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Dear Keston

1 Introduction

Colonial First State Global Asset Management (Colonial) is pleased to make this submission on regulatory issues specific to the gas sector as part of the Commerce Commission's Input Methodologies review.

Colonial appreciated the Commission's workshop in December and the agenda items discussed—which generally reflect what Colonial sees as the most important gas-specific issues to address as part of the review. We are keen to continue a constructive dialogue on how gas infrastructure is regulated to best stimulate a vibrant and competitive gas industry in New Zealand.

In summary, Colonial's position is:

- The Commission should focus on delivering stability and predictability in the regulatory settings, while taking opportunities for incremental improvements (**Section 2**)
- We have identified two areas where incremental improvements can be made by:
  - Incorporating a wash-up to the revenue cap that applies to gas transmission businesses. This change will better achieve the regulatory intent of ensuring that gas transmission businesses only bear risks that they can influence and are best placed to manage (**Section 3**)
  - Incorporating an approvals process for major capital expenditure (capex) items into the Default Price Quality Path (DPP) for gas transmission businesses. This change will better reflect the unique, lumpy nature of gas transmission capex (**Section 4**)
- An incremental rolling incentive scheme (IRIS) is unlikely to be warranted at this time for gas transmission and distribution businesses. If an IRIS is introduced for capital expenditure, it should focus solely on base or recurring capex and exclude major capex projects (**Section 5**).

2 Stability and Predictability in the Regulatory Settings

To promote further confidence in the regulatory settings and enable efficient gas infrastructure investment and pricing, the Commission should focus on promoting stability and predictability in the regime.

The current regulatory regime (Input Methodologies and DPP) has only been fully operational in the gas industry since 2013—a single regulatory period. The Input Methodologies have proven to be generally sound, and have contributed to gas industry success. There has been significant growth in gas use, wholesale gas spot market platforms have emerged, and industry participants have shown a willingness to work together to enhance network access arrangements.

The initial performance of the regulatory regime and the prospect of ongoing stability are important to Colonial's willingness to invest in the Vector and Maui gas transmission pipelines. As a result, for the first time, New Zealand's gas transmission pipelines will be under common ownership—offering the prospect of significant benefits for the industry stakeholders. This is also the first time that the gas transmission pipelines in New Zealand will be owned by a party without other interests—either in other regulated infrastructure or other parts of the gas supply chain.

We consider that this success story for gas requires a 'steady hand' on the regulatory settings to preserve the benefits of the existing regime. This does not mean avoiding any change whatsoever. However, we think that it is important for changes to focus on evolving current settings, rather than significantly changing the rules at this time.

3 Form of Regulatory Control

Gas transmission businesses are currently subject to a revenue cap, while gas distribution businesses are subject to a price cap. As the owner of both gas transmission and distribution assets, we consider that these are the right forms of regulatory control.

However, we see a strong case for changing the way that gas transmission businesses comply with the revenue cap to incorporate a wash-up for under and over-recoveries. We also consider that this form of regulatory control should be specified in the Input Methodologies. This will ensure that gas transmission businesses only bear risks that they can efficiently manage, while enabling more efficient transmission pricing arrangements to be developed.

Gas transmission should be under a revenue cap because it has little influence over demand

As the Commission found in setting the initial Input Methodologies for gas pipelines, efficient regulation will allocate demand risk to the party best placed to bear it—suppliers or consumers.[1] The form of control is the most direct way to influence that allocation of demand risk.

[1] Commerce Commission 'Input Methodologies for Gas Pipeline Services: Final Reasons Paper' 2 December 2010 at para 8.3.5, accessible at this link.

The Commission's view on who was best-placed to bear demand risk in establishing the initial Input Methodologies and the DPP was that:[2][3]

- **Gas distribution businesses** have a reasonable degree of influence over demand, and placing them under a weighted average price cap would therefore improve efficiency by encouraging them to increase the efficient use of gas distribution infrastructure
- **Gas transmission businesses** cannot influence demand, making a revenue cap more appropriate.

Our experience through the recent sales processes is that the Commission's rationale remains valid. Transmission pipelines have limited influence over demand. In contrast, there is greater ability to promote gas use through distribution networks through a combination of marketing, pricing, and strategic relationships.

The revenue cap should incorporate a wash-up to achieve the regulatory intent

While the Commission intends gas transmission businesses to not face demand risk, the current method of demonstrating compliance with the revenue cap under the DPP does not achieve this outcome. We recommend a wash-up be implemented to address this issue.

The DPP assesses the revenues of gas transmission businesses for compliance against the revenue cap using current period prices—but using quantities from 2 years prior ('t-2'). This approach provides certainty to suppliers when setting prices to enable them to confidently comply with the DPP.[4] This objective has been achieved, with both transmission pipelines' earning notional revenue very close to their respective revenue caps.

However, the unintended consequence of this compliance approach is that gas transmission businesses are exposed to demand risk (both upside and downside) when quantities in the current period 'q(t)' are different to quantities in 'q(t-2)':

- **If q(t) is less than q(t-2)**, then gas transmission businesses earn revenues that are lower than the building block costs estimated by the Commission to ensure regulatory compliance. This leads to lower actual revenues in years where demand falls relative to demand 2 years ago.
- **If q(t) is greater than q(t-2)**, then from a commercial perspective gas transmission businesses earn revenues that exceed the building block costs estimated by the Commission. However, gas transmission businesses still comply with the allowable notional revenue cap because compliance is assessed against q(t-2).

This risk is manageable for a transmission owner when decreases in demand are quickly reversed. However, if demand falls for several years in a row as appears likely, then gas transmission owners will under-recover the revenue cap for a sustained period. We

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2 See Commerce Commission 'Input Methodologies for Gas Pipeline Services: Final Reasons Paper' 2 December 2010 at paras 8.3.7 to 8.3.21, accessible at this link.

3 See also Commerce Commission 'Reasons for Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services: 28 February 2013', at F2 to F7, accessible at this link.

4 Commerce Commission 'Revised Draft Decision on the Initial Default Price-Quality Paths for Gas Pipeline Services' 24 October 2012 at Attachment L, accessible at this link.

therefore conclude the current revenue cap is inconsistent with the regulatory intent of ensuring that gas transmission businesses only bear risks that they can efficiently manage.

The most feasible option to achieve the regulatory intent is to implement a wash-up where the regulated revenues earned by gas transmission businesses are adjusted over time to align with actual demand. We have looked at the form of control applied to Transpower and believe that this approach represents a useful starting point for a revenue wash-up for gas transmission. This includes making adjustments for the time value of money between a wash-up amount arising and that amount being recovered from/returned to consumers.[5]

A revenue cap for gas transmission should be specified in the Input Methodologies

The form of control applying to gas transmission pipelines is currently specified in the Input Methodologies as being a decision based on two factors:

- Whether a pipeline is under common carriage or contract carriage
- The extent of non-standard customer arrangements.

This approach appears to draw a distinction between the Vector and Maui transmission systems. However, the Commission decided to override these factors in the current DPP and apply a revenue cap to both systems, focusing on the reality that transmission businesses cannot influence demand.

As discussed above, we consider that a revenue cap is the most appropriate form of regulatory control for gas transmission businesses because they cannot materially influence demand. We also do not see a bright line between common carriage and contract carriage systems—especially given an efficient set of arrangements in the future may well incorporate elements of both approaches. This makes it difficult to characterise an access regime as either common or contract carriage. Colonial therefore considers it appropriate that the form of regulatory control applying to gas transmission pipelines is specified in the Input Methodologies (rather than the DPP) as a revenue cap.

A pure revenue cap in the Input Methodologies will support code convergence

The gas industry is currently discussing the future of transmission access arrangements and is exploring opportunities to converge the two pipeline operating codes (the Vector Transmission Code and the Maui Pipeline Operating Code). This work is being led by the Gas Industry Company, which sees "strong reasons for favouring an outcome where there is essentially the same transmission and access pricing regimes across both sets of pipelines".[6] That process will now take place with common ownership of the two pipelines—which we believe will offer better prospects for efficient code convergence.

From our initial involvement in those discussions, we consider that the current approach to setting the form of control may inhibit progress by:

- Making contract carriage regimes more commercially attractive to asset owners, when there may be policy reasons to favour common carriage
- Creating incentives for pipeline owners to fix prices at the start of the year and avoid introducing more flexible pricing approaches (such as intra-year auctions

[5] Commerce Commission 'Transpower Individual Price-Quality Path: Final Reasons Paper' December 2010 at para 3.10, accessible at this link.

[6] GIC, May 2015, "Transmission Access; Options for Improvement", Paper #2.

or congestion pricing), which could be more efficient but lead to uncertainty in over- or under-recovery of allowable revenue

- Creating a perception of increased risk that the form of control may change at the next DPP, depending on how the criteria in the IMs are applied.

We therefore consider that the best way to align the economic regulation of gas transmission assets with the regulatory objectives of the GIC is to specify a revenue cap with wash-ups in the Input Methodologies as the form of control applying to gas transmission businesses.

4 Major Approvals Process for Capital Expenditure

A major approvals process for capital expenditure will significantly improve the investment incentives in the DPP for gas transmission pipelines.

'Lumpy' capex does not fit within a capex allowance based on a historical average

Under the DPP, the Commission sets capital expenditure (capex) allowances based on the forecasts disclosed in Asset Management Plans (AMPs)—subject to a cap of 120 percent of average historical levels (previously set using the previous 4 years).[7] As a result, gas pipelines that need to spend capex in excess of this cap must forego a return on and of capital (depreciation) on that excess capex for the rest of the regulatory period until the next reset (or until they apply for and receive a CPP). This issue is significant because the nature of gas transmission is that the majority of capex is 'lumpy'.

As discussed at the December workshop, the need to relocate sections of gas transmission pipeline due to coastal erosion (the Whitecliffs project) is a good example of needed capex that is not appropriately addressed under current regulatory settings. There are other examples of more regular capex items that are still outside the Commission's previous approach to forecasting capex (such as compressor overhauls).

Given that capex is lumpy and irregular, a historical average is inappropriate because its very nature presupposes that efficient capex occurs steadily through time. The absence of a major capex approvals process also creates incentives for gas pipeline owners to schedule major capex in ways that do not minimise total costs. As a result, the Commission could significantly improve the DPP by including a major capex approvals process to improve investment incentives.

The detailed design of the approvals process is more important than the label

Table 4.1 outlines Colonial's initial views on the required components for a major capex approvals process. Colonial would be pleased to work with the Commission to develop a detailed design of the approvals process.

Colonial's view is that the focus should be on the way these components are designed rather than the label given to the process (e.g. 'mini CPP' or 'listed projects'). Having said that, Colonial's view is that it is more appropriate to think of the approvals process as a 'listed projects' part of the DPP—since it signifies that there is no regime to transition to and from (like a CPP). The approval process is a targeted response to a specific project, rather than a whole regime change.

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[7] Commerce Commission 'Reasons for Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services: 28 February 2013', accessible at this link.

Table 4.1: Required Components for Major Capex Approvals Process

Regulatory component	Required decisions	Colonial's initial views
Eligibility criteria	▪ Type of project eligible ▪ Threshold for project size	▪ Generally, all projects should be eligible in principle. The appropriate point to approve or reject a projects is at the evaluation stage ▪ The threshold for project size should be cost-based
Approval process	▪ Application process: approval of form of application, stakeholder consultation, preliminary evaluation, negotiation with supplier, and decision ▪ Requirements for verification of proposal information ▪ Project information requirements from applicant ▪ How to deal with projects on a timeline that is too short for the usual approval process ▪ Validity period of approval	▪ Approval process should be in keeping with the low-cost approach required under DPP ▪ Self-certification with no audit or verification is consistent with DPP and Transpower rules[8] ▪ Information requirements should be reasonable and not unduly burdensome ▪ Where project is needed in shorter timeframe than usual approval process, there should be flexibility in applying for retrospective approval. Another option may be an 'approval in principle' being granted under urgency, with substantive approval occurring retrospectively ▪ Pipeline businesses should be able to propose an approval validity period and apply for extensions to incentivise efficient deferral
Evaluation criteria	▪ Criteria for approval	▪ Criteria should be a cost-benefit test
Mechanism for recovering return on and of capital	▪ How recovery is provided	▪ Asset added to RAB on commissioning date based on value of actual capex spent—which flows through to increase in return of and on capital as part of building blocks allowable revenue. This may require updates to be issued to the relevant DPP decision
Incentives for minimising costs	▪ How suppliers will be incentivised to minimise the cost of major projects ▪ Whether there are incentives for efficient deferral ▪ Flexibility for cost increases	▪ The regime should incentivise cost minimisation, so suppliers should share in any under- or out-performance on major project costs ▪ We recommend incentives for efficient project deferral ▪ Pipeline businesses should not be exposed to cost increases that are outside of their control e.g. foreign exchange and inflation

[8] For Transpower see Commerce Commission 'Transpower Capital Expenditure Input Methodology: Final Reasons Paper' at Chapter 9, accessible at this link.

Regulatory component	Required decisions	Colonial's initial views
Regulatory oversight	▪ Whether and if so, how, the Commission will monitor project implementation	▪ Supplier should report on major capex as part of the information disclosures regime
Interaction with other regulatory mechanisms	▪ Current limit of 120% of average historical capex	▪ Retain 120% rule as this rule was designed for base capex and was not designed to recover major capex

5 Implementation of an IRIS

Colonial favours stability and predictability in the regime, with incremental improvements made over time. In this submission, we have highlighted two changes to the Input Methodologies that we think are worth pursuing at this time for gas transmission businesses: shoring up the form of control and adding a major capex approvals regime to the DPP. In contrast, adding an IRIS at this stage seems premature, particularly given the uncertainty in how capex forecasting will work in the next DPP alongside a major capex approvals process.

The Commission has stated its intention to consider an IRIS for gas pipelines. We understand that an IRIS seeks to smooth out incentives over the regulatory period—encouraging regulated businesses to invest when it is most efficient, rather than responding to the timing of regulatory periods. The intention of the IRIS is therefore sensible and rolling incentive schemes are fairly conventional regulatory practice.

However, the appropriateness of implementing an IRIS in New Zealand depends on its interaction with the rest of the regulatory settings. For an IRIS to work as intended, we consider that:

- **The Commission must have sufficient confidence in its forecasts of the expense**—if it doesn't, then there is a reasonable likelihood that under-spend or over-spend is due to forecast error rather than the actions of the regulated business. This could penalise gas pipelines for incurring efficient expenditure and benefit them where forecast errors mean less expense is incurred. Expense forecasts depend on demand forecasts. Because gas is more discretionary than electricity and is harder to forecast, what might work for electricity will not work as intended for gas in relation to capex
- **The IRIS must align with other regulatory incentives**—if incentives conflict they can undermine the regulatory intent, and if incentives are cumulative they may have little benefit in influencing investment decisions. Gas pipeline businesses already have strong incentives not to over-spend on capex. In addition, another problem arises for a capex IRIS for gas distribution. A much greater proportion of base capex relates to making new connections for gas compared with electricity. Distribution pipelines under a capex IRIS will therefore have stunted incentives to grow the use of gas where doing so would involve incurring capex that exceeds forecasts of customer growth. Forecasts of customer growth would then become a barrier to growth rather than a measure of it, also conflicting with the regulatory intent of putting gas distribution businesses under a price cap.

The low-cost forecasting approach in the DPP suggests that a capex IRIS does not meet these criteria for gas in relation to major capital expenditure. Gas transmission investment is generally too lumpy and difficult to forecast for this approach to work, so IRIS rewards/penalties are likely to be more dependent on forecast error than any realised efficiencies. In the case of Whitecliffs, for example, it is clear that the capex is required. However, if this occurs under a DPP with a capex IRIS, the pipeline owner would be penalised twice for undertaking it:

- With a lack of return on and of capital within the regulatory period (because the RAB is not adjusted until the next regulatory period)
- As capex 'over-spend' under the IRIS.

The only capex IRIS Colonial might see working in principle would apply only to 'base' or recurring capital expenditure. If the Commission pursued this option, however, implementing it would likely involve costs and uncertainty that outweigh the benefit of better incentivising timely capex. For example, there would need to be a way of excluding major capex (for gas transmission) and capex associated with new connections (for gas distribution). This would require detailed and robust forecasts of capex with breakdowns of capex by type—and the Commission would need to have confidence that any under- or over-spend against those detailed forecasts fairly represented out- or under-performance for the incentive regime to work.

6 Conclusion

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

Best regards,

Gavin Kerr

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Colonial First State Global Asset Management