Decision

Approval of Demand Management Incentive Scheme (DMIS) incentives for electricity distributors in 2019–20

April 2021

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

AER Reference: 53792

Table of Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFIC	audio frequency injection cell
ARR	annual revenue requirement
Augex	augmentation expenditure
Capex	capital expenditure
DM	demand management
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme (December 2017)
DNSP	distribution network service provider
kVA	kilovolt-ampere
MPERS	minimum project evaluation requirements
MW	megawatt
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NNA	non-network alternatives
NNO	non-network option
NSP	network service provider
Opex	operating expenditure
PoE	probability of exceedence
RIT-D	regulatory investment test - distribution
ZS	zone substation

1. Summary

In December 2017 the AER introduced a new demand management incentive scheme (new DMIS) aimed at encouraging electricity distributors to find lower-cost alternatives to investing in network expenditure. The DMIS achieves this by encouraging distributors to undertake efficient expenditure on non-network options relating to demand management (DM).

The new DMIS encourages DM projects that are efficient and contribute, partially or wholly, to resolving a network constraint. In deciding whether a project is efficient, the AER requires distributors to test the DM services market. This increases transparency, promotes competition and puts downward pressure on electricity prices. This is because distributors can benefit from incentives only if they address the network constraint in the most efficient way available.

The incentive structure should encourage best-practice network planning that delivers value to consumers via lower electricity prices. The new DMIS will achieve by encouraging distributors to:

- select efficient projects that deliver the most value to consumers when solving network constraints, regardless of whether these projects constitute a demand-side or supply-side solution
- ask third parties to propose DM solutions, and form contracts with parties that propose solutions delivering the most value to consumers.

This report contains the first published decision on the new DMIS. It presents the assessment of four electricity distributors' claims for incentive payments under the new DMIS, in relation to reports for the financial year 2019 or 2019–20 respectively. The four distributors sought AER approval of incentive payments totalling $0.5 million for four projects. The AER considers the projects and incentive payment claims have met the DMIS criteria and has therefore approved the incentive payments for all the projects.

In August 2020, the AER approved United Energy's DMIS claim for the reporting year 2019. However, publication of the report was delayed until the assessment of other distributors' reports (due to be submitted in October 2020) could be completed. The purpose of delaying the publication of United Energy's DMIS project is to enable a meaningful comparison with DM projects undertaken by other distributors.

This AER report includes assessments of the new reports from Ergon Energy, Endeavour Energy and Ausgrid, and that previously submitted by United Energy in August 2020.

Other distributors did not report on committed projects for 2019–20 and therefore have not applied for DMIS incentives for the year.

Table 1 DMIS incentive payments approved by the AER

	Volume of DM delivered per project (kVA)	Estimated DM project costs (present value) ($)	Estimated DM project net benefits (present value) ($)	Total incentive claimed for 2019–20 or 2019 ($)	Total incentive approved ($)	Incentive payment per kVA of DM delivered ($/kVA)
Ergon Energy 2019–20	2400	[redacted] [1]	[redacted] [2]	112,000	112,000	47
Ausgrid Energy 2019–20	96	55,000	380,000	27,500	27,500	286
Endeavour Energy 2019–20	6000	460,000	1,500,000	230,000	230,000	38
United Energy 2019	2754	333,096	528,000	165,000	165,000	60
In aggregate	**11,344**	[redacted]	[redacted]	**534,500**	**534,500**	**47**

Source: AER analysis and DMIS reports submitted by DNSPs. Numbers may not add up due to rounding.

1 Ergon Energy, *Demand Management Incentive Scheme Confidentiality Claim 2020-25*, November 2020 (re-submitted in February 2021).

2 Ergon Energy, *Demand Management Incentive Scheme Confidentiality Claim 2020-25*, November 2020 (re-submitted in February 2021).

2. Background

The AER published an improved Demand Management Incentive Scheme (new DMIS) in December 2017 to encourage distributors to find lower-cost solutions to investing in network expenditure. The incentive scheme achieves this by encouraging distribution businesses to undertake efficient expenditure on non-network options relating to demand management (DM).

The AER is required to assess claims for financial incentives against the DMIS criteria every year. The DMIS criteria are set out below.

2.1. DMIS criteria for financial incentives for committed projects

Project incentives under the scheme are only available for eligible projects that have become committed projects. An eligible project is an efficient non-network option, relating to demand management, that is the preferred option to meet an identified need on the distributor's distribution network. To be the preferred option, the project must be the credible option that maximises the present value of the net economic benefit to all those who produce and consume electricity in (relevantly) the national electricity market.[3]

A committed project is one that has had expenditure committed to it by the distributor by means of either a demand management contract or a demand management proposal. [4]

The incentive payment under the scheme is provided as a cost uplift for an amount up to 50 per cent of the expected DM cost. The incentive is available for efficient DM projects only and is subject to two constraints:

- *Net benefit constraint* – the size of the incentive should not outweigh the value or net benefit the DM project delivers across the electricity market. To set this constraint, distributors estimate the net benefit of projects under the new DMIS. For large projects (with expected capital costs of $6 million or more), distributors do this using the regulatory investment test (RIT-D).[5] For small projects (with expected capital costs of less than $6 million), distributors may use simpler cost–benefit analysis as prescribed by the minimum project evaluation requirements (MPERS) under the scheme
- *Overall incentive constraint* – The total incentive in any year cannot exceed one per cent of a distributor's allowed revenue for that year. This limits the impact of the incentive on short-term prices.

To be an eligible project, the distributor must identify the project as an efficient non-network option either through a RIT-D process[6] or the MPERS specified under the new DMIS.

[3] AER, *Demand Management Incentive Scheme Electricity distribution network service providers*, December 2017, cl 2.2(1) and (2)

[4] AER, *Demand Management Incentive Scheme Electricity distribution network service providers*, December 2017, cl. 2.2.2.

[5] AER, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2018.

[6] Regulatory investment test for distr bution under NER cl. 5.17.

2.2. DMIS criteria for determination of financial incentives

The AER makes use of each distributor's DMIS compliance report to determine a distributor's total financial incentive for the regulatory year. The assessment framework requires the AER to assess whether:[7]

A. The distributor has identified and justified the need for the DMIS project.

B. The distributor has identified and selected the efficient non-network option.

C. The distributor's cost-benefit analysis of the DMIS project supports the project selection and incentive claim.

[7] DMIS, Clause 2.2.

2.3. Scope of this report

To enable greater uptake of the new DMIS, in 2018 the AER requested the Australian Energy Market Commission (AEMC) to approve amendments to the National Electricity Rules (NER) to allow early application of the new DMIS, despite the new DMIS not being a part of DNSPs' current distribution determinations. The amendment was made in July 2018.

Six distributors then applied for early access to the new DMIS and the AER approved their applications and the respective start dates:

- Ergon Energy – 15 December 2018
- Energex – 15 December 2018
- AusNet Services – 1 January 2019
- Ausgrid – 31 March 2019
- Endeavour Energy – 1 April 2019
- United Energy – 1 November 2019

Under the AER-approved early access to the new DMIS, United Energy and Ergon Energy applied for DMIS incentive payments.

- United Energy applied for an incentive payment for the regulatory year 2019.
- Ergon Energy submitted its incentive payment claim in October 2020 for the regulatory year 2019–20.

For the first year of their regulatory control period 2019–24, NSW distributors Endeavour Energy and Ausgrid submitted their DMIS incentive payment claims in October 2020 for DM projects undertaken in the 2019–20 reporting year.

This report sets out the assessment of the DMIS reports from Ergon Energy, Ausgrid and Endeavour Energy for the regulatory year 2019–20, and for United Energy for the regulatory year 2019. Energex submitted a DMIS report for 2019–20, and AusNet Services for 2019, but both did not report any committed projects and therefore have not made a claim for any project incentive.

3. Ergon Energy 2019–20

3.1. Cairns South Target Area

The AER approved Ergon Energy's DMIS incentive payment claim of $112,000, determining it meets the DMIA criteria. Detailed information about this project is available in Ergon Energy's DMIS 2019–20 report, which is published on the AER website.[8]

3.2. Ergon Energy's confidentiality claims

Ergon Energy claimed confidentiality over information it provided on the project's expected cost, net benefits, and actual expenditure for the year.[9]

Ergon Energy contended that this information is commercially sensitive because it reveals Ergon Energy's actual and potential payments to demand management service providers. Ergon Energy argued that because the information contains details relating to the cost of customer contracts, it may advantage other providers of demand management services by giving them access to market-sensitive data. Ergon Energy argued that this may affect its ability to obtain competitive prices for similar services in the future.[10]

3.3. Project description

Ergon Energy identified a constraint in its existing network supply relating to feeders to the Gordonvale area (in southern Cairns, Queensland) where it considers its distribution feeder security criteria are not met. Ergon's network options involved acquisition of property in Gordonvale or 22kV augmentation. Ergon issued a request for demand management solutions on its website and sent a notice to parties in its demand side engagement register. Only one response was received and later assessed as viable. Ergon decided to proceed with a demand management contract with the proponent for synchronised diesel generation at an expected total project cost of [redacted] for 2019–20.[11]

Ergon also reported on eligible projects with similar network constraints but these are not yet subject to DMIS incentive claims in 2019–20. They are for:

- Townsville North West Target Area
- Emerald Target Area

Ergon defines a target area as an area in its network with an emerging constraint five to ten years away.[12]

---

8 Ergon Energy, *Demand Management Incentive Scheme (DMIS) Annual Report 2019–20*, November 2020: https://www.aer.gov.au/networks-pipelines/compliance-reporting?f%5B0%5D=field_accc_aer_report_type%3A1203

9 Ergon Energy, *Demand Management Incentive Scheme (DMIS) Confidentiality Claim 2020-25*, November 2020 (re-submitted in February 2021).

10 Ergon Energy, *Demand Management Incentive Scheme (DMIS) Confidentiality Claim 2020-25*, November 2020 (re-submitted in February 2021), p. 1.

11 Ergon Energy, *Demand Management Incentive Scheme (DMIS) Confidentiality Claim 2020-25,* November 2020 (re-submitted in February 2021), p. 5.

12 Ergon Energy, *Distribution Annual Planning Report 2018-10 to 2022-23*, December 2018, p. 115.

3.4. Identified need for the project

Ergon Energy stated that its existing network supply (interconnector mesh 22kV feeders) to the Gordonvale area (Queensland) does not meet its distribution feeder security criteria. These criteria specify that a radial feeder with effective ties to three or more feeders should be loaded to no more than 75 per cent utilisation (target maximum utilisation (TMU) of 75 per cent) under system normal conditions at 50 probability of exceedence (PoE). On the loss of a feeder, closing the ties to other feeders allows supply to be restored to the affected feeder without overloading the tie feeders. Ergon Energy estimated the load at risk at 2.4MVA.

3.5. Identifying and selecting the efficient non-network option

Ergon Energy stated that it followed the minimum project evaluation requirements in identifying eligible projects (including the committed project Cairns South Target Area) by:

- publishing the Target Areas on its website
- sending a notice to parties enrolled in its demand side engagement register, including links to the incentive maps.[13]

Ergon Energy's 2019–20 annual planning report states its non-network program is market-led and involves informing the market of the opportunity including value, location and requirements. Ergon Energy clarified that:

- *This approach enables all technologies and provide (sic) customers and aggregators an opportunity to participate in its program and support network risk reduction at the lowest possible cost.*
- *Target Area incentives have been activated in areas identified with future constraints and incentives are offered for demand reductions so that network upgrades are deferred. Ergon published incentive maps showing the location, incentive value ($/kVA) and demand response required on its website.*[14]

Ergon Energy received one market response for the Cairns South Target Area for a synchronised generation solution. This non-network solution was chosen and a contract was signed with the proponent.[15]

3.6. Cost-benefit analysis of the project

Ergon Energy's estimated costs and benefits for the alternative options are set out in Table 2.[16]

[13] Ergon Energy, *Demand Management Incentive Scheme (DMIS) Annual Report 2019–20*, November 2020, p. 5.

[14] Ergon Energy, *Distribution Annual Planning Report 2018-19 to 2022-23*, December 2018, p. 110.

[15] Ergon Energy, *Demand Management Incentive Scheme (DMIS) Annual Report 2019–20*, November 2020, p. 5.

[16] Ergon Energy, *Demand Management Incentive Scheme (DMIS) Annual Report 2019–20*, November 2020, p. 3-4.

Table 2 Ergon Energy's estimate of costs and benefits of alternative options (in present values)

Option	Description	PV of benefits ($ million)	PV of costs ($ million)	NPV – Net Benefits ($ million)
Network option 1	Gordonvale property acquisition		0.593	
Network option 2	22kV augmentation		3.400	
Non-network option - Cairns South Target Area (preferred option 3)[17]	Embedded generation	[redacted]	[redacted]	[redacted]

As stated above, Ergon Energy claimed confidentiality over information it provided on the project's expected cost, net benefits, and actual expenditure for the year.[18]

3.7. Assessment against DMIS incentive criteria

We approve Ergon Energy's DMIS incentive payment claim of $112,000 for 2019–20 because this meets the DMIA criteria.

- *Criteria 1: Project incentives under this scheme are only available for committed projects.* The project is an eligible project and a committed project.
- *Criteria 2: Incentive payments will be up to 50 per cent of expected costs on efficient demand management projects.* The incentive payment claim is up to 50 per cent of the expected project cost (present value).
- *Criteria 3: The incentive payment for any project can be no higher than that project's expected net benefit.* The incentive payment claim is not higher than the project's net benefit (present value).
- *Criteria 4: The total incentive in any year cannot exceed one per cent of the distribution business's allowed revenue for that year.* The total incentive claim is less than one per cent of Ergon Energy's 2019–20 annual revenue requirement of $1.3 billion (one per cent is $13 million).

[17] Ergon Energy, *Demand Management Incentive Scheme (DMIS) Confidentiality Claim 2020-25*, November 2020 (re-submitted in February 2021), p. 1.

[18] Ergon Energy, *Demand Management Incentive Scheme (DMIS) Confidentiality Claim 2020-25*, November 2020 (re-submitted in February 2021).

4. Ausgrid 2019–20

4.1. Gillieston Heights residential air-conditioner demand response

The AER approves Ausgrid's DMIS incentive payment claim of $27,500 as it meets the DMIA criteria. Detailed information about this project is available in Ausgrid's DMIS 2019–20 report published on the AER website.[19]

4.2. Project description

Ausgrid identified an emerging network constraint relating to feeders in the Gillieston Heights (NSW). Ausgrid's initial network option involved installing new underground cables, and re-conductoring and augmenting certain sections of overhead lines in the area. An initial assessment indicated the potential of demand management (DM) alternatives to defer network expenditure. Ausgrid requested proposals from the DM services market to address the identified need. Only one response was received and later assessed as non-viable. Ausgrid opted for its own demand management proposal for a residential air-conditioner load control project with an expected project cost of $55,000 for 2019–20.[20]

4.3. Identified need for the project

Ausgrid identified this project as an eligible project in its previous year's DMIS report (for 2018–19)[21]. Ausgrid stated that based on its latest demand forecasts, Ausgrid identified an emerging network constraint associated with three interconnected 11kV feeders in the Gillieston Heights area, part of the City of Maitland local government area in the Hunter Region of New South Wales. Residential load growth in this area has been significant and is expected to continue in the near future.

Based on its DM project selection criteria[22] Ausgrid determined that demand management was likely to offer a cost-efficient alternative to augmentation of its distribution network.

The targeted demand reduction in summer 2019–20 was 130 kVA.[23] Three demand response dispatch events were scheduled and delivered over summer 2019–20, for an actual demand reduction of 96 kVA.[24]

4.4. Identifying and selecting the efficient non-network option

In Ausgrid's 2018–19 DMIS report, Gillieston Heights DM project (residential air-conditioner load reduction or Aircon Saver Program) was reported as an eligible project. Ausgrid stated that, in accordance with the minimum project evaluation requirements of the DMIS, it issued a request for demand management solutions from non-network proponents.[25]

---

19 Ausgrid, *DMIS Annual Report 2019–20*, September 2020: https://www.aer.gov.au/networks-pipelines/compliance-reporting?f%5B0%5D=field_accc_aer_report_type%3A1203

20 Ausgrid, *Addressing increased customer demand requirements in the Gillieston Heights area, Project assessment report*, September 2019; Ausgrid, *Demand management project proposal, Gillieston Heights*, July 2019.

21 Ausgrid, *DMIS Annual Report 2018–19*, October 2019, p. 4.

22 The selection criteria referred to in Ausgrid's assessment process are described in section 2.2.1 of Ausgrid's 2018–19 and 2019–20 reports.

23 Ausgrid, *DMIS Annual Report 2019–20*, November 2020, p. 3.

24 Ausgrid, *DMIS Annual Report 2019–20*, November 2020, p. 3.

25 Ausgrid, *DMIS Annual Report 2018–19*, October 2019, p. 4.

Ausgrid further stated that, having received only one submission from the market which it later assessed as non-viable, and after an assessment of its internal capability, it determined that this project could proceed as a demand management proposal undertaken by Ausgrid. The project would use an air-conditioning load control solution developed as part of an earlier Ausgrid innovation project. This solution was implemented in summer 2019–20 where the target demand reduction was obtained from participating residential air-conditioning and battery storage customers at an estimated cost of $55,000.

4.5. Cost-benefit analysis of the project

Ausgrid's expected costs and benefits for the project for summer 2019–20 are set out in Table 3.

Table 3 Ausgrid's estimate of expected costs and benefits of alternative options (in present values)[26]

Option	Deferral period	PV of benefits ($ million)	PV of costs ($ million)	NPV ($ million)
Network option	–	1.03	-0.65	0.38
DM (preferred option)	1 year	1.06	-0.68	0.38

Ausgrid indicated in its NPV analysis that the network option and non-network option (one year deferral of augex) have the same expected net benefits. Table 4 summarises the results of its NPV analysis.

Table 4 Ausgrid's estimate of expected costs and benefits of alternative options[27]

Option	Deferral period	PV of benefits ($ million)	PV of costs ($ million)	NPV ($ million)
Network option	–	1.03	-0.65	0.38
DM	1 year	1.06	-0.68	0.38
DM	2 years	1.09	-0.83	0.26
DM	3 years	1.12	-1.04	0.08

Since the network option and non-network option have an equivalent NPV, Ausgrid chose the DM one year deferral project. We agree with Ausgrid's choice because:

- The DM option for one year delivers a higher NPV than the 2 years or 3 years DM options.
- The one-year DM option will enable additional time for Ausgrid to further consider other options, rather than engaging a network option which cannot be reversed.

[26] Ausgrid, *DMIS Annual Report 2018–19*, October 2019, p. 4. Ausgrid, DM *CBA Gillieston Hts 2019-20 ACLC*, November 2020, tab: 2019-20 DM CBA.

[27] Ausgrid, *DMIS Annual Report 2018–19*, October 2019, p. 4, under "Part B – Eligible Projects".

4.6. Assessment against DMIS incentive criteria

The AER approves Ausgrid’s DMIS incentive payment claim of $27,500 for 2019–20 as it meets the DMIA criteria.

- *Criteria 1: Project incentives under this scheme are only available for committed projects.* The project is an eligible project and a committed project.
- *Criteria 2: Incentive payments will be up to 50 per cent of expected costs on efficient demand management projects*: the incentive payment is 50 per cent of the expected project cost of $55,000 when the project became a committed project.[28]
- *Criteria 3: The incentive payment for any project can be no higher than that project’s expected net benefit*. The incentive payment is not higher than the project’s expected net benefit of $380,000.[29]
- *Criteria 4: The total incentive in any year cannot exceed one per cent of the distribution business’s allowed revenue for that year*. The total incentive claim is less than one per cent of Ausgrid’s 2019–20 annual revenue requirement of $1.44 billion (one per cent is $14 million).

[28] Ausgrid, *DMIS Annual Report 2019–20*, September 2020, p. 5.

[29] Ausgrid, *DMIS Annual Report 2019–20*, September 2020, p. 5.

5. Endeavour Energy 2019–20

5.1. Albion Park zone substation load control replacement

We approve Endeavour Energy's DMIS incentive payment claim of $230,000 because this meets the DMIA criteria. Detailed information about this project is available in Endeavour Energy's DMIS 2019–20 report which is published separately on the AER website.[30]

Project description

The load control equipment in the zone substation in Albion Park (in NSW) has become overloaded due to continued load growth within the local area. The existing equipment has reached its thermal capacity and requires augmentation to continue to provide a service and to avoid failure of the load control equipment. Peak demand would increase substantially on failure of load control equipment exceeding the network capacity. Network options to address this limitation include either:

- replacing the load control equipment or
- replacing every load control relay on customers' switchboard with a time clock.

Endeavour issued a non-network option report (request for DM solutions) in July 2019 and three submissions were received. Endeavour's preferred DM solution was based on replacing the load control relay and basic meters with a smart meter with load control functionality at an expected total project cost of $460,000 (present value).[31]

5.2. Identified need for the project

Endeavour Energy stated that its Albion Park zone substation (ZS) is located south of Wollongong NSW and supplies a residential customer base of around 9000 customers. Of these customers, approximately 3000 have off-peak load control relays on their switchboards that are controlled by audio frequency injection cell (AFIC) systems at Albion Park ZS. These relays allow customers to access the controlled load tariff for their off-peak hot water heating. The controlled load is estimated to be 6MVA of coincident demand after diversity is taken into account.

Endeavour Energy considers the AFIC system is currently overloaded and at risk of failure. If the AFIC system were to fail it would result in significant additional load on Albion Park ZS which is near capacity. Therefore, a failure of the load control system could lead to material and ongoing loss of supply events due to overloading.

With continued load growth within the Albion Park ZS supply area, the overloaded AFIC systems require network investment. Without the existing controlled load being replaced, there is a high risk that from FY 2020 onwards, the AFIC equipment will fail, and the capacity at the Albion Park ZS would therefore be exceeded leading to unserved energy.

The AER questioned Endeavour Energy about the basis for its forecast network constraint that forms the basis of its DMIS project. Endeavour Energy explained the constraint is due not only to expected growth in the Albion Park area (of hot water storage systems) but also

30 Endeavour Energy, *Demand Management Innovation Scheme Compliance Report FY2019–20*, November 2020: https://www.aer.gov.au/networks-pipelines/compliance-reporting?f%5B0%5D=field_accc_aer_report_type%3A1203

31 Endeavour Energy, *Demand Management Innovation Scheme Compliance Report FY 2019-20*, November 2020, p. 5.

to the need for a different configuration of the network to account for the growing use of roof PV systems and smart meters in that area. Endeavour Energy's rationale for the DMIS project was accepted.

5.3. Identifying and selecting the efficient non-network option

Endeavour Energy stated that it determined that a DM solution delivered via load control could be a credible non-network option to overcome this constraint in its Albion Park ZS. Endeavour Energy said it issued a request for proposals for DM solutions in July 2019 and it received three submissions. Endeavour Energy provided a description of the responses received and its analysis which identified the efficient non-network DM option in its DMIS 2019–20 report.[32] The preferred option was based on replacing the load control relay and basic meters with a smart meter with load control functionality.

Endeavour Energy concluded an agreement in late 2019 with a service provider to carry out the meter replacement at around 2500 customer sites. The replacement work commenced in early 2020 and will continue into FY21. As at 30 June 2020, Endeavour Energy expected a total project cost of $460,000.[33]

5.4. Cost-benefit analysis of the project

Endeavour Energy assessed several options (network and non-network), with initial cost-benefit estimates set out in Table 5.[34]

Table 5 Endeavour Energy's estimate of costs and benefits of alternative options (in present values)

Credible option	Description	PV of benefits ($ million)	PV of costs ($ million)	NPV – Net Benefits ($ million)
Network option	AFIC replacement – installation of a replacement motor generator AFIC unit	1.6	0.7	0.9
DM option 1	Avoid the replacement of the AFIC with time clocks at customer's premises	1.6	0.4	1.2
DM option 2 (preferred option)	Avoid the replacement of the AFIC with smart meters at customer's premises	1.6	0.5	1.3

Endeavour Energy selected and committed to DM option 2 with an expected project cost of $460,000 (present value) and expected project net benefit of $1.5 million (present value).[35]

5.5. Assessment against DMIS incentive criteria

The AER approves Endeavour Energy's DMIS incentive payment claim of $230,000 for 2019–20 as it meets the DMIA criteria.

- *Criteria 1: Project incentives under this scheme are only available for committed projects.* The project is an eligible project and a committed project.

32 Endeavour Energy, *Demand Management Innovation Scheme Compliance Report FY2019–20*, November 2020, pp. 10 ff.

33 Endeavour Energy, *Demand Management Innovation Scheme Compliance Report FY2019–20*, November 2020, p. 5.

34 Endeavour Energy, *Demand Management Innovation Scheme Compliance Report FY2019–20*, November 2020, p. 11.

35 Endeavour Energy, *Demand Management Innovation Scheme Compliance Report FY2019–20*, November 2020, p. 3.

- *Criteria 2: Incentive payments will be up to 50 per cent of expected costs on efficient demand management projects*. The incentive payment claim is 50 per cent of the expected project cost (present value) of $460,000.
- *Criteria 3: The incentive payment for any project can be no higher than that project's expected net benefit*. The incentive payment claim is not higher than the project's net benefit (present value) of $1.5 million.
- *Criteria 4: The total incentive in any year cannot exceed one per cent of the distribution business's allowed revenue for that year*. The total incentive claim is less than one per cent of Endeavour Energy's annual revenue requirement of $835 million in 2019–20 (one percent is $8 million).

6. United Energy 2019

6.1. Summer Saver residential demand response program

The AER approved United Energy's DMIS incentive claim of $166,500 as it met the DMIA criteria. Detailed information about this project is available in United Energy's DMIS 2019 report which is published separately on the AER website.[36]

6.2. AER's previous approval of United Energy's DMIS incentive

In August 2020, we approved United Energy's DMIS claim for the reporting year 2019. However, at that time we decided to hold the publication of our assessment of United Energy's incentive claim and its 2019 DMIS report until such time we publish our assessment of DMIS reports from other distributors. We decided to wait for DMIS reports and incentive claims from other distributors due for submission in October 2020 to enable a comparison of DMIS projects and claims. This AER report combines United Energy's report with those October 2020 reports.

6.3. Project description

United Energy's 'Summer Saver' program targeted its constrained distribution substation areas with highly utilised distribution transformers and low voltage circuits that are at a higher risk of overload outages during summer. United Energy's network option involved augmenting the relevant distribution substation or low voltage circuit. An initial assessment indicated the potential of demand management (DM) alternatives to defer the network expenditure. United Energy requested proposals from the DM services market to address the identified need and one response was received. United Energy also assessed whether a DM project could be internally managed. Based on net benefit rankings of the different options, United Energy opted to proceed with its own demand management proposal for a residential demand response program at an expected DM project cost of $333,096 (present value) for 2019.[37]

6.4. Identified need for the project

In 2019, United Energy identified and committed to one eligible project under the new DMIS. This project was for the application of a demand management program ('Summer Saver' program) to defer capital expenditure under United Energy's distribution system augmentation program (DSS). The DSS is undertaken to augment overloaded distribution substations and low-voltage circuits to maintain reliability of supply. United Energy contended that 'Summer Saver' was implemented in place of the DSS to achieve the same outcomes for customers, but at a lower cost than the DSS.

United Energy stated that it has been deploying the 'Summer Saver' program since summer 2013–14. Originally conceived as a DMIA project, it is now fully transitioned to a business-as-usual program funded from United Energy's operational expenditure. The sites targeted

36 United Energy, *Demand Management Incentive Scheme Compliance Report – 2019*, 22 April 2020: https://www.aer.gov.au/networks-pipelines/compliance-reporting?f%5B0%5D=field_accc_aer_report_type%3A1203

37 United Energy, *Demand Management Incentive Scheme Compliance Report – 2019*, 22 April 2020, p. 4.

for ‘Summer Saver’ are economically re-evaluated by United Energy each year from the list of DSS sites.[38]

6.5. Identifying and selecting the efficient non-network option

United Energy stated that corresponding to the new DMIS requirements, in 2019 it sought proposals from third-party non-network providers to provide lower-cost alternative solutions to resolve the identified network constraints. United Energy received one third-party proposal for a demand response program. It considered that although the third-party solution was evaluated to be economic and technically viable across some of the identified DSS network-constraint sites, the solution had a higher cost than the ‘Summer Saver’ program, resulting in a lower net present value for each of these sites. United Energy presented the third party with the economic evaluation findings.

United Energy identified its ‘Summer Saver’ DM program as the preferred least-cost solution to address its network constraint. The program was deployed to 191 network-constraint sites in summer 2019–20 as an alternative to DSS augmentation. The expected cost of the ‘Summer Saver’ program for these sites for summer 2019–20 was $333,096.[39]

6.6. Cost-benefit analysis of the project

United Energy assessed the benefits and costs of the alternative options as set out in Table 6.

Table 6 United Energy's estimate of costs and benefits of alternative options (in present values)[40]

Credible option	Description	PV of benefits ($)	PV of costs ($)	NPV – Net Benefits ($) 2019
Do nothing	Maintain the status quo	0	0	0
Network option – 2019	Augmentation of distribution substation and LV circuit (DSS)	18,335	11,630	6,705
DM option 1 – 2019	United Energy’s ‘Summer Saver’ program	11,742	4,543[41]	7,199
DM option 2 – 2019	Third party DM proposal	9,056	6,503	2,554
DM option 1 – if 20 year project	United Energy’s Summer Saver program	861,000	333,000	528,000

Based on this assessment, United Energy selected and committed to the ‘Summer Saver’ DM program.

38 United Energy, *Demand Management Incentive Scheme Compliance Report – 2019*, 22 April 2020, p. 4.

39 United Energy, *Demand Management Incentive Scheme Compliance Report – 2019*, 22 April 2020, p. 4.

40 United Energy, *Demand Management Incentive Scheme Compliance Report – 2019*, 22 April 2020, p. 9; United Energy, *UE DMIS Cost Benefits Aug2020 20200805.xlsx*, August 2020.

41 To compare the network option and DM option 1, United Energy used a 20-year forecast period. The present value of the DM option’s expected cost of $333k per year for 20 years is $4.543 million. United Energy, *UE DMIS Cost Benefits Aug2020 20200805.xlsx*, August 2020.

6.7. Assessment against DMIS incentive criteria

We approved United Energy's DMIS incentive payment claim of $166,500 for 2019 because this met the DMIA criteria.

- *Criteria 1: Project incentives under this scheme are only available for committed projects.* The project is an eligible project and a committed project.
- *Criteria 2: Incentive payments will be up to 50 per cent of expected costs on efficient demand management projects.* The incentive claim is 50 per cent of the expected project cost (present value) of $333,096.
- *Criteria 3: The incentive payment for any project can be no higher than that project's expected net benefit.* The incentive claim is not higher than the project's net benefit (present value) of $528,000.
- *Criteria 4: The total incentive in any year cannot exceed one per cent of the distribution business's allowed revenue for that year.* The total incentive claim is less than one per cent of the United Energy's 2019 annual revenue requirement of $435 million (one per cent is $4 million).