AusNet Electricity Services Pty Ltd

2019 DMIS Report

Introduction

This report has been prepared pursuant to the AER's Demand Management Incentive Scheme (DMIS) for electricity distribution network service providers (DNSPs). The DMIS was introduced by the AER in 2018 and applied to AusNet Services on 1 January 2019. Accordingly, this is the first DMIS compliance report submitted by AusNet Services. For clarity, AusNet Services' annual reporting obligations under the Demand Management Innovation Allowance (DMIA) are satisfied through a separate report submitted to the AER.

In accordance with section 2.4 of the DMIS, DNSPs are required to submit a DMIS compliance report to the AER no later than 4 months after the end of each regulatory year. The regulatory year for AusNet Services' electricity distribution network is currently the calendar year ending 31 December. Effective 1 July 2021, AusNet Services' regulatory year will transition to the Australian financial year.

Each compliance report must include two parts—Part A and Part B. Part A includes information on committed projects and Part B contains information on projects that the distributor has identified as eligible projects.

AusNet Services confirms that, as of 31 December 2019, it has no committed projects and, therefore, has not provided any information under Part A. Information for four eligible projects has been provided under Part B in accordance with section 2.4, paragraph 5 of the DMIS.

Compliance Report – Part A

Not applicable.

Compliance Report – Part B

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1. West Gippsland Non-Network Solution

Project Status: Business case approved

Project Description:

The 22 kV feeders out of Warragul zone substation supplying precincts of Drouin, Bunyip and Longwarry are forecast to exceed thermal ratings by December 2020.

The network option to address this emerging constraint is a new 22 kV feeder out of Warragul zone substation which would be constructed by November 2020, pending responses from non-network solution providers.

The feeder augmentation option would not address emerging zone substation energy-at-risk as this new feeder would still be supplied by the existing Warragul zone substation assets (i.e. it would only address energy at risk on the feeder). Conversely, a non-network solution on the 22 kV feeder would act to reduce load on both the feeder and upstream zone substation.

The proposed non-network project is to strategically locate distributed energy resources (e.g. embedded generation, demand response or energy storage) in the Longwarry area which, in conjunction with load transfers from two of the three 22 kV feeders, would achieve a reduction in peak demand on all three feeders across the summer period until 2024. This would defer network augmentation until 2025.

Project Details:

> (5) For each **eligible project** that a **distributor** identifies as a **preferred option** in a **regulatory year**, Part B of the **compliance report** relating to that **regulatory year** must include the following information about that **eligible project**:
>
> (d) In present value terms, the expected costs and benefits that the **distributor** determined, in accordance with clause 2.2, that the **eligible project** would deliver to electricity consumers.

The preferred option is to engage a third-party to provide a non-network solution and defer the construction of a new feeder (i.e. the network solution) by five years.

The estimated costs and net benefits associated with the preferred option are as follows:

Present value expected costs:	Network support payments of $350,000 (comprising five annual payments of $79,000 (nominal)) and deferred capital cost of $2,149,054
Present value expected benefits:	$3,157,942, which reflects the feeder energy-at-risk associated with the “Do Nothing” option
Present value expected net benefits:	$659,000 (compared to the “Do Nothing” option)

An additional benefit of reduced zone substation energy-at-risk (up to $206,780 by 2024/25) was not included in the calculation of the maximum network support payment. This is due to the calculation of network support payments being based on deferral of financial costs only, with financial costs of the network option comprising the construction cost of a new feeder in 2020.

(e) A description of the responses that the **distributor** received to either its **RIT–D** or its **request for demand management solutions** under the **minimum project evaluation requirements** (as relevant) including, for each response:

A request for demand management solutions via a public Expression of Interest was communicated on the corporate website in April 2020, and communicated directly to Providers listed on AusNet Services' Demand Side Engagement Register. Responses have not yet been received.

(i) a short description of the proposed project;

Not applicable.

(ii) the proposed costs and deliverables put forward in the response to the **request for demand management solutions**; and

Not applicable.

(iii) for any response that proposed a potential **credible option**, the **distributor**'s estimate of that project's **relevant net benefit**.

Not applicable.

(f) Identify whether, if the **distributor** decides (or has decided) to proceed with the project as a **committed project**, it is likely that this will occur via a **demand management contract,** or whether this is likely to occur via a **demand management proposal**. If the former, the **compliance report** must also identify the proposed party or parties to the **demand management contract**.

AusNet Services will proceed with engaging a suitable Provider through a demand management contract. The contract will be entered between the successful Provider and AusNet Services, and will stipulate required capacity and timing of demand management services required to address the identified need of reducing feeder peak demand.

The Provider will be required to follow the standard processes and meet regulatory and network requirements for connection of an embedded generator (Chapter 5A for <5MW).

(g) The expected costs of delivering **demand management**, by means of the **eligible project**, that the **distributor** used as an input into its assessment, under clause 2.2, that the project is an **efficient non-network option** in relation to **demand management**.

See response to clause 5(d) above. The business case to determine the expected costs / maximum demand management costs payable to the Provider was based on the estimated annual deferral value of the proposed network option of feeder augmentation. To ensure the non-network solution would be the most efficient option, the network support payment was capped at 80% of this annual deferral value, which is the return on capital and regulatory depreciation for the relevant year the network solution is deferred from.

(h) the **kVA** per year of network demand that the **distributor**:

(i) would be able to call upon, influence, dispatch or control if the project is implemented (that is, the **kVA** per year of **demand management** capacity); and

AusNet Services is requesting up to 3 MW of network support during a single dispatch event. This is equal to 3 MVA at unity power factor[1].

[1] Power Factor is the ratio of Active Power (kW) to reactive power (kVAR) and is used to represent the electrical demand requirements in (phasor sum in kVA) to support customer demand. At Unity Power Factor 1 kW is equal 1 kVA).

(ii) expects to call upon, influence, dispatch or control, based on its probabilistic assessment of future demand, if the project is implemented.

Up to 6 MWh is expected per dispatch event and a total annual dispatch allowance of 120 MWh is requested. This is to cater to loads at a POE10 (10% probability of exceedance) level forecasted in 2019 for 2024/25 summer. AusNet Services will negotiate additional costs for dispatch over and above this 120 MWh allowance.

(6) Where a **distributor** decides, in a **regulatory year**, to defer or not proceed with an **eligible project** that it has previously decided (either in that **regulatory year** or in a previous **regulatory year**) to proceed with as a **committed project**, the **distributor** must identify that decision and project in its **compliance report** for that **regulatory year**.

Not applicable.

2. Doreen Non-Network Solution

Project Status: Business case under development

Project Description:

The DRN11 22 kV feeder out of Doreen zone substation supplying the precincts of Mernda, Doreen and South Morang is forecast to exceed thermal ratings by December 2020.

The network option to address this emerging constraint is a new 22 kV feeder out of Doreen zone substation which would be installed by November 2023. Options undertaken to manage this energy-at-risk in the meantime include transfers of load to adjacent feeders and demand-side response.

This network option does not address emerging zone substation energy-at-risk as this new feeder would be supplied by the existing Doreen zone substation assets.

The proposed non-network project is to engage an existing customer to operate their embedded generation facility at times of feeder peak demand. Up to 7 MW of generation capacity is available and would defer network augmentation until 2025, as well as address emerging zone substation energy-at-risk during the intervening years. Subject to market testing, a network support agreement (demand management contract) will be entered to pay the customer up to $15,000 per annum to ensure generation output is maintained upon request.

Project Details:

(5) For each **eligible project** that a **distributor** identifies as a **preferred option** in a **regulatory year**, Part B of the **compliance report** relating to that **regulatory year** must include the following information about that **eligible project**:

(d) In present value terms, the expected costs and benefits that the **distributor** determined, in accordance with clause 2.2, that the **eligible project** would deliver to electricity consumers.

The preferred option is to engage an existing customer to operate their embedded generator during times of network peak demand and defer the construction of a new feeder to 2027.

The estimated costs and benefits associated with the preferred option are as follows:

Present value expected costs: $1,097,900 (CAPEX) for augmentation of an existing feeder to divert generation to the Doreen feeder. This CAPEX is not included in the project for DMIS purposes.

$107,800 (OPEX) total, for annual network support payments for eight years.

Present value expected benefits: $30,265,000, which reflects the reduction in energy-at-risk from the "Do Nothing" option.

Present value expected net benefits: $29,060,000 net benefit compared to the "Do Nothing" option.

(e) A description of the responses that the **distributor** received to either its **RIT–D** or its **request for demand management solutions** under the **minimum project evaluation requirements** (as relevant) including, for each response:

Previous engagement with large commercial and industrial customers in this region as part of an internal Demand Management program yielded limited capacity and firmness of response, despite the financial incentives offered. This was primarily due to customers' limited ability to provide demand response of sufficient capacity and when required in order to defer or avoid network augmentation. This project seeks to engage a known customer with existing embedded generation assets that already provide generation into the network. However, to confirm that this is the most economic option available, once the business case is finalised a request for demand management solutions via a public Expression of Interest will be issued.

(i) a short description of the proposed project;

Not applicable.

(ii) the proposed costs and deliverables put forward in the response to the **request for demand management solutions**; and

Not applicable.

(iii) for any response that proposed a potential **credible option**, the **distributor**'s estimate of that project's **relevant net benefit**.

Not applicable.

(f) Identify whether, if the **distributor** decides (or has decided) to proceed with the project as a **committed project**, it is likely that this will occur via a **demand management contract,** or whether this is likely to occur via a **demand management proposal**. If the former, the **compliance report** must also identify the proposed party or parties to the **demand management contract**.

AusNet Services will engage the customer through a demand management contract, in the form of a network support agreement. The network support agreement will stipulate required capacity and likely timing of demand management services required to address the identified need of reducing feeder peak demand. AusNet Services would request the demand management services via telephone request.

(g) The expected costs of delivering **demand management**, by means of the **eligible project**, that the **distributor** used as an input into its assessment, under clause 2.2, that the project is an **efficient non-network option** in relation to **demand management**.

See response to clause 5(d) above. The business case to determine the expected costs / maximum demand management costs payable to the Provider was based on the estimated annual deferral value of the proposed network option of a new feeder supplied out of Doreen zone substation.

(h) the **kVA** per year of network demand that the **distributor**:

(i) would be able to call upon, influence, dispatch or control if the project is implemented (that is, the **kVA** per year of **demand management** capacity); and

AusNet Services is requesting up to 7,000 kVA of network support during a single dispatch event.

(ii) expects to call upon, influence, dispatch or control, based on its probabilistic assessment of future demand, if the project is implemented.

The customer will be requested to generate during periods as required by the AusNet Services, to cater to loads at a POE50 (50% probability of exceedance) level, forecasted in 2019 for summer 2020/21 and beyond.

> (6) Where a **distributor** decides, in a **regulatory year**, to defer or not proceed with an **eligible project** that it has previously decided (either in that **regulatory year** or in a previous **regulatory year**) to proceed with as a **committed project**, the **distributor** must identify that decision and project in its **compliance report** for that **regulatory year**.

Not applicable.

3. Combienbar Stand Alone Power System

Project Status: Business case under development

Project Description:

The project proposes decommissioning 32.8 kilometres of overhead 22 kV line that currently traverses a heavily vegetated, high bushfire risk area.

Stand-alone power systems would be installed at each customer premise and sized to enable year-round, off-grid operation.

Savings will result from avoided vegetation management, asset maintenance and replacement costs. A reduction in fire start risk would also result from undertaking this project, which has been quantified and included in the NPV analysis.

The CNR3 22 kV feeder which is supplied out of Cann River would also see a reduction overall demand.

The regulatory arrangements for the deployment of SAPS are currently being implemented by the COAG Energy Council, the AER, AEMO and jurisdictional governments and regulators and will be considered as we work through the timelines for this project.

Project Details:

> (5) For each **eligible project** that a **distributor** identifies as a **preferred option** in a **regulatory year**, Part B of the **compliance report** relating to that **regulatory year** must include the following information about that **eligible project**:
>
> (d) In present value terms, the expected costs and benefits that the **distributor** determined, in accordance with clause 2.2, that the **eligible project** would deliver to electricity consumers.

While the business case remains under development, the preferred option is expected to be to engage a third-party to provide a non-network solution which will be in the form of stand-alone power systems to individually supply a group of 22 customers in the Combienbar precinct.

The preliminary estimates of the costs and benefits associated with the preferred option are as follows:

Present value expected costs:	$3,541,000, present-value cost of deploying the solution for 45 years (assumes SAPS assets are replaced to achieve the same service life of BAU poles and wires assets).

Present value expected net benefits: $892,000 net benefit, compared to the option of business-as-usual operation of the section of 22 kV feeder for the next 45 years[2].

(e) A description of the responses that the **distributor** received to either its **RIT–D** or its **request for demand management solutions** under the **minimum project evaluation requirements** (as relevant) including, for each response:

A request for demand management / non-network solutions via a public Request for Expression of Interest would be communicated on the corporate website upon business case approval. The request will also be communicated directly to Providers listed on AusNet Services' Demand Side Engagement Register. The Request for Expressions of Interest has not yet been released as the business case is under development.

(i) a short description of the proposed project;

Not applicable

(ii) the proposed costs and deliverables put forward in the response to the **request for demand management solutions**; and

Not applicable

(iii) for any response that proposed a potential **credible option**, the **distributor**'s estimate of that project's **relevant net benefit**.

Not applicable

(f) Identify whether, if the **distributor** decides (or has decided) to proceed with the project as a **committed project**, it is likely that this will occur via a **demand management contract,** or whether this is likely to occur via a **demand management proposal**. If the former, the **compliance report** must also identify the proposed party or parties to the **demand management contract**.

AusNet Services will select a suitable Provider and enter a services agreement to procure, connect, operate and maintain the stand-alone power solution.

(g) The expected costs of delivering **demand management**, by means of the **eligible project**, that the **distributor** used as an input into its assessment, under clause 2.2, that the project is an **efficient non-network option** in relation to **demand management**.

To ensure the stand-alone power solution would be the most efficient option, the network support payment was capped at 80% of the annualised cost of business-as-usual operation, which includes the return on capital and regulatory depreciation of poles-and-wires, vegetation management costs and asset management costs.

(h) the **kVA** per year of network demand that the **distributor**:

(i) would be able to call upon, influence, dispatch or control if the project is implemented (that is, the **kVA** per year of **demand management** capacity); and

Total capacity of the systems that would supply the 22 individual connection points ~ 130.5 kVA. This is based on the diesel generator nameplate rating, which is the largest generating component of each SAPS. The solar and battery components would cater to most of the daytime demand, with the generator supplementing supply outside of the daylight hours or when the battery state of charge is low.

[2] The $892,000 net benefit is the difference between cost of BAU network operation (also comprising maintenance, vegetation management and asset replacement) and cost of engaging a third-party to deploy and operate SAPS for 45 years- equivalent to the asset life of normal poles and wires.

(ii) expects to call upon, influence, dispatch or control, based on its probabilistic assessment of future demand, if the project is implemented.

As a stand-alone power system, each customer will be relying on the assets as their sole source of energy.

(6) Where a **distributor** decides, in a **regulatory year**, to defer or not proceed with an **eligible project** that it has previously decided (either in that **regulatory year** or in a previous **regulatory year**) to proceed with as a **committed project**, the **distributor** must identify that decision and project in its **compliance report** for that **regulatory year**.

Not applicable.

4. Goongerah Stand Alone Power System

Project Status: Business case under development

Project Description:

The project proposes decommissioning 33.6 kilometres of overhead 22 kV line that travels through a remote, heavily vegetated, high bushfire risk area.

Stand-alone power systems would be installed at each customer premise and sized to enable year-round, off-grid operation.

Savings will result from avoided vegetation management, asset maintenance and replacement costs. A reduction in fire start risk would also result from undertaking this project, which has been quantified and included in the NPV analysis.

The BM8B31 22 kV feeder which is supplied via Essential Energy in NSW would also see a reduction overall demand. The section of this feeder that is geographically located in Victoria is owned and operated by AusNet Services.

The regulatory arrangements for the deployment of SAPS are currently being implemented by the COAG Energy Council, the AER, AEMO and jurisdictional governments and regulators and will be considered as we work through the timelines for this project.

Project Details:

(5) For each **eligible project** that a **distributor** identifies as a **preferred option** in a **regulatory year**, Part B of the **compliance report** relating to that **regulatory year** must include the following information about that **eligible project**:

(d) In present value terms, the expected costs and benefits that the **distributor** determined, in accordance with clause 2.2, that the **eligible project** would deliver to electricity consumers.

While the business case remains under development, the preferred option is expected to be to engage a third-party to provide a non-network solution which will be in the form of stand-alone power systems to individually supply a group of 16 customers in the Goongerah precinct.

The preliminary estimates of the costs and benefits associated with the preferred option are as follows:

Present value expected costs:	$4,282,000, present-value cost of deploying the solution for 45 years (assumes SAPS assets are replaced to achieve the same service life of BAU poles and wires assets).

Present value expected benefits: $1,070,000 net benefit, compared to the option of business-as-usual operation and maintenance of the section of 22 kV feeder for the next 45 years[3].

(e) A description of the responses that the **distributor** received to either its **RIT–D** or its **request for demand management solutions** under the **minimum project evaluation requirements** (as relevant) including, for each response:

A request for demand management / non-network solutions via a public Request for Expression of Interest would be communicated on the corporate website upon business case approval. The request will also be communicated directly to Providers listed on AusNet Services' Demand Side Engagement Register. The Request for Expressions of Interest has not yet been released as the business case is under development.

(i) a short description of the proposed project;

Not applicable.

(ii) the proposed costs and deliverables put forward in the response to the **request for demand management solutions**; and

Not applicable.

(iii) for any response that proposed a potential **credible option**, the **distributor**'s estimate of that project's **relevant net benefit**.

Not applicable.

(f) Identify whether, if the **distributor** decides (or has decided) to proceed with the project as a **committed project**, it is likely that this will occur via a **demand management contract,** or whether this is likely to occur via a **demand management proposal**. If the former, the **compliance report** must also identify the proposed party or parties to the **demand management contract**.

AusNet Services will select a suitable Provider and enter a services agreement to procure, connect, operate and maintain the stand-alone power solution.

(g) The expected costs of delivering **demand management**, by means of the **eligible project**, that the **distributor** used as an input into its assessment, under clause 2.2, that the project is an **efficient non-network option** in relation to **demand management**.

To ensure the stand-alone power solution would be the most efficient option, the network support payment was capped at 80% of the annualised cost of business-as-usual operation, which includes the return on capital and regulatory depreciation of poles-and-wires, vegetation management costs and asset management costs.

(h) the **kVA** per year of network demand that the **distributor**:

(i) would be able to call upon, influence, dispatch or control if the project is implemented (that is, the **kVA** per year of **demand management** capacity); and

Total capacity of the systems that would supply the 16 individual connection points ~ 96 kVA. This is based on the diesel generator nameplate rating, which is the largest generating component of each SAPS. The solar and battery components would cater to most of the daytime demand, with the generator supplementing supply outside of the daylight hours or when the battery state of charge is low.

[3] The $1,070,000 net benefit is the difference between cost of BAU network operation (also comprising maintenance, vegetation management and asset replacement) and cost of engaging a third-party to deploy and operate SAPS for 45 years- equivalent to the asset life of normal poles and wires.

(ii) expects to call upon, influence, dispatch or control, based on its probabilistic assessment of future demand, if the project is implemented.

As a stand-alone power system, each customer will be relying on the assets as their sole source of energy.

(6) Where a **distributor** decides, in a **regulatory year**, to defer or not proceed with an **eligible project** that it has previously decided (either in that **regulatory year** or in a previous **regulatory year**) to proceed with as a **committed project**, the **distributor** must identify that decision and project in its **compliance report** for that **regulatory year**.

Not applicable.