Industry Engagement Document -

Non-network and Stand-Alone Power System Solutions

CECG5064

May 2023

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1. Objective

This Industry Engagement Document - Non-network and Stand-Alone Power System Solutions describes how Essential Energy plans to engage with non-network solution providers, consider non-network options, and in relation to a Stand-Alone Power System (SAPS) enabled network, consider SAPS options.

This Document contains all information required as per Schedule 5.9 (clause 5.13.1 (h)) of the National Electricity Rules (NER).

2. Introduction

2.1 Non-Network Solutions

2.1.1 Demand Side Management

When demand for electricity approaches the capacity of network infrastructure at peak times, network service providers must act to maintain adequate electricity supply to customers. This can be achieved by increasing the network capacity (supply side management), reducing the peak electricity demand on the network (demand side management) or through a combination of supply and demand side management.

Demand side management is an important part of efficient and sustainable network operations – it can involve either the moderation of customer electricity demand at peak times or the supply of electricity from generators connected at customer's premises or to the distribution network. Effective use of demand side management can reduce costs associated with managing the network and result in lower electricity bills.

There are a range of demand side solutions available for use on electricity networks, including:

- Shifting appliance or equipment use from peak periods to non-peak periods (for example off peak hot water)
- Converting the appliance energy source from electricity to an alternative (for example switching from electric to gas heating)
- Use of more efficient appliances (for example replacing lights with more efficient, lower wattage options)
- Operating appliances at lower power demand for short periods (for example air conditioner load control)
- Operation of embedded generators
- Power factor correction.

When a review of a part of the network is initiated, Essential Energy completes a review of options that include both reducing demand and increasing capacity, with a goal of finding the lowest cost solution that meets the required reliability standards. To ensure a thorough investigation, Essential Energy consults with the community about network requirements and potential demand side options available.

2.1.2 Peak Demand

Peak electricity demand events occur when demand for electricity is significantly higher than average. These events are relatively rare, occurring only 20-40 hours in a year or less than 0.5 per cent of the time (for further detail the listed within the Distribution Annual Planning Report provides the hours above 95% of peak by Zone Substation). As the energy required to heat or cool can be a significant part of home or business energy use, peak events are typically during periods when the weather is very hot or very cold. Peak events that occur in colder weather are called winter peak events, and those that occur in hot weather are called summer peak events.

Winter peak events generally occur on the coldest working weekdays in winter and can be from as early as 5.00pm to as late as 10.00pm. A winter peak event is often primarily driven by the demand for heating of residential homes. The timing and duration of a peak event is a function of the mix of customers served by the network infrastructure.

Summer peak events typically occur on the hottest working weekdays in summer and can happen from as early as 2.00pm to as late as 8.00pm when load from residential customers is influential. Similar to the winter peak, a summer peak event is often driven by the demand for cooling of residential homes.

Figure 1 displays the correlation between summer peak demand and temperature for a particular zone substation in the Essential Energy distribution network.

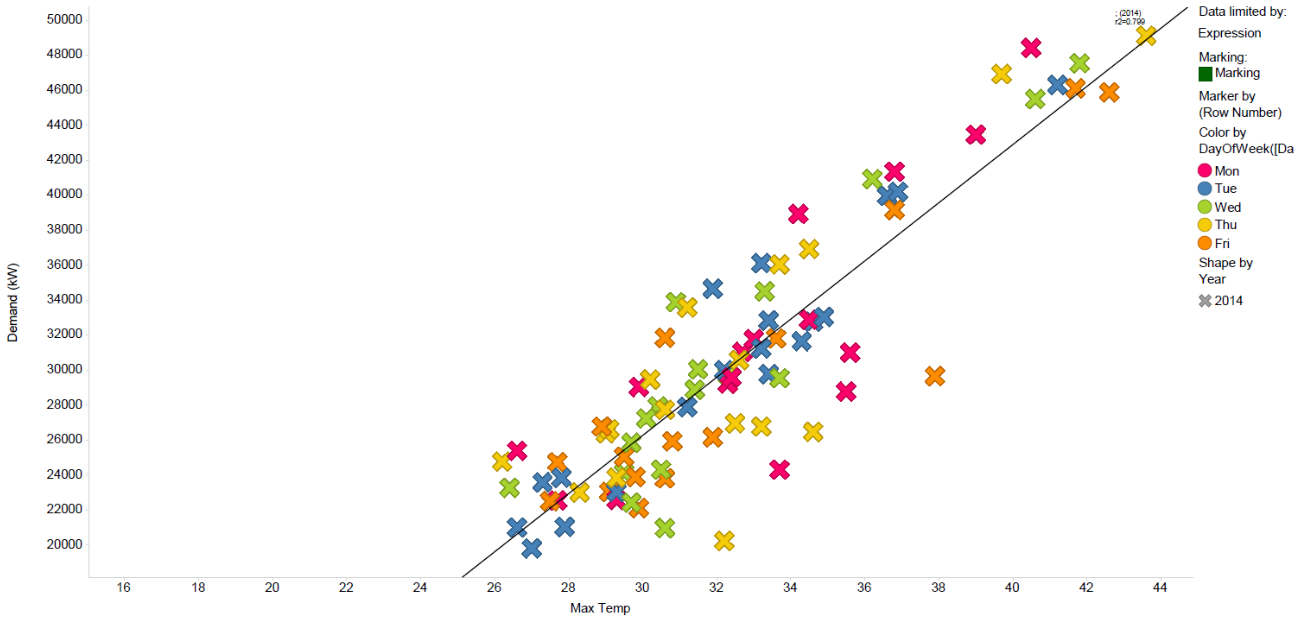


Figure 1 – Essential Energy Zone Substation correlation between demand and temperature

The peak demand event shown in Figure 1 occurred at approximately 6pm daylight saving time as shown in Figure 2.

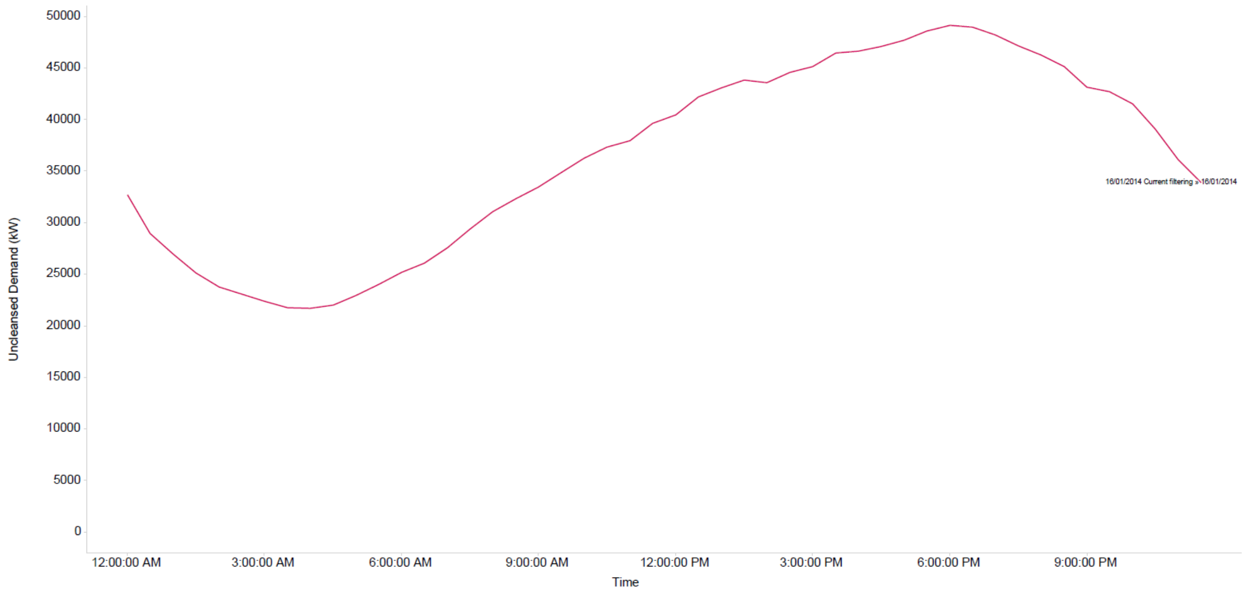


Figure 2 – Example time of peak demand

In the past, Essential Energy's distribution network was predominantly winter peaking, but in recent years it has shifted more towards summer peaking. This is primarily due to increased use of air conditioners in homes and businesses and the replacement of electric resistance heaters with gas and reverse cycle air conditioners for winter heating.

2.2 Stand-Alone Power Systems (SAPS)

For some Essential Energy customers, Stand-Alone Power Systems (SAPS) are an innovative and cost-effective way to ensure reliable and safe electricity supply. A Stand-Alone Power System is an independent power supply which typically includes a combination of solar panels, a battery for energy storage and a back-up diesel generator. It operates independently from the electricity network of poles and wires and can be used to power homes or other types of accommodation, sheds, workshops, and facilities.

These independent power systems:

- Deliver more reliable power to customers located at the end of long, remote powerlines
- Provide clean and sustainable energy via a system owned, operated and maintained by Essential Energy in the same way that we manage the current poles and wires
- Reduce outages caused by powerline maintenance, weather, wildlife and vehicle impacts
- Improve safety through removal of hazards that can be caused by poles and wires
- Improve resilience during natural disasters – on-site electricity generation removes the need to rely on infrastructure that could be affected by natural disasters
- Reduce environmental impact – there is no need to access and maintain long corridors of vegetation around poles and wires
- Offer flexibility and scalability – the modular design can be adapted to suit different situations, locations and changing needs
- May in future, deliver customers a reduction in electricity charges through a discount on generation costs within their electricity bill.

3. Publicly Available Information

3.1 Distribution Annual Planning Report (DAPR)

Essential Energy develops demand and capacity forecasts for the electricity supply system as part of the network planning process which are detailed in the Distribution Annual Plan Report (DAPR)).

The Distribution Annual Planning Report describes the Essential Energy network, forecasts for the forward planning period, Essential Energy's reliability performance and other information describing the network's performance and future needs. Copies of these reports are available on Essential Energy's website, http://www.essentialenergy.com.au

3.2 Contact

More information on the demand management process, use of SAPS at Essential Energy, recently completed screening tests and investigations, and current non-network option reports, is available on the Essential Energy website at www.essentialenergy.com.au.

To join the register of interested parties, please use the Essential Energy website.

For general enquiries please contact Essential Energy's network resilience team by email at mailto:networkresilience@essentialenergy.com.au or write to us at:

Network Resilience Manager
Essential Energy
PO Box 5730
Port Macquarie, NSW, 2444

4. Industry Engagement Process

4.1 Introduction

When forecasts indicate that a demand related issue is emerging and requires a solution, Essential Energy will investigate and, where viable, develop and implement demand management projects to maintain network service standards. The demand management investigation has five stages:

> **Stage 1:** Identify demand related investment from annual reviews
> **Stage 2:** Conduct demand management screening test
> **Stage 3:** Conduct demand management investigation including community consultation
> **Stage 4:** Select preferred option, where viable and cost effective
> **Stage 5:** Implement demand management solution

For projects where the augmentation and replacement components of the credible network options have a capital cost in excess of $5 million, the Regulatory Investment Test for Distributors (RIT-D) process will be utilised to assess non-network solutions.

For projects where the augmentation and replacement components of the credible network options have a capital cost less than $5 million, the likelihood of finding suitable cost-effective non-network solutions will be assessed on a case-by-case basis considering the nature of the constraint and the characteristics of the supply area.

4.2 Area Plans

In developing strategies for meeting the future electricity needs of the community, Essential Energy reviews network supply adequacy for the areas covered by individual transmission connection points.

Essential Energy's strategy considers the relevant planning criteria, asset replacement requirements, network reliability standards and anticipated longer term network needs. The aim is to meet the forecast network needs in the most cost-effective manner, while facilitating prudent longer term network investment decisions. Each Transmission Connection Point Supply Area Plan is reviewed annually and revised every two to three years. These plans typically cover forecasts over a ten-year network planning period.

Both supply side capacity expansions and demand side options are considered equally in developing the best solution to address the electricity supply requirements of the community. A mix of demand and supply side options may be utilised if this provides a more cost-effective solution.

4.3 Screening Test

For projects where the augmentation and replacement components of credible network options have a capital cost above $5 million, a demand management screening test is carried out to determine if it is reasonable to expect that a non-network solution could provide a cost-effective deferral or avoidance of the network investment.

A screening test is a desktop study and is conducted early in the planning process. The reasons or drivers for the network project are considered, along with the size of the demand that would need to be reduced, the year, time of day, duration and season the reduction is required, the rate the demand is growing and the characteristics of the load to be reduced.

The value of the network investment deferral is determined by calculating the difference between the Net Present Value (NPV) of the base case scenario, where the network infrastructure project is built by the required date, and a deferral scenario where the network infrastructure project is built at a later time. The assessment considers the associated market benefits for each option.

A judgment is made about whether it is reasonable to expect to be able to achieve a deferral for the proposed network infrastructure project at a value that makes the deferral cost effective. The deferral value is estimated based on available knowledge and past experience.

Important considerations include the:

- Amount of demand reduction required
- Value of deferral
- Complexity of the demand management requirements
- Time available for implementation
- Relationship between the timing of demand reductions needed and likely opportunities.

If the screening test concludes that it is reasonable to expect that a non-network option could cost effectively defer the network infrastructure project, a report on non-network options will be issued and Essential Energy will begin investigating these options.

If the screening test finds that it is not reasonable to expect that a non-network option could cost effectively defer the network infrastructure project, a notice detailing this will be published on the Essential Energy website with a final project assessment report to be published as soon as practicable after that.

An example screening test is shown in **Appendix A – Example screening test report.**

4.4 Demand Management Option Investigation

The investigation process is designed to identify potential cost-effective demand management options that could defer the supply side investment, and to identify the size, timing and budget costs of any feasible options.

Based on the demand reduction requirements identified in the demand management screening test, the investigation stage identifies non-network solutions to achieve the demand reductions. Options are identified by using Essential Energy's existing knowledge, through public consultation, and during field visits to customer sites and discussions with major customers. The investigation identifies the amount available, and the likely cost of each non-network option identified.

The various elements for the non-network options report are described in the following sections.

4.4.1 Community Consultation

The first formal interaction from Essential Energy to the potential non-network providers is when the non-network options report is uploaded to the website, issued to Australian Energy Market Operator (AEMO), and distributed to the members in the Register of Interested Parties record and other key stakeholders.

The non-network options report provides information on the network need, the geographic area of interest (for example a map outlining the boundary of the area supplied by the constrained asset), a load profile showing the peak time, maximum demand reduction, and duration of the required demand reduction. It also provides contact details for further information if required.

Essential Energy invites submissions on non-network options reports, and these can be sent to the demand management mailbox, mailto:networkresilience@essentialenergy.com.au

For projects with an augmentation and replacement component less than $5 million a final project assessment report will be published as soon as practicable following a minimum three-month consultation period on the non-network options report

For projects with an augmentation and replacement component of $5 million or more, following the minimum three-month consultation period on the non-network options report, a draft project assessment report will be published outlining the nature of the network limitation, the network options considered, submissions received on the non-network options report and advising a proposed preferred option.

After a minimum six-week consultation period on the draft project assessment report a final project assessment report will be published to include responses to any submissions received on the draft project assessment report.

A high-level flow chart of the consultation process is included as **Appendix B – Consultation process outline**.

4.4.2 Assessment Process

Essential Energy will respond to all submissions during the consultation process, outlining if the submission is of interest, or providing details about why it will not be considered further. There are a number of reasons a submission may not be of interest, for example where it is too expensive, is not technically feasible, or does not reduce demand on the constrained asset during the peak period.

If insufficient detail is provided in a submission to allow a reasonable level of confidence in a solution, to determine the impact on the peak demand, or to determine the costs, Essential Energy will contact the potential non-network provider to request further information.

For submissions which are of interest, Essential Energy will begin an engagement process with the potential non-network service provider, typically beginning with a request for more information. Once sufficient information is obtained to assess an option, a deferral cost ($/kVA) is calculated to allow the option to be compared with other known solutions.

All options identified are then ranked according to the following criteria:

> Demand reduction (kVA)
> Cost (NPV and $/kVA)
> Market benefits
> Time of day / seasonality demand reduction available
> Timeframe for implementation
> Reliability of demand reduction (risk of non-delivery).

Those options which are determined to offer insufficient confidence of delivery, cannot be implemented in the required timeframe, or do not provide demand reductions during the required time period are then excluded.

The remaining non-network options are ranked on cost effectiveness from lowest to highest $/kVA.

It's important to note that a network infrastructure deferral solution can be made up of a number of non-network solutions, as long as the demand reduction is greater than the volume required, and the total cost is lower than the deferral value.

For example, to defer a new 33kV feeder a 2.5MVA reduction is required. The total project cost for the preferred supply side solution is estimated at $9m and has a deferral value of $900,000 for the first year. A total of six non-network proposals (outlined in the following table) were determined to be viable and were ranked from lowest to highest $/kVA inclusive of market benefits.

No.	Proposal	Demand Reduction (kVA)	Option $/kVA	Option Cost ($)	Market Benefits ($)	Option $/kVA (inc. market benefits)	Cumulative Demand Reduction (kVA)	Cumulative Cost (inc. market benefits)
1	Power Factor Correction	500	$100	$50,000	$20,000	$60	500	$30,000
2	Load Curtailment	200	$310	$62,000	$1,600	$302	700	$90,400
3	Standby Generation	700	$305	$213,500	$0	$305	1400	$303,900
4	Pool Pump program	200	$800	$160,000	$1,600	$792	1600	$462,300
5	Air conditioner cycling	200	$1,000	$200,000	$1,600	$992	1800	$660,700
6	Energy Efficiency Campaign	100	$2,500	$250,000	$5,000	$2,450	1900	$905,700

A combination of the first three options would achieve the required reduction of 2.5MVA at a cost less than the deferral value of $900,000. In this example, Essential Energy would progress implementation of these three options.

4.4.3 Incentive Payment Schemes

At present there are no applicable incentive payment schemes for the implementation of non-network options.

If an applicable incentive payment scheme is developed, the Industry Engagement Strategy will be updated to reflect this. This information would then be published on the website, issued to AEMO, and distributed to the register of interested parties.

4.4.4 Investigation Report

The non-network options report describes the investigation process followed, identifies all demand side options considered, lists the cost and impacts ascribed to each and describes any feasible demand side options to be considered alongside network augmentation and replacement options. If necessary, it repeats the demand side requirements, augmentation, and replacement option details from the screening test with updates due to changes in load forecasts or the default supply side solution. It also provides a summary of the public consultation process and presents results of the comparison of cost to demand management value.

In the event that no demand side options are found to be feasible then this is clearly stated.

Reports are made public on the Essential Energy website. Any parties that made submissions in the consultation, as well as those listed in the Demand Management Register of Interested Parties, are contacted directly.

An example of a non-network options report is attached as **Appendix C – Example non-network options report**.

Where applicable, the results of the demand side investigation are included in the draft and final project assessment reports which detail the identified network need and summarise Essential Energy's investigation and final decision on the most efficient solution.

4.5 Stand-Alone Power Systems (SAPS) Enabled Network

Essential Energy's strategic driver for the SAPS program is to address high cost to network connections with suitable non network solutions such as SAPS to reduce ongoing costs to serve customers and manage network risks so far as is reasonably practicable.

The SAPS program requires economical evidence of least cost solutions via the analysis of cost to serve attributes such as maintenance, fault and emergency work, reliability performance, asset rebirth events, asset age etc. The cost to serve of the network connection is then evaluated against the load and consumption of the connection to determine the size and cost of the SAPS. Only sites where the 40-year lifecycle of a network connection exceeds the 40-year lifecycle cost of a SAPS will be considered for inclusion in the program of works.

Essential Energy's SAPS program is targeted at addressing a cost to service constraint for the fringe of grid, high cost to serve or low resilient areas of the distribution network. The cost to serve constraint is not an electrical limitation of the network, rather an economic constraint where alternative solutions such as SAPS are lower in lifecycle cost than a network supply. As such all potential SAPS locations will be for single distribution substation (Low voltage SAPS) sites which generally supply a single customer. Modelling has showed these locations are only viable on low consumption connections with demand generally less than 15kva. The transition of fringe of grid connections to a SAPS will not address system limitations such as peak demand.

Essential Energy's SAPS will be deployed in compliance with the AER Ringfencing Guideline Version 3 released in November 2021. Essential Energy will own and operate SAPS and provide the generation services as the SAPS resource provider under the category 1 classification. Essential Energy will be procuring SAPS assets from the private sector and new suppliers are encouraged to provide their products and specifications where they believe they are compliant with SAPS Supply and Performance Standards and Technical Specifications. For more information, please contact Essential Energy using the details provided in the Contact section on page 6.

For details referring to the deployment of SAPS, please refer to Essential Energy's Distribution Annual Planning Report (DAPR).

4.6 Embedded Generation

4.6.1 Connection to Essential Energy Distribution Network

The process under which Essential Energy will provide network services to a generator to enable its generating facilities to be connected and remain connected to Essential Energy's distribution system are detailed in Essential Energy operational procedure CEOP8079 Connection Guidelines for High Voltage Connections and Embedded generators which can be found on Essential Energy's website.

The document CEOP8079 outlines the regulatory requirements, factors considered in assessing connection, the application process and other issues associated with connecting a generator to Essential Energy's network.

Avoided Customer Transmission Use of Service (TUOS) charges are determined in accordance with clause 5.5 (i) of the National Electricity Rules.

5. Consultation Paper

5.1 Register of Interested Parties

Essential Energy maintains a register of interested parties, who are notified of the publication of relevant documents, including screening test reports, non-network options reports, draft project assessment reports, final project assessment reports and the annually published Distribution Annual Planning Report. Parties are invited to register their interest through the Essential Energy website or by emailing the network resilience team at mailto:networkresilience@essentialenergy.com.au

5.2 Responding to Consultation Paper

The public consultation is focused on identifying potential options and uncovering information that is already known (by another party) but otherwise unavailable to Essential Energy. A non-network options report is published seeking information from interested parties on non-network options in the geographical area of the constraint.

The content of the options paper will include all of the following:

- A description of the identified need
- The assumptions used in identifying the identified need
- The technical characteristics of the identified need including the size, location and time period required
- A map identifying the geographical boundaries of the constrained area
- A description of the preferred supply side solution
- Electricity demand profile data for the need
- The deferral value for the identified need
- The likely characteristics of suitable non-network options.

Submissions generated from the consultation process should include as much of the following information as is available:

- Name, address and contact details of the company or person making the submission
- Name, address and contact details of the company or person responsible for the load or alternate supply (if different to above)
- Size, type and location of load(s) that can be reduced, shifted, substituted or interrupted
- Size, type and location of generators that can be used if required
- Type of action or technology proposed to reduce peak demand / provide alternate supplies
- Time required to implement these measures and any period of notice required before loads can be interrupted, or generators started
- Approximate total cost to implement these measures and any cost savings that would accrue to the owners / operators of the equipment
- Approximate cost of any contribution / assistance that Essential Energy may be required to make in order to make use of this measure for demand management
- Other additional information to assist Essential Energy in investigating and evaluating the non-network option.

An example response to a consultation paper is provided in **Appendix D – Example response to non-network options report**. Responses should be comprehensive, demonstrating clearly the technology providing the demand reduction, the quantity of the potential demand reduction, the effectiveness during the peak period, and giving sufficient background into the potential non-network provider.

Consultation papers may, in certain circumstances be issued with a response template. For example, Essential Energy could be aware of a high number of embedded generators in an area of interest, and during the consultation process specifically target these as potential non-network solutions.

If negotiation is required to further develop a potential non-network option, Essential Energy will engage with the proponent on a case-by-case basis and update the process outline based on learnings from the completed development.

Appendix A – Example screening test report

AUGMENTATION OF ELECTRICITY SUPPLY TO THE XYZ AREA

Current supply arrangements

The area of investigation is the XYZ area and its surrounds.

The XYZ area is presently supplied via a single 66kV powerline, of approximately 104km in length. The feeder is predominately comprised of 6/4.75 + 7/1.60 ACSR/GZ 'CHERRY' conductor which is forecast to be over its serviceable design rating at times of peak load.

The diagram shows the XYZ area (light blue) and the 66kV powerline in question (yellow)

Supply capacity and demand forecast

THERMAL LIMITATION: 66kV Feeder

Based on the forecast load growth and rating of the existing 66kV line, the loading on the 66kV line will exceed its thermal rating at times of summer peak loading as per the following table.

Summer	Required Demand Reduction (MVA)
2020/21	4.5
2021/22	4.9
2022/23	5.3
2023/24	5.7

Supply strategy option

The preferred supply side option is the construction of a local 66kV substation in the XYZ area and the provision of associated interconnecting 132kV and 66kV powerlines between the existing TransGrid 132kV and Essential Energy 66kV networks.

The estimated cost of the project is $12m, with commissioning proposed in 2025. A decision on this investment is required by July 2023.

Required demand management characteristics

If demand could be reduced in the appropriate area by 4.5MVA before summer 2025/26 then the proposed investment could be deferred by one year with a saving from this deferral of $1.09m or $242/kVA.

If demand could be reduced in the appropriate area by 4.9MVA before summer 2025/26, then the proposed investment could be deferred by two years, with the saving from a two-year deferral being $2.08m or $425/kVA.

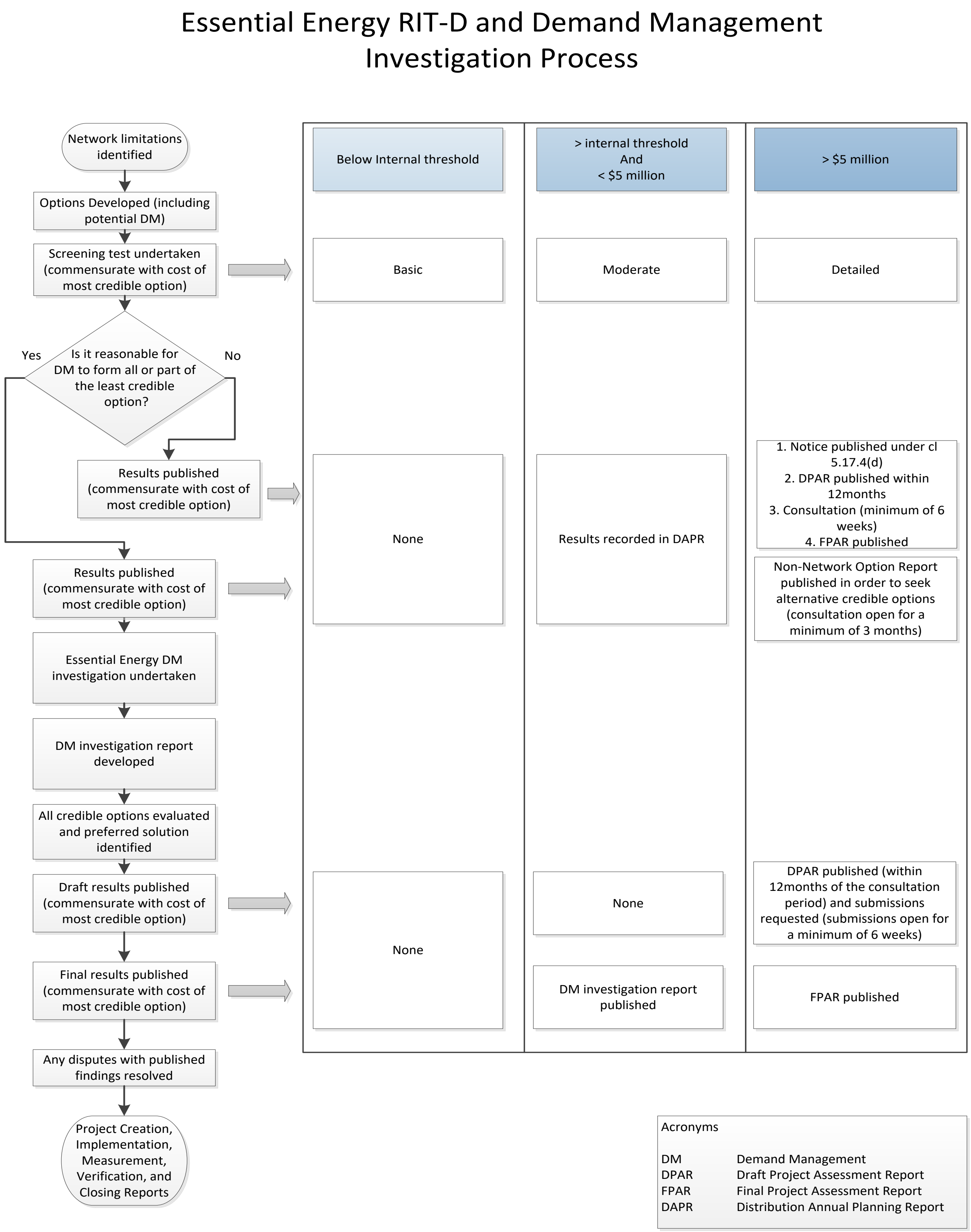
If demand could be reduced by 5.3MVA by summer 2027/28, then the investment could be deferred by three years. The saving from a three-year deferral is $2.99m or $563/kVA.

Year	Load Forecast (MVA)	Required Demand Reduction (MVA)	Required Demand Reduction as a % of load	Cumulative $/kVA (for permanent demand reductions)
1	30.0	4.5	15%	242
2	30.4	4.9	16%	425
3	30.8	5.3	17%	563
4	31.2	5.7	18%	668

Recommendation

Based on this analysis, taking into consideration the allowable timeframe and cost for implementation and the level of demand reduction required, it is considered reasonable to expect that it may be cost effective to postpone the proposed supply-side solution by implementing demand management strategies. A demand management investigation will be undertaken involving a full investigation including public consultation and field investigation.

Appendix B – Consultation process outline



Appendix C – Example non-network options report

AUGMENTATION OF ELECTRICITY SUPPLY TO THE XYZ AREA

Current supply arrangement

The area of investigation is the XYZ area and its surrounds.

The XYZ area is presently supplied via a single 66kV powerline, of approximately 104km in length. The feeder is predominately comprised of 6/4.75 + 7/1.60 ACSR/GZ 'CHERRY' conductor which is forecast to be over its serviceable design rating at times of peak load.

Supply capacity and demand forecast

THERMAL LIMITATION: 66kV Feeder

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Summer	Required Demand Reduction (MVA)
2025/26	4.5
2026/27	4.9
2027/28	5.3
2028/29	5.7

Required demand management characteristics

If demand could be reduced in the appropriate area by 4.5MVA before summer 2025/26 then the proposed investment could be deferred by one year with a saving from this deferral of $1.09m or $242/kVA.

If demand could be reduced in the appropriate area by 4.9MVA before summer 2026/27, then the proposed investment could be deferred by two years, with the saving from a two-year deferral being $2.08m or $425/kVA.

If demand could be reduced by 5.3MVA by summer 2027/28, then the investment could be deferred by three years. The saving from a three-year deferral is $2.99m or $563/kVA.

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1	30.0	4.5	15%	242
2	30.4	4.9	16%	425
3	30.8	5.3	17%	563
4	31.2	5.7	18%	668

Shown in Figure 3 is the existing system load profile, modified to show the forecast peak load in 2025/26.

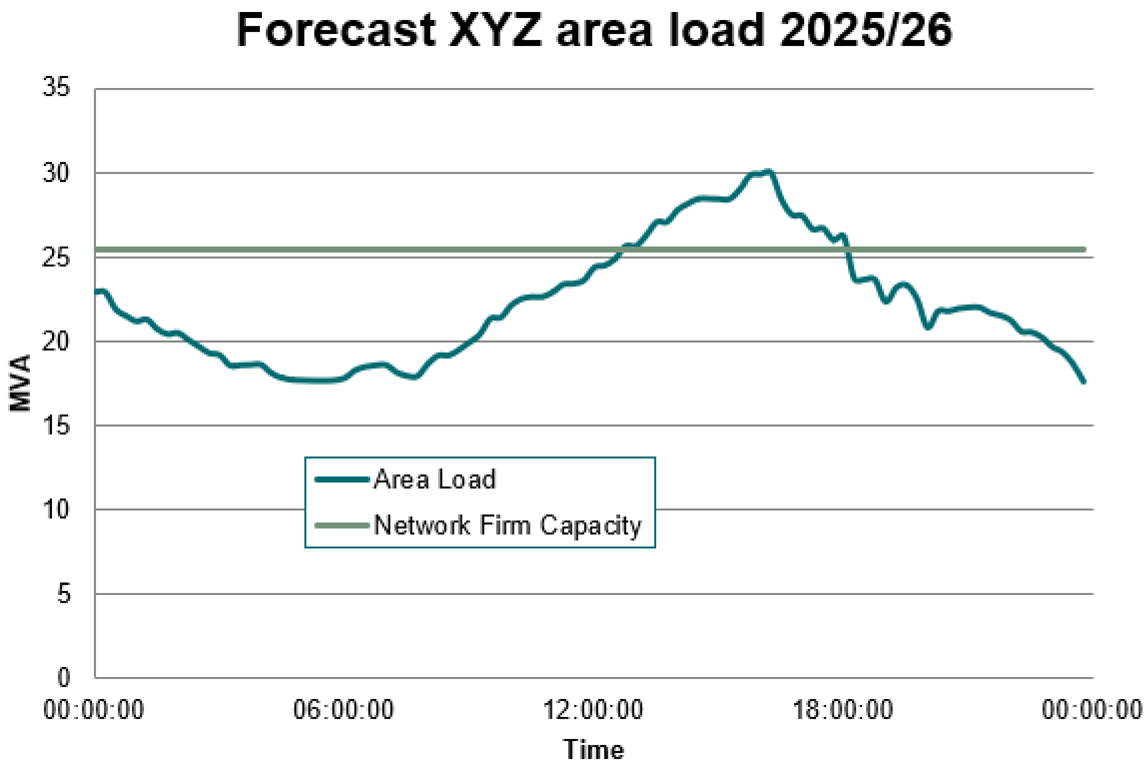

Figure 3: Example forecast XYZ area load

Potential credible options

Supply side options:

> Reconductor line at an estimated cost of $21m
> The construction of a local 66kV substation in the XYZ area and the provision of associated interconnecting 132kV and 66kV powerline between the existing TransGrid 132kV and Essential Energy 66kV networks. This is the preferred supply side option
> The estimated cost of the preferred supply side project is $12m, with commissioning proposed in 2025. A decision on this investment is required by July 2023.

Non-network options

For any specific option to be considered viable, it must;

> Decrease the load by the above specified amount, multiplied by a reliability factor dependent on the option type OR be willing to accept financial penalties for non-delivery
> Be able to be installed, commissioned, and tested by summer 2025/2026
> Be a permanent reduction in load OR be available on notice. Notice terms may be agreed on submission of proposals but must be under 24hours.

For the particular constraint outlined above this may include:

> Generation, which may include:
  - Stand-alone generation facilities based on rotating machines, such as large diesel or gas fired plants.
  - Embedded generation based on rotating machines, such as those used in commercial UPS

  - Embedded generation based on renewables, where it can be proven based on historical data that the load constraint coincides with the renewable generation OR where energy storage is available to increase the system reliability of coincidence
- Load curtailment, which may include:
  - Industrial and commercial processes which, through historical data can be shown to be running during the constraint period and which will be able to be reduced on notice by the utility
  - Embedded generation based on rotating machines, such as those used in commercial UPS arrangements, whereby the site operations are able to be taken offline on notice

- Load shifting, which may include:
  - Energy storage, used to shift processes (which through historical data can be shown to be running during the constraint period), from the constraint period into the shoulder or off-peak period and may include chemical or thermal storage
- Controlled load
  - Includes any processes (which through historical data can be shown to be running during the constraint period) which will be made available for utility control with or without notice, such as hot water, air conditioning, pool pumps and some commercial loads
- Fuel Substitution
  - Includes the substitution of an alternate energy source for a currently electrically powered process (which through historical data can be shown to be running during the constraint period) such as hot water, cooking, heating and cooling
- Other options
  - The non-network options outlined above are not an exhaustive list, if a proponent has a viable cost-effective alternative, Essential Energy would be happy to discuss the potential of any such alternative.

For any non-network providers wishing to present alternative potential credible options a non-network proposal can be submitted for consideration by the RIT-D proponent by emailing mailto:networkresilience@essentialenergy.com.au

Appendix D – Example response to non-network options report

ABC Consultants non-network proposal:

ABC Consultants has been an established load curtailment provider for approximately 20 years, delivering over 200MVA of load curtailment during this time with both Australian and international utilities and retailers.

ABC Consultants are able to source approximately 5.6MVA of load curtailment in the XYZ area in order to defer the construction of a local 66kV substation in the XYZ area with associated interconnecting 132kV and 66kV powerlines. This load curtailment can be available before the 2025/2026 summer, provided an agreement is reached between ABC consultants and Essential Energy by summer 2024/2025.

The load curtailment is available from approximately 15 different sources with demand reduction, peak coincidence, estimated setup and standing costs and delivery costs, as outlined in the following table.

For the purpose of this proposal, peak coincidence is defined as the probability that the equipment made available for demand reductions will be on during the network peak (determined from historical data), if required a minimum reduction at 100% peak coincidence can be made available.

No.	Reduction	Peak coincidence	Setup Cost	Standing Cost	Delivery Cost $/hr
1	250	96%	7000	12600	700
2	400	52%	7200	13900	12300
3	100	95%	7600	6300	3600
4	600	90%	5500	12600	5700
5	800	94%	4500	3300	1300
6	350	96%	9200	2800	14300
7	500	95%	9800	18600	13500
8	125	91%	3600	15800	10300
9	200	90%	3800	19800	6300
10	250	93%	2200	3200	6900
11	900	87%	7700	17100	11200
12	200	89%	7500	16700	5300
13	350	97%	9200	7500	4400
14	125	100%	8500	10800	3100
15	450	65%	4100	7100	2300

ABC Consultants feels that it would be possible to defer the preferred supply side option for two years based on the predicted peak coincidence and delivery cost, with years three and beyond requiring too great a demand reduction to be viable.

For any further enquires contact:

Mr Smith
ABC Consultants
123 Taylor Street
XYZ Area

Or phone 04XXXXXXXX

Appendix E – Alignment with National Electricity Rules requirements

The Industry Engagement document is required to comply with Schedule 5.9 of the National Electricity Rules, the location of the required information is provided in Table 1.

Schedule 5.9 of the National Electricity Rules;	Page Number
(a) a description of how the Distribution Network Service Provider will investigate, develop, assess and report on potential non-network options and (in relation to a SAPS enabled network) potential SAPS options;	7
(b) a description of the Distribution Network Service Provider's process to engage and consult with potential non-network providers to determine their level of interest and ability to participate in the development process for potential non-network options or where applicable, potential SAPS options;	7
(c) an outline of the process followed by the Distribution Network Service Provider when negotiating with non-network providers to further develop a potential non-network option or SAPS option;	10
(d) an outline of the information a non-network provider is to include in a non-network or DNSP-led SAPS project proposal, including, where possible, an example of a best practice proposal;	10, 16
(e) an outline of the criteria that will be applied by the Distribution Network Service Provider in evaluating non-network or DNSP-led SAPS project proposals;	7
(f) an outline of the principles that the Distribution Network Service Provider considers in developing the payment levels for non-network options or (where applicable) SAPS options;	8
(g) a reference to any applicable incentive payment schemes for the implementation of non-network options or SAPS options and whether any specific criteria is applied by the Distribution Network Service Provider in its application and assessment of the scheme;	8
(h) the methodology to be used for determining avoided Customer TUOS charges, in accordance with clauses 5.4AA and 5.5;	9
(i) a summary of the factors the Distribution Network Service Provider considers when negotiating connection agreements with Embedded Generators;	9
(j) the process used, and a summary of any specific regulatory requirements, for setting charges and the terms and conditions of connection agreements for embedded generating units;	9
(k) the process for lodging an application to connect for an embedded generating unit and the factors considered by the Distribution Network Service Provider when assessing such applications;	9
(l) worked examples to support the description of how the Distribution Network Service Provider will assess potential non-network or SAPS options in accordance with paragraph (a);	8
(m) a hyperlink to any relevant, publicly available information produced by the Distribution Network Service Provider;	5
(n) a description of how parties may be listed on the industry engagement register; and	5,10
(o) the Distribution Network Service Provider's contact details.	5