Wholesale Market Review

Submission to the Electricity Authority

December 2021

1 Introduction

We welcome the opportunity to make this submission and to contribute positively to the debate over the wholesale electricity market. Questions on this submission can be directed to Greg Sise, Managing Director, Energy Link Ltd, at 03 477 3572 or greg.sise@energylink.co.nz.

The papers issued by the Authority are very detailed and we only want to make a few general comments. The majority of our submission concerns issues that were relatively lightly covered in the review:

- oversight of the gas market – section 3;
- the hedge market – section 4;
- the impact of carbon prices on electricity – section 5.

Section 2 provides three comments on matters of particular interest to us.

2 Comments on the Detailed Analysis

The following comments are in no particular order.

2.1 Water values in times of market stress

In terms of water values over the review period, we make the following observations:

- the Authority's model (which uses DOASA) may give different water values to those calculated and used by generators, even with the same inputs as the generators' models, due to different optimisation techniques and tuning;
- even using the same model, the water value inputs could be quite different, e.g. looking into an increasingly uncertain future (in terms of fuel supply), generators may be more concerned about fuel price risk and fuel shortages than the Authority;
- each generator could have their own, different perception of risk, and hence they could all have different inputs to essentially the same optimisation problem.

There is a more fundamental issue here, however. We talk about water values as if generators should price their offers based purely on water values. This works fine in the modelled world, but in the real world a generator might calculate water values for the week on Monday morning, only to find that the inputs change during the week, e.g. other generators don't behave the way they were expected to behave.

It's fine to think of water values as setting a price for water (they are a value, after all), but it's probably more realistic to think of the water value optimisation providing a matching GWh quantity for the week or the day, that a generator might then set about targeting. The generators' spot traders would take these GWh targets and price in a way which sells this quantity of energy. This approach allows water values to work in the short-term while preserving information about the longer term.

For example, let's suppose the market is under stress, with lowering lake levels, and that Pukaki's water values are calculated on Monday assuming Huntly will offer at $100. But then if Huntly offers at $200 on Monday, Meridian has a problem in that it could over-generate just when it is trying to conserve water. So, the trader might increase the offer to $250 to avoid running the lake down further than the target: in this case, $50 could be an arbitrary margin that is hopefully enough to allow for fluctuations in Huntly's offer prices around $100. Genesis sees this, but its trader knows that there is insufficient fuel available to run so hard, so they put their offer up to $300. Meridian is then concerned about being dispatched ahead of Huntly, so they increase the offer to $350, and so on and so on until eventually one or the other party gets to a price they are prepared to run at given the new information that actual trading provides.

This simply a process of price discovery which could take place in any market, but in the electricity market it tends to have the biggest impact on prices when the market is under stress, and it can result in hydro generators being on the margin at prices that are higher than the thermal offers they are trying to "out-price", by a margin which is large enough to reduce the risk of being "over-dispatched" but which appears arbitrary, as in "Why is generator X offering $400 when Huntly is generating at $300!!???"

It would also be possible for Pukaki generation offers to be reduced in quantity to avoid over-dispatch, but then this 'missing quantity' is not available to be dispatched if it is unexpectedly required, e.g. if a unit trips at Huntly.

When behaviour like the above is observed, it may appear to be overpricing, whereas it may simply be an attempt to maintain a hydro generator's desired position in the generation stack.

2.2 Water Values Generally

"None of the generators' offers appear to be related to the DOASA water values.", Table 2

This doesn't surprise us. We have not used DOASA, because we have our own model (*EMarket*) with water values developed progressively since 1997 to work well in New Zealand conditions. But we note from section 5.61 that DOASA is an implementation of the SDDP algorithm. We haven't used SDDP either, but we have over the years seen the water values and results produced by SDDP when used by experienced modelers, and they seemed to bear little resemblance to water values that one would expect for NZ.

Particular reservoirs also have their own specific operating policies that may override what we typically think of as water values in the optimisation sense, e.g. Manapouri and Te Anau must be operated in line with the Guardians of the Lake; Taupo is operated to achieve a minimum storage value December-January, which is likely to reflect a risk-adjusted water value.

Even with our carefully calculated and calibrated water values, when we run back-casts to match the market, we still find long periods where prices appear to depart from water value-based prices, for no apparent reason. Maybe a contract was in place that altered behaviour, maybe not – we simply don't know based on publicly available data. 2020 was a particularly difficult year to back-cast, which we think may be due to unusually dynamic, and changing assumptions for demand in generators' water value algorithms.

The purpose of making this comment is to further highlight how difficult it can be to match water values from an independent model to those calculated by market participants.

2.3 Gas Contract Length

"Most gas for generation is bought through long-term contracts", section 4.24.

Exactly what 'long-term' means is not specified, but it does suggest that most gas is contracted for many years at known prices and in known quantities. This might have been the case in years gone by, but it is no longer true, or at least not for all participants. This particularly applies to Contact Energy, which is not a participant in the upstream gas market.

Based on public disclosures, some contracts signed with OMV and others do span multiple years, but volumes are contingent on gas deliverability. Other contracts appear to be for a matter of months. There is an obvious need for more flexible gas contracts as thermal generation becomes more volatile, and the implication for the electricity market is that gas prices will become more volatile as contracted terms become shorter. Flexibility may also come at a premium over and above truly fixed contracts, and this issue is covered (albeit indirectly) in section 3 below.

3 Gas Market Oversight

The Authority has correctly identified gas supply shortages as an underlying cause of high prices, and correctly stated that electricity generators (who find themselves short of gas) compete with major industrial users for gas. Economic theory says that when the supply curve retracts so that it no longer intersects the demand curve, then the market price will be bid up by consumers so that gas is allocated to the highest value use, which is typically electricity generation ahead of industrial users.

This is exactly what happened when major gas users could not find gas contracts at prices that allowed them to cover costs, and what drove Methanex to close two production trains and sell to Genesis. It also drove Genesis to increase its purchases and use of coal for generation.

The gas market is 30% larger than the electricity market (consumption of 755 PJ for 2017 to 2020 inclusive, versus 575 PJ for the same period), and gas prices flow through to gas consumers directly, and to electricity consumers directly (through the offers of gas-fired thermal generators) and indirectly, through water values[1].

A review of the wholesale electricity market can therefore not be complete unless it also includes a review of the wholesale (upstream) gas market.

It is not the Authority's role to review the gas market, but a review was carried out earlier this year by the GIC. Some relevant extracts from this report are listed below.

1. "Producers have some limited ability to adjust their level of production in a gas field once operational, but only within certain limits. This means it is difficult to significantly alter production rates in a field on a short-term basis, and consequently, production is not incentivised by short-term price signals. Storage can provide a degree of flexibility if it is filled in advance of need."
2. Estimates made for GIC are that 50 PJ – 100 PJ per annum will be the only supply remaining in 2030, falling to 26 PJ – 50 PJ in 2050: unless existing gas market participants convert to producing green gases, which mean that natural gas extraction is an industry entering its sunset phase.
3. GIC has assumed that electricity will be 100% renewable by 2030 and therefore will not require gas.
4. Ongoing investment in field development is required to ensure gas is available.
5. The cost of capital invested in extending gas reserves is increasing due to uncertainty about the timing and extent of reductions in gas demand, shrinking sales, and uncertainty about the policy and regulation applying to upstream gas.
6. Current committed arrangements do not appear to be sufficient to cover the large volume of thermal fuel support required for dry winters over the transition period.
7. A Gas Transition Pathway is recommended, eventually leading into a broader energy strategy.
8. There is a need to develop and improve commercial arrangements for gas supply to generators.
9. There is a need to develop the arrangements around Methanex's role in the gas market, especially in regard to demand response.

[1] Refer to our presentation to MDAG on 26th July 2021.

10. “Unlike with many parts of the electricity system, the gas production sector does not normally operate to ‘N-1’ security (where the system is planned to remain operating satisfactorily if a facility falls out of service).”

The upstream gas market is not only larger than the electricity market, but also more concentrated, with 75% of all production produced by two companies: Todd Group and OMV NZ. Greymouth Petroleum, Beach Energy and Genesis Energy make up most of the remaining 25%.

The GIC’s review does not once mention competition in relation to the upstream gas market. It mentions cost in many places, but never in the context of whether wholesale gas prices do, or are likely to reflect cost. These two facts strike us as rather odd given the level of scrutiny, in respect of competition and cost, applied to the electricity market, which is both smaller and less concentrated than upstream gas.

To be clear, we are not accusing gas producers of selling gas above its cost of production, as we do not possess the information that would be required to make an accurate assessment. But the gas market is clearly going through a difficult transition, and we are saying that a greater level of scrutiny could and should be applied to the upstream gas market, in contrast to the light-handed regulatory model that it currently operates under. In the worst case, if shortages continue due to a lack of investment, then gas prices could be set well above what would be considered a reasonable cost in a fully competitive, well-supplied market, and instead be bid up to much higher prices by gas consumers. The cruel irony is, that the electricity market would no doubt remain under close scrutiny due to the resulting electricity price increases.

In a market which has such a high level of concentration, and potentially low level of competition, there must be doubt as to whether the incentives are strong enough to drive the level of innovation required to make beneficial changes to physical facilities and commercial arrangements in support of the transition away from fossil fuels. Without the incentive to innovate, the incumbents may simply price gas higher and higher under the existing commercial arrangements, in order to make target risk-adjusted returns.

To increase scrutiny of upstream gas, the Commerce Commission could play a larger role in monitoring the upstream gas market, or the GIC could be given much greater powers, effectively becoming the Gas Authority, or the Authority and the GIC could merge to become the Energy Authority.

Given the gas sector currently has such an influence on electricity, which will only start to wane once electricity is beyond 95% renewable, an Energy Authority would take the governance lead in both sectors, developing the regulatory framework for upstream gas to:

- limit the use of market power;
- lead or incentivise the development of new technical and commercial arrangements, e.g. additional gas storage facilities for methane and ultimately for hydrogen;
- develop a consistent regime for transparency and information disclosure across gas and electricity markets;
- remove barriers to the development of new gas products such as biogas and green hydrogen;
- recommend to government other measures that will improve outcomes in the gas and electricity markets.

On the last point above, the lack of an N – 1 security regime in upstream gas is highlighted by the early run-down of Pohokura and the current supply squeeze. New Zealand does not have resident drilling equipment for offshore exploration and work-overs, and relies on suitable rigs coming from Asia or as far away as Europe. These rigs are very expensive, and as a result they are not a top priority for market participants to own. However, an Energy Authority could look at the type and cost of rigs that could be purchased, and the arrangements that this type of equipment could be purchased under, to ensure that equipment is available in timely fashion when required.

Alternative arrangements could also be looked at, including adding redundancy into key facilities. Whatever the details, the point is that what benefits consumers as a whole, may not benefit individual gas producers, and thus a co-ordinated multi-party approach is required.

In many sunset industries, cheaper alternatives are developed at a pace that overwhelms incumbents, e.g. replacement of analogue music recording with digital recording. In electricity, renewable technology is now available to produce more than enough energy on average, but the problem is that the energy will not always be available when required (dry periods and peak periods in winter). To fill the inevitable gaps, there needs to be a large amount of energy storage, along with expanded demand response, to replace the vast energy storage currently available in the form of gas and coal fields. Government has the NZ Battery project team, working on storage options, which could help to accelerate the transition to renewables, but creating large storage assets will take several years and in the meantime, electricity is likely to continue to face criticism for perceived problems that have their roots in upstream gas.

An Energy Authority, working with other government agencies and, most importantly, gas and electricity market participants, could help to smooth the transition while new storage facilities are developed and deployed to the point where electricity can, once and for all, end its reliance on fossil fuels.

4 Hedge Market

The review focuses on the spot market but from our point of view, this is not where the wholesale market's real problems lie. In theory, and in practice, hedge prices in our gross pool market are driven by expectations of spot prices, so we acknowledge that it is important to ensure that spot prices are a function of the actions of participants operating in a more-or-less competitive environment.

But the hedge markets (OTC, futures and FTRs) are markets in their own right, potentially with their own dynamics, prices, risks, opportunities, barriers to entry and costs to exit.

Because spot prices are highly volatile, a core discipline for market participants is risk management, and key risk management approaches include vertical integration (generation and customer business units hedging each other) and the trading of hedges. The review identifies vertical integration as creating barriers for independent existing and would-be generators seeking PPAs, but the impact of vertical integration is wider than this.

If we go back to the early days of the spot market, before the Electricity Industry Reform Act (EIRA) precipitated the high level of vertical integration we see today, the Electricity Supply Authorities (ESAs) of the day all had retail franchises (consumers connected to their respective local networks) but few of them had matching generation. Generation was owned by ECNZ and Contact Energy and so their existed a much larger OTC hedge market than today, at least in terms of the total physical volume needing to be hedged.

The EIRA put an end to that, and vertical integration has remained the dominant form of risk management ever since.

The major gentailers could be split even further[2], into individual reservoirs and hydro stations. For instance, Manapouri-Te Anau; Pukaki-Ohau A, B and C; Benmore; Aviemore; Waitaki; Taupo-Aratiatia; all of the other individual Waikato power stations; Tongariro Power Scheme; and so on. The commercial arrangements might be complex, but they are not impossible.

But we don't believe this would be in the best interests of consumers, however, because vertical integration is a perfectly good risk management strategy and it has other benefits as well, as mentioned in the review.

But we do believe that the market needs more independent retailers and independent generators, it is with these parties that we see there are barriers.

4.1 Independent Retailers

Where did the free hour of power and self-deprecating eclectic TV adverts come from? Who points out the market's shortcomings when the Authority overlooks them? Electric Kiwi, of course.

Where did the concept of a fixed retail fee[3] come from? Energy Club.

Where did carbonzero certified energy come from? Ecotricity.

Where did spot-priced electricity for residential consumers come from? Flick Energy.

Where did options to buy customised power packages come from? Powershop[4].

These are just a few better-known examples, and there are many more, but the point is that innovation in the retail sector is driven primarily by independent retailers.

If consumers are to get the full benefit of innovation, then it is vitally important that independent retailers and independent power producers (IPPs) do more than just survive: they need to thrive and grow.

The chart on the next page shows the number of independent retailers that purchase from the Clearing Manager (tier 1 retailers) and their total ICPs. The rate at which retailers enter the market has fallen off recently, but even more telling is the decline in the total ICPs, the result of this sector having to stop taking on new customers, and letting some go, because they could not replace or add hedges at a price that would provide a positive margin.

In fifteen years, the independent retailer sector has only managed to grow to supply 11% of all ICPs. We believe that a healthy sector would be closer to 20% by now.

That is not to say that each and every wannabe retailer should be supported, as some may simply not be prepared for the challenge they're taking on. Nevertheless, when established and sophisticated retailers have to shrink to survive, it points to a potential market failure.

[2] They were all once part of ECNZ, the Electricity Corporation of New Zealand.
[3] As opposed to a margin in cents per kWh.
[4] Powershop is owned by Meridian, but in its formative years it operated independently from Meridian.

The underlying problem for independent retailers is that to get good prices, they need to source hedges well in advance, by picking the times when hedge prices are lower. But they cannot forecast their customer growth accurately enough to avoid being significantly under or over-hedged based on a longer term hedging strategy[5]. So they can't hedge well in advance.

What happens in reality is that they end up hedging shorter term, which means buying at prices that may be unprofitable. New hedges purchased at the margin can also have a big impact on the weighted average hedge price paid by the retailer, simply because they are small.

On the other hand, large gentailers have high levels of hedge cover by virtue of their generation business, so when they hedge at the margin, the addition of these marginal hedges has a small impact on their weighted average hedge price.

To get around this issue, retailers have had to stop taking on customers during periods of high prices, which means that they shrink rather than grow. Beyond this strategy, there are two alternatives which we believe would allow growth to continue, both of which require substantial changes to the hedge markets, OTC in particular:

1. hedge products that have flexible volumes;
2. a requirement on large gentailers to offer hedges into the OTC market at their respective internal transfer prices, up to a regulated percentage of their total expected generation volume.

On the first point above, we developed a specification for a new product we call the "Flex-CFD" [6] which has built-in optionality on the volume during each month of the term. This would allow a retailer to hedge well in advance, and to build up a hedge portfolio consisting of a mix of plain vanilla CFDs[7] and Flex-CFDs.

In return for the optionality provided by the Flex-CFD product, the retailer would pay a fixed premium that compensates the hedge seller for the risk created by the uncertain volume.

The Flex-CFD spec was only finalised in August 2020, and since then the market has experienced so much stress that we haven't had the opportunity to work with a suitable client to test the product in the OTC market.

On the second point above, requiring gentailers to offer a portion of their total hedge portfolio at internal transfer prices would be a more heavy-handed intervention, probably requiring Code changes, but it would allow independent retailers to hedge shorter term, at prices that would not move their weighted average hedge prices to anywhere near the extent that they do now when the market is under stress. Such a move would reduce the level of vertical integration in the market, but probably not to the level that would lead to unintended consequences. On the assumption that the requirement would be of the order of 20%, all that would happen is that vertical integration would fall by a few percent.

The market value of hedges offered under such a requirement would be greater than their respective strike prices when the market is under stress, but often less when the market is not, and hence demand for shorter term transfer-priced hedges would be high when hedge prices are high, and not when hedge prices are low (lower than the transfer prices). However, the scarcity of transfer-priced hedges could also lead to a premium being paid for them when buying well in advance. This makes it clear that the market dynamics created by an intervention of this nature would need to be thoroughly studied before implementation.

[5] We're assuming a strategy requires being close to 100% hedged.
[6] A full specification is available on request.
[7] With fixed prices and volumes.

4.2 Independent Power Producers

We can see innovation happening with IPPs as well, as some IPPs move away from the standard "debt fund it then build it" approach to a funding strategy which involves substantially more equity.

But the main issue for most IPPs is that a large portion of their project funding comes in the form of debt, and funders want to see a PPA with fixed prices: no PPA, no project.

As noted in the review, there are signs that the market for PPAs is growing, but the change is relatively slow, and it is driven primarily by one gentailer, Genesis. Whether or not this trend extends to other gentailers remains to be seen, so unlike independent retailers, we think it too early to tell if the 'PPA problem' requires a degree of intervention for it to be 'fixed.'

5 Carbon Prices and Electricity

The theory behind emission trading schemes is well established: put a market price on carbon and the market will decide where emission reductions can be made most efficiently.

In the case of electricity, the carbon price flows through to electricity prices as a component of fuel prices for fossil-fuelled thermal generators. Because thermal generators aren't required at all times, the average impact on electricity prices is less than the market price of carbon, but as the carbon price grows, so does the impact on electricity prices.

In theory, electricity consumers should respond to carbon-driven price increases by improving their energy efficiency or by switching to alternative fuels such as wood waste, thus using less electricity. Fossil-fuelled generation also becomes more expensive than renewable generation, which incentivises replacement.

But there is a problem for electricity. Although more efficient use of electricity is desirable, and does reduce emissions, the nation also needs consumers to use more electricity, not less, as they switch away from fossil fuels.

In the case of EVs, they are so much more efficient than internal combustion engine vehicles, and so much cheaper to maintain, that even very high carbon prices won't have much impact on the rate at which the transport fleet converts to electricity once EVs are sufficiently available, priced for the mass market, and the charging infrastructure is available[8].

But the same cannot be said for industrial process heat, and commercial and industrial space heating[9], particularly where high grade heat is required, e.g. to produce steam, or water over 90° C. Gas can be burned at an efficiency in the high 80% range, so converting to an electrode boiler in the high 90% range is not a large gain in efficiency. With gas prices much lower than electricity, conversion to an electrode boiler does not yield a lower operating cost at any carbon price. Increasing the electric efficiency by installing heat pumps does reduce the operating cost, but the capital cost may be higher.

Where a heat pump can be installed to replace a boiler, this could be an attractive proposition, but for high grade heat, and where gas is available, a rise in the carbon price does not incentivise switching to electricity on purely economic grounds. This leads to the possibility of electricity prices rising and staying high for years if, for example, the transition from today's 8X% renewable electricity to 95+% renewable electricity is slow.

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[8] 20 kW – 50 kW chargers simply won't cut the mustard once EVs with ranges of a few hundred km are the norm.

[9] For example, a gas-fired boiler providing heating to a large office building.

An increase in electricity prices due to only to an increase in carbon prices, has an impact on all consumers. It may also lead to super profits for renewable generators. If these profits are reinvested in new renewable generation, then this speeds the transition to renewable electricity which in turn, reduces the impact of rising carbon prices. Higher prices may also help IPPs to make the case to potential funders. On the other hand, super profits may not be reinvested, prices could stay higher for longer, and IPPs may still have to take PPAs which are priced closer to their LCOE[10] than to market prices.

We believe there is case to allow the ETS to do its "magic" on the electricity sector, but also a case to recycle proceeds from the ETS, in proportion to electricity emissions, back to consumers. This already occurs for industries that are energy intensive and exposed to prices for similar goods produced offshore (EITEs), due to the potential for carbon leakage, but by extending the concept to all other consumers, this would help to soften the blow of electricity prices pushed higher by the requirements of the ETS, and help to incentivise switching to electricity, away from fossil fuels.

[10] Levelised cost of electricity, e.g. could be $70/MWh to build, own and operate a windfarm.