New Reg: Towards Consumer-Centric Energy Network Regulation

AusNet Services' Trial

Note for the Customer Forum on AusNet Services' negotiating position notes

Overview

On 9 August 2018, AusNet Services (AusNet) provided a series of Notes to the Customer Forum (the Forum) to establish its negotiating position on the items it wants to negotiate with the Forum.[1] As these numbers are preliminary in nature, they will be subject to change through the negotiation process and as AusNet refines its regulatory proposal. AER staff have prepared this note consistent with their role in identifying any issues that it identifies with the material that AusNet has provided the Forum as set out in Guidance Note 1. This note:

- identifies the key drivers of the overall revenue outcome in AusNet's negotiating position (both in and out of scope)[2]; and
- identifies questions for the Forum to consider and raise for the issues presented which are in scope.

Topics in and out of the agreed scope

AER staff's view on which topics should be in scope is set out in the second guidance note.[3] AusNet also has proposed that the Forum consider issues outside the agreed scope. While AER staff will not be preparing guidance notes for those topics that are out of scope, the Forum may still consider and discuss other topics with AusNet's customers.

In being asked to consider issues in and out of the agreed scope there is quite a bit of material in front of the Forum. Recognising that the AER will conduct its assessment of the proposal once lodged, we encourage the Forum to pursue those issues for which it considers will benefit from the perspective of customers and there is evidence of customers' preferences (for example, customer research and engagement).

Note: All dollar figures in this document are expressed in $real 2020 unless otherwise specified.

Overall outcomes

AusNet has provided models to the AER that show the total revenue it is seeking to recover from customers for network services and metering services.

Network services revenue

AusNet's modelling underpinning its negotiating position for the Forum results in an average increase of around $28 million per year (in $2020) in the revenue it is seeking to recover from customers for network services, (electricity networks services excluding metering). Figure 2 illustrates the main drivers of the proposed change in revenues.

---

1 AusNet Services, Overview of the revenue proposal, negotiating position for the customer forum, August 2018.

2 While some of the drivers of the overall revenue outcomes in AusNet's initial negotiating positions are out of scope, the impact that they have together with the in scope issues are important context for the Customer Forum to consider in forming a view about the issues that are in scope.

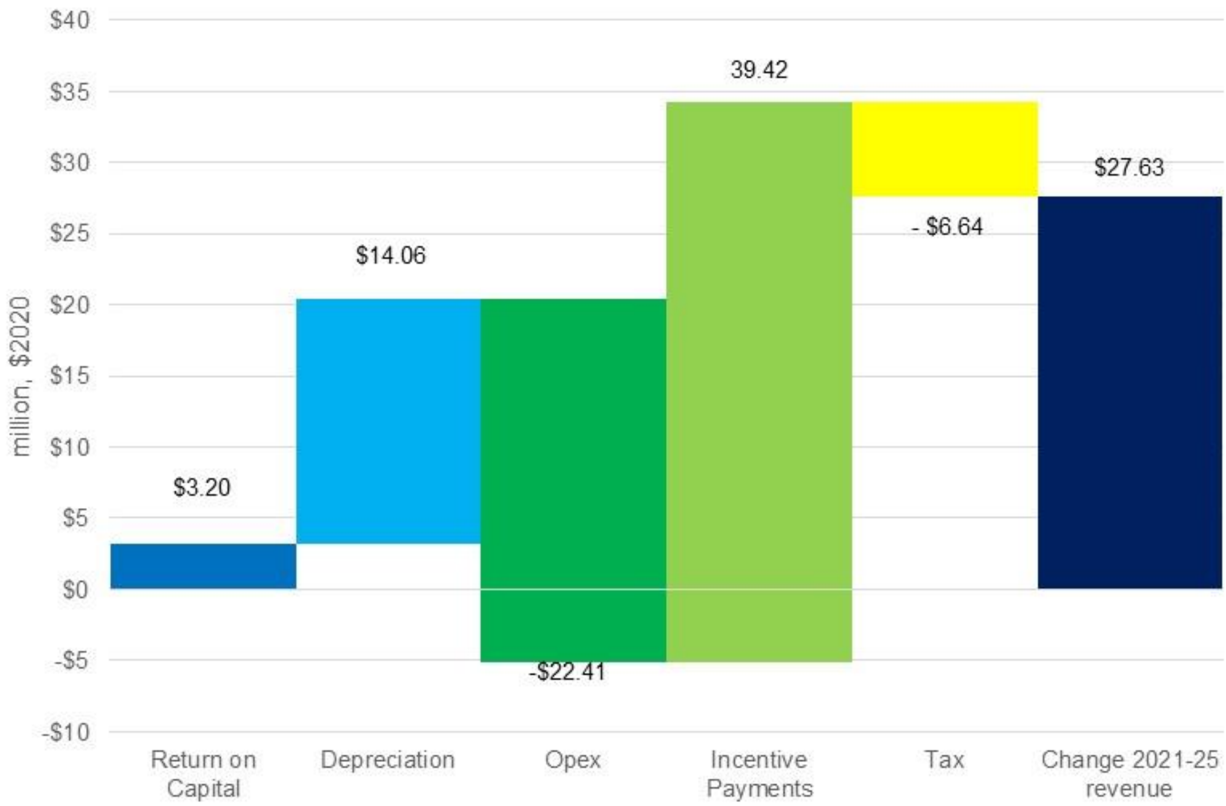
3 AER staff, *AusNet Trial – AER Staff Guidance Note 2: Scope of Negotiation*, July 2018.

This includes:

- an average annual increase of $17 million for the return on capital and depreciation;
- a $39 million annual increase in incentive payments; and
- average annual decreases of around $29 million per year due to reductions in tax and operation expenditure.

We have decomposed the drivers of the increase in AusNet's revenues into the building blocks in Figure 1. Please note the scale of the average annual changes in the underlying variables are listed above or below each bar and sum (from left to right) to the total change in the navy bar on the right-hand side.

Figure 1 Proposed change in annual Revenues, 2016-20 to 2021-25



AER Calculations, 2018; AusNet, *AST 2021-25 Draft Proposal PTRM (Confidential Draft)_Update 14.08.18,* 2018; AER, *AER - Final decision AusNet Services - Post tax revenue model - May 2016,* 2016.

There are a number of factors that are driving the changes in Figure 1:

- AusNet's models currently include a rate of return which looks consistent with our draft rate of return guideline.[4] The nominal vanilla rate of return for the first year of the 2021-25 regulatory period is 5.79% which is a reduction from the 6.31% rate of return in the AER's determination for 2016-20. This results in an average annual revenue reduction of $24.7 million, or 3 per cent.
- AusNet's models also adopt the AER's draft rate of return guideline position on a parameter that affects AusNet's tax building block (the value of imputation credits). This results in a reduction of $5.7 million, or 1 per cent, from what revenues would have been using the previous value.

4 We have not been able to review all of AusNet's rate of return calculations. Also, AusNet's rate of return is a placeholder which will be updated once the AER makes its final decision on the rate of return in December.

- AusNet's capex is driving the increase in both the return on and of capital despite proposed capex being lower in real terms. There are three reasons for this:
  - Capex from 2016-20 mostly occurs at the end of the period meaning that more depreciation on this capex is recovered in 2021-25.
  - Proposed capex for 2021-25 is mainly planned during the first three years of the period meaning more of it will be depreciated during the 2021-25 period and the return will be earned on this larger RAB over the full regulatory period.
  - AusNet is proposing to substantially increase IT capex which is depreciated over a shorter period (5 years in this case).
- AusNet's incentive payments are increasing:
  - AusNet forecasts a $23.1 million per annum efficiency benefit sharing scheme reward for spending less than its opex allowance in the 2016-20 period.
  - AusNet forecasts an $18.5 million per annum capital expenditure sharing scheme payment for spending less than its capex allowance in the 2016-20 period.[5]

Metering revenue

- AusNet's metering revenues are falling, driven by:
  - an allocation of capex and opex from metering to distribution services. This decreases metering revenues by $7.8 million per annum and increases network service revenues by $10.2 million per annum.[6]
  - a reallocation of opex to network services (which we discuss below).
  - the reduction in the rate of return (consistent with the AER's draft rate of return guideline).

In the following sections, we consider the drivers of AusNet's proposal in more detail.

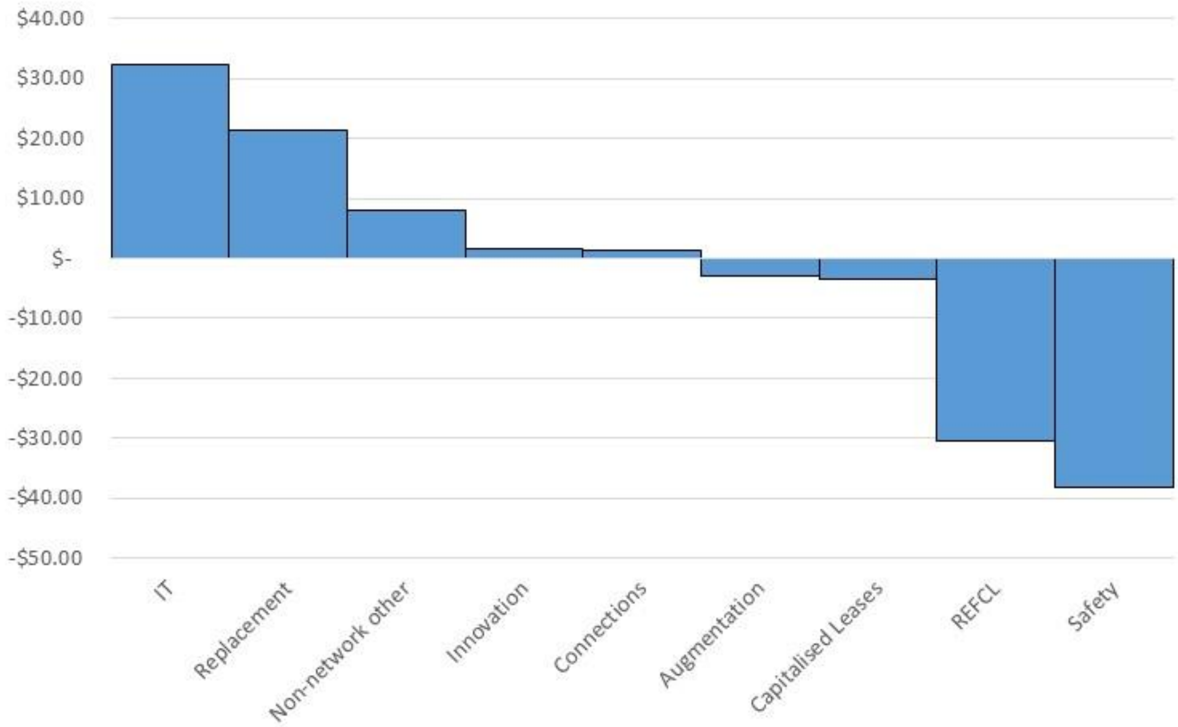
Changing Capex

Overall, average annual capex is around $10 million lower than the previous regulatory period. This is mainly a result of lower capex for safety measures (reduction of $38 million per year) and the REFCL programme ($30 million per year) offsetting higher replacement capex (additional $21 million per year) and IT related capex ($32 million per year). Figure 2 shows the movements in the different capex categories.

5 These numbers do not reconcile to those for incentive payments in figure 1 because this also includes other minor revenue adjustments.

6 The reallocation of capex from metering to distribution increases AusNet's total revenues because metering IT is depreciated over 7 years instead of the 5 years that is applied to distribution services IT. As a result, this shift increases AusNet's capex by $2.4 million per annum ($2020).

Figure 2 Average annual change in AusNet's capex categories



AER Calculations, 2018; AusNet, *AST Capex data 2011-2025 (Draft)*, 2018

IT Capex

AusNet is proposing an increase in IT capex. Figure 3 presents AusNet's forecast capex against its historical capex and average annual IT capex from 2011 to 2017. The proposed IT Capex for 2021-25 represents a 53% increase on average annual IT costs between 2011 and 2017. IT capex has a material impact on the revenue that AusNet is seeking from customers because it depreciates over a short period of time (5 years) compared to other capex (which can have asset lives up to 50 years). If, AusNet instead proposed its historic average IT capex for 2011-17, its distribution revenues would be 14.1 million, or 2 per cent, less per annum.

While not in scope directly, forecast IT capex is relevant to the Forum's consideration of operating expenditure (opex). The AER is considering IT capex in its current determinations, and its approach to assessing IT capex will be set out as part of these determinations.[7] AusNet is proposing a step change in opex to shift IT software to a cloud based system.[8] This shifts costs from capex to opex, increasing opex by $30m over the 2021-25 regulatory period.[9] AusNet is also proposing to re-allocate $78 million of capex from metering to standard control services over the 2021-25 regulatory period.[10]

These are technical issues the AER will assess when it receives AusNet's proposal. For example, the proposed step change appears to be a trade-off between opex and capex, and AusNet would need to demonstrate an offsetting ongoing reduction in IT capex.

---

7 The AER is currently considering distribution regulatory proposal from TasNetworks (Tasmania), Power and Water Corporation (NT), Evoenergy (ACT), AusGrid (NSW), Endeavour Energy (NSW) and Essential Energy (NSW). The AER will likely use a different categorisation of IT expenditures in its assessment to AusNet's. The AER expects to publish the draft determinations for TasNetworks and Power and Water Corporation by end September. The other determinations are expected to be published by end October. These will be available on the AER's website (link here).

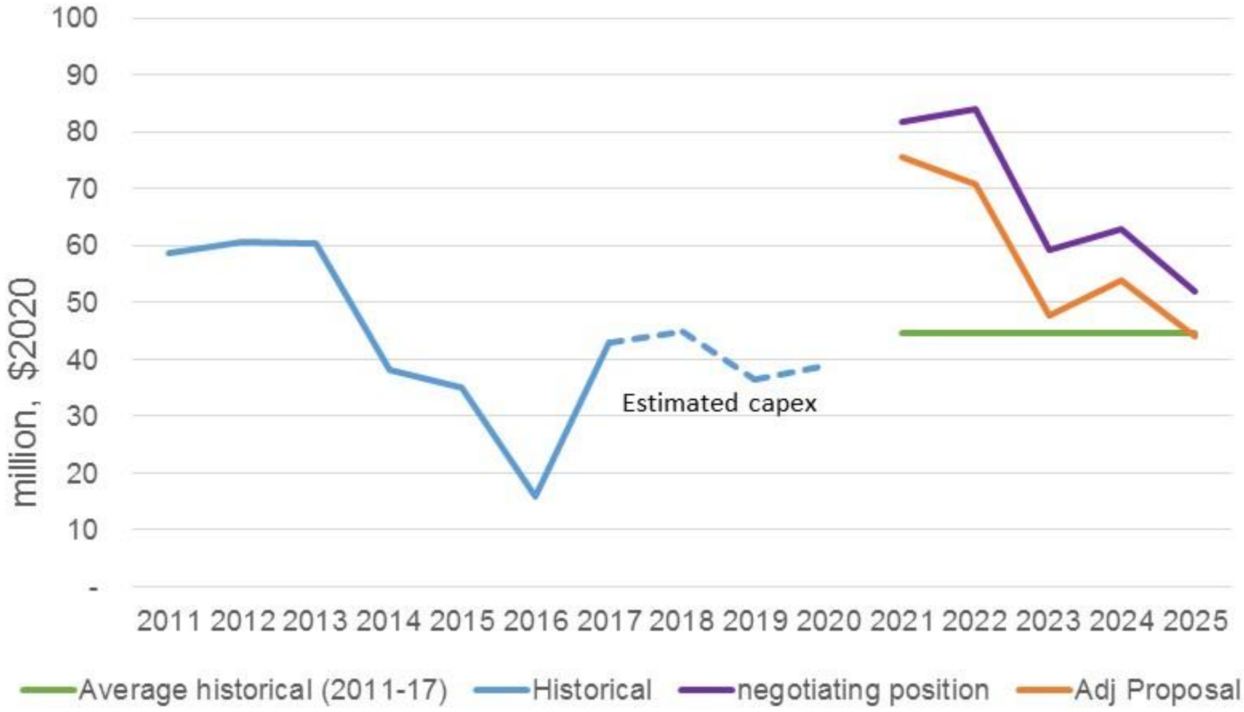
8 AusNet Services, Overview of the revenue proposal, opex, August 2018, p. 4.

9 AusNet Services, Overview of the revenue proposal, opex, August 2018, p. 4.

10 AusNet Services, Overview of the revenue proposal, opex, August 2018, p. 4.

These re-allocations make it difficult to compare proposed capex with historical capex[11]. The orange line in Figure 3 shows forecast capex without these reallocations. This forecast capex is still on average 8.3 per cent higher than average actual capex for 2011-17.[12]

Figure 3 IT Capex



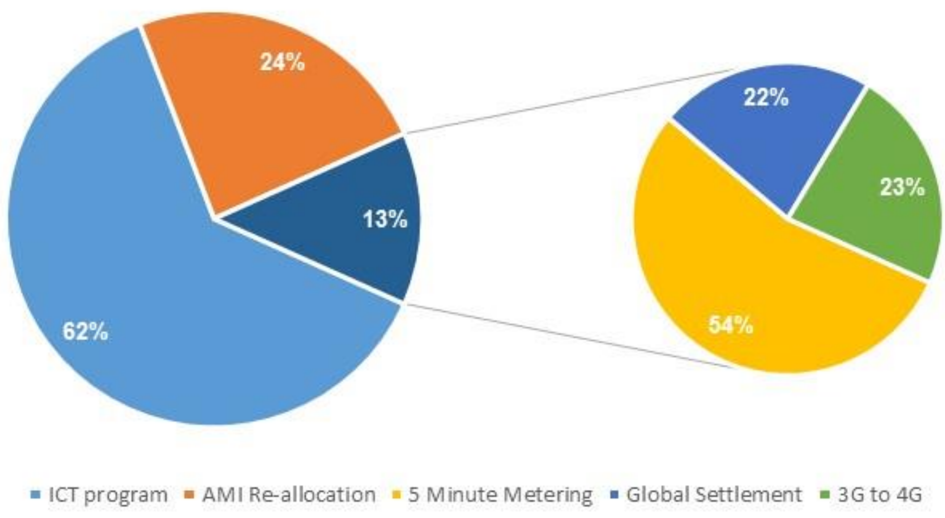
AER Calculations, 2018; AusNet, *AST Capex data 2011-2025 (Draft)*, 2018

Figure 4 presents the different components of AusNet's forecast distribution IT capex, with the new capex programs separated (step changes and reallocation of AMI IT Capex from metering). The step changes are for shifting from 3G to 4G, 5 minute metering and global settlement. Figure 4 shows the composition of forecast IT capex.

[11] Average historical IT capex reflects AusNet's ongoing and non-ongoing IT capex for the period 2011 to 2017, and has been included to demonstrate the magnitude of the proposed change in IT capex for 2021 to 2025 period.

[12] To remove the reallocations we subtracted the $78 million of capex for metering and added the $30m for the cloud based solution.

Figure 4 Composition of IT Capex 2021-25



AER Calculations, 2018; *AusNet, ICT expenditures 2021-25 (Draft)*, 2018

Metering

The proposed changes in AusNet's metering revenues are set out in Figure 5.

Figure 5 Proposed change in annual metering Revenues, 2016-20 to 2021-25

AER Calculations, 2018; AusNet, *Metering PTRM & Exist Fees (Draft)*, 2018

As noted above, AusNet is proposing to allocate both opex and capex from metering to distribution. This is mainly related to IT costs and is intended to reflect the relative usage and benefits to each business of these assets and services

Incentive Payments

While incentive payments are not in scope for these negotiations, they do have an impact on overall price outcomes. These payments mainly relate to two schemes targeted at driving efficiency within the business; the capital expenditure savings scheme (CESS) and the efficiency benefit savings scheme (EBSS) targeted at opex.

This is the first regulatory period for the CESS so there is no comparator data available (i.e. the CESS for 2016-20 was $0). In both schemes companies are rewarded for reducing costs below the allowances set for the regulatory period through the ability to retain a proportion of these savings.

As AusNet is estimating underspending over $400 million between 2016 and 2020 on capex, this results in an expected CESS payment of $78 million ($2020) over the 2021-25 regulatory period.

The opex reductions reported by AusNet during the 2016-20 period, result in EBSS payments of $116 million. These values will be reviewed by the AER as part of its assessment of AusNet's regulatory proposal and are not in scope for the negotiations.

Augex major projects

AusNet's proposed augmentation expenditure (Augex) is focused on two potential projects; augmentations for zone substations at Clyde North and Doreen. These projects represent capital costs of around $18 million ($2020) over the regulatory period, equivalent to 17% of total proposed Augex or 1% of proposed Capex. AusNet selected these two projects for negotiation to understand the Forum's "preferred price-service trade-off, based on their understanding of AusNet Services' customer preferences".[13]

We note that subsequent to AusNet developing its negotiating position on Augex major projects, the Victorian Government has announced new subsidies for investment in solar panels which may affect demand projections.[14] Additionally, subsidies for residential batteries have also been announced.[15] AusNet and the Forum should explore the implications of these announcements on these proposed projects.

To assist with analysis of information provided in the Augex Note on AusNet's proposed revenue proposal for the Forum, there are a few points about the presentation of information that may be helpful for the Forum clarify. These relate to comparisons made, the need to also consider the value of customer reliability (VCR) measure, and the treatment of battery technologies. AusNet Trial – AER Staff Guidance Note 5 provides specific information on the nature of Augex, AusNet's proposal and boundaries for negotiation.

Comparisons

Projects above a certain expenditure level must undergo a regulatory investment test (RIT). This test is a cost-benefit analysis and is intended to help identify the most efficient outcome. For distribution assets, the AER has established a guideline for these tests known as a RIT-D Guideline.

In undertaking a RIT-D, the cost of doing nothing must be considered in addition to the proposals presented. Figures 5 and 10[16] in AusNet's proposal illustrate the physical impact of not undertaking the Augex in terms of energy at risk and the expected volume of unserved energy during 2021-25 and beyond. However, Tables 2 and 4[17] do not quantify the indicative cost of continuing with business as usual (doing nothing) and facing these consequences. We consider that it is essential that the cost and benefit of "doing nothing" option be included so that the incremental costs and benefits of identified options can be adequately assessed and understood.

[13] AusNet, *Augmentation expenditure: major projects*, Negotiation position for the Customer Forum, 2018, Page 1.

[14] https://www.premier.vic.gov.au/cutting-power-bills-with-solar-panels-for-650000-homes/

[15] https://www.premier.vic.gov.au/cheaper-electricity-with-solar-batteries-for-10000-homes/

[16] Pages 6 and 13 respectively of AusNet, *Augmentation expenditure: major projects*, Negotiation position for the Customer Forum, 2018.

[17] Pages 9 and 15 respectively of AusNet, *Augmentation expenditure: major projects*, Negotiation position for the Customer Forum, 2018.

The initial comparison between the two major projects under consideration at Doreen and Clyde North has been made against the average urban zone substation data in Figure 2[18] of AusNet's Augex proposal. AusNet has advised that the average zone sub performance data in Figure 2 is derived from urban zone substations only. It is important that only the urban average is used as the point of comparison as these substations are both in urban areas and the AusNet network includes rural areas where design standards differ. For example, both the Doreen and the Clyde North substations have two transformers while some rural areas may only have one transformer at a substation. These design standards have implications for the frequency and duration of outages as substations built to higher design standards will perform better. Therefore it is helpful that AusNet used the urban zone substation average in undertaking a direct comparison between the performance of these substations with the Average Zone substation. Otherwise the data may imply further scope to relax reliability than a comparison with other zones with similar characteristics would indicate.

Additionally, information is presented in different formats and meanings throughout the note which may affect comparison between these sources. For example, Figure 2 presents the average annual minutes off supply per customer as a result of unplanned outage, while Table 2 presents the total minutes across a five year period as a result of capacity shortages. Additional explanatory text would be helpful.

Value of Customer Reliability (VCR)

Additionally, in considering issues of reliability and trade-offs between costs and service quality it is important to consider the established standard reference point for quantifying benefits: the Value of Customer Reliability (VCR). The VCR can be likened to the amount an average customer is willing to pay to keep the lights on. It is a vital input into the design and management of distribution networks and feeds into a number of key regulatory tools. For example, the RIT-D requires the cost of a proposed capex project to be less than the value of unserved energy (VCR x energy not delivered) to ensure positive net benefits for consumers. The STPIS also uses the VCR as one of the main measures to link outcome performance and the incentive value. Therefore any evidenced change to the VCR will have substantial implications for the broader regulatory framework.

In 2014 AEMO published a report outlining residential VCR in different states, as well as values for different groupings of business customers and directly connected customers. This report was the result of extensive surveys and analysis to evidence the values established for each customer grouping. The VCR for residential customers in Victoria was estimated at around $24.76/kWh, i.e. customers would support proposed projects which cost less than $24.76/kWh multiplied by the volume of energy (kW) that would otherwise not be delivered if the project did not go ahead ($2014).[19] It is worth noting that the AER is preparing to undertake a thorough review to update these VCR figures over the next year. So for an alternative value of the VCR to be accepted either AusNet or the Forum would have to demonstrate through rigorous analysis why a different value should be used for customers in AusNet's network or those customers specific to the Clyde and Doreen substations.

Distribution System Operator

The Forum requested further clarity on the idea of a Distribution System Operator. At this stage Distribution System Operators are a mostly theoretical concept. However, some elements of the proposal touch on activities that are outside the traditional role of distribution businesses, such as the procurement and/or development of embedded generation. These activities are not currently coordinated but may fall under the future remit of a Distribution System Operator. This theme also arises in relation to AusNet's proposals for DER Integration and Innovation.

---

[18] AusNet, *Augmentation expenditure: major projects*, Negotiation position for the Customer Forum, 2018, Page 3

[19] AEMO, *Value of customer reliability review final report*, 2014, p.18.

Energy businesses are being encouraged to explore alternatives to the standard 'poles and wires' approach to issues identified, however the framework in which these innovations are to occur, as well as the roles of different players are still being developed. This is particularly true for activities relating to the system operator functions, such as coordinating flows of energy and proactively engaging with the wholesale, retail and ancillary services markets to ensure balance. At this stage there is no institution specifically responsible for undertaking these activities at the distribution level, instead individual market participants are free to develop projects and bid themselves without anyone coordinating their activities. It is also worth noting that at the transmission level there is a clear separation between the business responsible for coordinating energy flows and those responsible for managing the physical transmission assets. It will be important to consider any developments in system operation at the distribution and transmission level when reviewing proposals and plans, as well as the potential for a coordinated approach to establishing platforms across distribution networks to be required.

The market and transmission system operator (AEMO) and the network industry body (ENA) recently published a consultation paper on DER integration into networks which the rule maker for energy markets (AEMC) is keen to engage with.[20] This consultation explores whether the transmission system operator (AEMO) should coordinate DER (either centrally or for each distribution) or whether distribution businesses should effectively become system operators for their networks and liaise with AEMO regarding activity at the transmission connection point. We also consider that there may be the potential for this service to be provided by a third party in a competitive environment.

There are advantages and disadvantages of each approach, for example distribution businesses will have greater insight into their network areas but as monopoly businesses they must ring fence any operations in competitive markets (such as generation) to prevent unfair advantage. However, the AEMC has encouraged distribution businesses to focus on building more detailed understanding of their low voltage networks, including the impact of connecting more DER and potential constraints, while this work is progressed.[21] As an economic regulator, we would expect any new expenditure proposals to clearly demonstrate clear evidence of consumer benefit and appropriate timing.

We would also note that smart meter technologies provide unique visibility to the low voltage network that can be effectively be used for this purpose, reducing the need for more network build to support increasing DER penetration.

Demand Management Approaches

The Forum also requested further information on the regulatory framework for Demand Management. Reference is made to a demand management offerings trial in Clyde North[22] funded by the demand management innovation allowance (DMIA). The demand management innovation allowance (DMIA) is targeted at demand projects with the potential to reduce long term network costs by reducing, delaying or avoiding the need for additional capacity.[23] The DMIA and associated incentive scheme (DMIS) are still available for distribution businesses looking to investigate non-network options, particularly through the involvement of third party demand management solutions. The initial trial was reported to achieve an average reduction of 40% across the 72 customers with the Critical Peak Rebate incentive during the three hottest days of the project. Only one potential option[24] appears to reference this approach as part of a hybrid including battery technology and delayed network investment.

---

[20] More information on this collaboration is available here: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program

[21] AEMC, 2018 Final report, *Economic regulatory framework review*, 26 July 2018

[22] AusNet, *Augmentation expenditure: major projects*, Negotiation position for the Customer Forum, 2018, Page 6.

[23] More information is available here: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism

[24] Table 1 in AusNet, *Augmentation expenditure: major projects*, Negotiation position for the Customer Forum, 2018, Page 8.

Battery Technologies

In considering alternative technology options it is important to consider the broader context in which they will operate. AusNet could develop a battery storage solution on the network rather than behind the meter. Under this approach AusNet may use the battery for network support while a third party, such as retailer or AusNet affiliate, may use a portion of the battery capacity to engage in wholesale market and ancillary services market activities. Ring-fencing obligations prevent AusNet itself from undertaking such market activities. Alternatively, AusNet is able to procure energy storage services from third party providers of battery storage solutions. In this instance we would expect AusNet to engage in competitive tenders to identify the most efficient and cost effective solution.

Also in December 2017 the AEMC published a final rule restricting the ability of distribution businesses to earn a return on assets 'behind the meter'.[25] This means that AusNet would have to seek a specific, formal exemption from the AER to be allowed to invest in technologies, such as batteries, at customer premises. Also, even if an exemption was granted, the network may not need to fund the full cost of the battery as multiple value streams are available. For example, the battery could be combined with other DER through an aggregator which combines the DER capacity of a number of customers to act as a virtual power plant and bid into the wholesale market. Additionally, the battery or aggregator could bid to offer ancillary services to the system operator. If wholesale and ancillary services markets covered, for example, half the costs of the battery, the network would only be required to fund the remaining half.

Opex

In this section we consider AusNet's opex proposal. AusNet envisages that the Forum's role would involve a high level assessment of the overall reasonableness of AusNet's opex forecast, taking into account regulatory obligations, as well as a consideration of customer preferences broader than the appropriateness of individual inputs to the AER's standard 'base, step, and trend' approach to assessing opex.[26] In particular, AusNet intends seeking the Forum's view on:

- the extent to which base year expenditure is appropriately targeted to deliver customers good value across a range of customer experience dimensions
- whether there are other areas AusNet should increase or decrease opex to deliver a different mix of customer outcomes
- whether customers are adequately sharing in the benefits of efficiency improvements made by AusNet.[27]

We consider that a number of elements of AusNet's negotiating position are technically quite complex. The Forum may find it difficult to effectively engage with these aspects of AusNet's proposal. We have provided some high-level observations on these matters in this section. However, to undertake a proper assessment of these matters we would require much more information and time.

As we note above, the AER will still undertake its assessment of AusNet Services' proposal as required by the National Electricity Rules (NER). However, we would value the customer perspectives the Forum might be able to bring to provide on AusNet's opex proposal.

In the following sections we consider the drivers of AusNet's opex proposal, with reference to how we would assess those drivers. Our opex assessment approach is set out in our opex

---

25 More information on this rule change is available here: https://www.aemc.gov.au/rule-changes/contestability-of-energy-services

26 AER staff, New Reg: Towards Consumer-Centric Energy Network Regulation AusNet Trial – AER Staff Guidance Note 2: Scope of Negotiation, July 2018, p. 4.

27 AER staff, New Reg: Towards Consumer-Centric Energy Network Regulation AusNet Trial – AER Staff Guidance Note 2: Scope of Negotiation, July 2018, p. 4.

note. As noted in the opex note, our assessment has four steps: consideration of the base, trend, step and additional costs. We consider these steps below.

Base opex

AusNet has proposed to use 2018 as its base year, which has not yet concluded. It is not uncommon for networks to propose the current year as the base year. Our usual process is to update our analysis once actual expenditures are known.

We consider the efficiency of the base year when deciding whether we should use those base year expenditures as the basis of our forecast. If actual expenditure in the base year reasonably reflects efficient and prudent costs, we will set base opex equal to actual expenditure (revealed cost).[28] We use a number of techniques including economic benchmarking and cost category benchmarking to identify whether there is material inefficiency in the chosen base year.[29]

Our updated benchmarking results for 2017 will become publically available in November when we publish our 2018 benchmarking report.

Trend

The trend covers the rate of change in recurrent opex expected in the next period. Our rate of change calculation is as follows:

$$Rate\ of\ change_t = output\ growth_t + real\ price\ growth_t - productivity\ growth_t$$[30]

We describe the elements of this formula in our opex guidance note.[31] AusNet's negotiating position appears to align with our current approach to measuring real price growth and output growth. However, as part of our determination we will examine these inputs. We may update this approach in our upcoming determinations for the Tasmanian and NT DNSPs – due to be published end September; and the NSW and ACT DNSPs – due to be published end October.

AusNet has proposed to apply a productivity growth factor of zero.[32] AusNet does not consider that there is evidence of industry wide productivity improvements at this time. AusNet notes that the electricity distribution industry has had declining productivity since 2006.[33]

The appropriate productivity growth to apply in our rate of change calculation is something that we are currently considering. We expect to consult on this in tandem with our upcoming draft determinations for Tasmanian, NT, NSW and ACT DNSPs.

Step changes

Step changes account for the major drivers of increases in AusNet's expenditure from its 2018 base year. Figure 6 shows that there are a number of step changes proposed by AusNet.

[28] AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 22.

[29] AER staff, AusNet Trial Guidance Note – opex, September 2018, p. 5.

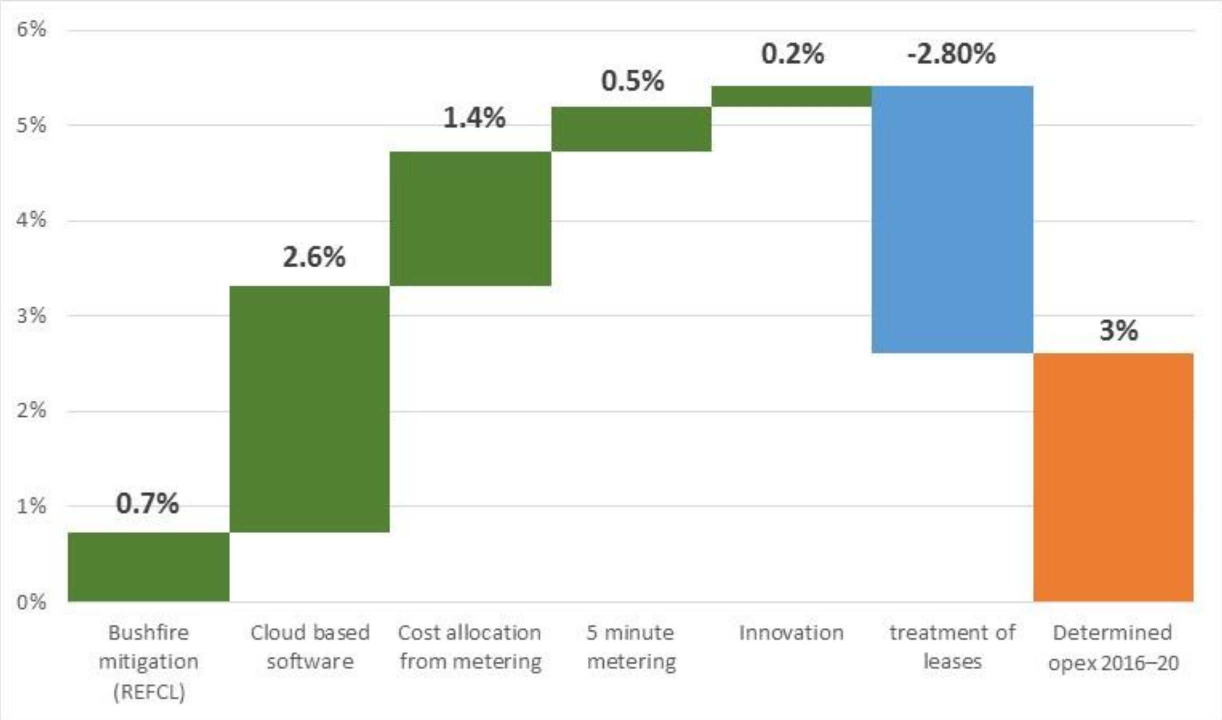
[30] AER, *Expenditure Forecast Assessment Guideline – Distribution*, 2013, p. 3.

[31] AER, *New Reg: Towards Consumer-Centric Energy Network Regulation, AusNet Trial – AER Staff Guidance Note 4: Opex*, 17 August 2018, p. 6.

[32] AusNet Services, *Overview of the revenue proposal, opex*, August 2018, p. 5.

[33] AusNet Services, *Overview of the revenue proposal, opex*, August 2018, p. 5.

Figure 6 How costs are shifting from AusNet's base year ($ per residential customer)



Source: AusNet's opex model, PTRM and underlying data for Figure 1 of its overview note.

Our comments below are based on the description of each step change provided by AusNet in its guidance note. We consider that further information would be required for a proper evaluation of the step changes. In making our determinations we would request justification for the need for the step changes against the criteria for assessing step changes set out in our expenditure forecast assessment guideline.[34] This aside, we make the following observations:

Bushfire Mitigation (REFCL) step change

- AusNet is proposing an additional $8.5 million in opex to progress the third tranche of is REFCL roll-out and for ongoing testing and maintenance of the REFCLs at 22 zone sub stations.
- The AER approved a contingent project for the installation of REFCLs in 2017. A consideration for the AER in assessing this step change would be whether these costs are already reflected in AusNet's (base year) operating expenditure.

Cloud base software step change

While this step change would be considered in the context of the AER's broader approach to assessing step changes, relevant considerations would include:

- Whether a binding and uncontrollable change underpins the step change.
- Any efficiency improvements or customer benefit improvements that might flow from the change.
- Whether AusNet's capex forecast should be reduced to account for the use of an opex solution.

[34] AER, *Expenditure Forecast Assessment Guideline – Distribution*, 2013, pp. 10-11, 24.

Cost allocation of shared data and communication systems

AusNet has proposed to reallocate costs for data and communication systems from metering services to distribution services to better reflect their integrated role in the delivery of core distribution services and metering services.

While this step change would be considered in the context of the AER's broader approach to assessing step changes, relevant considerations would include:

- The AER's previous considerations in regards to shared data and communication systems and advice received on the allocation of data and communication systems.[35]
- The need for metering costs and network costs to be cost-reflective
- The potential for the introduction of competition for metering services

Five minute metering

While this step change would be considered in the context of the AER's broader approach to assessing step changes, relevant considerations would include:

- Whether this expenditure should be part of distribution or metering expenditure. Relevant to this consideration are the following matters:
  - The AER's previous considerations in regards to shared data and communication systems and advice received on the allocation of data and communication systems.[36]
  - The need for metering costs and network costs to be cost-reflective
  - The potential for the introduction of competition for metering services
- The approach other DNSPs are taking to manage this rule change.
- The efficiency and timing of the costs. We note that the five minute settlement rule change will come into effect on 1 July 2021, which is six months into the next regulatory period.[37]

Accounting treatment of leases

Power and Water Corporation (the Northern Territory electricity distribution network), has proposed a step change for the accounting treatment of leases. We are currently considering this in the context of our 2019–24 decision. We will set out our draft determination on this step change in our draft decision in September.

Additional costs

Additional costs cover any costs that are removed from the base year and forecast using a different approach to that for base year opex. Consistent with previous determinations, AusNet is proposing to remove GSL payments and debt raising costs from its base year to forecast separately. AusNet is also proposing to separately forecast innovation costs.

---

35 Energy Market Consulting associates, *Victorian electricity Distribution Network Service Providers (DNSPs) regulated revenue 2016 to 2020 Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, April 2016.

AER, *Final Decision AusNet Services Distribution Determination 2016 to 2020, Attachment 7 – Operating Expenditure*, May 2016, pp. 7-37 to 7-48.

36 Energy Market Consulting associates, *Victorian electricity Distribution Network Service Providers (DNSPs) regulated revenue 2016 to 2020 Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, April 2016.

AER, *Final Decision AusNet Services Distribution Determination 2016 to 2020, Attachment 7 – Operating Expenditure*, May 2016, pp. 7-37 to 7-48.

37 AEMC, *INFORMATION, Five minute settlement*, November 2017, p.3.

GSL payments

AusNet is proposing to base its forecasts of GSL payments on GSL payments after 2016. This is because the Essential Services Commission changed the GSL payments in December 2015.[38] AusNet has detailed information on its network performance prior to 2016 which may also be used to forecast GSL payments.

Debt raising costs

The AER has developed a technical methodology which it has consistently applied over a number of determinations to forecasting debt raising costs.[39]

Price Path

In this section we consider AusNet's price path proposal, with reference to how we would consider the information presented.

AusNet is proposing three alternatives for the Forum to consider:

- An immediate sharp reduction in bills followed by a gradual increase over the remainder of the regulatory period which mirrors the proposed revenue profile;
- A moderate reduction followed by a more graduate increase over the remainder of the regulatory period to reduce the variation in bills; OR
- A gradual reduction in bills over the regulatory period.

In presenting these options AusNet acknowledges that it will be constrained by the National Electricity Rule that the difference between smoothed and unsmoothed revenues in the final year be minimised. Given this, AusNet could provide more information on what the implications of each of the proposed price paths are, i.e. what this difference will be. Using data provided, the difference between smooth and unsmoothed prices in the final year of the regulatory period is 4.4% (which would not be consistent with the way that we have applied this rule).

This rule was established to minimise price volatility between regulatory periods. The revenue in the final year is often used as an indicative baseline to calculation revenues over the subsequent regulatory period. So if the smoothed price were to be substantially above or below this value, there might be a price shock for customers in 2026. Also, this may be exacerbated by adjustments to the revenue requirement in the subsequent period due to changes in scope, scale, regulatory environment, etc. Therefore it is important that compliance with this rule can be demonstrated.

Customer experience

In this section we consider AusNet's customer experience proposal. AusNet is seeking Forum endorsement to include proposed customer experience initiatives in its proposal. AusNet has also made commitments to improve its current customer service.

AusNet is proposing to develop a small scale incentive scheme (SSIS). As set out in the AER's boundary note on customer experience, there are a number of considerations for Forum in thinking about the way in which such an incentive scheme should operate.[40]

The application of the SSIS could have material implications for AusNet's revenues. For example, if the revenue at risk from such a scheme were to be set at 0.5% of the revenue allowance, then if AusNet exceeded its performance targets in each year of the regulatory

---

[38] Essential Services Commission, *Review Of The Victorian Electricity Distributors' Guaranteed Service Level Payment Scheme Final Decision,* December 2015

[39] AER, *Final Decision, AusNet Services Transmission Determination 2017–22 Attachment 7 – Operating Expenditure*, April 2017, p. 7-45.

[40] AER, New Reg: Towards Consumer-Centric Energy Network Regulation AusNet Trial – AER Staff Guidance Note 3: Customer experience, 29 August 2018, pp. 4–5.

period, it could derive up to $3.3 million from the scheme per year. The Forum needs to carefully consider the rewards that AusNet obtains under the scheme with the value consumers derive from improved customer experience (and the costs to AusNet in improving its customer experience.

Given the revenue implications of such a scheme, there would need to be clear evidence to support the provision of these payments to AusNet from improving its customer experience. If this evidence is challenging to derive in this process, a scheme may, in the first instance, be trialled without financial penalties or rewards. This may be appropriate where AusNet is proposing to link employee performance to customer experience.

We consider that the development of such a scheme has potential merit. However, it may also be challenging to meet the NER criteria set out on p.4 of our customer experience guidance note. In particular we consider that the following would be required:

- The performance targets not be made too easy or too hard. We note that AusNet proposes that performance targets be based on historical averages. For the initial application of the scheme this might not be appropriate – particularly were a single year's performance to be the basis for the target.
- We would like the performance parameters to be objective, measured consistently over time and verifiable by a third party.
- The scheme should be targeted at areas of underperformance where customers desire improvement.

In its note, AusNet flags replacing the telephone answering parameter under the AER's STPIS. We would be interested in the Forum's consideration of whether this parameter is still necessary.