Jemena Gas Networks (NSW) Ltd

Revised 2020-25 Access Arrangement Proposal

Attachment 4.2

Response to the AER's draft decision - Capital expenditure

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Abbreviations

AA	Access Arrangement
AER	Australian Energy Regulator
APaIR	Asset Performance and Integrity Review
Capex	Capital Expenditure
CBD	Central Business District
CP	Cathodic Protection
E&I	Electrical & Instrumentation
GIS	Geographic Information System
HIA	Housing Industry Association’s
I&C	Industrial & Commercial
ICT	Information and Communications Technology
IS-U	Industry Specific for Utilities
MDL	Meter Data Logger
NGL	National Gas Law
NGO	National Gas Objective
NPV	Net Present Value
Opex	Operating Expenditure
PEM	Project Estimation Methodology
POTS	Packaged Off-take Stations
PRS	Primary Regulating Stations
RIN	Regulatory Information Notice
RMS	Roads and Maritime Services
SRS	Secondary Regulator Stations
TRS	Trunk Receiving Stations

Overview

Our 2020-25 capital expenditure (**capex**) program is focussed on our customers, reducing risks, maintaining our current service standards and reducing bills. Recognising that some of the investment choices required balancing trade-offs, particularly given the current uncertainty surrounding the future of the gas network, we engaged extensively with our customers and developed our 2020 Plan with their preferences in mind.

Our 2020 Plan included a lean capex forecast, supported by our customers, that is compliant with Rule requirements, and supported by relevant justifications.

Even though we are now are supplying 354,000 more dwellings than we did in 2011 (a 32% increase), and are forecasting to supply an additional 196,000 dwellings by 2025—and at a time when the costs of delivering infrastructure and utility services across Sydney is continuing to increase—**we proposed a reduction in capex relative to our 2015-20 period actuals.**

Despite this, the draft decision capex allowance is lower in every category of capex, **resulting in a forecast $108M (12%) below our proposal and $128M**[1] **(13.9%) below 2015-20 actuals.**

While we welcome the Australian Energy Regulator's (**AER**'s) draft decision to accept many aspects of our capex proposal for the 2020-25 Access Arrangement (**AA**) period, and its assessment of our historical capex for the period 2014-15 to 2018-19 as prudent and efficient, the level of disallowance in the AER's draft decision does not provide us with sufficient capex for the 2020-25 period.

The draft decision relies on:

1. Inconsistent forecasting assumptions – during the recent remittal process that just concluded in February 2019, the AER developed a connection capex forecasting model based on five-years of historical costs. We applied the same methodology but used four-years (as the oldest year of data would be six years old by the start of the 2020-25 period and the forecasting difference was not material at less than 1%). The draft decision opts to utilise different historical periods for each element and in all cases, where there is a significant difference, applies a historical period which results in the lowest forecast.

2. Justification hurdles that are difficult to achieve – the draft decision reduced our forecast for the Aerotropolis project by $22M on the basis of planning uncertainty[2] even though the AER accepted that augmentation would be required and included demand from connections in this area.

3. Unprecedented and anomalous forecasting approaches – an operating expenditure (**opex**) productivity factor was applied to capitalised overheads. This has never been done before, was not consulted on, and does not apply for electricity businesses.

In this response to the draft decision, we provide the AER with further detailed information on our plans with the aim of demonstrating that our capex proposal is prudent, efficient and represents the best forecast in the circumstances. We also provide the AER with additional information on our historical corporate overheads and property capex (in Attachment 4.3).

Table OV–1 provides an overview of our 2020 Plan capex forecast, the AER's draft decision, and our Revised 2020 Plan forecast.

In its draft decision, the AER has also rejected our proposal to include the Western Sydney Green Gas trial as speculative capex on the basis that it could never satisfy the Rule 79 criteria. This is at odds with its draft decision to maintain asset lives for new investments. The AER justified its draft decision on asset lives noting that hydrogen, whilst speculative, would have a positive impact on the future of gas distribution networks. The internal inconsistency of the AER's reasoning is clear – the AER has acknowledged the relevance (although speculative)

1 This is the difference between our actual/estimated capex for the 2015-20 (excluding corporate overheads) and our proposed capex for 2020-25 (excluding corporate overheads). We excluded corporate overheads to ensure a like-for-like comparison given that we will expense corporate overhead costs in the 2015-20 period,

2 The AER reduced our augmentation forecast by $13.2M and an additional $8.8M from our connections forecast.

of the role of hydrogen to future proofing the network to maintain asset lives, but in its capex draft decision, the AER has rejected the relevance of hydrogen entirely.

Table OV–1: Comparison of JGN's 2020–25 period proposed capex to AER's draft decision ($2020, $M)

	JGN's 2020 Plan	AER's draft decision	Revised 2020 Plan
Connections	387.5	363.9	392.2
Meter replacement	118.0	105.7	117.6
Facilities and pipes	72.2	63.2	71.5
IT	107.2	73.3	101.2
Augmentation	60.8	47.6	62.0
Mains replacement	44.8	36.2	44.6
Other[3]	34.3	30.1	31.2
Overheads	88.1	84.0	85.9
Gross total	**912.8**	**804.0**	**906.2**
Contributions	13.4	12.9	13.1
Net total	**899.5**	**791.1**	**893.1**

JGN response to the draft decision

Our Revised 2020 Plan seeks to address the key issues raised by the AER in its draft decision with the aim of demonstrating that our capex forecast represents the best forecast in the circumstances. Table OV–2 summarises the key elements of the AER's draft decision and our response.

We have structured this document to respond to the AER's draft decision on an issue by issue basis. The revisions have been limited to those either requested by the AER or required to address concerns raised, consistent with Rule 60.

Table OV–2: JGN's response to AER draft decision on capex

AER draft decision	JGN response
Connections	
The AER did not accept our connections capex for our new home, electricity to gas, and Industrial & Commercial tariff market segments. In contrast to our forecasting approach which relied on a consistent averaging period to calculate connection unit rates (using historical costs and volumes), the AER applied the lower of either a four or five year average. The only exception to this was where an even lower unit rate was calculated by excluding years with high costs or volumes. These adjustments reduced forecast capex by $19.6M. The AER also removed $8.8M as a result of its decision on the Aerotropolis (see below) and added $5.8M to reflect that it rejected our proposal to stop offering individual hot water metering.	We outline in section 1 that we have continued to use the AER's previous connection forecasting method, developed following the recent merits review and remittal processes. This approach applies a consistent averaging period (as the AER's previously raised concerns about inconsistent averaging periods). This approach does not exclude higher (or lower) cost years, or take into account the increasing cost pressures we face. We show that when connection volumes are adjusted for, the AER's forecasting approach materially under-forecasts our capex requirement for 2018-19 (8.1% less than actuals) while our forecast was much more accurate (3.9% less than actuals). Over 5-years a 8.1% error leads to a forecast $32M below cost.

3 Other includes property, fleet and SCADA (the system which controls our network), and relocations.

Meter replacement	
The AER's draft decision reduced our forecast meter replacement volumes by making more optimistic assumptions about our meter performance. These assumptions reduced our capex forecast by $8.4M. The AER also adjusted our forecast unit rates for defective hot water meters and meter data loggers to reduce our capex by $3M by removing years with high costs.	In section 2, we explain that we do not accept the AER's forecast as the optimistic assumptions about meter performance result in an under-forecast of replacement volumes that understate capex. This is shown when the AER's forecast is compared against actual 2019 meter performance data. Modifying the AER's assumptions but retaining the same approach results in a meter replacement volume forecast higher than our proposal. As we detail in section 2, we also do not accept the AER's inconsistent approach to forecasting metering unit rates, for the reasons outlined above in our connections forecast.
Facilities and pipes	
The AER's draft decision accepted $63.2M of our proposed facilities and pipes capex but was not satisfied that sufficient justification had been provided for eight projects.	In section 3, we provide additional information on these eight programs of work which demonstrates that they are justified and the costs are efficient. We note five of these projects relate to forecasts for minor capital works and our ongoing costs to rectify exposed pipeline assets. Even though our network has grown significantly and will continue to grow, and our assets are continuing to age, our capex forecast for this category of capex is almost 50% less than what we have actually incurred over the last four years in these same programs.
IT	
The AER notes that it has no issues with our overall methodology for estimating IT capex (which was developed using the IT Project Estimation tool) but disallowed $33.9M of our proposed $107.2M of IT capex on the basis that it required more justification of our proposed expenditure. It also included 'placeholder' decisions for a number of projects, totalling $7.4M.	In section 4, we set out additional justification for our proposed IT capex program which demonstrates that this capex is prudent, efficient and complies with Rule requirements.

<table>
<tr><th colspan="2">Augmentation</th></tr>
<tr><td>The AER:
Rejected our proposed capex on the Aerotropolis project on the basis of planning and asset scope uncertainty, only allowing $2.1M to continue planning and design work, noting that JGN can seek a further allowance under the rules as certainty is reduced. The AER also removed $8.8M in associated connections capex.
Requested that we provide an update on projects (which it has accepted) due for completion in 2020-21 and 2021-22.
Expressed concerns with our approach to demonstrating that our proposed augmentation capex complies with Rule 79(2)(b) – that the incremental revenue exceeds the capex.</td><td>In section 5 we:
Highlight that while there is general uncertainty regarding the Aerotropolis projects (as there is with any project), as recognised by the AER there is no uncertainty as to whether augmentation will be required. The issue is one of the quantum of capex.
Provide updated information on our plans and capex forecast, which demonstrates that our estimate is the best possible in the circumstances.
Explain that there is no mechanism in the National Gas Rules (NGR) for us to seek an additional allowance for the 2020-25 period after the AER makes its Final Decision, save for us triggering an early and full AA process.
Provide updated information on projects due for completion in 2020-21 and 2021-22, and as required by the AER. We have updated cost estimates (where we have newer estimates) and removed a project that is no longer required. We have also added a new project to allow renewable gas to be injected into our network.
Addressed each of the concerns identified on our approach to demonstrating compliance with Rule 79(2)(b).</td></tr>
<tr><th colspan="2">Mains replacement</th></tr>
<tr><td>The AER accepted our proposed mains replacement capex, with the exception of the Newcastle mains rehabilitation project.
Although it considers that the project is prudent and the cost reasonable it has deferred the project by one year, shifting this expenditure into the 2025-30 AA period. It has deferred the project on the basis that the mains can continue to be effectively managed for another year to maximise the use of the existing asset.</td><td>As we explain in section 6, we have not changed the timing of our Newcastle mains replacement project as:
Our proposed timing will deliver better outcomes for customers (by reducing customer frustrating with our deteriorating mains).
Deferring the project by one year will cost customers $1M as the financing cost savings from deferral are outweighed by the additional opex costs (which we have not forecast).</td></tr>
<tr><th colspan="2">Other[4]</th></tr>
<tr><td>The AER has disallowed some of our proposed capex on fleet and asset relocations.
The AER reduced our forecast relocation expenditure (which we estimated using the historical average of our costs) on the assumption that this is a legacy issue.</td><td>While we do not agree with the AER’s revised fleet forecast we have not had sufficient time to respond on all matters raised by the AER in the six week window provided. As a result, we have accepted the AER’s revised fleet forecast.
In section 7, we explain that relocation expenditure is incurred when we don’t have rights guaranteeing the location of our assets, for instance where we make agreements with government authorities, in install our infrastructure with existing infrastructure (roads, bridges, railways etc).
Given the planned level of infrastructure spending by the NSW government it is unlikely that these costs will be lower than the historical average.</td></tr>
</table>

4 Other includes property, fleet, SCADA (the system which controls our network), and relocations.

Capital contributions	
The AER accepted our forecast of capital contributions.	Our methodology for forecasting capital contributions is unchanged from that accepted by the AER. However, we have updated our capital contributions forecast for 2018-19 actual data and to be consistent with our revised capex forecast.
Western Sydney Green Gas Trial	
The AER rejected our proposal to include the Western Sydney Green Gas trial as speculative capex on the basis that the project "*is unlikely to meet the conforming capex criteria*", citing rule 79(2).	Section 9 explains that the AER's decision to not approve the creation of the speculative account does not reconcile with the NGR and the achievement of the National Gas Objective (**NGO**). Accordingly, we maintain in our revised proposal that a notional fund is created in accordance with Rule 84 and clause 6.1 of JGN's AA.

Revised proposal capex forecast

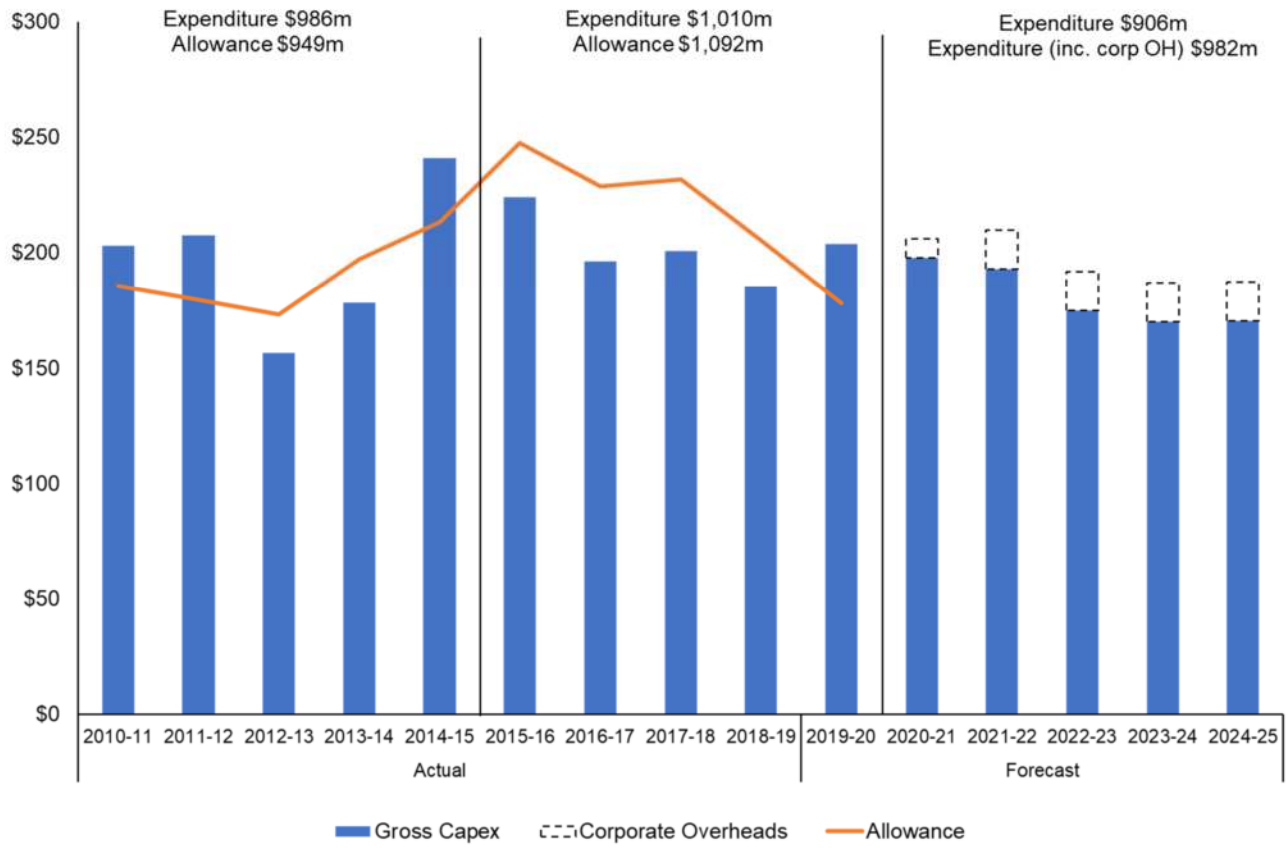
A breakdown of our revised proposal capex forecast for the five year period is set out in Table OV–3. This attachment (Attachment 4.2) includes a detailed discussion on the basis for our revised capex forecast.

Table OV–3: Capex over the 2020-25 period ($2020, $M, including overheads)

	2020-21	2021-22	2022-23	2023-24	2024-25
Connections	93.1	85.6	86.5	86.5	89.0
Meter replacement	20.0	21.4	25.9	31.1	33.5
Facilities and pipes	28.5	23.3	7.8	7.7	13.4
IT	15.6	22.4	26.4	18.8	18.0
Augmentation	18.1	25.8	14.5	10.6	0.6
Mains replacement	13.6	6.8	7.6	10.8	11.6
Other[5]	8.9	7.6	6.2	4.6	4.3
Gross total	**197.8**	**192.9**	**174.9**	**170.1**	**170.5**
Contributions	4.5	1.9	2.0	2.9	1.9
Net total	**193.3**	**191.1**	**172.9**	**167.2**	**168.6**

5 Other includes property, fleet and SCADA (the system which controls our network).

Figure 1-1: Our capex over time ($2020, $M, including overheads)



Dollar basis

All numbers in this document are in $2020 dollars unless stated otherwise.

Additional capex attachments

At the end of each section we list the further information we provide in response to the AER's draft decision and to support our revised capex forecast.

1. Connections unit rates

The AER accepted our connections forecast for our medium density / high-rise[6] and demand market segments.

The AER did not accept our connections forecast for our new homes, electricity to gas and Industrial & Commercial (**I&C**) tariff market segments. The AER accepted that our methodology was consistent with the forecasting approach used in the 2015-20 remittal process. However, the draft decision deviated from what we understood was now a settled approach and applied inconsistent averaging periods to forecast unit rates and volumes.

The draft decision represents a significant departure from the connections forecasting method which has taken over three years to work through and resolve. The AER said just nine months prior to making its draft decision that this forecasting method:

> *…represents the best possible forecast in the circumstances, conforms to the capex criteria and is likely to contribute to the achievement of the NGO.*[7]

Despite promoting a consistent approach to calculating unit rates and volumes during the 2015-20 AA review and subsequent remittal process, the AER's draft decision adopted an approach where almost all unit rates and volumes are calculated on an inconsistent basis, based on advice from Zincara.

The only consistency to the AER's approach is that where there is a material difference between a four-year average or five-year average it has selected the approach which provides the lowest capex forecast – even though this required making conflicting assumptions about which averaging period was appropriate. Neither the AER nor Zincara has provided sufficient reasoning or evidence to justify that departing from a consistent averaging period results will produce the best possible forecast in the circumstances.

The AER also made adjustments to remove years of data it considered to be outliers. However, the only outliers removed were years in which we undertook more costly or complex work or when costs were higher due to timing differences. As the work undertaken during these years was not atypical, excluding them results in an underestimate of our capex requirements.

The AER's change to the volume of mains required per new estate connection reduces the capex forecast by about $10M. The AER considered that the lengths of mains required per connection is reducing due to smaller frontages and substituted the 4-year average with data solely from 2017-18. However, this adjustment isn't supported by evidence:

- Although lot sizes have reduced by about 25% over the last 13 years there has been no reduction in the lengths of mains required per connection.
- We are laying more mains to reach homes in outer Sydney and are laying large amounts of mains outside metropolitan Sydney where we haven't seen the trend towards small lot sizes.
- Our Geographic Information System (**GIS**) data confirms that there has been no reduction in the lengths of main required per lot. The recent decline in the number of connections per metre is driven by timing differences between when new estates are reticulated (when the area is first developed) and when homes are connected (in the subsequent years as homes are completed).

The accuracy of the draft decision can be assessed by comparing our actual connection capex in 2018-19, adjusted for connections volumes (to isolate the impact of the capex forecasting approach). The draft decision forecast was 8.1% ($8.2M) lower than actuals, while our forecasting approach (based on the AER's previous (remittal) approach) was 3.9% ($3.9M) less, indicating that our proposal forecasting methodology produces the best possible forecast in the circumstances.

6 But not our proposal to remove our hot water metering product. This is covered in section 14.2.3 of our Revised 2020 Plan.

7 AER, *Final Decision Jemena Gas Networks (NSW) Ltd 2015-20 Access Arrangement,* February 2019, p.23

We have also considered whether to use a four-year of five-year average. Our analysis shows that as long as a consistent approach[8] is used all averaging periods result in a forecast within 1% ($3.3M) of our proposal. This compares to the inconsistent approach in the draft decision which results in a forecast 5% ($18.4M) lower.

In the following sections we set out our response to the AER's draft decision.

1.1 Connections capex forecast was a contentious issue until it was resolved in early 2019

How best to forecast connections capex has been a contentious issue between JGN and the AER since we lodged our 2015 Plan in June 2014.

The AER did not accept our connections capex forecasting approach for the 2015-20 period and we did not accept the AER's substitute forecast. We sought merits review of the AER's decision. The Australian Competition Tribunal remitted the decision back to the AER to be remade.

Through 2017 we worked extensively with the AER to understand our different assumptions and models. This process culminated in a round table discussion with the AER and CCP 10 in January 2018 where we reached an outcome on connections capex.

We accepted a new model developed by the AER to forecast connections capex, rather than the more granular method we had proposed.

The model implemented the AER's preferred approach for forecasting capex. The AER's model has two key parts:

1. Unit rates – the cost of laying mains and installing services and meters by market segment.
2. Volumes – the number of mains, services required on a per connection basis by market segment.

The AER's model averages the observed unit rates and volumes over the 2009-14 period. A consistent period is used so that the costs match volumes. The unit rates were then uplifted to reflect the increase in contracted prices. To calculate the forecast the unit rates and volumes are combined with a forecast number of new connections.

In October 2018 we submitted a proposal to the AER to resolve all outstanding matters subject of the remittal. This included a connections capex forecast based on the AER's model.

In February 2019 the AER accepted the proposed connections capex finding that

> *…it represents the best possible forecast in the circumstances, conforms to the capex criteria and is likely to contribute to the achievement of the NGO.*[9]

1.2 Our overarching aim was to prepare a lean capex forecast that was capable of being accepted by the AER

In preparing our connections forecast for the 2020-25 period the concerns the AER had previously raised were at the forefront of our thinking and approach. To progress from the previous debates summarised above we:

- Applied a top-down forecast, using revealed costs, consistent with the AER's preferred approach;
- Relied on audited data provided as part of the AA RIN;
- Adopted easy to understand forecast methods; and

8 Where the same averaging period is used to calculated all unit rates and volumes.

9 AER, *Final Decision Jemena Gas Networks (NSW) Ltd 2015-20 Access Arrangement,* February 2019, p.23

- Adjusted the unit rates for material changes, including the changes to supplier prices (resulting in overall cost reductions).

As unit rates vary year-to-year due to timing differences and natural variation in the type of jobs that are performed, we took a four-year average of costs to smooth out these fluctuations. We noted in our 2020 Plan:[10]

> *While taking a longer sample provides greater smoothing out [of] cost fluctuations it has the disadvantage of using older information which no longer reflects the costs of delivering services (it also affects the volume mix discussed in step 3). Given recent changes in the market (increasing tariff [traffic] management costs etc.) and as we have not taken into account real price escalation over this period we have not included data from 2013-14, 6 years prior to the start of the 2020 period. This results in a slightly shorter averaging period relative to the AER's previous approach (5 years). The difference between taking a 4 or 5 year averaging period has an immaterial (less than 1%).*

In November 2018 we provided the AER with an early view of our forecast capex. Given the history to forecasting connections capex we provided a detailed outline of our forecasting approach. No concerns were raised by AER staff at the time as part of the early engagement process.

As a result, we were still dedicated to ensuring that the AER's key concerns that arose from the 2015 merits review processes were proactively considered in developing our 2020 Plan model. These concerns and how we addressed them is summarised in Table 1-1.

Table 1-1: How our 2020 Plan addressed the AER's prior concerns

AER concern	How we addressed the AER's concern
The absence of material enabling the AER to comprehensively assess the reasonableness of data and the model. [11]	Rely on Regulatory Information Notice (**RIN**) data which has been independently audited by KMPG.
Deriving data from inconsistent data sets. To avoid error both unit rate and volume mix data should be derived from a single data set to avoid the potential for biases if different elements of different data sets are used.[12]	Rely on RIN data which presents cost and volume data from the same data source. Use the data consistently by using the same averaging period for unit rates and volumes.
The absence of explanatory material. [13]	Provide a clearly labelled model[14] and accompanying documentation[15] explaining the methodology and source of the data used.
As there can be significant differences in regional composition, material types and lay methods between years, the AER considered that to have confidence that the costs underlying a forecast are efficient, at least three years of data is required. [16]	Use a four-year average.

10 2020 Plan RIN Attachment JGN-2-3.15-2-Connection and metering forecasting methodology-20190630-confidential, p.9

11 Australian Competition Tribunal, *Application by Jemena Gas Networks (NSW) Ltd* [2016] ACompT 5, 3 March 2016, [145].

12 Ibid, [146].

13 Ibid, [147].

14 2020 Plan RIN Attachment JGN-2-3.15-2-Connections capex forecast model-20190630-confidential.xlsx

15 2020 Plan RIN Attachment JGN-2-3.15-2-Connection and metering forecasting methodology-20190630-confidential

16 AER, *Draft decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20 Attachment 6: Capital expenditure,* November 2014, p.6-21

AER concern	How we addressed the AER's concern
To have confidence that the unit rates calculated from historical averages are efficient, the AER considered that a consistent averaging process should be used. [17]	Use a consistent averaging period for all unit rate and volumes.
Concerns relating to inconsistent averaging periods in order to estimate the mains, services and meters per connection.[18]	Use a consistent averaging period for all unit rates and volumes.

Using a historical average will lead to a conservative forecast

As noted in our 2020 Plan[19] over the 2015-20 period, we have seen rising cost pressures due to:

- **Rising traffic management and restoration costs** – new connections are increasingly being made along transport corridors, along arterial roads, in business parks and high-density community use areas. Larger numbers of connections in these areas along with more stringent noise and traffic requirements have increased our costs.
- **Undertaking work across a large geographic area** – requires our contractors to travel longer distances to reach each customer in more remote areas.
- **Undertaking work in the most congested city in Australia and Oceania** – Sydney has the second lowest average speed, second highest travel time variability, and highest[20] or third highest[21] level of congestion in Australia. These travel times increase the time it takes (and in turn cost) for our contractors to complete each job.
- **Natural geography** – in addition to the natural bottlenecks (formed by Sydney harbour and the coastal spread of North and Central Coast population centres) the high proportion of rock and steep inclines increase the difficulty and cost of laying new underground mains and services.
- **Heighted competition for skilled labour** – over the past few years we have seen a large number of infrastructure projects across NSW competing for skilled labour. About 45%-50% of all Australian cranes are currently operating in our network area. These forces increase the pressure on labour costs required to deliver our connections program.

While we have been able to offset some of these cost increases we have been unable to fully mitigate them. This is particularly apparent in our mains and services costs which are most exposed to rising traffic management and restoration costs due to the location of the works. For instance connecting larger commercial customers in capacity constrained high density community use areas.

Despite there being a clear case to alter the averaging periods to reflect that increasing cost pressures we faced we decided to keep out forecasting methodology simple and consistent with the AER's remittal approach. This was to attempt to move on from our previous debates and ensure that we prepared a lean capex forecast capable of acceptance.

17 AER, *Draft decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20 Attachment 6: Capital expenditure,* November 2014, p.6-24

18 AER, *Final decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20 Attachment 6: Capital expenditure,* June 2015, p.6-23

19 2020 Plan RIN Attachment JGN-2-3.15-2-Connection and metering forecasting methodology-20190630-confidential

20 When average speeds are compared to free flow speeds.

21 When average speeds are compared against the posted speed limit.

1.3 The AER's draft decision

The AER agreed that our forecast was consistent with its remittal methodology:

> *JGN's proposed forecast methodology is consistent with the 2015–20 remittal, which is based on a historical revealed cost approach, with consideration of current and ongoing contractor rates.*[22]

However, the AER did not accept our connections capex forecast. The AER reduced our connections capex forecast by $23.6M on the basis that:

> *We consider that JGN did adjust historical data to reflect current circumstances when calculating unit rates for 2020–25 period. Our consultant has developed an alternative capex estimate by removing outliers in historic data used in the calculation of unit rates.* [23]

Given that the AER did not accept our forecast capex, we presume that the AER meant to say that we did not adjust data to reflect current circumstances.

As noted in Section 1.2, the AER raised no concerns about our approach as part of our engagement with the AER. Therefore the draft decision was a surprise especially as it contains no further analysis or consideration of our forecast. Instead the AER defers to Zincara who, despite also finding our forecasting methodology to be reasonable,[24] states:

> *Zincara considers that some of JGN's average unit rates may have been distorted by particular historic rates and proposed some adjustments to historic unit rates where there are distortions in the historic data* [25]

Zincara suggested an alternative approach which the AER adopted.

Rather than use a consistent averaging period the AER adopted different periods for each unit rate and for each volume by comparing unit rates and volumes using both five year and four year average periods. If there was any significant difference the unit rate or volume which resulted in the lowest capex forecast was always chosen. [26]

The only exceptions to this approach was where Zincara identified a single year with higher than usual costs. Where this occurred the AER adopted an alternative averaging period to remove the higher cost year. In all cases the alternative averaging period resulted in a forecast lower than both the four-year and five-year averages.

Figure 1-1 and Figure 1-2 present the AER's draft decision visually. The black arrow shows the unit rate or volume that was selected. The graph presents unit rates relative to the four-year average.[27] The four-year average is set to 100, so if a unit rate was 95% of the 4-year average it will be shown as 95.

Figure 1-1 shows that, wherever there is a difference, the AER selected the lowest unit rate.

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22 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-24

23 Ibid, p.5-11

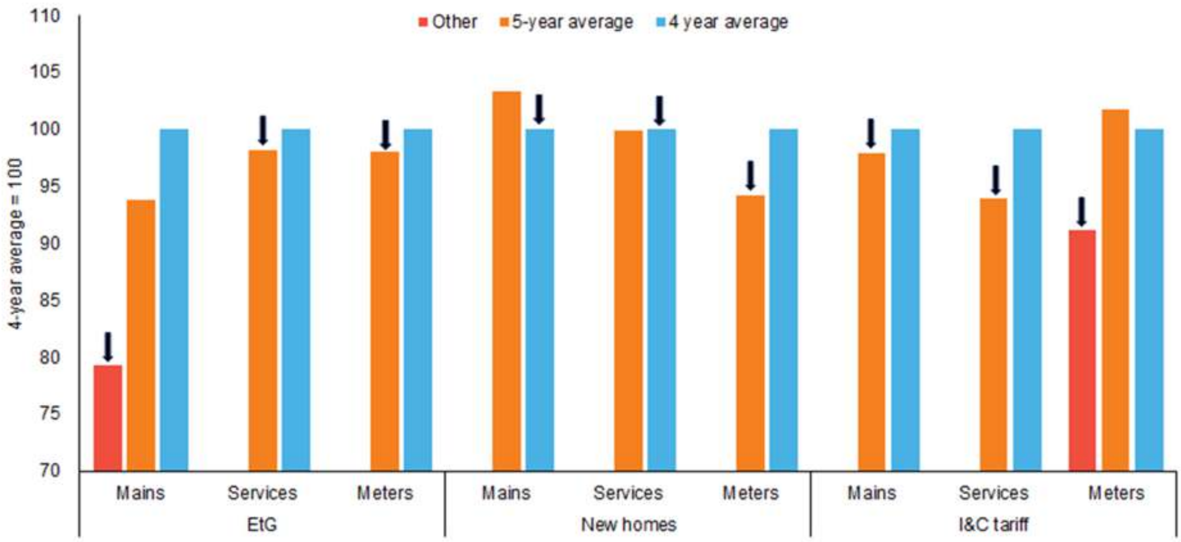
24 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.33

25 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-23

26 The only unit rate/volume where Zincara did not chose the lower one was for new home services, where there is was no significant difference.

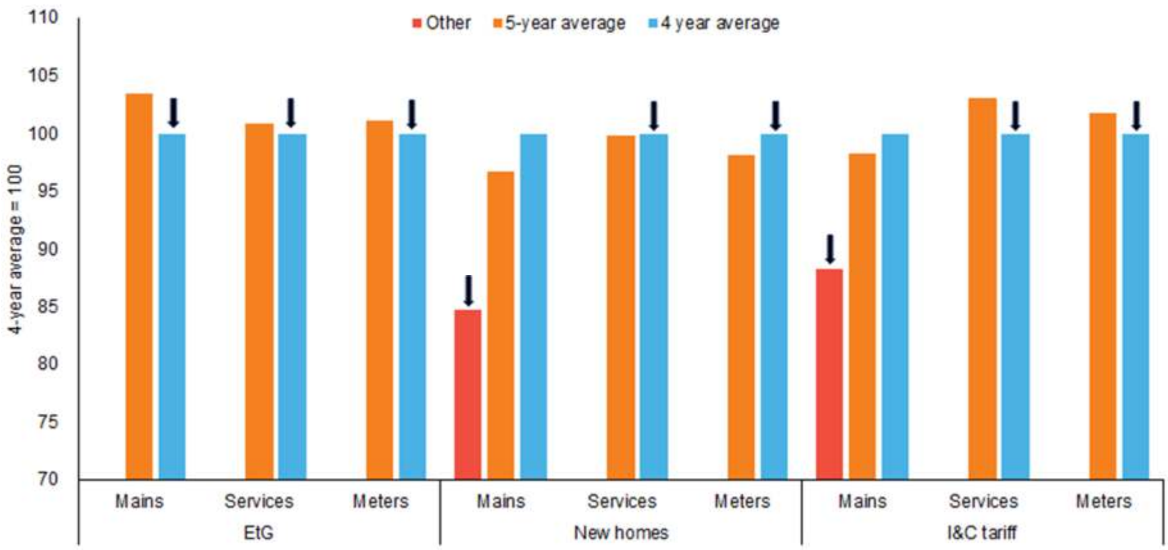
27 We did this for two reasons. Firstly, so that we can illustrate Zincara's analysis without making confidential data public. Secondly, to avoid scaling issues where unit rates for mains and services are in the thousands while meters are in the hundreds.

Figure 1-1 AER's approach to selecting unit rates



Similarly, Figure 1-2 shows that AER selected the approach which gave the lowest volumes. To select the lowest unit rates and lowest volumes the AER had to use inconsistent approach for each element, as shown in Table 1-2.

Figure 1-2 AER's approach to selecting volumes



(1) Volumes = the number of mains, services required on a per connection basis by market segment

Table 1-2: How the AER selected unit rates and volumes

	Component	Unit rate forecasting approach	Volume forecasting approach	Consistent?
EtG	Mains	Average of RY14, RY15, RY16, RY18	4-year average	Inconsistent
	Services	5-year average	4-year average	Inconsistent
	Meters	5-year average	4-year average	Inconsistent
New homes	Mains	4-year average	RY18	Inconsistent
	Services	4-year average	4-year average	Consistent
	Meters	5-year average	4-year average	Inconsistent

I&C tariff	Mains	5-year average	Average of RY14-RY17	Inconsistent
	Services	5-year average	4-year average	Inconsistent
	Meters	Average of RY14, RY15, RY17, RY18	4-year average	Inconsistent

Zincara states:

> *In reviewing the historic data and the four-year average results, Zincara considers that some average unit rates may be distorted by particular historic rates and has proposed adjusted rates where it considers these distortions occur. In doing so, we have also considered the earlier historic data to assess longer term trends, using a five-year average as a baseline and where this aligns closely with JGN's average we have accepted JGN's unit rates. Where there has been some variation, we accept the five-year unit rate. In some cases, we have found that a particular year's unit rates impact (distort) the average and in these cases, we have removed that year and applied the balance of the years to determine a unit rate.* [28]

We provided our consideration of Zincara's analysis and the AER's draft decision below.

1.4 Using inconsistent averaging periods results in a underestimate

The AER's draft decision methodology, which relies on inconsistent averaging periods, across unit rates and volumes, and between unit rates and volumes does not represent the best possible forecast in the circumstances, and significantly understates our require connections capex.

In the following sections we explain

- How using inconsistent averaging periods leads to significantly understated capex forecasts and that departures from a consistent averaging period should only be made with caution and where there is sufficient reasoning and evidence.
- Our proposal of using a consistent historical average leads to a conservative (lean capex) forecast given that we have experience rising cost pressures over the last few years.
- Neither Zincara nor the AER provide sufficient reasoning and evidence to justify departing from the historical average.

Departing from a consistent averaging period should be done with caution and evidence

As the AER has previously identified (see Table 1-1) selecting inconsistent averaging periods raises concerns.

Due to year-to-year fluctuations in costs and volumes, inconsistent averaging periods can lead to an underestimated forecast. Selecting an averaging period using years when costs and volumes are low will lead to an underestimate. Similarly, selecting an averaging period of high costs and volumes will lead to an overestimate.

As recognised by the AER's base step trend methodology for opex, on occasion departing from a historical average can lead to a more accurate forecast. For instance if there has been a step change in cost or there is a clear ongoing trend in costs.

However, such departures should be done extremely cautiously. For example, it is entirely appropriate to expect that reasoning is provided on why cost or volume drivers will change and this needs to be crossed checked and supported by evidence. It is simply not enough to speculate about cost possible movements, as in almost all cases counter-arguments are easily made. Evidence supporting the change should also be produced.

28 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.33

Neither Zincara nor the AER provides sufficient reasoning and evidence to justify departing from the historical average

Zincara stated that it applied the five-year average, unless the four-year average was similar to the five-year average (in which case it selected the four-year average) or it removed an outlier year where costs were higher.

No rationale or basis was provided for using a five-year average unless the four-year average was similar. We have not been able to identify any circumstances in which this approach would be reasonable.

Zincara stated that it considered earlier historical data to assess longer term trends. But this doesn't explain:

- Why it has relied on a five-year average, which places more weight on data from 2013-14 (six years prior to the start and 11 years before the end of the 2020-25 period) than the most recent four-years of data.
- Why, if it considered the longer five-year timeframe more reliable, it did not consistently apply a five-year average. Applying a consistent five-year average would have provided a capex forecast less than 1% different to our proposal, rather than 5% less.
- Why it didn't pay any regard to the challenging and rising cost pressures we face operating in Sydney which are pushing up some of our unit rates.
- No further explanation was provided in the AER's draft decision.

1.5 Removing outliers results in an underestimate of costs

In the subsequent sections we:

- Explain that our unit rates fluctuate year-to-year due to natural variation in the work completed. As the AER has previously recognised, only by taking a consistent average will the forecast properly reflect the work we will need to undertake. Removing outliers results in a underestimate of costs.
- Explain that there are timing differences between when some of our costs are incurred and when the work is undertaken. Only by taking a consistent average is the effect of these timing differences smoothed out. Removing outliers results in underestimate as it essentially removes costs based on when they have been incurred, for instance where we back-pay our contractors for work done in prior years.
- Consider each of the AER's adjustments for outliers:
  - Electricity to gas mains unit rates – The AER removed 2016-17 on the basis that this year did not reflect the trend. As we previously explained to the AER[29] the 2016-17 unit rate included costs relating to work undertaken in previous years. As a result making this adjustment will result in an underestimate.
  - I&C tariff meters unit rates – The AER removed 2015-16 on the basis that costs were higher in this year. Costs were higher in this year as we installing a large number of large meters. We will continue to install larger meters (and have several projects in our pipeline) in the 2020-25 period so removing this outlier results in an underestimate.
  - New home mains volumes – The AER based the forecast solely on 2017-18 data as it considered that declining block sizes will lead to reduce mains per connection.

    There is no data to support this hypothesis. We have seen a long term decline in block sizes but not in the meters of main we lay per connection – as we need to install more mains to connect new estates as they are built further away.

    We have also considered GIS data and found that there has been not reduction in the number of mains required to serve each customers. Rather, the short-term decline the AER has identified is likely due to the delay between when mains are laid and when customers connect and the building boom slowdown.

[29] See our response to information request 23 question 4.

- I&C tariff mains volumes – The AER removed 2017-18 on the basis that it was not reflective of trend. However, higher mains volumes are the new normal as shown by 2018-19 data and the projects in our pipeline. The AER's adjustment therefore results in an under-estimate.

Our unit rates fluctuate year-to-year due to natural variation in the work undertaken

As recognised previously by the AER (see Table 1-1) the kind of work we undertake differs year to year which affects the costs incurred.

There is natural variation in unit rates we incur each year due to:

- The proportion of mains which are laid in common trench versus direct lay. Our unit rates are lower when we lay a higher proportion of mains in common trenches (when connecting homes in new estates).
- The proportion of short versus long services. Long services is where we lay a service under a road to connect to the main on the other site of the road. The proportion of long versus short services depends on the lay-out of each area along with a cost assessment on whether it is better to lay mains on both sides of the road (dual reticulate) to achieve the cost savings from laying short services or otherwise (new homes and electricity to gas).
- The size and material of the mains/services laid. The proportion of larger mains we need to lay is driven by capacity concerns and is, again, dependent on the layout and design of new estates and/or the surrounding area (which we do not control). (All segments, in particular when steel mains are required for medium density / high-rise and commercial connections).
- The mix and size of meters required for customers individual capacity requirements. (Medium density / high-rise, commercial and to lesser extent electricity to gas)

Only by taking a consistent average will the forecast unit rates reflect the costs we expect to incur in the future. Removing outliers years where costs are higher than usual results in a underestimate that does not take into account in some years we will incur above average costs – due to the composition and type of work that needs to be undertaken.

Our unit rates fluctuate year-to-year due to timing differences

Also influencing the observed unit rates are timing differences between when some costs are incurred. Often we incur part of making a connection in the years preceding or after the works are undertaken. For example:

- Restoration costs. Councils manage their own workflow and tend to invoice sporadically. In many cases this has resulted in the cost of restoration works being finalised years after main or service was laid.
- Non-standard claims. While most contractor costs are paid on job completion, we individually review and assess traffic control and non-route civil works. This leads to a delay from when works are completed and when they are paid to account for the contractor preparing claims and our assessment. Backlogs tend to occur in busy periods (such as in recent years) where our contractors have focused their resources on delivering. This can results in the non-standard component of work being recognised in the year after the work was undertaken.
- Bulk recognition of material costs. Many of our materials, such as regulators, are recognised in our financial accounts when they are taken by our contractors from our stores rather than when they are installed. This results in timing issues where regulator costs are recognised in our financial accounts in the years prior to when they are installed. For example if 100 meters are taken from stores in year 1 but installed in year 2, these costs will sit in year 1's unit rate. Year 1 unit rate will look relatively higher while the year 2 unit rate will look relatively low.
- Back-pay. In line with our commercial arrangements we may be required on an ad hoc basis to backpay our contractors for costs incurred in prior years. A recent example of this was a substantial ([redacted]) increase in the cost of [redacted]. To ensure our contractors did not operate at a loss we agreed to amend the unit rates to reflect this change in cost. Before we could do this we needed to complete our analysis

to determine what an efficient and reasonable uplift to unit rates would be. Only once we had determined the new rates could the required system changes be made.

The time taken to assess and determine revised unit rates required us to make an ex-post adjustment for the work already complete but paid at the older rates. As a result costs were for work done in the previous year.

Only by taking a consistent average can the effect of these timing differences smoothed out. Removing outliers results in an understated forecast as it essentially removes costs that should otherwise be included despite timing differences.

Electricity to gas mains unit rates

Zincara used a customised averaging period on the basis that:

> *..the historic data for mains shows a step change from 2017 compared with the earlier years, with 2017 being a peak year. Removing the peak 2017 year from the five years average gives a unit rate of [redacted] compared with the four-years average unit rate of [redacted].* [30]

And notes that:

> *2017 not reflective of trend. Remove that year and average remaining four years of RY14-RY18.* [31]

We provided the AER further information on 2016-17 electricity to gas mains unit rates in response to information request IR023:[32]

> *As we note in our connections and metering forecasting methodology, unit rates vary year-to-year in part due to timing differences between when connections are made and when some costs (like restorations) are incurred.*
>
> *We pay restoration costs several months after a connection is made, based on the invoice issued by local Councils. In 2016-17 we incurred a higher than usual amount of restoration costs. This was primarily due to:*
>
> - *NSW Council Amalgamations where many councils either merged (or were proposed to merge). This resulted in many councils issuing outstanding invoices sooner than normal in order to close their books.*
> - *A backlog of restoration costs which were not processed in RY16 due to the GASS+ to SAP transition.*
>
> *Smoothing out these timing differences (and to account for the natural variation in the jobs performed) is why we take a 4-year average of unit rates.*

So while 2016-17 is a higher year, it is higher because it includes costs for work undertaken in prior years. Excluding this year will result in an under-estimate of capex that does not fully reflect the cost of laying mains in existing areas.

Figure 1-3 shows the actual unit rate incurred (black) against Zincara's forecast (red), both relative to the four-year average (set to 100). It also includes the latest 2018-19 data.

While we acknowledge that 2016-17 costs were higher than average we do not agree that it is not reflective of the trend. These are efficient and prudent costs.

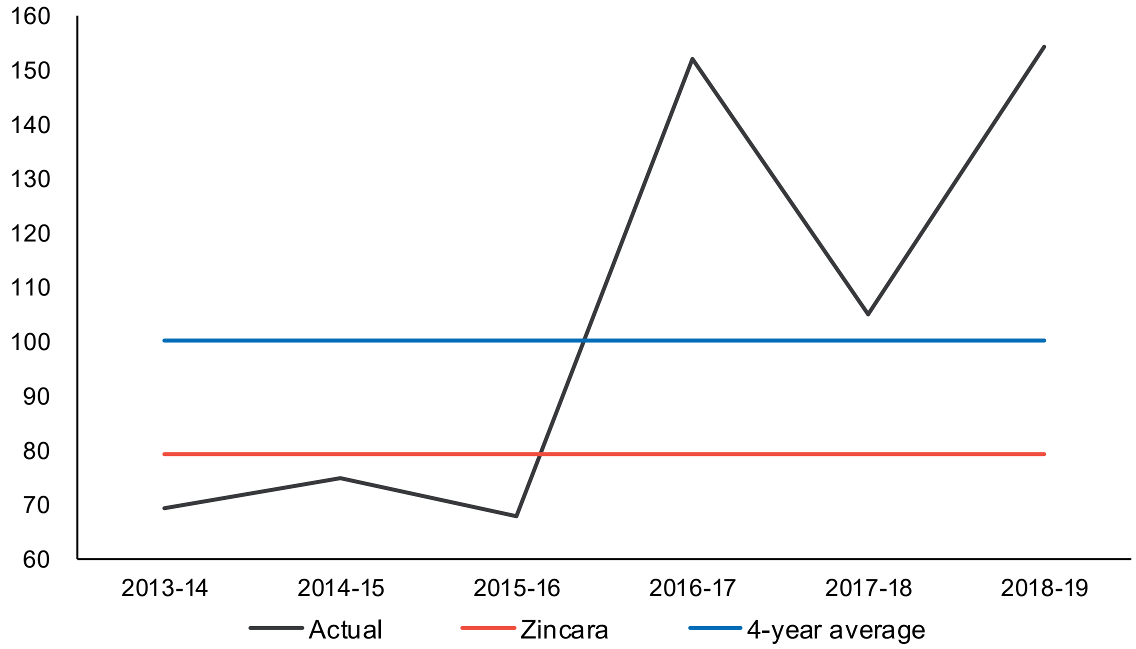
30 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.33

31 Ibid, p.127

32 JGN, *Response to AER information request IR023*, 26 September 2019, pp 4-5

Zincara's approach of excluding 2016-17 results in a forecast 21% less than the four-year average and less than every year of costs since 2015-16.

Figure 1-3 Electricity to gas mains unit rate trend (4-year average = 100)



We note that costs fell in 2017-18 only to rise again in 2018-19. The increase in costs in 2018-19 is due to back-paying our contractors for work was done in 2017-18 (related to the increase in the cost of [redacted] discussed above).

It is also important to note that given the increase in [redacted] the unit rates of these mains will remain higher than the historical average.

As a result, Zincara's approach to forecasting electricity to gas mains does not produce the best estimate in the circumstances.

I&C tariff meters unit rates

Zincara used a customised averaging period on the basis that:

> *For meters, 2015-16 is a relatively high peak which distorts the average. Removing that year from the five-year average give a unit rate of* [redacted]*, compared with the four-year average unit rate of* [redacted][33]

And states that:

> *2016 not reflective of trend. Remove that year and average remaining four years of RY14-RY18.* [34]

We provided the AER further information on 2016-17 I&C tariff meters unit rates in response to information request IR023:[35]

> *The size (and cost) of commercial meters ranges from the same of a residential meter up to very large meters (and associated meter kits) for hotels or manufacturers. The number of larger*

33 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.34

34 Ibid, p.127

35 JGN, *Response to AER information request IR023*, 26 September 2019, p.4

connections capacity connections we make each year depend on the connection requests we receive.

In 2015-16 we installed a greater proportion of larger meters and more expensive meter kits which pushed up the average unit rate for that year. Examples of 2015-16 connections which required larger and more expensive meters include:

[redacted]

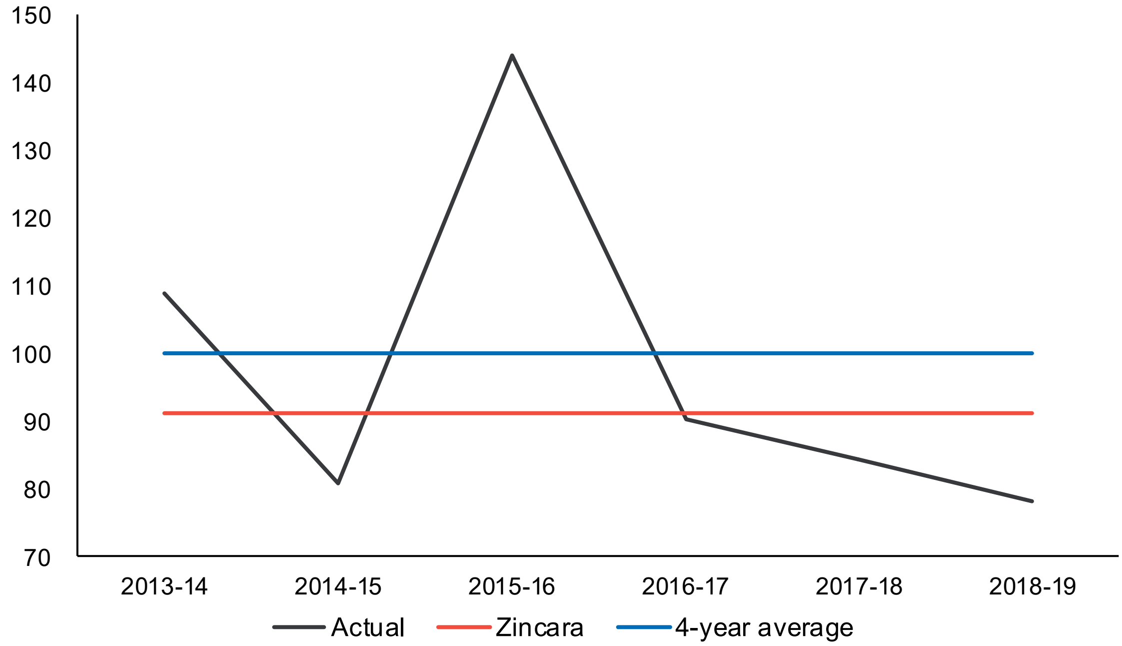
While we recognise that costs in 2015-16 were higher than the average (as shown by Figure 1-4) this simply reflects the variety of connections we make in each year.

Removing this outlier will result in an underestimate our costs over the 2020-25 period as it does not reflect that at times we will need to install larger meters.

We are currently preparing connection offers for several sites which we require larger meters and associated kits to be connected in 2020-21 and 2021-22. This includes [redacted]

[redacted]

Figure 1-4 I&C tariff meter unit rate (4-year average = 100)



New home mains volumes[36]

The AER stated:

> *The data shows a reducing trend for the length of mains which is likely to be consistent with smaller frontages for new estate allotments. Zincara recommends the use of the most recent year's data for mains as it is likely to be more representative of the forecast period.* [37]

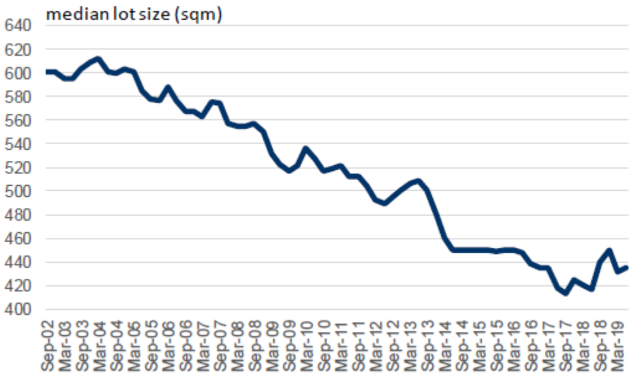
Zincara stated:

> *Mains (metres per connection) for the four-year average is* [redacted] *The data shows a reducing trend for the length of mains and we consider that this is likely to be consistent with smaller frontages for new estate allotments and also aligns with earlier historic data. We therefore propose that the most recent year is likely to be more representative of the forecast period and recommend using a connection length of* [redacted] *In response to the AER's request for information, JGN provided a draft(unaudited) mains length for 2019 showing* [redacted] *This further supports our recommendation that there is a decreasing trend on the size of blocks.* [38]

We demonstrated in our response to AER information request 023, there is no correlation between long-term decline in smaller block sizes and the average length of mains per home. This is visible when comparing Figure 1-5 and Figure 1-6. This is because while smaller block sizes may be reducing the lengths of mains required, we are also having to lay more mains to connect new estates on the edge of Sydney's fringe.

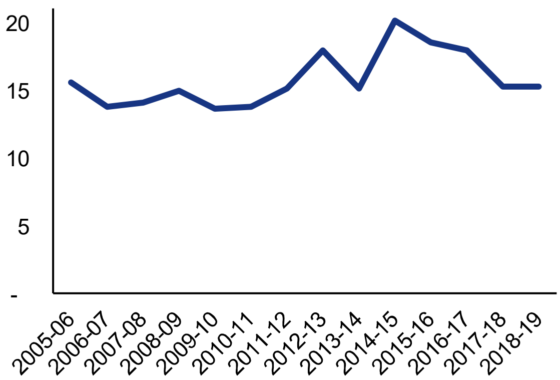
We are also reticulating a significant number of new estates outside of metropolitan Sydney, where we are not seeing the trend towards smaller block sizes. Over the 4-year years we have laid more than 10,000 metres of main in Maitland, Lake Macquarie, Shellharbour, Cessnock, Wyong, Wingecarribee, Wollongong, Dubbo, Orange, Hawkesbury, Wollondilly, Bathurst, Newcastle, Goulburn, Port Stephens and Gosford.

Figure 1-5 Median lot size outer Sydney (sqm)



Source: BIS Oxford Economics

Figure 1-6 Average length of mains per new home (metres)



While there does appear to be a declining trend in the number of meters per connection in the last few years, this statistic does not provide any insight into whether less metres of main will be required per connection.

New estates are generally reticulated before the first houses connect and with other services, to take advantage of the savings from common trenching and other synergies. It will typically take several years for all new houses in a new estate to connect.[39] The speed of housing completions varies depending on market forces, developer

[36] Volumes = the number of mains, services required on a per connection basis by market segment

[37] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-24

[38] Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.36

[39] This is apparent in the maps of Largs and Cecil Park, provided in response to information request IR07, which show mains along streets with some homes completed and others lots still vacant.

financing, skill shortages etc. This is another reason we have used a four-year averaging period to smooth out these timing differences.

However, given the AER's concern we also looked at the number of lots served per metre of main[40] to check whether a small number of mains can be expected. We looked at lots as this avoids the timing issue when using the ratio between connections and mains.

Table 1-3 shows there is no declining trend demonstrating that smaller lot sizes are not driving a reduction in the metres of main required to reticulate new estates.

Table 1-3: Metres of main per lot

	2015-16	2016-17	2017-18	2018-19
Lots served per metre of main	22.9	25.5	25.5	24.3

As a result, we do not accept the AER's draft decision and instead have retained our approach of using a four-year averaging period.

I&C tariff mains volumes

Zincara used a customised averaging period on the basis that:

> *The four-year average for mains is* [redacted]*, however 2018 is approximately* [redacted] *higher than the next highest year. We have removed this year and applied the remaining years of the five-year average to give a unit length of* [redacted]*.* [41]

And:

> *2018 not reflective of trend. Remove that year and average remaining four years of 2014-2018.* [42]

We do not agree that 2017-18 is an outlier. Rather, we consider that the length of volumes we laid in 2017-18 to be consistent with the trends we are seeing in this market segment and with the pipeline of projects currently in our horizon. As a result, Zincara's forecast reflects an underestimate in the lengths of mains we expect to need to lay.

Unlike residential areas, we do not reticulate commercial areas when they are developed. At the time each area is developed we are unsure of how land will be used, whether the sites will want a gas service/connection and their potential capacity requirements.

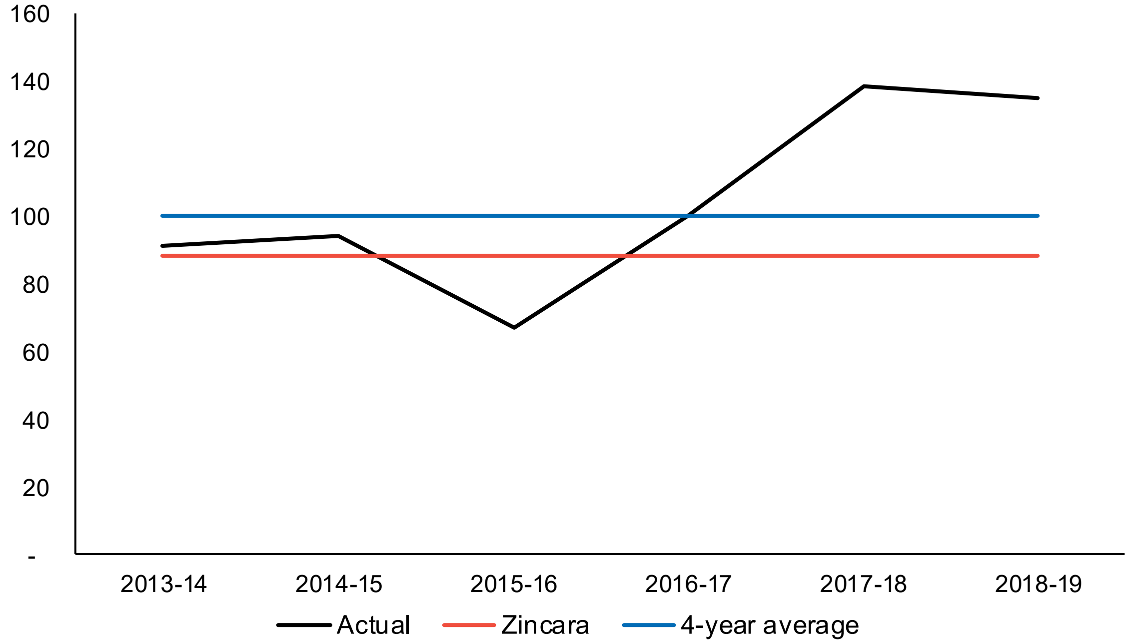
This means that connecting a new commercial customer often requires a large main extension (if the area has not been previously reticulated). Similarly, given the block sizes in commercial business parks mains extensions often require to be very long - even if they are just extending the main a few blocks.

40 We extracted this data by running a query on our GIS system to count the number of unique lots to the side of each main.

41 Zincara 2019,*Access Arrangement 2019 JGN Capital Expenditure Review,* p.36

42 Ibid, p.129

Figure 1-7 I&C tariff mains volumes (4-year average = 100)



Although the AER considered 2017-18 to be an outlier, we consider it to be consistent with what is occurring in the field, where longer lengths of main are being required as we extend our network out and connect businesses in new developments.

We saw a similarly large number of meters of main required in 2018-19 and we have a pipeline of commercial connections with a large number of meters required:

For instance:

[redacted]

The size of these mains extension materially affects the market segment average given that we typically only make 800 commercial connections per year.

1.6 The AER's draft decision forecasting methodology results in an underestimated capex forecast

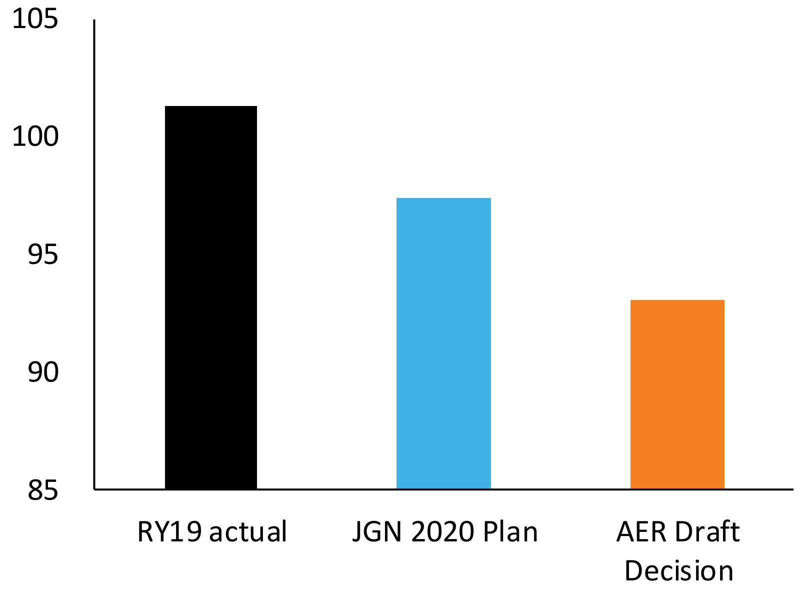
Actual data from 2018-19 provides an objective test on whether the AER's draft decision forecasting methodology provides a better or worse forecast than the methodology we proposed.

Figure 1-8 compares the AER's draft decision the forecast included in our 2020 Plan. This is on a connections adjusted basis in order to isolate the accuracy of each capex model.

Overall our forecast was much more accurate than the AER's draft decision – although still lower than our actuals. Actual connections adjusted capex was $101M while we had forecast $97M, $3.9M or 3.9% less.

The AER's draft decision was significantly lower coming in at $93M, $8.2M or 8.1% less than actuals. This demonstrates that Zincara's inconsistent averaging approach leads to a underestimate of our capex requirements.

Figure 1-8 2018-19 forecast connection capex (adjusted for actual connections) ($2020, $M direct, unescalated)



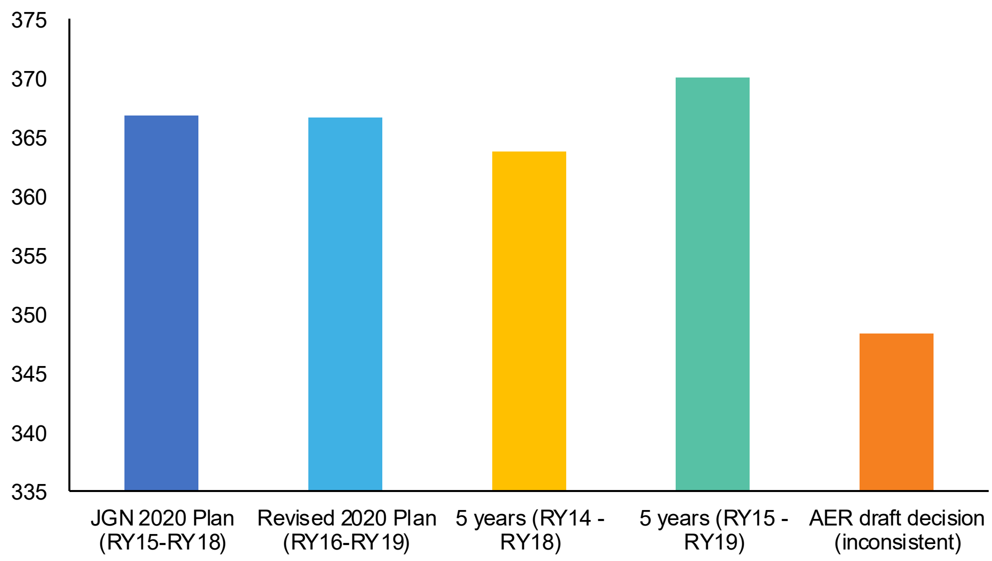
1.7 Forecasting options

In preparing our Revised 2020 Plan we again considered which averaging period is appropriate. We found that no matter which approach is used, as long as the method is applied consistency the four-year and five-year averaging periods product a similar capex forecast (see Figure 1-9).

We have continued with our approach of using the most recent four-years as we still consider that the best approach in the circumstances is to use the most recent five-years.

As noted in Section 1.1 of this attachment, an expected outcome of the merits review and remittal processes was to move away from debates and differences in view on which model to use. Therefore, we adopted a forecasting approach and model, as outlined in Section 1.2, that is consistent with the AER's remittal decision.

Figure 1-9 Forecast capex using each forecasting approach ($2018, $M, direct, unescalated)



1.8 Revised capex forecast

Our revised connections capex forecast has been updated to include:

- 2018-19 cost data. To do this we changed the four-year averaging period (for volumes and unit rates) to use the 2015-19 period rather than the 2014-18 period.
- Core Energy's revised connection forecast.
- The costs of our individual hot water metering product consistent with our decision to continue to provide this product. This update was mainly applied via Core Energy's updated demand forecast (as Core Energy reflected the change in its update). However it also required amending our forecasting model to ensure that the metering unit rate for our individually metered high-rise connections reflected that we will continue to install hot water meters and gas meters (rather than just gas meters).

Overall these updates increase our 2020-25 connection capex forecast from $387.5M to $392.2M.

1.9 Supporting information

Table 1-4 lists the additional supporting document we have provided in response to the AER's draft decision.

Table 1-4: Connections supporting documentation (included in attachment 4.5)

Document reference and name	Author
JGN-RP-Connections capex forecast model-20200109-public.xlsm	JGN
JGN-RP-Capex Projects list (real $2018)-20200109-Public	JGN

2. Meter replacement

The AER's draft decision accepted $105.7M of our $118M forecast meter replacement capex. We welcome the AER's decision on the programs and costs which it has found to be prudent and efficient. We provide no further information on these elements of our forecast. Instead our response focusses on the aspects of our forecast which the AER did not accept.

Residential gas meter replacement volumes

The largest reduction was due to the AER's draft decision to lower our forecast residential gas meter replacement volumes forecast and, in turn, reduce our capex forecast by $8.4M.

After 15 years of age, consistent with Australian Standards, we test our meters every five years to confirm whether they are accurate. If the meters are not accurate they must be replaced.

In our 2020 Plan we assumed that our meters will still be accurate at their 15 and 20 year tests and would need to be replaced at 25 years.

The draft decision adopts an alternative forecast by assuming that some meters will pass at the 25 year mark. This reduced the planned replacement volumes by 55,468 meters.

The AER made this change to take into account that some meters will pass at the 25 year mark. While we consider the assumptions optimistic we do agree that some meters will pass their 25 year tests. In isolation this assumption is reasonable.

However, this approach is not reasonable when preparing a forecast for a portfolio of meters. Just as some meters will pass the 25 year tests, some meters will fail their 15 and 20 year tests. As a result the draft decision will underestimate meter replacement capex.

This is shown by our 2019 meter test results where a batch of meters failed their 20 year test. Together with poor performance from two other batches of meters, we will need to replace 44,549 meters in the 2020-25 period. This compares to the AER's forecast of zero and our forecast of 29,975.

Once 2019 test results are taken into account the difference between our forecasts narrows down to 28,225 meters. It is reasonable to assume that at least 28,225 (13%) of the 220,759 meters scheduled for testing at the 15 and 20 year marks will fail. As a result, we think there is no material difference between our forecast and a version of the AER's approach which also takes into account failures at the 15 and 20 year marks.

Accordingly, our Revised 2020 Plan makes no changes to our metering volumes forecasting methodology.

Other changes

The AER's draft decision also reduced the forecast costs for our defective hot water meter replacement program and meter data loggers replacement program by changing which historical years are used to forecast costs. Rather than adopt a 4-year average over the 2014-15 period to 2017-18 period the AER removed the 2014-15 year (but only for these programs).

We disagree with the AER's approach for the reasons outlined in our response to the AER's approach to connection capex in section 1. However, given that we now have 2018-19 data we have updated our forecast to use the latest 4-year average – the period from 2015-16 to 2018-19. As a result, disagreements about 2014-15 data are no longer relevant.

Revised forecast

Our revised forecast incorporates 2019 testing results, updates our forecast to include 2018-19 cost data and corrects a calculation error in our meter volumes forecasting model. These updates result in a meter replacement forecast with higher volumes but at a lower cost of $117.6M relative to our 2020 Plan $118M.

2.1 Meter replacement volumes

2.1.1 2020 Plan

We test residential gas meters in accordance with Australian Standards to determine their accuracy and leak tightness.

When a batch of meters approaches 15-year of age a sample of these meters is tested. The results determine whether we will replace this batch of meters or extend their lives:

- If the meters are accurate to ±2% we extend their life by five years. We then subsequently test these meters again two years prior to the end of their life extension.
- If the meters are accurate to ±2.5% we extend their life by three years and then replace the meters. We do not retest these batches given the high-likelihood they will be inaccurate.
- Otherwise the whole batch of meters is scheduled for replacement.

We have prepared a meter replacement volume model which takes into account the statistical sampling test results for each batch of meters.

If the meters:

- Fail – they are scheduled for replacement two years out from when replacement is due.
- Receive a three year life extension – they are scheduled for replacement three years from when replacement is due. This outcome is relatively rare.[43]
- Pass – another statistical test is scheduled in five years (the meters to be tested are removed from the meter population in the model to ensure they are not double counted).

Where we don't have testing results we assume that all untested residential gas meters will pass their 15 and 20 year life extensions and will be replaced at 25 years. We do not account for the proportion of meters which will be replaced at 15 and 20 years leading to a lean capex forecast.

Relative to what we assumed for the current 2015-20 period, these assumptions are much more optimistic. We had forecast that meters would need to be replaced at 20 years of age, beyond their design life of 15 years. At the time, the AER found that the age we proposed to replace meters to be in a reasonable age range and accepted our approach as prudent and efficient.[44]

2.1.2 The AER's draft decision

The only concern the AER, and its' consultant Zincara raised, was around our assumption that all meters tested at the 25 year stage would fail:

> *Our assessment was informed by analysis of metering by our consultant, Zincara, and our own review of the proposal. Detailed analysis for each metering category can be found in the Zincara report, while in this section we have focused only on our alternative forecasts for the metering replacement program.* [45]

[43] This functionality is new in our revised meter volumes replacement model [JGN-RP-2-3.15-2-Meter replacement volume forecast model-20200109-confidential.xlsx]. This functionality wasn't needed in our 2020 Plan but has been included as a meter family tested in 2019 was given a 3-year life extension.

[44] AER, *Draft decision Jemena gas Networks (NSW) Ltd Access arrangement 2015-20, Attachment 6: Capital expenditure,* November 2014, p.6-39

[45] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, November, p.5-30.

…

Zincara has reviewed the historical performance of each meter family and based on its performance, and that of similar families, determined the likelihood of whether each family has to be removed when it reaches a life of 25 years, or whether it can extend past the 25 year life. Given that a large number of meters are reaching their 25 years field life during 2020–25 period, the program is substantial. Zincara's analysis is that a number of meter families can be extended past the 25 year life which will result in a reduced meter replacement program. [46]

Zincara said its approach was:

..to review the historical performance of each meter family and based on its performance and that of similar families determine the likelihood of whether each family has to be removed when it reaches its field life of 25 years or whether it can extend past the 25-year field life. This methodology is even more relevant given that there are 180,000 meters reaching their 25 years field life during the 2021-2025 period. The capex of such a program is significant.

The outcome of our analysis is that a number of meter families can to extended past the 25-field life which will result in a reduced meter replacement program.[47]

Zincara and the AER only reviewed historical performance at the 25-year mark – where we assumed that all meters will fail. No corresponding adjustments were made to reflect that some meters will fail at the 15 or 20 years.

At a meeting with the AER and Zincara on the 19 of November 2019, Zincara acknowledged that some meters may fail at the 15 and 20 year mark. Zincara said that they did not conduct similar analysis for performance at the 15 and 20 year marks as they did not have sufficient data.

As a result, the draft decision is an underestimate that does not represent the best forecast possible in the circumstances.

2.1.3 2019 meter testing results

The degree to which the AER's forecast leads to an underestimate can be seen in our 2019 meter test results, shown in Table 2–1.

The AER had forecast that no meters would fail in 2019. We had forecast 29,975 meters would fail and would need to be replaced in the 2020-25 period. In reality 20,665 meters failed and 23,884 meters received a 3-year life extension. This means that 44,549 meters of the meters tested in 2019 will need to be replaced in the 2020-25 period.

While the AER did correctly forecast that a batch of meters undergoing at 25-year test would pass, its assumption that all meters would pass their 15 and 20 year test resulted in an under-estimate. In contrast our forecasting approach was more accurate than the AER's , although it still produced an under-estimate.

Table 2–1: 2019 testing results

	2020 Plan	AER draft decision	Actual
15 year tests	None fail (55,520 pass)	None fail (55,520 pass)	No fail (55,520 pass)
20 year test	None fail (37,831 pass)	None fail (37,831 pass)	Fail: 20,665 3 year life extension: 17,166 Pass: 0

46 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, November*,* p.5-30.

47 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.48

25 year test	All fail (29,975)	None fail (29,975)	3 year life extension: 6728 Pass: 23,247
Total	**93,351 pass** **29,975 fail**	**123,326 pass** **0 fail.**	**78,767 pass** **23,884 3-year extension** **20,665 fail.**

2.1.4 Issues with Zincara's specific assumptions about 25-year tests

Generally, Zincara's assumptions around meter performance at their 25-year tests are optimistic. Table 2–2 sets out the assumption applied by the AER/Zincara and compares this performance to what we have observed. We also note that the manufacturers design life for their latest equivalent meter is only 20 years indicating that manufacturers are not confident that there meters will continue to be accurate at that age.

Table 2–2: Concerns with the AER/Zincara 20-year test assumptions

Meter	AER/Zincara assumptions	Our concern
[redacted]	40% of lots and 20% of meters pass	Design life of the latest model [redacted] is only 20 years. We have only tested two lots where one (3,885) passed and another (6,728) only gained a 3-year life extension.
[redacted]	25% of lots and 23% of meters pass	Design life of the latest model [redacted]) is only 20 years. 75% of lots and 56% of meters have failed their 25-year tests 22% of lots and meters failed their 20-year tests
[redacted]	50% of lots and 65% of meters pass	Design life of the latest model [redacted]) is only 20 years. We have not yet tested a single lot at 25-years 42% of meters failed their 20-year tests indicating poor performance of this meter family The meter is similar to the [redacted] where 75% of the lots tested and 56% of the meters failed the 25-year tests.
[redacted]	25% of lots and 17% of meters pass	We have not yet tested a single lot at 25-years. We will not be testing these meters given the field failures (failing indexes) we have seen in the field.

2.1.5 Updating our meter replacement forecast

There are two parts to forecasting meter replacement volumes:

1. Volumes based on actual test results – where we have tested meters and know whether their life has been extended or whether they have been scheduled for replacement.
2. Volumes based on forecast test results – where we have not yet tested meters and have to forecast future test results.

We discuss each part separately below.

Volumes based on actual testing results

Neither the AER nor Zincara raised any issues with this element of our forecasting approach, and on this basis, we have assumed that it has accepted this forecasting approach.

We have updated this element of our forecast to reflect 2019 test results.

Table 2–3: Meters tested in 2019 that will be replaced in the 2020-25 period

	2020 Plan	AER draft decision	Actual
Total	29,975	0	44,549

Volumes based on forecast test results

Our 2020 Plan forecast meter replacements by assuming that all meters tested would pass their 15 and 20 year tests but would fail their 25 year tests. While this approach appears simple, we consider that it is appropriate given that it is not possible to determine with any certainty whether each batch of meters will fail their tests.

We accept some meters will pass their 25-year tests, but some will fail their 15 and 20 year tests

The AER's draft decision sought to address this uncertainty by examining individual performance by meter family to forecast a proportion of meters which would pass their 25-year tests. While we consider the specific assumptions optimistic, we recognise what the AER is trying to achieve. We agree that in isolation it is not unreasonable to assume that same meters will pass their 25-year tests. Our concern is that this assumption is not reasonable at the portfolio level. In reality while some meters will past their 25-year tests, other meters will fail their 15 and 20 year tests.

Our forecasts are not materially different, once the AER's forecast recognises meters fail at the 15 and 20 year tests

As we now have 2019 test results (and no longer need to forecast these results) the difference between our forecasts narrows to 28,225 meters.

Forecasting whether each batch of meters will pass or fail is difficult. While past meter accuracy performance gives some indication, history has shown that past performance is not always indicative of future results. This is particularly true for our 15 and 20 year tests.

Aside from whole meter family failures (such as the 32,000 [redacted] meters which all failed at 15 years), we have seen failures in meter families which have had previously strong performance. Take for example our [redacted] meters. Although the first 100,000 meters we tested passed their 15-year test, the next 120,000 failed. We have seen similar results with our 2019 tests where:

- A batch of 12,000 [redacted] meters failed their 20 year test even though 16,000 meters across five batches had previously passed.
- A batch of 9,000 [redacted] meters failed their 20 year test even though 49,000 meters across four batches had previously passed.
- A batch of 17,166 [redacted] meters were only granted a 3-year life extension at the 20 year mark even though the 119,000 meters across four batches had previously passed.

Reasonable minds can differ on how to forecast the probability that a batch of meters from a family with strong past performance will fail.

If only one of seven batches of [redacted] meters fail their 15-year test or 20 year tests, this will result in an additional 35,000 meters which need to be replaced in the 2020-25 period.

We consider that a reasonable forecast, no matter how it was calculated, would assume that at least 28,225 (13%) of the 220,759 meters scheduled for testing at the 15 and 20 year marks will fail.

While 28,225 meters may pass their 25-year test a similar amount of meters are likely to fail either their 15 or 20 year tests. As a result, if the AER's forecasting methodology takes into account failures at 15 and 20 years there will be no material difference between our forecasts.

What would a prudent service provider forecast?

We recognise that forecasting replacement volumes is not a perfect science, which is why we have adopted a forecasting approach that, while simple, effectively takes into account the uncertainty in future meter performance.

It is important to note that updating our forecasting assumption that meters will fail at 25-year rather than 20-years (as we had previously forecast and the AER had previously accepted) is what a prudent service provider operating efficiently would do. While it may be possible to extend the life of our meters out further this can only be done once the outcome of testing meters over the upcoming regulatory period is known.

2.2 Unit rates and costs

The AER also reduced our proposed costs for two programs:

3. Defective residential hot water meter replacements.
4. Meter data loggers.

For both of these programs we applied a four-year average of historical costs to forecast capex, consistent with our methodology for the connections capex.

The AER, on Zincara's advice,[48] removed the 2014-15 year on the basis that this year was an outlier that should be removed. In both cases these adjustments lower forecast capex. [49]

In section 1.5, in the context of our connection capex forecast, we explain that removing higher cost years will not result in the best forecast as costs and volumes fluctuate year-to-year. This is due to natural variation in both the work undertaken and due to timing differences between when costs are incurred and when the work is undertaken. These arguments apply equally to our metering forecast.

To be consistent with our connections forecast, we have also updated our metering forecast to reflect 2018-19 data which is now available. As part of this we moved from using a 2014-15 to 2017-18 average to a 2015-16 to 2018-19 average. In doing so 2014-15 is no longer used in our forecast.

2.3 Revised capex forecast

Our revised meter replacement capex forecast includes the following updates:

- As we now have 2019 meter testing results, these have been incorporated into the forecast.
- We have updated the four-year averaging period for unit rates and average annual costs to reflect that we know have 2018-19 data. We now use the 2015-19 period rather than the 2014-18 period, consistent with our connections forecast.
- Corrected a referencing error in our metering volumes forecast model.[50]

Overall these updates reduced our 2020-25 meter replacement capex forecast from $118M to $117.6M.

2.4 Supporting information

Table 2-4 lists the additional supporting document we have provided in response to the AER's draft decision.

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48 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.52

49 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, pp 5-30 – 5-31

50 Our model was incorrectly using a formula to look up "Industrial and Commercial" but the values it should have been looking up were "Industrial & Commercial". The corrected formula can be found on the "Calc|All Data" sheet in the columns with the heading "Unable to Replace (E.g. difficult access)" of the Meter replacement volume forecast model.

Table 2-4: Meter replacement supporting documentation (included in attachment 4.5)

Document reference and name	Author
JGN-RP-2-3.15-2-Meter replacement capex forecast model-20200109-confidential.xlsx	JGN
JGN-RP-2-3.15-2-Meter replacement volume forecast model-20200109-confidential.xlsx	JGN

3. Facilities and pipes

The AER's draft decision has accepted $63.2M ($2019–20, direct cost) of our proposed facilities and pipes expenditure is prudent and efficient. We welcome the acceptance of these projects and provide no further information in this response.

The AER also stated that for eight projects it was not satisfied that sufficient justification has been provided had been provided. [51] These projects are:

- Minor capital works
  - Minor capital Trunk Receiving Stations (**TRS**)
  - Minor capital Secondary Regulator Stations (**SRS**)
  - Minor Capital Primary Regulating Stations (**PRS**)
  - Minor capital pipe works
  - Minor capital washaway works
- Appin Packaged Off-take Stations (**POTS**) upgrade Stage 2
- Installation of secondary isolation valves
- Path valves low and medium pressure

In the subsequent sections we provide the information that the AER has stated it requires to be satisfied that our proposed projects are justified and the costs are efficient

3.1 Minor capital works

To ensure we that can continue to provide a safe, reliable and competitive pipeline service, we need to incur capex to undertake minor capital works.

Minor capital works are identified and typically undertaken in a short timeframe generally as a result of equipment failure or external party requirements. These projects range from replacing a powerline at one of our facilities to installing bushfire valves during major fire incidents based on advice from emergency services.

Given the nature of these works costs fluctuate year-to-year but are generally expected to increase as we serve more customers and our assets degrade.

As shown in Table 3-1, despite our network getting larger and our assets ageing, we have proposed minor capital works and washaways capex below our historical four-year average consistent with our lean capex proposal approach.

[51] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-32

Table 3-1: Annual capex for each program ($2020, $M, direct, unescalated)

Program	Forecast requirement	4 years average annual capex
Minor capital works - TRS	0.21	0.16
Minor capital works – PRS	0.13	0.90
Minor Capital works – SRS	0.42	1.01
Minor Capital works - Pipework	0.26	0.29
Washaways	0.32	0.20
Total	**1.33**	**2.56**

3.1.1 Minor capital TRS

Minor capital works on our TRS and POTS facilities is required to replace failed or at risk equipment. These high-pressure facilities are among the most critical in the network as they are the main gateways to supplying towns and cities. They also operate at high pressure levels where equipment failures can result in catastrophic outcomes.

We proposed an annual spend of $0.21M to undertake minor capital works at these 55 high-pressure critical facilities.

The requirements for works is triggered by field investigations, generally to correct an issue or risk concerning operability or safety. The costs we incur depend on the condition and issues identified.

The AER did not approve this program on the basis of advice from Zincara who stated:

> *It is noted that in Capex Model spreadsheet, its 2019 forecast is $122 ($2018, 000) which shows a declining trend of capex. In addition, the total of JGN's annual allocation for five years is $1 million which would make it a material amount. Zincara considers that further details of the capex are necessary to show why the allocation of the capex is reasonable before it can recommend acceptance of the expenditure.*[52]

The proposed capex of $1M over five years needs to be considered in context of the relatively large scale of our network. Our annual spend of $0.21M is intended to cover all minor capital works across 55 facilities. This amounts to less than $4,000 per facility per year.

This response provides further details on the kind of minor capital projects we have undertaken on our TRS and POTS (and expect to undertake) and also explains why a decline in costs is not expected.

Further details on our minor capital TRS

Over the last four years recent minor capital works undertaken at our TRS and POTS facilities has included:

- Safety improvements to country water bath heaters.
- Upgrade of earthing, communications lines to TRS facilities due to damage on ageing services to ensure our SCADA system can continue to operate and that we can, if needed, implement our safety management plans.
- Installing TRS air conditioning units to maintain station temperature to prevent failure of electrical components, loss of SCADA communications and meter data and leaking batteries due to excessive heat.
- Power pole and overhead power line replacement required due to corrosion and to ensure safety (remove threat of pole falling) and avoid loss of power to the site and associated SCADA systems.

52 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.65

- Upgrade/install silence trim to control high pitch noise coming from active regulators, impacting personnel working on site and surrounding neighbourhood on peak flow days.
- Install additional pressure switches at country Sites (Cowra, Orange, Blayney and Oberon) to reduce risk of injury to personnel and damage to assets.

While the exact works to be undertaken will depend on outcome of reviews not yet conducted and issues not yet identified we are already aware of the following issues will which likely need to be addressed:

- Poor regulator station flows performance at our TRS and POTS facilities. A review is planned to investigate which obsolete regulators will need to be upgraded with Gorter regulators.
- During APA's (the upstream transmission pipeline owner) pigging operation of its Blaney to Lithgow Pipeline, oil contaminants caused loss of gas supply to 600 customers supplied by JGN's Wallerawang POTS. The outage was attributed to large quantities of oil within APA's pipeline causing the Wallerawang POTS filters and regulators to be contaminated. To prevent this from happening again we intend to install a "drop-out vessel" at the inlet to the POTS station.
- Rather than undertaking the Appin POTS Stage 2 upgrade we will instead install a flow meter. This meter will allow us to monitor the capacity performance of the downstream network.

Is a decline in costs expected?

While costs vary year-to-year we do not expect costs to decline as:

- **Our TRS and POTS facilities will continue to age.** Over time this will result in more issues being identified which need to be corrected as equipment degrades. Of the 55 TRS/POTS in our network 10 TRS facilities are over 30 years and 15 POTS facilities are over 20 years of age. We will also need to continue replacing components to keep up with changes to community and regulatory expectations (e.g. around noise) and changes in standards from when these facilities were first constructed (particularly around safety).
- **The critically of the infrastructure.** We have seen significant growth in our network. Since 2011 the number of dwellings we supply has increased by 32%, an increase of about 350,000. While we are expecting growth to slow we are still forecasting to make 145,000 additional connections over the 2020-25 period. This means that a failure at one of our facilities will result in a greater loss of supply.
- **The surrounding area of our facilities has changed**. Over the last 10 years we have also seen significant growth across NSW. This development has changed the kind of areas which surround our facilities. This changes how we can operate our facilities (we have to reduce noise) and also the consequence of a catastrophic failure.

These factors will continue to drive our costs up. Our facilities will continue to age and degrade all the while supplying more customers as the surrounding area is developed. While costs do move year to year the long-run trend has been for costs to increase.

3.1.2 Minor capital SRS

Minor capital works are required to replace SRS and secondary meter sets, with an inlet pressure of secondary (1050kPa) and below. These works are generally triggered by field investigations and undertaken to correct an issue or risk, concerning operability or safety.

In regards to this program the AER stated:

> *For one of the projects no justification has been provided, and how the proposed estimated capex was derived.*[53]

[53] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-35

Zincara stated:

> *Given the cost of such replacement, it is unclear why the replacement of SDRS is not part of a managed program to replace aged SDRS. The total of the annual allocation is $2million which is a material amount. Zincara does not consider that the information provided justify recommending the expenditure.* [54]

Consistent with our lean capex forecasting approach we did not put forward a planned replacement program for our SRS assets. Incorporating a planned SRS program will result in a higher capex forecast. Instead we have forecast to continue making reactive replacements consistent with our historical spend – even though our assets are continuing to age and degrade.

While we have chosen to adopt a reactive approach this does not mean our approach is not managed. We carefully monitor the condition of our assets through our annual Asset Performance and Integrity Review (**APaIR**) process and respond to issues as they arise, for instance based on reports from field crews etc.). The APaIR process allows us to first identify then prioritise the works required based on asset performance, location and risk.

It is also worth noting that while the program is significant it needs to be considered in the context of our network. There are 634 SRS in our network and almost 20% of SRSs will reach the end of their nominal design life with in the next 10 years.

In the sections below we outline the basis for our capex forecast for these minor capital works along with further details of the kind of costs we have incurred, and the recent issues that have arisen that will need to be resolved. Of course, additional issues will arise over the 2020-25 period which we have not yet identified.

How we developed the forecast capex

Our forecast of minor capital works is capex is $0.42M. This is based on the capex required to replace one or two SRS with an average cost in the order of $200,000 - $400,000 ($2018). This forecast is less than half of what we have actually incurred in this program over the last four years.

Further details on our minor capital SRS

Through annual APaIR process we identify whether any SRS (or major components of SRS) need replacing. These assets will generally need to be replaced due to asset integrity issues (poor seals, corrosion), compliance requirements for operational health and safety issues (including operator safety, confined spaces and ergonomics) or to ensure ongoing maintainability.

Recent works undertaken include:

- Leppington Cocon[55] bypass – An above ground Cocon bypass was suspected to be damaged by a hit and run car, damaging pipework connected to the bypass.[56] Emergency work was completed to resupply approximately 400 customers. Without the installation of a bypass replacement, operational checks and maintenance to meet technical policy could not be completed. Modification was required to prevent a repeat of this incident, including a bypass arrangement, risers, flange brace.
- Prestons SRS apron and concrete pad – Civil works were required at the SRS and associated valves to stop water ingress, vegetation and dirt pile-up on the access lids to the SRS preventing accessibility and maintenance.
- Sussex Street SRS – A gas leak was detected on the bypass inlet valve of this SRS, which is located in Sydney's Central Business District (**CBD**). To remove this safety risk we undertook a hot tap and installed a Williamson tee to isolate the bypass and replace the leaking valve.

54 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.66

55 Concon is a brand of SRS

56 As we cannot identify the person who damaged our assets we cannot recovery these costs from the responsible third party.

- Meter set modification – The asset is a filter vessel fitted to a demand customer's meter set which is a make and model (from legacy infrastructure dated from the Newcastle Gas Company) which no longer has spare elements or seals. The function of the filter is to remove dry contaminants from passing through the meter set, which was required due to the customer's location at the end of network increasing probability of contaminants in the gas.
- Cranebrook Cocon – This concon was upgraded to prevent vandalism. The cocon is located within parkland where vehicles were driving over the asset causing damage. The same cocon was forced open and tampered with, leading to the gas supply shutting off. The solution was to install bollards and a protective chain wire fence around the Cocon and syphon stones.

We will need to continue replacing SRS where:

- The condition of the SRS has degraded over its lifetime (e.g. corrosion, gas leaks, water ingress).
- The surrounding area has been developed over time (e.g. changes to roads, reduced width of road reserve, no parking), making it increasingly difficult to access and maintain the SRS.
- The surrounding area is reclassed as a high consequence area.
- There is a safety risk to our field staff when performing maintenance.

Through the 2019 APaIR process, there are a number of sites requiring review and may require SRS minor capital allocations to address. These include:

- Water ingress issues identified at Cartwright, Caringbah and Dapto SRS.
- Strathfield and Gladesville SRSs may require upgrade/replacement due to noise, vibration, being an older model with no spares, and by-pass issues.
- A review of over pressure shut off is planned for cocons providing a single feed to 7kPa areas following an incident where several hundred customers lost supply.

3.1.3 Minor capital PRS

Minor capital works PRS are required to replace equipment at our Primary Regulation Stations. These works are usually trigged by field investigations and are generally undertaken to correct an issue or risk, concerning operability or safety.

There are 17 PRS within the JGN network which reduce gas pressure at each off-take on the primary main from 3,500kPa to 1,050 KPa to supply the downstream secondary network or lower metering pressures to specific customers.

Zincara stated:

> *..JGN had said that it had put forward a significant lower estimate but does not say how it has derived this lower estimate. Zincara also considers that the total cost for the five annual capex is $600k which is material*

Consistent with our objective to propose a lean capex forecast we proposed capex of $0.13M per annum, which is well below the costs that we have recently incurred in carrying out these works—over the last four years, we have incurred an average of $0.9M per annum.

Our lower capex forecast reflects our plans to replace Electrical & Instrumentation (**E&I**) at several of our PRSs, which should result in a reduction to the amount of minor capital works that will be required at these PRS. The proposed capex of $0.13M per annum will cover the various other components of our PRS that may need replacement, given that ten of 17 of our PRS are older than 30 years old.

As we outline below, the types of components we will need to replace include valves, pressure regulators, over-pressure protection, cathodic protection equipment, gas escape detectors and other ancillary equipment. The costs of these components varies. For instance, replacement costs for pilot regulators or pressure relief valves can range between $1,000-$2,000 per unit, whereas major valves can cost up to $50,000 per unit.

Further details on our minor capital PRS

Historical minor capital projects have included:

- Pit fan Upgrade at Tempe PRS – The existing single-phase motorised pit fan system at Tempe PRS was replaced with a new three phase system to address two risks. Firstly, prior to pit fan upgrade, only one of the two runs was able to be in service, leaving the site only 50% operable and with no redundancy for the station which is an integral part of the Sydney Primary Loop system supplying approximately 80,000 customers. Secondly, without an operatable fan, ventilation inside hazardous areas of the PRS pit could not be provided. The scope included installation of an isolation valve, a new put fan and associated electricals.
- Overpressure protection upgrade at Horsley Park PRS – Capex was incurred to upgrade the overpressure protection system on site to enable the monitor control valve to work independently of electricity supply. The PRS is the single supply point to Andell Park and Huntingwood areas and supplies approximately 7,000 customers. The works were undertaken after a near-miss incident due to the loss of power at the site. The project removes the risk of the monitor control valve closing in the event of loss of electricity supply, which would stop the gas supply to the network.
- Bollard protection installation at Banksmeadow PRS – Bollards were installed at the PRS to protect exposed assets from being hit and damaged by vehicles, which could result in leaks or a major facility failure. The bollards also ensure vehicles cannot enter the hazardous area zone.
- Power pole replacement at Flemington PRS – Capex was incurred to replace the power pole and overhead power line due to age/poor condition and to ensure safety (remove threat of pole falling), loss of power to the site, and loss of power to SCADA.

There is an ongoing requirement to replace degraded equipment at the end of their life, especially given that ten of the 17 PRS's have an age between 30 to 40 years. Specific equipment within the stations will need to be replaced at various times during the life of the facility driven by varying operational and environmental conditions.

For instance, a recent field review identified that compressors can overheat and cause an hazardous area environment in pits (confined spaces) during the warmer months. The unmitigated risk is gas release with potential for ignition in confined space. These compressors are also required for redundancy to ensure security of supply. To mitigate these identified risks, the likely solution will be to replace the now obsolete compressors within these PRS. There are two compressors per PRS in the field with a likely replacement cost of $20,000 - $30,000 each.

3.1.4 Minor capital pipe works

Capex for minor capital works covers a range of reactive work we need to undertake on our pipework, both underground and above ground.

For example, we need to replace cathodic protection (**CP**) systems and major equipment (e.g. anode beds or current drainage systems) which fail unexpectedly and install of new CP equipment to ensure that we maintain compliance with technical regulations as a result of identified changes in the operating environment.

Zincara stated:

> *It is also unclear why such work has been capitalised and not part of opex. Given the lack of information and justification for the capex, Zincara is unable to recommend acceptance of the capex.*

As this category covers the cost of replacing network components and does not include repair costs we have capitalised these costs in accordance with Australian accounting standards.

However, if the AER prefers that these costs are expensed for regulatory purposes, our 2020-25 opex allowance will require adjustment as these costs are not included in our base year opex. If required, we can assist the AER by submitting revised capex and opex forecasts.

Further details on our minor capital pipe works

Historical minor capital works relate to:

- The purchase of CP equipment to provide integrity assurance to JGN's network steel pipes and to ensure compliance as mandated by regulations. This project upgraded the CP equipment at approximately 1,400 test points and the telemetry at CP sites.
- The installation of a CP system at Pennant Hills Rd was required to protect the yellow jacket coated steel main (5.4km in length) along the now major Pennant Hills Road. This was recommend following a review of CP systems which found that the main was only partly protected. The objective was to re-establish CP continuity to reduce the risk of escapes due to corrosion.
- Bushfire valves are installed as identified based on advice from Emergency Services on pockets of residential/customers' dwellings that could be engulfed by fire or have the potential to be in the line of sight of a fire. This threat is seasonal during the summer months when extreme bushfire events. We respond by reviewing the network configuration and, where required, installing valves to enable isolation of the network to reduce the chances of explosion during bush fires.

3.1.5 Minor capital washaway works

Minor capital works for washaways are required to rectify exposed pipeline assets to ensure the long term integrity of assets. Depth cover can be reduced by erosion and expose the main as a result of natural events, such as flash flooding and illegal 4WD activities in pipeline easement. The identified washaway sites are generally areas which are subject to flash flooding either because they are near creeks, tidal waters/wetlands or steep/gully terrain.

Once the depth of cover is reduced or removed the pipeline is exposed and un-supported leading to overstress of the pipeline. If left untreated, it can lead to loss of supply or loss of containment and significant loss of supply to downstream networks from our high pressure pipelines and secondary mains.

Risks assessments at washaway sites have confirmed that "do nothing" is not an option. Controls are required to support the pipeline and minimise future damage and meet all regulatory and compliance requirements.

Zincara stated:

> *… there is no information on why this is an ongoing issue and why the last three years cost is representative of the forecast period cost. At $300 ($000 2018) per annum, the total cost for the five years forecast period is $1,500 ($000 2018). It is also unclear why this is not an opex item. Zincara is therefore unable to recommend acceptance of the work.* [57]

Below we explain why washaway works will continue to be required, provide more detail on our past costs and explain why these costs are capitalised.

Washaway works are an ongoing issue

Erosion resulting in loss of cover of our high pressure gas pipelines is an ongoing issue which will require washaway remediation works in the future. Our patrols have identified 29 sites on our Southern and Northern trunks (400km of high pressure pipelines) which may require remediation works.

We will not be sure how many of these sites will require remediation until we have completed our investigations (scheduled to be undertaken in 2020).

Although patrols have identified that up to 29 sites could require washaway works, we have forecast that only one remediation will be required per year at a cost of $0.32M per year, based on the rounded average cost of two recent projects: $150,000 (Canoelands) and $400,000 (Hexham 350mm Secondary Mains Washaway) ($2018).

[57] Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, pp 82-83

As outlined in the next section the proposed cost per project is reasonable when considered against historical project costs.

Further details on our minor capital washaways

Capex to address washaways was recently required for:

- Wyee Creek washaway project – This site is located on Northern Trunk High Pressure Pipeline which is the single supply from Horsley Park to domestic and industrial customers in the Central Coast, Newcastle and Hunter Regions. This site had significant erosion following heavy rain and flooding events exposing the pipeline and resulting in unstable ground support. Following an assessment to determine integrity and environmental risks a project was undertaken to rectify the washaway. The scope included design and construction of civil works, hydraulic studies, drawings, permits, environmental studies, consultation and land owners, approvals from local authorities. This project is ongoing with an expected cost in the order of $700,000.
- Canoelands Washaway Project – As per Wyee Creek at a different location with heavy erosion due to high slopes causing a conduit for water. This project was completed in 2015-16 for an overall cost of about $150,000.
- West Gosford Washaway Project – As per Wyee Creek at a different creek crossing. This project was completed in 2015-16 and cost about $360,000.
- Hexham 350 mm Secondary Steel Main – This site required rehabilitation and stabilisation of ground cover, providing protection from future high water flows in tidal/wetlands. This project was completed in 2017-18 at an overall cost of about $400,000.

This spend is of a capital nature and is capitalised in accordance with accounting standards

The design and construction work at sites with exposed mains typically involves structural design and civil works to remediate the water course to control flow/turbulence over the pipeline/main to minimise future erosion and exposure due to wash away. As a result, these works are capitalised in accordance with Australian accounting standards.

However, if the AER prefers that these costs are expensed for regulatory purposes, our 2020-25 opex allowance will require adjustment as these costs are not included in our base year opex. If required, we can assist the AER by submitting revised capex and opex forecasts.

3.2 Appin POTS upgrade Stage 2

Since lodging our 2020 Plan, we have changed our strategy for Appin POTS. Instead of undertaking the upgrade we will install a flow meter (funded via minor capital works TRS – discussed in section 3.1.1). The flow meter will allow us to determine the optimal timing of this project. As it is currently uncertain we have not included the Appin POTS upgrade stage 2 in our Revised 2020 Plan.

3.3 Installation of secondary isolation valves

Zincara stated:

> *JGN said that need for isolation or throttling of secondary mains for emergency response has been highlighted following the Martin Place incident. This project is to install new secondary valves in the Sydney CBD to enable isolation during an emergency response. JGN has estimated the direct cost of project at $1.05 million ($2018). There are no further details of how JGN has derived this cost.*
>
> *Given the material cost of this project, Zincara considers that there needs to further work done to justify the project and its cost. The lack of detail analysis of the need and risk mitigation of the project*

> *means that Zincara does not consider the project prudent or efficient. Zincara is therefore unable to recommend the project.* [58]

Need and risk mitigation

In July 2018 a rock breaker punctured a secondary gas main causing a large gas escape and evacuation of a large area of the CBD.

In investigating this incident we identified that the limited number of secondary isolation valves in the CBD hampered our ability to safety and quickly isolate sections of main in response to loss of containment, without impacting a large number of customers.

Isolating sections of main using isolation valves allow us to quickly stem the loss of gas lowering the risk and consequence of ignition. In turn this lowers the safety risk to the public and our staff as well as the risk to third party property damage. Well placed isolation valves also allow us to limit how many customers loose supply as we make an area safe following a loss of containment incident.

Given the safety risks and loss of supply risks we have considered options to mitigate the risk. The only feasible options (aside from reconfiguring our mains and regulator locations – at immense cost) is to install secondary isolation valves.

We considered whether to install 15 valves to mitigate this risk in only high density community use areas (at a cost of $1.125M ($2018)) or whether to install 51 new secondary isolation valves across our secondary network (at a cost of $3.8M ($2018)). Given there is a lower risk outside high density community use areas we have opted for the first, lower cost option.

Further information on the need, risk mitigation and cost build up is provided in an Options Analysis (JGN-RP-R-RAKS-Secondary Isolation Valves-Options Analysis-20191220) provided with this Revised 2020-25 AA Proposal.

3.4 Path vales low medium and secondary pressure

Zincara accepted that our proposal was prudent but recommended a reduction in capex on the basis that the capex in the Opportunity Brief was lower than the capex included in our forecast:

> *JGN has therefore planned to replace 10 path valves at a cost of $10 ($000 2018) per unit, giving a total of $100 ($000 2018) per annum*
>
> *Zincara accepts that it is prudent to replace such valves if they are no longer functional. However, as shown in Table 7-17, JGN proposes to incur a capex of $180 ($000 2018) per annum. As JGN is only proposing to replace 10 per annum, Zincara recommends a capex $100 ($000 2018) per annum.* [59]

We submitted two Opportunities Briefs[60] for this capex as part of our 2020 Plan:

- Path Valves – Medium and Low pressure: which outlined a project to replaced 10 medium and low pressure path valves at a cost of $0.1M per annum ($2018) and
- Path Valves – Secondary Pressure: which outlines a project to replace 2 secondary path valves at a cost of $0.08M per annum ($2018).

It appears that Zincara overlooked the second opportunity brief when it undertook the review of this capex.

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58 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.69

59 Ibid, p.84

60 Submitted together in *JGN-2-3.15-2-R-RAKV-Path Valves - Low, Medium and Secondary Pressure-OB-20190512-public.pdf.*

We have resubmitted the Opportunity Briefs (see *JGN-PR-2-3.15-2-R-RAKV-Path Valves - Low, Medium and Secondary Pressure-OB-20190512-public)*, and note that isolation of secondary path valves of industrial and commercial customers are at equal risk of not being isolated safely in case of an emergency.

Given that Zincara accepts that the program is prudent, and there is no inconsistency in our proposal our Revised 2020 Plan includes the costs for the medium and low pressure valves as well as the secondary pressure valves at a combined cost of $0.18M per annum.

3.5 Supporting information

Table 3-2 lists the additional supporting document we have provided in response to the AER's draft decision.

Table 3-2: Facilities and pipes supporting documentation (included in attachment 4.6)

Document reference and name	Author
JGN-RP-R-RAKS-Secondary Isolation Valves-Options Analysis-20200107-public	JGN
JGN-RP-2-3.15-2-R-RAKV-Path Valves - Low, Medium and Secondary Pressure-OB-20190512-public	JGN

4. ICT

4.1 AER's draft decision

In its draft decision, the AER has made significant cuts to our Information and Communications Technology (**ICT**) capex—and a number of 'placeholder' decisions—which we require to ensure the ongoing operation of business critical IT systems.

The AER allowed $73.3M (or 68.4%) of JGN's total proposed $107.2M for ICT capex over the 2020-25 AA period.[61] The $73.3M includes 'placeholder' decisions on JGN's proposed projects for metering-mass market no access and asset management and Geographic Information System (AM & GIS) totalling $7.4M.

Table 4-1 shows our 2020 Plan ICT forecast capex, the AER's draft decision and our Revised 2020 Plan ICT capex forecast.

Table 4-1: JGN's revised ICT projects and capex forecast ($2020, $M direct)

ICT category	2020 Plan forecast	AER draft decision		Revised 2020 Plan forecast
		AER accepted	AER not accepted	
Asset Management (AM) & GIS(1)	9.5	3.9	5.7	9.4
Corporate Systems/SAP ERP	20.3	7.7	12.6	20.2
Customer Experience (1)	6.9	0.8	6.1	5.6
Cyber-Security	10.3	10.3	-	10.2
Enabling Platforms & Networking	21.3	20.5	0.7	21.2
End User Services & Support	11.7	11.7	-	11.7
Market Interactions & Regulatory Compliance	9.3	9.3	-	9.2
Metering	16.4	8.5	7.8	12.2
Real Time Systems/SCADA	1.6	1.6	-	1.6
Labour and inflation adjustments		-1.0	1.0	-
Total	**107.2**	**73.3**	**33.9**	**101.2**

(1) We have reclassified two projects from Customer Experience to Asset Management & GIS totalling $0.6M.

4.2 JGN's response to the draft decision

We accept the AER's draft decision on the projects that it has allowed[62] and consequently provide no further information on them.

In relation to the AER's draft decision to disallow $33.9M proposed ICT capex, we accept that $6M of this capex is not required. We have not, therefore, included this expenditure in our Revised AA 2020-25 Proposal.

For the remaining projects, the AER requested that we provide sufficient justification for our proposed ICT capex in order for it to assess whether it meets the NGR requirements. In particular, the AER stated:[63]

61 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, Table 5.4

62 As set out in the 'Data' worksheet of the AER's working file 'AER JGN IT Worksheet 22112019 Confidential with project description'

63 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-39

> *We have no issue with the overall methodology of the IT Project Estimation Tool in developing the costs of proposed projects. However this tool does not, nor should it, provide justification for the proposed capex.*[64]

In addressing the AER's concerns in the draft decision, we have prepared investment briefs which set out the issue we are trying to resolve, the options to resolve the issue, supporting NPV analysis and for the preferred option how it is justified under Rule 79(2). These investment briefs are listed in Attachment A of this document, and are included as part of Attachment 4.7 of our Revised 2020 Plan.

Our response to the AER's draft decision on its placeholder and disallowance decisions on various projects is as follows:

- **AM & GIS Lifecycle** – the AER made a placeholder decision on our proposed $3.9M capex. We have provided an investment brief and supporting NPV analysis that includes more information on how we have compiled our estimates across the 12 sub-projects, noting that we no longer require one Project ID ITGF04 for $83k.
- **AM & GIS Enhancement** – we have provided an investment brief and supporting NPV analysis which covers the ten projects the AER disallowed totalling $5.6M.

  We note that the program is to fully implement the GIS which commenced in the current AA period which will improve safety, maintain integrity of services and assist JGN in complying with regulatory obligations consistent with Rule 79(2)(c)(2). In light of this and the release by the AER of its Non-network ICT capex assessment approach, we have reclassified the proposed capex as non-recurrent.

- **AM & GIS Dial Before You Dig (DBYG)** – in our 2020-25 AA Proposal we included Project IDs ITSE04 and ITSD01 as part of Customer Experience.

  Upon reflection we think they should be part of AM & GIS program of work, so we have provided a separate investment brief (totalling $0.6M) and supporting NPV analysis demonstrating how the project will maintain safety and how the proposed capex is prudent.

- **Data Storage and Management Systems Lifecycle**[65] – we provide an investment brief that covers Project IDs ITSA05 and ITSA15 totalling $0.7M.

  The projects are unrelated to SAP ERP and IS-U modules or the potential migration to S/4HANA. We note that the projects will maintain integrity of services and assist JGN in complying with regulatory obligations consistent with Rule 79(2)(c)(2)(ii)&(iii) respectively.

- **Reporting and Analysis**[66] – we provide an investment brief that covers the six projects the AER disallowed totalling $3.4M.

  The projects are unrelated to SAP ERP and Industry Specific for Utilities (**IS-U**) modules or the potential migration to S/4HANA. We note that the projects will improve safety and maintain integrity of services and assist JGN in complying with regulatory obligations consistent with Rule 79(2)(c)(2).

- **Records and Document Management**[67] – we provide the following investment briefs and supporting NPV analysis (which are all unrelated to SAP ERP and IS-U modules or the potential migration to S/4HANA).
  - Kofax Lifecycle of $0.4M which is expected to enable JGN to maintain integrity of services consistent with Rule 79(2)(c)(2)(ii).

[64] NGR, r. 79(1)(b).

[65] This was originally included as part of Enabling Platforms & Networking in our 2020 Plan, submitted in June 2019.

[66] This was originally included as part of Corporate Systems/SAP ERP in our 2020 Plan, submitted in June 2019.

[67] Ibid.

- Enterprise Systems Lifecycle covers six projects the AER disallowed totalling $1.4M. The projects are expected to improve safety and maintain integrity of services consistent with Rule 79(2)(c)(2)(i)&(ii) respectively.

- **SAP S/4HANA Migration**[68] – we provide a Jemena business case that covers two SAP projects (Project IDs ITSE12 and ETSE13) the AER disallowed totalling $7.3M (JGN share only).

  We also include an investment brief that acts as a bridging paper between the Jemena business case—which covers the provision of this project to the whole of Jemena—and our JGN 2020-25 Revised AA Proposal.

- **Customer Experience** – in addition to separating out Project IDs ITSE04 and ITSD01 relating to DBYD (discussed above), we accept the AER's decision to disallow three projects (Project IDs ITGG01, ITGG02 and ITGG16) totalling $1.2M.

  We have provided an investment brief and supporting NPV analysis for the remaining five projects (that total $5.1M) which demonstrates that the customer experience hub will improve safety, maintain integrity of services and assist JGN in complying with regulatory obligations consistent with Rule 79(2)(c)(2).

  We have also included a system roadmap in the investment brief as requested by the AER in its draft decision and note that the customer experience hub is focussed on being competitive with alternative energy sources in the long term and achieving customer connections as forecast (as opposed to growing customer connections).

- **Metering Management Lifecycle** – we accept the AER's draft decision to disallow the MVRS replacement and lifecycle projects totalling $4.1M.

  We provide investment briefs and supporting NPV analysis for the two remaining projects disallowed by the AER (maintain the I&C meter reading back end systems and Meter Data Logger (**MDL**) Backend systems) that total $4.8M which demonstrate that the two projects will improve safety, maintain integrity of services and assist JGN in complying with regulatory obligations consistent with Rule 79(2)(c)(2).

  For the mass-market no access project of $3.6M which the AER made a placeholder decision, we provide an investment brief and supporting NPV analysis which includes details of the assumptions and sources used to derive system benefits.

Based on further information we provide in our Revised 2020-25 AA Proposal, we expect that the AER will reconsider its draft decision on the ICT projects that has included as placeholders or disallowed and allow the capex in full.

For completeness, if the AER was to make a different decision from its draft decision on those ICT projects that it has allowed, or from the reasons for its placeholder decisions or projects that it disallowed, JGN will not have been provided with an opportunity to make submissions in respect of the substance of that element of the AER's decision. We expect that, in accordance with the NGR, we will be provided with at least 30 business days to respond to its decision.

68 This was originally included as part of Corporate Systems/SAP ERP in our 2020 Plan, submitted in June 2019.

4.3 Supporting information

Table 4–2 lists the additional supporting document we have provided in response to the AER's draft decision on ICT capex. In addition, in Attachment A (of this document) we identify each project, its forecast capex, and the corresponding Investment Brief in which we provide our justification for the project.

Table 4–2: ICT Supporting information provided (attachment 4.7)

Name	Author
JGN-RP-IB-Asset Management and GIS Enhancement-20191220-Public	JGN
JGN-RP-NPV-Asset Management and GIS Enhancement-20191220-Public	JGN
JGN-RP-IB-Asset Management and GIS Lifecycle-20191220-Public	JGN
JGN-RP-NPV-Asset Management and GIS Lifecycle-20191220-Public	JGN
JGN-RP-IB-Customer Experience Hub-20191220-Public	JGN
JGN-RP-NPV-Customer Experience Hub-20191220-Public	JGN
JGN-RP-IB-Enterprise Systems Lifecycle-20191220-Public	JGN
JGN-RP-NPV-Enterprise Systems Lifecycle-20191220-Public	JGN
JGN-RP-IB-GIS DBYD-201921220-Public	JGN
JGN-RP-NPV-GIS DBYD-20191220-Public	JGN
JGN-RP-IB-Kofax Lifecycle-20191220-Public	JGN
JGN-RP-NPV-Kofax Lifecycle-20191220-Public	JGN
JGN-RP-IB-Reporting Server and Database Lifecycle-20191220-Public	JGN
JGN-RP-NPV-Reporting Server and Database Lifecycle-20191220-Public	JGN
JGN-RP-IB-Enterprise Systems-Reporting & Analysis-20191220-Public	JGN
JGN-RP-NPV-Enterprise Systems-Reporting & Analysis-20191220-Public	JGN
JGN-RP-IB-Metering-MDL Backend System-20191220-Public	JGN
JGN-RP-IB-Metering-MDL Backend System-20191220-Confidential	JGN
JGN-RP-NPV-Metering-MDL Backend System-20191220-Public	JGN
JGN-RP-IB-Metering-Mass Market No Access-20191220-Public	JGN
JGN-RP-NPV-Metering-Mass Market No Access-20191220-Public	JGN
JGN-RP-IB-Metering-Industrial and Commercial (IC)-20191220-Public	JGN
JGN-RP-IB-Metering-Industrial and Commercial (IC)-20191220-Confidential	JGN
JGN-RP-NPV-Metering-Industrial and Commercial (IC)-20191220-Public	JGN
JGN-RP-IB-SAP Migration to S4-20191220-Public	JGN
JGN-RP-IB-SAP Migration to S4-20191220-Confidential	JGN
JGN-RP-NPV-SAP Migration to S4-20191220-Public	JGN

5. Augmentation

The AER has accepted $47.6M of our proposed augmentation capex. This includes all of our connections driven augmentation, aside from the Aerotropolis, and as well as the Sydney Primary Main Integrity Management (Lane Cove to Willoughby) project.

The AER's draft decision on augmentation can be broken down into the following components:

- Rejection of the Aerotropolis projects on the basis of planning and asset scope uncertainty. Our response is in section 5.1.
- A request for an update on projects (the AER has accepted) but are due for completion in 2020-21 and 2021-22. This information is provided in section 5.2.
- Concerns with our approach to demonstrating that our proposed project complied with Rule 79(2)(b) – that the incremental revenue exceeded the capex. Our consideration is presented in section 5.3.
- Questioning why we included the Sydney Primary Main Integrity Management (Lane Cove to Willoughby) project in augmentation. Section 5.4 explains why we made this decision (to be consistent with the AER's RIN) and that we are happy for this spend to move to a different category.

Lastly, we have also added an new augmentation project: the Malabar biomethane project as a new opportunity has come to light which will enable us to provide additional economic value to our customers, and reduce the revenue lost as our customers decarbonise.

Table 5-1 summarises the information that the AER requested and where it is provided within this document.

Table 5-1: AER's requested information and where it is provided

Information requested	Where the information is provided
Further clarifications of the demand and project risks at each site within the Aerotropolis development including:	
○ Clearly separating committed demand from developers as opposed to inferred demand from third party sources as well as their supply arrangements.	See section 5.1.1.
○ Exploration of other planning options that might offer greater investment flexibility other than different main sizes and their associated timing.	See section 5.1.3
○ Identify any efficiencies and synergies that might have been discussed in the various planning forum and stakeholder meetings JGN participated in which are not typically available in other developments and how JGN has considered and incorporated them into the proposal.	See section 5.1.4
For developments with a project completion year in 2020–21 and 2021–22, provide further details on project scope and cost estimates beyond Gate 1 requirements.	See section 5.2
Given the size of JGN's network and the amount of construction activities in NSW over the past 5 to 10 years, provide further details on why JGN used only seven sites to represent the penetration rate for all new developments.	See section 5.3.1
Based on recent developments and the associated billing data, provide the indicative timeframe between capex spend and demand realisation.	See section 5.3.2

5.1 Aerotropolis

The AER has not accepted our forecast expenditure to lay the mains to the Aerotropolis, Sydney's third city with the new Western Sydney Airport at its centre.

The AER reduced our augmentation forecast by $13.2M and our connection forecast by $8.8M – a total cut of $22M (for a project proposed to cost $15.2M).

The AER explains that it made this decision due to uncertainty and that we can seek a further allowance under the Rules when uncertainty is reduced:

> *Our alternative capex forecast is based on advice from Zincara and our assessed planning and asset scope uncertainty of the Aerotropolis development. We have substituted the Aerotropolis development with $2.1 million allowance for JGN to continue planning and design until such a time the planning and project scope is more certain. This allowance should provide sufficient funding and lead time for JGN to seek a further allowance under the rules as uncertainty is reduced.* [69]

As we explain in section 5.1.1 there is no mechanism within the Rules for us to seek additional allowances during the 2020-25 period.

Regardless, uncertainty is not a basis for rejecting expenditure. Uncertain costs and projects still qualify as conforming capex under Rule 79.

While there is general uncertainty regarding this project (as there is with any project) there is no uncertainty as to whether the project is required and costs will be incurred:

- The AER's consultant Zincara considers there is a high level of confidence that the Aerotropolis will proceed.[70]
- The AER accepts that we will need to invest in augmentation in some form to supply the area.[71]

The AER also appears[72] to accept that the Aerotropolis passes the incremental revenue test set out in Rule 79(2)(b) and is justified:

> *JGN's assumptions mean that the Aerotropolis passed the incremental revenue test under rule 79(2)(b) of the NGR. We are not satisfied that it passes the efficient and lowest sustainable cost test under rule 79(1)(a).* [73]

The AER has requested that we provide further information on demand, other planning options and the identification of any efficiency and synergies that might have been discussed.

Since we lodged our 2020 Plan, the plans for the Aerotropolis has solidified (and uncertainty has reduced). We have been working with other utilities (Sydney Water, Endeavour Energy, TransGrid etc.) to collaborate and help plan the underpinning infrastructure. We are now able to present updated plans which taken into account our latest view of what synergies can be achieved and when mains will need to be laid. Our analysis of the available options is set out in our Aerotropolis Options Analysis.[74]

In the following sections we respond to the AER's draft decision and provided the additional information requested:

69 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-55.

70 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.91

71 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November, 2019, p.5-53

72 The AER did raise a number of issues with our modelling which we address in section 5.3.

73 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-49

74 JGN-RP-Aerotropolis-Options Analysis-20191220-public

- Section 5.1.1 – explains that we cannot seek an additional allowance for the Aerotropolis after the final decision. We also set out that excluding expenditure on the basis of uncertainty is inconsistent with the Rules, increases regulatory risk, creates barriers against timely and efficiency investment, and penalises us for acting in consumers' interest.
- Section 5.1.2 – provides the basis for the demand forecast. We also explain how demand uncertainty affects the options considered and how we have tested the sensitivity of our forecast.
- Section 5.1.3 – summarises the options we considered. We show that our approach to avoiding costly rework based on customer feedback (contrary to the AER's suggestion otherwise) is consistent with the AER's call to put consumers at the heart of decision making and is entirely consistent with good planning, economics and the long term interests of our customers.
- Section 5.1.4 – provides an update on our cost estimates which now reflect synergies as well as an additional project to provide gas to Sydney Water's Water Factory. Overall our cost estimate for the Aerotropolis has fallen from $14.4M to $13.2M.
- Section 5.1.5 – highlights two inconsistencies in the AER's decision on the Aerotropolis, such as assuming that we will earn revenue from customers we do not connect.

5.1.1 We cannot seek an additional allowances for the Aerotropolis

The AER's draft decision reduced our capex allowance on the basis that the Aerotropolis is uncertain and we can seek a further allowance under the Rules:

> *We have substituted the Aerotropolis development with $2.1 million allowance for JGN to continue planning and design until such a time the planning and project scope is more certain. This allowance should provide sufficient funding and lead time for JGN to seek a further allowance under the rules as uncertainty is reduced.*[75]

We understand that the AER is referring to Rule 80 which allows the AER to make an advance determination on whether a project will meet the new capital expenditure criteria.

This Rule does not allow the AER to change the allowance once set in a final decision or provide additional funding. Instead the Rule works to provide service providers some certainty on how investments not approved in the AER's AA decision will be treated in the future.

Our access arrangement does not include a contingent project mechanism akin to the one included in the National Electricity Rules, which means that there is no mechanism for us to seek an additional allowance for the 2020-25 period after the AER makes its final decision, save for us triggering an early and full AA review process.

The AER's approach of substituting a capex forecast which only includes "certain" expenditure is:

- Inconsistent with Rule 74(2) which requires that a forecast must be arrived at on a reasonable basis and represents the best forecast possible in the circumstances. Based on the information currently available, there are no circumstances under which an allowance of $2.1M capex could be seen as the best forecast possible to undertake the Aerotropolis project.
- Increases regulatory risk and creates barriers against timely and efficiency investment contrary to the purpose of Rule 80[76] and inconsistent with the Revenue and Pricing Principles in the National Gas Law (**NGL**).

[75] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-55

[76] COAG Energy Council, *Options to improve gas pipeline regulation, COAG Regulation Impact Statement for Consultation,* October 2019, p.21

- Penalises JGN for acting in customers' interests. Despite the project delivering ~$30M in customer benefits (via lower bills), making this investment (due to the operation of the Capital Expenditure Sharing Scheme) will incur a $4M[77] penalty.

5.1.2 Demand

In its draft decision, the AER has requested that we provide:

> *Further clarifications of the demand and project risks at each site within the Aerotropolis development including:*
>
> - *Clearly separating committed demand from developers as opposed to inferred demand from third party sources as well as their supply arrangements.*[78]

The AER noted that:

> *Although JGN has provided an overview of the type and magnitude of expected demand at each site, it is not clear to us which are committed demand from developers through reviewed load applications, and which are non-committed demand inferred through third party sources or websites.*
>
> *While we accept that JGN would need to invest in augmentation in some form to supply the area, the accuracy of demand projections impacts on the feasible planning options available, their timing, and the associated economic assessment that might trigger the need for capital contributions.*[79]

However, the AER also said:

> *While we do not accept JGN's proposed Aerotropolis expenditure in our draft decision, this is primarily due to significant planning and asset scope uncertainty rather than demand risks. As such, we did not adjust the demand forecasts as we accept CORE's demand forecast as reasonable (Attachment 12 – Demand).*[80]

As the AER has stated that it accepts that we will need to invest to supply the Aerotropolis, we understand that it is seeking further information to understand how uncertainty around demand affects the planning options, their timing and whether there may be a need for capital contributions.

As requested, we provide the basis for our forecasts—and how they are consistent with the NSW Government's plans for the Aerotropolis—below. We also explain why it is not possible to provide committed demand at this stage.

We also explain how uncertainty around demand affects the options considered and how we have sensitivity tested our forecast.

Our forecast is consistent with NSW Government plans for the Aerotropolis

Our demand forecasts for the Aerotropolis are based on the best information available. This includes information released publicly (such as the NSW Government in the Western Sydney Aerotropolis Land Use and Infrastructure and Plan Stage 1: Initial Precincts)[81] as well as our discussions with the Greater Sydney Commission and Western

77 Assuming $2M is allowed for a $15M project.

78 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-50

79 Ibid, p.5-53

80 Ibid, p.5-51

81 NSW Government, *Western Sydney Aerotropolis, Land Use and Infrastructure Implementation Plan, Stage 1: Initial Precincts,* August 2018

City & Aerotropolis Authority,[82] the Department of Planning and the Environment, Western Sydney Airport, developers and other utilities.

Our plans are also consistent with the recently published draft Western Sydney Aerotropolis Plan[83] and development control plan (phase 1) along with the Western City and Aerotropolis Authority's plans to deliver the Western Parkland City.[84]

As Zincara notes there is a high level of confidence that the Aerotropolis will proceed.[85]

The draft Western Sydney Aerotropolis Plan sets out the next steps for the area. The initial precincts (including the Aerotropolis Core and the Northern Gateway) will be rezoned in mid-2020 with precinct plans finalised by late 2020. Development applications will then follow. Only once development applications are approved we will expect to see requests to connect from developers.

The exception to this is the approved Sydney Science Park which has already been re-zoned. We have had several discussions with the developer [redacted][86] The developer has already commenced work on site with a lead in road completed in early 2019 and is looking to developed residential uses by around 2022.

Sydney Water has also identified that its Water Factory (an advanced wastewater treatment plant which will service the new Western Sydney Airport and Western Sydney growth demand) will require a connection to the gas network. We have included an additional augmentation project in this Revised 2020 Plan.[87]

Impact of demand forecasts on planning options and timing

Given the greenfield nature of the Aerotropolis, the planning options and timing is primarily driven by when gas needs to be available and whether it is possible to build earlier to achieve cost savings.

As recognised by Zincara, it is prudent to have gas supply infrastructure available at the various precincts during the early stages of construction.[88]

If gas is not available when the first dwellings are completed then it is likely that the developers will install electric appliances to ensure homes are move in ready. Once electric appliances have been installed we lose the ability to connect these homes resulting in higher bills for our remaining customers.

As a result, any option to defer investment will result in a lower net-benefit than building infrastructure in time to service the initial customers in a development.

The number of connections drives the capacity of the initial main built. This is considered in our Aerotropolis Options Analysis.[89]

Impact of demand forecasts on whether any contributions will be required

In our 2020 Plan we tested whether we would achieve sufficient revenues to cover the capex. We conducted sensitivity tests by varying the penetration rate (the proportion of new homes in a new area which connect to gas)

82 See JGN-RP-Aerotropolis-WCAA-Letter of support-20200106-public

83 NSW Government, *Western Sydney Aerotropolis Plan,* December 2019

84 Western City & Aerotropolis Authority, *Delivering The Western Parkland City*, 2019

85 Zincara 2019,*Access Arrangement 2019 JGN Capital Expenditure Review,* p.91

86 JGN-RP-Aerotropolis-Sydney Science Park-Letter of support-20191212-confidential

87 Based on the projected loads we have also forecast that a capital contribution will be required. Both the augmentation and the capital contribution have been included in our Revised 2020 Plan.

88 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.91

89 JGN-RP-Aerotropolis-Options Analysis-20191220-public

between 80% and 100%. Using a range of penetration rates gave us not only a sense of what could happen if gas take-up falls but also if developments in each area are larger or smaller than forecast.

In each of these scenarios all of the Aerotropolis mains provided revenue in excess of the capex required–which means that a capital contribution is unlikely to be required.

Table 5-2: NPV of the Aerotropolis investments across penetration rate scenarios ($2018, $M)

Penetration	80%	90%	94.3%	100%
Aerotropolis Core	2.4	3.1	3.5	3.9
Water Factory	-	-	-	-
WS Airport & Syd. Science Park	4.4	5.8	6.5	7.3
Total	**6.8**	**9**	**9.9**	**11.2**

5.1.3 Investment scope

In its draft decision, the AER stated:

> ***Planning and asset scope***
>
> *JGN have no details on the locations of new roads and any potential removal of existing roads. JGN stated that it is its intention to construct new mains prior to the new roads being built to avoid costly restoration based on customer feedback. JGN may wish to reconsider this position from a planning perspective, and also importantly from an economic perspective and consider how to achieve the least cost for consumers over the long term.*
>
> *In addition, demand uncertainty combined with scope uncertainty ultimately impacts on planning options.*
>
> *As a result, we find the planning and asset scope for Aerotropolis materially more uncertain compared to other sites, especially given that all of JGN's proposed assets for this development resides within the Aerotropolis development boundary.* [90]

In turn, the AER requested that we provide:

> *Further clarifications of the demand and project risks at each site within the Aerotropolis development including:*
>
> *…*
>
> - *Exploration of other planning options that might offer greater investment flexibility other than different main sizes and their associated timing.*

This section provides a summary of the other planning options considered and why our plans will deliver the greatest customer benefits. A more detailed assessment is included in the Aerotropolis Options Analysis we have prepared.[91]

We also respond to the AER's suggestion that we reconsider our position to avoid costly rework based on customer feedback.

90 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-54

91 JGN-RP-Aerotropolis-Options Analysis-20191220-public

Our approach to the Aerotropolis investments will deliver the greatest customer benefits

Our plan for the Aerotropolis is straightforward. We aim to provide gas to locations when they need it via the shortest possible (and lowest cost) route. Delivering gas via more complex routes or at a later point in time will result in a higher cost to customers – both in terms of capex and in terms of lost opportunities to connect customers and lower bills.

As noted above, since preparing our 2020 Plan the plans for the Aerotropolis has solidified. Our Options Analysis[92] methodically works through:

- When gas is required to be supplied to each area.
- The infrastructure in place which sets the foundations for any possible augmentation option and possible routes to each area.
- What pipe size provides sufficient capacity for the forecast loads. Here we also consider whether we should lay mains with only enough capacity for immediate loads (medium term approach) or build additional capacity to account for future growth in the area (long term approach).

We considered four options (aside from the base case):

1. **Defer investment until 2026**. In this scenario we consider the implications of delaying investment until loads are 'certain' (although by this point we would have missed the opportunity to connect the 'certain' loads).
2. **Gas available for the first dwellings/businesses (recommended approach).** In this scenario we build the infrastructure along the shortest possible routes so that we can supply gas when the first dwellings/businesses are completed and avoid losing the opportunity to connect more customers and lower bills. Where possible, we align our construction timing with other utilities to achieve construction synergies.
3. **Delay connecting the Sydney Science Park.** In this scenario we delay connecting the Sydney Science Park until December 2024 to achieve synergies along Elizabeth Drive but forgo construction synergies between the airport and the Sydney Science Park. This option not only is more expensive but also means that the first dwellings and businesses in the Sydney Science Park will not connect to gas.
4. **Alternative supply route**. In this option rather than supplying the Sydney Science Park via the Airport we instead build a separate main from the North. There are no other alternative supply options to the Aerotropolis Core or Water Factory.

As shown in Table 5-3 our preferred option provides the greatest customer benefits. This is primarily because building infrastructure on-time facilitates the greatest number of possible connections and results in the largest bill reductions.[93] Deferring investment not only results in missed opportunities to connect customers (and higher bills for our remaining customers) but results in higher capex costs.

Table 5-3: Aerotropolis options ($2018, $M)

Option	NPV of net customer benefits	Gross capex
Base case	0	0
1. Defer investment until 2026	-4.46	18.7
2. Gas available for first dwellings/businesses (proposed approach)	9.92	13.7
3. Delay gas to Sydney Science park	7.28	14.4
4. Alternative supply route	4.23	17.5

92 JGN-RP-Aerotropolis-Options Analysis-20191220-public

93 Connection more customers allows us to spread our largely fixed costs across more customers.

Avoiding costly rework based on customer feedback

The AER noted:

> *JGN stated that it is its intention to construct new mains prior to the new roads being built to avoid costly restoration based on customer feedback. JGN may wish to reconsider this position from a planning perspective, and also importantly from an economic perspective and consider how to achieve the least cost for consumers over the long term.*

We have two main concerns with this suggestion:

1. It is at odds with the AER's call to put consumers at the heart of their decisions—The importance of the consumer voice is also outlined by Professor Cosmo Graham in Attachment 8.4 of our Revised 2020 Plan.
2. Listening to customers and avoiding rework is entirely consistent with prudent planning, sound investment and business economics and is in the long term interests of our customers.

The AER should place customers at the heart of their decisions

The former Chair of the AER, Paula Conboy, recently reflected that:[94]

> *Five years ago I set out with a clear focus on the regulation of networks – putting new tools into practice (launching the Consumer Challenge Panel, benchmarking efficiency, and implementing the 2013 Rate of Return guidelines) and calling for a more collaborative approach that would put consumers at the heart of our decisions – bringing them in to the process rather than asking them to watch from the sidelines. I wanted to foster a process that focusses on understanding and testing proposals and on delivering decisions that everyone can understand.*
>
> *And when I look back today, I am satisfied that we've made great strides in that regard. We've moved away from a highly adversarial process based on a presumption of I win/you lose to one that is truly more collaborative.*
>
> *But there is more than can be done.*
>
> *I'd like to suggest that we need to look at ways we can move away from regulation that focuses on the engineering and financial characteristics of assets to the services that the assets can deliver and that consumers value. Gone are the days of the paternalistic approach to the propose-respond model of businesses telling the regulator what consumers need and the regulator agreeing to what is economically efficient. …*

Consistent with Paula Conboy's vision, we have taken steps to hear from customers what they want and, while working within the Rules, have reflected their preferences in our 2020 Plan—one of the key topics that we tested with our customers was our plans for the Aerotropolis.

We do not agree with the AER's suggestion that listening to our customers and avoiding rework is somehow inconsistent with good planning, economics or contrary to achieving least cost outcomes:

- Our customers, in providing guidance to us, took into account the planning impacts of both medium and long term options. See Box 1 for a summary of how we engaged customers and how their guidance took into account the trade-offs at stake.
- Installing additional capacity earlier—to avoid future rework—when likely to lower long term costs is the very objective of good and prudent planning.
- Consumer preferences (expressed as 'utility') are central to economics and optimising planning decisions.

[94] Conboy, Paula, *Looking back and looking forward, an AER Chair perspective,* 1 August 2019

Box 1: How we engaged customers on the Aerotropolis

Given the risk that usage of the gas network declines, we asked customers whether we should invest in the long or medium term.

Investing for the medium term (lower capacity) provides lower bills in the short term. However, if the gas network thrives we will need to go back and install additional capacity in the future. In contrast investing for the long term (higher capacity) provides the lowest cost option in the long-term, unless usage of the gas network declines in which case we would have built capacity that is not required.

The feedback from customers revealed that they understood the nuance of the choice (and the planning and economic implications). They told us:

- To limit how much rework we do in the future – to reduce additional traffic disruption and repairs to local (non-gas) infrastructure.
- Rework is wasteful and that we should install the right amount of infrastructure in the first place.
- Excess capacity is not as wasteful as it could be used by future generations.
- Be bold and invest with confidence.

Based on this guidance and their guidance that affordability is their number one priority, we decided to adopt a mixed approach to our augmentation investments:

- We chose a medium term approach where we do not expect significant higher costs in the future or where the chance of additional development is low.
- We chose a long term approach when the likelihood of further development in the future is high (such as when there are future plans for development nearby) and the costs of providing additional capacity now is relatively low.

53% of customers support our approach. [95] Again the customers feedback indicated that they understood the trade-offs between each option. For example one customer said that:

> *I think that the scale of the Aerotropolis means that it should logically be planned for the long term, but that just as Jemena has planned, it makes sense for the Science Park [to] less likely expand as dramatically, meaning that a medium-term plan for that area is more than reasonable.*

5.1.4 Cost estimates

In its draft decision, the AER stated that:

> ***Unit rates***
>
> *As the Aerotropolis development can be considered a greenfield site, JGN have selected similar projects as the basis for their cost estimation. While we acknowledge that JGN may have used the best available project as a sample, we also established that there is no representative sample that JGN can use with the scale and significance of Aerotropolis.*
>
> *Due to the establishment and involvement of the Aerotropolis Authority and Utilities Coordination Group as well as other government bodies, we would expect a certain amount of synergies above and beyond historical observations between the different utilities and stakeholders. It is not clear to us how the cost estimates proposed by JGN fully capture these potential benefits through future negotiations and memorandums of understanding (MOUs).* [96]

[95] Of the remaining customers 34% told us to always adopt a long term approach while 13% told us to always adopt the medium term approach.

[96] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-54

In turn the AER requested that we provide:

> *Further clarifications of the demand and project risks at each site within the Aerotropolis development including:*
>
> *…*
>
> - *Identify any efficiencies and synergies that might have been discussed in the various planning forum and stakeholder meetings JGN participated in which are not typically available in other developments and how JGN has considered and incorporated them into the proposal.* [97]

Updated cost estimates

As plans for the Aerotropolis have solidified since we have lodged our 2020 Plan we have been able to estimate the costs of using our Project Estimation Methodology (**PEM**).[98]

These updated cost estimates take into account synergies we expect to achieve. These synergies include common trenching and shared restoration activities but also take into account the tight time-frames we will need to work through and that several site mobilisations may be required.

We have also identified that by laying the main to the airport and Sydney Science Park together will help reduce costs (reduced mobilisations etc.) so have combined these two mains into a single project.

Sydney Water has also informed us that its Water Factory will require a gas connection. [redacted]

Table 5-4: Aerotropolis cost estimates ($2018, $M)

	2020 Plan	Revised 2020 Plan
Aerotropolis Core	5.4	3.8
Sydney Science Park	5.7	7.8
Airport	3.3	
Water Factory	N/A	2
Total	**14.4**	**13.7**

5.1.5 Inconsistencies in the AER's decision

Inconsistency between the AER's decision on demand and connections capex

The AER's draft decision also reduced our connections capex on account of the Aerotropolis. The AER states:

> *As the reticulation of mains, services and meters are part of Aerotropolis development, $8.8 million is also removed from connections capex to reflect the same uncertainty in planning and asset scope (section 5.4.2).*[99]

While the AER reduced our capex forecast no corresponding adjustment was made to demand:

97 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-50

98 See JGN-RP-13033933-Aerotropolis Core-PEM-20191211-confidential, JGN-RP-13033942-Western Sydney Airport and Sydney Science Park-PEM-20191211-confidential and JGN-RP-10049740-Water Factory-PEM-20191220-confidential.

99 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-51

> *While we do not accept JGN's proposed Aerotropolis expenditure in our draft decision, this is primarily due to significant planning and asset scope uncertainty rather than demand risks. As such, we did not adjust the demand forecasts as we accept CORE's demand forecast as reasonable (Attachment 12 – Demand).*[100]

We are having trouble understanding how the AER came to a view that we will earn revenue from customers we do not connect. Such an decision is inconsistent with the Revenue and Pricing Principles in the NGL which states that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing reference services.[101]

It is important to note that we did not forecast any additional connections for the Aerotropolis. Our connection capex was developed using the forecast connection numbers from Core Energy's demand forecast, which is based on the Housing Industry Association's (**HIA**'s) NSW new dwelling commencement forecasts, and therefore includes dwellings that would be constructed as part of the Aerotropolis development.

As the AER has accepted the Core Energy's demand forecast, subject to an update for 2018-19 actuals, it follows that the AER has by default also accepted our entire connection forecast and the subsequent capex required to make those connections.

Inconsistency within the AER's decision on connections capex

As discussed in section 1, the AER also lowered the forecast cost per connection. However, when the AER removed our forecast connection costs for the Aerotropolis, it used our proposed unit rates – rather than the lower costs from its draft decision. This means that the cost per connection for the remaining 'allowed' connections is effectively lower than the AER's draft decision.

5.2 Connections driven augmentation due to be completed in 2020-21 and 2021-22

Zincara considered our connections driven augmentation program and found that:

- Our approach in proposing augmentation to occur when minimum pressures will be reached is prudent and efficient and in accordance with good industry practice.[102]
- We have used best endeavours to develop our forecast acknowledging that actual infrastructure and timing can be expected to change. [103]
- Our forecast connections driven augmentation program has been arrived at on a reasonable basis and the best available at this time. [104]

Zincara recommended that we provide updated project cost estimates for three projects (Menangle Park, Cecil Park and Lidcombe CBD) and an update of our capital contribution negotiations of the developer for Menangle Park. These updates are provided below.

While the AER accepted our connections driven augmentation program the AER stated:

> *For major developments with a project completion year in 2020–21 and to some degree in 2021–22, it is not unreasonable to expect to see detailed planning scope and cost estimates including the calculated and*

100 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-51

101 Revenue and Principles, Division 2, cl 24 National Gas Law

102 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.98

103 Ibid, p.98

104 Ibid, p.98

> *agreed capital contribution component of the project. However, this information was not provided at the time of our review.* [105]

The AER also recommended – going beyond what was requested by Zincara – that we provide further details on all projects in 2020-21 and 2020-22:

> *For developments with a project completion year in 2020–21 and 2021–22, provide further details on project scope and cost estimates beyond Gate 1 requirements.* [106]

As requested by the AER, to the extent possible, we provide an update on all projects due for completion in 2020-21 and 2021-22 below.

However, to be clear, for most connections driven augmentation projects we cannot and do not prepare detailed planning scopes or cost estimates years in advance. Accordingly, we do not agree capital contributions years in advance.

We are unsure why the AER expects that we would (or should) have this information as:

- Detailed designs and costs estimates can only be produced using information from developers, which we do not yet have. Until we receive an application to connect we have to rely on higher level information from the developers, councils and the Department of Planning and the Environment which generally do not include sufficient detail on the design of the new estate/building, loads or where other infrastructure will be located. As Zincara recognises, the actual infrastructure required and timing can be expected to change. [107]
- We do not control the timing of our connections driven augmentation projects. The number of connections depends on developers plans which are in turn driven by market forces, council approvals, and other utilities requirements (in particular electricity distributors) etc.

Except for Access Arrangement forecasts, we only prepare detailed cost estimates once a developer lodges a connection request. This generally occurs only after development approval has been granted.

The developer will provide the detailed information (designs, number of dwellings, expected loads etc.) to allow us to prepare a detailed cost estimate and in turn a connection offer. If required, the connection offer will also set out a capital contribution.

If the offer is accepted we will generally be in construction within three to six months to meet the developer's timeframes. We need to work fast as if we do not have gas available in time there is a high risk that developers will instead select electric appliances to avoid delays in finalising their developments.

Menangle Park (2020-21)

We have forecast to construct a 6km 150mm secondary steel feeder main and new regulator to provide gas to a new greenfield area with no existing gas infrastructure. The feeder main will need to be laid at the start of the estate construction.

Zincara requested:

> *With this augmentation project required during the first year of the 2021-2025 regulatory period, and initial project activities commencing in RY20, we recommend that JGN provide an update of their capital contribution negotiations with the developer along with an updated project cost estimate.*[108]

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[105] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-50

[106] Ibid, p.5-50

[107] Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.98

[108] Ibid, p.92

[redacted]

Cecil Park (2020-21)

In Cecil Park we will extend an existing 150 mm secondary steel main 310 meters and to install a new regulator in 2020-21.

Zincara requested:

> *With this augmentation project required during the first year of the 2021-2025 regulatory period, we recommend that JGN provide an update of their project cost estimate.* [110]

There has been no update to the cost estimate as it still represents the best forecast possible in the circumstances. However, we can report that winter 2019 gauging has confirmed that the augmentation will need to be in place before winter in 2021.

Lidcombe CBD (2020-21)

In Lidcombe we had planned to construct a new 1.3km 150mm secondary steel main to support the proposed developments.

Zincara requested:

> *With this augmentation project required during the first year of the 2021-2025 regulatory period, and with expenditure occurring in 2020, we recommend that JGN provide an updated project cost estimate.* [111]

We do not have an updated cost estimate for this project.

Edmondson Park (2021-22)

To address a forecast capacity constraint in Edmondson Park we will lay 500m of secondary steel and a regulator in 2021-22. There has been no update to the scope or cost of the proposed solution. Winter 2019 gauging data confirms that the investment will be required by Winter 2022.

Largs (2021-22)

To address a forecast capacity constrain in Largs we will install a new medium pressure feeder main (1.9km of 110mm PE). Winter 2019 gauging data confirms that the project will be required by winter 2022. There has been no change to the scope or cost estimate.

Bankstown (2021-22)

We have removed this project as it is no longer required. We no longer require this project as by installing mains for new customers in 2019-20 we have been able to also strengthen the capacity of the network.

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109 JGN-RP-2-3.15-2-Capacity Augmentation Development Plan-NPV Model-year 2050-20191220-public.xlsm

110 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.93

111 Ibid, p.93

5.3 Compliance with Rule 79(2)(b) – incremental revenue versus capex

Our 2020 Plan included analysis demonstrating that each of our connections driven augmentation projects will provide incremental revenue in excess of the incremental capital expenditure. This demonstrates that each project will provide customer benefits by lowering bills[112] and this expenditure is justified under Rule 79(2)(b).

The AER raised three main concerns with our analysis:

- That the base-case assumption that 94.3% of homes in new estates is "*difficult to accept*". [113]
- There may be a lag between when capex is incurred and demand is realised.
- The AER expected overheads to be included in our analysis.

In the subsequent sections we address the AER's concerns in detail:

- We provide information from the NSW Government that validates our baseline new-estate penetration rate.
- We explain how we have adjusted our model to lower the first two years of revenue from each new connection as they are unlikely to be consuming at their mature load.
- We explain why it is not appropriate and not consistent with best practice to include overheads in a comparison of incremental revenue and capex.

5.3.1 New estate penetration rates

Our analysis included a baseline assumption that 94.3% of houses in new estates would connect to gas. As described in our Capacity Augmentation Plan[114] we calculated this figure by looking at satellite maps of new suburbs and counting how many homes had an active gas connection.

We selected areas (see Figure 5-1) which have had time to develop over the last few years, taking into account the lag between when a gas main is laid, a home is built and gas is connected. We did not include areas which were developed 20 or 30 years ago or where gas mains were laid after houses were built as this would not provide an accurate indication of penetration rates we expect to see in new estate areas.

As most of our new estate type augmentation projects are in Sydney's west we checked 13,041 homes across seven new suburbs in Western Sydney. We found that 12,142 had an active gas connection giving a penetration rate of 94.3%.

We then conducted sensitivity tests around this baseline assumption by varying the penetration rate between 80% and 100%. Using a range of penetration rates gave us not only a sense of what could happen if gas take-up falls but also if developments in each area are larger or smaller than forecast.

The AER had two concerns with the new estate penetration rate assumption. Firstly, the consistency between the NSW-wide penetration rate used by Core Energy to forecast connection numbers and secondly the number, size and selection approach used to calculate the baseline penetration rate:

> *Although sensitivity tests have been carried out on penetration rates for each new development, we still have concerns over the limited historical samples JGN has used to derive its 94 per cent penetration rate for new developments. Given that the average penetration rate in JGN's proposal is 74 per cent, and has*

[112] This analysis was presented in Appendix A of JGN-2-3.15-2-Capacity Augmentation Development Plan-20190630-public.pdf based on the outputs of two models: *JGN-2-3.15-2-Capacity Augmentation Development Plan-NPV Model (1) -50 years-20190630-public.xlsm* and *JGN-2-3.15-2-Capacity Augmentation Development Plan-NPV Model (1) -70 years-20190630-public.xlsm.*

[113] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-53

[114] JGN-2-3.15-2-Capacity Augmentation Development Plan-NPV Model (1) -50 years-20190630-public.xlsm

gone as low as 66 per cent in the past 10 years, we find that a penetration rate with a lower bound of 80 per cent high for the purpose of a robust sensitivity test.[115] …

Given the size of JGN's network and the amount of construction activities in NSW over the past 5 to 10 years, provide further details on why JGN used only seven sites to represent the penetration rate for all new developments.[116] …

In particular, we find JGN's 94 per cent penetration rate for new estates difficult to accept as a base case given that it is based on a sample of only seven suburbs going as far back as 2003–04. Even if we accept that these are random samples, the sample size is simply not statistically significant enough to support 94 per cent penetration rate as an appropriate figure to use for a base case scenario. [117] …

While we acknowledge that JGN has made an attempt to carry out sensitivity analysis using an 80 per cent penetration rate, the average penetration rate in JGN's proposal is 74 per cent, and has gone as low as 66 per cent in the past 10 years. We find that a penetration rate with a lower bound of 80 per cent high for the purpose of a robust sensitivity test. [118]

The NSW penetration rate and new estate penetration rate are not like-for-like

It seems that the AER's concern is driven by a difference between:

- The NSW-wide penetration rate calculated by Core Energy of 76%.[119] This penetration rate is calculated by looking at the five-year average ratio between the number of new dwellings we connect and the HIA's housing commencements data for the whole of NSW (lagged 1-year).
- The baseline new estate penetration rate (94.3%). The proportion of new homes in a new estate that will connect to our network.

Comparing these two penetration rates is like comparing apples and oranges. While they both represent "penetration rates" they are represent different concepts. They cannot be used cross-check each other without taking into account the differences between the two.

The main difference is that the NSW-wide figure reflects that our network does not cover the whole of NSW. HIA's housing commencements data covers the whole of NSW while our network does not.

Many new dwellings in NSW are served by other gas networks (for instance AGN's Albury and Wagga Wagga networks) or simply don't have access to mains gas (such as the towns north of Newcastle) and either use LPG or electricity instead. Unless all new dwellings are built in our network area the NSW-wide penetration rate will always be lower than a penetration rate for a specific area.

To cross check the NSW-wide penetration rate again the new-estate penetration rate you need to account for the proportion of new dwellings not connected within our network area.

We estimate that our network covers about 80% of new dwellings in NSW. If we use this figure to adjust the NSW penetration rate we get a network specific penetration rate[120] of 95% (76%/80%) this figure is entirely consistent with the estimate we provided of 94.3%.

115 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-50

116 Ibid, p.5-50

117 Ibid, p.5-53.

118 Ibid, p.5-53

119 Core has updated the penetration rate to reflect RY19 data, as requested by the AER, bringing the penetration rate up from 74% to 76%.

120 A network wide penetration rate and a new-estate penetration rate are also different as not all new homes are built in new estate areas.

It also suggests that applying a lower bound of 80% is a conservative lower bound. If we had a network wide penetration rate of 80% and our network covered 80% of all new dwellings in NSW we would expect to see a NSW penetration rate of 64% - much lower than Core Energy is finding.

NSW Government data validates our new-estate penetration rate of 94.3%

We are unsure why the AER considers that a sample based on 13,041 homes across seven suburbs in Western Sydney is "..*simply not statistically significant enough to support a 94 per cent penetration rate*" [121] and "..*difficult to accept as a base case..*".

The AER did not explain what base case it considers to be appropriate or how an alternative estimate should (or could) be derived.

Given the extent of the AER's concern we turned to external data to validate our baseline new estate penetration rates.

Each development application for a new residential dwelling must lodge a BASIX (Building Sustainability Index) certificate. This specifies whether the installed hot water system, heating and cooktop appliances use gas. The NSW Government has published data from these certificates for the 2011-12 to 2017-18 period. While there are data limitations (the data only covers single dwellings, there are more certificates than buildings built etc.) this data can be used to validate our assumptions around new-estate penetration rates.

Using the BASIX data-set we have identified the suburbs in our network area with the largest number of new certificates. We then calculated the proportion of these certificates that lists a gas appliance listed on the assumption that these customers are connecting to our network.

Across the top 100 suburbs[122] there were 92,322 certificates lodged over the seven financial years. 87,695 of these certificates listed a gas appliance providing a penetration rate of 95%, remarkably close to the our baseline new-estate penetration rate of 94.3%.

The BASIX data covers new homes and major renovations[123] in existing and new areas. Many existing suburbs were not reticulated with gas when they were developed. In these areas (Blacktown, Chester Hill, Castle Hill, Fairfield, Smithfield, Fairfield West, Cabramatta, Canley Heights, Bossley Park, Liverpool) we see less than 80% of BASIX certificates being lodged with a gas appliance. As we did not remove existing areas from our top 100 suburb cross-check the 95% figure produced is an underestimate of the likely penetration rate we achieve in *new estate* areas.

In Table 5-5 we show the top 20 suburbs. The orange shaded rows highlight areas included in our initial sample. This shows that the areas we selected are the areas in which most development has been occurring and that the penetration rates seen are consistent with other suburbs. Looking at only the top 20 suburbs (as they are more likely to capture new estates rather than new homes or renovations in existing areas) provides a new estate penetration rate of 98%.

This data supports increasing the new-estate baseline penetration rate from 94.3% to 98% when evaluating how many dwellings in a new area will connect to our network. The data also shows that the only time we see penetration rates of 80% or less is for new homes and renovations in existing areas we do not have street level reticulation in place. As a result, using a 80% when considering how many customers in a new area will connect is an appropriate, if extremely conservative, lower bound.

Despite this additional evidence we have retained our baseline assumption of a penetration rate of 94.3% and a lower bound of 80%.

121 We are also unsure what the AER means when it says that the penetration rate sample mean is not statistically significant.

122 Suburbs with the most certificates reported.

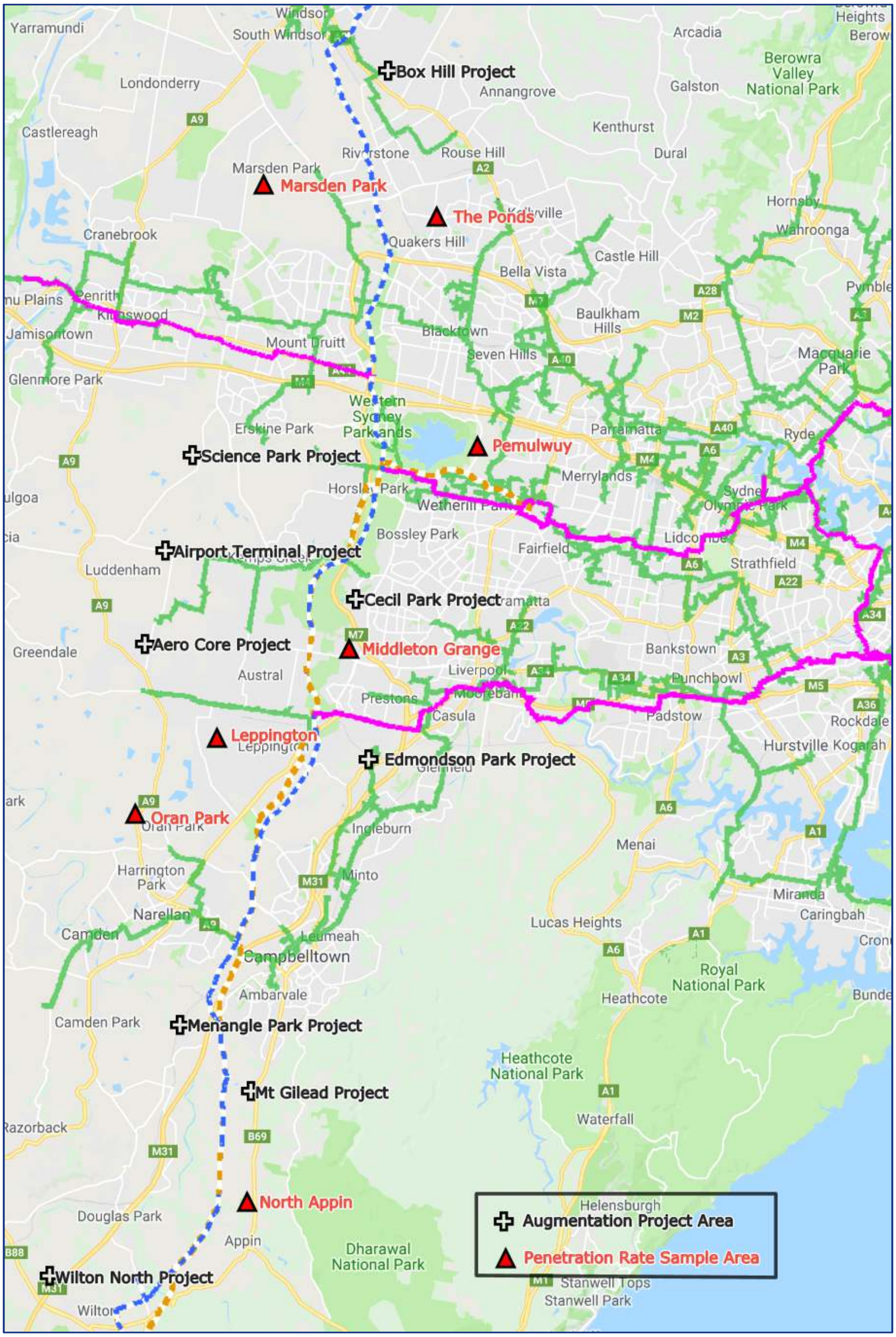
123 BASIX also applies to all alterations and additions in NSW that are valued at $50 000 and over and/or involve the installation of a pool and/or spa with a total volume greater than 40,000 litres.

This additional analysis is further evidence that in preparing our 2020 Plan we applied reasonable assumptions in developing our lean capex forecast.

Table 5-5: Gas penetration calculated using NSW Government BASIX data (top 20 suburbs)

Suburbs	Gas (#)	No gas (#)	Gas (%)	No gas (%)
Kellyville	4,756	50	99%	1%
Oran Park	3,866	19	100%	0%
Schofields	3,818	21	99%	1%
Jordan springs	2,743	35	99%	1%
The Ponds	2,754	8	100%	0%
Edmondson Park	2,522	10	100%	0%
Gregory Hills	2,344	12	99%	1%
Marsden Park	2,335	6	100%	0%
Spring Farm	2,142	6	100%	0%
Orange	1,839	65	97%	3%
Dubbo	1,771	55	97%	3%
Riverstone	1,696	67	96%	4%
Leppington	1,446	11	99%	1%
Gledswood Hills	1,424	6	100%	0%
Middleton Grange	1,395	10	99%	1%
Box Hill	1,351	7	99%	1%
Blacktown	994	267	79%	21%
Merrylands	1,111	57	95%	5%
Goulburn	1,096	47	96%	4%
Ropes crossing	1,115	3	100%	0%
Total	**42,518**	**762**	**43,280**	**98%**

Figure 5-1 Augmentation Projects and Penetration Rate Suburbs



5.3.2 Capex and revenue realisation

The AER raised concerns about the lag between capex and when customers will start generating revenue:

> *Although JGN has adjusted the incremental revenue calculation on certain developments to take into account that customer benefits cannot be realised until after the completion of the augmentation component of the project, we have concerns there might still be a lag between capex expenditure and demand realisation.*[124] *…*
>
> *During our initial review of JGN's incremental revenue analysis for the Aerotropolis development, we found that revenue benefits are being realised prior to the completion of the project. While JGN has since amended the model to better reflect reality, we are still unclear how JGN can realise the demand for hundreds of customers in the same project completion year in its incremental revenue analysis. Especially when CORE's demand and customer forecast report stated that first year residential customers are forecast to consume 29.3 per cent of their mature demand and 81.6 per cent of their mature demand in their second year based on historical averages. …*
>
> *It is unclear to us the reason why JGN did not align its demand forecast to its own consultant's methodology.* [125]

The AER requested that

> *Based on recent developments and the associated billing data, provide the indicative timeframe between capex spend and demand realisation* [126]

We forecast that we will begin to earn revenue as each dwelling is completed and people move into their new homes and start to use gas.

Housing completions in each development is based on the best information we have available for that geographic area, either from developers, councils or the Department of Planning and the Environment.

We then optimise our investment program to ensure we augment the network to bring gas to an area to ensure the first houses have access to gas when they are complete (otherwise there is a risk that these homes do not connect) or when minimum supply pressures are reached.

We lay mains to a new estate so that we are able to supply the first customers in the development. Depending on the size of the development this could be in the order of hundreds of homes that we connect in the initial year. If the AER wishes to adopt a more conservative forecast we would need to move our augmentation program earlier to ensure that the required infrastructure is in place for the initial homes forecast to be complete.

Zincara found our approach is prudent and efficient and in accordance with good industry practice and that our new estate and medium density / high-rise augmentation program has been arrived at on a reasonable basis and the best available at this time. [127]

In terms of how much revenue we recover from new connections in their first two years, we did consider reducing how much revenue we would earn from customers in their initial ramp-up pahase, where they consume gas at less than their mature load. However, given the materiality of the impact and the additional complexity required in our models we decided against this change.

Given the AERs concern we have now implemented this adjustment. We made this adjustment by relying on Core Energy's analysis of our billing data, given the AER has accepted its demand forecasting methodology in the draft decision. As a result, we have scaled down revenue to 29.3% and 81.6% of a mature load in the first and second year a customer is connected.

[124] Ibid, p.5-50

[125] Ibid, p.5-55

[126] Ibid, p.5-50

[127] Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.98

Our updated model does not materiality change the outcome for any proposed project.

5.3.3 Overheads

The AER stated that it expected overheads to be included in our analysis of incremental revenue and capex:

> *It is also unclear to us the reason why JGN used direct costs for capex in its analysis when the revenue appears to be based on total cost. Depending on which cost allocation method JGN decides to adopt between access arrangement periods, we would expect a 10 to 15 per cent increase to the capex inputs to reflect an appropriate overhead allocation so it can be compared against revenue on the same basis. For the purpose of our review and for simplicity, we have introduced a 10 per cent uplift to capex inputs.* [128]

The AER correctly notes that on the benefits side we have included revenue based on the prevailing tariffs (which are based on total costs) but on the costs side we have only direct direct capex in our analysis. This was deliberate.

The purpose of the analysis is to identify whether the incremental costs of undertaking the investment exceed the incremental benefits.

On the benefits side the incremental benefit is the incremental revenue we earn from the additional customers. The revenue we earn depends on the prevailing tariffs in place, not on the cost to connect. These tariffs don't just include overheads but cost recovery from past investments, tax, operating costs etc. For this analysis the basis for the charges is irrelevant. All the matters is how much incremental revenue we will generate from the additional connections.

Calculating revenue based on the prevailing tariffs is also required by Rule 79(4)(a).

It is important to note that recovering revenue from new customers directly translates into bill reductions for our existing customers. The more customers we have the less we need to charge to recover our largely fixed costs.

On the costs side we used direct costs as this represents the incremental cost in connecting these customers. We did not include overheads as these costs are not incremental. This approach is consistent with the National Gas Rules,[129] the AER's current guidance[130] and Ofgem's guidance to gas distribution businesses.[131]

5.3.4 Inconsistent horizon

The AER stated that it did not consider any costs and benefits for our investments beyond 30 years given "..*uncertainties beyond this point*":

> *For each growth driven augmentation project, JGN has selected to justify its capex expenditure by carrying out analysis to demonstrate that the revenue generated as a result of the expenditure exceeds the present value of the capex. JGN has also carried out the analysis based on an investment horizon to 2050, and an investment horizon to 2070 where no further costs and benefits are taken into account post that time.*

[128] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-54

[129] Rule 79(2)(b) and 79(4) are clear that incremental revenue and operation expenditure are to be used in this analysis. To be consistent incremental capital expenditure must also be used.

[130] See AER, *Application guidelines, Regulatory investment test for distribution*, December 2019, p.50 and AER, *Application guidelines, Regulatory investment test for distribution,* December 2019, p.30

[131] See Ofgem 2019, *RIIO-GD2 Investment Decision Pack guidance,* p.13 as well as the cost benefit analysis template provided by Ofgem to businesses (*RIIO-GD2_CBA Template_v4*) which specifies direct costs to be included for each option.

In line with our previous decisions, we do not consider costs and benefits for these types of investments beyond 30 years given uncertainties beyond that point. As such, we do not accept JGN's incremental revenue analysis for an investment horizon to 2070. [132]

However, in the same decision, in response to our proposal to reduce assets lives given the real risks that future gas customers will either not use our gas network in the way they do now, the AER said:

We do not consider that there is sufficient evidence to show the utilisation of JGN's network will decline in a way that results in a material risk of assets being stranded. [133]

If the AER takes the view that there is insufficient evidence to show the utilisation of JGN's network will decline then implicitly the AER also considers that we will continue to recover revenue from customers connected via these investments.

The AER cannot claim that there isn't sufficient certainty to consider costs and benefits beyond 2050 while also claiming that there is sufficient certainty that we will be able to recover our costs over the period to 2105.

In contrast, our proposal is consistent. Given the real risk to our network we are proposing to reduce asset lives for new investments and to limit these investments to those that provided customers benefits in excess of the costs by 2050. For this reason we only relied on our model with a 2050 horizon. We presented the 2070 horizon model for completeness.

5.3.5 Updates to revenue cost assessments

The AER requested that we update all of our connection NPV models:

We also expect JGN to review and update the capital requirements for the other augmentation projects in its revised proposal based on our findings. [134]

Updates to the models since our 2020 Plan include:[135]

- Cost of capital assumptions that reflect the latest market movements
- Revenue per connection assumptions (based on the AER's draft decision)
- Cost estimates where available, see section 5.2.
- Load assumptions to reflect that connections do not use their full load in their first two years, see section 5.3.2.

A summary of the results, including a comparison to the values report in our 2020 Plan, is provided below. We present the results with 2050 and 2070 horizons consistent with our 2020 Plan.

Table 5-6: Net benefits from each connection driven augmentation project to 2050 ($2020, Millions)

	2020 Plan	Revised 2020 Plan
Lidcombe	0.4	1.3
Aerotropolis Core	3.6	3.5
Water Factory	N/A	0
Menangle Park	-	-
Edmondson Park	5.4	6.1

132 Ibid, pp 5-54 – 5-55

133 Ibid, p.5-18

134 Ibid, p.5-5

135 See JGN-RP-2-3.15-2-Capacity Augmentation Development Plan-NPV Model-year 2050-20191220-public.xlsm and JGN-RP-2-3.15-2-Capacity Augmentation Development Plan-NPV Model-year 2070-20191220-public.xlsm

Wilton North	0.8	1.3
WS Airport & Syd. Science Park	7.6	6.4
Box Hill	5	6.2
Campsie	0.8	0.8
Cecil Park	0.1	0.2
Largs Low	0.2	0.2
Total	**23.0**	**26.8**

Table 5-7: Net benefits from each connection driven augmentation project to 2070 ($2020, Millions)

	2020 Plan	Revised 2020 Plan
Lidcombe	1.3	2.3
Aerotropolis Core	12	11
Water Factory	N/A	
Menangle Park		3.5
Edmondson Park	11.7	12.9
Wilton North	8.1	9.2
WS Airport & Syd. Science Park	19.8	17.9
Box Hill	17.5	19.6
Campsie	1.5	1.6
Cecil Park	1	1.1
Largs Low	0.9	1
Total	**73.6**	**80**

5.4 Categorisation of the Lane Cove to Willoughby section of mains

In its draft decision, the AER stated that:

> *We note that the Lane Cove to Willoughby section of the Sydney primary main integrity management program does not fit well into our definition of augmentation as this project is no longer driven by demand growth, but is part of a series of projects under facilities and pipes to mitigate asset condition risks. It is unclear to us why JGN did not re-categorise this expenditure in their proposal when there is a clear shift in the project's primarily driver since its initial conception.*[136]

We included augmentation driven by safety risks to be consistent with the AER's RIN which states:

> *Augmentation of a transmission of distribution system means work to enlarge the system or to increase it capacity to transmit or distribute natural gas. Augmentation also includes work relating to improving the quality of the network.*

We are more than happy to shift this expenditure into another category if the AER prefers that this category only includes capex driven by demand growth.

[136] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-53

For the time being we have kept this expenditure in this category for consistency with the AER's RIN, our initial proposal and the AER's draft decision.

5.5 Malabar biomethane augmentation project

Interface Carpets, City of Sydney and Dexus have advised they are seeking access renewable gas or will discontinue their gas use and invest in alternatives (such as electrification). In addition, the next version of the Green Star energy rating tool to be released in 2020 incentivises the removal of Natural Gas appliances. As a result, significant demand destruction is forecast if these customers are not provided with a decarbonised gas option.

Losing these customers will result in an existing revenue loss of $2.1M per annum by 2050, not including the potential future connections and increase in throughput from these customers. Unless averted, this reduction in network utilisation and the resultant revenue loss will result in higher network charges for our remaining customers.

The Sydney Water Malabar Sewage Treatment plant currently produces approximately 1500 m3/h of biogas that is burnt in generators to create electricity and flared. Sydney Water intends to upgrade its facility so that it can convert this biogas to renewable gas (biomethane).[137] This facility would have the capacity to inject up to 268 TJ/yr of methane into our network.

Augmenting our network by building a secondary main to the Malabar Sewage Treatment plant will allow renewable gas to be injected into our network. The customers that want to decarbonise would be able to procure this renewable gas from Sydney Water through an accreditation and certification scheme instead of electrifying or relocating their operations.

In addition to avoiding revenue loss, this investment would provide a pathway for additional renewable gas to be injected into our network by providing a proof of concept (lowering technical risk for future projects), enabling development of certification and creating a market for renewable gas.

JGN has considered three options:

1. Maintain the status quo and do not augment the network to connect the Malabar Sewage Treatment plant to our network. This option avoids any network augmentation costs but results in revenue loss, and higher bills for our customers.
2. Provide a connection direct to our secondary network. This option would provide enough capacity for the Malabar Sewage Treatment plan to inject all the renewable gas it can produce at a cost of $2.5M.
3. Provide a connection to our local distribution network. This option provides a lower capital cost connection option ($2.5M) however it will limit how much renewable gas can be supplied into our network and so the number of customers that can be retained on the network.

Evaluation of these options indicates that the secondary main provides the most benefits to our customers with an NPV of $20.2M relative to the status quo.

This project meets the requirements of Rule 79.

Firstly, facilitating access to renewable gas is consistent with good industry practice and is consistent with Rule 79(1). This is demonstrated by gas networks around the world[138] who are actively working to facilitate and encourage the injection of renewable gas into the networks to ensure that they can play a role in a decarbonised future. Facilitating the injection of renewable gas will also help lower bills, than they otherwise would have been, helping achieve the lowest sustainable cost to consumers.

137 This renewable gas will meet the specifications of natural gas.

138 Over 1,000 sites across Europe are injecting biogas into local distribution networks. For instance SGN in the UK have connected 25 biomethane plants with another 11 planned over the next year while Wales and West Utilities has 19 plants connected.

Secondly, this project is justified as the present value of the expected incremental revenue to be generated ($22.7M) as a result of the expenditure exceeds the present value of the capex ($2.5M).

Further details of this proposed investment is provided in the attached Options Analysis. [139]

5.6 Supporting information

Table 5–8 lists the additional supporting document we have provided in response to the AER's draft decision.

Table 5–8: Supporting documentation (attachment 4.8)

Name	Author
JGN-RP-Aerotropolis-Options Analysis-20191220-public	JGN
JGN-RP-Aerotropolis-NPV Model-20191220-public	JGN
JGN-RP-13033942-Western Sydney Airport and Sydney Science Park-PEM-20191211-confidential	JGN
JGN-RP-13033933-Aerotropolis Core-PEM-20191211-confidential	JGN
JGN-RP-10049740-Water Factory-PEM-20191220-confidential	JGN
JGN-RP-Aerotropolis-Sydney Water-Letter of support-20191219-confidential	Sydney Water
JGN-RP-Aerotropolis-Sydney Science Park-Letter of support-20191212-confidential	Sydney Science Park
JGN-RP-Aerotropolis-WCAA-Letter of support-20200106-public	WCAA
JGN-RP-Aerotropolis-MOU-signed-20191211-confidential	Multiple
JGN-RP-2-3.15-2-Capacity Augmentation Development Plan-NPV Model-year 2050-20191220-Confidential.xlsm	JGN
JGN-RP-2-3.15-2-Capacity Augmentation Development Plan-NPV Model-year 2070-20191220-Confidential.xlsm	JGN
JGN-RP-13033925-Menangle Park-PEM-20191211-confidential	JGN
JGN-RP-13046264-Malabar Biomethane Project-Options Analysis-20191220-public	JGN
JGN-RP-13046264-Malabar Biomethane Project-Options Analysis-20191220-confidential	JGN
JGN-RP-13046264-Malabar Biomethane Project-Appendix A-NPV model-20191220-Confidential	JGN
JGN-RP-13046264-Malabar Biomethane Project-Appendix B-Option 2-Drawing-Public	JGN
JGN-RP-13046264-Malabar Biomethane Project-Appendix C-PEM-20191211-Confidential	JGN
JGN-RP-13046264-Malabar Biomethane Project-Appendix D-Interface Carpets-Letter-20191022-Confidential	Interface Carpets
JGN-RP-13046264-Malabar Biomethane Project-Appendix E-City of Sydney-Letter-20191213-Confidential	City of Sydney
JGN-RP-13046264-Malabar Biomethane Project-Appendix F-Dexus Letter-20191219-Confidential	Dexus
JGN-RP-BASIX Penetration rate analysis-20191224-Public.xlsx	JGN

[139] JGN-RP-13046264-Malabar Biomethane Project-Options Analysis-20191220-public

6. Newcastle mains replacement project

The AER's draft decision accepts all of our proposed mains replacement projects except for Newcastle, which the AER deferred by one year. We welcome the acceptance of these mains replacement projects and have accordingly focussed our response on the timing for the Newcastle project.

The Newcastle mains replacement project aims to replace ageing cast iron mains which are deteriorating and leading to an increasing number of leaks. These leaks pose a safety risk, cause customer frustration and concern. Given the extent of the leaks and the associated costs of adhoc emergency repairs, systemically replacing the entire distribution system will cost less than making ongoing reactive repairs.

Although the AER and Zincara found the project is prudent and the cost reasonable,[140] the AER deferred the project on the basis that the mains can continue to be effectively managed for another year to maximise the use of the existing asset. The AER asserts that this will save consumers $8.5M.

The AER's and Zincara's analysis does not focus on customer outcomes in terms of price, quality or safety. Instead the AER focuses on maximising the use of a deteriorating asset.

Delaying the project one year will cost customers over $1M as the financing cost savings from deferral are more than outweighed by the additional future opex costs. Further delaying the project also increases safety risks, as given the state of the network we cannot continue to effectively manage the leaks, and will leave our customers in the Newcastle area continuing to deal with lower levels of amenity as a result of gas smells and the disruption of reoccurring leaks and repairs in their local streets.

Given that our proposed timing delivers better outcomes for customers we have not changed the timing of our Newcastle mains replacement project.

6.1 The AER's draft decision

The AER stated:

> *The information provided for the Newcastle mains rehabilitation project shows that while the networks are in poor condition, they are not deteriorating at any significant rate, based on the leakage data. Using the leakage data, we agree with Zincara that the Newcastle mains can continue to be effectively managed for at least one to two years, maximising the use of the existing asset.*
>
> *Based on our analysis of the projects and review by Zincara, five projects should be supported as proposed, with one project delayed by one year. Delaying the Newcastle project by one year results in a saving of $8.5 million ($2019–20, direct cost) (Table 5.29).*[141]

Zincara stated that it is prudent to proceed with the Newcastle mains replacement project[142] and that based on its knowledge and experience the cost appears to be reasonable.[143] However, Zincara considered that the project could be deferred by one year solely on the basis of leakage rates:

> *JGN's benchmarking comparisons with some other network companies (refer IR025) shows that the leakage rate for cast iron and unprotected steel in the Newcastle network is not as high as leakage rates experienced in other network companies, which vary between 1.7 to 2.28 leaks/km for cast iron and varying between 0.6 and 6.7 leaks/km for unprotected steel. While we consider that it is prudent to proceed with this project, the timing is more flexible, with JGN currently managing leak repairs and*

[140] Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.110

[141] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-58

[142] Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.109

[143] Ibid, p.110

monitoring the networks with its maintenance programs to ensure maximum use of the existing network assets.[144]

..

Based on the asset condition analysis, Zincara considers that the rehabilitation project could be reasonably deferred by at least one or two years, as further options. [145]

..

Given the level and trend of leaks, we believe that the mains can continue to be effectively managed for at least one to two years, and thereby maximising the use of existing assets. When considering the overall program and the mains replacement experiences here and around the world, in removing the aging cast iron and unprotected steel, we consider that it would be prudent to defer the project by one year, recognising that there will be ongoing opex and UAG costs during that period. This brings the length of mains rehabilitation program during 2021-2025 to around 105 kilometres (a two year deferral would reduce this period rehabilitation to closer to 60 kilometres, which may be too low).. [146]

6.2 Delaying the Newcastle mains replacement program increases costs and the risk to consumers

While it is true that the Newcastle mains replacement *could* be deferred one year this doesn't mean that it *should* be deferred. To meet the NGO the timing of the project must maximise customer outcomes rather than be driven relative asset performance between gas distribution businesses.

In particular, in considering whether to defer a project the following factors need to be taken into account:

- Our ability to repair the 60-140 leaks that occur each year.
- Higher than necessary safety risks to the community and our staff.
- Cost increases from the additional leaks (lost gas and additional repairs that could be avoided).
- Increased customer frustration and concern.
- The financing cost savings from deferring the project.

It appears that neither the AER nor Zincara conducted any analysis on these factors to inform their recommendation to defer the project.[147] This approach is inconsistent with the previous AER Chair's suggestion that we move away from a focus on engineering and financial characteristics of assets to the services that the assets can deliver and that consumers value.[148]

If focussed on costs alone, the reduction in financing costs from deferring the project one or two years will be more than offset by the increasing costs of the leaks and repairs.[149] The AER's/Zincara's approach of deferring the project one year will increase costs by more than $1M rather than, as the AER asserted achieve a cost saving of $8.5M.[150]

144 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.109

145 Ibid, p.109

146 Ibid, p.110

147 While Zincara did recognise that there will be ongoing opex and Unaccounted for Gas (**UAG**) costs no analysis conducted to compare the financing cost savings from deferring the product against the increase in opex costs as the mains continued to deteriorate. See: Zincara 2019,*Access Arrangement 2019 JGN Capital Expenditure Review,* p.110

148 Conboy, Paula, *Looking back and looking forward, an AER Chair perspective,* 1 August 2019

149 As identified in our response to Information Request, IR08.

150 JGN-RP-10022511-Newcastle with updated leakage data-NPV Model-20191211-public.xlsb

Leaks in Newcastle are becoming increasingly difficult to repair

Although Zincara stated that the leaks are able to be effectively managed that is not consistent with our experience in Newcastle. Due to the condition of the mains and the surrounding environment in many cases it is not possible to effectively manage the leaks that are occurring. In just the last three months there have been two sections of main where we haven't be able to make cost effective repairs as a result of the lower operating pressure of the existing system.

- The first section is a cast iron main laid in a sloping front footpath verge which makes it extremely difficult to excavate. Rather than make a temporary repair we need to lay a new main in a 240 meter trench in the street.
- The second section is between a busy Roads and Maritime Services (**RMS**) road and the Fernleigh cycle/walking track. The main is partly exposed and at least one large tree will need to be removed to make the repairs.

Given the serious public safety risk from these leaks we cannot make band-aid repairs and wait three years to commence the Newcastle mains replacement project. Instead we are being forced to replace mains in short bursts which comes at a much higher unit cost than would be incurred in a planned project.

These mains also take much longer to repair, increasing safety risks and customer frustration as explained below.

Delaying the Newcastle project will lead to higher than necessary safety risks to the community and staff

Each leak poses a risk to public safety and repairs are a risk to JGN personnel and contractors. Sections of mains are at unacceptable level of leakage with a series of short term band-aid repairs. Only a systematic replacement program will permanently reduce the leaks and in turn the safety risks.

Our ability to quickly respond to leaks is also limited given that large natural gas volume escapes need special equipment to isolate supply (WASK and Ravetti stopping gear). In an emergency or Class 1 leak situation,[151] this special equipment takes a long time to transport to site, and must be set up by trained personnel to stop gas flow. This exposes the public to far greater risk by not being able to isolate supply in an emergency in a timely fashion.

Leaks in Newcastle are affecting people's lives and causing customer frustration

The deteriorating conditions of the mains has led to numerous customer complaints. Several of our customers in the Newcastle area have told us that the smell of leaking gas is wafting into their homes to a degree where they cannot open their windows or front doors. Customers have told us that the gas has caused them headaches.

These concerns are exacerbated by our inability to make permanent repairs. Often after we repair the mains, another leak will occur causing the customer immense frustration as despite work being undertaken the issue has not been resolved.

On several occasions customers have been so concerned that they have called emergency services. In one case this has led to a customer contacting the Energy and Water Ombudsman NSW.

The only way to permanently address these leaks is to undertake the Newcastle mains replacement project.

Delaying the project increases the cost to consumers

Each year as the mains deteriorate we incur greater opex to replace lost gas and on an increasing number of repairs.[152] As discussed above we are also incurring greater capex from our need to replace sections of mains in a reactive rather than planned manner.

Our options assessment took into account the forecast number of leaks to calculate these additional costs.

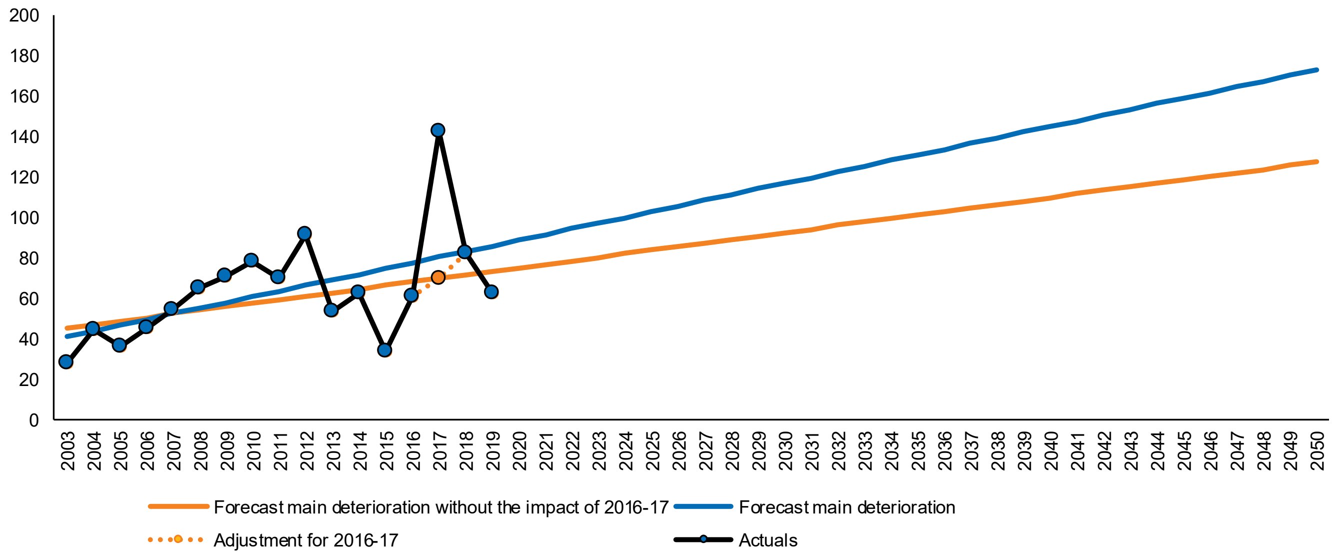
151 Leaks are classified based on the severity of gas escape with a classification of 1, 2 or 3. A class 1 requires the leak to be repaired immediately, class 2 repaired within 7 days and class 3 are noted for reference purposes.

152 It is important to note that we did not seek a step change to account for the increase opex costs that we will continue to incur.

We have revised our cost forecast with the latest available data, to take into account the number of actual leaks during 2019. We have also considered two scenarios:

1. A forecast of leaks based on all data known to date.
2. A forecast of leaks incorporating an adjustment to remove the impact of 2016-17, as Zincara considered that the leakage rates were steady aside from 2016-17. [153]

Figure 6-1 Forecast leaks in the Newcastle area



We used these updated leak forecasts to identify the net-present value (**NPV**) of starting the Newcastle mains replacement project in 2021-22 (as we had proposed) versus 2022-23 (deferred by one year as recommended by the AER/Zincara). The results of this analysis is presented in Table 6-1.

In both scenarios starting the mains replacement program in 2021-22 provides a lower cost outcome to consumers.

Table 6-1: Comparison of NPV of benefits under each leakage scenarios ($2018, $M)

	2021-22 start	2022-23 start (1 year deferral)	Difference
Main deterioration continues in line with trend	15	13.9	1.2
Main deterioration (adjusted to remove impact of 2016-17)	13.6	12.5	1.1

As delaying our Newcastle mains replacement program one year will increase costs to customers, and to ensure that we address increasing customer concerns about the leaking main, our revised proposal has retained the timing included in our 2020 Plan.

6.3 Supporting information

Table 6-2 lists the additional supporting document we have provided in response to the AER's draft decision.

153 Zincara, *Access Arrangement 2019 JGN Capital Expenditure Review,* November 2019, p.108

Table 6-2: Facilities and pipes supporting documentation (included in Attachment 4.6)

Document reference and name	Author
JGN-RP-10022511-Newcastle with updated leakage data-NPV Model-20191211-public.xlsb	JGN

7. Relocations

From time to time, government authorities or private landowners require JGN to move its gas mains or facilities to enable the authority to perform works such as road re-alignment or widening, or to make way for activities that the property owner has planned. Where arrangements with the relevant authority or landowner do not provide JGN with a right guaranteeing the location of its assets, we are bound to relocate them as required by the authority or landowner at our own expense.

We forecast relocations based on an average of historical costs.

The AER did not accept our relocation cost forecast by speculating that our relocation costs are falling:

> *JGN proposed $3.7 million ($2019–20, direct cost) for relocation of its assets in private properties without easements based on a historical average method. Given this program is mostly driven by a legacy asset installation policy, we would expect to see a declining trend in expenditure requirements moving forward. Since the historical trend is not available for our review, we took the 2019–20 year estimate of $0.5 million ($2019–20, direct cost) as a flat base and provided an alternative forecast of $2.6 million ($2019–20, direct cost). In addition, we would like JGN to clarify if any past expenditures on this program might have overlapped with any shallow mains requirements.*

Although the AER states that the historical trend isn't available for review, our relocation costs have been reported in our response to the AER's RINs since 2005-06. While our costs fluctuate year-to-year there is no declining trend as shown by Table 7-1. The AER's forecast results in an allowance below what is has been incurred over the last three regulatory periods.

Table 7-1: Annual average relocation spend ($2020, $M, direct)

	2005-10	2010-15	2015-19	2020 Plan Forecast	AER draft decision
Relocations	0.53	1.35	0.77	0.74	0.53

Below we explain that the rationale behind the AER's forecast is also not consistent with the drivers of our relocation expenditure. Lastly, we clarify that there is no overlap between past expenditure and our shallow mains requirements.

7.1 Relocation costs are not declining

In building gas infrastructure we are focussed on delivering efficiently in the long term interests of our customers.

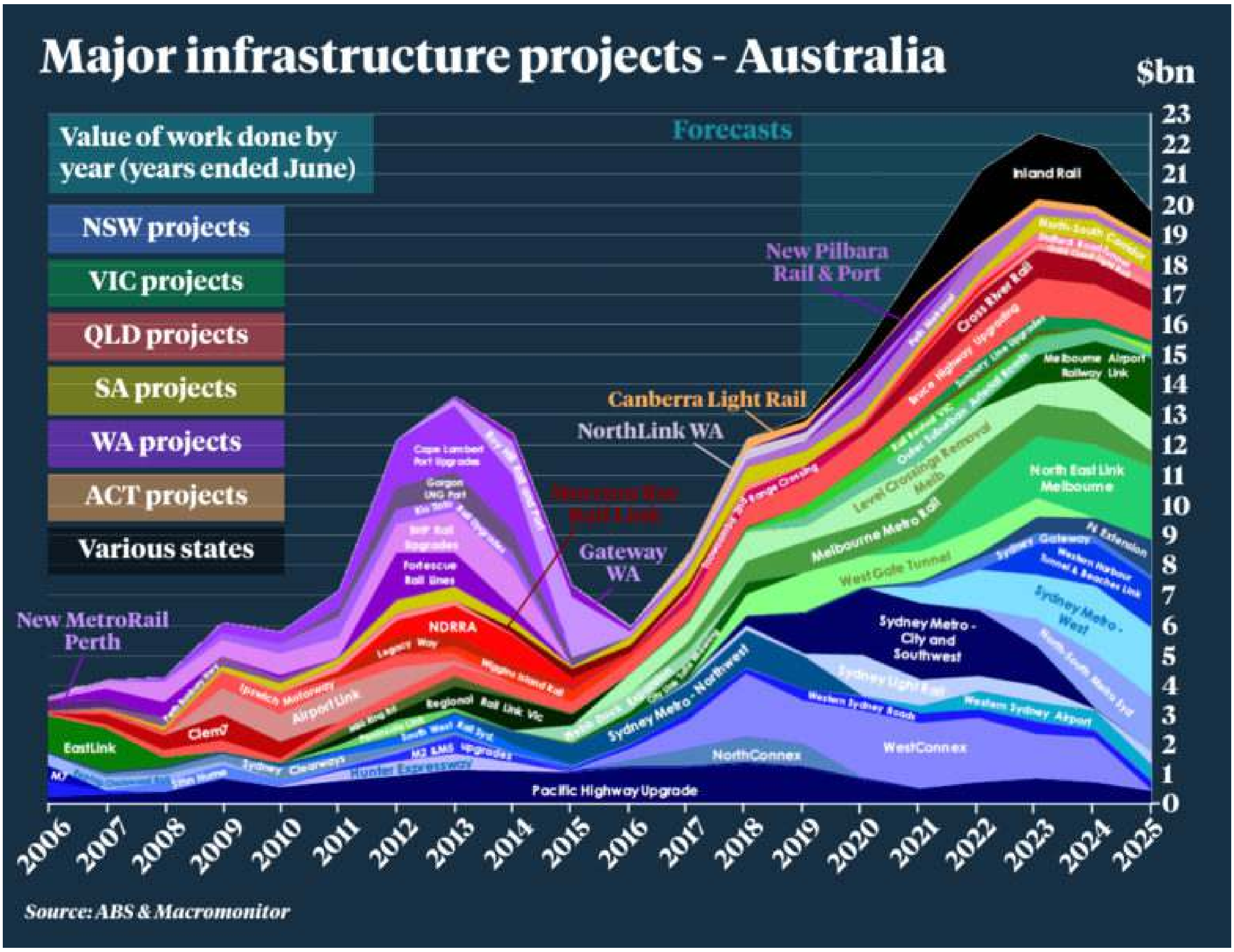
In many cases the most efficient solution is to install infrastructure where it is not possible to obtain rights guaranteeing the location of our assets. We may only be able to obtain rights to lay a main or install an asset with the condition that we relocate our assets at the request of a third party.[154] The third party is typically a government authority but could also be a private land owner.

A good example is our agreement between JGN and the Commissioner for Main Roads. This agreement allowed us to install infrastructure on the bridge across the Swansea channel at the entrance to Lake Macquarie but did not provide for JGN to recover the cost of altering/moving its infrastructure where required to do so by the Commissioner. In 2013-14, when the fenders on the bridge were modified we were required to alter our infrastructure. Instead we chose to remove our assets and the main by drilling underneath the channel.

Given the forecast increase in major infrastructure projects across NSW, as shown by Figure 7-1, it is unlikely that our relocation costs will fall.

[154] Where we do have the rights around the location of the assets, we recover the cost of relocation from the authority or landowner. No capex for recoverable works is included in our forecast.

Figure 7-1 Major infrastructure projects in Australia[155]



7.2 There is no overlap between historical relocations costs and forecast shallow mains requirements

We confirm that there is no overlap between our historical relocation spend and the forecast shallow mains requirements. The costing for the shallow mains project is based on a series of assumptions based on our previous experience and knowledge of the network. These assumptions have taken into account information on our network obtained when relocating assets, responding to hits to our network and connecting new customers.

155 The New Daily, *The infrastructure boom bigger for longer, but then what?*, August 2016. See: https://thenewdaily.com.au/finance/finance-news/2019/08/26/falling-infrastructure-investment/

8. Mobile plant and equipment

The AER requested that:

> *In terms of mobile plant and equipment, we would like JGN to provide some insight into the proposed $2.9 million ($2019–20, direct cost) capex for tools in its revised proposal. For this draft decision, we accept that the proposed $2.9 million ($2019–20, direct cost) is conforming capex.*[156]

Mobile plant and equipment covers a range of minor equipment and tools necessary to ensure the safety operation of the gas network. Spend in this category includes tools, gas detectors, bench grinders, heavy duty battery drills, road drillers, wet and dry vacuums, safety equipment, purge burners, temperature probes, high-pressure gauges, two-way radios, valve replacement tools, air supply hoses etc.

Historically, our spend has fluctuated based on the requirements we have that year but on average we spend $0.69M per annum, as shown by Table 8-1. Our proposal includes $0.58M per annum.

Table 8-1 Historical spend for Plant and Equipment as shown in the RIN ($2018, $M, direct)

	RY16	RY17	RY18	RY19	Average
Mobile plant and equipment	1.05	0.71	0.61	0.40	0.69

[156] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-62.

9. Speculative capex account

The AER determined in its draft decision to not approve the establishment of a speculative capex account for the Green Gas Trial on the basis that the project "is unlikely to meet the conforming capex criteria", citing Rule 79(2). It is not clear from this statement whether the AER has concluded that:

- the capex does not currently meet the Rule 79 criteria (but may do so in future); or
- the nature of the project is such that the capex could never satisfy the Rule 79 criteria.

We address each of these possible conclusions below.

For reasons set out below, we consider that the AER's decision to not approve the creation of the speculative account is inconsistent with the NGR and the achievement of the national gas objective. Accordingly, we maintain in our revised proposal that a notional fund is created in accordance with Rule 84 and clause 6.1 of JGN's AA.

We also note that the AER's view that the Green Gas Trial capex could never satisfy the Rule 79 criteria is at odds with its draft decision to maintain asset lives for new investments. The AER justified its draft decision on asset lives noting that hydrogen, whilst speculative, would have a positive impact on the future of gas distribution networks. The internal inconsistency of the AER's reasoning is clear – the AER has acknowledged the relevance (although speculative) role of hydrogen to future proofing the network to maintain asset lives, but in its capex draft decision, the AER has rejected the relevance of hydrogen entirely.

The AER does not have discretion under the Rules or the JGN's AA to disallow the creation of a speculative capex account on the basis that the capex does not currently meet the conforming capex criteria in Rule 79(2)

We consider there is no basis under the rules or JGN's AA for the AER to determine to not create a speculative capex account on the basis that the capex is non-conforming capex. The premise of that decision – that the capex does not currently satisfy the Rule 79 criteria – is in fact the proper basis for JGN to establish a speculative capex account in accordance with Rule 84 and clause 6.1 of the AA. The whole purpose of having a speculative capex account is to accommodate non-conforming capex.

Specifically:

- Rule 84 provides that a service provider's AA may establish a speculative capex account for capex which is non-conforming (i.e. capex that does not comply with the new capex criteria)[157]
- consistent with Rule 84, clause 6.1 of JGN's AA provides that JGN may recover non-conforming capex by surcharge or capital contribution, but if it does not it will add that amount to its speculative capex account.[158]

Given the above, there is no basis under the rules or the AA for the AER to reject the establishment of a speculative capex account for capex on the basis that the capex is not conforming.

We note that Rule 84 has not been used since NGR commenced in 2008,[159] but that its intent appears to be to accommodate projects which are in trial phase or do not yet have a firm business case, and which may, depending on the outcome of any trial / investigations be justifiable under Rule 79. The Green Gas Trial represents such a project.

As explained below, JGN considers that the Green Gas Trial represents capex for the purposes of Part 9 of the NGR, but at this trial stage, the costs do not meet the requirements of Rule 79 because it is not yet certain that the technology will deliver material network benefits. This is a sufficient basis for JGN to add the speculative capex to a notional fund in accordance with Rule 84 and clause 6.1 of JGN's AA. That fund will be adjusted

[157] AEMC, Rule Determination - National Gas Amendment (Regulation of Covered Pipelines) Rule 2019, 14 March 2019, p 72

[158] For completeness we note that the AER, in its Draft Decision, accepted the current formulation of clause 6.1 of the AA to apply in the 2020-25 AA period. AER, Draft Decision, JGN AA 2020-25, Attachment 11, Non-tariff components.

[159] AEMC, Rule Determination - National Gas Amendment (Regulation of Covered Pipelines) Rule 2019, 14 March 2019 p 73

annually by the allowed rate of return for the regulatory year in which the adjustment is made, until such time as it considers that compliance with the Rule 79 criteria can be established.

We note that the creation of the speculative capex account does not impact the tariffs that may be charged by JGN, unless and until JGN can prove that the capex is conforming. Specifically, at the time that JGN seeks to roll the capex into the capital base (in accordance with Rule 84(3)), the AER may then assess whether the conforming capex criteria is met. However at this stage, its determination of those matters is premature and, for reasons provided above, not open to it under the NGR.

The AER cannot reasonably conclude that the Green Gas Trial capex could never satisfy the Rule 79 criteria

As noted above, the other possible basis for the AER's decision is that the Green Gas Trial capex could never satisfy the Rule 79 criteria. The AER expresses two concerns regarding conformity (or potential future conformity) with the Rule 79 criteria:

- that hydrogen is not covered by the definition of "natural gas".
- that the electrolyser which forms part of the proposed trial capex, is akin to a production facility, and therefore is not covered by the definition of a "pipeline".

As discussed above, we consider it premature and unnecessary for the AER to be expressing a view on whether the Green Gas Trial capex could (in future) satisfy the Rule 79 criteria.

In any event, the AER's concerns regarding the "natural gas" and "pipeline" definitions are unfounded. The assets to be constructed need not satisfy the "pipeline" definition – it is only necessary that they are used to provide pipeline services (including ancillary services). Similarly, the fact that hydrogen does not fall within the definition of "natural gas" does not matter, since hydrogen injection, is only an input, which supports the provision of pipeline services and/or ancillary services.

As discussed above, the threshold for the establishment of a speculative capex account is simply whether the Green Gas Trial is capex for the purposes of Part 9, but which, for one or more reasons, is non-conforming under Rule 79.[160]

"Capital expenditure" is defined as "costs and expenditure of a capital nature incurred to provide, or in providing, pipeline services" (Rule 69).

> Pipeline services" is defined under the NGL as —
> (a) a service provided by means of a pipeline, including—
>
> (i) a haulage service (such as firm haulage, interruptible haulage, spot haulage and backhaul); and
>
> (ii) a service providing for, or facilitating, the interconnection of pipelines; and
>
> (b) a <u>service ancillary to the provision of a service referred to in paragraph (a),</u>
> but does not include the production, sale or purchase of natural gas or processable gas.

JGN considers that the Green Gas Trial capex represents "capital expenditure" for the purposes of Part 9 of the NGR – in that, it will support delivery of a service ancillary to the haulage service provided by means of the JGN distribution network.

Specifically, if successfully proven, the Green Gas Trial will deliver services ancillary to the reference service by enabling JGN to make up UAG by injecting hydrogen into the distribution network. JGN's obligations to procure Replacement Gas to make up for UAG is provided for under the Reference Service Agreement.

If the trial is proven successful, JGN will be able to scale up its hydrogen production to meet all of JGN's UAG needs, as well as accommodate hydrogen receipts and transportation requests from third party access seekers.

Noting the above, JGN does not need to demonstrate that the capital costs are attributed to a "pipeline" in order to be eligible capex under Part 9. It is sufficient to demonstrate that, as above, the capital costs are incurred to

160 NGR, Rule 69.

support the provision of pipeline services (including ancillary services). The broad definition of "pipeline assets" supports this view, which clarifies that capital assets may constitute the pipeline "or be assets otherwise used by the service provider to provide pipeline services".[161]

The AER also denied the creation of a notional fund for the Green Gas Trial on the basis that "hydrogen" is not covered by the definition of "natural gas". Whilst we agree that hydrogen does not meet the definition of natural gas, we consider this is not a relevant matter, when the Green Gas Trial capex is considered in the context of ancillary services it will deliver (in that it will be used to supplement, and ultimately replace, all sources of Replacement Gas to make up for UAG). In particular, we note that:

- The aim of the pilot is to demonstrate the safe distribution and use of 'blended gas' in the gas distribution network, which as noted above, will be able to be used to replace UAG.
- Whilst the pilot will seek ministerial approval for the injection of hydrogen into the gas network, the resultant blended gas will remain within the gas specification and consistent with the definition of natural gas. This is because JGN's trial will limit the blending to 2%, and therefore the gas distributed through the network will remain principally methane .

Given the above, the fact that the Green Gas Trial involves injecting hydrogen does not preclude it from being characterised as "capital expenditure" for the purposes of Part 9 of the NGR.

We note that the planned phase 2 of the pilot, will take the plant to full scale production. At this stage, JGN may be able to prove a positive overall economic value of the initial trial capex in accordance with Rule 79 and seek to have this capex rolled into its regulated asset base.[162]

Establishing of a speculative capex account for the Green Gas Trial would be consistent with the NGO

For reasons provided above, the AER was in error to reject our inclusion of the Green Gas Trial in the speculative capex account – noting that, at this stage, it does not have any discretion to determine whether or not the capital expenditure currently is or could ever be conforming.

Given this, JGN elects to establish the notional fund for this project, on the basis that the capex is capital expenditure for the purpose of Part 9, but is yet to be able to proven as conforming.

JGN considers the initial investment will enable JGN to explore, assess and test the benefits of injecting hydrogen to its network under small-scale conditions. We are hopeful that the outcomes of the initial investment will indicate the potential for material network benefits, and therefore pave the way for phase 2. Through full-scale production of hydrogen, JGN has the ability to prove a positive economic case for the initial pilot investment, deliver sustained lower network prices through lower input costs of Replacement Gas. These outcomes are consistent with the national gas objective, but can only be realised with the commitment of speculative capex.

In addition, JGN's initial pilot and future phase 2 will make a contribution to reducing carbon emissions by lowering the volumes of natural gas from domestic gas use – helping to achieve the NSW Government's net-zero emissions target, as well as improve long term sustainability and growth of JGN's gas network in a decarbonising environment.

161 NGR, rule 69. We note that JGN's capital base includes various assets which are used to provide pipeline services but which do not constitute the pipeline – for example, land, buildings, computers, software, vehicles.

162 JGN may consider seeking an advance determination under Rule 80 that the expenditure for the project as a whole will meet the new capex criteria.

10. Cost escalation and reconciliation

10.1 Labour escalation – cross reference to opex attachment

The AER's draft decision has made adjustments to each category of capex to align labour real cost escalators in line with its opex assessment, which is based on a forecast by Deloitte Access Economics. Our response to the AER's draft decision on labour real cost escalators is contained within Attachment 5.3.

10.2 Capex model vs RFM – cross reference to historical capex attachment.

The AER notes that it found a discrepancy between JGN's capex model and the roll-forward model on inflation for 2018-19, and that the discrepancy also extends to the $2019-20 calculation of capex from 2014-15 to 2019-20.[163] Our response to this aspect of the AER's decision is contained within Attachment 4.3.

10.3 Reconciliation

The AER requests that we provide a revised proposal in which all figures are in $2020, and models for capex, revenue and pricing are linked and reconciled.

Consistent with our 2020 Plan, our revised proposal is presented in $2020 unless stated otherwise.

To assist the AER we have:

- Submitted our Revised 2020 Plan models package (capex, opex, roll-forward model, roll forward model – pigging costs, efficiency carry over model, rate of return, depreciation model and post-tax revenue model) in a manner so that if the confidential versions are saved in one place the links between the models will continue to function.
- Submitted our capex model package (which includes our meter replacement volume forecast model, meter replacement capex model, connections capex model and a consolidated project capex list) in a manner so that when the models are saved in one place the links between the models will continue to function. The consolidated project capex list is an input into the capex model included in our Revised 2020 Plan models package. These are all provided in attachment 4.5.
- Updated our capex model so that it provides a project level list of documents in both $2018 and $2020.
- Submitted the models which map the revised demand forecast to the PTRM for the Volume market (in Attachment 13.4) and the Demand market (in Attachment 13.5).

If the AER has any difficulty at all with any of our models we are always more than happy to assist. Our preference (relative to emails and information requests) is for face-to-face discussions with a model open or over the phone with screen sharing technology. We have found that talking with a model open is a much faster way to communicate, understand difficulties and resolve issues.

[163] AER, *Draft Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital Expenditure,* November 2019, p.5-69

Attachment A
ICT Information briefs

A1. Summary of the AER's draft decision on ICT projects and JGN's response

The tables below set out the AER's draft decision for JGN's ICT projects that the AER made placeholder decision or did not allow, and JGN's response to those draft decisions in its revised AA proposal.

Table A1–1 Response to AER's placeholder decisions on JGN's ICT projects

Investment brief in initial 2020-25 AA Proposal	Project ID	Project name	$2018 (direct, unescalated)	$2020 (direct, escalated)	JGN Revised 2020-25 AA Proposal response
AM & GIS lifecycle	ITS2022	GIS DBYD System Consolidation	12,639	13,590	Further information provided in Asset Management & GIS lifecycle Investment Brief (**IB**) and NPV
	ITGF03	GIS Data Sharing Capability (C&I Customers) Lifecycle Upgrade	303,600	338,343	
	ITGF04	Drawing Management Vault Separation	N/A	N/A	JGN no longer requires this project
	ITGF05	GIS Engineering Analysis Lifecycle Upgrade	379,500	415,159	Further information provided in Asset Management & GIS lifecycle IB & NPV
	ITGF06	GIS Mobile Enterprise Server Major Lifecycle Upgrade	400,752	446,613	
	ITGF07	GIS Mobile Enterprise Server Minor Lifecycle Upgrade	303,600	329,069	
	ITGF08	GIS Gas Office Major Lifecycle Upgrade	801,504	873,066	
	ITGF09	GIS Gas Office Minor Lifecycle Upgrade	200,376	221,081	
	ITGF10	GIS Web Viewer Lifecycle Upgrade	303,600	329,069	
	ITSD29	AutoCAD & Drawbridge Intray Lifecycle Upgrade	137,531	149,810	
	ITSD30	DrawBridge Major Lifecycle Upgrade (or new product)	332,825	370,912	
	ITSD31	DrawBridge Minor Lifecycle Upgrade	137,531	149,068	
	ITSE06	Integrated Project Portfolio Management - Lifecycle	103,490	115,333	
Meter Management Life Cycle	ITGG18	Mass-Market No-Access Solution	3,272,808	3,562,152	Further information provided in Metering Mass Market No Access IB and NPV
Total			**6,689,756**	**7,313,264**	

Table A1–2 Response to AER's disallowance decisions on JGN's ICT projects

Investment brief in June AA	Project ID	Project name	$2018 (unescalated)	$2020	JGN revised AA proposal response
AM & GIS Enhancement	ITGG03	Asset Data Structures & Data Optimisation	510,048	555,141	Further information provided in Asset Management & GIS Enhancement IB and NVP
	ITGG09	GIS Data Asset Reporting & Dashboard - Service Improvement Requests	500,940	548,011	
	ITGG10	GIS Automate Generation of Schematics	400,752	434,371	
	ITGG11	GIS Data Sharing Capability (e.g. iWorks - Customer Portal)	303,600	331,813	
	ITGG12	GIS Data Warehouse Trend Analysis	801,504	868,896	
	ITGG13	GIS Field Capability	303,600	331,813	
	ITGG14	GIS High Definition Data Sources (New Capability)	510,048	565,584	
	ITGG15	Land Management System	303,600	329,069	
	ITGG17	GIS Service Improvement Requests (Across all GIS, Drawing & DBYD tools)	1,065,636	1,167,985	
	ITSE05	Integrated Project Portfolio Management - New System	451,594	493,559	
Customer Experience	ITSD01	GIS DBYD Consolidated System Lifecycle - PK1	225,797	251,636	Further information provided in GIS DBYD IB and NPV
	ITSE04	DBYD System Consolidation - PK1	289,088	312,089	
	ITGG01	Ancillary Services Optimisation Part 1	N/A	N/A	JGN accepts the AER's draft decision
	ITGG02	Ancillary Services Optimisation Part 2	N/A	N/A	
	ITGG16	Outage Portal	N/A	N/A	
	ITGG21	Outage Notification Automation	473,616	511,298	Further information provided in Customer Experience Hub IB and NPV
	ITSE01	Customer Data Quality Management – PK3	451,594	489,478	
	ITSE02	Customer Experience Hub Establishment (CRM/IS-U Integration) – PK1	2,346,919	2,544,026	
	ITSE03	Customer Experience Hub Enhancement – PK2	564,492	617,534	
	ITGF02	Gas Distribution Portal CX Hub Integration & Lifecycle Upgrade	367,356	403,784	

Investment brief in June AA	Project ID	Project name	$2018 (unescalated)	$2020	JGN revised AA proposal response
Meter Management Life Cycle	ITGF14	MVRS Lifecycle Upgrade	N/A	N/A	JGN accepts the AER's draft decision
	ITGG20	MVRS Replacement	N/A	N/A	JGN accepts the AER's draft decision
	ITGG19	MDL Back-End Replacement	2,210,208	2,405,609	Further information provided in Metering MDL Backend System IB and NPV
	ITGG23	Replace / Upgrade Powerspring/Metretek	2,210,208	2,405,609	Further information provided in Metering Industrial and Commercial IB and NPV
Reporting & Analysis	ITGG06	Credit Management & Billing Reporting & Analysis	510,048	562,841	Further information provided in Enterprise Systems – Reporting & Analysis IB & NPV
	ITGG27	Corporate Works KPI Reporting & Dashboards Enhancements	759,000	830,319	
	ITSD16	Business Objects/Cloud Analytics Lifecycle	495,111	541,750	
	ITSD17	Data Warehouse Lifecycle (SAP BW/4HANA)	907,703	993,209	
	ITSD57	SAP HANA SDI Life Cycle (SLT, ESP, Data Services)	302,568	331,262	
	ITSD58	SAP HANA SDI Minor Patches (SLT, ESP, Data Services)	103,148	112,780	
Records & Document Management	ITSD35	Kofax Replacement	363,081	393,540	Further information provided in Kofax Lifecycle IB & NPV
ERP	ITGG04	Billing Exception & Enquiry Optimisation	473,616	515,488	Further information provided in Enterprise Systems Lifecycle IB & NPV
	ITSD15	Budgeting & Planning Migration (to SAP Analytic Cloud)	90,770	99,205	
	ITSD47	SAP Environment, Health & Safety Module Lifecycle Upgrade	181,541	195,199	
	ITSD49	SAP ERP Desktop Client Upgrades Lifecycle	171,914	188,067	
	ITSD65	SuccessFactors Lifecycle Integration Testing	189,105	206,701	

Investment brief in June AA	Project ID	Project name	$2018 (unescalated)	$2020	JGN revised AA proposal response
	ITSD66	Treasury System Lifecycle Integration Testing	171,914	188,067	
	ITSE12	SAP S/4HANA Cloud Migration (Finance, Procurement, HR/Payroll)	5,660,768	6,226,073	Further information provided in SAP Migration to S4 IB/Business case and NPV
	ITSE13	SAP S/4HANA Migration Business Case (Asset Mgt, Works Mgt, ISU, et al.)	1,001,224	1,110,241	
Data Storage & Management	ITSA05	HANA Database Upgrades	332,825	353,727	Further information provided in Reporting Server and Database Lifecycle IB & NPV
Platforms & Processing	ITSA15	HANA TDI (Hardware & OS) Replacements	365,751	388,722	
Total			**25,860,639**	**28,804,500**	