HB) has two 20/30 MVA power transformers operating at 66/11 kV and seven 11 kV feeders supplying approximately 9,000 customers. The two power transformers are manufactured by Wilson Transformer Company (WTC) and are 53 years old.

The cellulose in the transformers' paper insulation has deteriorated to the extent that the transformers are at an increasing risk of failure. The paper insulation condition indicate the transformers have reached end of life and need to be replaced to maintain customer supply reliability. Insulation condition assessment testing completed in 2011 and 2014 indicated high ageing and high moisture content. In addition, the existing 1-2 66 kV bus-tie CB at HB is no longer supported by the manufacturer and consequently spare components such as 66 kV bushings, turbulators, solenoids and mechanism components are no longer available. The lack of spare parts translates to not being able to repair defects and recover from major faults.

HB zone substation is an island supplying 11 kV feeders with no load transfer capability to other zone substations due to being surrounded by 6.6 kV and 22 kV zone substations.

## Summary of findings

The criteria used to assess the potential credibility of non-network options were:

- Addresses the identified need: by delivering energy to reduce or eliminate the need for investment
- Technically feasible: there are no constraints or barriers that mean an option cannot be delivered in the context of this investment
- Commercially feasible: non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment
- Timely and can be delivered in a timescale that is consistent with the identified need.

Table 1–1 shows the rating scale applied for assessing non-network options.

**Table 1–1: Assessment criteria rating**

| Rating | Colour Coding |
|---|---|
| Does not meet the criterion | |
| Does not fully meet the criterion (or uncertain) | |
| Clearly meets the criterion | |

Table 1–2 shows the initial assessment of non-network options against the Regulatory Investment Test for Distribution (RIT-D) criteria.

**Table 1–2: Assessment of non-network options against RIT-D criteria**

| Options | Assessment against criteria | | | |
|---|---|---|---|---|
| | Meets Need | Technical | Commercial | Timing |
| **1.0 Generation and Storage** | | | | |
| 1.1 Gas turbine power station | | | | |
| 1.2a Generation using renewables (Solar) | | | | |
| 1.2b Generation using renewables (Wind) | | | | |
| 1.3 Dispatchable generation (large customer) | | | | |
| 1.4 Large customer energy storage | | | | |
| **2.0 Demand management** | | | | |
| 2.1 Customer power factor correction | | | | |
| 2.2 Customer solar power systems | | | | |
| 2.3 Customer energy efficiency | | | | |
| 2.4 Demand response (curtailment of load) | | | | |

Jemena has concluded that none of the potential non-network options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. Hence, under National Electricity Rules (NER**)** clauses 5.17.4(c) and 517.4(d), the publication of a non-network options report is not required.

The remainder of this report provides the evidence underpinning the conclusion that a non-network options report is not required.

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# GLOSSARY

| | |
|---|---|
| Constraint | Refers to a constraint on network power transfers that affects customer service. |
| Jemena Electricity Network (JEN) | One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 319,000 customers via an 11, 000 kilometre distribution system covering north-west greater Melbourne. |
| Maximum Demand (MD) | The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or inter) and year. |
| Megavolt ampere (MVA) | Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes. |
| Network | Refers to the physical assets required to transfer electricity to customers. |
| Network augmentation | An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand. |
| Network capacity | Refers to the network's ability to transfer electricity to customers. |
| Non-network option | Any measure to reduce peak demand and/or increase local or distributed generation/supply options. |
| Probability of Exceedance (PoE) | The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year. |
| Regulatory Investment Test for Distribution (RIT-D) | A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a certain limit ($5M), in the National Electricity Market (NEM). |

# ABBREVIATIONS

| | |
|---|---|
| AER | Australian Energy Regulator |
| DAPR | Distribution Annual Planning Report |
| DM | Demand Management |
| EG | Embedded Generation |
| HB | Heidelberg Zone Substation |
| HV | High Voltage |
| JEN | Jemena Electricity Network |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NSP | Network Service Provider |
| PoE | Probability of Exceedance |
| RIT-D | Regulatory Investment Test for Distribution |
| VCR | Value of Customer Reliability |

# 1. BACKGROUND

The 20/30 MVA power transformers installed at zone substation Heidelberg are in a deteriorating condition. The cellulose in the transformers' paper insulation has deteriorated to the extent that the transformers are at an increasing risk of failure. The paper insulation condition indicate the transformers have reached end of life and need to be replaced to maintain customer supply reliability. Insulation condition assessment testing completed in 2011 and 2014 indicated high ageing and high moisture content. In addition, the existing 1-2 66 kV bus-tie CB at HB is no longer supported by the manufacturer and consequently spare components such as 66 kV bushings, turbulators, solenoids and mechanism components are no longer available. The lack of spare parts translates to not being able to repair defects and recover from major faults.

Jemena has developed network solutions to remediate the assets that are in poor condition and to meet the long term demand for electricity in the area.

In November 2017, the Australian Energy Regulator (AER) introduced a new requirement that impacts these plans. It required that a Regulatory Investment Test (RIT-D) should be undertaken that includes the issue of a non-network options report for those projects greater than $5M in value where a non-network solution is potentially viable. Distribution businesses are required to go through the Regulatory Investment Test for Distribution (RIT-D) process to identify the investment option that best addresses an identified need on the network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option).

The RIT-D applies in circumstances where a network problem (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $5M. As part of the RIT-D process, distribution businesses must also consider non-network options when assessing credible options to address the identified need. Should viable non-network solutions exist, Jemena is required to publish a non-network options report and request stakeholder submissions.

## 1.1 RIT-D PROCESS

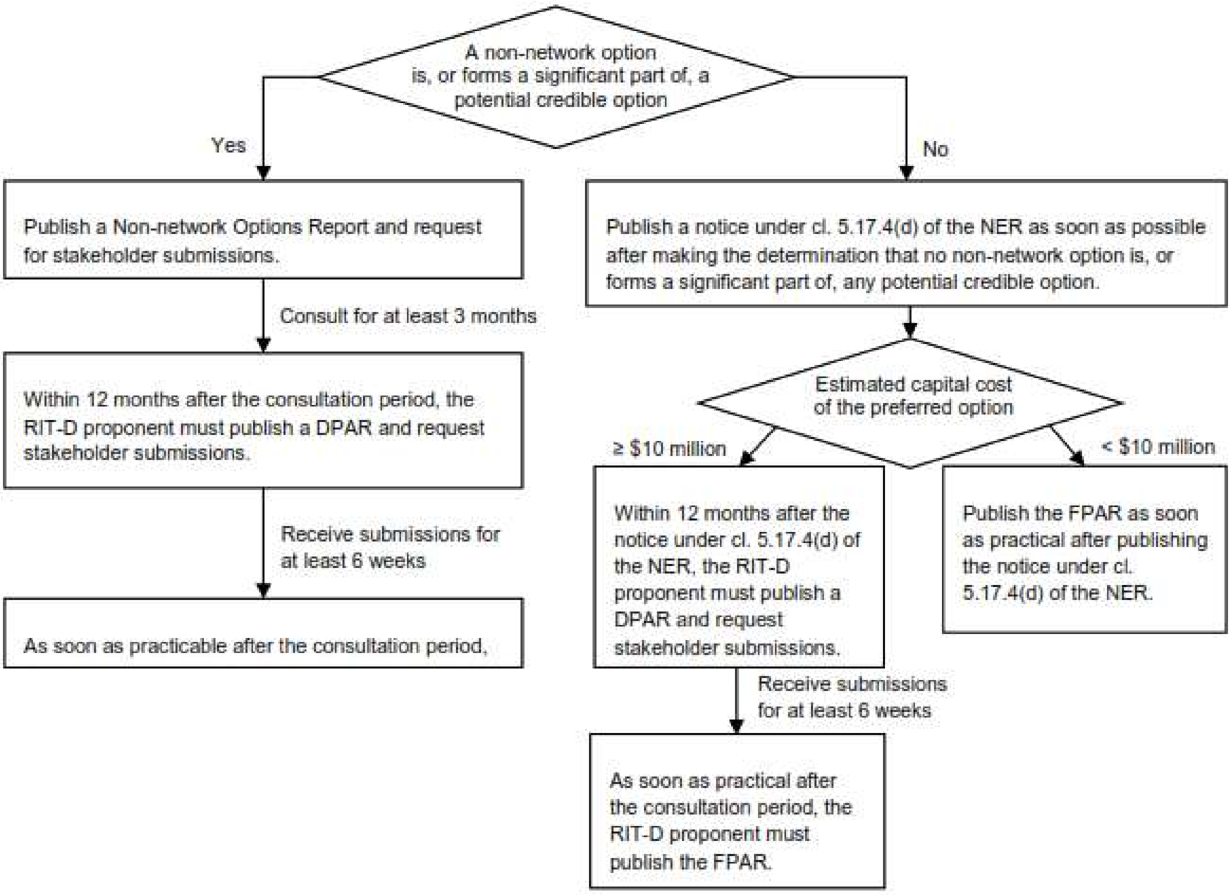
The Regulatory Investment Test for Distribution (RIT-D) process is summarised in Figure 1–1. This shows that the first step is to screen for non-network options by determining whether they are likely to form:

- A potential credible option(s) or:
- A significant part of one or more potential credible options to address the identified need.

This report:

- Summarises the non-network screening requirements and the assessment approach (Section 2)
- Describes the identified need the project is aiming to address (Section 3)
- Describes the network options tested to date (Section 4)
- Assesses the potential of non-network options to help address the identified need (Section 5)
- States the conclusion reached on the need for a non-network options report (Section 6).

**Figure 1–1: RIT-D Process**




Source: AER - Final RIT-D application guidelines - September 2017

# 2. SCREENING REQUIREMENTS AND APPROACH

This section:

- Defines the Australian Energy Regulator's (AER) screening requirements as set out in the documents:
  - AER-Final RIT-D application guidelines-September 2017 (https://www.aer.gov.au/networkspipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments2017)
  - National Electricity Rules (NER) Version 117 (https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current)
- Describes the approach to assessing the credibility of non-network options.

## 2.1 DEFINITIONS

Non-network options include (Guidelines Section 7.1):

- Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or Smart meters and associated cost-reflective pricing)
- Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators or using energy storage systems and load transfer capacity

An identified need is defined in Chapter 10 – Glossary of the NER as the objective a Network Service Provider (NSP) seeks to achieve by investing in the network.

According to the Application Guidelines (Section 2.1), an identified need may be addressed by either a network or a non-network option and:

- May involve meeting any of the service standards linked to the technical requirements of schedule 5.1 of the NER, or in applicable regulatory instruments (reliability corrective action) and/or an increase in the sum of consumer and producer surplus in the NEM.
- RIT-D proponents should express an identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. A description of an identified need should not mention or explain a particular method, mechanism or approach to achieve a desired outcome.

  In describing an identified need, a RIT-D proponent may find it useful to explain what will or may happen if the RIT-D proponent fails to take any action (Application Guidelines Section 2.1).

  A credible option is defined in Clause 5.15.2(a) of the NER as an option, or group of options that:

- Addresses the identified need;
- Is (or are) commercially and technically feasible; and
- Can be implemented in sufficient time to meet the identified need.

Clause 5.15.2(c) conveys that: In applying the regulatory investment test for distribution, the RIT-D proponent must consider all options that could be reasonably classified as credible options without bias to:

- Energy source;
- Technology;
- Ownership; and
- Whether it is a network or non-network solution.

Jemena have interpreted the guidance to mean that a credible option could consist of a non-network component and a network component which combined meet the identified need. For example, where a non-network solution reduces peak demand so that the RIT-D proponent can install smaller capacity or less costly equipment (Application Guidelines Example 4, Section 7.2).

## 2.2 APPROACH

The approach to assessing the credibility of potential non-network options includes:

- Describing the identified need being addressed by this project including the condition issues driving the proposed investment and the capacity, demand and the minimum contribution required if non-network options are to be potentially credible
- Describing the network options considered together with a preliminary designation of the preferred network solution
- Documenting an initial assessment of the full range of non-network options against the criteria in Clause 5.15.2(a) of the NER (defined in Section 3.1)
- Concluding whether there is sufficient and appropriate evidence to determine that there are no non-network options that are potential credible options and identifying any issues that require further examination.

# 3. IDENTIFIED NEED AND PROJECT OBJECTIVES

Jemena has prepared this non-network screening report to assess whether the demand and safety requirements of the Heidelberg Zone Substation could be achieved either fully, or in part through non-network options. To assess whether the non-network options could be beneficial, it is important firstly to define the identified need for this location.

Jemena has identified the Heidelberg Zone Substation as a priority for investment based on two key needs:

- Firstly, the need to protect power sector workers and members of the public from harm caused by equipment failure (Safety); and,
- Secondly, the need to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (Reliability).

## 3.1 SAFETY

The ability to provide a safe network is limited by the deteriorating condition of transformer insulation at HB zone substation. The cellulose in the transformers' paper insulation has deteriorated to the extent that the transformers are at an increasing risk of failure.

### 3.1.1 CONDITION OF PLANT

The investment is driven by the deteriorating condition of the transformer insulation, which are at risk of failure and pose a safety risk.

The cellulose in the transformers' paper insulation has deteriorated to the extent that the transformers are at an increasing risk of failure. The paper insulation condition and hence the transformers have reached end of life and need to be replaced to maintain safety and customer supply reliability. Insulation condition assessment testing completed in 2011 and 2014 indicated high ageing and high moisture content.

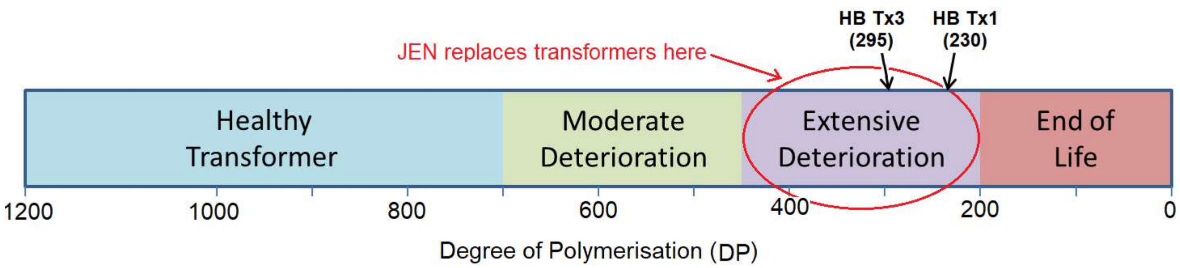



**Figure 3–1: Degree of Polymerisation Index**

#### 3.1.2 CREDIBLE SOLUTION REQUIREMENTS

Credible solutions would be required to allow the decommissioning of the existing transformers to ensure the safety of staff and the public.

### 3.2 RELIABILITY

Jemena's planning standard for its zone substation assets is based on a probabilistic planning approach which:

- Directly measures customer (economic) outcomes associated with future network limitations;
- Provides a thorough cost-benefit analysis when evaluation network or non-network augmentation options; and;
- Estimates expected unserved energy which is defined in terms of megawatt hours (MWh) per annum, and expresses this economically by applying a value of customer reliability (VCR) ($/MWh).

Jemena uses this approach to identify, quantify and prioritise investment in the distribution asset. Typically, the expected unserved energy is calculated through understanding the load at risk for each substation. This is normally calculated through modelling loads at risk under system and if any single item of equipment was out of service (called a normal minus one or N-1 scenario). A credible non-network solution should maintain a level of supply reliability which is consistent with Regulatory obligations. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply all load under a N and N-1 network reliability scenario in which the annualised cost of expected unserved energy at risk exceeds the cost of augmentation.

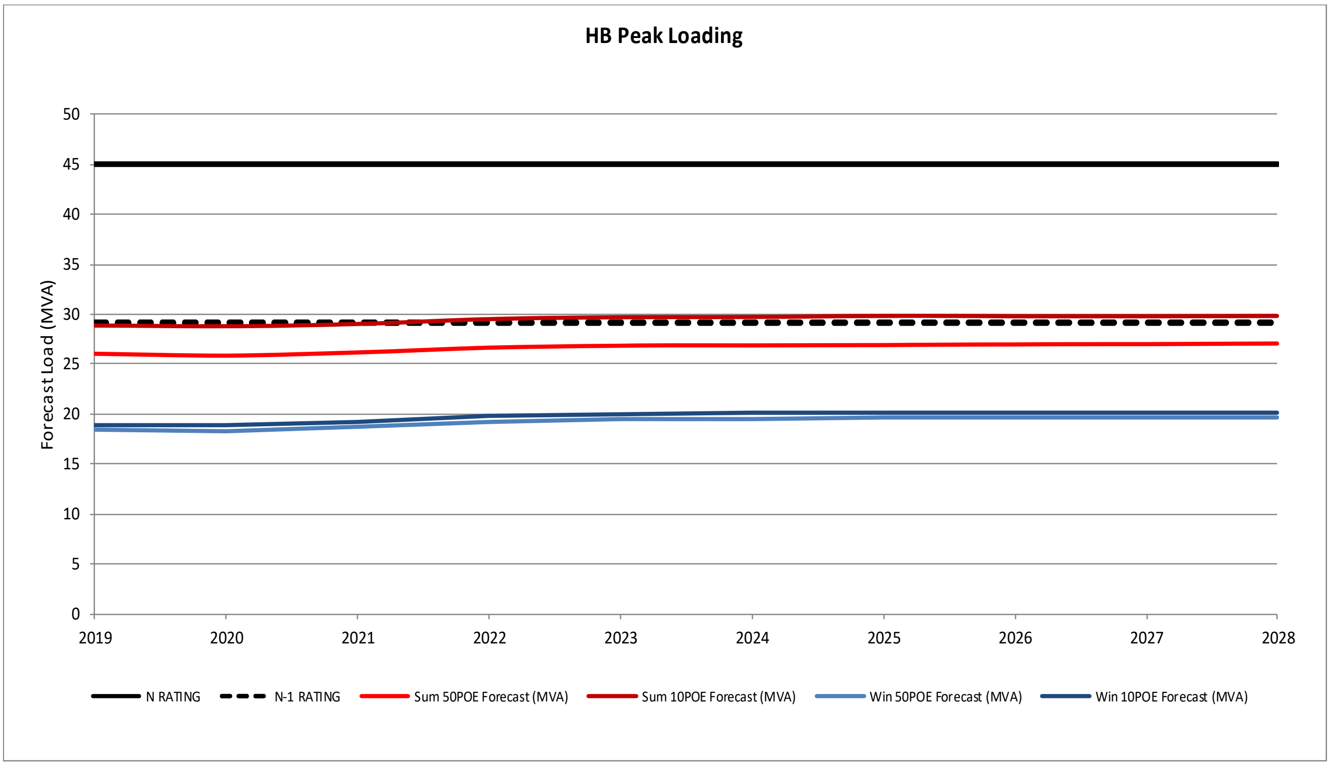
This will depend on the design and capacity of the current network and the forecast load, presented below in Sections 3.2.1 and 3.2.2.

#### 3.2.1 LOAD FORECASTS

The demand forecasts for HB are shown in Figure 3–2. It is noted that the demand is forecast to remain relatively flat over the period from 2019 to 2028. These forecasts include known spot loads where a customer has made an enquiry or application but do not include potential spot loads that may arise. The load supplied by the substation under 50% PoE summer maximum demand conditions is within the substation's N-1 capacity in summer. Based on the 10% PoE summer maximum demand, outage of a 66/11 kV transformer would result in involuntary load shedding of up to 0.3 MVA in 2022.

- The maximum expected demand is 26.0 MVA for summer 2019 under 10% Probability of Exceedance (PoE).
- By 2028, it is forecast that demand will be approximately 27.0 MVA for the summer 10% PoE.

**Figure 3–2: HB maximum demand forecast**




### 3.2.2 SUBSTATION CAPACITIES

The station plant summer and winter capacities are limited by an overvoltage limit. Zone substation HB consists of two 66/11 kV power transformers, one 66 kV circuit breakers and has seven 11 kV feeders from three indoor switchboards. The ratings of the key assets are:

- Two transformers rated 66/11 kV, 20/30 MVA
- Each 11 kV bus is rated at 2500 A and consists of space for:
  - Bus #1: Bus metering and earth switch, three feeders, No.1 Transformer incomer.
  - Bus #2: Five feeders, No.2 Transformer incomer.
  - Bus #3: Three feeders, No.3 Transformer incomer.
- Seven feeders circuit breakers rated 630 A are currently in use.

The total nameplate rating of the station is 45 MVA. The N-1 rating is based on a single transformer in service with a rating of 29.2 MVA due to the overvoltage limit.

There is no load transfer capability to surrounding substations as HB operates as an island at11 kV whilst surrounding substations operate at 6.6 kV and 22 kV.

### 3.2.3 CREDIBLE SOLUTION REQUIREMENTS

To meet reliability requirements, credible solutions would be required to achieve a N-1 planning scenario. This could be achieved through a range of solutions, including:

- Meeting the identified need in its entirety through a non-network option
- Replacing one transformer providing 29.2 MVA of capacity and meeting the remaining capacity through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting maximum forecast summer energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). The total requirement from all power sources is in excess of 26.0 MVA (maximum forecast varies between 26.0 MVA in 2019 to 27.0 MVA in 2028).

# 4. NETWORK OPTIONS

The following network options have been considered to manage the risk associated with the deteriorating condition of the transformers:

- Option 1: Do nothing, run to fail;
- Option 2: Increased maintenance and monitoring;
- Option 3: Replace the two existing 66/11 kV transformers;
- Option 4: Install a new No.2 66/11 kV transformer, replace the No.1 transformer and operate the No.3 transformer as a hot-standby.

The preferred replacement Option 4 would address all issues at an estimated cost of $5.3M and would involve replacing the existing No.1 66/11 kV 20/30 MVA transformer with a modern equivalent 66/11 kV 20/33 MVA transformer. Install a new modern 66/11 kV 20/33 MVA transformer in the vacant No.2 transformer slot at HB zone substation. The existing No.3 transformer is to be retained as a hot spare as zone substation HB is an island (surrounded by 6.6 kV and 22 kV zone substations), therefore there is no transfer capacity available at HB.

Three options have been considered to manage the risk associated with the aging 66 kV CB at HB:

- Option 1: Do nothing, run to fail;
- Option 2: Increased maintenance and monitoring;
- Option 3: Replace 66 kV CB with SF6 dead tank CB.

Option 3, to replace the existing 66 kV CB with new modern equivalents at an estimated cost of $0.26M is the preferred option and will address all the condition issues identified and maintain safety, reliability and security of customer supply. The replacement will consist of:

- Installation of two new outdoor dead tank 66 kV CBs (1-2 66 kV and 2-3 66 kV Bus Tie CBs).
- Replacement of 66 kV hardware.

# 5. ASSESSMENT OF NON-NETWORK OPTIONS

Potential non-network options that could meet the project objectives (as envisaged in the AER Guidelines Section 7.1) are listed below:

- Demand Management (DM) – Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or Smart meters and associated cost-reflective pricing)
- Embedded Generation (EG) – Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators or using energy storage systems and load transfer capacity)

Generation solutions owned by a customer could have cost benefits to that customer and hence be more economic than a generator for the sole purpose of network support.

Potential embedded generation, energy storage or demand reduction solutions are limited by the demand of a customer, i.e. an individual customer can only reduce its demand to zero. Typically, the absence of large customers limits the potential for large demand side solutions.

**Demand composition and customers**

Jemena load demand forecasts 2018 report provides information on customer composition and their share of maximum peak load in 2018 estimating that there is a total of 8,819 customers consuming 27 MVA peak summer load in 2018 and comprising:

- 8,046 residential customers consuming 18.387 MVA peak summer load (average 0.002285 MVA)
- 767 commercial customers consuming 6.804 MVA peak summer load (average 0.00887 MVA)
- 6 industrial customers consuming 1.809 MVA peak summer load (average 0.3015 MVA)

At HB, there are currently no HV connected customers. In addition, there is no HV connected embedded generation supplied from HB zone substation other than the small residential and commercial solar PV. For HB, there are 614 solar installations with a total overall capacity of 2.3 MW.

## 5.1 CREDIBLE SCENARIOS

The aim is to test whether a non-network option (or combination of non-network measures) is a viable way to avoid or reduce the scale of a network investment in a way that addresses the identified need. A non-network option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

Potential non-network scenarios are:

1. Meeting the identified need in its entirety through a non-network option
2. Replacing one transformer providing 29.2 MVA of capacity and meeting the remaining capacity through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting maximum forecast summer energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). The total requirement from all power sources is in excess of 26.0 MVA (maximum forecast varies between 26.0 MVA in 2019 to 27.0 MVA in 2028).

The non-network screening criteria is applied in the next section with these generation requirements or savings in mind.

## 5.2 NON-NETWORK ASSESSMENT SCENARIOS

### 5.2.1 SCENARIO 1 – MEETING IDENTIFIED NEED THROUGH A NON-NETWORK OPTION

A viable non-network generation option that replaces the capacity currently provided by HB that reliably meets customer requirements in an N-1 situation requires:

- Two generators each supplying 26 MVA
- Or three generators each supplying 13 MVA.

This would enable the system to meet maximum demand in an N-1 situation. Adding demand management or efficiency measures to the non-network option would reduce the generation requirements stated above. For example, if management and efficiency reduced peak summer demand to 20 MVA, the non-network generation component could be reduced to two generators of 20 MVA or three generators of 10 MVA each.

The costs of the total replacement scenario are likely to exceed those of the preferred network option. For example, the cost of a 23 MVA gas fired generator is approximately $15.9M plus installation and operating costs (Source: Gas Turbine World 2017). A non-network option is likely, therefore, to cost over $27M (e.g. providing 3 generator each costing $9.0M = $27M plus installation and operating costs). This does not allow for some reduction in peak demand through non-network management and efficiency measures. This would lead to a much higher marginal cost to the customer compared to a network solution of around $6M for the replacement of 66/11 kV transformers and 66 kV CBs.

Additionally, the maximum demands of individual customers indicate that no potential existing customer owned generation would be large enough to meet the need.

### 5.2.2 SCENARIO 2 – REPLACING ONE TRANSFORMER

If only one transformer were replaced providing the network capacity equivalent to one transformer (29.2 MVA), a viable, non-network would be required to supply enough power, to supply the peak load should the single transformer fail.

A viable non-network generation option that could meet customer requirements in an N-1 situation requires two generators each supplying 13 MVA (assuming no demand management or greater efficiency). This is likely to cost at least $18M (gas generation of 26 MVA excluding installation and operating costs) (Source: Gas Turbine World 2017).

The requirement for generation cannot be reduced by transferring load to surrounding substations. HB operates at 11 kV whilst surrounding substations operate at 6.6 kV or 22 kV.

## 5.3 NON-NETWORK ASSESSMENT OPTIONS

This section reports on the credibility of potential non-network options as alternatives or supplements for the Heidelberg replacement works. The criteria used to assess the potential credibility was:

1. Addresses the identified need: by delivering energy to reduce or eliminate the need for the investment
2. Technically feasible: there are no constraints or barriers that mean an option cannot be delivered in the context of this investment
3. Commercially feasible: non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment
4. Timely and can be delivered in a timescale that is consistent with the identified need

Table 5–1 shows the rating scale applied for assessing non-network options.

**Table 5–1: Assessment criteria rating**

| Rating | Colour Coding |
|---|---|
| Does not meet the criterion | |
| Does not fully meet the criterion (or uncertain) | |
| Clearly meets the criterion | |

The assessment has also considered whether a non-network option (or combination of non-network measures) is a viable way to avoid or reduce the scale of a network investment in a way that meets the identified need. A non-network option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

Table 5–2 shows the initial assessment of non-network options against the RIT-D criteria. The assessment did not find any of the non-network options to be potentially credible against RIT-D criteria (considered both in insolation, and in combination with network solutions). The assessment commentary for each of the generation and storage options is set out in the following sections.

**Table 5–2: Assessment of non-network options against RIT-D criteria**

| Options | Assessment against criteria | | | |
|---|---|---|---|---|
| | Meets Need | Technical | Commercial | Timing |
| **1.0 Generation and Storage** | | | | |
| 1.1 Gas turbine power station | | | | |
| 1.2a Generation using renewables (Solar) | | | | |
| 1.2b Generation using renewables (Wind) | | | | |
| 1.3 Dispatchable generation (large customer) | | | | |
| 1.4 Large customer energy storage | | | | |
| **2.0 Demand management** | | | | |
| 2.1 Customer power factor correction | | | | |
| 2.2 Customer solar power systems | | | | |
| 2.3 Customer energy efficiency | | | | |
| 2.4 Demand response (curtailment of load) | | | | |

## 5.4 NON-NETWORK ASSESSMENT COMMENTARY

### 5.4.1 GENERATION AND STORAGE

The assessment commentary for each of the generation and storage options is:

- **Gas turbine power station (1.1)**

*Identified need* – Reduces safety and reliability risks of running old plant beyond life. Capable of meeting identified need through provision of multiple gas generators. (**Fully met**)

*Technical* – Significant constraints and barriers to deployment of equipment to generate 26 MVA in a dense urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). In addition, we cannot establish the availability of a suitable high pressure gas pipeline in the locality that is essential for this type of generation. (**Not met**)

*Commercial* – Costs of this type of generation appear much higher that the network alternatives. For example, the minimum scenario of installing a 26 MVA gas fired generator at a cost of approximately $18M plus installation does not provide any savings compared to installing a second transformer. It is noted that non-network proponents rather than Jemena would bear the cost of these additions and they would recoup these costs through selling power generated at market prices. The scale of estimated capital costs illustrates the quantum of additional capital costs compared to a network solution and this will lead to a much higher cost per MWh compared to the preferred network solution. (**Not met**)

*Timing* – Planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 11 kV connections to HB) mean this is unlikely to be completed by 2020. (N**ot met**)

*Overall* – Not a potentially credible option.

- **Generation using renewables solar (1.2a)**

*Identified need* – Reduces safety and reliability risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. There is no information on current solar generation by customers but estimate that the generation of 26 MW (the minimum required for a viable non-network option) using solar is likely to require 65 acres of land (https://www.quora.com/How-much-land-is-required-to-setup-a-1MW-solar-power-generation-Unit-1). Devoting this amount of land to energy production in a dense, urban environment is not feasible. As noted in Section 5 solar installations in HB provide a relatively small capacity of 2.3 MW. In addition, the generation profile of solar power may not align to the consumption profile of consumers. (**Not met**)

*Technical* – While it is technically feasible to use this well understood and applied technology for this type of power generation, there are significant constraints to the deployment of a solar facility to generate 26 MW in this locality. These include zoning, planning and environmental constraints given the land requirements and the lack of evidence of the availability of approximately 65 acres for this type of purpose. (**Not met**)

*Commercial* – Costs of this type of generation are unlikely to be commercially viable or comparable with the costs of network alternatives. The SolarShare 1 MW solar project in Canberra (https://solarshare.com.au/solar-farm-project/greenfield-project/) is costing $3M and in the Heidelberg environment purchasing up to 65 acres of land is likely to be significant. This is unlikely to be cost effective when compared to the network alternatives. (**Not met**)

*Timing* – planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 11 kV connections to HB) mean this is unlikely to be completed by 2020. (**Not met**)

*Overall* – Not a potentially credible option.

- **Generation using renewables wind (1.2b)**

*Identified need* – Reduces safety and reliability risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. Based on a 2 MW wind turbine requiring 1.5 acres of land (https://sciencing.com/much-land-needed-wind-turbines-12304634.html), a 26 MW wind turbine/farm would require 19.5 acres. Devoting this amount of land to energy production in a dense, urban environment is unlikely to be feasible. (**Not met**)

*Technical* – It is unclear whether there is an adequate site available in terms of elevation, wind conditions for wind generation. The planning constraints and environmental factors involved in securing planning permission for using land for this purpose are very significant and the use of land for this purpose unlikely to be allowed. (N**ot met**)

*Commercial* – As for commercial solar generation, the cost of acquiring land and installing wind turbines is likely to significantly exceed the costs of the preferred network solution and means this form of generation is unlikely to be viable. Large scale windfarms are delivering capacity at $2.5M per MW (https://reneweconomy.com.au/agls-new-200mw-silverton-wind-farm-to-cost-just-65mwh-94146/) and this small scale installation is likely to be more expensive in an urban environment. (**Not met**)

*Timing* – planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 11 kV connections to HB) mean this is unlikely to be completed by 2020. (**Not met**)

*Overall* – Not a potential credible option.

- **Dispatchable generation (large customer) (1.3)**

*Identified need* – Reduces safety and reliability risks of running old plant beyond life. There are 6 industrial customers consuming 1.809 MVA at the summer peak (average 0.3015 MVA) and 767 commercial customers consuming 6.804 peak MVA (average 0.00887 MVA). As noted in Section 5 there are no larger industrial (HV) customers. It's unlikely that a small number of industrial customers is consuming sufficient energy for this type of generation to provide a viable non-network option. The practical difficulties of coordinating generation efforts for a large number of small consumers are too great for this to be viable. (**Not met**)

Note: Jemena's *2018 Distribution Annual Planning Report* (Section 5.9.4) on customer proposals reports that:

*In 2018, Jemena has received only one connection enquiries for embedded generators that have a generation capacity greater than 5 MW. Jemena believes this to be a reflection of:*

- *The nature of the* JEN *network, which services the north east of greater metropolitan Melbourne, where there is limited availability of physical space for a significantly sized embedded generator.*
- *Underlying weaker energy and maximum demand growth in the Victoria region.*
- *A preference for smaller scale embedded generation, particularly roof top solar, for which the* JEN *network has seen an ongoing increase in installed capacity.*

*Technical* – This type of generation is technically feasible within existing industrial sites but would face planning and technical constraints. (**Not fully met**)

*Commercial* – The estimated cost of a relatively small generator 4 MVA to be about $3.9 million excluding installation and operating costs. This is unlikely to be commercially viable given the much lower costs of providing this capacity using a network solution as well as the unlikelihood of multiple large customers installing a generator of this size. (**Not met**)

*Timing* – Planning processes, the nature of the investment and likely obstacles, together with design requirements (both for turbines and any required 11 kV connections to HB) mean this is unlikely to be completed by 2020. (**Not met**)

*Overall* – not a potentially credible option.

- **Large customer energy storage (1.4)**

The responses to this option (1.4) are similar to option 1.3. The overall finding that this is not a potentially credible option is driven by the relatively small power requirements per industrial customer and the need to coordinate efforts across many power users – this is likely to be time consuming and difficult to achieve. In addition, the costs associated with battery storage to manage peak demand and therefore reduce the scope of the non-network project are likely to be high in relation to the marginal costs for a full network solution.

*Overall* – not a potentially credible option

### 5.4.2 DEMAND MANAGEMENT/EFFICIENCY

Under both non-network assessment scenarios, there is a requirement to meet the maximum forecast summer energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). As there is no transfer capability to surrounding substations, there is no way a fully demand management solution could be implemented without a combination of EG as all load would be required to be shed. Combining EG and DM would lead to a reduction in the required generating capacity for non-network solutions. In the assessment commentary for the demand management/efficiency options, non-network assessment scenario 2 is considered with EG of 10 MVA.

- **Customer power factor correction (2.1)**

*Identified need* – Reduces safety and reliability risks of running old plant beyond life. This option is unlikely to meet the identified need because of the absence of very large industrial power users where this type of action could result in significant power savings. (**Not met**)

*Technical* – This type of saving is technically feasible for industrial users on a certain type of contract and is achievable. 10 MVA of embedded generation would face planning and technical constraint. (**Not fully met**)

*Commercial* – This could be cost-effective. The estimated cost of 10 MVA embedded generation is unlikely to be commercially viable. (**Not met**)

*Timing* – This option could be completed by 2020. (**Fully met**)

*Overall* – Not a potentially credible option.

- **Customer solar power systems (2.2)**

*Identified need* – Reduces safety and reliability risks of running old plant beyond life. Solar household installations in Australia is on average 20% and around 15% in Victoria (https://www.cleanenergycouncil.org.au/resources/technologies/solar-energy). Satellite imagery suggests that the proportion for the HB catchment is unlikely to exceed this average figure. Approximately 5400 of the 8046 residential customers (67%) would need to have a 3 kW solar system installed to provide 16.0 MW capacity (26 MVA demand – 10 MVA of EG). Currently, as noted in Section 5 solar installations in HB provide a relatively small capacity of 2.3 MW. This rate of take up is not considered to be achievable. (**Not met**)

*Technical* – This option is technically feasible and the technology well understood and tested. 10 MVA of embedded generation would face planning and technical constraint. (**Not fully met**)

*Commercial* – Achieving a greater than average solar take up would require a financial incentive and to achieve the level of take up for this option to be potentially credible would require a very high subsidy. The estimated cost of 10 MVA embedded generation is unlikely to be commercially viable. (**Not met**)

*Timing* – This option could be completed by 2020 but there is uncertainty given the large number of customers that would need to install solar. (**Not fully met**)

*Overall* – not a potentially credible option.

- **Customer energy efficiency (2.3)**

*Identified need* – The assessment for this option is similar to the results for Option 2.2. Each of Jemena's approximately 9,000 customers would have to reduce consumption by approximately 61.5% for the summer peak to achieve a 16 MVA reduction (16 MVA / 26 MVA = 61.5%). This scale of reduction is considered unrealistic even if accompanied by subsidies to consider doing this. (**Not met**)

*Technical* – This option is technically feasible and the type of efficiencies required achievable if sufficient customers are willing to invest in such measures. 10 MVA of embedded generation would face planning and technical constraint. (**Not fully met**)

*Commercial* – Unclear that this is commercially feasible. The estimated cost of 10 MVA embedded generation is unlikely to be commercially viable (**Not met**)

*Timing* – This type of mass action would be difficult to promote and implement by 2020. (**Not fully met**)

*Overall* – not a potentially credible option.

- **Demand response (curtailment of load) (2.4)**

This option has a similar assessment profile to options 1.3 and 1.4. All essentially rely on the actions of a small number of high consumption users. There is no evidence of a small number of very large users who might be persuaded to curtail load and hence this is unlikely to meet the identified need. We also do not think this is likely to be commercially feasible or achievable within the intended timing of the network solution.

*Overall* – not a potentially credible option.

# 6. CONCLUSIONS AND NEXT STEPS

## 6.1 CONCLUSION

In conclusion, the evidence shows that none of the non-network options are potentially feasible.

In addition, the analysis demonstrates that there are no combinations of non-network options, or non-network and network options, that are likely to adequately meet the criteria that would necessitate the production of a non-network options report.

## 6.2 NEXT STEPS

Jemena has determined that non-network options are not feasible to meet the identified need. As the preferred network option is less than $10 million, Jemena does not intend to publish a draft project assessment report as per clause 5.17.4(n) of the NER. Furthermore, as the preferred option is less than $20 million, Jemena will publish its final project assessment report summary as part of its Distribution Annual Planning Report (DAPR).