AUGMENTATION

LOWER MORNINGTON PENINSULA

UE RRP BUS 3.3.02 – PUBLIC

2026–31 REVISED PROPOSAL

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1. Overview

This business case addendum sets out our response to the AER's draft decision for the lower Mornington Peninsula supply area and describes the further work we have undertaken since our original proposal.

In our original proposal, the preferred capital expenditure program was to construct a 54km sub-transmission line between our Hastings (HGS) to Rosebud (RBD) zone substations by FY31. This option maximised value for customers by avoiding pre-contingent load shedding to avoid a voltage collapse limit in the area. We also proposed to construct a new zone-substation at Shoreham (SHM) that would tie into this line to deliver resilience benefits for customers.

The AER’s draft decision did not accept our proposed capital expenditure for the sub-transmission line or the new SHM zone substation, but did include a lower cost substitute estimate to provide resilience benefits. The AER determined that continuing or expanding the existing non network solution in FY31 is a cost-effective way to defer the new line, and the resilience benefits can be delivered through the use of mobile generation.

Our revised lower Mornington Peninsula supply area addendum and confidential economic model set out our responses to the AER’s draft decision, including additional options analysis, updated forecasts and a stronger evidence base to support our non-network cost and benefit assumptions.[1]

Our economic modelling shows that the preferred option remains to construct and commission the new sub-transmission line by FY31, supported by the existing diesel generation solution in the meantime.

Our modelling also shows that maintaining or expanding the non-network solution reduces the net present value (NPV) delivered for customers and is not economic relative to construction of the sub-transmission line. Constructing the line will also utilise existing easements and line routes, which will address the potential for community concerns regarding aesthetic or environment impacts for communities (particularly relative to ongoing operation of diesel generators).

We have, however, accepted the AER’s draft decision on resilience in the lower Mornington Peninsula area as despite customers’ dissatisfaction with diesel generation, faster rectification of power supplies following major storm events in the Shoreham area is preferable to our customers compared to long duration outages.

Our revised expenditure forecast to address reliability and resilience needs in the lower Mornington Peninsula supply area is presented in table 1 below. The remainder of this addendum focuses on the voltage collapse limit rather than the resilience need.

1 See UE RRP MOD 3.3.02 - Lower Mornington Peninsula supply area - Dec2025 – Confidential.

TABLE 1 EXPENDITURE FORECAST: PREFERRED OPTION ($M, 2026)

PROJECT	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
HGS-RBD sub-transmission line	38.2	-	38.0
Shoreham zone substation	25.0	8.4	8.4
Total	**63.2**	**8.4**	**46.4**

2. Background

This section briefly summarises our regulatory proposal to provide a reliable supply of electricity to customers across the lower Mornington Peninsula supply area as forecast demand continues to increase, and the AER's draft decision in response to our proposal.

2.1 Our regulatory proposal

The lower Mornington Peninsula is currently served by two sub-transmission lines. With ongoing growth in the area, a fault in either of these lines gives rise to a material risk of voltage collapse that would lead to cascading blackouts across the entire lower Mornington Peninsula.

We currently have an operational non-network solution implemented within the lower Mornington Peninsula network to defer the economic timing of the need for further interventions (such as network augmentation). This non-network solution currently consists of 9MW of diesel generation and 1MW of battery storage. Forecast demand growth in the lower Mornington Peninsula, however, is driving increasing amounts of energy at risk that will surpass the capabilities of our non-network program in the 2026–31 regulatory period.

We have investigated several options to address increasing energy at risk including maintaining our existing non-network solution, expanding our non-network solution and building a new 66kV sub-transmission line from our HGS to RBD zone substation.

Our preferred solution to address the voltage collapse constraint was to construct the sub-transmission line as it maximised net benefits to customers.

We also proposed to construct a new zone substation at Shoreham that would connect into the new sub-transmission line to economically manage resilience challenges.

2.2 AER draft decision

In its draft decision, the AER did not accept our proposed expenditure to construct the new sub-transmission line. The AER instead determined that the current non-network solution can be continued or expanded in the 2026–31 regulatory period.

The AER stated that EMCa's review supported its conclusions, noting EMCa found that:

- continuing or expanding the current non network solution in FY31 may be a cost-effective way to defer the new line, citing the cost in our economic model for this option is $111k per year (commencing in FY32) and increasing by about $111k per year every second year
- an alternative option to expand the non-network solution for one or more years to defer the need for the HGS-RBD 66kV line was not considered before committing to the new line
- using a 10 per cent probability of exceedance (PoE) forecast for determining the time diesel generators are required is overly conservative in establishing the required operational times of the diesel units.

In addition, EMCa found that:

- the NPV of our preferred option was relatively small and has a negative NPV under a scenario where capital expenditure is 10 per cent higher and energy at risk is 10 per cent lower
- the load duration curve was based on 2019 data.

3. Our revised proposal

Our revised proposal accepts the AER's draft decision to defer construction of the Shoreham zone substation, but for the reasons set out below, we have re-proposed the HGS-RBD sub-transmission line in the lower Mornington Peninsula.

The HGS-RBD sub-transmission line is supported by our economic analysis and maximises the net economic benefit (compared to other feasible options) for customers in the lower Mornington Peninsula supply area.

In the event the AER does not accept our revised proposal, then the alternative solution determined by the AER should include the sub-transmission line as a contingent project.

3.1 Response to AER draft decision

In response to the AER's draft decision, we have updated our analysis to include new demand forecasts, 2024 VCR values and updated assumptions for non-network solutions consistent with market prices.

We have also reset the base case in our model to represent a true 'do nothing' approach, rather than to continue the existing non-network solution. This provides more clarity for the NPV of each option.

This section discusses these changes and addresses each of the AER and EMCa's concerns about the prudency and efficiency of our regulatory proposal.

3.1.1 Our revised proposal demand forecasts in the lower Mornington Peninsula have increased compared to our regulatory proposal

Our revised proposal forecasts growth in the lower Mornington Peninsula area across the three zone substations of Dromana (DMA), Rosebud (RBD) and Sorrento (STO). Forecast demand across the lower Mornington Peninsula in 2031 has increased in our revised proposal from our regulatory proposal, as shown in table 2 below.

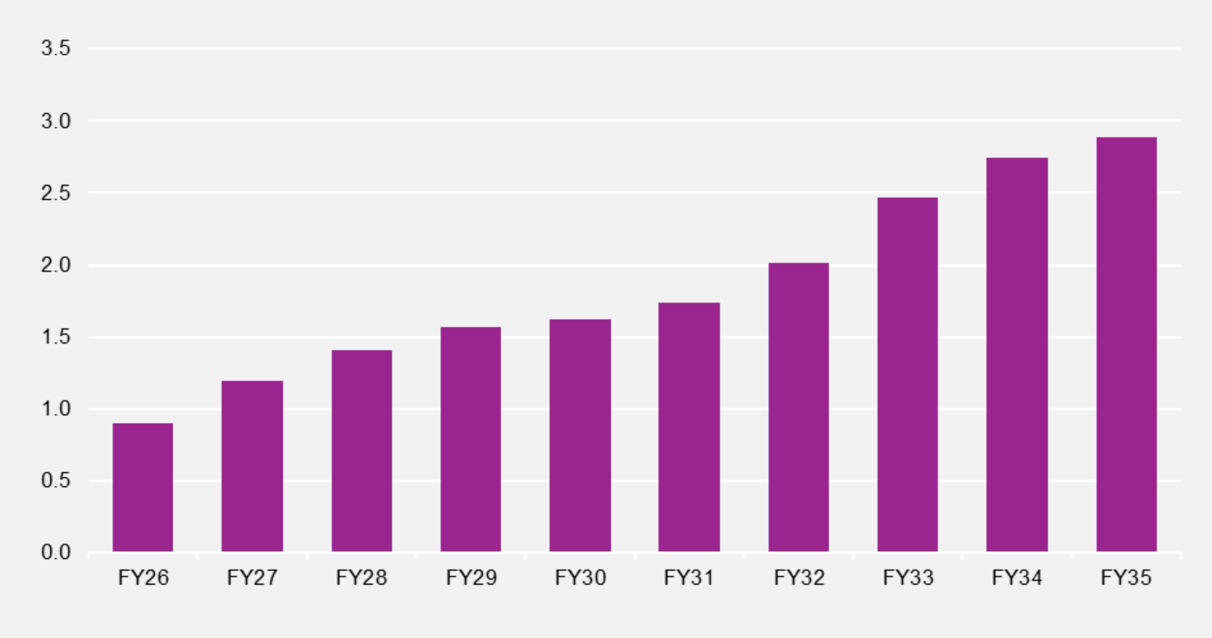
TABLE 2 COMPARISON OF FORECAST DEMAND IN 2031 (MW)

FORECAST DEMAND	REGULATORY PROPOSAL	REVISED PROPOSAL
Dromana (DMA)	45.2	46.9
Rosebud (RBD)	42.7	44.3
Sorrento (STO)	47.7	47.3
Total	**135.6**	**138.5**

Increased demand growth is being driven by electrification of transport and gas, customer growth and consumer energy resources (CER) integration that we now have further visibility of following our recent summer. All else equal, this has the impact of increasing the economic viability of building the sub-transmission line because it defers more risk per dollar spent.

The corresponding total value of energy at risk under the 'do nothing' scenario across the lower Mornington Peninsula for the revised regulatory proposal is shown in figure 1 below.

FIGURE 1 LOWER MORNINGTON PENINSULA: VALUE OF EXPECTED UNSERVED ENERGY ($M, 2026)



3.1.2 Our assessment of required diesel generation run times is appropriate

An input into our economic modelling was the expected running time of diesel generation units. EMCa stated that our use of the 10 PoE demand forecast, rather than the 50 PoE or other alternative, appears to be overly conservative.

We expect the diesel generators to be required when demand is highest. It is therefore reasonable to use the 10 PoE forecast to determine how long we would be required to run diesel generators. The 50 PoE forecast is not relevant for this use case.

In addition, running the diesel generators comprises a small portion of the total non-network solution cost. The significant majority of costs are incurred to hire and operationalise the solution rather than running the diesel generators. These costs are shown in section 3.1.5 below.

For the avoidance of doubt, we have used 70 per cent weighting on the 50 per cent POE forecast and 30 per cent weighting on the 10 per cent forecast to determine all energy at risk and optimal timing of additional non-network solutions, consistent with standard industry practice.

3.1.3 We have repositioned the base case to improve the clarity of our modelling

The AER cited EMCa's finding that continuing or expanding the current non network solution in FY31 may be a cost-effective way to defer the new line. EMCa noted that this option included additional non-network solution costs of $111,000 per year commencing in FY32 and increasing by around $111,000 per year every second year.[2]

The AER did not publish EMCa's modelling, however, it appears to mis-state the costs of our non-network solutions.

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2 AER, Draft decision, United Energy electricity distribution determination, 1 July 2026 – 30 June 2031, Attachment 2 – Capital expenditure, p. 29 and EMCa, United Energy 2026-31 regulatory proposal, review of aspects of proposed expenditure on augex, p. 26.

For example, the model we submitted to support our regulatory proposal considered that the base case included the continuation of the existing non-network solution, with operating expenditure of $900,000 per year. Options two and three included the $900,000 in operating expenditure to maintain the existing non-network solution until it was no longer required (i.e. once the sub-transmission line was built). Our model showed no further increased costs in these options as there was no additional operating expenditure required relative to the base case.

The exception to this was our fourth option to expand the non-network solution, which included an additional $111,000 per MW of required capacity (i.e. bringing the total cost of this option to $900,000 plus $111,000 per MW of additional capacity, required to maintain existing energy at risk). While the specific costs identified in our expanded non-network solution option were $111,000, it is not clear whether the AER has interpreted the costs of expanding our non-network solution as $111,000 per MW in total, rather than $900,000 plus $111,000 per additional MW.

To improve the clarity and simplicity of our modelled options, we have adjusted our revised proposal model so that the base case is now a true 'do nothing' scenario. That is, continuing with our existing non-network solution is now assessed as a stand-alone option. This has improved the ease with which the costs and benefits of our modelled options can be compared.

Our revised options analysis is attached in our confidential economic modelling, with the five options we have considered being:[3]

- option one: do nothing, meaning cessation of the existing non-network solution and load shedding to keep below the voltage collapse limit
- option two: maintaining the existing non-network solution without expansion
- option three: maintaining the existing non-network solution and then building the sub-transmission line when the benefits exceed the costs
- option four: expanding the existing non-network solution to maintain current levels of energy at risk
- option five: expanding the existing non-network solution to maintain current levels of energy at risk and then building the sub-transmission line when the benefits exceed the costs.

3.1.4 We have considered expansion of the non-network solution and then constructing the sub-transmission line in our revised proposal

The AER stated that we did 'not appear to have considered expansion of the power station for one or more years to defer the need for the HGS-RBD 66kV line'.[4]

We did investigate the option of expanding the non-network solution to defer the optimal timing of the sub-transmission line in the early development of our regulatory proposal and found that it was not as economic as maintaining the size of the current non-network solution and building the sub-transmission line. However, we did not include this option directly in our options analysis for the regulatory proposal.

We recognise that this omission was an oversight and have included a separate option in our revised proposal model that assesses the economics of an expanded non-network solution. This option maintains current levels of energy at risk and subsequently builds the sub-transmission line when it becomes economic. This option, however, remains non-preferred compared to other options.

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[3] See UE RRP MOD 3.3.02 - Lower Mornington Peninsula supply area - Dec2025 – Confidential. Model is confidential due to use of specific quotes and capacity references from service providers.

[4] The AER and EMCa's references to a 'power station' appears to be to our non-network solution, which consists of large diesel generators connected in populous areas.

3.1.5 We have accounted for the realistic capabilities of non-network solutions across the 2026–31 regulatory period

Under our option to expand the non-network solution—option four in both our original proposal and revised proposal—EMCa considered that the extent of our proposed expansion increased the required capacity at a rate that appeared inconsistent with the business case requirements.

The AER also stated that the cost estimate for an expanded non-network solution option does not appear to have been derived from the market, and that continuation or expansion of the non-network solution should be investigated further to determine the most cost-effective solution to remediate energy at risk in the lower Mornington Peninsula.

Given these concerns, we have:

- outlined our methodology to derive the optimal timing of increasing the required non-network solution capacity under each relevant option in section 3.1.6
- refined the assumed costs of both our current non-network solution and expansion of our non-network solution with updated information.

We have summarised our assumptions, costs and supporting evidence below.

The market-tested cost of our current non-network solution has been updated

We have revalidated that the costs for our current non-network solution are the lowest available by testing the market for all applicable costs. Quotes were sourced from our existing service provider who has delivered the solution since the 2018/19 summer and alternative service provider(s), which are shown in table 3 below.

TABLE 3 MARKET TESTING OF NON-NETWORK SOLUTION COSTS ($2025)

[redacted]

The existing provider provides a service that is inclusive of diesel generator hire and annual deployment to site, while comparator service providers only provide individual diesel generator hire or deployment to site services. The combined comparator prices of hiring diesel generators and site deployment exceed the combined cost from our existing provider.

[redacted]

The market-tested cost of expanding our current non-network solution has also been updated

The cost of our expanded non-network solution comprises all costs from our current non-network solution plus the additional costs associated with sourcing, deploying and connecting additional generators as the forecast grows.

We have updated our costs to expand the non-network solution beyond its current capacity with updated quotes sourced from alternative service providers, which are shown in table 4 below.

TABLE 4 MARKET TESTING OF EXPANDED NON-NETWORK SOLUTION COSTS ($2025)

[redacted]

Expanding our non-network solution will require the once-off establishment costs of a new connection point. In addition, we will need to hire and deploy generators and also lease new land to support them.

Costs for these services, excluding those provided internally, have been derived from market quotes provided by our existing service provider and other comparator service providers. Our existing service provider remains the most cost effective provider of external diesel generation services.

Similar to our existing solution, our existing provider would provide inclusive diesel generator hire and annual deployment to site, while comparator service providers only provide individual diesel generator hire or deployment to site services. The combined comparator prices of hiring diesel generators and site deployment exceed the combined cost of our existing provider.

Options four and five in our economic assessment, which contain expanded non-network solutions, show the number of new sites and ongoing sites per annum required to maintain current levels of energy at risk. This is added to the costs of our existing annual non-network solution to comprise total annual costs for an expanded non-network solution.

Opportunities for BESS providers to effectively defer augmentation are driven by commercial enterprises and we are not aware of any additional BESS opportunities. We have therefore used generators and their associated costs to support our non-network solution options.

3.1.6 Diesel generators are more impactful to communities than 66kV lines

Diesel generation units are shipping container-sized units that make large amounts of noise when operated. Our existing diesel generation solution has been subject to strong community opposition due to the negative community amenity. We have received several complaints from customers and members of Parliament to remove the diesel generators and prioritise another more sustainable solution.

For example, the Victorian parliamentary member for Nepean is on record in the Victorian Government Parliament calling for an alternative option to the diesel generators:[5]

> *I would love to see the government invest in an extra line to the Mornington Peninsula so we do not have to come over the summer period and drop eight to 10 diesel generators out on farms and in the Sorrento town centre. You can smell them and you can hear them burn. They are a blight on the peninsula over the summer period, but at the moment they are a necessary evil for people to be able to get through that summer period.*

EMCa, in its response to our regulatory proposal, surmised that the 54km of sub-transmission line may also be opposed by a significant number of community members due to the environmental and amenity impacts.[6]

The sub-transmission line route, however, would be over-built along an existing line route for our 22kV network. This would involve the replacement of each 22kV pole with marginally taller poles, maintaining the existing 22kV line and constructing the new 66kV line on the same poles. This would not generate any noise or smell, the environmental impact is likely lower than running diesel generators, and the additional visual impact would be negligible.

Notwithstanding this, we recognise EMCa's feedback to allow sufficient engagement time with landowners and local communities to ensure they are comfortable with the proposed line route and removal of diesel generators. We have therefore extended the delivery timeframes of the sub-transmission line from two to three years in our relevant options.

3.1.7 Our updated analysis continues to show that non-network solutions are no longer the most economic way to address energy at risk

We have been deferring the economic build of the HGS-RBD sub-transmission line through the use of non-network solutions since 2016. We completed our first RIT-D in 2016, with a further RIT-D completed in 2020 after the initial demand side response solution contract ended.

For our revised proposal, we sought to test the relative economics of each of our options to identify which was most economic for our customers over the long term. A summary of the economic outcomes under each of our options, relative to our revised base case, is shown in table 5 below.

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5 Hansard, Legislative Assembly, 60th Parliament, Thursday 17 October 2024, p. 87.
6 EMCa, United Energy 2026-31 regulatory proposal, review of aspects of proposed expenditure on augex… p. 27.

TABLE 5 SUMMARY OF OPTIONS CONSIDERED IN OUR REVISED PROPOSAL ($M, 2026)

OPTION	DESCRIPTION	PV COSTS	PV BENEFITS	NET BENEFITS
Option one (base case)	Do nothing (e.g. discontinue existing non-network solution)	-	-	-
Option two	Existing non-network solution	(15.2)	26.2	11.0
Option three	Existing non-network solution and new sub-transmission line	(23.5)	38.2	14.6
Option four	Expanded non-network solution	(24.5)	34.8	10.3
Option five	Expanded non-network solution and new sub-transmission line	(24.7)	38.3	13.6

Base case

The base case comprises the value of all existing energy at risk in the lower Mornington Peninsula with no costs. This option would see no non-network solution implemented and pre-contingent load shedding when aggregate demand on the lower Mornington Peninsula reaches 123MW.

All options are considered relative to the base case, meaning all costs and all mitigated energy at risk of each option compared to the base case are incremental.

Option two

Option two maintains the capabilities of the existing non-network solution, where the current non-network solution consists of 9MW of diesel generation capacity and 1MW of battery capacity. These do not increase the costs or the benefits of the solution over time.

We state the generation capacity in MW although it should be noted that, while the diesel generation can be refuelled, the battery support is only capable of providing 1MW of two hours or 0.5MW for four hours. The battery is usually dispatched first as it presents lower cost for shorter periods of operation.

Option two is economic relative to the base case (i.e. it has a positive NPV), however it is not the most economic outcome of the options assessed.

Option three

Option three maintains the existing capabilities of the non-network solution as described in option two, however, the 66kV sub-transmission line is constructed when it is economic to do so. This option sees growing energy at risk in the lower Mornington Peninsula as demand growth surpasses the existing capability of our non-network solution.

We have determined the economic timing of constructing the sub-transmission line by comparing the annualised capital expenditure of the sub-transmission line against the mitigated risk costs when the line is complete and the avoided need for operating expenditure to support non-network solutions. The value of risk mitigated and avoided operating expenditure surpasses the annualised capital expenditure in FY32, indicating optimal timing under this option is to commission the sub-transmission line prior to FY32.

This option maximises net benefits for customers compared to all options, and is therefore our preferred option.

Option four

Option four increases the capacity of our non-network solution by adding additional diesel generation on top of our current non-network solution. Our economic modelling adds a new 1MW diesel generator when it is efficient, which is when the additional energy at risk mitigated surpasses the additional costs. Additional 1MW generators would be contracted and new sites would be established to support new generators in line with demand growth. This leads to three new 1 MW generators by FY31 and six new generators by FY34.[7]

While this solution is also economic relative to the base case, it is not the preferred solution because it has a lower NPV compared to all other options. This option is uneconomic compared to maintaining the current non-network solution, indicating that adding new generators at market-tested rates to complement the existing non-network solution is no longer efficient.

Installing more generation beyond this option in any year would increasingly address lower amounts of energy at risk, meaning additional marginal generation would also be uneconomic compared to the existing non-network solution.

Option five

Option five includes the expanded non-network solution as described in option four while also considering construction of the sub-transmission line when it is economic to do so. This option sees similar levels of energy at risk maintained albeit with increasing costs, supported by economic commissioning of the sub-transmission line by FY33 with costs incurred through FY30 to FY32.

Similar to option three, we have determined the economic timing of constructing the sub-transmission line by comparing the annualised capital expenditure of the sub-transmission line against the mitigated risk costs when the line is complete and the avoided need for operating expenditure to support non-network solutions. The annualised capital expenditure surpasses the value of risk mitigated and avoided operating expenditure in FY33.

Option five is economic relative to the base case, however it is not the most economic outcome, with maintaining the existing non-network solution and constructing the sub-transmission line being preferable.

Consideration of alternative LMP supply from mobile generators to support worst served customers

The draft decision did not accept our proposed capital expenditure to construct a new Shoreham substation and instead allowed a substitute estimate for the procurement and deployment of six 1.5MVA diesel generators non-network solution to support worst served customers in the region. The AER reasoned that these mobile generators would produce the equivalent capacity to supply the average demand.

It is prudent to consider the alternative solution of deploying these diesel generators allocated to worst served customers through the eight to 10 week summer period to support the voltage collapse constraint in the lower Mornington Peninsula. We have assessed the viability of this option, and it is neither technically feasible nor an economic solution (to defer the sub-transmission line):

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7 The additional risk mitigated in our economic modelling is the difference between row 32 in the option 4 and option 2 tabs. New generators avoid 1MW of demand in our 'Working Risks – HGS-RBD' tab.

- it is not technically feasible to supply constrained areas in the lower Mornington Peninsula with the generators installed in the Shoreham area alone due to the radial nature of the lower Mornington Peninsula supply area
- transferring the generators is also not cost-effective due to the additional direct costs of disconnection, relocation and reconnection, noting that each of these costs would occur at least twice per year. We would also need to store and maintain the assets when not in use in a third location that has not been considered or costed
- the current connection kiosks used in the lower Mornington Peninsula are for 1MVA generators, whilst the generators for the Shoreham area would be 1.5MVA, resulting in the need for augmentation of the existing connection kiosks to make them operational or forcing the generators to run to a lower capacity
- relocation of the mobile generators to service the voltage collapse constraint would cease to deliver the resilience benefits they are primarily designed to provide for the period of their relocation, defeating the purpose of the solution to begin with.

All of these factors contribute to our assessment that using the mobile generators would not be a fit-for-purpose or an economic solution to the growing voltage collapse constraint in the lower Mornington Peninsula.

Preferred option

Our updated economic model assesses the economic merits of all credible options, including maintaining and/or expanding the non-network solution. Based on this model, our preferred option is building the HGS-RBD sub-transmission line (e.g. option three) as it provides the highest net economic benefits for customers.

This option provides a reliable supply of electricity to the lower Mornington Peninsula, with our detailed economic assessment showing that the net economic benefits for customers are maximised if this project is commissioned no later than FY31.

Additionally, constructing the sub-transmission line also addresses community concerns because it allows the existing diesel generation solution to be decommissioned.

Alternative preferred option: contingent project

As outlined previously, to the extent the AER does not accept our preferred option above—which we consider is sufficiently certain in the 2026–31 regulatory period—we note the proposed sub-transmission line would meet the contingent project criteria set out in the Rules because:[8]

- the expenditure would not otherwise be provided for in the total of the forecast capital expenditure for the 2026–31 regulatory period
- the expenditure would reasonably reflect the capital expenditure criteria in clause 6.5.7(c) taking into account the capital expenditure factors in clause 6.5.7(e)
- the expenditure would exceed $30 million or 5 per cent of the value of our proposed annual revenue requirement for the first year of the relevant regulatory period, whichever is greater
- there are no relevant regulatory information instrument requirements, other than the requirement that we include our contingent projects in our reset regulatory information notice.

To the extent required, therefore, the proposed triggers are set out in table 6 below.

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8 Clause 6.6A31(b)(2) of the NER.

TABLE 6 ALTERNATIVE: CONTINGENT PROJECT TRIGGERS

DESCRIPTION	EXPENDITURE	TRIGGER
Lower Mornington Peninsula: new HGS-RBD 66kV line	$38 million	1. United Energy has completed a Regulatory Investment Test for Distribution (RIT-D) that determines the preferred credible option to address the voltage collapse constraint in the lower Mornington Peninsula is the construction of the proposed sub-transmission line, pursuant to the NER; and 2. United Energy commits to proceed with the preferred credible option from the RIT-D, subject to the AER amending United Energy 2026–31 regulatory determination pursuant to the NER. To provide objective verification of this trigger, a letter from the Chief Executive Officer of United Energy will be sent to the AER to confirm such commitment.

3.2 Revised proposal forecast

Consistent with the reasons provided in this addendum and our revised options analysis, constructing the HGS-RBD sub-transmission line by FY31 is the most economic option to address reliability concerns from growing demand in the lower Mornington Peninsula supply area and deliver the most long-term value for customers.

Our revised proposed capital expenditure forecast is set out in table 7 below.

TABLE 7 DETAILED EXPENDITURE FORECAST ($M, 2026)

CAPITAL EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
HGS-RBD sub-transmission line	-	-	12.7	12.7	12.7	38.0

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