Level Playing Field Measures

Submission to the Electricity Authority

7th May 2025

1 Introduction

We welcome the opportunity to make this brief submission and to contribute positively to the debate over competition concerns raised by the collective market share of our four largest gentailers.

Questions on this submission can be directed to Greg Sise, Energy Link Ltd.

2 Outline

We agree that independent retailers face barriers to entry that are not faced by gentailers, and that level playing field measures are required to allow this market segment to grow at a rate and to a market share that will ensure there is continuing downward pressure on prices, and innovation in the retail space.

We agree that Option 2, non-discrimination measures, is a good place to start, however we do not believe there needs to be a firm escalation path to other options. It would better to learn from the experience gained with non-discrimination measures and work from there if required.

We submit there is currently insufficient evidence to prove there is insufficient competition in building new generation and that the Authority should monitor this segment over the next two to three years for any signs this might be the case.

We submit that, when it comes to keeping downward pressure on prices, the cost of new generation is the bigger issue, with LCOEs of new generation having increased 50% - 80% since 2020/21, for gentailers and independent power producers (IPPs) alike. With shrinking gas supply pushing gas prices up, electricity prices have risen, but rapidly rising LCOEs are unable to counteract this rise to the extent they could have only a few years ago.

We submit that the shrinking firming generation segment is a bigger issue than lack of competition in generation, and that the Authority should take measures to (i) increase transparency around the cost and availability of firming, (ii) to facilitate and promote an increase in demand-side response that comes with price signals, and (iii) to ensure there are no barriers to new firming alternatives entering this segment, that are not faced by the gentailers.

3 Response to Questions

Q1. What are the benefits of vertical integration between generation and retail? Do you have any evidence to better specify and quantify these benefits? In particular, we are interested in benefits that would be realised by New Zealand's electricity consumers.

The four large gentailers provide benefits to the market which are often forgotten when the market is under stress. The following are in addition to the benefits mentioned in the LPF Options paper.

1. The NZ market is energy-only, so there are no capacity payments in the Code, but gentailers provide this capacity. A good example is the reported negotiations between the four gentailers to keep the Rankine units running through the 2030s, and possibly beyond, which are likely to lead[1] to contracts that include fixed (capacity) and variable (energy) payments to Genesis Energy.
2. The gentailers are now developing capacity mechanisms for demand response, e.g. the fixed annual payments made to NZAS for making demand response available at Tiwai.
3. Gentailers provide the majority of the peaking and firming capacity and energy, with capacity relevant to short-term peaks, and energy relevant to dry years. As the market closes in on 100%RE, this firming

[1] In our opinion.

plant will operate progressively less, which will make it progressively less economic based purely on revenue from generation, requiring support from gentailers to keep it in the market. Ultimately, and perhaps already in some cases, it will only be viable as part of a much larger, vertically integrated portfolio, while benefiting all consumers.

4. Gentailers manage hydro storage conservatively with respect to shortages in the current year and with respect to ensuring storage recovers going into the next year.

Looking at the four items above, we can see that the gentailers currently provide the majority of the resource and capacity that collectively ensures the lights stay on.

Consumers, and politicians on their behalf, are unhappy when the price of electricity rises, but the message that the electricity sector consistently gets is that the lights must stay on, regardless of all other considerations. This creates a conflict for gentailers, because there is an obvious negative correlation between security and price: low-low prices and highly secure electricity supply are mutually exclusive.

Conservative hydro management is one of the results of this conflict, which means that prices rise rapidly when storage falls below expected levels, and vice versa. Through vertical integration, gentailers have the incentive to keep additional resources available to supply their customers and cover hedges.

It is important to note that vertical integration, where retail demand is approximately matched with generation (plus hedges), reduces incentives to raise the price of generation offers to increase profits, because generation that is effectively hedged, either by customers' demand or by hedges, is ideally offered at or close to SRMC.

So vertical integration reduces incentives to use market power. The development of any measures which reduce vertical integration need to take into the consideration the possibility that gentailers could become significantly long on generation (net generators), which could lead to a greater issue with market power than might be the case now.

Q2. Do you agree with our description of the competition concerns that can arise from the combination of Gentailer vertical integration and market power? Why/why not? Do you have any evidence to better specify and quantify the competition risks of vertical integration?

Independent retailers

We agree that independent retailers cannot compete effectively with the gentailers, and face barriers not faced by the gentailers, evidenced by the absence in growth of ICPs supplied by this market segment since late 2020 (Figure 2 on page 21). This is the segment which has tended to drive innovation in the retail space since 2007[2], and to put additional downward pressure on prices, but it is now hamstrung by having to contract (hedge) at prices that follow futures prices, compared to gentailers that have weighted average hedge prices which are averaged over longer periods and over a greater variety of instruments including futures, OTC hedges, and existing and new generation[3].

Figure 2 appears to show the aggregate market share of small and medium retailers sitting at about 15% of all ICPs, which we assume includes companies like Nova. If we exclude smaller gentailers, then the aggregate market share (by ICP) of independent retailers is sitting at around 13%, after 15 odd years. Arguably, a thriving independent retailer segment would (a) ideally be at 25% or greater, and (b) have reached this point much earlier than 2020.

In respect of (a), we cannot offer empirical evidence, but we note that if the aggregate market share of the top 10 independent retailers was 25%, taking ICPs away from gentailers in proportion to their respective market

[2] Free hours of power, spot electricity for residential consumers, club membership, and much improved TV ads, to mention a few.

[3] A falling market would produce the opposite effect – independent retailers would be contracting at lower prices than a portfolio averaged over a number of years.

shares, then the HHI[4] would be around 1,500 which is considered to be the top of the range for a competitive market. Based on Figure 2, the HHI is currently estimated to be between 1,800 and 2,000, which reflects moderate concentration in the retail market.

Going beyond 25% would further reduce the HHI until potentially reaching a low of around 900 when the total share of the independent retailer segment reaches 65%.

But going beyond 25% also increases the risk that gentailers will either decide to retire fossil-fueled thermal generation earlier than would otherwise be expected or desirable, in terms of security of supply, because it is no longer economic to retain an integrated portfolio, or exert market power as noted in our response to Q1.

Going beyond 25% potentially exposes the market to the negative impacts of concentration in generation. Put another way, reducing vertical integration could actually make market power more of a problem. As a result, we urge the Authority to be careful about facilitating 'open slather' in retail, unless there are actions taken to mitigate market power in generation.

IPPs

After a long period of little or no demand growth, and the threat of Tiwai closure hanging over the market, we are now in a "new era" of growth in renewable generation, on the assumption that demand grows. This is assumption is probably not unrealistic, but history shows that forecasting demand involves a high degree of uncertainty: one only has to look at 2024 to see how tenuous the growth assumption can be[5].

Even if demand does grow, then timing of growth is highly uncertain: when will EV demand take off? Will there be more closures of industry, for whatever reason? Will population growth continue at recent rates? Will energy efficiency improvements offset demand growth? And so on and so on.

Notwithstanding this uncertainty, one only has to look at Transpower's connection queue to see how much interest there is in building new generation in NZ, with much of this interest from local and international developers and investors that are not associated with the gentailers.

There appears to be no shortage of capital that would make its way into generation investments in NZ if it could. NZ is currently seen as a good place to invest in renewables.

The question of whether IPPs face barriers to entry not faced by gentailers, or not, cannot be reliably answered yet, because we are less than one year into the post-Tiwai-closure era, and there is insufficient data with which to draw any firm conclusions. There is anecdotal evidence that some IPPs find it difficult to obtain suitable PPAs, but those that are out there doing it already, e.g. Lodestone Energy, appear to have strategies that will work in NZ and allow them to build more generation and to grow.

As a result, we do not agree with the Authority's view that "the limited growth of competing … generators suggests there may be barriers to entry and/or expansion in … generation."[6] To be specific, we do not believe there is sufficient evidence to justify this view in respect of competing generators. Furthermore, it would be totally unrealistic to expect there to be more independent generation by now given that demand has not grown since the mid-2000s and that if Tiwai had closed, no new generation would be required for several years yet.

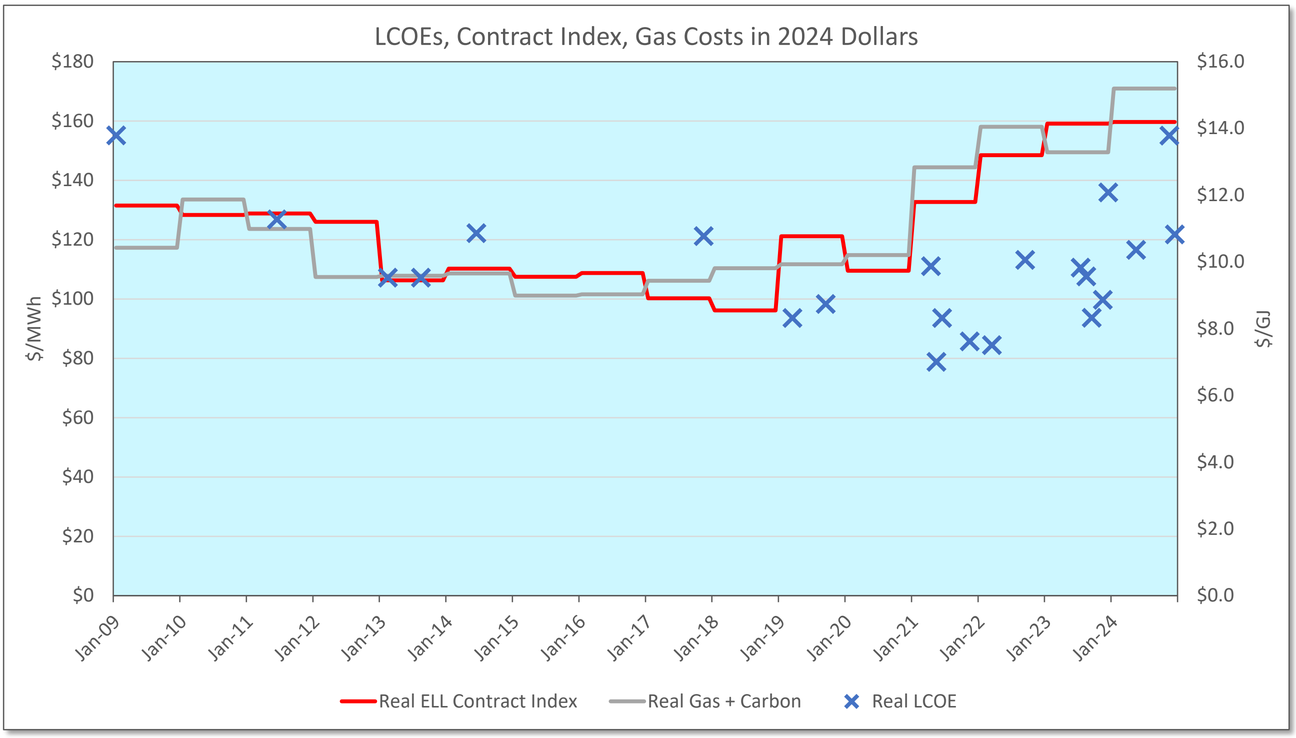
But this does not mean that we believe the Authority should do nothing in respect of generation and the gentailers. At the least, this issue needs close monitoring, and potentially also development of options that could be implemented quickly and efficiently if over the course of the next two to three years it does turn out there is a competition issue in this segment.

[4] Herfindahl-Hirschman Index. The relevant calculations use some simplifying assumptions.
[5] Demand initially looked to be significantly up on 2023, only to end up on 31st December about 0.6% up on 2023.
[6] Section 3.15. Reference to retailers removed.

In addition, if independent retailers are able to obtain firming contracts at competitive prices, they will be more able and willing to enter into PPAs with IPPs. So improving the competitive landscape for independent retailers could also assist IPPs.

In our view, the much bigger issue in respect of generation is the large increase in the cost of building, owning and operating new generation (usually expressed through LCOEs[7]) since 2019 which, although difficult to generalise on, is currently in the range of 50% - 80%.

We cannot reconcile Figure 4 (page 30) in the LPF Options paper with actual data points relevant to LCOEs in NZ. The following chart, which is all in 2024 dollars, shows estimated LCOEs of projects actually built in NZ since 2009, using our standard LCOE methodology[8] and data in the public domain for solar, wind and geothermal projects. Four of the points are calculated using early announcements concerning projects that were eventually built, and these are in the range of \$79 to \$107 and feature in 2013 and 2021.



Over the period shown in the chart, the cost of capital fell through to 202/21 but has risen since due to the post-covid inflation spike, however, we have not included this change in the cost of capital in the LCOEs: if we had, then the fall and then rise in LCOEs would be even more dramatic.

The LCOEs shown may or may not match exactly on each project, but the overall trend is clear: generally downward from 2009 to 2020/21 then sharply upward thereafter, ending at between \$120 and \$155 in 2024.

Also shown on the chart are:

- the electricity OTC contract index calculated by Energy Link since 2009, referenced to Haywards, which represents longer-dated contracts and which (on average) trades at a premium to ASX prices;

[7] Levelised cost of energy, which is defined as the constant average annual electricity price attained by the plant over its lifetime that just achieves target return on investment after covering all cash costs.

[8] Despite being in the public domain, there are LCOE inputs which are typically not disclosed, notably including inflation assumptions, and cost of capital including gearing ratios and the costs of debt and equity relevant to each project.

- MBIE's annual average wholesale gas price with the cost of carbon added (righthand vertical axis in $/GJ).

The chart shows the high correlation between electricity contract and wholesale gas prices, which is caused by the use of gas for thermal generation, along with the influence that thermal generation has on the value of water stored in hydro lakes.

In the short term, the rise in the cost of gas explains most of the increase in the price of electricity.

The future of Tiwai was confirmed in May 2024, so if LCOEs had remained at the levels reached in 2020/21, the 'race to build' would be bringing prices down already.

But the chart shows just how much LCOEs have increased. Furthermore, the increase in LCOEs may have further to run, depending on a range of factors.

The uncertainty caused by the increases in LCOE has probably also delayed the building of some projects. For example, a developer will make an early estimate of the LCOE of a project and then updates this estimate as the project progresses toward FID[9]. If LCOEs are on a steep upward trend, then the developer could have a project which initially looks to be 'bankable'[10] but then becomes 'unbankable', which triggers another round of equipment sourcing, repricing, and so on.

Assuming it is unlikely gas prices will come down significantly, to bring prices down the market needs to increase supply. This could happen to a limited extent if there is currently insufficient competition and changes are made which increase competition. But lower prices simply reduce returns to new generation, which turns investors off, unless LCOEs can be reduced.

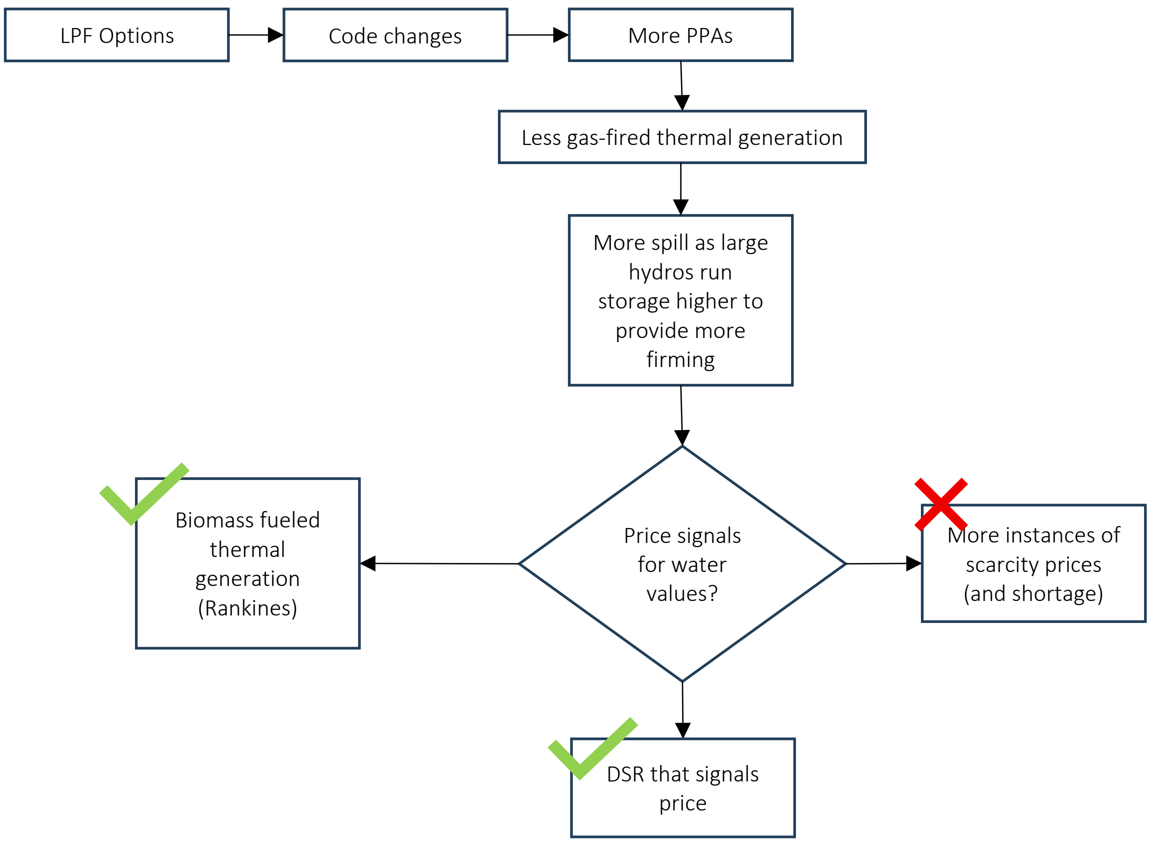
Returning to the LPF Options paper, the area of greatest concern is the ability of IPPs to successfully execute power purchase agreements (PPAs) with the widest range of potential counterparties, including larger consumers, independent retailers and gentailers. Solar and wind generation output profiles, the typical purview of IPPs, do not match the demand profiles of larger consumers and independent retailers, and the vast majority of larger consumers don't want to manage a portfolio of hedges including a PPA, so IPPs must either be a minor part of the hedge portfolio of an independent retailer, or sell to a gentailer (which could be as a PPA or an entire generation project).

This potentially gives gentailers a high degree of influence over the fortunes of IPPs.

Up until quite recently, the gentailers chose to build their own generation, but this has changed, starting with Genesis Energy's PPA with the Waipipi windfarm which commenced late 2020. If this trend continues, then the potential barriers faced by IPPs may not develop to any significant extent. This should obviously be monitored.

But let us for a moment assume the Authority goes ahead with measures to make it easier for IPPs to contract their respective projects, and that the rate of build increases substantially: the following is a scenario that could play out. In the flow chart, it is assumed the market accelerates toward 100%RE relative to recent progress.

[9] Final investment decision.
[10] Refers to the need to secure debt funding from financiers.



First, assume that Code changes lead to more generation being built so the renewables share accelerates its upward trend. This would cause the gas-fired thermals to run less, and let's also assume early retirement, which is more likely if the gentailers have lower market share as the independent retailers collectively increase market share.

The large hydro reservoirs would be run higher through summer so they can provide more firming during dry autumn and winter periods, but also resulting in more spill.

What would provide pricing signals the large hydros could use to calculate water values? Throughout the history of the market, and still the case today, thermal generation collectively prices the alternative to hydro generation. But as the thermal segment shrinks, we are left with a much smaller pool of thermal generation, and with DSR (demand-side response).

Today, coal provides a price signal for water values, but biomass is still some time away at Huntly. Genesis Energy has said that Huntly could operate until the 2040s, but after that, this pricing signal could be gone unless Huntly's life can be, and is extended.

DSR that provides price signals is virtually non-existent today, and will take time to develop to any meaningful extent.

Scarcity prices that result from actual shortages can provide strong price signals to water values, either directly when they occur, or through the threat of occurrence. However, as noted in the response to Q1, the highest priority of the sector is to avoid shortages, so scarcity prices cannot be relied on to provide signals, either by actually occurring or via the threat of occurrence[11].

[11] If the threat of occurrence is to be credible, then the probability of actual shortage must be significantly non-zero.

In summary, if the move towards 100%RE accelerates due to a Code-change-triggered increase in the rate of build, then we could find the market reliant on a very small pool of thermal generation, with few or no price signals from consumers (via DSR), and increased potential for shortage and scarcity prices, for use in calculating water values.

It is not certain that this scenario would play out, but simultaneously reducing the retail and generation market share of gentailers could have unintended consequences, and the scenario above is one of them. As a result, we urge caution. Yes, independent retailers need a level playing field, but when it comes to generation, and given the current lack of evidence, the more pressing issue is the cost of building new generation, not the possibility there is not enough competition in this segment.

Firming

The flow chart above fundamentally expresses the potential dynamics of a shrinking firming segment, but the corollary of this is that the firming segment needs to grow. As noted, biomass, and renewable fuels in general, including biofuels and green hydrogen, could help to grow this segment, or at least halt shrinkage.

Also noted is the need to grow DSR, but in a way which provides price signals for new generation, i.e. in the same way as scarcity prices do (in theory) but without unscheduled demand curtailment. This topic has received a lot of attention in the last few years, but little has changed to promote DSR, so urgent attention is needed.

One Code-related measure that we believe would help grow the firming segment is to promote or mandate greater transparency in the pricing of firming. This has some similarity to the measures addressed in the LPF Options paper, but motivated from an entirely different point of view: not from lack of competition in generation, but from the need to develop the firming segment.

Measures that should be taken include:

1. developing transparency in firming pricing and availability, e.g. through disclosure of the price at which firming is provided internally within each gentailer, and externally to other parties, and disclosure of the amount of firming capacity that is uncontracted at any point in time;
2. disclosure of gentailers' forecast firming capacity over a period of time, e.g. to match the duration of the ASX futures forward curve;
3. implementing Code changes or other measures to incentivise greater supply of DSR;
4. otherwise ensuring there are no barriers to new firming alternatives entering this segment, that are not faced by the gentailers.

If the firming segment can be grown by new players, or even kept from shrinking further, this would help to alleviate competition concerns by giving IPPs more potential counterparties with which to execute PPAs.

Q3. To what extent does vertical integration of smaller gentailers, such as Nova and Pulse, raise competition concerns? Should these smaller gentailers be subject to any proposed Level Playing Field measures?

We do not have a view on this question.

Q4. Are there other specific areas (other than access to hedges) where Gentailer market power and vertical integration are causing competition concerns?

As noted in our response to Q2, the shrinkage of the firming market segment is a looming issue as the market moves closer to 100%RE, which is of concern. But this is not the result of vertical integration or market power, but rather the result of renewable generation taking a greater share of the total market

Q5. Do you agree with our preliminary view that the evidence indicates there may be good reasons to introduce a proportionate Level Playing Field measure to address the competition risks in relation to hedging/firming? Why/why not?

In respect of independent retailers, we agree.

In respect of IPPs, we can hardly disagree with the statement that "the gentailers that own critical flexible generation resources should treat all businesses that need supply from that generation fairly" but, as noted above, we don't believe there is sufficient evidence at this point in time to suggest there is an issue, at least not in the way that it is presented in the LPF Options paper.

Q6. Have we focused on the right Level Playing Field options? Are there other options that we should add or remove to the list in paragraph 4.1?

No comment on this question.

Q7. Are there any other important factors we should consider when identifying options (see paragraphs 4.2 to 4.5)?

As noted in our response to Q2, a fundamental issue the market is facing is the shrinkage of the firming segment (hydro, thermal) relative to the baseload sector (geothermal, wind, solar). The LPF Options paper takes this as inevitable, and focusses on how perceived impacts of market concentration and market power can be mitigated and managed.

We believe it is critically important to consider how this shrinkage can be avoided, by allowing other forms of firming to develop, and the options considered need to take this into account.

Q8. Are there other key features, pros or cons we should consider in our description of the four Level Playing Field options?

As noted in our response to Q2, the issue of water values is critical. In our current hydro-thermal market the value of water is highly impacted by the supply and price of thermal fuels, natural gas in particular. Each option needs to consider how they would impact on water values, and the behaviour of the major players in the largest segment of all, hydro generation.

Q9. Have we identified the right criteria for assessing Level Playing Field options (Figure 6)? Is there anything we should add or remove?

Under Competition, Reliability, Efficiency we suggest the criterion "Impact of the option on the market behaviour of the major gentailers" should be added explicitly.

Under Competition, Reliability, Efficiency we suggest the criterion "How would large amounts of new generation built by new entrants impact reliability" should be added explicitly.

We believe these two criteria should be added so that unintended consequences are minimised. For example, if large amounts of new renewable generation are built by others, would this lead to early retirement of thermal plant that is currently available for firming, putting the market at greater risk of shortage during dry periods?

The gentailers collectively have many decades of experience building and operating a variety of generation technologies in NZ, honing strategies to ensure reliable supply. But if gentailers were to stop building tomorrow and new entrants built all new generation instead, would their location low on their respective learning curves reduce the overall reliability of supply?

Q10. Do you agree with our application of the assessment criteria (Table 5)? Are changes needed to the colour coding or reasoning?

We agree in respect of hedging for independent retailers, but we believe most IPPs[12] do not want to execute firming contracts with gentailers, as this forces them into portfolio management as a retailer.

IPPs generally want one PPA per project, as a generator. This could be with a gentailer, but it could be with an independent retailer if independent retailers have access to appropriately priced firming contracts: this is where the emphasis should be.

Q11. Are there any other material benefits or risks that should be considered (but are currently not) in our assessment of options?

See our response to Q9.

Q12. Do you agree with our selection of non-discrimination obligations as our preferred Level Playing Field measure? Why/why not?

We agree these are a good place to start in respect of independent retailers.

Q13. What are your views on our proposed roadmap for the implementation of non-discrimination obligations?

Nothing to note.

Q14. Which products should any non-discrimination obligations apply to? Should all hedge contracts be captured, or should the rules be focused on super-peak hedges only? Are there are other interactions between Gentailers and their competitors which would benefit from non-discrimination rules?

Ultimately, independent retailers need a combination of baseload, peak or super-peak, and tailored firming contracts specific to one or more large consumers. For mass market residential customers, baseload plus super-peak is a good mix, but for mass market SMEs baseload plus peak could be better.

Large consumers have their own, widely varying daily-weekly-monthly demand profiles, which could require a mix of baseload and non-standard firming contracts.

Therefore, ideally all hedging with independent retailers should be on as close to a non-discriminatory basis as possible, noting that non-standard firming contracts can pose issues.

We do not have any view on whether this is currently feasible, but it might ultimately become feasible as experience is gained with baseload and super-peak or peak contracts in the first instance.

Hence, we submit that the measures should apply to baseload and super-peak contracts initially.

Gentailer hedging for mass market and C&I[13] sectors can be markedly different. Mass market customers tend to be hedged by a portfolio including generation, futures, FTRs, OTC hedges, but offers to C&I customers may be based purely on ASX futures pricing, because the successful party (gentailer or not) may hedge the resulting C&I contracts only with futures traded once the outcome of RFPs or tenders is known.

If C&I hedge contracts are included, then gentailers may simply stop offering contracts to C&I customers because they would be obliged to disclose their pricing to competing independent retailers, and end up simply being the 'middle man' caught between futures and a competitor.

[12] But not all, as evidenced by Lodestone Energy.
[13] Commercial and industrial.

Q15. Do you have any feedback on the indicative draft non-discrimination principles (and guidance) set out in Appendix B? Without limiting your feedback, we would be particularly interested in your views on the following questions:

It is not clear how two business units within a gentailer would have a risk management contract in place between them, e.g. who are the contracting parties?

Principle 1 mentions a cost-based reason but not a risk-based reason, e.g. when two parties request pricing for identical contracts, but one is assessed as having higher counterparty credit risk. Should this be added, or is cost-based intended to include the cost of risk?

Q15a. Have we got the level of detail/prescription right? For example, do you consider that the principles and guidance will lead to economically meaningful Gentailer ITPs being put in place? What would be the costs and benefits of instead applying a more prescriptive ITP methodology?

See response to Q15.

Q15b. How far should the allowance in the principles for different treatment where there is a "cost-based, objectively justifiable reason" extend? Do you agree with the guidance that this allowance should not be extended to volume (at paragraph 13 of Appendix B)?

Non-discrimination measures will incentivise gentailers to introduce (if they haven't already) an internal transfer pricing regime which varies with time of day, time of week and time of year. An obvious example is a transfer price that is uniform across all periods in a year – an independent retailer would then have the incentive to cherry pick customers whose demand is skewed towards periods of the year when retail prices are higher than the average retail price, e.g. winter-centric or daytime load.

Focussing on peak periods, given the developing shortage of firming capacity, gentailers may have limited capacity constraints that would incentivise them to update their transfer prices as they lose customers to competing retailers. If this is a type of volume-based change in pricing, then we do not agree that volume should be excluded.

Q16. Do you agree that escalation options are needed if principles-based non-discrimination obligations are implemented initially? Why/why not?

To have any teeth, these should ideally be clearly indicated for implementation if certain milestones and goals are not met, yet this is probably very difficult to do because implementing non-discrimination measures is likely to produce learnings which could modify further options.

Perhaps it would be preferable to implement Option 2 and give it the best chance of succeeding?

Q17. Are prescribed non-discrimination requirements and mandatory trading of Gentailer hedges via a common platform suitable escalations given the liquidity, competitive pricing and even-handedness outcomes we are seeking? Why/why not? What alternatives would you suggest (if any)?

See response to Q16.

Q18. What costs and benefits are likely to be involved in setting more prescriptive regulatory accounting rules which detail how ITPs should be calculated? What would be appropriate triggers for introducing more prescriptive requirements for ITPs?

As noted in our response to Q15b, prescriptive rules would need to allow for a range of adjustments to transfer prices as a gentailer's portfolio position changes over the course of each year, potentially in response to competition. Other obvious circumstances that could require repricing include major generation outages.

Q19. Do you have any views on how the non-discrimination requirements should best be implemented to ensure that Gentailers are no longer able to allocate uncontracted hedge volumes to their own retail function in preference to third parties? What are the key issues and trade-offs?

No views.

Q20. Do you have any views on the triggers for implementing the stronger regulation proposed in our roadmap?

No views.

Q21. Does our proposed approach to implementing non-discrimination obligations (as set out in the roadmap in Figure 7) sufficiently address the underlying issue that originally led to MDAG recommending virtual disaggregation?

No comments.

Q22. Do you have any views on whether virtual disaggregation provides a useful response to the competition risks we have identified (relative to the proposed roadmap) and, if it does, how it should be best applied?

No comments.