Jemena Electricity Networks (Vic) Ltd

Demand Management Options Analysis Report

Table of contents

Abbreviations

ADMS	Advanced Distribution Management System
AER	Australian Energy Regulator
DLC	Direct Load Control
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DR	Demand Response
DRED	Demand Response Enabling Devices
EV	Electric Vehicles
FCAS	Frequency Control Ancillary Services
JEN	Jemena Electricity Networks (Vic) Ltd
NEM	National Electricity Market
NPV	Net Present Value
RERT	Reliability and Emergency Reserve Trader
RIT-D	Regulatory Investment Test for Distribution
WACC	Weighted Average Cost of Capital
ZSS	Zone Substation

Executive summary

The National Electricity Market (**NEM**) is undergoing rapid transformation as it progresses towards a decarbonised, decentralised and digitised future. Recognising the importance of being properly prepared, Jemena Electricity Networks (Vic) Ltd (**JEN**) has developed its Future Network Strategy to understand this transformation better. Providing Demand Management (**DM**) is in line with this customer-focused, least-regret strategy that looks to implement initiatives that address common themes in future state scenarios to benefit customers.

What is Demand Management?

Traditionally, we addressed load at risk on our network by augmenting or replacing network equipment. However, with advances in technology, there are an increasing number of non-network solutions—such as demand management—which we may be able to employ in combination with or in place of network solutions. Demand management aims to manage the electricity use profile on the distribution network to minimise the cost of supplying customers while maintaining or improving customer options and service levels.

DM schemes incentivise customers to change their energy consumption behaviour. This translates into greater load flexibility and dispatchability for network operators, which can be used to relieve network constraints during peak demand events. DM also offers system benefits, including the ability to reduce peak demand and achieve system-wide supply and demand balance. These benefits provided by DM as a non-network solution allows for networks to better manage their grid investments, which ultimately translates into benefits for electricity customers.

Interest in DM has increased in recent years as technological improvements and innovative business models have yielded more accessible and affordable solutions, and trials have confirmed the potential for reducing peak demand in electricity networks. DM has been trialled by most Australian distribution network service providers (**DNSPs**), with the Australian Energy Regulator (**AER**) encouraging DM through its Demand Management Incentive Scheme (**DMIS**) and Demand Management Innovation Allowance (**DMIA**). JEN has utilised these incentive programs to investigate the possible benefits of DM by conducting several trials on its network.

When considering the viability of DM on its network, JEN has been unable to identify any network investment projects in its 2021-2026 regulatory control period (**next regulatory period**) in which DM is the most cost-efficient option. JEN has identified several challenges in justifying DM as the most cost-efficient solution as required by its economic justification process, primarily being the high costs of its implementation. In light of the rapid changes currently occurring in emerging energy markets, JEN will revisit the viability of DM options when commencing projects in its next regulatory period, in partnership with aggregators and C&I customers.

1. Background

The NEM is undergoing a rapid transformation as it progresses towards a more decarbonised, decentralised and digitised future. Recognising the importance of being adequately prepared for these changes, JEN has developed its Future Network Strategy to better understand this transformation[1]. Its objective is to implement least-regret initiatives that address common themes identified in future state scenarios that are designed to benefit JEN's customers. DM is in line with this customer-focused, least-regret strategy.

Network operators can employ DM schemes to incentivise customers to change their energy consumption behaviour, which translates into greater load flexibility and dispatchability. The primary application of DM from network operators' perspective, is to relieve network constraints during peak demand events which, typically present for a few hours every year, reduces the need for traditional network investment. This includes both augmentation expenditure (**augex**) and replacement expenditure (**repex**) that is necessary to maintain a safe and reliable electricity network.

DM also offers system-wide benefits. Of particular importance is its ability to balance system-wide supply and demand. System-wide levels of unserved energy (**USE**) in Victoria are forecast to exceed the 0.002% threshold of total energy demand in the next regulatory period[2], increasing the risk of involuntary load shedding. Decreasing demand during peak hours would contribute towards achieving system-wide balance and increase reliability by mitigating this risk.

Interest in DM has increased in recent years as technological improvements and new business models have yielded more accessible and affordable solutions, and trials have confirmed its potential in electricity networks. In Victoria, for instance, the installation of smart-meters makes it possible to implement customer-specific solutions by monitoring real-time energy consumption. The development of 'smart' connected technologies can also facilitate DM by remotely controlling customer loads to mitigate peak demand events.

Most Australian DNSPs have implemented DM in the form of trials[3]. In recent years, the AER has encouraged the development of innovative solutions such as DM to reduce overall market costs. Specifically, it has been promoting DM through its DMIS and DMIA. These programs encourage DNSPs to trial different DM mechanisms, and to publicly share their findings to improve industry knowledge of DM.

In light of these technological advancements encouraged by changes in regulation, JEN has developed several objectives for DM as part of its overall network development strategy:

1. Development of options and flexibility for its network and customers through the application of DM

2. Establishment of policies, systems and processes that support DM

3. Operationalisation of DM to provide a credible alternative to traditional investment for network supply, quality and capacity constraints.

The following section provides an overview of the DM initiatives that have already been undertaken by JEN (see section 2). This includes key findings and recommended next steps to develop JEN's DM capabilities further. Potential market benefits offered by DM are discussed, before describing their employment in a cost-benefit analysis methodology that assesses the potential of DM as a viable non-network solution (see section 3). The proposal will conclude with key findings relating to the use of DM to address JEN's proposed capital expenditure projects in the next regulatory period (see section 4).

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1 Jemena Future Network Strategy.

2 Australian Energy Market Operator, Electricity Statement of Opportunities, 2018.

3 Jemena, Demand Management Review, 2018.

2. Demand management initiatives

This section includes details of the DM initiatives already conducted by JEN. An overview of each initiative is provided before detailing the key findings and recommended next steps to further develop JEN's DM capabilities in these areas.

- Section 2.1 details JEN's Power Changers (residential behavioural demand response) program.
- Section 2.2 details JEN's investigation into the direct load control of smart air conditioners.
- Section 2.3 details JEN's commercial and industrial (C&I) demand response initiatives.
- Section 2.4 details JEN's zone substation voltage reduction trials.
- Section 2.5 details JEN's controlled electric vehicle (EV) charging desktop study.

JEN has funded these initiatives using the DM incentive schemes offered by the AER, and through its own operational expenditure. Through these initiatives, JEN has both increased its working knowledge of DM and better positioned itself to operationalise DM for the benefit of its customers.

2.1 Power Changers – residential behavioural demand response

2.1.1 Overview

JEN, in partnership with the Victorian Government, introduced its Power Changers program throughout summer 2017/18. This voluntary demand response (**DR**) trial looked to empower residential customers in six suburbs within JEN's network to make informed decisions in relation to their energy consumption.

Customers were incentivised to participate in DR 'challenges' to reduce their energy consumption during periods of peak demand to ultimately save money on their electricity bills. In addition to reducing their energy consumption, participating customers were rewarded for engaging in 'learn and earn' challenges that looked to increase their knowledge of the electricity market and metering.

2.1.2 Key findings

Of the 30,000 targeted customers, only 613 chose to register, translating to a sign-up rate of approximately 2%. These customers were segregated into two groups that dictated whether they received personal rewards (i.e. gift cards) for reducing their energy consumption or community rewards such as donations to schools and community organisations. Customer engagement and participation in the challenges was facilitated via a smart phone app and web portal, while the achieved DR was measured using customer smart meter data.

The key findings from the Power Changers program are as follows:

1. Households reduced their electricity consumption by an average of 26-35% during challenges that occurred on two optimal DM challenges that took place on hot days. This was found to be comparable to demand response trials from around the world and translated to approximately 0.29 kW load reduction per household.

2. Participation in each challenge ranged between 43-53%, with a higher participation rate witnessed by customers within the personal rewards group.

From JEN's perspective, the Power Changers program was a success with participating customers expressing a high level of satisfaction (85%). This program also allowed for customers to understand their electricity usage better and provided JEN with rich behavioural insights to inform future residential DR programs.

At this stage, however, JEN has found that the cost to achieve peak demand reductions by residential DR is significantly higher than DR from large business customers. This is because of the more distributed nature of residential resources, leading to limited economies of scale.[4] As such, JEN intends to continue its Power Changers program throughout summer 2019/20 to test different ways to make the program economically viable. Key areas of exploration to achieve this include:

- Reaching a larger customer sign-up rate
- Targeting customers with higher energy usage
- Refining how the baseline for DR events are set
- Targeting locations where other forms of DR are not possible

2.2 Air conditioner load control

2.2.1 Overview

Direct load control (**DLC**) of smart residential air conditioners using demand response enabling devices (**DRED**) is another form of DM investigated by JEN. These air conditioners provide DR by:

- Running with the compressor off (i.e. with the fan only)
- Running at a reduced duty cycle (e.g. at 50 or 75%).

As an example, Energy Queensland has utilised the DR potential of air conditioners to address peak demand requirements on its network. This was achieved by offering a rebate to incentivise the purchase and installation of smart air conditioners. As a result, 70,000 smart air conditioners have been installed, with Energy Queensland now managing a portfolio of 100,000 smart air conditioners in its DR portfolio (Jemena, 2018).

JEN has investigated the use of both Wi-Fi and an internet-of-things (IoT) device that utilises the AMI RF mesh to communicate with smart air conditioning units.

2.2.2 Key findings

The key findings of JEN's investigation of the DR potential of air conditioners on its network are as follows:

1. The AMI RF mesh appears as the most capable communication option given the potential distances between smart meters and air conditioners.

2. Approximately 80% of households already have air conditioners installed; however JEN believed that only a small percentage could be DR-enabled. This is because DRED can only control air-conditioners that have been specially manufactured as per Australian Standards; and Victoria, unlike other states, has a very low proportion of these air-conditioners.

Based on the last finding, JEN believes that the DLC of air conditioners does not currently provide a credible DM solution due to its lack of achievable scale. As such, JEN will not continue the direct load control of air conditioners in the next regulatory period.

[4] In particular, the trial involved third party costs (through apps/systems), and participating households had lower electricity consumption (hence lower DR potential in absolute terms). Both reasons are expected to remain true in a business-as-usual DR program implementation.

2.3 Commercial and industrial demand response

2.3.1 Overview

JEN has investigated the ability of C&I customers to provide demand response. To manage the safety and supply risk from forecast high demand conditions at Flemington Zone Substation, a trial was conducted in which 2 MW of network support was contracted from C&I customers within that area. In addition to mitigating supply risk, the opportunity was taken to increase operational knowledge in key areas of DM such as:

- Customer engagement models
- Technical requirements
- Capacity firmness
- Cost efficiencies
- Challenges and limitations

On Friday 25 January 2019, in response to the Australian Energy Market Operator's request to the networks across Victoria to load shed, JEN deployed its demand response program to support the grid. This event helped JEN keep the lights on for hundreds of residents in its network.

2.3.2 Key findings

At the time of the trial, several key observations were noted regarding utilising C&I load curtailment for DM purposes:

1. A limited number of aggregators were found within the market

2. Restrictions on sharing customer information with these aggregators inhibited the identification of suitable customers

3. Fragmented IT systems were required for 'real-time' communication with customers (in the absence of systems that automate DR).

To establish a sufficient C&I customer portfolio for DM purposes, JEN recognises the need for further engagement with aggregators and customers to address potential future constraints. Additionally, JEN has identified the need for better integration of IT platforms to enable efficient operations. In the next regulatory period, JEN will liaise with aggregators and progressively build a larger portfolio of C&I customers with DR capabilities.

2.4 Voltage reductions at zone substations

2.4.1 Overview

Voltage reduction is a proven method of managing network load during times of peak demand or to increase solar PV network hosting capacity. Through slightly lowering the voltage at the zone substation (**ZSS**) level and monitoring customer supply voltage using smart meter data for ensuring compliance, DNSPs can reduce network load as required. Based upon learning from other DNSPs, JEN has the potential to reduce its overall network load by 10-20 MW through deploying this capability across all zone substations.

JEN is developing its capabilities in this form of DM with the technology trialled on four ZSS during summer 2017/18. In addition to the trials conducted, this DM mechanism was implemented at Coburg South (CS) ZSS where there was a load risk under both N and N-1 contingency scenarios in 2018-19 summer. In partnership with RMIT, we are analysing the data to establish a voltage-power relationship on a hot day.

This DR program also has the potential to support the electricity wholesale market through the Reliability and Emergency Reserve Trader (**RERT**) mechanism and ensure grid stability during times of stress.

2.4.2 Key findings

JEN has acquired several learnings regarding this form of DM through both trials and its implementation on the CS ZSS:

1. DR capacity attainable is approximately 0.5-1.5 MW per ZSS

2. Load reduction achieved is dependent on the nature of customer loads connected at the time of dispatch. While effective at the ZSS level to manage capacity risks, this finding infers that the mechanism will not be equally effective on its own in deferring individual feeder upgrades.

3. Life support and sensitive load customers will need to be proactively managed as this mechanism risks poor quality of supply (i.e. voltage levels outside of the standard) to all customers if not appropriately managed.

There are only six zone substations which do not currently have a remote (i.e. from network operations centre) voltage reduction capability on JEN's network. Given JEN's substation transformer upgrade program, it is proposed to include the implementation of this capability in this program.

Also, JEN will look to further develop its load models to predict the impact of DR events and integrate the operationalisation of this mechanism with the conservation voltage reduction module in its advanced distribution management system (**ADMS**).

2.5 Controlled EV charging

2.5.1 Overview

It is anticipated that the electrification of transport could lead to a significant increase in network demand. Electric vehicles (**EV**) in particular have been identified as a source of possible peak demand growth, with potential aggregate charging events leading to a new peak demand. Conversely, EV has also been identified as a possible source of energy storage with flexible and dispatchable capacity for demand response purposes.

To ensure that JEN is positioned to deal with the proliferation of EV on its network, it conducted a desktop study and preliminary trial design that looked to establish 10 to 20 EV charging stations in public locations. The objectives of this study were:

1. To understand customer charging behaviour – to create optimum cost-reflective charging conditions, and allow JEN to establish a view on how to proactively manage EV charging and load demand to avoid network upgrades.

2. To test EV technologies – to understand how stored energy from charging stations could be used to manage and reduce peak loads. This would allow for the optimisation of asset investments and potentially defer network investment for the benefit of all customers.

3. To promote and support the mass adoption of EV – to improve network utilisation and thus lower network charges for all customers.

2.5.2 Key findings

Before commencing the trial, JEN already identified that it would not be permitted to own EV charging infrastructure. As such, it identified the need to understand the communication protocol required to exchange network and charging infrastructure information to manage network demand. It also identified the need to collaborate with external partners to both share power quality and energy profile data from charging infrastructure to understand the impact of EVs better.

3. Cost-benefit methodology

This section outlines the considerations that JEN takes into account when assessing the viability of DM as a non-network alternative to traditional network investment. The benefits offered by DM will be first discussed before presenting the cost assumptions employed by JEN in the cost-benefit analysis of DM. An overview of the three options assessed for network-planning tasks is then presented before discussing the current viability of DM solutions for JEN's network.

3.1 Demand management benefits

To understand the credibility of DM as an alternative to network investment (AUGEX or REPEX), it is first necessary to understand the benefits that DM offers to network operators. Depending on the mechanism employed, and the firmness of the capacity achieved, DM solutions can assist network operators to realise the following benefits:

1. Improved network reliability – DNSPs can utilise DM solutions to mitigate USE risk during peak demand events. By avoiding involuntary customer load shedding in contingency events, DNSPs can improve the reliability of their networks.

2. Investment flexibility – DM solutions allow DNSPs to retain flexibility through the provision of incremental capacity relief in situations where there is a declining rate of demand growth or uncertainty about future demand. This provides DNSPs with more time to better understand future network requirements and mitigate the risk of committing to high-cost network investments that may become stranded assets at the customers' expense.

3. Asset development deferral – DM solutions can defer network investment through the improved utilisation of existing assets attained from the expected improvements offered by DM (e.g. reducing peak demand).

In addition to the benefits available to network operators, DM offers several system benefits that could be valued for inclusion in the cost-benefit assessment of DM options in some circumstances.[5] These benefits can include:

1. Avoidance of involuntary load shedding – similar to improving network reliability at the distribution level, DM solutions can avoid involuntary customer load shedding when system supply is at risk by reducing overall system demand. Benefits from this system-wide balancing service can be realised through participation in schemes such as the Reliability and Emergency Reserve Trader (**RERT**), or valued through the reduction of USE.

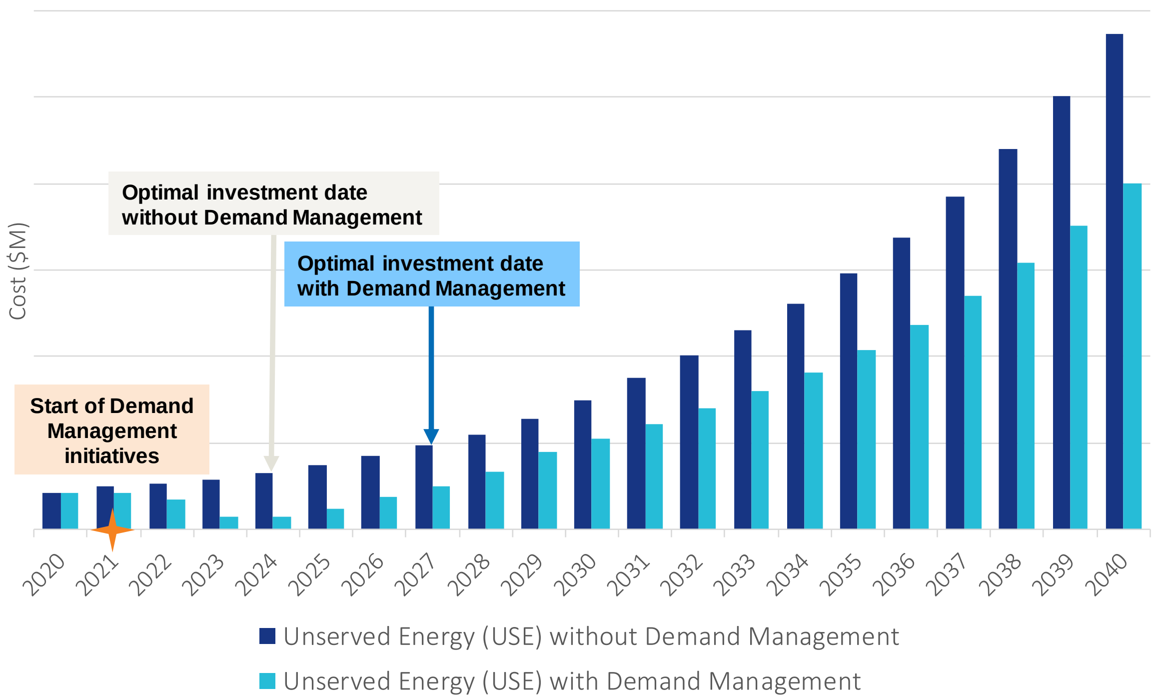
2. Avoidance of fuel costs – DM solutions can reduce system peaking generation requirements by reducing system peak demand. This translates into system-wide benefits through a reduction in peaking generation fuel costs.

3. Provision of ancillary services – when properly implemented, DM mechanisms can provide ancillary services, such as Frequency Control Ancillary Service (**FCAS**), by managing the system-wide real-time balance between supply and demand.

5 However, wholesale energy and FCAS market benefits have been assumed immaterial for distribution network demand management of 2 MW or less.

The culmination of the benefits available to network operators results in a reduction in USE costs. This reduction allows for the deferral of traditional network investments, as seen in Figure 3–1, which displays the impact that DM can have on USE and the optimal date for network investment.

Figure 3–1: Illustrative effect of DM on network investment timing



3.2 Demand management costs

JEN's assessment of DM costs is based on the assumption that large C&I customers will provide the DR.[6] These costs have been obtained from JEN's DM trials and have been scaled for implementation across its network. An overview of the cost basis of DR programs is provided in Table 3–1. This cost basis is illustrative of an example with a high level of automation and 60 minutes response. In addition to this, JEN is exploring other arrangements with various aggregators and also considers other non-network options (e.g. battery storage) when assessing alternatives to traditional network investments.

Table 3–1: Cost basis for demand response programs

	Unit	Value
Load available (from two industrial customers)	MVA	2
Capacity factor (delivered load vs contracted load)	%	100
Cost per customer for hardware	$/customer	[redacted]
Cost per year for programme setup and software license	$/year	[redacted]
Payments to customers for capacity	$/MVA	[redacted]
Payments to customers for delivery	$/MWh	[redacted]

6 This assumption is taken for simplicity reasons as other forms of DR are also actively considered, including behavioural DM, load control, voltage reduction and storage. It is considered that other forms of DR have higher costs.

3.3 Options analysis

Three options are taken into consideration for network-planning tasks (i.e. capital expenditure projects) proposed in JEN's regulatory periods:

1. Do nothing
2. Traditional network investment
3. Non-network alternatives (including DM and electricity storage)

A cost-benefit analysis is completed for each option, with the most cost-efficient solution determined as that with the highest net present value (**NPV**).

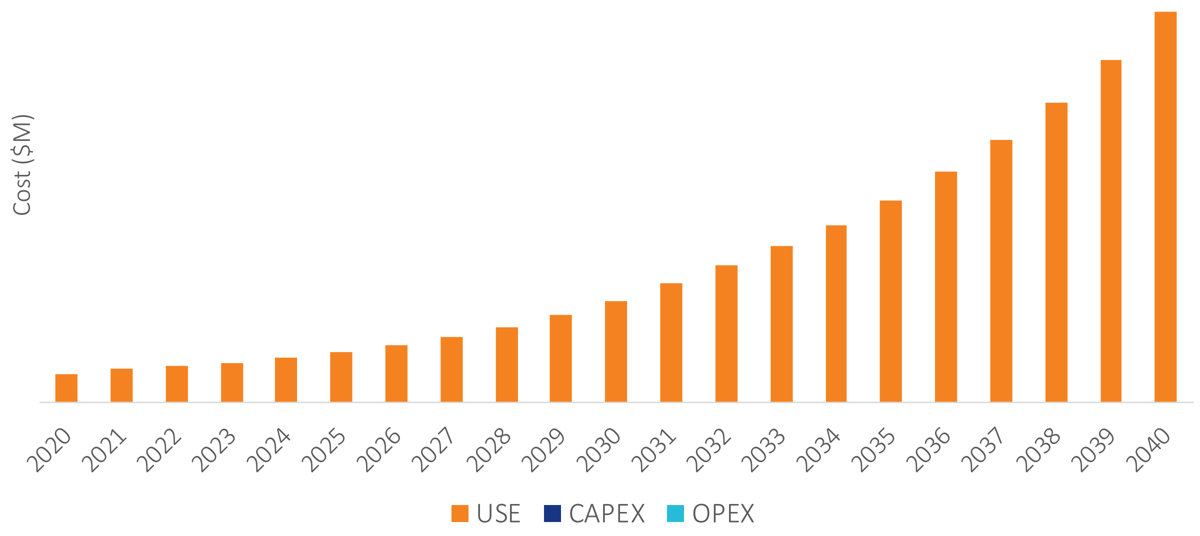
To determine the economic benefit of network and non-network options, expected USE costs are determined via the options' development process and compared to the "Do nothing" option. The USE forecast is then used to calculate the optimal investment date for the most economical network solution, which is considered viable when the NPV of the investment is lower than the NPV of USE costs. In the case of the DM option, it is assumed that the investment date of the most economical network solution will be deferred due to its ability to reduce USE costs (as seen in Figure 3–1).

Capital expenditure cash flows are then brought to present value terms using JEN weighted average cost of capital (**WACC**). The NPV of each option is finally compared with the most cost-efficient solution retained. When the NPV of two options are close, a sensitivity analysis is performed on the assumptions made for the DM solutions (e.g. assumptions presented in Table 3–1). DM is considered a viable alternative to traditional network investment when its NPV costs are lower than the other two options in the majority of scenarios.

3.3.1 Option 1 – Do nothing

The "Do nothing" option considers that no changes are made to the network or to the way it is operated. As seen in Figure 3–2, the only cash flow is the cost of USE which grows with time.

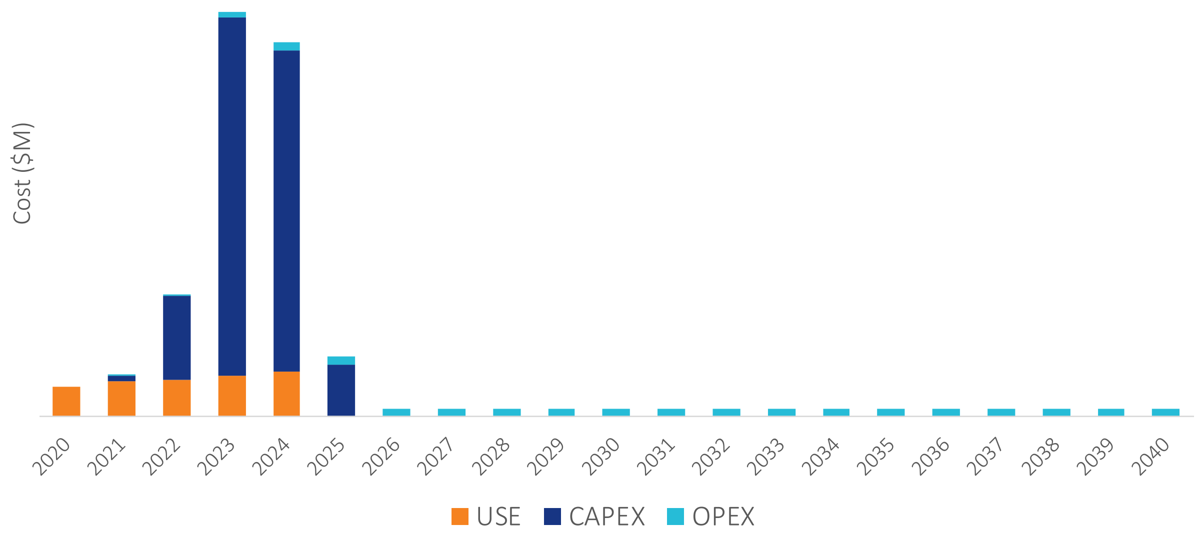
Figure 3–2: Cash flow example for a "Do nothing" option (Ausgrid, Demand management cost benefit assessment, 2018)



3.3.2 Option 2 – Traditional network investment

Traditional network investments are considered viable when the investment becomes cost-efficient, that is when the NPV of the investment is lower than the NPV of USE costs. In this option, the cost of USE is considered up until the project is complete and operational expenditure continues for the duration of the asset life.

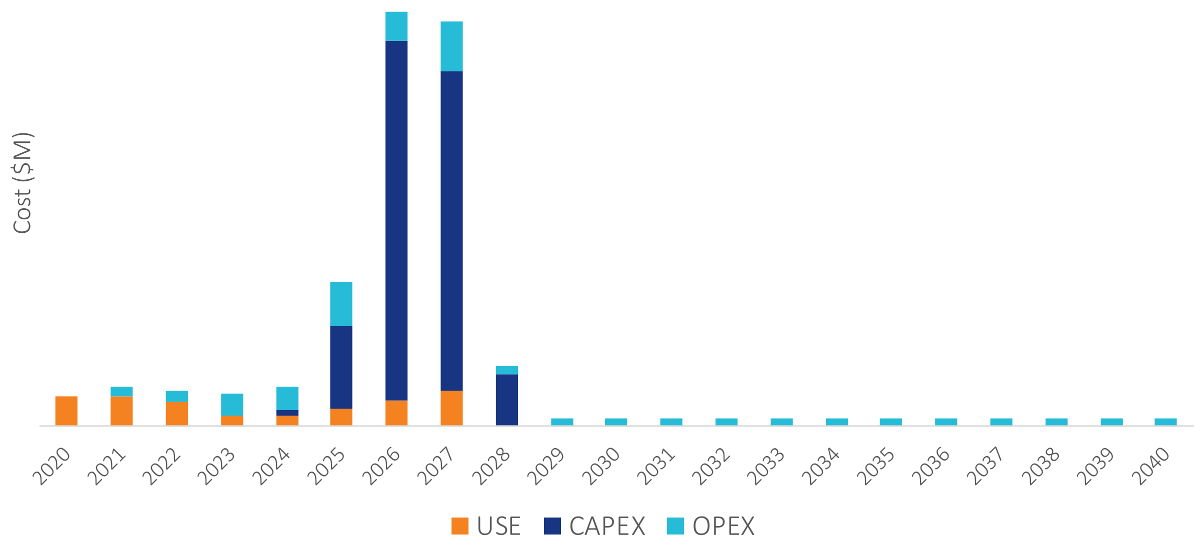
Figure 3–3: Cash flow example for traditional network investments (Ausgrid, Demand management cost benefit assessment, 2018)



3.3.3 Option 3 – Demand management (including DM and storage)

The value streams considered for DM solutions include deferred capital expenditure of the most economical network solution and DM operating expenditure. The ability of DM to defer the investment date of the traditional network option through USE reduction are derived from past JEN and industry trials. Other benefit streams attainable from DM can also be included in its NPV calculation which may make the non-network solution economically favourable.

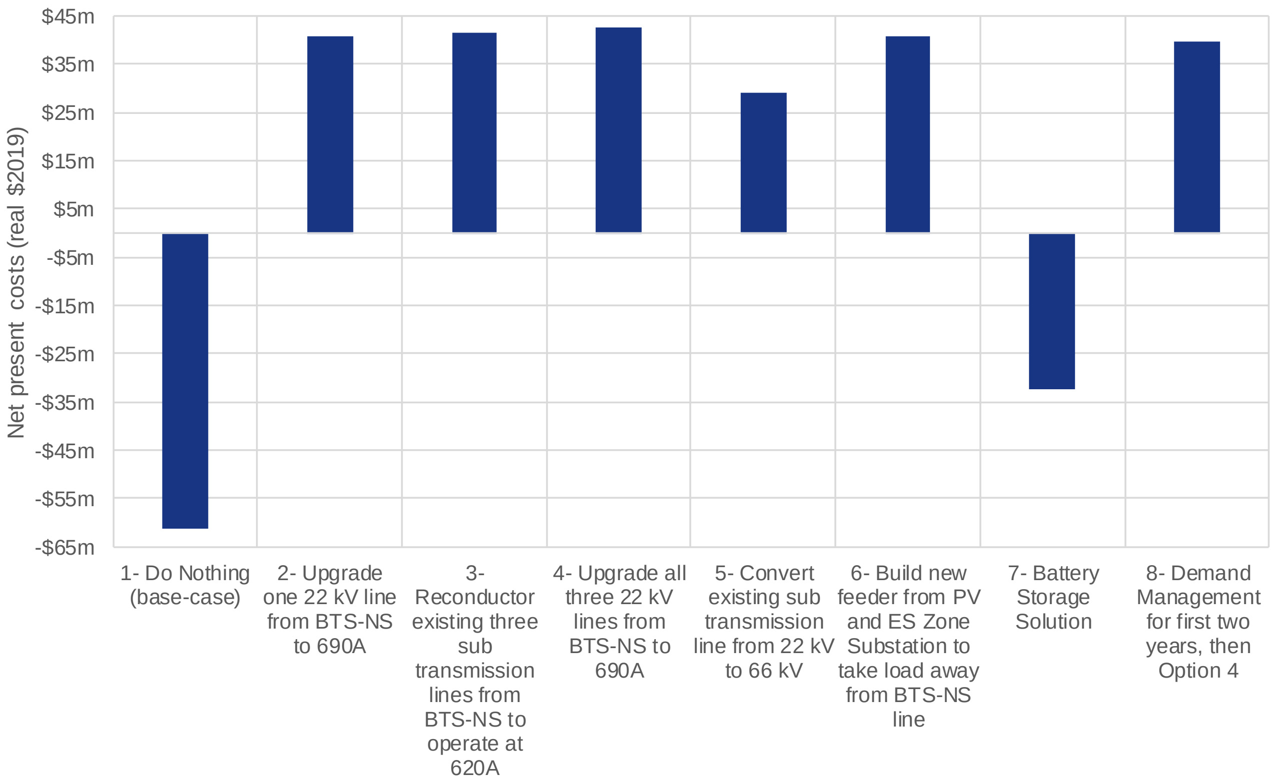
Figure 3–4: Cash flow example for DM solutions (Ausgrid, Demand management cost benefit assessment, 2018)



3.4 Findings

JEN has applied this options analysis methodology to the network planning tasks identified in its 2021-2026 regulatory period. As a result, JEN has not identified any projects where DM would be the preferred option. For example, when assessing the NPV of a range of options for addressing the capacity constraint on BTS-NS 22kV Sub Transmission Line to relieve a constraint (see Figure 3–5), DM ranked fifth out of eight possible options.[7]

Figure 3–5: Comparison for option costs to relieve the capacity constraint on BTS-NS 22kV Sub Transmission Line

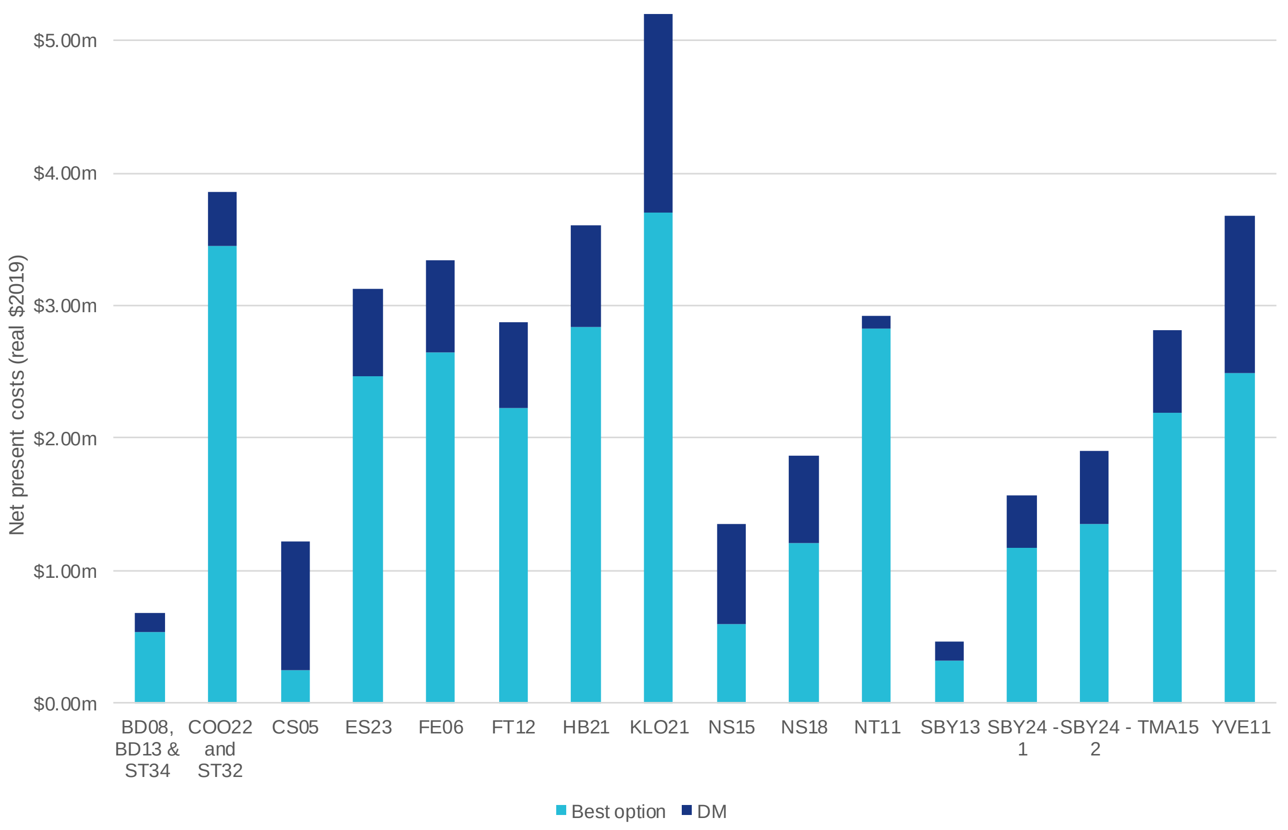


This outcome also arose across a broader set of business cases. DM did not emerge as the preferred option in terms of NPV for any of the 16 distribution feeders with load at risk in the 2021-26 regulatory period (see Figure 3–6)[8].

[7] Jemena, Network Development Strategy - Distribution Feeders, 2019.

[8] Jemena, Network Development Strategy - BTS-NS 22kV Sub Transmission Line, 2019.

Figure 3–6: Comparison of option costs to address load at risk on JEN's 16 constrained distribution feeders in the 2021-26 regulatory period



While JEN acknowledges the efficacy of DM to reduce peak demand, as exhibited by in-house and industry trials, it believes that costs of DM are higher than these of network options. At this point, JEN believes that several impediments are preventing DM options from being considered the most cost-efficient solution as required by the BAU economic justification process. These include:

- The high cost of scaling and implementing DM solutions
- Firmness in DR capacity attainable
- Market maturity in terms of technology and service providers
- Implementation of DM options in time frames to address project needs
- Considering non-network options well in advance.

In light of these challenges, JEN also recognises the rapid transition that emerging energy markets are undergoing and has, therefore not ruled out the viability of DM as a credible non-network solution in the future. As such, JEN will revisit the potential of DM when projects are initiated during the next regulatory period. This will be for all projects and not just those required by the Regulatory Investment Test for Distribution (**RIT-D**) process.

4. Conclusion

JEN has undertaken six primary DM initiatives in its current regulatory period to position itself to implement non-network solutions for the benefit of its customers. As a result, JEN has identified several key findings concerning the DM initiatives that it has conducted:

1. JEN's residential demand response program (Power Changers) proved positive with participating customers reducing their electricity consumption by an average of 26-35%.
2. Direct load control of residential air conditioners is being investigated further.
3. JEN will be required to work closely with aggregators to maximise the potential of DR from C&I customers within its network.
4. Demand response capacity attainable from voltage reduction at distribution zone substations is approximately 0.5-1.5 MW per ZSS.
5. Sufficient protocols will be required for JEN to understand the opportunities and impact that electric vehicle charging stations may have on its network.

In light of these findings, JEN will focus on behavioural DM for its residential customers and will continue to explore DM in partnership with aggregators and its C&I customers.

Despite improving its working knowledge of DM, JEN has not identified any projects in its next regulatory period that can be addressed cost-effectively through DM and battery storage. While JEN will continue to assess DM options as an alternative to traditional network investments, it has identified a number challenges that may be preventing it from being the most cost-efficient solution as required by the BAU economic justification process. These primarily include the high cost of scaling and implementing DM solutions and ensuring the DR capacity is available when needed.

In light of this, JEN intends to undertake several activities in the next regulatory period to better understand the costs and the value streams by DM so that it is in a better position to assess the economic viability of the non-network option under DMIS and DMIA. These activities include:

- Improvement of its internal DM capabilities through trials and incentive schemes
- Changes in planning practices to identify more opportunities for DM, including:
  - Working proactively on DM for feeder constraints
  - Assessing DM to reduce the risk of "at-risk" or near capacity asset
- Expansion of its DM portfolio years to allow for the achievable reduction in USE to be better understood
- Assessment of DM solutions in the present to defer network investments in future regulatory periods.