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Mr Sebastian Roberts
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Australian Energy Regulator
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By email: JGNAAR2020-25@aer.gov.au

17 February 2020

Dear Mr Roberts,

Jemena Gas Networks (NSW) Access Arrangement 2020-25

AGL welcomes the opportunity to provide comments to the Australian Energy Regulator (AER) in relation to the AER Draft Determination (published in November 2019) (Draft Decision) and Jemena Gas Networks (NSW) Ltd (JGN) revised access arrangement proposal (published in January 2020) for the period from 1 July 2020 to 30 June 2025 (Revised Pan). AGL has previously provided a submission on JGN's initial 2020-25 revenue proposal (Original Plan).

AGL appreciates that there is a significant amount of work undertaken by JGN and the AER in these regulatory proposals and decisions.

We make the following observations:
- There is a significant reduction in the weighted average cost of capital (WACC) from 5.4% to 4.46% - 4.6%;
- If the revenue handback is applied to the 2015-20 revenue, the revised revenue represents an increase in real terms from the current regulatory control period, even after accounting for the reduction in the cost of capital;
- Revised operating expenditure and revenue adjustments are generally in line with the Draft Decision;
- Capital expenditure is the key area of difference between the Draft Decision and the JGN proposal; and
- There are real increases in the regulated asset base over 2020-25 despite concerns about the risk of a low carbon future.

In response to the Draft Decision, AGL has provided further evidence to support the separation of disconnection fees from reconnection fees. We have also highlighted the proposed increase in the disconnection/reconnection fee as well the level of abolishment fee.

While we appreciate JGN's engagement on the review of the Reference Services Agreement (RSA) and the revised RSA is greatly improved relative to the current RSA, the lack of performance targets for service orders remains a material concern for AGL.

These concerns and other comments on aspects of the Revised Proposal are discussed in more detail below.

Annual revenue requirement

The Revised Plan proposes revenue of $2,099 million ($2020) during 2020-25 which is approximately the midpoint of the revenue proposed in the Original Plan and the Draft Decision, after deducting the revenue handback of $169 million. It is $90 million higher than the Draft Decision. JGN's allowed revenue for 2015-20 was $2,296 million ($2020) excluding the revenue handback.

As we pointed out in AGL's submission on JGN's Original Plan, when considering the changes in revenue from 2015-20 to 2020-25, the revenue handback $169 million should be applied to the 2015-20 period as it is attributable to the remade final decision for that period. Accordingly, the 2015-20 allowable revenue would amount to $2,127 million ($2020) and the 2020-25 revised proposal would be $2,268 million ($2020). On this basis, the Revised Plan proposes a real increase of 6.6% or $141 million ($2020).

This increase of $141 million is despite the material reduction in revenue allowance due to the lower weighted average cost of capital. In the Draft Decision, the AER had estimated the impact of the reduction in the WACC from 5.4% to 4.46%, to amount to $233 million. If the WACC in the Revised Plan of 4.6% is applied instead, the revenue reduction will be about $200 million on a pro-rata basis.

AGL's concern is that the Revised Plan actually provides a real increase in revenue of 16% or $340 million if the impact of the WACC is excluded and the revenue handback is considered in the 2015-20 period.

Operating expenditure

The base-step-trend approach is used to set operating expenditure. While this simplifies the assessment of operating expenditure, it does lack granularity and the inclusion of a productivity factor of 0.5% is therefore a critical safeguard to ensure there is improvements in efficiency. However, this approach tends to encourage incremental improvement in cost efficiency rather than step improvements in the baseline. We agree with the Draft Decision in using 2017-18 as the base year instead 2018-19 which included transformation costs.

Overall, JGN has revised down its operating expenditure over 2020-25 to levels that are generally in line with the Draft Decision. We note that even after including the productivity factor, the revised operating expenditure of $1,092 million ($2020) will allow for real increases over 2020-25 compared with the base year expenditure of $923 million, a total increase of 18% or $169 million.

Capital expenditure

We note JGN's concern that the Draft Decision does not provide sufficient allowance for capital. This is the key area of difference between the Draft Decision and JGN's proposals. The Revised Proposal is $102 million ($2020) higher than the Draft Decision

Table 1: Changes to JGN's Revised Capital Expenditure

$million, $2020	2015-20	2020-25	Change
Connections	481	392	-89
Metering replacement	85	118	+33
Facilities and pipes	64	72	+8
IT	120	101	-19
Augmentation	40	62	+22
Mains replacement	27	45	+18
Other	46	31	-15
Overheads	163	86	-77
Gross capex	1,025	906	-119
Customer contributions	15	13	-2
Net capex	1,011	893	-118

Source: JGN Table 4.1 and AER Table 5.1

Gross capital expenditure in the Revised Plan of $906.2m ($2020) is $119m lower that actual capital expenditure in 2015-20. The Revised Plan includes increases in capex totalling $81 million, compared with

2015-20, in meter replacement, facilities and pipes, augmentation and mains replacement. The decreases in all other capex categories totalled $200 million.

The need to ensure that capital investments are prudent and efficient is particularly important as JGN considers that it is imperative to prepare for a low carbon future.

One area of capex which AGL generally supports is in meter replacement. We welcome the plan to replace 438,000 meters over 2020-25. The Revised Plan includes a cost of $118 million ($2020), which is an increase of $33 million over 2015-20. We note that over 2015-20 JGN spent only about half the allowance, and we expect that JGN will ensure the meter replacement programme is fully undertaken in 2020-25.

Regulated asset base

In the Revised Plan, the regulated asset base is expected to increase by over 15% ($nominal) to $3,850 million by end of the 2020-25 regulatory period. This represents a small increase in real terms and demonstrates continued overall investment despite higher depreciation. However, this does not align with the concern about the preparation for a low carbon future and the need to recover costs over a reasonable time period.

Boundary metering

We note that following the Draft Decision, the Revised Plan has withdrawn the volume boundary strategy for water metering for new high-rise customers. We had agreed with this strategy as it would have simplified the metering requirements for customers providing for more appropriate solutions for JGN, which in turn ensures customer meter data is efficiently provided. We encourage JGN and the AER to continue to consider this approach and to ensure that customer protections are in place that will also deliver gas at competitive prices to these customers.

Price path

In its Revised Plan, JGN has proposed a price path which attempts to smooth the overall retail bill by accounting for forecast wholesale gas costs in the future. Forecast wholesale gas costs are based on AEMO's Gas Statement of Opportunities (GSOO).

Table 2: JGN's Revised Price Path

	2020-21	2021-22	2022-23	2023-24	2024-25
Forecast wholesale gas price change	-5.6%	-5.5%	6.3%	1.6%	-1.5%
JGN network – X-factors (real)	21.25%	2.25%	3.25%	-1.75%	-9.02%
Forecast retail bill change (nominal)	-9%	-1%	3%	3%	5%

Source: Table 12.3 & Table 12.6, Revised Plan

While we support reducing price volatility, AGL believes JGN's revised price path is not without risk as the GSOO forecast of wholesale gas cost is subject to assumptions on economic growth and other domestic and international factors, including oil prices and exchange rates.

Ideally, we would prefer to see minimal price changes after the initial price reduction. However, the requirement to set prices to return revenues within 3% of the building block in 2024-25 will limit the range of possible price changes in the final year of the regulatory control period. In this case, JGN's proposed price path will require a real increase of 9% in 2024-25 which we consider to be excessive. If the forecast wholesale gas price reduction in 2024-25 does not eventuate then it could compound the retail price increase.

In the Revised Plan, the AER price path based on JGN's revised revenue will result a real reduction of 26.9% in 2020-21, followed by annual real price increases of 3.09% in each of the following 4 years. Depending on the final decision by the AER, this is preferable.

Tariffs and tariff variation mechanism

JGN has proposed no changes to the current tariff structure.

We welcome the decision in the Draft Decision and JGN's proposals to retain the current tariff variation mechanism which uses a weighted average price cap (WAPC) using the CPI-X price control formula with no adjustment for changes in actual gas consumption. This provides greater certainty for retailers and customers unlike the revenue cap approach in electricity distribution determinations which has created significantly price variations from one year to the next due to errors in forecasting electricity consumption.

Ancillary Services

The Access Arrangement in the Revised Proposal lists five categories of ancillary charges.

However, JGN's listing of ancillary charges (T2125-Ancillary-charge-listing-1-July-2019.xlsx), which is publicly available, outlines about 40 types of charges. We believe there is opportunity to simplify these charges as it is unclear if certain fees, such as homed gas meters, are additional to other fees.

We welcome the additional information on the new wasted visit fee in the Revised Plan. As this new fee is implemented, we expect JGN to provide further clarifications as any issues arise.

There are two ancillary services fees which we continue to have concerns – the combined disconnection and reconnection fee and abolishment fee. These fees are discussed below.

Disconnection and reconnection fee

In relation to the combined disconnection and reconnection fee, we note that the AER has requested information to support the separation of the disconnection and reconnection fee. This fee is payable only when a customer is disconnected. No fee is charged by JGN when a customer is reconnected for gas.

We have analysed AGL data on completed disconnections and scheduled reconnections in the JGN distribution region from 1 July 2018 to 30 June 2019[1]. Our findings are:

- 48% of the disconnections were reconnected after a disconnection, or conversely, 52% of the disconnections were not reconnected (within 3 months), and
- 33% of customers which we had reconnected are not the same customers which we had disconnected.

Instances where there are disconnections without reconnections include:

- customers disconnected for debt churning to another retailers,
- customers disconnecting for renovation, then selling the property, and
- customers ceasing the use of gas, but without abolishment.

Instances where there are reconnections without disconnections include:

- customers churning in after disconnected by another retailer, and
- customers moving in.

These findings show that having a combined disconnection and reconnection does not reflect a 'user pays' or 'causer pays' principle. The combined fee results in some customers paying a "fee for no service" and

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[1] To improve the data quality, we also checked if a reconnection scheduled in FY2019 had been previously disconnected up to 3 months prior to 1 July 2019, and if a disconnection scheduled in FY2019 was later reconnected up to 3 months after 30 June 2019.

other customers receiving a service which they have not paid for. Splitting the fee into disconnection and reconnection fees will align the charges with the services that customers receive.

This combined fee is at odds with the practice undertaken by other gas distributors that AGL deals with in New South Wales, Queensland, Victoria, South Australia and Western Australia. We do not anticipate any significant cost to implement this change.

We also note that the Revised Plan sets this disconnection fee at $182 for 2020-21 (excluding GST). This is an increase of 20% from 2019-20.

Abolishment fee

JGN's abolishment fee is significantly higher than other gas distributors. Table 3 below shows a comparison of meter removal fees.

Table 3 Current 2019/20 fees for meter removal (excluding GST)

Region and distributor	Fee (ex GST)
NSW - JGN abolishment (de-commissioning) fee	$1,063 - $2,215
NSW – AGN (meter removal plus service line removal)	$548.54
SA - AGN	$74
VIC - Ausnet - AGN - Multinet	 - $104 $69.23
QLD – AGN	$72
WA - ATCO	$123.86

Due to the high cost of this abolishment fee, there is a risk of meters been removed without the delivery point been properly de-commissioned.

Reference Service Agreement

AGL acknowledges and appreciates the engagement that JGN has undertaken in reviewing and amending the RSA. In our view, the revised RSA is a significant improvement on the previous 2015 RSA.

We welcome JGN's amendment in the Revised Proposal to cease network charges for volume customers on the date of disconnection rather than 20 business days after the date of disconnection as proposed in the Original Proposal.

However, there are two important issues relating to customer outcomes that the RSA has not addressed.

First, there is no reference in the RSA to performance standards for service orders. Previously, the RSA referred to a Network Code which specified performance targets or standards for services such as connections, reconnections, special meter reads, meter tests and investigations. Without performance standards for service orders, we are unable to advise customers on the timeframes for services making it difficult to manage customer expectations. We note that in Victoria, the gas distributors incorporate the timeframes for many of these services in the terms & conditions of their Access Arrangement. These performance standards can be set out in the Access Arrangement, RSA or another document such as a network code.

The second issue relates to sites which have been de-listed with no designated retailer, but customers have commenced using gas. As the local retailer, AGL is allocated these unclaimed sites. These customers may have signed up with a retailer other than AGL for electricity and may have assumed that their electricity retailer is also their gas supplier. When AGL invoices these sites, this has created confusion, often resulting in poor customer experience and unnecessary calls to the contact centres. AGL would prefer that JGN contact these customers in the first instance to inform them that they have the opportunity to choose their gas retailer before assigning them to the local retailer. This could be set out in the RSA or in another form so that the process is clearly understood at an operational level. While we recognise this situation is not specifically outlined in the National Energy Retail Rules, this does not preclude JGN from taking action that will improve customer experience.

If you have any questions in relation to this submission, please contact Meng Goh, Senior Manager Regulatory Strategy, on mgoh@agl.com.au or (02) 9921 2221.

Yours sincerely,

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