First State Investments

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Regulation Branch
Commerce Commission

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Dear Tricia

Re: Gas Default Price-Quality Path: General Matters Cross-submission

First State Investments (FSI) is pleased to make this cross-submission on the Commerce Commission's (Commission) process and issues paper related to resetting the default price-quality path (DPP) for gas pipelines. This cross-submission responds to the points raised by other parties on the Commission's process and issues paper for resetting the gas DPP.

Approaches used to set opex and capex allowances

The Commission has proposed to explore the use of supplier forecasts for the gas DPP reset. We have begun the process of preparing our AMPs to be disclosed this year, and plan to:

- Rely on existing technical capability and processes in Vector and MDL to generate asset related forecasts (such as network opex and capex)
- Use FSI/First Gas Limited budgeting processes to generate non-asset related forecasts (such as non-network opex) and to allocate corporate overheads and other shared costs.

The main uncertainty that remains is how the Commission will gain comfort that AMP forecasts represent efficient costs that a prudent supplier would incur to meet expected service levels. The challenge here is to ensure that any additional scrutiny of AMP forecasts (over and above existing process such as director certifications) is calibrated to the low-cost nature of the DPP, and therefore clearly distinct from CPP requirements.

We would greatly appreciate knowing as soon as possible how the Commission will gain confidence on the credibility and accuracy of our AMP forecasts. This will enable us to design forecasting approaches that deliver on the Commission's expectations. We clearly want to avoid having to regenerate cost forecasts later or having to retrofit additional processes to our AMP forecasts–as this would duplicate effort and would not be in the interests of consumers.

We are also keen to continue to engage with the Commission on the best ways to set cost allowances for the next DPP period.

Expected synergies of common ownership and regulatory treatment

We note that MGUG expects our cost forecasts to "not be the sum of the two transmission businesses", but instead to "provide (and demonstrate) the benefits of the synergies generated through the common ownership model". Our response to this statement has two components: first, to provide some context on the level and form of expected synergies, and second, to present our understanding of the regulatory treatment of synergies under the IMs.

As explained in our original submission, our current focus is to ensure the smooth transition of the Vector Gas business and the Maui pipeline into FSI ownership. The role of Vector Gas as the technical and system operator of the Maui pipeline also clearly constrains the extent of synergies involved. Once the transition process is complete, we are keen to pursue opportunities to grow the use of gas pipelines and improve the quality of service provided—redeploying resources within the business. We see this process as ultimately benefitting gas users through lower prices and better service. As a result of this focus, synergies and cost efficiencies should be seen as something to realise over time—rather than factored in from the outset.

This view of cost synergies is consistent with our understanding of the regulatory settings in New Zealand. The 2010 IMs Reasons Paper makes it clear that suppliers should temporarily retain the benefits of any merger efficiency gains before those benefits are shared with consumers (providing a positive incentive to seek out such gains). While we share MGUG's hope that we can achieve synergies during the next DPP period, we do not expect any synergies to be reflected in regulatory allowances until the DPP reset is in 2022. This outcome is also consistent with the design of the Incremental Rolling Incentive Scheme applied in other regulated sectors, which enables suppliers to retain efficiency benefits for a period before sharing those gains with consumers.

Major capital expenditure

We agree with Methanex that the current DPP/CPP settings create disincentives to invest and it is appropriate to address these issues through the IMs review and DPP reset.

We understand that the Commission is considering two sets of changes that will provide additional channels to facilitate investment if needed:

- Improving CPP information requirements to make this a more attractive option for suppliers. We are actively following progress in this area, but will not be able to submit a CPP application until after the DPP is reset (pursuant to section 53Q(3) of the Commerce Act). While we remain open-minded, a complete review of all business costs and processes seems ill-suited to funding discrete, major capital projects
- Providing for DPP-reopeners in the event that a clearly established case for investment is presented. We also agree with Methanex that the circumstances for re-openers need to be clearly defined in advance.

Methanex suggests that the cap on capex allowances to 120 percent of average historical capex applied in the last DPP reset should be revisited if major capex is addressed through another channel. However, we understand that the Commission never anticipated that the cap would accommodate major capex projects. We would expect that the approaches used to gain comfort on suppliers' AMP forecasts (discussed above) may also enable the Commission to increase or remove this cap for the next DPP. If the Commission is confident that the forecasts are reasonable, it would seem undesirable to artificially constrain investment to historic levels.

Form of control

MGUG contends in its submission on "Emerging views on form of control" that a weighted average price cap would be a better form of regulatory control for both gas transmission and distribution businesses. MGUG's position is based on the view that gas transmission businesses can forecast demand just as well as gas distribution businesses and that there are means to control the risk of changing use of gas transmission.

We disagree with MGUG on this point. We see a number of opportunities to manage demand risk on our distribution network, for example by working with retailers and other stakeholders to market new connections (both in areas where our networks already exist and in other areas), promote the sale of gas appliances, and to explore innovative ways to increase gas consumption. We are keen to explore these avenues for growth in our gas distribution business, and it seems appropriate for us to have incentives to do so and to bear risk in failing to do so.

In contrast, demand from major users for gas transmission is significantly influenced by factors outside of our control, such as global commodity prices and the relative cost of generating electricity from different sources. Where we see opportunities to increase the use of gas transmission we intend to explore them, however these opportunities are limited in the context of overall changes in demand.

The graphs presented in MGUG's submission make this point very clearly. The change in demand observed on gas distribution networks (paras 29-35) is generally incremental, and new connections have grown over time at a steady rate. Gas distributors can influence these trends in the ways described above, and failing to do so should lead to under-recovery of regulatory revenue forecasts. In contrast, demand on the Maui pipeline in particular (para 20) has been much more volatile, with the ramp up in Methanex's demand significantly increasing total demand from mid-2012.

MGUG places weight on the ability of GTBs to manage demand risk through their pricing methodologies. However, in our view, there are only limited opportunities for pricing to be an effective demand management tool given that demand responds to total price–and transmission fees make up only a fraction of the cost of delivered gas. The use of transmission pipelines is clearly driven more by the relative value of processing gas into petrochemicals or using gas to generate electricity–an area that should not form part of a transmission owner's core business or risk profile.

MGUG contends that changes in gas transmission use by customers such as Methanex are reasonably foreseeable, and supports this point by referring to public statements made by Methanex in October 2014. We note that pricing information on Methanex's website suggests that methanol prices in the months prior to that statement were as high as US$590/MT, and have since fallen to US$265/MT in April 2016.[1] These price trends demonstrate the significant commodity price shifts faced by users of gas transmission that we suggest are not efficient for infrastructure owners to bear.

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1 See https://www.methanex.com/sites/default/files/methanol-price/MxAvgPrice_Mar%2031%2C%202016.pdf

We are also unsure whether MGUG has identified the link between form of control and pricing methodologies that led us to support a revenue cap with wash-ups for gas transmission. As noted in our original submission, we believe that a revenue cap with wash-ups will enable a more open debate on the most efficient pricing approach for gas transmission by removing commercial implications for the gas transmission owner. We consider the appropriate forum for this debate is through the code convergence workstream facilitated by the Gas Industry Company (GIC).

GIC-linked workstreams: quality and pricing methodologies

Several submissions highlight the close link between the Part 4 regime and the workstreams being facilitated by the GIC. It is pleasing to see this link being understood by the Commerce Commission and co-ordinated with the GIC.

The closest link is in the area of gas transmission quality measures, where the GIC is actively reviewing available information on pipeline security and reliability and considering how these quality measures can be most effectively promoted.

We also see a strong link between this GIC work and AMP disclosures. We agree with MGUG that the information contained in AMPs could be better presented. In some areas, common ownership of gas transmission systems will help (for example, where Vector and MDL currently present information on different quality measures). AMPs provide a wealth of information–but could be made more digestable to major users (ideally without compromising the depth of information available).

We also note comments from Fonterra and Oji Paper that pricing methodologies deserve regulatory attention. The specific concern raised is that current transmission pricing approaches (particularly under the VTC) have resulted in sharp prices increases when major sources of demand (such as power stations) no longer use gas. In our view, the most appropriate place to address these concerns is through the process of code convergence. As mentioned above, we consider that moving to a revenue cap with wash-ups provides the space needed for the right decisions to be made on pricing methodologies under the code, without decisions being constrained by the commercial interests of the pipeline owner.

Conclusion

We appreciate the Commission's clarity on the process being used to reset the DPP alongside reviewing the IMs. We also support the question and answer sessions held by the Commission, and look forward to engaging in the sector workshops the Commission is considering for quality of service and forecasting of revenue and expenditure.

Thank you for the opportunity to make this submission. We look forward to continuing our engagement with the Commission on developing and applying the regulatory settings for gas pipelines in New Zealand.

Yours sincerely

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