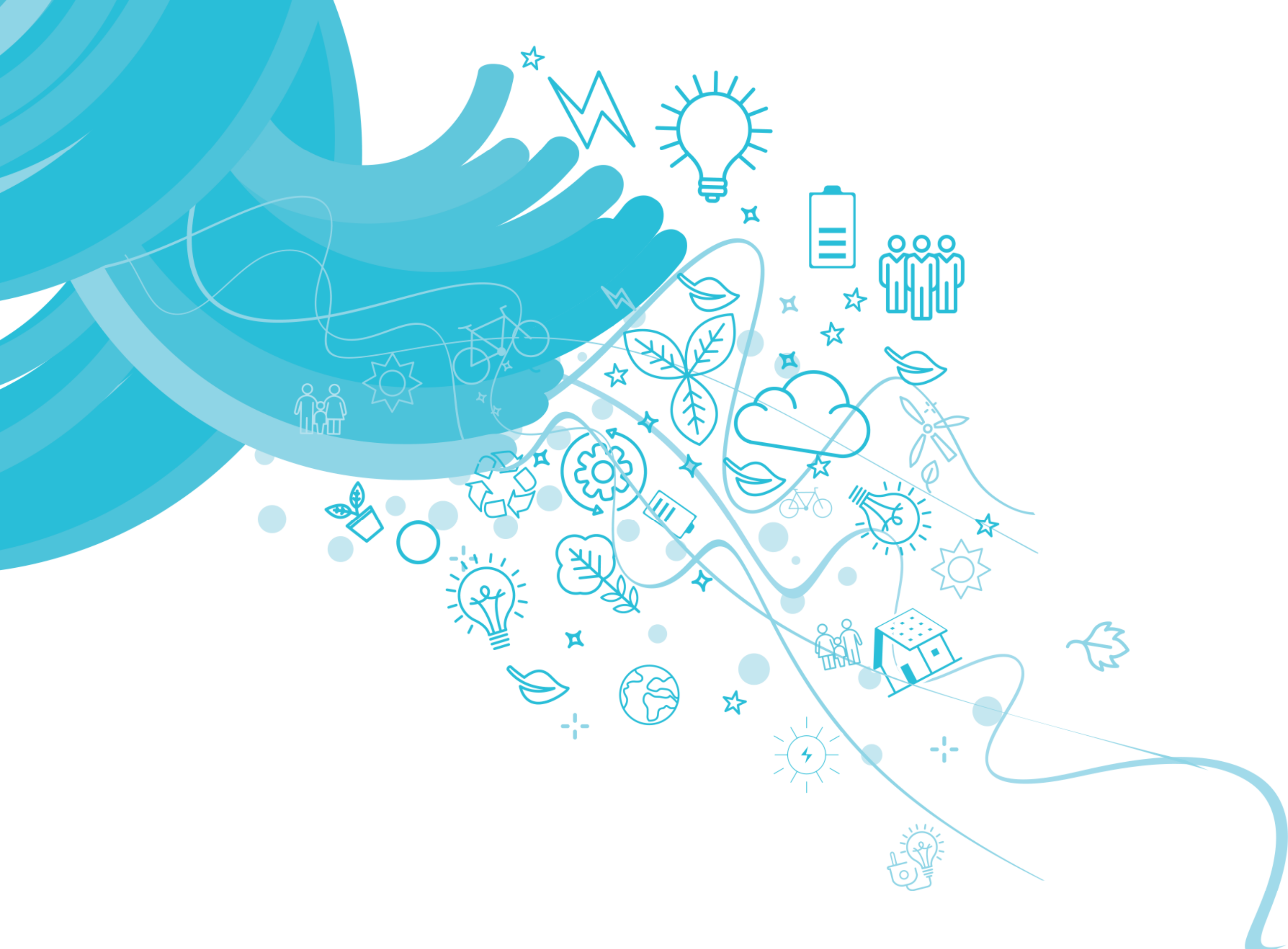
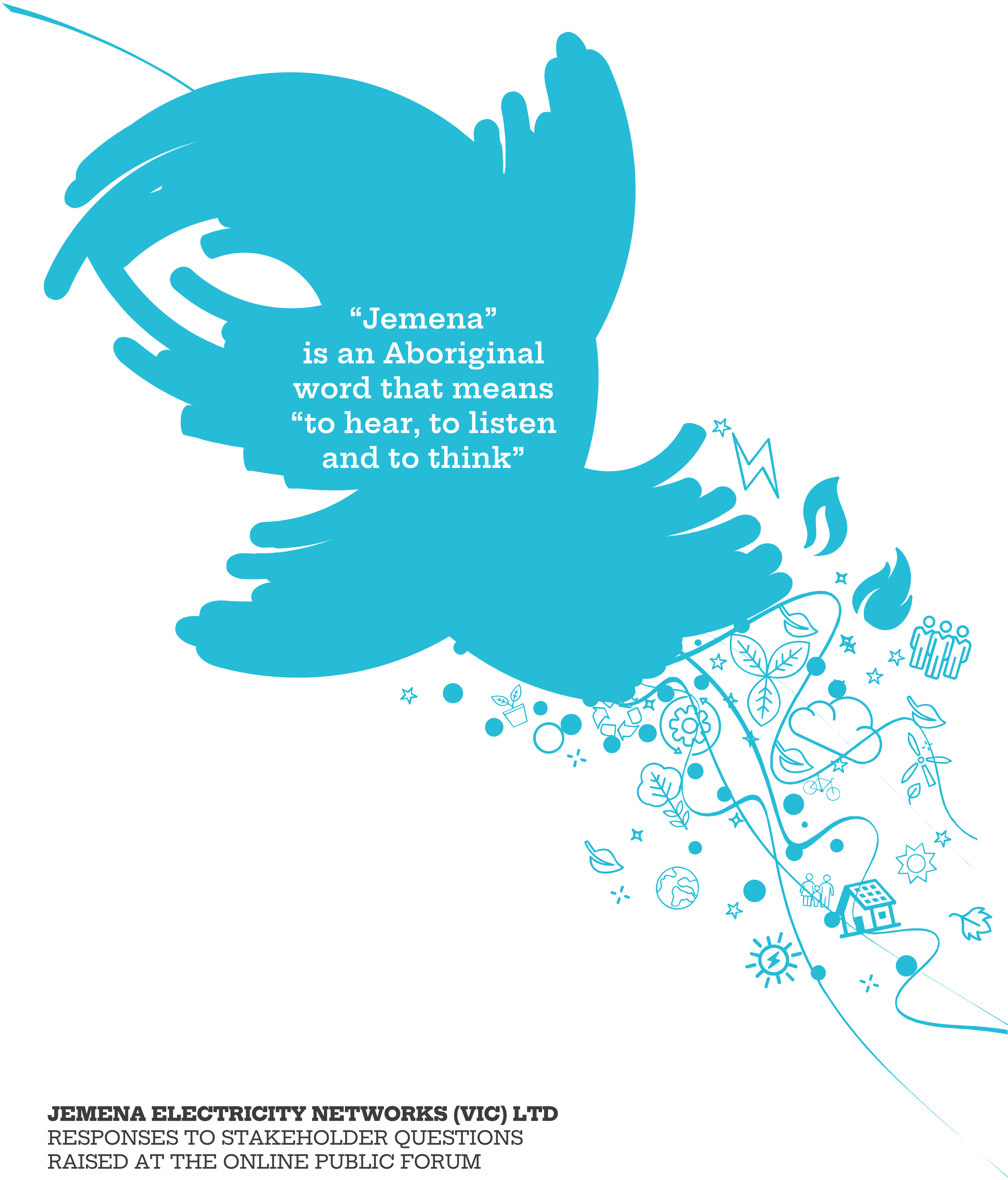
JEMENA ELECTRICITY NETWORKS

VICTORIAN EDPR 2021-26 ONLINE PUBLIC FORUM RESPONSES



MAY 2020

Jemena
bringing energy to life



JEMENA ELECTRICITY NETWORKS (VIC) LTD

RESPONSES TO STAKEHOLDER QUESTIONS RAISED AT THE ONLINE PUBLIC FORUM

Contents

1. Introduction

Jemena’s approach

As a part of the process for assessing the price review proposals of electricity distribution businesses, the Australian Energy Regulator (AER) holds a forum where network businesses, the AER and stakeholders have an opportunity to present to the public. It also provides an opportunity for stakeholders to ask questions of the network businesses.

In this round of price reviews, social distancing requirements has meant that a public forum could not be held, and instead, the presentations have moved to an on-line format. On 22 April 2020, the AER released Jemena's public form presentation onto their website. A link to Jemena's presentations can is (here).

This also meant that the way questions were asked and responded to also had to change. In this process, the AER collated questions from stakeholders and asked us to respond to them. This document outlines those questions and includes our response.

2. Responses to Questions

Answering our stakeholders

Received from	Topic	Question	Response
Dr Judith Landsberg Chair, Village Power		Jemena says they want to encourage DER and in order to do this are upgrading software and sub-stations (to reduce local congestion). There appears to be little consideration of absorbing the afternoon solar peak using distributed (community) batteries to provide a more efficient response to increasing local solar energy than up-grading substations. This approach has been recommended by the WA grid as a vital component of future distributed energy resources. Furthermore it sounds like this is what the community wanted '*we consistently heard that our customers want us to green the grid*' (Future Network: Customer Engagement). The current network tariffs charged by Jemena and other networks penalise local trading by effectively doubling the network charge as energy is fed into the battery and then returned to consumers. In effect the current tariffs actively discourages community batteries and local energy trading. Is there scope to change this tariff policy or at least introduce special tariffs for community batteries and local energy trading?	It is important that the incentives provided for the use of community batteries align to positive outcomes for all our customers, especially where its operation extends beyond the community and uses the shared network. These incentives could occur contractually or via a price signal. In terms of price signal, JEN's tariff proposal includes options that a community battery could benefit from, including demand charges and time of use charges that provide an incentive to charge before 3pm and discharge between 3-9pm. In terms of contractual or other solutions, we recognise that local trading and incentives for community batteries is a very topical discussion, and more thinking across the energy sector is required to ensure long term outcomes that benefit customers and society. For example, these issues are being considered by the Energy Security Board's two-sided markets review and the Distributed Energy Integration Program (DEIP).
CCP17 (questions for all DNSPs)	Prices and reliability	Consumer engagement has consistently shown that consumers want price reductions and are happy with current reliability levels. The DNSP's have shown that reliability measures are generally improving while repex spending remains a significant proportion of total capex spending. Is price the main driver for considerations of reliability related spending?	Price implications of investments are a consideration in reliability planning, however, the main driver for reliability-related spending is maintaining the current levels of service and risk. Through our engagement, customers directed us to continue with existing practices of ensuring safety risks are as low as practicable, and customer supply risks are maintained at existing levels. To ensure customers understood the price versus reliability trade-offs inherent in reliability planning, we presented them scenarios for improving, maintaining or reducing reliability, together with the associated price impacts of these scenarios. Initially, our People's Panel cohort was divided between maintaining and improving reliability. They ultimately landed on recommending we maintain current levels of reliability, but challenged us to continue to find ways to invest in ways that should see the customer experience improving, as has occurred with our use of AMI data to be faster at responding to outages.

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	RAB Growth	We understand that proposed real RAB is growing for all 5 DNSP's over the next regulatory period. RAB per customer is set to decline for some DNSP's. Expecting that WACC will increase again, quite possibly during 2021-26, what impact would rising WACC have on customer bills?	Our proposal is guided by the objective of addressing affordability concerns of our customers and one way of doing that is to remain focused on a low growth in RAB per customer. Our proposal shows that it is expected to increase by an an average of [x%] driven by x,y,z. A view that WACC will increase over 2021-26 is not assured. The regulatory WACC allowances are based on market conditions that would exist in the averaging period approved for a DNSP and these may result in higher or lower allowances and customer bills. We consider that movements in market conditions—which are outside of Jemena's control—are automatically reflected through the mechanisms in the AER's rate of return guideline and these will ultimately be reflected in customers' bills.
	Asset lives	Is there a standard set of asset lives (and depreciation rates) for all businesses? If not, why not?	Every business has approved standard lives for different asset categories – these categories may sometimes differ as well. The weighted asset live for a particular asset category could differ across businesses due to different asset mix within asset categories – for example, some businesses may have more rural infrastructure and some more urban, etc.
	Opex	What were the criteria that were taken into account to determine that the proposed base year is efficient?	Jemena applied AER's benchmarking techniques (including partial performance indicators, multilateral productivity and econometric methods) as well as performing a comparison to its regulatory allowances to ensure that the base year proposed is efficient and suitable for forecasting opex for the next regulatory period. (Refer to section 4.4 of our opex chapter for more details).
	Step changes	How do each of the various proposed "step changes" meet step change criteria?	The operating expenditure criteria [NER 6.5.6(c)], requires that the cost be prudent, efficient and realistic. For each step change proposed, we have only included new obligations that we cannot avoid or change in the market where Jemena has no ability to influence. In all case, we have considered the options available, through market testing and options analysis, and have only included those costs that we believe meet the operating expenditure criteria.

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	Efficiency	Multifactor productivity analysis (benchmarking) shows a declining utilisation of the network. Does this suggest that there is scope for greater efficiency of network utilisation without more spending, particularly on capital programs?	Multifactor productivity analysis measures the change in productivity (output produced per unit of labour and capital input) over time. It does not provide any useful measure of network utilisation. However, Grattan Institute undertook independent work on network investment where it benchmarked network utilisation for Australian DNSPs.[1] Grattan defined network use as the aggregate growth in customer numbers and growth in maximum demand. They measured network utilisation as the increase in RAB relative to growth in network use which indicates the highest network utilisation for JEN (figure 3.2 of the report). Figure 2.6 in the same report also shows that JEN's RAB growth aligns closely to the growth in demand, implying a high network utilisation rate.
	Efficiency	Can an efficient business and a high EBSS payment for that business co-exist? What factors could lead to such an outcome?	It is possible for an already efficient business to continue reducing costs through innovation and improvements in productivity and receive EBSS payments for doing so.
	Repex	We are not clear on the status and impact of the ESV report into pole failure risk in Powercor. It appears that the CPU group are approaching this report as a mandatory requirement. Could the DNSPs please be clear what activities undertaken as a direct result of mandatory (legislative and regulatory) bushfire mitigation requirements, and which are being undertaken for other reasons?	The Electricity Safety (Bushfire Mitigation) Regulations 2013 contain a number of specific actions which must be undertaken (e.g. installation of REFCLs, vibration dampers and armour rods) as well the requirement to develop a Bushfire Mitigation Plan which must be accepted by Energy Safe Victoria. JEN's Bushfire Mitigation Plan contains a number of programs (e.g. relating to Electric Line Clearance, Poles in Hazardous Bushfire Risk Areas (**HBRA**), installing crossarms in HBRA, overhead conductors in HBRA) ensuring we have appropriate controls in place to manage bushfire ignition risks.
	DER Integration	Analysis from CCP17 and ECA suggests that the costs to integrate DER are similar to, or perhaps even higher than, utilities elsewhere who already have higher DER penetration. We would expect that	AMI data provides us with extensive insights into the issues that high levels of DER penetration create. From this AMI data we are able to identify customers who are experiencing high/low voltages, as well as

[1] Grattan Institute, *Down to the write: A sustainable electricity network for Australia*, March 2018.

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		with the quality and quantity of data available through AMI which provides extensive insights into customer terminal voltage, phase balance and the like, this would provide an almost unique opportunity to efficiently reduce some of the impacts, make better risk management decisions and provide a platform for innovative voltage management. Such opportunities are not clear in the proposals, especially in leading to lower DER integration costs and innovative grid voltage management. Would the distributors care to comment on this observation?	customers with high impedance connections (which we use a part of our service replacement program). However, the AMI data does not in itself make the network capable of receiving higher levels of export from DER customers. Our Future Grid Investment Proposal is based on a strategy of developing Low Voltage (**LV**) network modelling tools (using both AMI data and LV circuit/distribution substation asset data) to enable us to determine what is the most prudent and efficient approach to increasing DER hosting capacity (i.e. minimising DER export constraints) for each LV circuit and distribution substation in our network, noting that there is not one solution for them all. This foundation piece of work, which is needed before we start upgrading the network to enable more DER, will require investment in our AMI systems, as well as upgrades, process changes and data capture/validation on our asset data systems GIS and SAP. Developing these LV network models will ultimately improve our customer connections, operations and network planning processes in the future, when other technologies (e.g. electric vehicles) are connected to the network.
	DER Integration	DER integration costs centre almost exclusively on managing voltage rise above legislated limits. Could the distributors comment on analysis that may have been done to implement advanced grid voltage management strategies or even voltage reduction. We also note that some utilities have offered voltage reduction as a demand response or market response opportunity, suggesting voltage reduction is possible. The change in household appliances suggests sensitivity to low voltage may be less than it has been in the past. Have distributors considered the risk and costs of reducing grid voltage and addressing low voltage issues as an alternative or delaying option to investing as widely in customer controls and LV augmentation? Have any trials to do so been considered or undertaken?	JEN has investigated various voltage management strategies and has determined that distributed voltage control is required to enable the increasing levels of DER penetration, as voltage regulation only at the zone substation level is inadequate. At our Coolaroo zone substation, which supplies several new estates in the Northern Growth Corridor, we have some customers experiencing DER inverter trips due to high voltages. In this situation, we identified that existing voltage control systems (e.g. ZSS voltage setpoints & LDC, and distribution transformer tapping) are unable to be configured to keep all customers in the supply area within the maximum and minimum voltage limits. We have also observed different LV circuits supplied from our Sunbury zone substation experiencing high volts and low volts, at the same time.

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	Forecasts	How material is the disparity between the business's load forecast and AEMO forecasts, and what are the reasons for and implications of the disparity?	Each year JEN undertakes a comparison of the AEMO transmission connection point forecasts against the forecasts developed by our independent consultant. AEMO's 2019 summer POE10 connection point forecasts for Victorian predict demand growth at terminal stations BTS, SMTS, TSTS, KTS and WMTS, and declining demand at terminal stations BLTS and TTS. This outcome is consistent with our forecasts.
	Sensitivity analysis	In these difficult and very uncertain times no doubt the distributors are looking at their forecasts (customer growth, major infrastructure projects, demand growth, energy delivered and cost inputs) very closely. We recognise that there will be an opportunity to revise forecasts at the revised proposal stage. Can the AER and the distributors provide some insight into the key environmental variables they are watching, and what mechanisms they will be employing to revise the forecasts as necessary?	We are keenly watching out for the impacts of the current environment on many fronts. Our immediate concern is on the health and safety of our customers, contractors and staff, and we are making operational changes to address these. From an industry support point of view, we have developed a relief package to respond to the current situation, this will help to alleviate the stresses in the industry and get us all through the current challenges. With the situation changing rapidly, it is too early to make a statement around changes to our regulatory proposal because of the impacts of Covid-19.
	Demand Management	Apart from those already outlined in opex step changes, could you provide information about the business's Demand Management programs for 2021-26, and how that differs from current programs?	JEN is not proposing any step changes associated with Demand Management programs, or any specific Demand Management projects in the next regulatory period. When developing our forecast capital projects for 2021-26, JEN tested a variety of non-network options for load-driven augmentation projects and zone substation transformer and switchgear replacement projects. This analysis did not identify any demand management projects which could economically defer these investments. During the next regulatory period, at the time of these projects being initiated, we will again test non-network alternatives as part of regulatory investment test and internal processes, recognising that

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			Demand Management and other non-network technologies continue to evolve rapidly and can be deployed outside of a price reset process. JEN will also continue to trial various demand management initiatives under the Demand Management Innovation Allowance Mechanism, with the aim of identifying viable demand management opportunities in the future.
	Consumer Engagement	Recognising that COVID-19 has dramatically appeared since revenue proposals were lodged, we would like to know what plans the individual businesses have for engagement in a setting where face to face engagement is likely to be constrained for a while yet? (Note that CCP17 believes that consumer and stakeholder engagement remains essential, but that the methodologies for some engagement will need to be adapted.)	Our customer engagement is a centre-piece in developing our proposal, and we have every intention of continuing this through to the final decision stage. However, the rapid and significant changes requiring social distancing will make this objective more difficult to achieve. Moving forward, we will seek to engage customer groups through the robust and reliable channel we have developed, along with the on-going use of our customer council. We continue to maintain our relationship with members of the Peoples Panel through social media and through the jemena.yourgrid.com.au website, which is a channel that these members are accustomed to.
CCP17 (questions for AusNet, Powercor and Jemena)	REFCL benefits	Significant investment has been made in REFCL technologies, along with a long history of other bushfire mitigation investments (sparkless fuses, reclosers and the like) to address fire risk. In addition, we note in the proposals the significant investment and operating costs associated with the need to manage and operate the REFCL systems, address the reliability degradation consequential to these installations and to update plant and equipment that no longer operates as required a result of the REFCL impact on the network. We certainly note the community benefits of the REFCL investment, and do not seek to revisit any cost/benefit considerations associated with this initiative. However, two things would greatly assist consumers' assessment of the DNSP proposals, being: (a) A consolidated view of the aggregate cost of the REFCL program and related expenses, and (b) clarity as to how the DNSPs have changed their approach to evaluating the residual BFM risk that drives their capital program as a result of the installation of the REFCLs? Can	A consolidated view of JEN's proposed REFCL program expenditure during the 2021-26 regulatory period is provided below (real June 2021 dollars, excluding overheads): Capital expenditure: $43.3M Operating expenditure step change: $1.3M Total expenditure: $44.6M Once JEN installs, commissions and has some operational experience with the REFCL installed to meet our bushfire mitigation obligations at our Coolaroo Zone Substation (by May 2023), we will assess the impact this may have on the residual bushfire mitigation risk in this area. Because the deployment of REFCLs to mitigate bushfire risk to the specification mandated in Victoria is new and has not been previously undertaken internationally, until we gain this operational experience

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		the DNSPs point to cost benefit analyses for work proposed to address BFM risk that have changed since the installation of the REFCL systems?	we are unable to comment on what impact having the REFCL will have on other bushfire mitigation programs. We do, however, note that the risks associated with asset failure (e.g. poles or crossarms) in the HBRA will remain even with a REFCL installed, with *some* risk consequences being reduced.
	Capex	The expenditure on REFCL technology has been significant, and the benefits in the reduction of bushfire start risk are noted. However, the large 'lumpy' expenditure on REFCL projects, in both the current and the next regulatory period, makes a 'top down' assessment of the capital investment proposals difficult. Would the DNSPs consider reframing their capex build-up and current period / proposed comparisons with the REFCL expenditure split out for clarity?	Our Proposal Attachment 05-01 presents our forecast REFCL capital expenditure separately to other programs and subcategories.
Brotherhood of St Laurence, Renew and VCOSS		A large cost item in the DER plan is the replacement of transformers, and sometimes other LV assets. Replacing transformers appears to differ from the augmentation proposed by Ausnet Services, who are proposing to replace old type ZSS and line regulator VRRs with 2-way models, as well as LV reconductor work and split circuits. Why has Jemena determined that transformer replacement is required, rather than VRR replacement? Are these transformers being replaced to accommodate a larger (reverse) peak flow, or are they being replaced for specific functionality reasons (Eg 2-way flow)?	There are a number of different technical strategies and solutions which can enable more DER to be connected to the grid. Once JEN has developed our LV network modelling tools, we expect that most of our existing DER constraints will be addressed by replacing LV circuit joints, rebalancing and reconfiguring the LV network, and installing LV voltage regulation assets—with these solutions likely similar to those which the other Victorian distributors may implement. Replacing or adding new distribution transformers is one of the more costly solutions to enable DER, but remains part of our toolkit when individually assessing each identified network problem. There will likely be some instances (with particularly high levels of DER penetration) where the most prudent and efficient solution may be to replace or install a new distribution transformer. Given the relatively low levels of DER penetration for most of our network, we have not included replacement or augmentation of any HV feeder or ZSS assets in our forecast capital expenditure—however we note that each distributor may face different levels of DER penetration and different technical challenges.

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		Do you expect solar exports to the HV network to lead to constraints on the HV network? How will this be managed?	Our forecasts of DER penetration suggest we are unlikely to see HV network constraints during the 2021-26 regulatory period. We may be required to modify some of our HV protection settings, and possibly replace some of our HV circuit reclosers to be by-directional. Nonetheless, our focus during the next regulatory period is on the LV network.
ECA, all DNSPs	DER integration	Both the ECA and CCP17 have carried out some broad-brush analysis regarding the cost of integrating Distributed Energy Resources. This is useful analysis, and we appreciate the ECA also exploring this area. It is difficult to draw a conclusion as to the actual cost of DER integration as the costs are often spread across a number of categories (Augex, ICT capex, opex, innovation, LV remediation). Whilst the findings draw similar conclusions, we note some differences in the output of the analysis. CCP17 is happy to share the calculations behind our analysis. Our questions are: a) Could ECA share their analysis to help understand the different analytical approaches taken by ECA and CCP17? b) Could the utilities comment on the findings?	JEN notes that two of the capital expenditure items included in its total (the 'Optimised Asset Investment' projects under the augmentation and non-network IT categories) do not relate to DER integration or hosting capacity (despite forming part of our broader 'Future Grid' program). The objectives and drivers of our Optimised Asset Investment initiative are explained in Proposal Attachment 05-01. Once this initiative is excluded, JEN's DER integration capex per customer using the other information contained in the CCP's email is $69 (opex per customer unchanged). We echo the views of the CCP that there are different issues and concerns that each distributor will need to address in relation to DER. It is difficult to comment on comparisons between proposals, however, at a high level, we note that the technical challenges and external factors are likely to vary considerably between distributors, and indeed even within a single network. For example, not only will DER penetration levels vary, but LV network designs and configurations can result in very different problems. The solutions required to address these problems can, therefore, also vary significantly. As noted in our responses to questions above, JEN envisages deploying several different technical solutions to different DER integration issues even within our own network. Additionally, a number of the activities JEN proposes to undertake, such as the development of an LV network model, require the implementation of new IT systems. Although there may be a degree in the scalability of the expenditure required for some DER-enablement activities, the implementation of IT systems is likely to involve higher degrees of fixed costs, which may not vary according to the size of

Received from	Topic	Question	Response
			customer base—noting that JEN has a smaller customer base than most other distributors.