22 September 2017

Submissions
Commerce Commission
PO Box 2351
Wellington

Via email: powercocpp@comcom.govt.nz

Dear Commission

Re: Invitation to have your say on Powerco's proposal to change its prices and its quality standards: issues to explore and consider

Thank you for the opportunity to provide comments on Powerco's CPP, and for your invitation to provide our views on matters requiring further scrutiny.

As an electricity retailer with around 30,000 customers on the Powerco network, the focus of this submission is on ensuring the best outcomes for our customers. Accordingly our submission is focused on two aspects of Powerco's CPP:

- Ensuring Powerco is making sensible, fiscally prudent investment decisions on behalf of customers, and

- Powerco's financial assumptions.

In advance of making this submission to the Commerce Commission (**Commission**) Contact has met with Powerco to discuss the points raised.

In addition to the views provided in this submission, Contact also endorses the views in the submission of the Electricity Retailers' Association of New Zealand (ERANZ).

1. A customer-centric view of regulation is likely to result in the best market outcomes

Since 2010 Powerco has been subject to default/customised price-quality regulation and information disclosure under Part 4 of the Commerce Act 1986 (the Act), but, like most electricity distribution businesses (EDBs), it has managed the business within the bounds of the default price path (DPP) revenue and has not pursued the option of proposing a CPP until now.

Powerco's argument is that it needs to increase investment to prevent deterioration in performance and ensure that the network can meet future needs, an uplift which it says cannot be accommodated within the current DPP. While Contact supports Powerco ensuring it can provide a reliable flow of power, this must be delivered through the most economical solution with the best interests of customers in mind.

It is our view that the Commission must put consumers at the heart of its decision-making and satisfy itself, and consumers, that:

- Powerco's proposal is in the long-term interests of consumers
- consumers will continue to have safe and reliable access to energy
- consumers are not paying more than they ought to be.

While this CPP is important in its own right — given its potential impact on the power supply and wallets of around 320,000 consumers — it is particularly important given the precedent this decision will set, as the first CPP to be looked at by the Commission outside of Orion's CPP proposal[1].

2. Ensuring the most economical solutions for consumers – have non-network solutions been discounted prematurely?

Subject to the Commission's approval, Powerco plans to spend more than $1.3b over the five-year CPP period – a 50% increase in capex ($873m[2]) and a 28% increase in opex ($455m[3]) over the previous five-year period. For consumers across Powerco's network, these numbers represent real bill increases of around $41 per year. However, this accumulates, so is more likely to be around $200 per annum by the end of year five. We also note that this is an average, so some will be higher, potentially in low socio-economic areas.

[1] which was triggered in response to unique circumstances, the Canterbury earthquakes in 2011, as opposed to ageing infrastructure.

[2] Page 74, Powerco CPP Main Proposal

[3] Page 75, Powerco CPP Main Proposal

Given that it's consumers who will ultimately bear the brunt of any additional spend by Powerco, we believe consumers must be assured that Powerco is making sensible, fiscally prudent investment decisions on their behalf.

In reading through Powerco's proposal we believe insufficient weight has been given to third party non-network solutions and the savings these may provide to consumers. We believe this is a matter the Commission and Powerco should investigate further as neither Powerco's main proposal, nor its asset management plan (AMP), provide confidence that Powerco has a process in place to ensure that third party non-network solutions are being utilised where they provide the most efficient option for network development.

While Powerco's AMP mentions that "*our planning and approval process for larger projects includes a formal review of non-network solutions*"[4] and Powerco's AMP also "*includes a discussion on non-network options which have been considered for a number of projects"*[5], these processes, on the information provided, appear to be only an internal consideration of whether, for example, it is more economical for Powerco to invest in battery storage at Whangamata rather than traditional lines infrastructure.

We think this process could be more effective as, based on the information provided, Powerco is evaluating and dismissing non-network options without transparently engaging with the market to understand what demand management solutions might exist and how competitive third party services are.

In Powerco's 2017 AMP, it notes in relation to the Mt Maunganui/Papamoa growth project that "*continued growth in peak demand is causing, or projected to cause, numerous capacity related issues, including in relation to 110kV lines, 33kV lines, 11kV lines and substations*[6]*… in Northern Tauranga continued growth in peak demand is projected to exceed the N-1 rating of the 33kV overhead lines"*.[7]

Given the situation outlined above, we would expect these issues—which relate directly to capacity—to present opportunities for demand side management. However, Powerco has dismissed demand side options saying "any practical non-network options would have required close coordination with developers to achieve very high uptake and effectiveness".

[4] Page 48, Powerco 2017 AMP
[5] Chapter 11, Powerco 2017 AMP
[6] Page 344, Powerco 2017 AMP
[7] Page 342, Powerco 2017 AMP

While there may be valid reasons for this, it is unclear from the AMP why working with developers is the only option to reduce network capacity issues (especially at the 33kV and 110kV level), and why, with the right incentives from Powerco, solutions can't be achieved with developers. We think this point is worthy of further exploration by the Commission.

For other projects, Powerco has dismissed non-network options on the basis that "*non-network solutions did not offer sufficient capacity and availability*", "*the magnitude of the required step change in capacity/security … meant there were no feasible non-network options to resolve the constraints*", "*demand side responses … would not provide the magnitude of capacity necessary*". However Powerco provides no detail or evidence as to how these decisions have been reached, despite the dismissal of these options meaning consumers may pay more than they would under an alternative solution.

Whilst we appreciate there may be a natural limit on the potential capacity of load reduction (although opportunities may exist with residential, SME, commercial and industrial customers), we think the utilisation of energy storage and diesel generation effectively removes any limit on the capacity or duration of solutions which network support providers can develop and offer to Powerco.

We think the Commission should seek more evidence and analysis on how Powerco has considered the use of non-network options and whether they have discounted the use of non-network alternatives prematurely, despite the fact they may provide a more economical solution for consumers.

Given consumers will fund any additional spend, we believe they should receive an assurance that Powerco's CPP has been rigorously tested and that the most economical solutions will be delivered to meet their network requirements.

In our view, in order to minimise the cost of Powerco's $1.3b CPP for consumers, it is essential to improve Powerco's non-network options assessment process and make the process transparent. This should include the following:

- Development of a consultation process to engage with third parties when evaluating growth and replacement projects above a certain threshold. At a minimum we would consider that, in order to be effective, the process must involve issuing a request for proposals for non-network solutions which clearly identify both the required network support service parameters, and the estimated annual cost (based on capital and operating costs) of credible traditional network options. This will ensure non-network service providers can evaluate whether they can develop solutions which are economical relative to the deferred or avoided cost of the proposed traditional solutions. The process must also include a cost-benefit analysis assessing both traditional network options and any proposed third party solutions which are subject to full disclosure of assumptions and inputs to enable external consultation.

- Development of a formal demand response programme to manage the delivery of third party services. The purpose of the programme would be to standardise processes to bring down barriers to entry and transaction costs. This could include standardising elements of the programme such as contracting and demand response communications between Powerco and third parties.

3. Network evolution capex

In principle we support investment in network evolution given the need over time to transform from a distribution network managing predominantly one-way power flows, to a more dynamic network effectively requiring system operations at the distribution level. Therefore we support elements of Powerco's network evolution capex including low voltage (LV) monitoring to better understand capacity and constraints, which will support more efficient utilisation of the network as well as integration of third party network support resources. However we are concerned that Powerco's planned network evolution capex appears to be primarily focused 'internally', on testing and developing new Powerco non-network solutions, rather than engaging externally to leverage services delivered by a competitive market.

We have two key areas of concern with Powerco's network evolution capex which we believe the Commission should look into in making a draft determination on Powerco's CPP. They are as follows:

- The apparent absence of investment in control systems which will facilitate usage of third party network support resources. Once third party network support resources have been contracted, systems are required to integrate those resources with network operations, and ensure efficient utilisation of those resources in real-time. In our view this is essential and we support investment in this area. We note that Powerco's AMP discusses the "implementation of an advanced distribution management system to provide the core smart grid platform", which is planned for FY22 and FY23.

- The focus on Powerco's development of non-network solutions. This is inconsistent with Powerco's stated 'open-access' vision, and puts Powerco in direct competition with potential energy services providers to customers on the Powerco network. The main proposal discusses that the network evolution capex will provide for "development of promising solutions into fully-fledged business applications".[8] As an example, Powerco is asking for funding for energy storage projects (which is discussed further in the section below). We support Powerco participating in trials to develop an understanding of how new technology will impact the network, but in our view trials must be focused on learning how Powerco can integrate third party network support resources into the network, rather than Powerco itself developing 'fully fledged' applications which will crowd out a competitive market and are underpinned by revenue certainty from being part of the Regulated Asset Base (RAB), an advantage not available to potential competitors.

4. Battery storage and generation

Powerco has noted that Whangamata is supplied by a single sub-transmission line and, as a result, does not have N-1 security. Accordingly it has identified an $18.7m combined battery storage and diesel generation solution as an interim solution to a second line.[9] We are concerned with two aspects of this proposal.

1. The lack of any external consultation and cost-benefit analysis on the proposed solution makes it impossible to determine whether the $18.7m proposal is the most economical solution for consumers on the Powerco network who will pay for it. We note that Top Energy has a similar network issue at Kaitaia where there is an absence of a second line and therefore n-1 security is also absent, and Top Energy has assessed that diesel generation is the most economical solution. It is therefore unclear to us how Powerco has reached a different conclusion, being to include energy storage in addition to the diesel generation. Given the necessity for diesel generation to manage outages, it's unclear what additional benefits would be obtained by including battery storage in the solution. A cost-benefit process which is subject to external consultation would assist in ensuring decisions like this are verified, and ensure costs to consumers on the Powerco network are minimised.
   These are issues we believe should be looked into by the Commission.

2. We are concerned about the impact of the proposal on competitive markets. Powerco has mentioned that they see value in offering battery capacity into other non-network markets such as the instantaneous reserves[10] market. It is our view that Powerco's usage of regulated funds in this way will have the effect of distorting the operation of competitive markets. Our view is strongly supported by the recent 'distribution market model' report published by the Australia Energy Market Commission (AEMC). The AEMC clearly states that in

[8] Page 152, Powerco CPP Main Proposal
[9] Page 91, Powerco 2017 AMP
[10] Page 153, 372, Powerco 2017 AMP

relation to maximising the value of assets that can provide services to multiple parties, the "optimising service should be provided separately from the provision of regulated services". The AEMC also notes that "if the optimising function is taken on by a party who has a particular regulatory interest in the provision of a particular service, then that party is acting in accordance with its own interests and is unlikely to make decisions that result in the full value of that distributed energy resource being maximised".[11]

While we are supportive of trials being undertaken, we believe there is no need for Powerco to own these planned assets. The asset is not monopoly-like in nature, could be owned by a number of different parties, and can also provide services to a number of different parties. The Whangamata development presents an ideal opportunity for Powerco to engage with third party network service providers who can propose and develop solutions to optimise the cost of the network support provided to Powerco. It is our view the Commission should look into this further.

Customers on the Powerco network will benefit from Powerco utilising the lowest cost demand management/network support it can source. This will only occur if a competitive market exists for the provision of network support.

5. Exploring the role of ripple control in the future

Powerco has outlined plans to acquire a fleet of 35,000 ripple receivers in Tauranga and invest up to $15m[12] in replacing these assets with modern 'smart' ripple relays. This equates to up to ~$450 per ripple relay. Powerco currently has 36 ripple injection plants, with plans to replace a number of them over the CPP period at a cost of ~$800-$850k each. This equates to a total investment of ~$30m in ripple injection plants across the network. Powerco also notes that "past distribution price structures and instantaneous gas hot water options have eroded the base of switchable load on the electrical network".[13] Assuming 55%[14] of Powerco's approximately 330,000 electricity connections are on a controlled load tariff, this equates to an injection plant cost of up to $150 per controlled load. This assumes that all of the customers on a controlled load tariff actually have working ripple receivers which have not been bypassed; in reality the effective injection plant cost is higher.

[11] AEMC, Final Distribution Market Model report, August 2017
[12] Based on figure 11.31, page 125, Powerco CPP Main Proposal
[13] Page 213, 372, Powerco 2017 AMP
[14] Based on figure 11.31, page 125, Powerco CPP Main Proposal. Of ~ $18m above BAU spend we have assumed ~$15m for the ripple receivers and ~$3m for the extended reserves upgrades.

The total ripple capital cost for a controlled hot water customer therefore appears to be up to $600. In addition to this, in Tauranga it costs Powerco ~$100[15] per annum in tariff discounts per controlled load customer to obtain load control rights. Based on our experience, these costs are likely to deliver ~0.7kW of peak load control per customer. On these metrics, hot water ripple control is costing Powerco >$250/kW. Not only this but, due to the network-wide controlled load tariff approach, the cost of procuring this service is effectively higher as not all of the load control is in areas where it is needed. We think the Commission needs to look at this issue and satisfy itself that customers on Powerco's network will have access to the lowest cost demand management/network support and that the decisions being made today are in the long-term interests of consumers.

From the papers provided, it appears Powerco is assuming that continuing to invest and maintain in ripple equipment, predominantly to control hot water heating, is the most efficient solution for its network. We question whether this assumption may be outdated and is a question the Commission should look into. Demand management today is possible with different customer types, asset types, and technology types to control the same asset – in the absence of a competitive procurement process engaging third parties for network support, we are unsure how consumers on the Powerco network can support >$20m in ripple equipment over the CPP period.

Likewise, Powerco has noted that "investing in 'smart' ripple relays in the Tauranga area aligns with its strategy of becoming a 'Distribution System Integrator'".[16] On the contrary, we believe Powerco's investment in 'behind the meter load control assets' is in direct competition to potential third party service providers, and will effectively maintain exclusivity of a potential network services market in the area. We believe an open-access platform will create a market opportunity for third parties to create network services which replace the role of the legacy ripple receivers and ultimately deliver better outcomes for customers. We encourage the Commission to investigate these matters further, before committing consumers to higher bills.

[15] Based on tariff discount of ~1.33c/kWh for ~7MWh total load, 2017 Tauranga network pricing

[16] Page 126, Powerco CPP Main Proposal

6. Concerns regarding inputs for forecast WACC

Contact has some concerns over Powerco's assumed Weighted Average Cost of Capital (WACC) over the CPP period and thinks this is an area deserving of further interrogation by the Commission. We note Powerco's assumptions for WACC (once the DPP ends) assume the somewhat high, favourable WACC continues unchanged for 2019 and 2020 despite the switch out of the DPP into a CPP.

Table 5.2: Impact of applied cost of capital

$M - EXCEPT WHERE NOTED	1-APR-18	FY19	20	21	22	23
APPLIED COST OF CAPITAL						
Applied cost of capital (%)		7.19%	7.19%	6.78%	6.78%	6.78%

Whilst we recognise the outcome of the latest IM review was for the existing DPP WACC to apply at the start of a CPP period[17], we maintain our view[18] that, under a CPP, a split WACC is the most appropriate approach, and the fairest for consumers. Certainly applying the existing WACC of 7.19% is an economically punitive outcome for consumers, who are already potentially facing the burden of significant increased costs as a result of the quantum of additional capex and opex under the proposed CPP.

We believe that, for new investment under a CPP, especially given the size of the circa $1.3 billion investment proposed by Powerco, the most appropriate approach would be to set a new WACC using current inputs for the portion of new investment that relates to the CPP, rather than extrapolating a WACC that was set in 2015 when this investment was not contemplated (and certainly not committed).

In particular, for any new WACC determination, be it for part or all of the CPP period, we would like to see more transparency in relation to the determination of key inputs, specifically the average debt premium and risk-free rate.

In relation to the cost of capital input set out in Powerco's CPP proposal, we provide comment on the two key inputs that are not prescribed as hard values under the IM, namely the debt premium and risk-free rate (RFR) assumptions.

Table 5.3: Forecast WACC

PARAMETER	IM CLAUSE REFERENCE	INPUT ASSUMPTION
Risk-free rate	4.4.3	3.60%
Average debt premium	4.4.4	1.90%
Leverage	4.4.2(1)	42%
TAMRP	4.4.2(7)	7.0%
Corporate tax rate	4.4.2(4)	28.0%
Debt issuance costs	4.4.2(6)	0.20%
Equity beta	4.4.2(5)	0.60
67th percentile WACC z score	4.4.5(3)	0.440
Standard error	4.4.5(3)	0.0101
67th percentile vanilla WACC	4.4.5	6.78%

[17] Per clause 5.3.22(1) of the consolidation of the Electricity Distribution Services Input Methodologies Determination 2012 dated 28 February 2017

[18] Para 8 of Contact's "Submission on Cost of Capital Update Paper: 30 November 2015" dated 5 February 2016

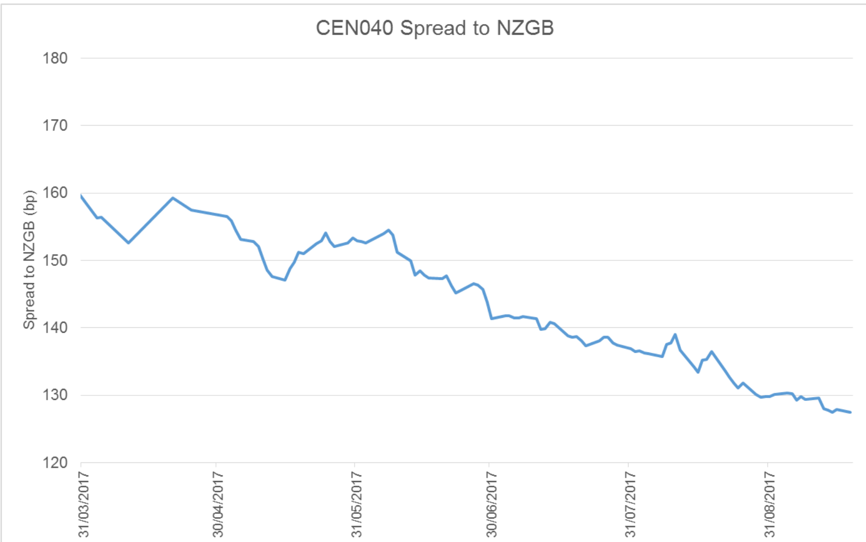
Debt premium assumption

The Commission's recent reset of the debt premium for EDBs[19] is set out below.

	EDBs	
	Debt premium	Average debt premium (5 year rolling average)
Debt premium reference year (DPRY)	*1 September to 31 August*	
DPRY 2013	2.24%	N/A
DPRY 2014	2.04%	
DPRY 2015	1.76%	
DPRY 2016	1.59%	
DPRY 2017	1.59%	**1.84%**

We are unclear as to how Powerco has determined a future debt premium, given there is no forward market or other means for forecasting this parameter. We believe the basis for this assumption and any supporting rationale should be disclosed.

We note that Powerco's assumed average debt premium input of 1.90% for 2021-2023 is greater than the 2017 rolling average. We are unclear why this is an appropriate assumed level of debt premium, given that the rolling average will naturally decline unless the annual debt premium increases by some 0.40% over the next few years from the current 2017 level of 1.59%. Market conditions suggest this is highly unlikely and, in fact, indicate the opposite is happening, as is demonstrated by the debt premium on Contact's bonds that mature on 15 November 2022 (5.4 year average remaining tenor over the period shown):



Given the inability for companies to hedge the debt premium component of the cost of borrowing, recognised by the move to using an averaging mechanism by the Commission, we believe the fairest and most accurate approach would be to continue to apply an averaging approach under a CPP.

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[19] http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/cost-of-capital-2/cost-of-capital-2017/

a) Risk-free rate not supported by evidence and requires further explanation

Similarly, the risk-free rate (RFR) assumption in the CPP 2021-2023 forecast WACC appears to be very high.

As shown below, the recent reset[1] showed an average RFR of 2.76%. The current five-year RFR is 2.55% and the five-year average is around 3.08%. It is therefore unclear to us why Powerco would assume a RFR of 3.60% (for 2021-2023) without any supporting evidence of their calculations. At the very least we think Powerco should be completely transparent on this point so we, and others, can test their assumptions/rationale.

EDBs information disclosure WACC estimate
(Estimated as at 1 April 2017)

Parameter	Estimate	Std error
Risk-free rate	2.76%	
Average debt premium	1.84%	
Leverage	42%	
Asset beta	0.35	
Debt beta	0.00	
TAMRP	7.0%	
Corporate tax rate	28.0%	
Investor tax rate	28.0%	
Debt issuance costs	0.20%	
Equity beta	0.60	
Cost of equity	6.19%	
Cost of debt	4.80%	
Vanilla WACC (mid-point)	**5.60%**	0.0101
Post-tax WACC (mid-point)	**5.04%**	0.0101

7. RAB roll-forward – significant implications for customers

6.1 RAB roll-forward

The forecast RAB and its roll-forward components for the Next Period are shown below.

Table 6.1: RAB roll-forward

$M	FY17	18	19	20	21	22	23
Opening RAB	1,528.0	1,600.3	1,679.0	1,865.2	2,000.3	2,139.7	2,310.1
Value of commissioned assets	110.9	116.0	226.5	179.1	186.9	221.1	226.4
Depreciation	- 61.2	- 62.2	- 64.5	- 69.0	- 74.0	- 79.2	- 84.0
Revaluations	32.0	34.4	35.1	37.8	40.3	42.7	45.5
Disposals	- 9.4	- 9.5	- 11.0	- 12.9	- 13.8	- 14.3	- 14.6
Closing RAB	**1,600.3**	**1,679.0**	**1,865.2**	**2,000.3**	**2,139.7**	**2,310.1**	**2,483.4**

Descriptions of each of the RAB components (total value of commissioned assets, revaluation, depreciation and disposals) are included later in this chapter.

On the proposal put forward, the Regulated Asset Base (the RAB) will increase from $1.53bn to $2.48bn over a seven-year period (62.5%).

Assuming the use of a like for like WACC (e.g. 6.0%), the revenue over this period would increase significantly from $91.7m to $149.0m p.a.

This is material and represents an increase of $179 per customer (assuming 320,000 customers) over the period, i.e. by 2023 consumers will be paying $179 p.a. more than they were in 2017, and this is without taking into account increased annual opex costs.

8. Cost of debt – borrowing costs do not represent available cost of funding

Table 6.8: Cost of financing

$M - EXCEPT AS OTHERWISE IDENTIFIED	FY17	18	19	20	21	22	23
Forecast weighted average borrowing cost	6.57%	5.23%	6.11%	6.12%	5.69%	5.51%	5.61%
Cost of financing - simple commissioning approach	-	-	-	-	-	-	-
Cost of financing - specific date commissioning approach	1.1	2.1	3.8	1.5	2.3	2.7	2.5

CPP Financial and Modelling Information 27

We also think the assumed borrowing costs (for capitalising investment, shown in table 6.8 of Powerco's application) are worthy of further investigation.

Powerco has assumed an average borrowing cost of 5.81% for FY19-FY23 for new borrowing resulting from the increased capital investment under the CPP. Powerco states that these borrowing costs were calculated from projected cost of debt from their internal modelling, including the cost of existing hedging.

Given the borrowing requirement for the investment under the CPP is new debt (and therefore does not have a historical cost element), we think the borrowing cost inputs should reflect the *latest* cost of debt, which the Commission assessed for EDBs as 4.80%. By way of further comparison, Contact's current cost of debt (for year ending 30 June 2017) is 5.00%, noting the following:

- Contact has a triple BBB rating, a notch lower than that allowed for under the IMs.
- This cost of funds rate for Contact has an element of historical cost (debt premia and hedging). New debt would be accessed at a lower rate, e.g. new borrowing under Contact's bank facilities would be at an average of 3.15%; Contact's bond maturing 15 November 2022 (5.2 year remaining tenor) is currently trading at 3.71%.

9. General comments

In addition to the specific examples provided regarding the input assumptions into Powerco's CPP, we believe the following are necessary to ensure a fair outcome for consumers:

- Full transparency regarding *all* WACC assumptions, not just those outlined above, e.g. the derivation of the TCSD.
- The Commission to consider the appropriateness of using historical data in relation to the new investment contemplated under the CPP, not only as outlined above but in respect of all aspects of the application, e.g. Powerco's cost of debt input of 6.09% (for 2019-2020) for deductibility of interest (which is the rate that was set for the DPP in 2015).

We believe that if the CPP progresses, the approach used to set an appropriate WACC and other financial inputs needs to be fair, robust and reflect the 'current' nature of the change, i.e. the methodology should not apply historical data and assumptions to new future investment.

Concluding comments

This request by Powerco raises important issues for consumers, competitors and the Commerce Commission. The way the proposal is handled will also set important precedents and signals for subsequent possible applications for CPPs from other lines businesses. We look forward to continuing to engage on this matter with the Commission and urge the Commission to take a customer-centric view of regulation, as we believe that is likely to result in the best market outcomes.

Yours sincerely

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