Revised Regulatory Proposal
Augex Summary

energex

1 Executive Summary

The AER's Augex assessment for Energex in its Draft Decision considered in detail a range of proposals for the 2020-25 regulatory control period. The AER also identified some themes in terms of the adequacy of our investment proposals.

This document forms part of our Revised Regulatory Proposal (RRP). It addresses in detail our response to both the comprehensive feedback on individual business cases plus the general themes identified by the AER. It provides a linkage between the RRP document and the individual business cases that have been re-submitted to the AER.

We appreciate the feedback from the AER on a range of issues regarding our proposals. We also obtained feedback from customers on these proposals. In regard to some of our proposals, we've accepted the AER's position in the Draft Decision. For some of our other proposals we have worked to address the feedback from the AER's Draft Decision and address the issues identified both in this document plus in individual business cases.

Contents

1. Introduction

This document provides details of the changes Energex has made from the Regulatory Proposal to the Revised Regulatory Proposal in Augex in response to feedback that we have received from the AER and our customers.

1.1 Purpose of document

This document summarises the changes that have occurred between the Regulatory Proposal and the Revised Regulatory Proposal in Augex based on the feedback received from our discussions with the AER and from the Draft Decision.

1.2 Scope of document

The scope of this document is limited to the areas where there have been material changes in our forecast Augex, or where there was specific feedback from the AER that we have to address as part of our Revised Regulatory Proposal. It does not include projects and programs that have been accepted as prudent and efficient expenditure by the AER in its Draft Decision.

1.3 Overview of Draft Decision

The table below has been extracted from AER's draft decision[1].

Table 1 : AER's Draft Decision on Augex

Category	Proposal	Position	Difference ($m)	Difference (%)
Subtransmission growth	74.8	28.2	-46.6	-62%
Distribution growth	96.3	96.3	0.0	-
Network communications	64.9	23.2	-41.7	-64%
Power quality	42.4	25.0	-17.4	-41%
Worst performing feeders	22.6	22.6	0.0	-
Total	**301.1**	**195.4**	**-105.6**	**-35%**

Source: AER analysis and Energex.

In this Revised Regulatory Proposal, we have carefully considered the feedback from the AER and our customers. We have reviewed our plans to determine whether there is scope to reduce capex by revisiting each project based on the specific feedback provided by the AER. We have examined the potential to make better use of existing assets and have reviewed programs where appropriate. In addition, we have examined AER's feedback on some themes in terms of adequacy of our investment proposals and these themes have been addressed, as detailed below.

[1] AER Draft Decision, Energex Distribution Determination 2020-25, Attachment 5 Capital Expenditure, October 2019

2 How We've Addressed AER's General Feedback

The AER has provided significant and valuable feedback in its draft decision regarding our capex proposals in general. Several key points have emerged from this feedback and each of these is discussed below:

2.1 Lack of Necessary Material to Demonstrate Prudency and Efficiency

What the AER Found: The AER found in its draft decision that we had sometimes not provided adequate supporting evidence that each of our proposals / business cases represented a prudent and efficient investment.

What We've Done: We've thoroughly reviewed each of our investment proposals and re-written our business cases as necessary. We've adopted several different approaches depending on the feedback:

- In some proposals, we've accepted that the investment is not required or that a better option is available – in these instances we've accepted the AER's reduction to our investment proposal.
- In other proposals we've examined the short-fall in our evidence base and re-written the business case to add additional evidence.
- In a number of proposals, we've tested the AER's assessment of our investment and provided clarifying comments and additional evidence to support our proposal.
- In every case that we've re-submitted, we've provided clearer and more succinct documentation to assist the AER in its review process.

2.2 Inadequate Cost Benefit Analysis

What the AER Found: The AER found in its draft decision that our business cases did not always provide a rigorous cost benefit analysis. The AER found that many of our business cases provided least cost options without any real examination of risks or benefits. The AER also found that our business cases did not test alternative options adequately through a rigorous sensitivity analysis.

What We've Done: We've thoroughly reviewed each of our investment proposals and re-written our business cases to address the AER's concerns. We've included the following key elements in every business case:

- A clear and well document business case, including a NPV analysis in every case. In a limited number of cases this remains a least NPV cost approach, however this is the only feasible approach in some cases and the rationale for this is fully documented.
- We've carried out sensitivity analysis, in every case where it is appropriate to do so.
- We've carried out a Value of Regret analysis in every case to provide greater insights into the merits of our proposed option.

2.3 Establish the Need for Investment and Address Capex Criteria

What the AER Found: The AER found in its draft decision that our business cases did not always clearly identify a need for investment. This is linked to a related finding that our proposals did not provide a rigorous cost benefit analysis.

What We've Done: We've thoroughly reviewed each of our investment proposals and re-written our business cases to address the AER's concerns. We've included the following key elements in every business case:

- We've included a section in every business case to clearly identify the need for the investment. This is linked to a range of drivers including compliance and risk.
- We've included a table in every business case that details the alignment of the proposal with the NER capital expenditure requirements as set out in Clause 6.5.7 of the NER.

2.4 Application of the Safety Net

In its Draft Decision, the AER outlined that it accepts Energex's Safety Net obligations that require us to limit the amount of load and number of customers without supply against predefined timeframes in the event of an outage. Table 2 below outlines the Safety Net criteria (extracted directly from Energex's Distribution Authority.

Table 2 – Energex Safety Net Criteria

Feeder Type	Targets
CBD	• Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute
Urban – following an N-1 event	• No greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • No greater than 12 MVA (5,000 customers) is without supply for more than 3 hours; and • No greater than 4 MVA (1,600 customers) is without supply for more than 8 hours.
Short rural – following an N-1 Event	• No greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • No greater than 15 MVA (6,000 customers) is without supply for more than 4 hours; and • No greater than 10 MVA (4,000 customers) is without supply for more than 12 hours.

The table below shows how to apply the Safety Net to Urban and Rural category substations.

Table 3 – Energex Safety Net Criteria Interpretation

Category	Demand Range	Allowed Outage Duration to be OK
Urban	>40MVA	No outage OK
	12-40MVA	30 minutes OK
	4-12MVA	3 hours OK
	<4MVA	8 hours OK
Rural	>40MVA	No outage OK
	15-40MVA	30 minutes OK
	10-15MVA	4 hours OK
	<10MVA	12 hours OK

In its Draft Decision, the AER appears to have applied the load thresholds and timeframes incorrectly in their assessment of some of Energex's augmentation projects. As an example, it appears that the AER interpreted that under the Safety Net for an urban substation, it would be acceptable that 11MVA would be without supply for 3 hours and 1 minute. This is an incorrect application of the Safety Net - rather, the expectation of the Distribution Authority is that at 3 hours and 1 minute the load that can be without supply is required to be lower than 4MVA. In section 4 below we've discussed how the application of the Safety Net applies to the specific projects that have been assessed by the AER. Appendix 1 gives further evidence to support our position that we have interpreted the Safety Net standard correctly.

2.5 Other Planning Criteria

In our analysis, we've applied a range of standards to identify network limitations that form the basis of our augmentation proposals. These standards are explained in detail on our Distribution Annual Planning Report, and the key elements in summary are:

- Safety Net: The safety net provisions arise from the Distribution Authority for Energex issued under section 195 of *Electricity Act 1994 (Queensland)*. These provisions mean that Energex will ensure, to the extent reasonably practicable, that it achieves its safety net targets as specified in the planning and design of its network.
- Minimum Service Standards (MSS): The MSS provisions arise from the Distribution Authority for Energex issued under section 195 of *Electricity Act 1994 (Queensland)*. These provisions mean that Energex must use all reasonable endeavours in the planning and design of its network to ensure that it does not exceed in a financial year the MSS.
- Voltage Limits: Energex uses a range of internal standards and modelling to ensure that voltage on the network complies with the provisions of the *Electricity Regulation 2006* pursuant to the *Electricity Act 1994 (Queensland)*, in relation to voltage.
- Distribution Feeder Utilisation: Energex has an internal Target Maximum Utilisation for distributions feeders. This utilisation figure has been designed to ensure that under outage conditions, adequate load transfers can be made between distribution feeders and between zone substations to enable supply restoration to occur to deliver Safety Net and MSS requirements.
- Fault Level Limitations: Energex plans its network to ensure that all plant and lines are able to withstand fault currents without causing damage to the equipment.

3 Other Changes Impacted our Revised Regulatory Response

3.1 Reduction in Weighted Average Cost of Capital (WACC)

As part of the Draft Decision, the regulated WACC has been reduced. Energex is now using 4.87% as its real vanilla WACC for its NPV analysis (2.62% real pre-tax). The effect of the reduction in WACC is to reduce the discounting of future cash flows, which lowers the value of deferring capital expenditure. This has had a particular effect on a number of business cases where the trade-off in lower upfront capital cost projects to delay larger investments is significant. Further discussion of the effect of the change in WACC can be seen in the discussions on each project and program below.

3.2 Revised Load Forecast

As part of Energex's standard business processes, a new load forecast was produced in August 2019 following the 2018/19 summer period. This forecast has seen an increase to loads in a number of areas that have resulted in possible additional forecast future augmentation projects within the next regulatory period. Consistent with Energex's Asset Management, Risk and Optimisation approach, Energex regularly reviews and re-optimises the program portfolio to address the highest risk items. The increase in load forecast following the 2018/19 summer period and resulting network limitations identified demonstrates that volatility in the mix of augmentation work will occur.

While additional projects could have been added as part of the RRP, Energex recognises that the regulatory proposal represents a snapshot in time, and we have carefully considered whether or not it is appropriate to update all projects consistent with our re-optimisation of the program. Such an approach would lead to significant additional work for both Energex and the AER.

Accordingly, Energex is not proposing to include these projects or increase its Augex proposal; rather we will manage the risk of these projects or others being required over the next regulatory period. This recognises that load forecasts change over time, and Energex does not want to put pressure on customer prices more than absolutely necessary to deliver good outcomes for its customers.

This is in the interests of both Energy Queensland and the AER so as not to create additional workload for both entities and to demonstrate to the AER that their feedback has been received and actioned from the draft decision.

The fact that these extra projects could have been added to our revised proposal, and we've chosen not to include them, reinforces that we do need the investments outlined below as part of the RRP. We are not seeking to arbitrarily increase our investments, rather we are genuinely of the view that our investment proposals are needed. The total forecast capex as set out in this Revised Regulatory Proposal is required to enable us to prudently and efficiently maintain our network and to comply with all regulatory and legislative instruments that we operate under. It will provide us with the flexibility to vary and re-prioritise the projects and/or programs as required in the 2020-25 regulatory control period.

4 Specific Projects and Programs

In its Draft Decision the AER identified some specific projects and programs that need to be addressed in our RRP. These projects are discussed below.

4.1 Sub-transmission Growth

4.1.1 Bells Creek Central zone substation

What the AER Found[2]: The AER found in its draft decision that there is a need for investment in the area and that there is a need for Bell's Creek Central in the medium term, however was concerned over the need for this significant substation in the 2020-25 regulatory period. The AER noted: *"that it is unclear how Energex has derived its forecasts, how they compare with historical loads, or what assumptions Energex has made about future energy efficiency improvements"*.

What We've Done: We've thoroughly reviewed our investment proposal, reconsidering the options based on AER's feedback and introduced a further option for analysis. Our further work includes the following:

- We've re-written this business case and provided a clear and succinct examination of the need for investment and the linkages to the NER capex criteria.
- We've re-done the NPV analysis to address the AER's concerns, including a detailed sensitivity analysis, and Value of Regret Analysis.
- We've done a bottom up estimation on the 11kV feeder option proposed by the AER to more rigorously examine this option.
- We've re-examined the demand growth for the Aura development, including an analysis of After Diversity Maximum Demand (ADMD), taking into account future energy efficiency improvements. Energex modelled an ADMD of 1.6kVA/dwelling. In discussions with the AER on 7th August 2019, the AER accepted that the volume of dwellings being completed was a reasonable forecast of expected customer growth but required more information on how the ADMD was determined and how Energex has incorporated potential reduction in demand. In the Revised business case, Energex have outlined that the ADMD for the two existing feeders currently supplying the initial stages of Aura are at 1.8kVA and 2.9kVA. The ADMD that Energex has modelled under its Medium Growth case has assumed that the ADMD will be 60% of the current ADMD for the area. Energex considers that this reduction in ADMD from the historic values for the area constitutes a conservative approach about future energy efficiency improvements for the area.
- The reduction in WACC as part of the AER's Draft Decision has had a material impact on the NPV for the Bell's Creek Central planning proposal, reinforcing that the proposed substation establishment has a significant NPV advantage over other options.
- Full details are provided in the business case for this project.

Cost Change Summary: The direct cost of the project remains unchanged at $28.6M.

[2] AER Draft Decision comments have been summarised, rather than repeated in full

4.1.2 Abermain to Amberley

What the AER Found[3]: In its Draft Decision, the AER suggested that *"load shedding would be appropriate to manage a contingency event. Further, Energex could develop operational planning procedures for restoring load for various scenarios."* Energex agrees that is an acceptable solution to the limitation described, however does not agree that an operational strategy would suitably address this limitation.

What We've Done: We've thoroughly reviewed our investment proposal, reconsidering the options based on AER's feedback and introduced a further option (automated load shedding) for analysis. Our further work includes the following:

- We've re-written this business case and provided a clear and succinct examination of the need for investment and the linkages to the NER capex criteria.
- We've re-done the NPV analysis to address the AER's concerns, including a detailed sensitivity analysis, and Value of Regret Analysis.
- We have included an Option 3 as part of its revised planning proposal for an automatic load shedding scheme.
- We have thoroughly reviewed the load forecast for this proposal including a potential block load increase in the area.
- Full details are provided in the business case for this project.

Cost Change Summary: The direct cost of project remains unchanged at $8.5M.

4.1.3 Doboy to Queensport

What the AER Found[4]: In its Draft Decision the AER stated that *"we reviewed the relevant Safety Net target, and found that the relevant target is to have no greater than 12 MVA without supply for more than 3 hours".* The AER also stated *"that the planning proposal does not adequately establish that the alternative solutions are unfeasible as it has stated".*

What We've Done: We've thoroughly reviewed our investment proposal, considering the AER's feedback. Our further analysis and revised business case includes the following:

- We've re-written this business case and provided a clear and succinct examination of the need for investment and the linkages to the NER capex criteria.
- We've re-done the NPV analysis to address the AER's concerns, including a detailed sensitivity analysis, and Value of Regret Analysis.
- Energex has thoroughly reviewed the load forecast for this proposal including a potential block load increase in the area.
- Energex believes that the AER incorrectly applied the Safety Net in its review. The correct application is detailed in the revised business case.
- The proposed solution is a single stage option that once complete does not require any further network augmentation. As such, the only options that would be considered legitimate alternatives are those that are cost competitive. Energex identified a number of alternative options that are simply longer versions of a 33kV feeder without any other benefits. As such, these are technically feasible, however are not commercially feasible. In its revised business case, Energex have added further information on each of these options, including cost estimate details.

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[3] AER Draft Decision comments have been summarised, rather than repeated in full

[4] AER Draft Decision comments have been summarised, rather than repeated in full

- Full details are provided in the business case for this project.

Cost Change Summary: The direct cost of the project remains unchanged at $5.1M.

4.1.4 Establish Petrie zone substation

What the AER Found[5]: In its Draft Decision, the AER stated that for Kallangur zone substation *"after load transfers, forecast remaining load without supply is 2.4 MVA after eight hours in the event of an outage. However, the Safety Net requires unsupplied load to be less than 12 MVA after three hours, and less than 4 MVA after eight hours"*.

The AER also stated that "*Energex's preferred option does not account for the replacement cost of two transformers at SSKLG expected to reach the end of life in 2029. Energex's preferred option including this extra cost is $4.5 million higher and is not the least cost option"*.

What We've Done: We've thoroughly reviewed our investment proposal, considering the AER's feedback. Our further analysis and revised business case includes the following:

- We've re-written this business case and provided a clear and succinct examination of the need for investment and the linkages to the NER capex criteria.
- We've re-done the NPV analysis to address the AER's concerns, including a detailed sensitivity analysis, and Value of Regret Analysis.
- We believe that the AER incorrectly applied the Safety Net in its review. The correct application is detailed in the revised business case.
- In addition, we described a further driver that the 10PoE load was greater than the NCC rating of the substation, meaning that the substation is unable to supply peak load under system normal conditions.
- SSKLG currently has three transformers, two of which are forecast to require replacement in 2029 which the AER have accepted as a network limitation. Option 1 establishes Petrie zone substation to supply the new Mill at Moreton Bay development. The effect of establishing Petrie zone substation is that SSKLG will only require two transformers to supply its forecast load. In simple terms, the total transformer capacity for the area will increase as a result, meaning that we will only be required to replace one (instead of both) of the transformers at SSKLG.
- Full details are provided in the business case for this project.

Cost Change Summary: The direct cost of the program remains unchanged at $5.5M.

4.2 Power Quality

What the AER Found[6]: In its Draft Decision, the AER found:

- Energex proposed a total of $42.4M, including Power Quality (PQ) monitoring $17.4M, customer voltage remediation $13.1M, solar PV augex $11.9M.
- AER accepted expenditure proposals for voltage remediation and solar PV augex.
- AER rejected the PQ monitoring expenditure because Energex did not demonstrate the prudency and efficiency of the program based on the following concerns:
    - Energex assumed that each new PQ monitoring device would deliver a $1600 annual saving through avoiding quality of supply investigations. The AER asserted that Energex did not provide evidence to support this amount and that the average annual benefit of a monitor is $90.
    - Energex identified that it could avoid the installation of some voltage regulators and

[5] AER Draft Decision comments have been summarised, rather than repeated in full
[6] AER Draft Decision comments have been summarised, rather than repeated in full

distribution transformer tap adjustments as a benefit of PQ monitoring. The AER asserted that PQ monitoring could not reduce these needs.
    - The AER identified that Energex did not include operational costs associated with PQ monitoring programs.
    - The AER asserted that Energex compared the benefits against the capital cost rather than the annualised capital cost.

What We've Done: We've thoroughly reviewed our investment proposal, considering the AER's feedback. Our further analysis and revised business case now includes the following:

- We've re-written this business case and provided a clear and succinct examination of the need for investment and the linkages to the NER capex criteria.
- We've re-done the NPV analysis to address the AER's concerns, including a detailed sensitivity analysis, and Value of Regret Analysis.
- We've provided more detail on the basis for justifying the savings delivered from PQ monitoring.

Cost Change Summary: The direct cost of the program remains unchanged at $44.1M.

4.3 Network Communications

We proposed some $64.8M for network communications, protection and control projects. AER examined two major sub-categories as below and reduced the allowed expenditure for the total program to $23.2M. These two programs are discussed below.

4.3.1 Intelligent Grid Enablement

What the AER Found[7]: In its Draft Decision, the AER found:

- Energex has not justified the proposed program of $36.8M based on the concerns:
    - Energex has not clearly identified the need for the program and has not provided a NPV analysis showing how the benefits exceed the costs.
    - Energex has not provided enough information to show that the program is prudent and efficient.
    - AER has concerns about the base case assumptions.
    - Energex has not explained the interdependencies between this program and other programs such as ADMS and LV monitoring.

What We've Done: We've thoroughly reviewed our investment proposal, considering the AER's feedback. Our further analysis and revised business case includes the following:

- We've re-written this business case and provided a clear and succinct examination of the need for investment and the linkages to the NER capex criteria.
- We've re-done the NPV analysis to address the AER's concerns, including a detailed sensitivity analysis, and Value of Regret Analysis.
- We've provided more detail on the basis for justifying the savings delivered from this program.
- We've written another paper (Energy Queensland Smart Network Overview) that explains the linkages between this business case and other related Intelligent Grid programs.

Cost Change Summary: The direct cost of the program has decreased from $36.8M to $30.2M.

[7] AER Draft Decision comments have been summarised, rather than repeated in full

4.3.2 Backup Protection Reach

What the AER Found[8]: In its Draft Decision, the AER found:

- Energex has not justified the proposed program of $18.9M based on the concerns:
    - Energex has identified the program based on a desk-top assessment only – field measurements are required to validate this assessment and demonstrate that the investment is prudent.
    - Energex has not provided enough evidence of the shortfall in protection coverage.
    - Energex's proposal provides duplicate protection on individual distribution feeders. It is AER's view that this is not required under the AER and duplication is only required in cases were protection failure can lead to instability of the network.
    - Energex has not identified why low cost solutions downstream will not work.

What We've Done: We've thoroughly reviewed our investment proposal, considering the AER's feedback. Our further analysis and revised business case includes the following:

- We've re-written this business case and provided a clear and succinct examination of the need for investment and the linkages to the NER capex criteria and the NER protection requirements. We are of the view that AER's interpretation of the NER protection requirements are incorrect.
- We've re-done the NPV analysis to address the AER's concerns, including a detailed sensitivity analysis, and Value of Regret Analysis.
- We've shown how we have considered a range of options in regard to delivering prudent and efficient solutions to this compliance obligation.

Cost Change Summary: The direct cost of the program remains unchanged at $18.9M.

[8] AER Draft Decision comments have been summarised, rather than repeated in full

Appendix 1 – Energex's Safety Net Interpretation Justification

1 Introduction

Discussions with the AER subsequent to the Draft Decision suggest that the AER has a different interpretation on the how the safety net targets are to be applied in the planning and development of our network augmentation. The safety net target was introduced into our Distribution Authority on 30 June 2014. There have been two subsequent amendments in 22 March 2016 and 3 October 2019. However, the Safety Net Target as set out in Schedule 3 has remained unchanged.

We believe that our proposed augex is prudent and efficient based on our interpretation of the Safety Net Targets as set out in Schedule 3 of our Distribution Authority.

We provide below some evidential justification of how and why we believe that our interpretation is in accordance with the intent of our Distribution Authority.

2 Comparison and Intention of the Energex and Ergon Safety Net

Both the Ergon and Energex Safety Net provision have the same intention to enable high consequence, low probability events to be planned for under the planning criteria. Extracts of the Safety Net Targets for each business are set out below. It should be noted that in the Ergon Safety Net, there is an explicit requirement that all load be restored.

Energex's Safety Net targets

SCHEDULE 3

Service Safety Net Targets

Feeder Type	Targets
CBD	• Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute
Urban – Following an N-1 event	• no greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • no greater than 12 MVA (5,000 customers) is without supply for more than 3 hours; and • no greater than 4 MVA (1,600 customers) is without supply for more than 8 hours.
Short Rural – Following an N-1 event	• no greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • no greater than 15 MVA (6,000 customers) is without supply for more than 4 hours; and • no greater than 10 MVA (4,000 customers) is without supply for more than 12 hours.

Note: All modelling and analysis will be benchmarked against 50 POE Loads and based on credible contingencies.

[as inserted on 30 June 2014]

Ergon Energy's Safety Net Targets

SCHEDULE 4

Service Safety Net Targets

Area	Targets (*for restoration of supply following an N-1 Event*)
Regional Centre	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour; • Less than 15MVA (6000 customers) after 6 hours; • Less than 5MVA (2000 customers) after 12 hours; and • Fully restored within 24 hours.
Rural Areas	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour; • Less than 15MVA (6000 customers) after 8 hours; • Less than 5MVA (2000 customers) after 18 hours; and • Fully restored within 48 hours.

Note: All modelling and analysis will be benchmarked against 50 POE Loads and based on credible contingencies.

'Regional Centre' relates to larger centres with predominantly urban feeders.
'Rural Areas' relates to areas that are not Regional Centres.

[as inserted on 30 June 2014 and 16 September 2014 and further amended on the date shown on page 14 herein]

Under the AER's interpretation of the Energex Safety Net, it would be allowable to leave up to 4MVA (Urban) and 10 MVA (Short Rural) without supply indefinitely. This is clearly a contradiction with the stated outcome of the Safety Net and does not align with the Ergon version. As such, the final line of the Safety Net criteria "no greater than 4MVA without supply for no longer than 8 hours" should be read as the equivalent to requiring full restoration in this period. Under the AER's interpretation, it would appear that a more onerous Safety Net Targets would apply to the Ergon's network than to Energex's network.

Furthermore, under the AER's interpretation there would be no limit to the amount of load unsupplied following a contingency event, which would not appear to be consistent with the intention of catering for high consequence events. Given these contradictions in the Safety Net requirements, it is clear that the AER's interpretation does not align with the intention of the Safety Net obligations.

3 Ergon Energy Analysis and Correspondence

The two attached documents are correspondence between Ergon Energy and Department of Energy and Water Supply (DEWS); the predecessor to the Department of Natural Resources, Mines and Energy (DNMRE). Ergon's letter of 1 August 2014 sets out its proposal and application of safety net. The letter of 26 August 2014 from the Department confirmed and accepted the proposal as set out in Ergon's letter.

In the letter, Ergon provided an analysis of the comparison of the Safety Net obligations for Energex and Ergon and included the table below.

When compared this proposal with the Energex Safety Net the comparison is shown below:-

Ergon Energy Safety Net	Energex Safety Net
CBD	**CBD**
N/A	CBD restored in less than 1 min
Regional Centre	**Urban**
	Between 12MVA and 40 MVA restored in less than 30 mins
Between 20 MVA and 40 MVA restored in less than 1hour	
	Between 4MVA and 12MVA restored in less than 3 hours
Between 15 MVA and 20 MVA restored in less than 6 hours	
	Less than 4 MVA restored in less than 8 hours
Between 5 MVA and 15 MVA restored in less than 12 hours	
Less than 5 MVA restored in less than 24 hours	
Rural / Remote	**Rural**
	Between 15MVA and 40 MVA restored in less than 30 mins
Between 20 MVA and 40 MVA restored in less than 1 hour	
	Between 10MVA and 15MVA restored in less than 4 hours
Between 15 MVA and 20 MVA restored in less than 8 hours	
	Less than 10MVA restored in less than 12 hours
Between 5 MVA and 15 MVA in less than 18 hours	
Less than 5 MVA in less than 48 hours	

It is clear from this table that the interpretation that we have taken from the Distribution Authority Safety Net is the expectation from the Department. As an example, the intention that the amount of load that can be left unsupplied for the first 30 minutes is between 12MVA and 40MVA.

Ltr from Ergon Energy Revised Safet

Letter to Ergon Energy re Safety Net

4 Energex Department Correspondence

The attached letter from us to the Minister Mark McArdle outlines Energex's interpretation and application of the Safety Net. Importantly, there is a subtle wording difference in our response which removes the ambiguity around the time thresholds. Specifically, rather than specifying the timeframes as "no more than", we have clarified the meaning to be "without supply for".

The attached letter also references the Customer Outcome Standard, which is our planning manual which outlines our application of the Safety Net criteria. The current version of this document has also been attached.

Queensland Government Reforms

Energex Security Standards - COS.pdf

5 2015-20 Regulatory Proposal

The Safety net target was discussed as part of the 2015-20 distribution determination. Neither the AER nor its consultant (EMCa) raised an issue with our interpretation. As the safety net targets remain unchanged since 1 July 2014, we have applied the same and consistent interpretation of the safety net targets in our 2020-25 Regulatory Proposal and this Revised Regulatory Proposal.

6 Distribution Annual Planning Report (DAPR)

Clause 5.13.2 of the National Electricity Rules (NER) clause 5.13.2 requires us to prepare and publish a Distribution Annual Planning Report (DAPR).

The aim of a DAPR is to inform network participants and stakeholder groups about development of the Energex network, including potential opportunities for non-network solutions – particularly for large investments where the AER Regulatory Investment Test for Distribution (RIT-D) applies.

We have consistently published our application of the Safety Net in each of our DAPRs since it was introduced. Specifically, Appendix C of the 2017 and 2018 DAPR (available here) outlines our application of the Safety Net. We have adopted the same application in our Regulatory Proposal and this Revised Regulatory Proposal.