CAPITAL STRATEGIC ADVISORS

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Meridian Energy Limited

Review of the Electricity Authority's Level Playing Field options paper

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About Capital Strategic Advisors (CSA)

Based in the capital city of New Zealand, CSA provides strategic policy advice to government and private sector clients. CSA has expertise in regulatory and tax policy, market and organisational design, institutional economics, pricing theory and practice, competition and infrastructure issues, and the implications of innovation and technology change for regulatory design, productivity, and economic growth.

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Contents

Key points

1. The Authority's problem definition, proposal and alternatives are presented in a paper entitled *Level Playing Field measures: Options paper* (Options paper).

The Authority's problem definition needs further thought

2. The Options paper compares 'apples and oranges' when it compares prices for ASX contracts (less than 4 years) with generation costs estimated over 25^{+} years.
3. The paper does not mention that real retail prices have declined since December 2020, which does not correlate well with its concerns about stalled competition.
4. The paper places significant weight on the lack of definitive empirical results about prices for super-peak hedge products. However, the Authority's risk management modelling implies those prices would have minimal impact on the competitiveness of non-integrated retailers (NIRs).
5. Crucially, the paper ignores the reality that vertical integration enables control of arbitrage risk. The proposed non-discrimination rules will need to address this issue if gentailers are to sell long-term contracts to NIRs at historical prices. On the other hand, if the rules allow sale of long-term contracts at forward-looking prices, then retail prices may rise significantly (see points 10-13 below).
6. The paper seems to assume incumbent NIRs want to buy long-term hedge contracts at forward-looking prices. However, this would expose them to the risk of new entrants outcompeting them if hedge prices decline for a sustained period. As retailing is a thin-margin business, they would need to hold significant cash reserves or have access to additional debt and equity to ride through the price cycle.

Market outcomes reflect adverse supply shocks and market asymmetries, not market power

7. There are valid alternatives to the claim that market outcomes reflect gentailer market power.
8. Recent retail market outcomes reflect several asymmetries:
   a. Since 2018, the wholesale market has suffered many adverse supply shocks, and they have been longer lasting than anticipated. The wholesale market is experiencing a *price supercycle*.
   b. There is a fundamental asymmetry between hedge and retail markets. Prices for hedge products must align with expected spot prices (and with each other) to avoid arbitrage, whereas prices for retail supply contracts do not have to align.
   c. Incumbents with long-lived generation assets are typically better placed to ride through price supercycles than competitors with short-lived assets and thin margins.
9. A prolonged period of price smoothing can be a competitive equilibrium because it serves the interests of retail consumers. It could occur even if the electricity market had 20 incumbent gentailers with 5% market share each, for example.

The Authority's proposal carries significant price risks for households

10. The Options paper says there is a disconnect between internal transfer prices and retail prices but then ignores the retail price implications of fixing that disconnect. This is surprising, as hedge prices have increased about 90% in real terms since mid-2018 yet residential retail prices have declined 6.7% in real terms.
11. The non-discrimination obligations require gentailers to set their internal transfer prices based on market prices, and the no cross-subsidy obligation requires them to set their retail prices based on those internal transfer prices. These obligations will increase retail prices. Electricity bills for households could increase by 21-26%, or $460-570 per year.
12. If hedge prices remain elevated for another year and then decline steadily to neutral, the average household could end up paying $818 more in electricity bills during that period. It could easily take another 15 years for households to be better off.
13. These considerations suggest the proposal increases the risk of a future government introducing price caps, which tend to harm NIRs. They become insolvent when wholesale prices rise faster than regulators allow retail price rises.

The Authority's proposal has significant implementation and compliance problems

14. The Options paper flips between two non-discrimination benchmarks. Paragraph 4.15 requires gentailers treat themselves substantially the same as they currently treat non-integrated competitors, whereas paragraph 4.16 requires the converse: gentailers must treat others the same as they currently treat themselves. The retail price risks with 4.15 were discussed above.
15. The problem with 4.16 is that hedge contracts are easily arbitraged. If gentailers must base their offers on a subjective assessment of prices implicitly charged to their own retail division, then contract buyers can arbitrage the price differences across gentailers. This pricing approach is infeasible. Indeed, so is any approach that systematically deviates from competitive pricing of hedges.
16. The paper understates the implications of its proposal for gentailer compliance costs and uncertainty. This is reflected in its own evaluation of the principles-based approach, which states that it would leave room for interpretation, may make it difficult to identify discrimination, and monitoring and enforcement could be challenging.
17. The proposal risks further harming the reputation of the electricity market if the Authority assesses compliance breaches, introduces prescriptive rules, creating more compliance breaches until gentailers learn what the Authority expects, and on and on. Reputational harm could be very costly for the wider industry.
18. Unless the Authority offers a 'safe harbour' option, in my view it may be better for the Authority to introduce prescriptive non-discrimination obligations. At least that way the Authority would have to confront the realities of what they are requiring of gentailers.

The Authority should allow the negotiate-arbitrate option as a safe harbour

19. If the Authority decides to proceed with its non-discrimination proposal, a safe harbour option is warranted to reduce uncertainty and costs for all parties.

20. Making the negotiate-arbitrate approach a safe harbour option will avoid compliance risks for gentailers, give NIRs greater certainty, and avoid the risk of short-term price rises for residential and commercial consumers.

21. If any gentailer elects the negotiate-arbitrate safe harbour, the Authority would gain valuable information about its pros and cons before it considered more intrusive options, such as step 2 in the Options paper. NIRs would be better placed to offer their views on the pros and cons, based on actual experience rather than hypotheticals. Arbitrators would also have valuable insights.

Concluding comments

22. I have long advocated for reducing barriers to entry for NIRs and viewed their involvement in the market as a contest between business models. However, it was never a case of viewing one model as better than the other, or that the absence of one signalled the market wasn't working. It was up to the market to decide whether one model wins, or they coexist.

1 Introduction

The Energy Competition Task Force (Task Force) recently announced that non-discrimination measures are its preferred option to level the playing field between gentailers and independent participants in the electricity market.[1] The proposal and alternatives are presented in a paper released by the Electricity Authority entitled *Level Playing Field measures: Options paper* (Options paper).

The analysis and proposal in the Options paper relies on analysis and evidence presented in two previous reviews: a companion paper providing an update on its review of risk management options for electricity retailers (Update paper), and its review of internal transfer pricing and retail gross margins (ITP/RGM paper).

Meridian Energy requested I prepare an independent assessment of the Authority's Options paper. I agreed to do so because it seemed odd the Authority was proposing a wide-ranging intervention to address a narrow hedge market issue in the Update paper. Further, the Update paper makes it clear the Authority does not have robust empirical evidence the narrow issue is a problem requiring regulatory intervention.

I am very concerned the Task Force has mis-diagnosed the problem confronting non-integrated retailers (NIRs) and does not appear to have fully considered important factors, such as asymmetries between the hedge and retail markets and retail pricing in the face of repeated adverse supply shocks, that were thought more temporary than has turned out to be the case. In my view, this is leading the Authority to propose options that are likely to materially increase prices for households and businesses. It could also harm non-integrated retailers in the long run. Both are unnecessary.

I am concerned about the workability of the non-discrimination rules, which arises because the proposed rules are in the form of high-level principles, allowing the Authority to ignore important details. I am particularly concerned that it does not appear to have considered the arbitrage implications of its proposal, and it has given scant attention to implications for retail prices.

In my view, the Authority's proposal will inevitably result in more intrusive interventions and needlessly harm the reputation of the retail electricity market. If the Authority proceeds with its proposal, it would be wise to introduce 'safe harbour' provisions.

I am sympathetic to the plight of NIRs. They have been caught by a supercycle that no one anticipated, for which they are poorly placed to manage. The best thing the Authority can do is encourage more supply to the market, to reduce wholesale electricity prices and end the price supercycle as soon as possible.

[1] https://www.ea.govt.nz/news/press-release/energy-competition-task-force-looks-to-level-the-playing-field-between-the-gentailers-and-independent-generators-and-retailers/

2 Concerns with the problem definition and proposal

The Task Force is over-focusing on hypothetical competition concerns and short-run risk management. In my view the underlying issue is that NIRs have traditionally been more focused on the short-run and therefore have poor long-run price-smoothing capabilities relative to incumbent generator-retailers (*gentailers*).[2] This is a key drawback of their business model, as long periods of price-smoothing can occur in competitive markets and are likely to be welfare-maximising. These considerations are presented in section 3.

This section focuses on concerns I have about the analysis in the Options paper. Sections 2.1 - 2.4 discuss concerns with the problem definition, and section 2.5 discusses concerns with the logic and workability of the proposal.

2.1 Concerns about barriers to generation competition are unconvincing

The Options paper states that gentailers have the opportunity and incentive to restrict generation competition because of their control of the flexible generation base, and therefore of the firming/hedging input their competitors need, at least in the short to medium term (3.51a).[3]

The Options paper does not offer any rigorous evidence regarding *opportunities* or *incentives*. Rather, it infers there may be barriers to entry and/or expansion in generation because there has been limited growth of competing generators (3.15). It also discusses the persistence of price vs cost margins (see next subsection).

The casual approach to this topic is surprising, for the reasons discussed below.

Flat electricity demand

Firstly, it is well-known that electricity demand has been largely flat since 1990, so minimal new generation has been needed other than to replace plants that have reached their end of life. Further, uncertainty around the future of NZAS since 2012, and even earlier, likely chilled generation investment.[4] In these circumstances, why would there be significant growth of competing generators?

Non-gentailers account for 51% of committed investment

Secondly, now that demand is expected to grow rapidly, the Authority's investment pipeline shows that 51% of investments committed for the period to December 2028 were driven by parties other than "NZ integrated", that is, other than gentailers. This is highlighted in Figure 1 below. For actively pursued projects, the gentailer share is only 23%.[5]

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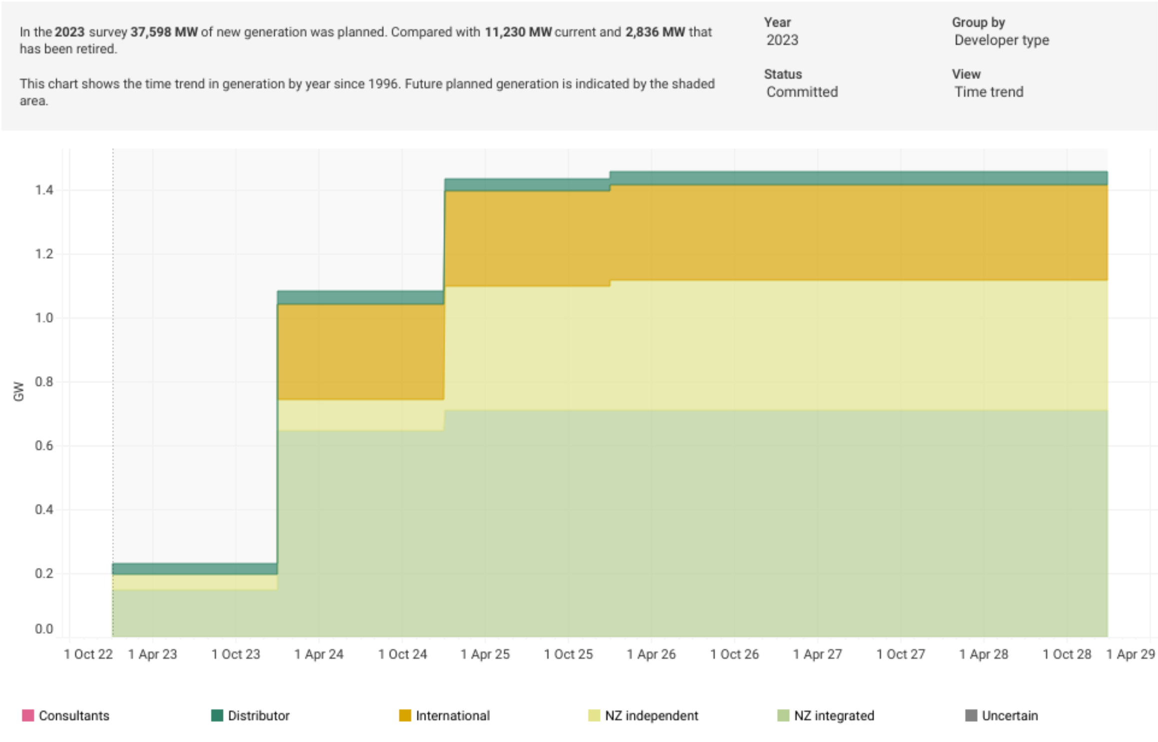
[2] An *incumbent* in this note is any market participant operating in the market prior to mid-2018, as wholesale market prices have remained elevated since then. All major gentailers in the market are incumbents, as are many NIRs. Participants who entered the market after mid-2018 are called *new entrants* in this note.

[3] Numbers in parentheses refer to paragraph numbers in the Options paper.

[4] https://www.treasury.govt.nz/sites/default/files/2013-09/nzas-2392548.pdf.

[5] https://public.tableau.com/app/profile/electricity.authority/viz/Investmentpipeline/Investmentpipeline

Figure 1: Committed generation investments by type of developer, gigawatt capacity



Further, there are over 100 separate generation companies operating in New Zealand, most of whom are connected to distribution networks.

The large proportion of investments made by non-gentailers, and the large number of generators, suggests minimal barriers to entry or expansion. Rather, the issue has been low growth in electricity demand.

Public policy has likely undermined the business case for thermal investment

The investment pipeline shows that 67% of committed investments were for intermittent generation. The remainder comprised 22% geothermal, 9% batteries, and 2% firming generation (hydro and thermal).

Although there are resource and environmental limits to adding geothermal and hydro generation, the only limit to building thermal generation is its commercial viability, which is driven primarily by availability and cost of fuel and public policies affecting dispatch of thermal generation over the expected life of the plant.

Those policies include the NZ Battery project and the offshore exploration ban, which raised sovereign risk and had a chilling effect on investment in maintaining gas field output, the effects of which are now evident. It appears those policies significantly weakened the commercial case for investment in thermal peaker plants.

Gentailers are often net buyers on the spot and hedge market

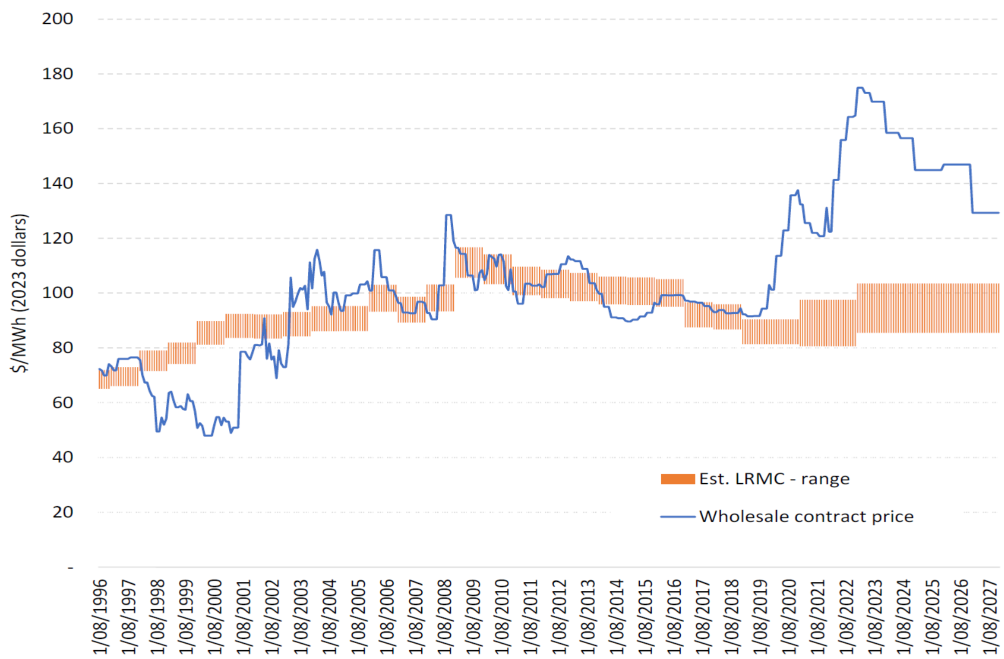
Each gentailer has incentives to compete strongly in the spot and hedge markets. When the hydro lakes are lower than average, the hydro gentailers become net buyers on the spot and hedge market, so their incentive is to minimise spot and hedge prices. When the hydro lakes are higher than average, the non-hydro gentailers become net buyers, and seek to minimise prices.

The volatile dynamics of the various fuel sources – hydro, wind, solar and even gas and coal – makes for an unpredictable operating environment for generators. However, each gentailer is highly incentivised to make timely investments as soon as it believes future market prices will justify the costs. Each knows that if it dithers, a competitor may jump in with an investment that crowds them out until market demand grows sufficiently to justify another investment. We are currently witnessing this dynamic, with gentailers racing to invest in solar, wind and batteries.

Price vs cost comparisons need to be interpreted with care

The Options paper notes there is a large and ongoing gap between ASX hedge prices at Otahuhu and the long run marginal cost (LRMC) of new baseload generation (3.41). Figure 4 in the Options paper is repeated below for easy reference.

Figure 2: Repeat of Figure 4 from the Options paper



The chart shows hedge prices peaking in 2023, at about 75% higher than the upper estimate of cost, declining to about 30% by August 2027. However, these price-cost margins must be interpreted carefully because the hedge prices are only for 2-4 years ahead, whereas the LRMC estimates are the average cost of energy over a plant's entire life.[6] For example, solar and wind plants last 25-35 years, and many baseload plants last far longer. In essence, the chart is comparing 'apples and oranges.'

A numerical example is provided in Appendix 1 to illustrate the care needed. It assumes the cost estimates are based on a 7% cost of capital. Observing the 75% price-cost

[6] The LRMC estimates are derived by calculating the present value of the estimated fixed and variable costs of a plant over its economic life and dividing that by the present value of the energy the plant is expected to produce. This is often called the levelized cost of energy, or LCOE. The hypothetical new generation plant may be a hypothetical (a) baseload coal or geothermal plant or (b) a combination of new wind or solar plant and associated firming generation, whichever is the cheapest.

margin in 2023 and naively thinking it will remain for the plant's life gives an internal rate of return (IRR) of 13.9%, substantially exceeding the investor's 7% cost of capital.

However, investors can expect generation will enter the market and drive spot and hedge prices closer to cost. The Authority's investment pipeline, for example, shows committed investments equal to 13% of existing capacity (1,456 MW), and actively pursued projects equal to 166% of existing capacity.[7] Under reasonable assumptions, the IRRs that can be expected by investors range from 7.6% to 9.9% (refer Appendix 1).

The Task Force is rightly concerned about the potential for unchecked market power in the generation market – it would not be doing its job if it was complacent about these matters. To that end, the Authority should request the business cases for all large generation investment decisions approved by electricity industry participants since mid-2018 and compile a one-off dataset of IRRs. The Authority could publish summary statistics, such as the mean or median IRR by year, type of investment and type of industry participant. I would be very surprised if the average or median IRRs for the generators greatly exceeded their weighted-average cost of capital.

2.2 Concerns about super-peak hedges are not credible or material

The Options paper states that the Task Force's competition concerns relate primarily to gentailer offers of firming contracts or hedges backed by flexible generation (3.26). It refers to evidence from the Authority's Issues paper on risk management that it is unable to affirm that super-peak hedges are likely to be competitively priced, and concerns that over a third of the time retailers receive only one offer in response to requests for shaped hedges (3.39).

In my view, the concerns about super-peak prices are neither material nor credible.

Materiality

The Options paper repeats the Authority's earlier conclusions that it believes baseload and peak hedge offer prices are likely to be competitive (3.39f). This is important because the Issues paper shows that adding a super-peak hedge to a portfolio of baseload and peak hedges provides minimal additional cover for a NIR.[8]

In other words, any NIR concerned about super-peak prices can obtain an essentially equivalent amount of hedge cover by purchasing products that the Authority affirms are likely to be competitively priced. How can the pricing of super-peak products *materially* affect the ability of NIRs to compete?

To be more specific, let p denote the offer prices for super peaks and let p^* denote the (unobservable) competitive price of those products. The Issues paper is saying that ($p - p^*$) is not large enough for the Authority to be confident that super peak prices are

[7] https://public.tableau.com/app/profile/electricity.authority/viz/Investmentpipeline/Investmentpipeline

[8] Refer Figure 1 (p16), Figure 2 (p18) and Figure 3 in the Options paper. In each case, compare the red bar with the dark blue bar labelled Baseload & Peak. They are essentially equal in terms of volume of risk cover.

uncompetitive and not small enough for it to be confident they are competitive. So, $(p - p^*)$ is neither small nor large. It is moderate.

Let v denote the additional volume of cover provided by adding super peaks to a portfolio of baseload and peaks. My reading of the Issues paper (refer Footnote 8) is that v is very small. As $(p - p^*)$ is moderate, then $(p - p^*) \times v$ is small, suggesting a small profit impact for any NIR earning a normal return on investment.

Credibility

If any party firmly believes that super-peak hedges are materially over-priced, there is nothing to stop them from selling those products and 'creaming it' when spot prices during super-peak periods turn out lower than their hedge price.

Octopus Energy, Electric Kiwi and Flick Energy, for example, are owned by large parent companies that have the financial resources needed to pursue those opportunities at scale. Further, the hedge market is open to large financial firms in Australasia, not just to firms involved in electricity generation and retailing in New Zealand.[9]

It is not credible for the Authority to believe it has identified opportunities for excess profits, publicised them, and yet speculative activity has not reduced the gap.

2.3 Concerns about retail competition are unconvincing

Similar to its claims about generation, the Options paper states that gentailers have the opportunity and incentive to restrict retail competition because of their control of the flexible generation base, and therefore of the firming/hedging input their competitors need, at least in the short to medium term (3.51).

Opportunities and incentives

No evidence is offered regarding *opportunities* or *incentives* for gentailers to restrict retail competition. Instead, the Options paper claims that "we would typically expect to see small to medium retailers vigorously competing to grow their share, as occurred until 2020, including through innovation, agility and/or highly competitive pricing. That competitive impact appears to have stalled" (3.15).

Surprisingly, the Options paper makes no effort to explain why gentailer opportunities and incentives (supposedly) changed suddenly in or around 2020 and offers no evidence regarding opportunities and incentives.

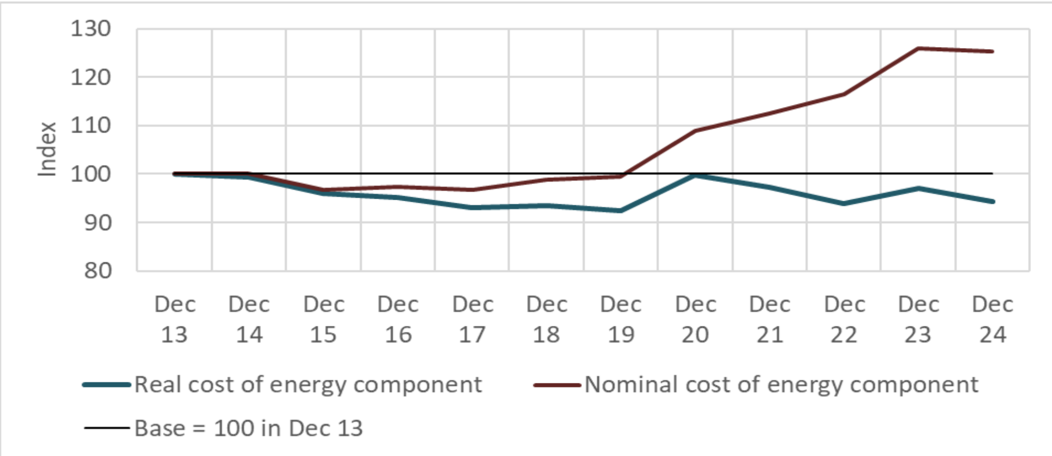
Section 3 in this submission presents an alternative explanation for why NIRs have found it difficult to compete recently, which is to do with weaknesses in their business model. This explanation is consistent with NIRs being able to compete effectively before 2020 but only weakly since then.

[9] For example, see https://www.afr.com/companies/financial-services/savvy-energy-traders-are-betting-the-house-on-australian-power-20240326-p5ffej.

Electricity prices (adjusted for inflation) are not consistent with a sudden weakening in retail market competition

I was surprised the Options paper did not consider retail prices. I was expecting a chart like Figure 3 below, which plots the trend in prices residential consumers paid for the energy component of their electricity bill. The nominal energy component is the household electricity bill minus transmission and distribution charges, divided by electricity consumed.[10] The real value is the nominal value divided by the Consumer Price Index (CPI).[11] Both are normalised to 100 in December 2013.

Figure 3: The real price of the energy component of household bills has declined since 2020



The real cost of the energy component has declined since 2020, which does not support concerns that retail market competition is weak. It is not possible to know whether real prices would have been even lower had NIRs been able to compete more effectively.

However, we know the 2013-18 period is a period of strong competition from NIRs. Some 20 additional retailers became active[12] and the aggregate market share of small and medium retailers nearly doubled, rising from 6.4% to 12.2%.[13] Despite that activity, the real cost of the energy component declined by only 6.5%, which is not materially greater than the 5.8% reduction from December 2020 to December 2022, when the small and medium retailers had flat market share, in aggregate.

Figure 4 plots the trend in real electricity prices for residential, commercial and industrial consumers (the data are for March years).[14] The real price for residential and commercial consumers is lower than in 2014, with commercial prices falling in real terms over 2016-

[10] The energy component is officially referred to as the 'energy and other' component. This was obtained from MBIE's Quarterly Retail Sales Survey (QRSS), available at https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring.

[11] The CPI is from StatisticsNZ at https://infoshare.stats.govt.nz/SelectVariables.aspx?pxID=9ada1805-31d4-4eb2-96a7-d7f3910aa2f6.

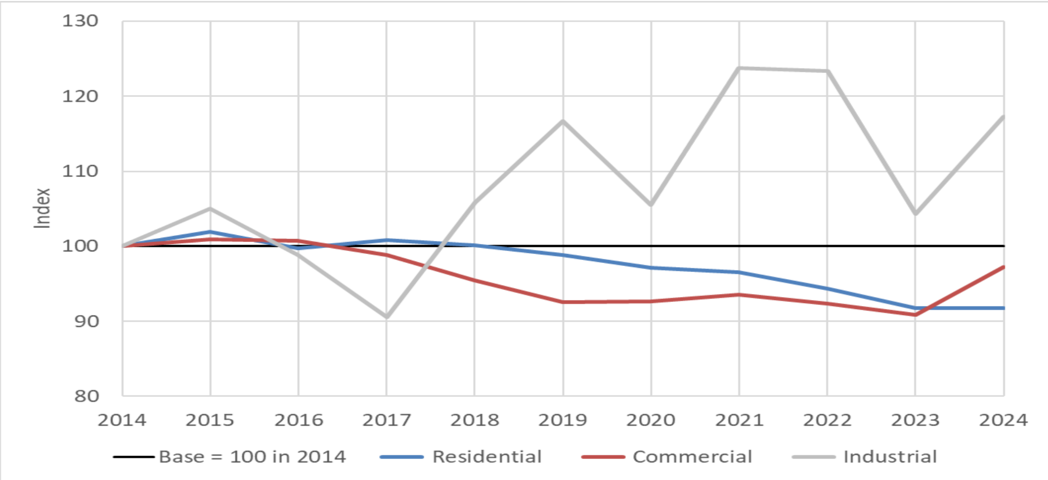
[12] Source: www.emi.ea.govt.nz/r/y01cr.

[13] Source: www.emi.ea.govt.nz/r/e5xlb. Small and medium retailers are all retailers excluding the five largest retailers by market share. Market share is the percentage of installation control points (ICPs).

[14] Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices

2019 and then remaining relatively stable until 2024. The volatility in industrial prices reflects timing of major contract renewals, significant variability in annual production and that they pay prices more closely aligned to wholesale market prices.

Figure 4: Real electricity prices have declined for commercial and residential consumers



The above charts do not lead me to be concerned about gentailer incentives to compete against each other. The charts are consistent with strong competition between them.

At the end of the day, what matters is retail market competition, not whether a particular business model is succeeding or not. It is a mistake to think that NIRs are the primary drivers of innovation. Some will be, some of the time. But my understanding is that several gentailers have been revamping their retail divisions and introducing more technology to reach and retain customers during this period of allegedly stalled competition.

2.4 The analysis of vertical integration is perplexing

The discussion of vertical integration bundles several matters together, making the analysis more obtuse than necessary. Nor does it consider the role integration plays in controlling arbitrage. My sense is that both factors have clouded the Task Force's understanding of the retail price implications of its proposal.

Integration vs contractual mechanisms for managing risk

The Options paper provides a list of the efficiencies of vertical integration (3.17) and acknowledges that the natural hedge from having generation and retailing in the same business is valuable for risk management. The paper concludes that price volatility can be managed through contracts and demand response (3.20). However, this misses the crucial point that contracts typically do not cover super long-term price risk, whereas vertical integration does.

In practice, retailers prefer contracts with durations ranging from 0 - 4 years (*short- and medium-term contracts*). Contracting any longer than four years leaves them very exposed to the risk of new entrants outcompeting them if hedge prices decline for a sustained period. As retailing requires minimal assets and is a thin-margin business, they can become insolvent relatively easily.

If incumbent NIRs contract short-term to manage their exposure to new entrant NIRs, they are exposed to price supercycles and competitive pricing by gentailers with long-lived assets. On the other hand, if they contract long-term to manage their exposure to supercycles, they are exposed to competitive pricing by new entrant NIRs. In both cases, it is critical they have a cash rich, flexible balance sheet or can readily call on shareholder equity or debt.

In practice, NIRs are reluctant to take contracts with terms reflecting the life of generation assets, or even for just 10 or 20 years (*super long-term contracts*).[15]

Vertical integration of generation and retailing addresses the absence of super long-term contracts between those activities. The retail arm of a gentailer is backed by super long-term generation assets and solvency constraints are more relaxed. This makes it viable for gentailers to cope with supercycles in wholesale prices, delivering value to customers by reducing their exposure to those price cycles (section 3 elaborates).

Generally, retailing to a large portfolio of residential customers is far less risky than contracting to retailers serving those customers. Although gross customer churn can be significant due to strong competition, net customer churn tends to be considerably lower and so a large portfolio of customers adjusts incrementally.

Further, it is well-known that integration occurs when contractual arrangements perform so poorly that the additional costs of operating as an integrated business are justified by the efficiency gains of displacing contracts. Most of the efficiency gains come from concentrating residual control rights over generation and retail with a single party rather than separate parties. This enables gentailers to better align their retail pricing with their longer-term perspective without fear of being arbitraged (refer section 3.1).

In summary, the Options paper implies that contracts are an effective risk-management substitute for vertical integration. But that is not the case because it does not provide super long-term risk management, which is what integration provides.

Concerns about the disconnect between ITPs and retail price setting

The Authority's review of internal transfer prices found that gentailers use them for accounting purposes rather than for setting retail prices. The Options paper states the internal transfer prices are not being reliably constructed to take account of future price expectations in a comparable way as hedge contracts sold to retailers (3.44).

It further states that the <u>disconnect</u> between the gentailer internal transfer prices and retail pricing suggests there may be an uneven playing field (3.45). It concludes the existing approach to internal transfer pricing is <u>not fit for purpose</u> in an environment where level playing field and margin squeeze concerns have been raised (3.46, the underlining is my emphasis).

These concerns underpin the Authority's non-discrimination proposal. In essence, the Authority is proposing to require gentailers to treat their internal arrangements as if they are governed by implicit contracts and to price them based on observable market rates for comparable contracts (15a, p75). It is also requiring these prices be set at levels that

[15] Later sections refer to the price of long-dated hedge contracts, defined by the Authority as contracts with 1 - 4 year durations. To minimise confusion, I refer to super long-term.

avoid any cross-subsidy that results in an internal business unit not being commercially viable on a standalone basis (17, p76).

Implicit prices are to be benchmarked against traded prices

The Options paper states that the underlying issue is that internal transfer prices are currently not set on a basis that would allow the Authority to make a meaningful comparison between how the gentailers treat themselves compared to how they treat third parties (3.43). It states that vertical integration, combined with internal transfer prices that are not fit for purpose, makes it difficult for any third party to assess price risks and competition issues (3.51c).

Hence, the proposal is for implicit contract prices to be based on observable market rates for comparable contracts, including baseload, peak and super-peak contracts adjusted for the internal requirements of the gentailer (15a, p75). The draft non-discrimination Principle 1 requires any adjustment to be cost-based and objectively justifiable (1, p73).

Which conduct is the Task Force seeking to address?

The Options paper is vague about where the misconduct lies. Is it in the retail or generation side of the gentailer business? The paper does not provide any numerical analysis of the size of the problem, so it is not possible to resolve the puzzle through that source.

Is the concern about mispricing on the retail side?

The implication of the statement that there is a disconnect between the gentailer internal transfer pricing and retail pricing is that the Task Force wants them to be connected. This implies the Task Force wants gentailers to set their retail prices based on implicit contract prices that are in turn benchmarked to ASX prices and other market prices.

Hedge market prices are currently elevated due to supply side factors. If the Task Force believes gentailers are cross-subsidising their retail arms, then prohibiting cross-subsidies will inevitably increase retail prices.

Yet the Options paper discusses this risk only once and does not provide any numerical analysis of it.[16] This implies the Task Force believes the mispricing is in the generation side of the business, discussed next.

Is the concern about mispricing on the generation side?

In discussing foreclosure by vertically integrated businesses, the paper states this would involve gentailers acting upstream (at the generation level) to disadvantage NIRs. For example, this could include imposing a margin squeeze or refusing to supply hedge products to NIRs (3.23b). This implies the mispricing is on the generation side of the business.

But if the Task Force believes gentailers are cross subsidising their generation arms, then it is implicitly claiming that the non-discrimination obligations will reduce ASX and OTC hedge prices. Alternatively, the Task Force may be creating an obligation to sell hedges below prevailing market prices, enabling arbitrage by other parties and disincentivising

[16] I am concerned the Options paper downplays this risk and discuss it further in section 4.

investment in generation assets. Both approaches would be consistent with their concern that the Authority's risk management review was unable to affirm that prices for super-peak hedges were at competitive levels.

Perhaps the concern is about the availability of super long-term hedges?

Perhaps the Task Force believes the core problem is a lack of super long-term hedges for NIRs. Certainly, if NIRs had a balanced portfolio of hedges, they would be better able to ride through the price supercycle discussed in section 3, significantly reducing the risks for retail prices outlined in section 4 below.

But as discussed earlier in this section, incumbent NIRs would be exposing themselves to being undercut by new entrant NIRs when the supercycle ends. New entrant NIRs (those entering after the supercycle ends) would be able to buy short, medium and super long-term contracts at prices considerably lower than what incumbent NIRs will have paid. There is no reason to expect incumbents will want to expose themselves to that risk after having managed through the downsides of relying on short and medium-term hedges.

The Options paper mentions longer-term hedges only once, in Appendix C on mandatory trading of gentailer hedges. Hence, the rest of my commentary assumes the Task Force did not consider the absence of super long-term hedging was the core issue.

2.5 The proposed solution is misguided and not 'a quick fix'

The Options paper states that non-discrimination obligations would give NIRs and independent generators access to products (for example, hedge contracts, firming) on substantially the same terms as gentailers supply themselves internally (4.16, 5.5 and 6.18(c)-(d)). However, that is not what the non-discrimination obligations require, as elaborated below.

The proposal implies internal hedging is short- and medium-term

As discussed at the start of section 2.4, the standard economic analysis of integration is that it displaces inefficient or ineffective <u>super long-term</u> contracts between the buy and sell sides of an exchange. So, paragraph 4.16 implies gentailers must offer super long-term contracts to NIRs and independent generators.

But that is not what the non-discrimination obligations require. They require gentailers benchmark their implicit contract prices to observable market rates. This implies the Task Force thinks the implicit contracts are short- and medium-term, because observable market rates do not exist for super long-term contracts.[17] As discussed in section 3, this approach is likely to have significant retail price implications.

The short- and medium-term focus arises because the Options paper flips between two different notions. Paragraph 4.15 requires gentailers treat themselves substantially the same as they currently treat non-integrated competitors, whereas paragraph 4.16 requires the converse: gentailers must treat others the same as they currently treat themselves.

Although the paper states that the Authority respects the right of businesses to choose their own structure and prefers to not unnecessarily restrict those choices (3.19), it is in

[17] Section 2.4 defined super long-term as terms matching generation asset lifetimes, or 20$^+$ years.

fact proposing very significant restrictions. Although it may not think so, the Task Force is effectively requiring gentailers to take a short-term approach; that is, to adopt the inherent limitations of the non-integrated model. It is overturning the key feature of integration, which is that it displaces the contractual approach to managing price supercycles.

The Authority's proposal has significant implementation issues

A fundamental problem with implementing the requirements of paragraph 4.16 is that hedge contracts are easily arbitraged. If gentailers base their offers on a subjective assessment of prices implicitly charged to their own retail division, then contract buyers can arbitrage the price differences. For example, any party, including other gentailers, could buy contracts from the lowest price gentailer and sell contracts at a higher price (pitching just under the next highest gentailer offer), and so on.

In other words, it is infeasible for each gentailer to treat others the same as they currently treat their own retailer. The best they can do is offer contracts based on prevailing hedge market prices, with a modest and temporary margin above or below.

The same logic also applies to Principle 1 in Appendix B, which requires there can only be differences between internal and external offers where there are cost-based, objectively justifiable reasons. Cost-plus pricing is misguided in a market where arbitrage is relatively easy.

The proposal is costly and not a quick fix

The Options paper puts considerable store on the speed at which the proposal can be adopted in the Electricity Industry Participation Code (Code) (Table 2, p38). Inserting high-level principles in the Code does not amount to fixing something.

Further, the pros and cons discussion in Table 2 states that the principles-based approach would leave room for interpretation, may make it difficult to identify discrimination, and monitoring and enforcement could be challenging. This portends significant implementation issues and costs for gentailers, which is not mentioned in the table. Surprisingly, the formal evaluation in Table 5 (p50) makes the understatement that "Gentailers will incur some systems costs to ensure compliance."

Table 2 also states that additional detail may need to be prescribed over time to identify discrimination, such as accounting separation and improved disclosure of internal transfer prices. The earlier discussion of that approach rightly expresses concern about the scope for debate about whether different approaches are efficient and/or justified by different circumstances (4.14). Surely the same applies to whatever details gentailers include in their compliance report.

Further, a gentailer can do its best to comply with the non-discrimination rules but will be dragged down by the lowest common denominator. That is, if the Authority is not happy with how one gentailer has complied with the principles it could impose step 2 or step 3 on all gentailers. Presumably the Authority will publish criteria for adopting these steps, however it seems likely they will provide minimal guidance.

Overall, the proposal risks harming the reputation of the retail electricity market if the Authority assesses compliance breaches, tightens the rules, creating more compliance breaches, and on and on. Reputational harm can be very costly, and unnecessary if it derives from vague rules.

2.6 A numerical cost-benefit assessment is needed

The Options paper uses several criteria to determine which of their options is preferred but does not appear to have undertaken an indicative cost-benefit assessment (CBA) and the paper does not signal any intention of doing so.

In the next stage of this work, I would hope to see a numerical cost-benefit assessment of the proposal rather than a high-level qualitative assessment of the competition, reliability, efficiency and other effects of the proposal.

3 An alternative perspective about market performance

Ronald Coase, a key figure in the modern analysis of vertical integration, has remarked:

> *If an economist finds something—a business practice of one sort or another—that he does not understand, he looks for a monopoly explanation. Coase (1972, p67)*

In that vein, it is prudent to consider non-market power reasons for why there is a perception that NIRs in general have struggled to compete since 2020. It is not obvious to me why gentailer structure and market position – which has barely changed since 2010 – was benign for NIRs through to 2020 and then hostile after that. Likewise, why has protection from spot price risks during super-peak periods supposedly become a more essential input for NIRs than pre-2020?

As mentioned earlier, in my view the key issue is not gentailers overpricing their super-peak hedges or failing to set their retail prices according to their internal transfer prices. Rather, the key issue is that NIRs are poorly placed to offer super long-term price smoothing services to consumers, as they do not own assets or have capital structures that enable them to ride through a supercycle.

3.1 Segmentation and arbitrage in electricity markets

A pure arbitrage opportunity occurs when a party can make a riskless profit by buying in one market and simultaneously selling in another. Markets are segmented when price differences do not attract sufficient arbitrage activity to close the price difference.

Variable-volume contracts are segmented from the hedge market

It is not feasible for consumers, of any size, to arbitrage price differences between the hedge market and their variable-volume contracts. This is because the volumes in these contracts are metered by the retailer or an independent third party. Selling an offsetting hedge contract would increase consumer risk, not reduce it. There is no arbitrage opportunity.

In other words, variable-volume contracts are physical offtake contracts. Retailers can offer discounted prices on variable-volume contracts without the risk of their customer selling offsetting contracts on the ASX market and coming back for another contract, *ad infinitum*. Variable-volume contracts are segmented from the hedge market.

Standardised hedge contracts are easily arbitraged

It is widely accepted that financial contracts are often subject to arbitrage risk, and the more standardised they are, the easier it is to arbitrage them.

This is important because, unlike in most other industries, contracts between electricity generation and retail are purely financial, as electricity retailers never take physical delivery of electricity. They are financial intermediaries, not physical retailers.

The upshot is that generators cannot offer contracts to NIRs at prices materially below market prices without risking being arbitraged on the ASX futures market. It also means that market-making arrangements effectively constrain or discipline any price misalignments between hedge products.

Vertical integration prevents arbitrage between generation and retail

Although the Options paper lists the potential efficiencies with integration (3.17), it does not discuss the fundamental role of residual control rights, which is the underlying attribute that enables those efficiencies.

In essence, integration gives residual control rights over both generation and retailing to gentailer chief executives.[18] They use those rights to remove any risk of the managers of the retail arm arbitraging the managers of the generation arm, and vice versa.

This control assists gentailers to offer greater price-smoothing services to consumers, materially improving their welfare when supply side shocks would otherwise create more volatile retail prices (refer section 3.3).

3.2 Price supercycles occur from time-to-time in commodity markets

Over the last six and half years, ongoing increases in the cost of gas and uncertainty about gas availability has driven a prolonged increase in electricity spot and hedge prices in New Zealand. There were also significant uplifts in the cost of solar panels and wind turbines with the Russian invasion of Ukraine in February 2022 and President Biden's Inflation Reduction Act in August 2022, however those prices have reversed significantly (in real terms).

Figure 5 plots the average price of long-dated baseload quarterly electricity futures contracts at Benmore over the period 2 July 2018 to 31 December 2024.[19] The cumulative price increase over that period was 102%, and the corresponding increase at Otahuhu was 130%.[20] The average increase across both locations was 116%.

[18] Technically speaking, the residual control rights are held by the owner of the entity. The owners delegate residual decision rights to the board, who in turn delegate a subset of those rights to the chief executive, and so on down the organisation.

[19] The corresponding chart for Otahuhu is similar and available at www.emi.ea.govt.nz/r/z3vh0.

[20] The Benmore price increased from $69.59 to $140.81 and the Otahuhu price from $76 to $175. All prices are $ per MWh.

Figure 5: Average ASX prices for long-dated baseload electricity futures contracts at Benmore

In real terms, after adjusting for consumer price inflation, the average price of Benmore and Otahuhu hedges increased 90%. It is widely expected that elevated prices could last another two or three years before reverting to a downwards trajectory.

These types of long run price cycles in commodity markets are called *supercycles*, as they reflect structural factors, such as macroeconomic, technology and geopolitical developments.

3.3 Considerable price smoothing has occurred over the current supercycle

Electricity is a necessity for most small consumers, and on average it accounts for 4.2% of household disposable income.[21] As a result, the price elasticity of demand is relatively low, making it feasible for retailers to increase residential electricity prices to maintain their profit margins without suffering significant demand reductions. However, real price rises have not occurred over the current supercycle.

Adjusting for inflation, the real price of household electricity declined by 6.7% over July 2018 to December 2024.[22] However, the household bill includes transmission and distribution charges, which are largely set by regulators. The energy component of household electricity bills more closely reflects the competitive segments of the electricity market. The real price of this component declined by 0.2% over 2018 –2024.[23]

[21] According to the QRSS, average residential expenditure on electricity was $2,378 in the year ended June 2023. According to Statistics New Zealand, average annual household equivalised disposable income (after tax and transfer payments) was $56,919 over the same period. The income statistics are available at https://www.stats.govt.nz/information-releases/household-income-and-housing-cost-statistics-year-ended-june-2023/.

[22] The nominal price increased 20.1% (QRSS, ibid) whereas the CPI increased by 26.8% over the same period.

[23] The nominal price of the energy component increased 26.6% (QRSS, ibid).

With hedge prices increasing by 90% in real terms, the 0.2% decline in the energy component reflects considerable price-smoothing. The underlying reason for this outcome is that a significant portion of residential and SME consumers prefer stable electricity prices and retailers expected the elevated hedge prices would be temporary.

My understanding is that, in most years since mid-2018, generators and retailers have expected wholesale prices to be elevated for two or three more years and then revert towards pre-2018 levels (in real terms) and reduce even further in the very long-term as the cost of wind, solar and batteries continue to decline.[24] In these circumstances, it can be optimal for retailers to try to ride through the turbulence to avoid annoying customers with price rises that will later be reversed. This promotes consumer welfare and saves the retailer the cost of winning back customers. It is easy to see how this can be a competitive equilibrium.

However, as explained in detail below, an unusual series of large adverse supply and demand shocks have occurred since 2018, prolonging the elevated hedge prices far longer than any retailer initially anticipated. The outcome is that retailers have probably provided deeper and longer price smoothing than they would have done if they had perfect foresight and knew wholesale prices would be elevated for a decade or so.

Another factor is that electricity retailers appreciate that sharp and ongoing increases in real retail price rises would likely have induced a consumer backlash and political intervention to cap residential prices, as has occurred in other jurisdictions (eg, Australia, UK). No retailer benefits from price caps in the long-term, as discussed in section 4.3.

3.4 Most supply and demand shocks were expected to reverse in due course

A series of large adverse shocks have affected demand and supply since 2018, and especially since mid-2021. Many of the adverse shocks originated from the prices and availability of domestic gas and Indonesian coal.

Figure 6 shows average prices for short-dated and long-dated electricity futures at Benmore since the start of trading on the ASX market in 2009.[25] It is clear that both prices have become far more volatile post-2018.

The increased volatility of the long-dated prices implies that expectations about the longevity of supply and demand shocks were volatile, indicating high uncertainty. Prior to 2024, significant increases in long-dated prices were followed by significant retreats.

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[24] The Authority can test this claim in two ways. It can obtain the wholesale market price forecasts prepared by retailers for each year since 2018 – these extend far longer than the 3-4 years ahead for ASX futures contracts. Secondly, it can compile an index of prices for long-term contracts and adjust for ASX prices, to obtain an 'y in x' years assessment of price expectations. For example, suppose a long-term hedge contract is signed for z=10 years. Backing-out the effects of elevated prices for x years (as measured by ASX prices) will enable the derivation of the implied price for electricity for y years starting in x year's time (y = z - x).

[25] The corresponding chart for Otahuhu prices is available at www.emi.ea.govt.nz/r/1yrjn.

Figure 6: Prices for short- and long-dated electricity futures contracts at Benmore, 2009-25

Drilling into the details (dates for adverse supply shocks are highlighted in bold):

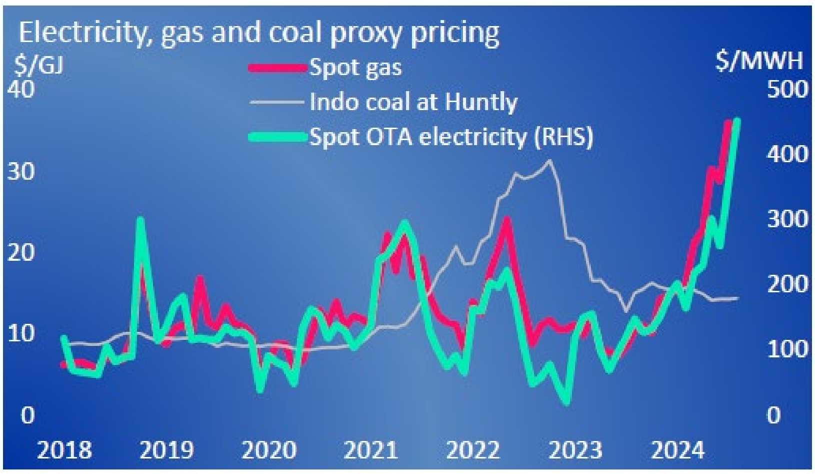
- **Mid-2018**: *Pohokura gas outages*. Significant unplanned gas production outages at Pohokura. Prices for long-dated futures contracts at Benmore were only slightly elevated, at around $88.
- **Early 2019**: *Uncertainty about gas outage*. Realisation that Pohokura outages are longer lasting than initially thought and it becomes uncertain if production will return to pre-outage levels. Long-dated Benmore prices remain around $88.
- March 2020: *Covid-19 lockdown*. Long-dated Benmore prices had been declining since 4 March and neither the announcement of the lockdown on 23 March nor the lockdown materially affected those prices.
- 9 July 2020: *NZAS termination*. Meridian announces NZAS' intention to close its Tiwai Point aluminium smelter and terminate its electricity contract with Meridian, causing long-dated Benmore prices to fall to $50. This led to expectations that elevated hedge prices would not return
- 27 August 2020: *NZAS may be on again*. NZAS announced it was in talks with generators, hoping to secure a short-term contract to tide it over until upgrades to the transmission grid in the Lower South Island would allow it to export more power to the North Island. Long-dated Benmore prices increased steadily through to 3 December, from around $50 to $87. Although modestly higher than the average for 2010-2017, this further cemented expectations that elevated hedge prices would not return.
- 14 January 2021: *Stop-gap NZAS contract*. Meridian announces a short-term agreement with NZAS, keeping the smelter operating through to December 31,

2024. Long-dated Benmore prices had been rising ahead of the announcement. They jumped from $79 to $115 by 11 February 2021.

- **Mid-2021**: *Prices for Indonesian coal trebled by middle of 2022*. This followed China's ban on Australian coal imports in late 2020, increasing Indonesian coal exports to China. Long-dated Benmore prices increased steadily towards $100 and hovered around that mark until mid-February 2022.
- **23 February 2022**: *Russia invades Ukraine*. This caused record international wholesale gas prices and significant volatility due to supply restrictions, sanctions and sabotage. Europe became more desperate to increase their installation of renewable energy. Increased demand for solar panels, wind turbines and batteries caused the prices for those components to spike by 30-40% in 2022-23. Long-dated Benmore prices jumped 50%, from $100 on 2 February to $150 by 16 May.
- **August 2022**: *US ramps up renewable energy subsidies*. President Joe Biden's Inflation Reduction Act gains congressional approval. This further increased global demand for solar panels and wind turbines.
- **17 July 2023**: *NZ gas reserves falling*. MBIE releases data showing a 17% decrease in proven plus probable (2P) reserves and states that natural gas held in reserve will last less than 10 years. Long-dated Benmore prices barely move, hovering around $115 - $120.
- **Early May 2024**: *Gas production falls more quickly than expected*. The Gas Industry Company (GIC) reports that gas supply was at the bottom of expected volumes for the year, and insufficient gas is available to meet all contracted demand. Long-dated Benmore prices continued to hover around $115 - $120.
- **22 May 2024**: *Kupe KS-9 drilling results disappointing*. Genesis Energy and NZ Oil & Gas announced that attempts to increase gas production from the Kupe field had failed. Long-dated Benmore prices continued to hover around $115 - $120.

The increasing scarcity of gas from mid-2023 is reflected in spot gas prices, which fed through to spot electricity prices and eventually to prices for long-dated hedges (refer Figure 7).

Figure 7: Spot electricity prices are highly correlated spot gas prices



Source: Meridian Energy Limited

- 31 May 2024: *NZAS announces new long-term contracts*. NZAS signs contracts with Meridian Energy, Contact Energy and Mercury Energy to power the Tiwai Point aluminium smelter for another 20 years. This provided the sector with much-needed certainty from New Zealand's largest electricity user. The contract with Meridian contains significant elements of callable demand response. Long-dated Benmore prices continue to hover around $115 - $120.
- **Mid-August 2024**: *Worsening gas shortages for electricity generators leads them to pay extraordinarily high prices to Methanex to temporarily shut its production.* Contact Energy and Genesis Energy agree terms with Methanex to idle its remaining Motunui plant and re-route its gas to Contact and Genesis' for use in their closed-cycle thermal generation plants.

Reverting back to Figure 6 (page 23), long-dated prices were reasonably aligned with short-dated prices pre-2018, but this changed in mid-2018. Since then, long-dated prices are almost always lower than short-dated prices, consistent with my view that prior to 2024 the market expected most of the adverse supply shocks to be temporary. The Authority could examine this further by compiling a yield curve for ASX traded hedge contracts.

3.5 Incumbent gentailers can provide price smoothing for long periods

In practice, generators with a large proportion of long-dated assets and moderate debt levels are well-placed to ride through a prolonged period of adverse price shocks, and the same applies to gentailers.

All incumbent gentailers in NZ have asset portfolios that mainly comprise long-dated generation assets. This reflects the fact that generation assets are often exceptionally long-lived – wind farms have 20-25-year expected lifetimes, solar farms up to 35 years, and hydro and geothermal far longer than that. It also reflects that minimal demand growth over the last 34 years (1990 - 2024) has meant only a modest amount of new generation has been needed to replace retiring plant.

Moreover, as generation is a highly capital-intensive business, earning a normal return on generation produces large cash flows, and large net cash flows if they have modest debt levels. In contrast, electricity retailing operates on low capital costs and is a thin margin business.

In principle, incumbent gentailers need to earn a normal return from their retail division over the super long-term to satisfy investors they should remain integrated. This means they may try to recoup their retail losses when favourable shocks occur, however they will be constrained by new players entering the market to take advantage of low wholesale prices.

The upshot is that incumbent gentailers are well-placed to smooth residential retail prices for a prolonged period, which benefits consumers. In contrast, NIRs are generally poorly placed to do that, as discussed next.

3.6 Non-integrated retailers have poor long-term price-smoothing capability

NIRs tend to have a portfolio of short-term hedges, with the tenor of their longest-dated hedges typically no longer than 4 years. The weighted average tenor of their hedge portfolios tends to be around 18-24 months. This means fully hedged NIRs experience large cash outflows when wholesale prices increase sharply and remain elevated well beyond their average contract tenor.

In principle, incumbent NIRs should be better placed to cope with serial adverse supply shocks, as they could have secured long-dated power purchase agreements, but that does not appear to have occurred in practice. One reason is the reasonably static level of electricity demand since 1990, but especially since 2000. There has been very limited need for new generation, so retailers entering the market since 2000 have had limited opportunity to acquire power purchase agreements.

3.7 New entrants tend to struggle when adverse market shocks occur

NIRs entering the market since 2018 are likely to be very poorly placed to withstand adverse market shocks. Most will not have reached the scale they needed to achieve profitability in a steady-state market, let alone in a market suffering a prolonged period of high wholesale prices.

The same logic applies to new entrant gentailers. This is because their new generation assets will have been costly to purchase and install (one of the reasons for the high hedge prices), so they will be competing for consumers with an elevated cost base. In other words, vertical integration is not in itself the saviour for a retailer.

For example, suppose a potential entrant to the residential retail market has access to enough gas to run a 100 MW peaker plant. There are no problems sourcing the capital equipment to install the gas peaker and solar and wind plants, and doing so completely avoids the hedge contracting concerns discussed in the Options paper. Based on spot gas prices since 2020, it would be straight forward for the Authority to show that this gentailer would not be a viable proposition at current residential prices.

3.8 Retail market outcomes reflect market asymmetries, not market power

The key issue is not that gentailers are trying to overprice their OTC hedge offers to NIRs to make it difficult for them to compete. Arbitrage prevents that becoming a material problem.

Rather, recent retail market outcomes reflect several asymmetries:

- Most shocks since 2018 have been adverse supply shocks, and most have been longer lasting than anticipated. There has been only one favourable demand shock, which lasted only seven months (July 2020 – January 2021).

- There is a fundamental asymmetry between hedge and retail markets. Prices for hedge products must align with expected spot prices to avoid arbitrage, whereas prices for variable volume retail supply contracts do not have to align.
- Incumbents with long-lived generation assets are better placed to ride through prolonged periods of adverse shocks than competitors with short-lived assets.

A prolonged period of price smoothing can be a competitive equilibrium because it serves the interests of retail consumers, and suppliers serving a large share of the market are able to serve those interests. It would occur even if the electricity market had 20 incumbent gentailers.

For example, assume each incumbent gentailer has a 5% share of the generation market, a 4% share of the retail market and the remaining 20% of the retail market is served by a single NIR. Under these hypothetical circumstances, no gentailer could materially influence hedge prices by refusing to supply some hedges or offering them at prices above its competitors. But, as each incumbent gentailer has long-dated generation assets, they are able to withstand repeated adverse supply shocks for a prolonged period.

4 If effective, the proposal carries significant price risks for households

The Options paper mentions only once that its proposal carries the risk of a short-term increase in retail prices. The risk is not even mentioned in the announcement material.[26] This is very surprising, given the severe cost-of-living pressures households have been experiencing recently, and the political sensitivity of higher electricity prices for households.

4.1 Household electricity prices are likely to rise sharply in the short-term

The Options paper states that any level playing field (LPF) measure runs some risk of a short-term increase in retail prices, "to the extent that Gentailers may not be currently passing through the full extent of wholesale price increases over recent years." It dismisses the risk, saying "That is the trade-off for longer term competition benefits" and seeks to minimise the issue by saying the risk is smaller for the non-discrimination proposal than for stronger interventions such as corporate separation (5.12). Nowhere does the Options paper indicate the potential size of the price increases.

However, it is irrefutable that price smoothing by gentailers has kept household electricity prices substantially lower than what would otherwise occur. As mentioned in section 3.3, in real terms long-dated hedge prices have increased by about 90% since July 2018 yet the energy component of household electricity prices has been flat over that period after adjusting for inflation.

It is notable the Authority suspended producing its *retailer cost index* in 2020. This index estimated the residential price at which a new entrant retailer, without a generation

[26] https://www.ea.govt.nz/news/press-release/energy-competition-task-force-looks-to-level-the-playing-field-between-the-gentailers-and-independent-generators-and-retailers/

portfolio, could viably enter the market and sell to customers. Comparing movements in the index with measured retail prices would have been informative for the Authority's Options paper.[27]

In the absence of that information, I have estimated how much gentailer price smoothing is likely to have constrained household electricity prices. My calculations suggest those prices would have been 21-26% higher in December 2024, or $460-570 higher per year. The lower end of the estimate is based on the internal transfer prices Meridian has previously submitted to the Authority and the upper estimate is based on an average of prices for long-dated quarterly baseload contracts at Benmore and Otahuhu. Appendix 2 provides details of the calculations.

4.2 The short-term price jump could persist for many years

The Options paper admits there is a risk of increased household electricity prices, and it implies that stronger competition would reduce prices over the long run (5.12). This raises the question of how long it might take for household prices to return to the level they would be without the initiative and how long it would take for households to be better off.

Not surprisingly, the Options paper did not provide any timeframe estimates as it did not estimate the potential size of the price jump risk. To get an indication of timeframes, I made assumptions about the initial price jump and then considered two factors that may drive subsequent price reversion: competitive pressure and subsequent reductions in hedge prices.

Competitive pressure works very slowly

To get an indication of timeframes, I made the following generous assumptions:

- the lift in long-dated hedge prices and associated internal transfer prices is permanent
- the Authority's proposal causes a permanent, one-off, jump in household electricity prices by the lower of my estimate (ie, by 21%)
- the energy component accounts for about 57% of the total household bill, implying the 21% price jump arises from a 37% increase in the price of the energy component
- enhanced retail competition drives a 1.1-2.2% annual reduction in the real cost of the energy component. The 1.1% figure is discussed below. The 2.2% figure is simply a doubling of the 1.1% figure and is very generous.

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[27] A chart of the Authority's retailer cost index is available at www.emi.ea.govt.nz/r/inawh. It compares the retailer cost index with the Quarterly Survey of Domestic Electricity Prices (QSDEP) reported by MBIE and the electricity component of the Consumers Price Index (electricity CPI) reported by Statistics New Zealand. The ratio of the retailer cost index to the QSDEP is quite volatile, as the index is calculated with a simple average of all electricity futures prices at Benmore and Otahuhu. This includes highly volatile short-dated hedge prices, which are heavily influenced by hydrological conditions. NIRs presumably take a longer-term view when setting their prices and deciding their marketing effort. It would be useful to calculate a version of the index based only on long-dated futures prices.

The 1.1% figure is the average annual rate of decline in the real energy component over 2013-18, as shown in Figure 3 (page 13). Enhanced competition over that period is unlikely to be solely or even mainly responsible for the 1.1% rate, however, let's assume it is. Under that assumption, it would take just over 28 years for the additional competitive pressure to bring household electricity prices back to their current level. If the 2.2% assumption is used, the timeframe reduces to 14 years. Details are provided in Appendix 2.

From a householder's perspective, the short-term price risk is not actually short-term, as they would be paying higher prices (than otherwise) for 14^{+} years. Although the initial percentage change in price is one-off, the price level remains high for many years as competitive pressure reduces prices gradually.

High hedge prices revert to normal in four years' time

In practice, the currently high hedge prices will eventually revert to their long-term average in real terms and will fall even further if solar and wind installation costs continue their previous downward trends.

Long-dated Benmore prices have generally exceeded $150 since mid-January 2025, due to ongoing concerns about gas and coal prices and availability amid an intensifying drought ahead of winter 2025. However, hydro lake levels were above average over late spring and into mid-summer (7 October 2024 – 17 January 2025), yet long-dated Benmore prices ranged $125-$150.[28] This suggests wholesale prices are expected to remain elevated over the next three to four years.

For brevity, assume the average price is the mid-point, which is $137.50. This is a $50.05 gap from the $87.45 ASX price needed to bring household electricity expenditure back to the 2024 level of $2,343. The $87.45 price is slightly lower than the $95 nominal price needed to maintain the real price of long-dated contracts at their value in June 2018.[29]

My calculations assume the $50.05 gap persists for one year and then reduces by a third each year to reach the neutral price of $87.45 at the start of the fourth year. Over that period, the average household would pay about $818 more in electricity bills. Under the very generous assumption that enhanced competition would reduce household electricity prices by 2.2% annually, it would take over 15 years for households to break even (after the three years it takes for ASX prices to reach neutral). Details are in Appendix 2.

Concluding comment

The Authority needs to quantify the price jump risk, and present calculations of the welfare implications for consumers.

[28] See www.emi.ea.govt.nz/r/3apsc for hydro lake levels and Figure 5 (page 22) for long-dated Benmore prices.

[29] Benmore and Otahuhu prices for long-dated baseload contracts averaged about $75 in real terms in June 2018. Cumulative CPI inflation since then was 26.8%, so in December 2024 a $75 real price is $95 in nominal terms.

4.3 The proposal increases the risk of price caps, which harm non-integrated retailers

Retail electricity prices will mimic supercycles

If the non-discrimination principles are effective, the ultimate consequence is to drive gentailers to adopt shorter-term pricing for residential and SME consumers. This implies larger cycles or swings in retail prices than have occurred recently.

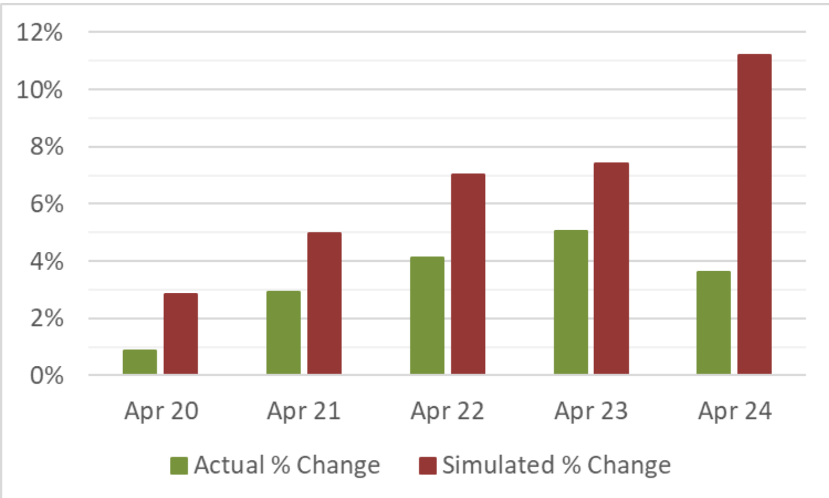
The size of the retail price swings depends on the timeframe for assessing the 'no cross subsidy' rule. This is because the proposed non-discrimination obligations would require gentailers to avoid cross-subsidies that result in an internal business unit being commercially unviable on a standalone basis (Appendix B, para 17).

The commercial viability of standalone business is typically assessed over a period, as many businesses incur losses from time to time and it is not unusual for them to operate at below normal returns on capital for several years. Their ability to withstand losses and below-normal returns depends on their level of financial reserves and the risk appetite of its owners.

If the Authority interprets commercial viability on an annual basis, then gentailers will need to adjust their retail prices in lockstep with annual changes in the value of their implicit contracts (which are to be marked against market prices for hedges). Large changes in retail prices are likely to occur from time to time, as shown in the chart below.

Figure 8 compares the percentage change in actual versus simulated retail prices, where simulated prices are the prices that Meridian would have had to charge if it was required to set its prices based on the internal transfer prices reported to the Authority.

Figure 8: Retail price changes with no cross-subsidy, for years beginning 1 April



On the other hand, if the Authority allows a longer period for determining commercial viability, price adjustments can be driven by a smoothed function of internal transfer prices. This would reduce the risk of price shocks for small consumers, although of course eventually they will pay the full cost.

However, there are two obvious downsides to the smoothed approach. First, it leaves NIRs with slower revenue growth than their cost growth until internal transfer prices have stabilised for a period. Second, it leaves existing gentailers and NIRs exposed to cherry-picking by new entrant retailers.

The risk of retail price caps is increased

The Options paper does not consider the longer-term consequences of larger swings in household electricity prices. For example, there is no mention of the price controls introduced in other markets due to voter backlash to large jumps in household electricity bills. The United Kingdom (UK) introduced price caps in January 2019[30], and Australia followed in July 2019.[31] Many other European countries introduced some form of price cap in 2022.[32]

There is little reason to assume the political incentives are materially different in New Zealand. In my view, introducing the non-disclosure obligations materially increases the risk that a future government will introduce price caps.

Retail price caps often bankrupt non-integrated retailers

No retailer benefits in the long-term from inducing a consumer backlash that leads to price caps. The experience in both Australia and the UK is that NIRs suffer disproportionately under those regimes. Many go broke because regulators are slow to adjust the price caps and do not adjust them fully, to reduce consumer backlash and further political intervention.

In the UK, for example, 31 energy companies ceased trading over 1 January 2021 to 18 February 2022.[33] These failures occurred due to high wholesale gas prices (before Russia invaded Ukraine).

5 Allow the negotiate-arbitrate option as a safe harbour

Section 4 identified three key risks with the Task Force's proposal:

1. Short-term retail price risks, which my calculations suggest are likely to be material for households and small businesses.
2. Longer-term solvency risks for NIRs as the proposal increases the prospect of a future government capping retail prices, which in practice disproportionately harm small retailers.
3. Longer-term reputational risks for the electricity market due to difficulties objectively demonstrating compliance with the proposed non-discrimination rules.

The first two risks arise from the specifics of the non-discrimination obligations. These risks would be avoided by allowing the negotiate-arbitrate option as a safe harbour. That is, any gentailer complying with the safe harbour provisions would be exempt from most of the non-discrimination regime.

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[30] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/energy-price-cap-default-tariff-policy

[31] https://www.aer.gov.au/industry/registers/resources/reviews/default-market-offer-prices-2025-26

[32] https://www.en-former.com/en/price-caps-have-become-the-norm-across-europe/

[33] https://www.forbes.com/uk/advisor/energy/failed-uk-energy-suppliers-update/

In addition to reducing risks, the proposed safe harbour is warranted because the problem definition underpinning the Authority's proposal is strongly contested, it is broad sweeping rather than targeted, and it is not as practicable as indicated in the Options paper. It creates considerable uncertainty and costs for gentailers and non-integrated parties.

The proposed safe harbour benefits all retailers. It provides an option that gentailers can be certain meets the Authority's aims for a level playing field between gentailers and non-integrated parties. And it gives non-integrated parties a practicable way in which to ensure they have access to hedge contracts at competitive prices.

5.1 Proposed features of the safe harbour

The safe harbour would be introduced through a Code provision allowing gentailers to elect a defined negotiate-arbitrate regime. This approach is well-suited for addressing concerns about the pricing of bespoke OTC hedge products, as several of the cons become pros when introduced as a safe harbour option.

The key features would be those outlined in the Options paper, but with the scope of the negotiate-arbitrate obligation limited to the products the Task Force is concerned about. Appendix D (paragraph D.9) expresses a short-term concern about competition in the provision of short duration flexibility, as it recognises that falling hardware prices and increased availability of batteries should address those concerns. It expresses a longer-term concern about the provision of flexible supply providing cover for periods of a week or more (*longer duration flexibility products*). This suggests the negotiate-arbitrate approach could apply in the near term to OTC super peak products, with a trigger to remove them from the regime once competitive supply is more demonstrable. Longer duration flexibility products may remain in the regime for longer, however, a defined trigger for removing them should also be adopted.

Key features

The key features of the safe harbour regime could take the following:

1. *Safe harbour entry* - If a gentailer wishes to use the safe harbour option, it must formally notify the Authority of its choice by the date that the non-discrimination obligations first become effective and by every anniversary date thereafter.
2. *Safe harbour exit* - Gentailers using the safe harbour option cannot withdraw from it within 12 months of electing to use the safe harbour.
3. *Eligibility* – Only negotiations with non-integrated retailers would be covered by the regulated arbitration regime and only to the extent their retail book is uncovered.
4. *Arbitration products* - OTC super peak and longer duration flexibility products. Baseload and peak products are excluded.
5. *Arbitration principles* - Gentailers are required to provide access to arbitration products on fair, reasonable and non-discriminatory terms (FRAND).
6. *Arbitration method* - Final-offer arbitration occurs if commercial negotiations are unsuccessful. As the Options paper states, this will incentivise the negotiating

parties to submit their best offers to the arbitrator and it would alleviate information asymmetry issues for the arbitrator (4.23).

7. *Arbitrator selection* - The negotiating parties can appoint any arbitrator by agreement. If the parties are unable to agree on the arbitrator within a period specified in the Code, the gentailer and counterparty would have alternate rights to appoint an arbitrator from an Authority-approved list of qualified independent experts.[34]
8. *Arbitration timeframe* - The negotiating parties can decide the arbitration timeframe by agreement. A default timeframe will be specified in the Code to guard against delaying tactics.
9. *Arbitration costs* - The arbitrator's costs are paid by the party that loses the arbitration. Ordinarily, each party pays their own costs of participating in arbitration. The arbitrator has authority to require a party to pay costs to the other party if the arbitrator determines the initiating party is acting vexatiously.
10. *Contract disclosure* - The arbitrator lodges all arbitrated contracts with the Authority and the Authority publishes a summary of the key terms and conditions. Any arbitrator currently handling a case for negotiating parties has full access to the details of any arbitrated contracts for which at least one of the negotiating parties has been party to over the previous 12 months.

Exemptions from non-discrimination requirements

The safe harbour provisions would exempt the gentailer from most of the non-discrimination regime:

- *Exempt from most non-discrimination principles* - Any gentailer using the safe harbour option would be deemed to be compliant with the principles of the non-disclosure obligations, except for draft Principle 5 (or P5).[35] This principle requires gentailers protect buyer confidential information and not disclose this information to any internal business units that compete with the buyer. In my view, this should apply regardless of the regime applying to the gentailer.

  For the avoidance of doubt:

  - The gentailer would not be required <u>by the Code</u> to provide a cost-based, objectively justifiable reason for discriminating (P1) as final-offer arbitration incentivises this approach anyway.
  - The gentailer would not be required to establish an economically meaningful portfolio of internal transfer prices that reflects its internally traded hedges (P2), as FRAND principles do not require this approach.

[34] That is, if a gentailer appointed an arbitrator from the list for a previous arbitration involving the gentailer, then whoever is the counterparty in the current arbitration has the right to appoint an arbitrator from the list. The next time the gentailer is subject to an arbitration request, the gentailer has the right to appoint from the list.

[35] The draft principles are in the Options paper, Appendix B, p73.

  - The gentailer would not be required by the Code to provide an objective assessment of the risk of trading with a buyer when setting their credit terms and collateral arrangements (P3) as final-offer arbitration incentivises this approach anyway.
  - The gentailer would not be required to make available to any buyers any commercial information relating to risk management contracts made available to its internal business units (P4). Gentailers have incentives to make this type of information available to parties during negotiation to secure their agreement, and to the arbitrator if arbitration is required.
  - The gentailer would not be required to establish, maintain, keep and disclose records that demonstrate its compliance with the standard non-discrimination principles (P6). This is unnecessary for voluntary agreed contracts (the Authority has disclosure requirements for these anyway) and the arbitration process ensures, as best as practicable, that arbitrated contracts satisfy FRAND principles.
- *Exempt from most reporting requirements* - The gentailer would be exempt from the detailed record-keeping, reporting, certification and publication requirements in outlined in paragraphs 7 – 11 in Appendix B.

Arbitration would work well for a subset of OTC products

The Options paper says the negotiate-arbitrate approach may face challenges where there is inherent uncertainty and information asymmetries regarding highly material issues such as future hydrology risk (4.25a). This concern is overdone in my view. Repeated consideration of these issues will result in arbitrators becoming adept at these issues. Further, arbitrators can seek advice from external experts.

The paper says that the negotiate-arbitrate approach is challenging for markets with high-frequency trading as it potentially leads to a large volume of arbitrations (4.25b). The OTC market for super peak and longer duration flexibility products are not particularly high frequency. However, if they become high frequency then participants will have a more informed basis for reaching agreement without arbitration and likewise arbitrators will have more information to quickly make arbitration decisions. Precedents will quickly be established, and the public database of contracts will become more relevant and robust, facilitating voluntary agreements.

5.2 The advantages of the proposed safe harbour

The optional safe harbour approach converts some cons into pros

The Options paper states the arbitration approach could be costly if used regularly, depending on the decisions needed (Tables 5 and 6, pp50-51). However, having the approach available as an option means gentailers will consider those costs when choosing the negotiate-arbitrate safe harbour. Gentailers will only choose to incur additional costs if the additional benefits exceed those costs. As the interests of non-integrated parties is protected by their right to appoint arbitrators (item 7 above), offering the negotiate-arbitrate approach as a safe harbour option will be welfare improving.

The paper states that an issue-by-issue arbitration process is likely to be slow and legalistic (Table 5, p50). These concerns are not so relevant when the arbitration approach is optional, because the arbitrator and negotiating parties have incentives to make the approach practicable and valuable. In my view, non-integrated parties are unlikely to gain great comfort from a set of high-level non-discrimination principles, giving gentailers considerable scope to interpret as they see fit. Concerns about uncertainty and information asymmetries apply under both approaches.

A safe harbour is sensible when considerable judgement is involved

The negotiate-arbitrate approach can be likened to common law. Arbitration decisions will be based on the facts of each negotiation, precedents will arise for dealing with difficult issues, and decisions will evolve as circumstances require. Arbitrations will provide clarity for all parties.

In contrast, relying solely on having non-discrimination obligations in the Code rests on the presumption that regulators have excellent foresight about what will work in hypothetical circumstances. If the high-level principles approach proposed by the Authority proves unsatisfactory, then long delays are likely before it is operating satisfactorily.

The Options paper states the negotiate-arbitrate approach would take longer to implement than the proposal (Table 5, p50). However, the more important issue is which approach will take longer to become effective. Given the divergence of views about how the wholesale and retail markets are performing, the wide scope for interpretation and the inherent information asymmetry, there is no grounds for confidence that adding new principles to the Code will be the end of the matter.

Allowing the negotiate-arbitrate approach as a safe harbour option reduces information asymmetry issues for the Authority. Arbitration decisions will provide information relevant for interpreting their high-level non-discrimination principles, assisting the Authority to specify more detailed guidelines or rules if it deems them necessary. If those rules work well, then gentailers will be more inclined to opt out of the safe harbour.

The negotiate-arbitrate approach is a targeted and proportionate option

The negotiate-arbitrate approach allows a more targeted approach because the contract-by-contract approach means it is easy to restrict it to a subset of OTC products. Item 4 restricts it to super peak products and longer duration flexibility products, which are the areas of concern identified by the Authority. The Authority could add peak products later if it becomes concerned about their availability and price.

The negotiate-arbitrate option is proportionate because the need for intervention (ie, arbitration) will be determined by industry participants on a case-by-case basis, rather than on a broad-sweeping rules-basis by the Authority.

The safe harbour approach is low risk for the Authority

As discussed in section 4, I am deeply concerned about the short-term retail price risks with the Authority's proposal. These derive from the requirement to benchmark implicit contract prices against market trades for comparable products and the prohibition on cross-subsidies. My level of concern depends, in part, on the specifics of that prohibition.

Making negotiate-arbitrate optional addresses the Authority's problem that it is unable to affirm that prices for super peak products are likely to be competitive. If arbitration reduces super peak prices sufficiently to address concerns about cross-subsidies, then 'all good'.[36] However, if it does not address those concerns, then allowing gentailers the negotiate-arbitrate option avoids "forcing" them to raise retail prices to remove cross subsidies. This avoids the risk of material short-term price rises for residential and commercial consumers.

5.3 Negotiate-arbitrate versus other options

If any gentailer elects the negotiate-arbitrate safe harbour, the operation of the regime would provide valuable information about its pros and cons before the Authority considered more intrusive options, such as step 2 in the Options paper. NIRs would be better placed to offer their views on the pros and cons, based on actual experience rather than hypotheticals. Arbitrators would also have valuable insights.

In my view, it is a 'no brainer' to provide a negotiate-arbitrate option as a safe harbour, as surely there is a non-negligible positive probability the Task Force will consider step 2. It would also assist with consideration of even more intrusive options, as discussed briefly below.

Negotiate-arbitrate vs mandatory market-making of super peak products

The negotiate-arbitrate approach is a few steps short of market-making arrangements. Both create incentives for competitive pricing. However, market-making is only suitable for standardised products, and incentives for competitive pricing depend on bid-offer spread obligations. The wider the spread, the weaker the incentive. In contrast, the wider the spread of bids and offers submitted to an arbitrator, the greater the value at-stake for both parties, so the greater the incentive to submit the most credible position.

A key disadvantage with market-making is that it is not a suitable safe harbour option, as no gentailer will provide market-making on a standardised product without other gentailers doing the same. However, if all gentailers indicate they would prefer to market make standardised super peak products, then the Task Force should consider this option rather than introduce non-discrimination obligations.

If market making was adopted for super peak products, the Task Force could retain negotiate-arbitrate for longer duration flexible products and exclude super peak products. Adopting the proposed safe harbour provides the Task Force with more information without restricting its future market-making options.

Negotiate-arbitrate vs mandatory supply of firming (MSOF)

Appendix D in the Options paper outlines the range of matters that would need to be decided if the MSOF option was introduced. It would clearly be costly and complex to design and operate.

[36] Arbitrated contracts influence cross-subsidies through their influence on the prices agreed in negotiated OTC contracts. Arbitrage opportunities mean that prices for negotiated contracts influence prices for comparable market-traded contracts, against which implicit contract prices are to be benchmarked.

As with market-making, standardised firming products would need to be defined. The Options paper states that prices would be set by product buyers (if all bid prices exceed the reserve price) or by the regulator (who sets the reserve price). In fact, as the regulator specifies the offer quantity, it is in effect setting the market price even when the cleared price exceeds the reserve price.[37]

This carries significant price risks for parties required to offer the firming product, as they would not be directly involved in bargaining over prices. The problem for the supplier is that the regulator has no financial incentive to set the right quantities and reserve prices, and it would have minimal independent sources of information to do so.

In practice, the regulator would at times come under intense political pressure to set low reserve prices and large offer quantities, to reduce firming prices. Further, it would be heavily reliant on supply and contract information from gentailers, creating strong incentives for intense gentailer lobbying. In my view, the Task Force needs to carefully consider whether it is a good idea to create a regime with incentives for political and/or producer capture.

In contrast, the negotiate-arbitrate option "contracts out" the price determination decision to parties independent of the regulator. The plurality of arbitrators, and the bespoke nature of transaction-based decision-making, will make it far more difficult for politicians to put pressure on pricing. Further, both the bid and offer side of the negotiation have incentives to provide transaction-specific information.

Negotiate-arbitrate vs mandatory trading of gentailer hedges

Whereas Appendix D presented some detail about a possible MSOF regime, the matters outlined in Appendix C regarding mandatory trading of all gentailer hedges was scant. I would be surprised if it turned out to be significantly cheaper and easier to design and operate than MSOF.

6 Concluding comments

The above analysis argued the underlying problem facing NIRs is that they have poorer long-term price smoothing capabilities vis-a-vis incumbent gentailers. This was not important prior to 2018, as wholesale market prices varied over reasonably short cycles. However, the large and prolonged disturbance to the supply side of the wholesale market changed that.

For many years I have viewed the entry of NIRs as a contest between business models: a contest between gentailers with their large customer base and long-lived generation assets versus the nimbleness of new entrants with new technology and marketing ideas.

When I was a regulator, it was never a case of viewing one model as better than the other, or that the absence of one signalled the market wasn't working. It was up to the market to decide whether one model wins, or they coexist.

[37] This follows from standard microeconomics, that quantities are the dual of prices.

Appendix 1: Interpreting price-cost margins requires care[38]

The Options paper notes there is a large and ongoing gap between ASX hedge prices at Otahuhu and the LRMC of new baseload generation, as shown in Figure 4 on p30 of the Options paper. This appendix explains why the chart is comparing 'apples and oranges.'

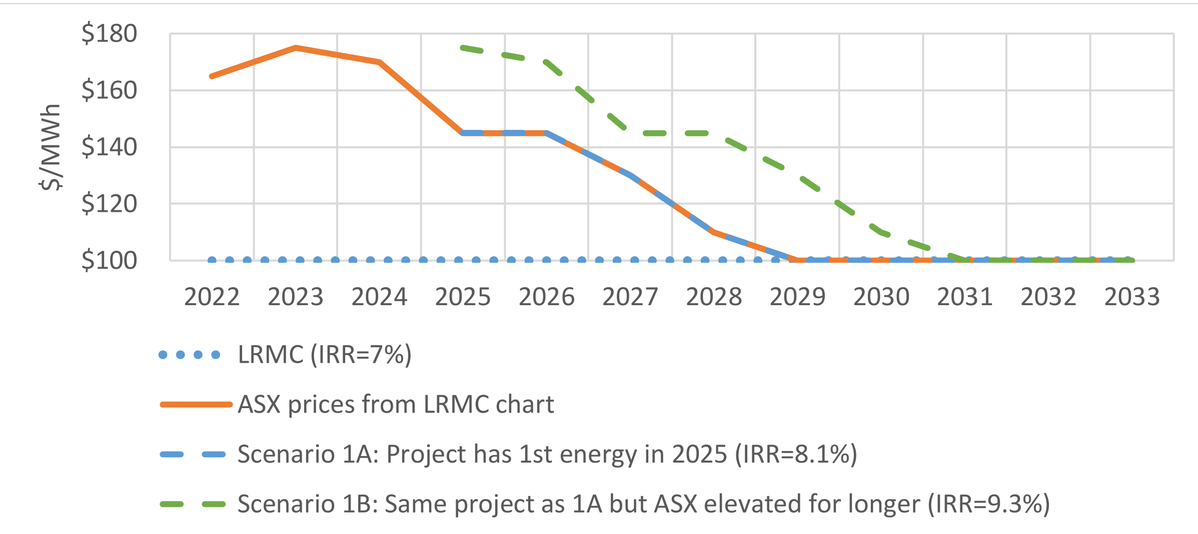
Suppose the LCOE of new baseload generation is $100.[39] LCOE includes a return on invested capital equal to the weighted average cost of capital facing investors. Suppose this is 7% per year. Projects with an internal rate of return (IRR) of 7% just 'wash their face', and their net present value is zero.

According to Figure 2 on page 10, hedge prices in 2020 were nearly $140, dropped to $120 in 2021, then jumped to $165 in 2022 and $175 in 2023. If sustained at this elevated level for the 25-year life of a solar plant, the plant's IRR would be 13.9% versus a 7% cost of capital. An exceptional IRR for generation investment, but this is a naïve scenario.

It takes about three years to find suitable property, design, consent, procure, and build solar farms. With spot prices expected to exceed LCOE in three years, investors are incentivised to act quickly to bring generation into the market in three years. They can be expected to continue doing so until hedge prices equal LCOE.

The orange line in Figure 9 mimics the ASX prices in the previous chart over 2022-2027, and from there, I assume prices fall to $110 in 2028 and equal LCOE from 2029 onwards. The dashed blue line (on the orange line) highlights the prices a plant receives if it produces energy by January 2025. The green dashed line is for an alternative scenario discussed later.

Figure 9: Price paths and IRRs for various investment scenarios



With hedge prices reaching $165 in 2022, suppose investors immediately began searching for a suitable property for a solar farm. Assuming a plant was operational three years later, at the start of 2025, it would earn revenue based on prices from January 2025 to

[38] The contents of this Appendix, apart from the last paragraph on the next page, were written in September 2024, hence assumptions about future hedge prices are outdated and not consistent with those in Appendix 2. However, the core message remains true.

[39] All prices and costs in this example are per MWh.

January 2050. In this case, the plant would earn an average price of $105.20 over its life and an IRR of 8.07%. This is Scenario 1A in the chart.

Consider a second scenario, where market prices remain elevated for two further years, perhaps due to gas and hydro shortages, before declining with the same pattern as for the orange line. As above, assume the project was started in 2022 and becomes operational in 2025. The project earns an average price of $111 and an IRR of 9.26%. This is Scenario 1B in the above chart.

Some investors may already own land suitable for a solar farm and battery and may have completed their design work. Suppose it takes them two years to procure and install their solar systems and connect the farm to the grid. Further, suppose they decided to invest in 2020, reacting to the $140 hedge prices in that year. Their first energy would be in January 2022, generating a 9.92% IRR if prices followed the orange path, as predicted in 2023.

Alternatively, suppose some parties invest in wind farms, which take at least six years from initial property selection to completion. Beginning their planning in 2020, they achieve first energy at the start of 2026. Under the orange price path, the wind farm earns an IRR of 7.60%. The following table summarises the IRRs in the above discussion.

Table 1: A wide range of IRRs are consistent with large price-cost margins

	Scenario A: ASX price path @ 2023	Scenario B: Delayed ASX price decline	Naive scenario: $175 ASX price
1. Solar project 1st energy 2025	8.07%	9.26%	13.90%
2. Solar project 1st energy 2022	9.92%		
3. Wind project 1st energy 2026	7.60%		

These calculations illustrate why three-year hedge prices should not be compared with 25-year cost estimates. A 75% price-cost margin in 2023 suggests an incredibly profitable opportunity, but that is misleading. The margins are far smaller when comparable timeframes are used for both prices and costs, as shown in Table 2 below.

Table 2: Price-cost margins when comparable timeframes are used

	Scenario A	Scenario B	Naive scenario
1. Solar project 1st energy 2025	5.2%	11.0%	75.0%
2. Solar project 1st energy 2022	13.6%		
3. Wind project 1st energy 2026	3.4%		

Charts like Figure 2 on p10 above (Figure 4 on p30 of the Options paper) should be accompanied by another chart (or a table) showing implied 25-year average prices so readers can compare prices and costs with comparable timeframes. Judgments are required to make comparisons, so high and low-price scenarios should be presented, as is done for LCOE. Alternatively, a table of IRR estimates could be presented for a suite of stylised scenarios.

Appendix 2: Estimated increases in household electricity prices

This appendix provides details on the calculations that underpin the figures reported in sections 4.1 and 4.2.

Composition of household electricity price

Let T denote the total household electricity bill, E the energy component and L the lines (transmission and distribution) component. Then T = E + L.

According to the quarterly retail sales (QRSS) measure of household electricity prices published by MBIE:

- T_{18}=29.14
- E_{18}=16.60
- L_{18}=12.54

where the subscript denotes the June 2018 quarter and prices are in cents per kWh.

Separating out generation

The Authority's website (https://www.ea.govt.nz/your-power/bill/) states that generation costs account for about 32% of the total household electricity bill. Letting G denote generation costs, G = 0.32 x T.

As E includes G, let A denote all other energy costs, ie, let A = E – G. Then T = G + A + L. Plugging in the above statistics gives G_{18} = 9.33 and A_{18} = 7.28.

From the QRSS, T_{24}=35.01, E_{24}=21.01 and L_{24}=13.99 in the December 2024 quarter. Define alpha as the generation share of the Energy Component in the June 2018 quarter. That is, let $\alpha \equiv G_{18}/E_{18} = 0.562$.

The details so far are summarised in the table below. The beta parameter is used later below.

Table 3: Summary of data and key parameters

Key parameters					
G as a % of T	32.0%				
E_{18} as % of T_{18} (beta)	57.0%				
	T	E	L	G	A
2018 Q2	29.14	16.60	12.54	9.33	7.28
2024 Q4	35.01	21.01	13.99	11.20	9.81
% increase	20.1%	26.6%	11.6%	20.1%	34.8%

Hypothetical vs actual household prices for December 2024 quarter

Let G^* denote the hypothetical value of G_{24} if escalating generation costs had been fully passed through to household electricity prices. Then the hypothetical total cost for households is $T^* = G^* + A_{24} + L_{24}$. For simplicity, assume the non-generation component of E is exogenous, that is, A_{24} equals 9.81 regardless of the value of G^*.[40]

If generation cost increases were passed onto households, and all other components of the electricity bill increased as they did in the QRSS, then residential electricity prices would increase by $(T^*/T_{24} – 1) \times 100$.

The following table shows the price impact for two scenarios. Scenario A uses the internal transfer price (ITP) Meridian reported to the Electricity Authority for the year ended June 2018/19 and an estimate of the ITP for the year ended June 2024/25.[41] Scenario B uses a simple average of ASX prices for long-dated electricity futures contracts at Benmore and Otahuhu, as of 2 July 2018 and 31 December 2024.

Table 4: Estimated short-term price increases

	Scenario A Meridian ITP	Scenario B ASX Average
2018 Q2	75.82	72.80
2024 Q4	150.24	157.91
% increase in G	98.2%	116.9%
G*	18.48	20.23
A_{24}	9.81	9.81
T*	42.28	44.03
Percentage by which T* exceeds T_{24}	20.8%	25.8%
Increase in household bill	$464.53	$576.24

Note: The ITP for 2024 Q4 is an estimate

These calculations suggest household electricity prices could rise by 21 – 26%.

How long before competitive pressure offsets the initial jump in prices?

Let $\beta \equiv E_{18}/T_{18} = 0.57$. This means $\%\Delta E = \%\Delta T/\beta$, allowing us to calculate an implied value of E under each scenario.[42] The table shows the number of years it would take to reduce E from E^* to E_{24} based on two scenarios for the effect of enhanced competitive pressure:

- 1.1% scenario – this is the rate at which the price of the energy component reduced in real terms over 2013-18, which was a period when retail entry and market share growth were particularly high.
- 2.2% scenario – this is simply twice the previous scenario, to consider the possibility that retail competition is far stronger than has occurred in the market to-date.

[40] Strictly speaking this share should be adjusted for the larger relative value of generation in 2024, however the unadjusted approach provides a reasonable first-order approximation to prices in 2024.

[41] I have estimated 2024Q4 ITP by escalating the 2023Q3 ITP by the half the rate at which the ASX Average increased over that period. The latter increased by 18.8%, so the escalator for the 2024Q4 ITP is 9.9%.

[42] We wish to consider a situation where ΔT is driven entirely by ΔE. That is, $\Delta E = \Delta T$. Then $\Delta E/T = \Delta T/T$, which means $\Delta E/E \times E/T = \Delta T/T$, which means $\%\Delta E \times \beta = \%\Delta T$, or $\%\Delta E = \%\Delta T/\beta$.

Table 5: Estimated time for initial price increase to be offset by competitive pressure

	Scenario A Meridian ITP	Scenario B ASX Average
Percentage by which T* exceeds T_{24}	20.8%	25.8%
Implied % change in E	36.5%	45.3%
Implied E*	28.68	30.52
Years to reach T_{24} for 1.1% scenario	28.1	33.76
Years to reach T_{24} for 2.2% scenario	14.0	16.8

The best-case outcome is that it would take around 14 years for enhanced competitive pressure to outweigh the effect of an initial increase in retail prices.[43] This is under the highly optimistic assumption that competitive pressure is double the strength that it was over 2013-18.

Number of years for break even if hedge prices revert to neutral prices after three years

The following table shows the additional expenditure households incur under the assumption that ASX prices are $137.50 for Year 1, declining to $87.45 for Year 4. This is the neutral price as T^* equals T_{24}, as shown in the right-hand-side column. The table shows that the additional spending over years 1 – 3 aggregates to just over $818.

Table 6: Estimated additional household expenditure

	Year 1	Year 2	Year 3	Year 4
2018 Q2 ASX price	72.80	72.80	72.80	72.80
Projected ASX price	137.50	120.82	104.13	87.45
% increase in G	88.9%	66.0%	43.1%	20.1%
G*	17.61	15.48	13.34	11.20
A_{24}	9.81	9.81	9.81	9.81
L_{24}	13.99	13.99	13.99	13.99
T*	41.42	39.28	37.14	35.01
Percentage by which T* exceeds T_{24}	18.3%	12.2%	6.1%	0.0%
Additional household bill	$409.36	$272.92	$136.48	$0.05
Total cost to consumer	$818.82			

Once ASX prices reach $87.45, competitive pressure is assumed to reduce household electricity spending by 2.2% per year (over and above other factors reducing household electricity bills, such as consumption efficiencies).

The following table shows the number of years it would take for households to save $818, to reach break-even.[44]

[43] Number of years = $\log(E_{24}/E^*)/\log(1\text{-}r)$, where r is the rate at which competitive pressure reduces real the price of the energy component. One scenario assumes r=-1.1% and the other assumes r=-2%.

[44] Number of years = $\log([P\text{-}S]/P)/\log(1\text{-}r)$, where r is the rate at which competitive pressure reduces the real price of the energy component.

Table 7: Estimated number of years to reach break-even

Total expenditure in 2024 from QRS	$2,343
Additional HH expenditure	$409.36
Year 1 HH expenditure (P)	$2,752.36
Savings goal (S)	$818.82
Competitive pressure effect on prices (r)	2.2%
Number of years to reach saving goal for 2.2% scenario	15.87

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