23 October 2018

Electricity Price Review
Secretariat, Ministry of Business, Innovation and Employment
15 Stout Street
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Electricity Price Review: First Report for Discussion – Meridian submission

Meridian appreciates the opportunity to submit on the Electricity Price Review Panel's First Report.

Our submission is provided on behalf of Meridian and Powershop and contains certain commercially sensitive information we request is kept confidential. A version for public release omitting this information has also been provided.

Meridian's submission incorporates our feedback on specific consultation questions and additional, more general comments, in consolidated form. The following reports from expert external consultants supplement our submission:

- '*Retail Lessons for New Zealand from UK regulation and the CMA's Energy Market Investigation, including a critique of Professor Cave's analysis*' – by Professor Stephen Littlechild;
- '*Competition in New Zealand Electricity Markets*' – by Competition Economists Group (CEG);
- '*Vertical integration and competition in the New Zealand electricity markets*' – by NERA; and
- '*An Economic Perspective on the New Zealand Electricity Market*' – by Dr E Grant Read.

Further details regarding those who can be contacted in relation to this submission are as follows:

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Yours sincerely

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PUBLIC VERSION

Electricity Price Review: Meridian and Powershop Submission

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Introduction and recommendations

About Meridian and Powershop

This submission is made by Meridian and by Powershop.

Meridian is New Zealand's largest electricity generator. We produce electricity only from renewable sources – hydro and wind. We employ over 1,000 people across our businesses in New Zealand, Australia and the UK. Meridian's hydro stations in the Waitaki Valley and at Manapouri generate enough electricity to power around 1.4 million homes each year. Our wind farms around the country at White Hill in Southland, West Wind and Mill Creek near Wellington, Te Apiti near Palmerston North, and Te Uku near Raglan, generate enough electricity to power around 152,000 homes each year.

Meridian is also the 5th biggest electricity retailer in New Zealand. We currently have approximately 230,000 business and residential customer connections. We also have a large hedge contract with New Zealand's Aluminium Smelter at Tiwai Point, Bluff.

Meridian is the parent company of Powershop, an innovative retailer with a further 70,000 business and residential customer connections across New Zealand. In Australia, Meridian owns hydro and wind assets and retails electricity to approximately 105,000 customers as Powershop Australia. The Powershop brand also operates in the UK under an agreement with a large UK electricity retailer where it has approximately 40,000 customers and is growing.

The software platform for the Powershop operations worldwide is built, developed and supported by Flux Federation, Meridian's software development subsidiary, based in Wellington which employs 130 plus software developers, designers, testers and product experts and provides end-to-end software solutions for power companies worldwide. Meridian is in the process of moving its own New Zealand retail operation onto the Flux platform.

Meridian is listed on the New Zealand and Australian stock exchanges and is 51% owned by the New Zealand Government. As well as maintaining offices in Auckland, Wellington and Christchurch we have an office at Twizel and smaller offices at our wind farm sites. A contact centre in Masterton provides customer support to the Powershop operations in New Zealand and across Australia.

New Zealand's electricity industry is a world leader

The New Zealand electricity industry is widely considered to be a world leader in delivering fair, equitable, efficient and sustainable outcomes for New Zealand consumers.

New Zealand's residential electricity prices are around 20% lower than the OECD average. Many of the countries with cheaper prices have achieved this using government subsidies to power companies or directly to consumers. New Zealand's relatively cheap prices have been achieved without subsidies and despite New Zealand's low population density and relatively high network costs (due to our geography). Since the commencement of this Electricity Price Review ('the Review') New Zealand's ranking in the World Energy Council's (WEC's) Energy Trilemma index has improved from 9th to 8th out of the 130 countries they track.

The trilemma highlights the dynamic interaction of the different elements of a country's energy system. The three Energy Trilemma dimensions are:

- Security – the ability to effectively and reliably meet current and future energy demand;

- Equity – the accessibility and affordability of energy across the population; and
- Environmental sustainability – achievement of energy efficiencies and the development of energy supply from renewable and low-carbon sources.

New Zealand also has an overall balanced rating of AAB ('A's for security and equity and 'B' for environmental sustainability[1]) indicating that we manage the trilemma well across all three dimensions. We are the only representative from the Asia/Pacific region, as well as the only non-European country, to be placed in the global top ten.

From a consumer perspective, there are a lot of positives in addition to relatively cheap prices. New Zealand is one of the easiest places in the world to compare and switch electricity suppliers. Over 20 percent of consumers switch their retailer each year and this figure is growing. In 2017 there were more than 440,000 switches between retailers - the highest level on record. In addition, a 2016 survey by the Electricity Authority showed that 30% of consumers actively investigated switching but decided not to.[2] This means that in any one year, half of New Zealand consumers are likely to shop around and decide whether to switch retailer. Even if a consumer does not proactively shop around, an Electricity Authority study found that high levels of competitive activity "saw 69% of New Zealand households being approached by a competitor in the past two years, significantly higher than in other markets."[3]

There are also an increasing number of retailers for consumers to choose from with more entering the market on a regular basis. The New Zealand electricity market now has over 36 retailers offering a range of innovative and customer-centric services. This level of competitive intensity means electricity suppliers are forced to innovate just to stand still in the market.

As well as driving innovation, intense competition is driving good price outcomes for consumers. Since 2011 there has been no real price increase to consumers arising from the competitive parts of the electricity supply chain (generation and retail), in fact, average real prices across this component of the bill are 0.35 c/kWh lower now than they were in 2011.

The New Zealand market also delivers an extremely high percentage of electricity generation from renewable sources and does this while maintaining security of electricity supply. Around 85 percent of the electricity generated in New Zealand is from renewable sources. This is up from 65 percent only ten years ago and is growing.

Since 1996, the New Zealand electricity sector has invested in over 20,000 GWh of new electricity generation at a cost of over $9 billion. This investment has been diversified and has not been dominated by any particular technology or fuel source or by any single company or companies. The risks of these investments are borne by private investors rather than directly by taxpayers. This level of investment along with the increased prudence in hydro reservoir management that has followed the introduction of the market in 1996 has meant that New Zealand has not had a country wide interruption to supply since 1992 (well before the establishment of the market) despite several record setting dry years in the period since then.

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[1] New Zealand's CO2 emissions released in generating electricity are low by international standards. Our 'B' trilemma sustainability score is largely a consequence of our higher energy and emissions intensity.

[2] Electricity Authority *Market Commentary: Chief Executive's Introduction* 21 June 2018

[3] Electricity Authority *International comparison of activity, behaviour and attitudes towards electricity industry - A quantitative study* August 2014

In summary, there is much that is working well in the New Zealand electricity market. It is critical for New Zealand's lower emissions future that reforms from the Review do not inadvertently damage what is working well – particularly incentives for investment.

All that said, Meridian agrees there is still a lot of work to be done in the sector and many areas where there is room for improvement particularly in terms of how our market is working for financially vulnerable consumers. We completely agree with the Minister's comment that for '…people to have confidence in our system, New Zealanders need to know that our electricity market is efficient, delivers fair prices and is working for the good of all New Zealanders.' We hope the findings and recommendations from this Review go some way towards achieving that goal.

Suggested solutions

The Chair of the Expert Advisory Panel to the Review (the Price Review Panel) has encouraged submitters to briefly identify possible solutions to issues identified. Meridian's suggested solutions appear in the table below.

Where possible we believe any solutions should look to build on the strengths of our current electricity system. We should be wary of 'importing' supposed policy solutions from overseas markets and jurisdictions in the mistaken belief that they will produce improvements in a New Zealand context. New Zealand is already well ahead of many other countries in many aspects of the performance of our electricity system. An 'improvement' in another jurisdiction may be a backward step here. Also:

- Regardless of whether prices are fair, equitable, and efficient **we know that some customers struggle to pay their power bills**. There are multiple reasons for this. They relate not just to electricity costs but to factors such as income level, quality of housing, and the cost of other key goods and services. Concerted efforts to improve New Zealand's poor housing stock are likely to be critical in improving energy outcomes for vulnerable consumers.[4] The Government is already taking several actions on this front and, as we said in our submission on the draft terms of reference for the Review, "any steps to improve regulatory settings in the energy sector must be progressed alongside broader social policies to ensure the best outcomes for all customers." Meridian welcomed the Government's introduction of a Winter Energy Payment and we continue to support consideration of how broader social welfare policy could better support vulnerable customers. We note that of the $7 billion paid by consumers to electricity suppliers in the 12 months to June 2017, 23% or $1.6 billion went to the Crown in tax, dividends and GST,[5] and this may assist with such objectives.

- **Prompt payment discounts are hurting low income households.** The problem with these discounts – which have become prevalent throughout the New Zealand retail market – is they have over time been 'competed up' so that the scale of discounts on offer for prompt payment no longer reflects the actual cost to retailers of consumers paying late. As of 1 October 2018, Meridian has stopped offering prompt payment discounts to our customers. Instead we have moved to ensure that all our customers receive the discount even if they pay late. Meridian is the first major retailer to take this step, and we estimate it will save our customers about $5 million per annum. If all retailers took similar action we estimate it would put around $40 million per annum back into the pockets of New Zealand electricity consumers. This money would flow particularly towards low-income households as they are the ones who struggle to pay on time.

[4] The First Report notes at page 11 that a staggering 55% of New Zealand homes lack adequate insulation.
[5] First Report at page 9.

- The electricity market can be complex and some consumers are unaware of the potential benefits of engaging with the market to secure the best price**. A range of simple steps as outlined below can be taken to ensure all consumers, including those most vulnerable, can better compare and switch** electricity providers and access the best one for them.

- **Regulatory settings need to keep pace with changes in technology** and enable consumers to benefit from these changes. The pace and scale of change in the sector has never been greater. New technologies – like solar panels, batteries and electric vehicles – promise to disrupt the traditional electricity and transportation sectors and will create challenges for retailers and for the monopoly lines businesses who have till now been insulated from competition.

- The **Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 or LFC regulations are poorly targeted and have a variety of adverse impacts.** The LFC regulations were supposed to make electricity more affordable but for many people on lower incomes they have had the opposite effect. They are poorly targeted and are a major source of inequitable outcomes. The regulations also effectively double the number of tariffs retailers are required to offer adding significantly to the complexity of industry pricing and increasing costs to serve customers.

- **As the key driver of residential price increases since 1990 and, together with transmission, the sole driver of real price increases since 2011, distribution charges warrant close attention.** Representing around 27 percent of residential consumer bills, there is considerable scope to improve the efficiency of distribution charging. Historical re-balancing of distribution charges across consumer groups has also undeniably had a large impact on residential consumers, with the scale of the adjustments called into question by analysis undertaken by Concept Consulting[6] and the Price Review Panel.

#	Solution	Indicative time to execute	Consumer benefit
Consumer and retail market solutions			
1.	**Regulate prompt payment discounts** by restricting them to the level of any increased costs to retailers from consumers paying late.	6 months.	**$40 million** once implemented by all retailers

[6] Concept Consulting *Issues and options for moving towards more cost reflective network tariffs* 2017, page 61.

#	Solution	Indicative time to execute	Consumer benefit
2.	**Establish and strongly promote an enhanced price comparison site for retail electricity prices**. Perhaps run by the EA or a commercial provider, further to a competitive tender process, this would link to registry information and potentially consumption information if authorised by consumers and also enable comparisons of prices across a range of sample consumption profiles.	6 – 12 months.	Greater transparency would make it even easier for consumers to compare and switch between retailers.
3.	**Require all retailers to advertise the comparison site on all customer bills.** This could be in a standardised format and include: • the benefits of checking available offers; and • the logo and contact details of the site.	As above.	As above with increased consumer awareness.
4.	**Regulated minimum standards for retailers to apply in their dealings with vulnerable customers** based on the existing *Guidelines on arrangements to assist vulnerable customers*.	6 months.	Would ensure best practice is followed by all retailers.
5.	**Repeal the Low Fixed Charge regulations**	6 months.	Remedy the inequitable outcomes of the existing cross-subsidy and reduce cost and complexity resulting in lower prices.
6.	**Housing New Zealand and other social housing providers should consider entering into bulk purchasing arrangements for electricity on behalf of their tenants**. Social housing providers could also reduce electricity prices for their tenants by taking on their credit risk.	12 months.	Lower prices for this subset of customers. Social housing providers would also have stronger incentives to improve their properties' thermal efficiency.
7.	**Extend the Winter Energy Payment in a targeted manner to provide greater relief to low-income households.** Payments could be means tested and extended beyond beneficiaries**.**	12 months.	As per the current Winter Energy Payment but with greater benefit to more low-income households.

#	Solution	Indicative time to execute	Consumer benefit
Transmission sector solutions			
8.	**The Electricity Authority should conclude the review of the transmission pricing methodology.**	12 – 18 months.	Without reform consumers are likely to be paying **hundreds of millions** of dollars more for electricity than necessary.
Distribution sector solutions			
9.	**Distribution pricing reform should be expedited, if not through an industry led process, then through a regulatory deadline.** Could include the partial reallocation of non-demand-related network costs from residential to business customers.	2 years for distribution pricing reform; 6 months for reallocation.	Estimated **$180 million** benefit to residential customers (and cost to businesses) through reallocation of distribution costs. From **$2 - $5 billion** in efficiency gains from pricing reform.
10.	**Reduction from 67th to 50th percentile in the setting of the regulated Weighted Average Costs of Capital (WACC) used to calculate the allowable revenue of the monopoly lines companies.**	1 year	Significant savings to electricity consumers. Perhaps $45 - $65 million.
11.	**The Electricity Authority's default distribution agreement should be progressed to completion**.	6 months	Remove a practical barrier for retailers wanting to trade on multiple networks and increase levels of retail competition to the benefit of consumers.
12.	**All distributors should be price-quality regulated (currently only 17 of 29 are subject to such regulation).**	1 – 2 years.	Increased efficiency incentives for currently unregulated distributors.
Wholesale market solutions			
13.	**Strengthen the current voluntary ASX market-making arrangements by introducing greater incentives for market-makers.** Any incentivised scheme should be funded by all ASX participants either via ASX fees, a levy, or by some other means.	1 year.	Probably limited. The current market-making arrangements are robust. This will make them more robust.

#	Solution	Indicative time to execute	Consumer benefit
Wholesale market solutions			
14.	**The Electricity Authority's Real-Time Pricing project should be progressed to completion.** This will require Government approval of increased levy funding.	3 years	Estimated net benefit of **$53 million**. Real-time pricing is critical to enabling efficient demand side participation in the wholesale market.
15.	**Remove unnecessary barriers to the development of new renewable generation under the Resource Management Act.** National Policy Statements and Environmental Standards should use directive language and be more explicit about how the benefits of renewable electricity generation should be recognised and given effect in planning instruments.	2 years	Additional development costs are ultimately paid by consumers of electricity.

Attached to this submission are reports from:

- Competition Economists Group on *Competition in New Zealand Electricity Markets*. This addresses:
    - Competitiveness of the New Zealand Energy Retail Sector
    - Competitiveness of the New Zealand Wholesale Market
    - Vertical Integration and Liquidity of the Hedge Market
    - Price Levels and Trends
    - Price Dispersion and Discrimination;
- NERA on *Vertical Integration and Competition in the New Zealand Electricity Markets*;
- Professor Stephen Littlechild on *Retail Lessons for New Zealand from UK regulation and the CMA's Energy Market Investigation, including a critique of Professor Cave's analysis*; and
- Dr E Grant Read on *An Economic Perspective on the New Zealand Electricity Market*.

Consumers and prices

Consumer interests

> ***1. What are your views on the assessment of consumers' priorities?***

Meridian's experience is that consumer priorities are diverse but at some level all include, as detailed by the Panel, 'a reliable supply of electricity and fair and affordable prices.'

Service is also important to customers. For example, many consumers value the interactive online tools offered by retailers which allow consumers to monitor and manage their usage. Consumers also value how retailers interact with them during outages, their retailer's commitment to sustainability, having different payment options, the 'bundling' of electricity with other goods and services and so on. Some consumers value the fact that they get a constant year-round tariff from their retailer and their retailer absorbs and insulates them against wholesale price risk and fluctuations. Others are unaware of this fact or, in contrast, value the type of service provided by retailers like Flick who offer consumers direct exposure to such fluctuations. The strength of the competitive retail electricity market is that it responds directly to consumers diverse priorities and interests by providing a diverse range of offerings for consumers to choose between.

The case studies on pages 14 and 15 of the First Report reflect the experience of a number of our customers. We know, for example, that we have customers who ration their use of power, who stay cold rather than turn on heating, who struggle to pay their bills, who live in cold and damp housing and who are unable to afford insulation or efficient appliances. As detailed below Meridian has put in place a series of initiatives to help our vulnerable customers. We are working to do more.

In relation to how retailers are performing in responding to consumer priorities, the evidence is generally positive. As cited in the issues paper, survey research confirms there is a high level of trust amongst consumers of retailers.[7] In addition, 83 percent of consumers are satisfied overall with their electricity provider[8] and satisfaction with retailer service standards overall is similarly high – with 68% of consumers indicating general satisfaction with their retailer's services in Electricity Authority-commissioned UMR research.[9] According to the same UMR survey, half of consumers are satisfied their retailer also provides value for money.[10]

> ***2. What are your views on whether consumers have an effective voice in the electricity sector?***

Meridian believes that for the most part consumers have an effective voice. But there is room for improvement. We agree the electricity sector is complex and it can be difficult for consumers to engage with it.

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[7] In particular, Consumer NZ research has found that 68% of consumers trust their retailers, as discussed on page 18 of the Price Review Panel's First Report.

[8] Consumer *Energy Provider Retailer Survey* 2018

[9] See for further details August 2014 UMR '*International comparison of consumer activities, attitudes and behaviours towards the electricity industry*' report, available: https://www.ea.govt.nz/dmsdocument/19155-survey-international-comparison-of-activity-behaviour-and-attitudes-towards-electricity-industry

[10] Ibid.

As a starting point, the statutory purpose of the Electricity Authority is to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers.

The purpose of the Commerce Commission under Part 4 of the Commerce Act is also to promote the long-term benefit of consumers through regulation of the monopoly lines companies such that they deliver outcomes consistent with outcomes produced in competitive markets.

While the regulators exist to promote consumer interests (and Meridian believes they generally do a good job), it is another thing for individual consumers to feel they have a voice and can engage with the industry. The First Report offers a variety of suggestions for what this may mean precisely. Important areas to consider are:

- The ability of consumers to engage with switching processes, understand and navigate different price, service and service level offerings;
- The ability of consumers to engage with regulatory processes; and
- General transparency and information availability.

Overall, Meridian believes that consumers are well supported in relation to each of these. Supplementing the things detailed in the First Report assisting consumers in these areas are the following:

- Work by the Electricity Authority to promote the What'sMyNumber site, to educate and empower consumers about the savings available from switching.
- The right for consumers (and third parties) to require a retailer to provide them with details of all of that retailer's generally available retail tariff plans. Introduced by the Electricity Authority in 2016, this amendment to the industry Code ('the Code')[11] has provided consumers, price comparison websites, and service providers alike with the ability to access tariff information from all market participants.
- Price notification guidelines, in place since April 2015, requiring transparent and comprehensive supporting information is provided each time a price change is made and promoting consistency in information from distributors and retailers.

Despite efforts of retailers like Meridian, and of the organisation itself, awareness of the consumer support services provided by Utilities Dispute Limited (UDL) – the sector's free-to-consumers complaints and disputes resolution body – remains low.[12]   Meridian supports further steps to lift awareness of UDL's services particularly among financially vulnerable customers.

Further, while the retail and generation parts of the supply chain are relatively intuitive, engaging with the 37.5% of the average residential bill that is the product of lines company price and quality regulation is challenging. The Commerce Commission has been encouraging lines companies to engage more with consumers, particularly as they consider pricing reforms on their networks. As our response to question 33 details, we consider the Commerce Commission has recently done good work in this area but we believe it could do more.

[11] Specifically to section 11.32G of the Electricity Industry Participation Code ('the Code').
[12] UMR 2017 research, for example, has found that 6% of consumers only are aware of UDL's services.

To assist consumers in having a more effective voice, and as outlined further at question 15 below, Meridian considers the existing range of price comparison services could be enhanced, and that actions could also be taken on the part of retailers to improve general consumer awareness. In addition, a broader consumer advocacy service – whether provided by Consumer NZ, or other provider – is of potential merit and should be further investigated.

> ***3. What are your views on whether consumers trust the electricity sector to look after their interests?***

As confirmed by Consumer NZ's survey research cited in the paper, and UMR research noted above[13], retailers are highly trusted. The relevance of other survey evidence – namely Acumen Edelman Trust 'Barometer' research – discussed in the paper is questionable, given its generic focus on businesses not necessarily part of the electricity industry.

Operating in a competitive market environment, with some 40 brands, retailers face a huge imperative to work hard every day to maintain the trust of their customers.

Prices

> ***4. What are your views on the assessment of the make-up of recent price changes?***

Meridian notes the First Report's findings that collectively, over the period 1990 to 2018, average electricity prices rose from 15c/kWh to 18.9c/kWh expressed in 2018 dollars. This is an increase of 26% in real terms or an average yearly rise of 0.8%. As the First Report rightly notes a different picture emerges once the figures are disaggregated between residential, commercial and industrial consumers. It is nevertheless worth stressing that, on the whole, the rise in prices has been relatively modest.[14]

As the First Report notes, at the disaggregated level, residential prices have risen 79% in real terms since 1990, commercial prices have fallen 24% in real terms and industrial prices have risen 18%.

In relation to residential prices Meridian agrees with the First Report's finding that over the period 1990 to 2018 the increase has been most heavily influenced by:

- The re-balancing of distribution charges from commercial and industrial consumers to residential consumers. Contributing to increases of some 548% for households since 1990[15], re-balancing has probably been the most significant driver of overall price trends for all customer groups.[16]

- GST adjustments from 10% to 15% between 1989 and 2017.[17]

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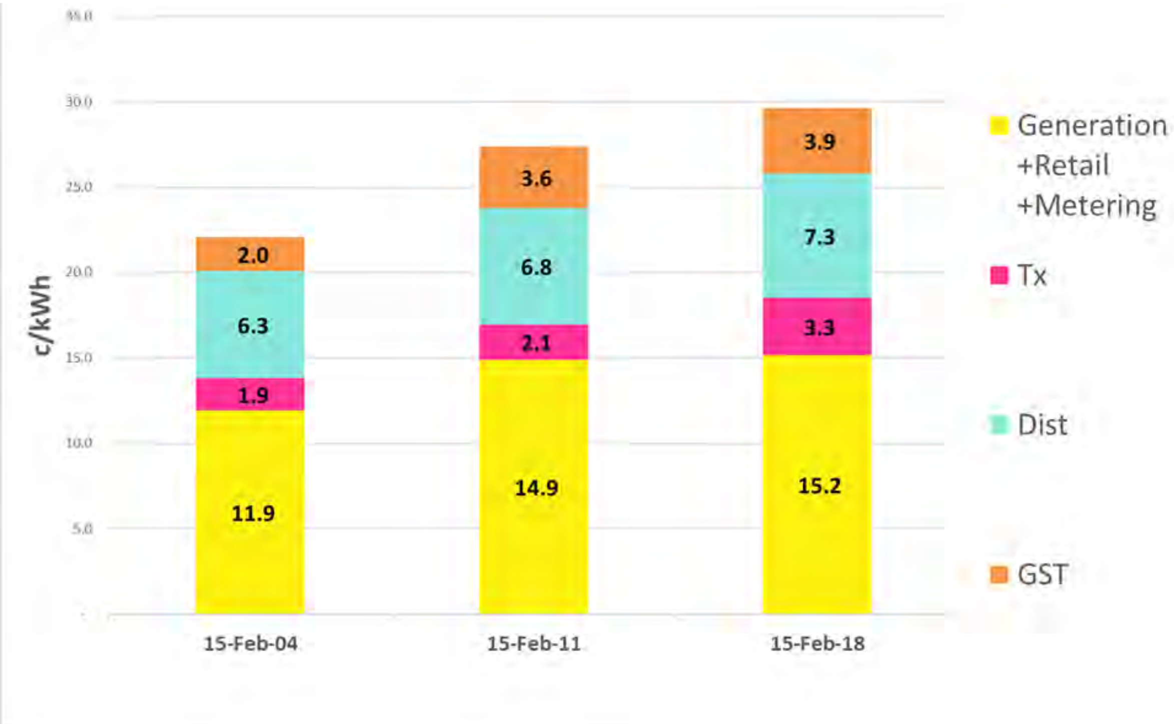
[13] Insert cross reference to previous section.
[14] First Report, page 19.
[15] First Report, page 60.
[16] With commercial usage at roughly 3 times the level of residential usage (see Figure 4 at page 18 of the First Report) the fall in average commercial prices of 24% mirrors the rise in average residential prices of 79%.
[17] First Report, page 20.

Other underlying cost increases have, in addition, had an influence. The cost of labour, for instance, is up 65% in real terms, since 1992[18] and the cost of gas up 125% in real terms since 2000.[19] The First Report refers also to increased retailing related costs and these have clearly had an impact but the First Report's Figure 4 shows the impact is about half the impact of the rise in GST and less than a fifth of the impact from the rise in distribution costs. Further these costs include the costs of metering services providers which retailers have limited control over. The roll out of smart meters has seen an increase in metering costs over the relevant period. Between 2007 and 2018 Meridian and Powershop's metering costs have roughly doubled from $16M to $31M per annum.

As well as the First Report's 3 dates of 1990, 2004 and 2018 it is worth also looking at the change in prices since 2011:

Figure 1 – Changes in the composition of residential prices



Source: Meridian

This shows that since 2011 the rise in distribution costs to residential consumers has been more modest i.e. the 're-balancing' from commercial and industrial consumers seems to have been largely completed prior to 2011. Since that time the biggest increase has come from the transmission component of the bill. In real, inflation-adjusted terms the "energy and other" component of residential bills has fallen by around 2 percent (0.35 c/kWh) since 2011. The regulated transmission and distribution lines component, in contrast, has increased by around 20 percent (2.25 c/kWh) in real terms.

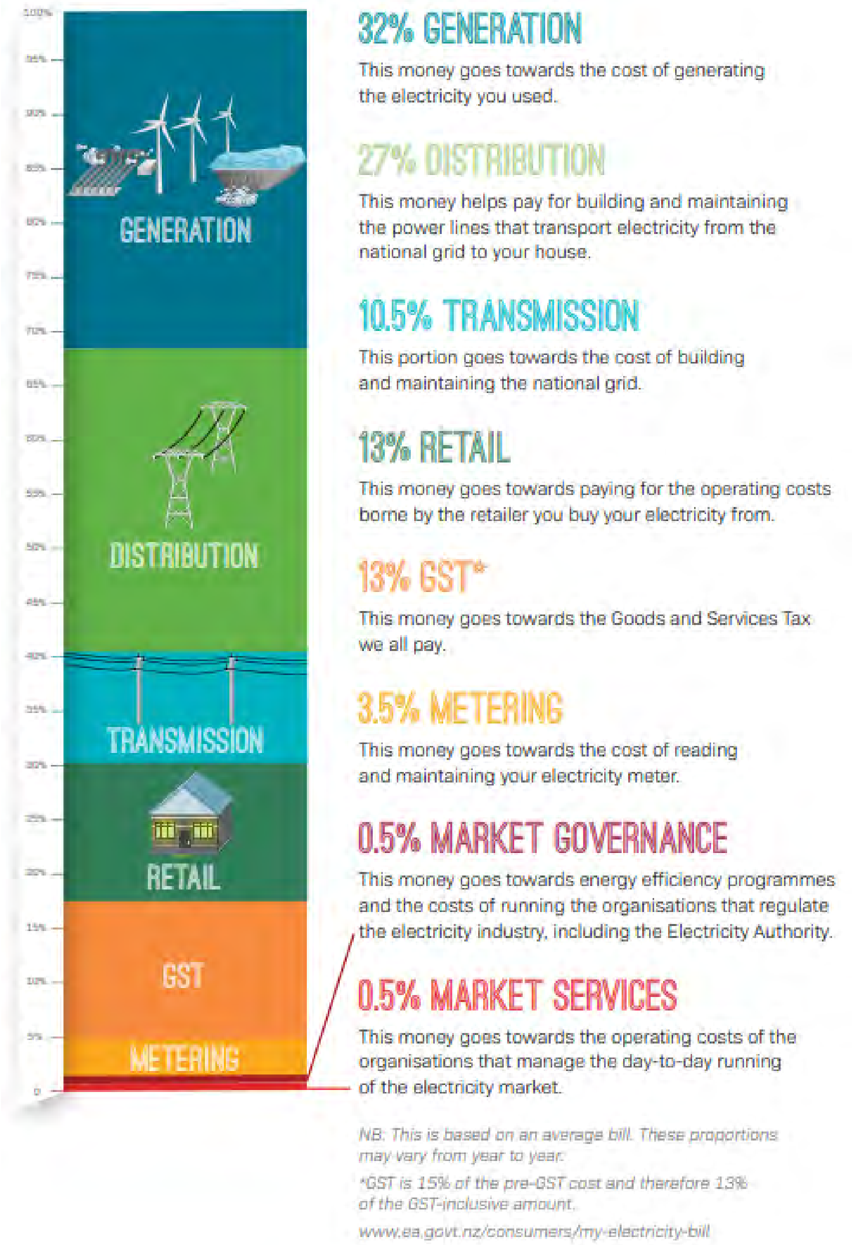
We discuss each of these points in further detail below.

[18] Calculated from Statistics NZ data using a 1992 baseline, due to pre-1992 information not being available.
[19] Pre-1999 information not available from MBIE's data set.

Breakdown of prices

Pricing is made up of the following costs: generation, transmission, distribution, retail, metering, levies and taxes. Figure 1 below shows the breakdown of the average power bill.

Figure 2 – What does your power bill pay for?



Source: Electricity Authority

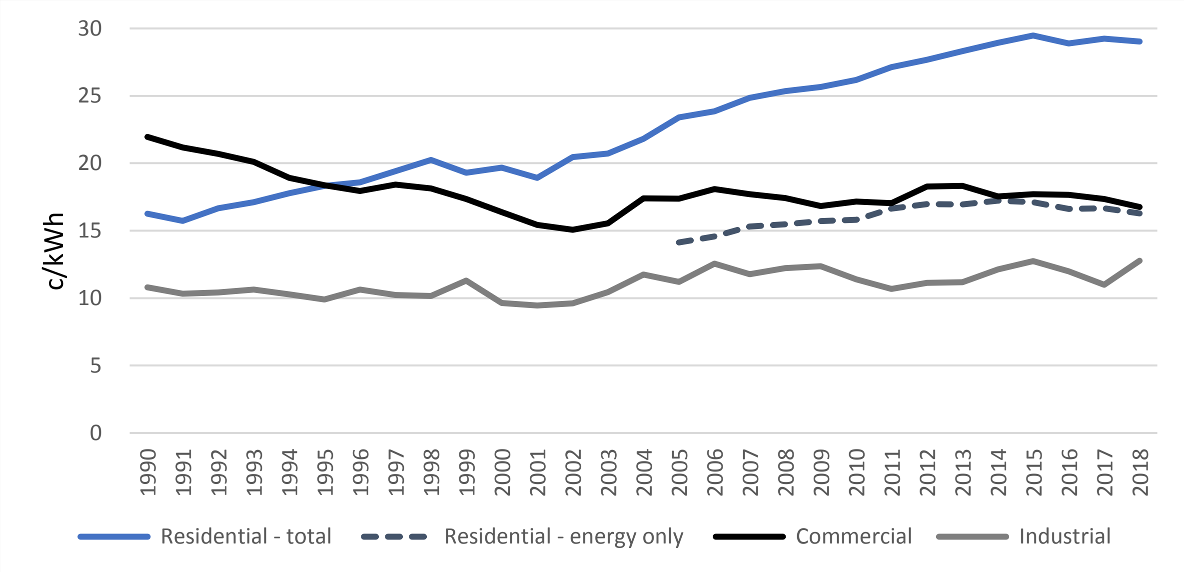
MBIE monitors electricity pricing broken down to:

- **Lines** – the cost of delivering electricity (the regulated monopoly transmission and distribution infrastructure), which accounts for around 37.5% of the final bill.
- **Energy** – the cost of electricity generation and retailing including metering costs (the competitive parts of the sector), which account for around 50% of the final bill.
- **Other** – the cost of levies and taxes, which accounts for around 12.5% of the final bill.

Basis for the increase in real electricity prices

The chart below shows price trends for different customer groups since 1990, exclusive of lines charges – where obtainable from MBIE data:

Figure 3 – Average electricity prices 1990 – 2018 by customer group



Source: MBIE real electricity price data. Provides residential 'energy only' prices (exclusive of lines charges) where MBIE data is available.

The residential price increases since 1990 reflect a variety of underlying cost movements. In addition to those already mentioned, large-scale infrastructure investment – generation and network-related – is another important influence. In terms of new generation infrastructure for example:

- 1026 MW of thermal capacity has been retired and replaced by new largely renewable generation since 2012; and
- Between 2003 and 2014 Meridian alone commissioned over 400 MW of new wind generation.

As already noted lines cost components have been the primary source of residential cost increases since 2011 – as is observable from the flat trend in 'energy only' elements from that time.

The First Report notes that the process of re-balancing distribution charges has contributed to growth of some 548% in residential distribution costs since 1990 (while those for commercial and industrial businesses have fallen 58%).[20] The chart below produced by the Electricity Authority[21] in 2014 illustrates, at a more general level, that these distribution cost adjustments form part of broader changes addressing historic under-recovery of electricity charges from residential customers.

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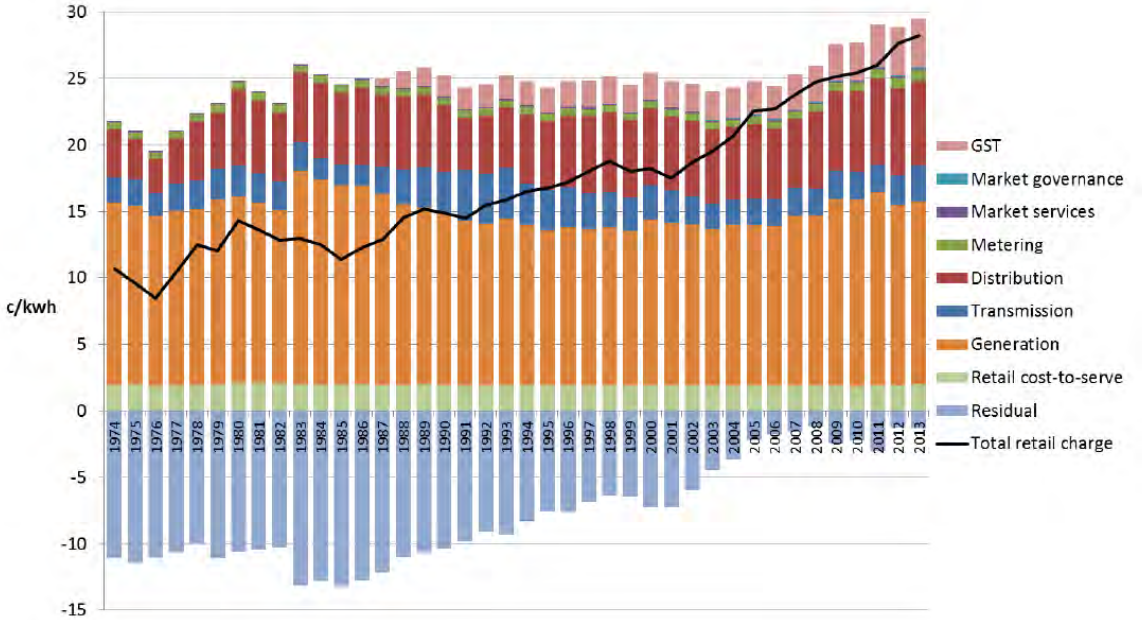
[20] First Report, page 60.

[21] Electricity Authority *Analysis of historical electricity costs* available at: https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2013/historical-analysis-of-electricity-costs/

Figure 4 – Electricity Authority historical analysis of residential cost components



Source: Electricity Authority

How price increases compare with other sectors

Even if we ignore the fact that for much of the relevant period residential electricity prices were cross-subsidised to such an extent that they didn't recover the underlying costs of production, a real pricing increase of 79% over 28 years is not unique or exceptional.

Highlights from the CPI basket of household expenses over the period 2000 to 2018 include (in real terms):[22]

- the price of gas increased by 125%.
- the price of dwelling insurance increased by 279%.
- rates increased by 71%.

Electricity price changes since 1998 are also broadly in line with the changes in income levels.[23] Since 1998 average weekly incomes for salary and wage earners have increased from $584 to $1168[24] and the minimum wage has risen from $7 to $16.50 an hour[25]. As can be seen, in recent years electricity prices have stabilised and been overtaken by the increases in minimum wages and the labour cost index.

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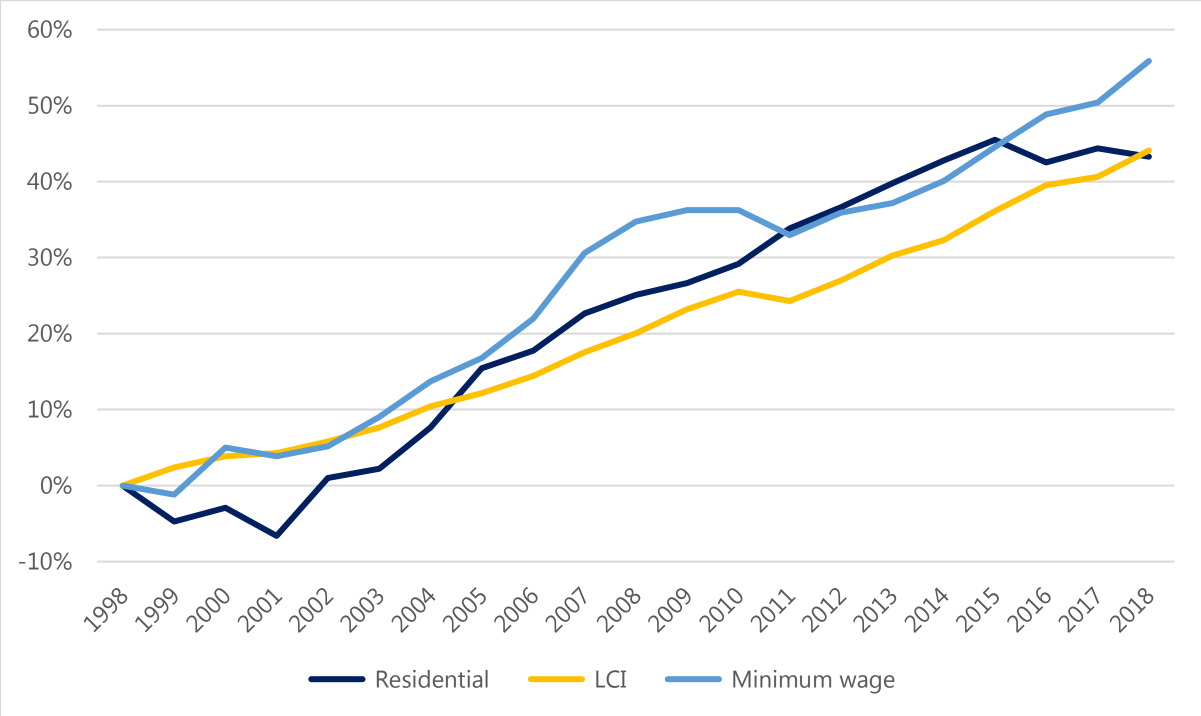
[22] StatsNZ available at http://archive.stats.govt.nz/infoshare/

[23] The truncated, post 1998 period adopted here ensures comparability in earnings data and an exclusive focus on the period where the modern NZEM trading market has been active.

[24] Source: StatsNZ, available: http://nzdotstat.stats.govt.nz/wbos/Index.aspx

[25] https://www.employment.govt.nz/hours-and-wages/pay/minimum-wage/previous-rates/downloadpdf

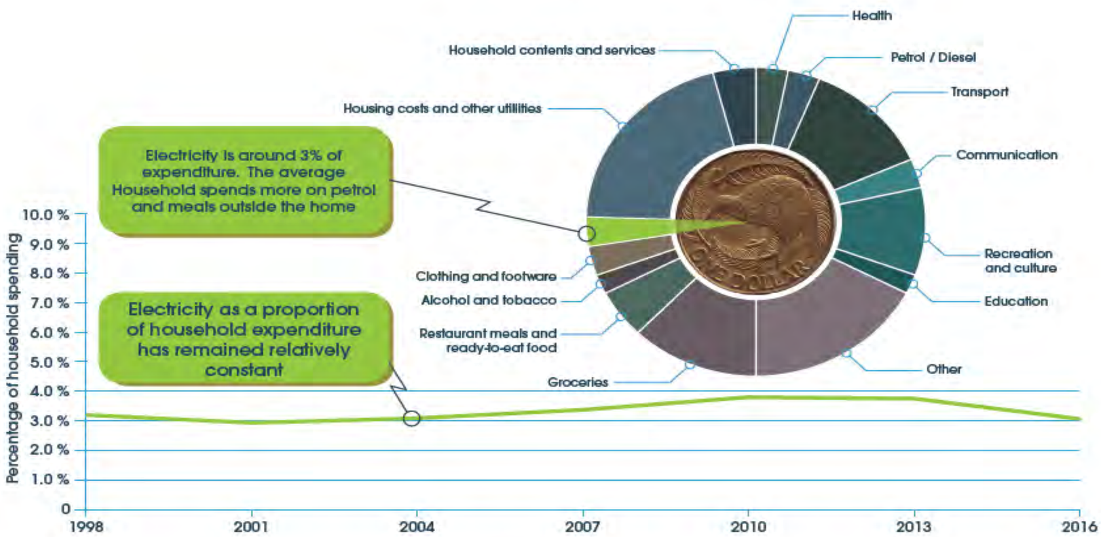
Figure 5 – New Zealand Residential Electricity Costs, Labour Cost Index and Minimum Wage changes since 1998



Source: StatsNZ and MBIE data, adjusted to account for inflation.

Despite relatively high consumption levels in New Zealand, relative to other OECD countries, electricity is generally a low proportion of overall average household spending (~3%). The level of spend on electricity has ranged between 3% and 4% for the last 20 years and is now at its lowest since 2000/01 according to the StatsNZ's Household Expenditure Survey for 2015/16. This indicates that although electricity prices have increased over time, overall spending on electricity has not generally increased any faster than other components of average household expenditure.

Figure 6 – Electricity spending as a proportion of overall household expenditure 1998-2016



Source: ERANZ

Industrial, Commercial and Residential split

As already noted the First Report highlights contrasting trends in electricity prices across different customer groups. Against a 1990 baseline, the report finds that real electricity prices: [26]

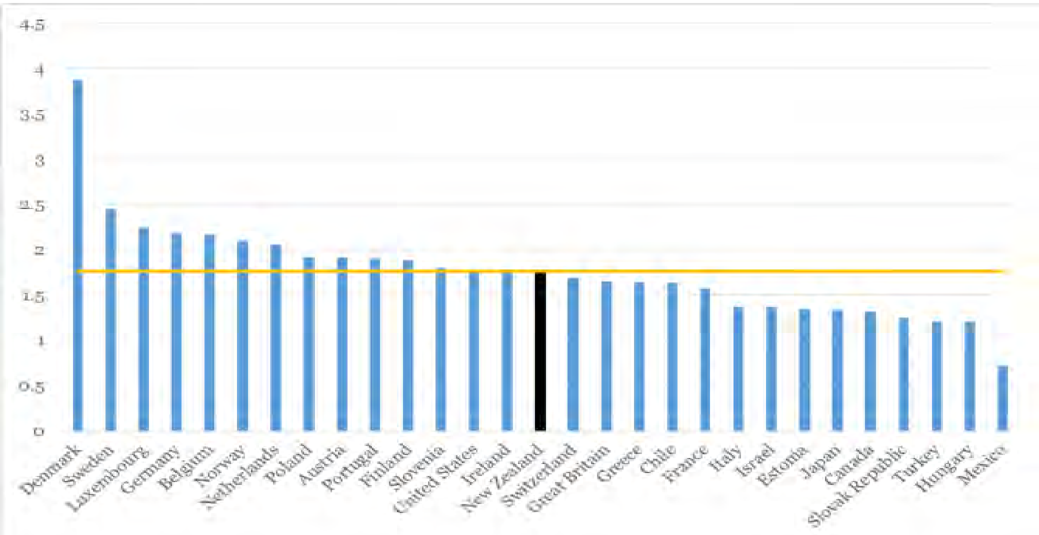
- Measured across all customer groups, have increased in real terms 0.8% annually since 1990;
- For residential consumers, have increased at an average rate of 2.1% per year and 79% overall;
- For industrial consumers, have increased at an average rate of 0.6% per year and 18% overall; and
- For commercial consumers, decreased at an average rate of 1% per year and 24% overall.

The differences across these groups reflect a variety of factors.

As acknowledged in the First Report, differences in underlying costs are one part of the picture. Large industrial and commercial customers benefit from their scale and the reduced cost to serve an individual consumer per kWh. For example, a large industrial consumer might consume many thousand times more than a residential customer. By comparison servicing several thousand residential customers who consume a similar amount of power requires a significantly greater investment in call centre and customer service representatives, metering and software to process the consumption information those consumers generate, reconciliation, billing, hedging of "peaky" residential load and other services, all of which increase the overall cost to deliver electricity to those consumers. For example, on the Orion network Meridian has calculated that its average cost to serve a commercial business is only **[ ]**% of the average cost to serve a residential customer.

Analysis by CEG shows a difference in price between residential and commercial and industrial customers is the norm internationally and that New Zealand's residential-to-industrial-price ratio is at the international median.

Figure 7: Ratio of Residential to Commercial and Industrial prices in IEA countries



Source: IEA, MBIE, CEG analysis; Note: Data is missing for Australia, Korea and Spain. The Smelter has been excluded in the analysis.

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[26] First Report, page 19

Also important to note is the high degree of aggregation in the MBIE commercial and industrial price monitoring. This means that the “average” prices MBIE derive are heavily influenced by the prices paid by the large industrial and commercial consumers respectively.

In a competitive market, prices paid are based on the cost to serve not on the somewhat arbitrary classifications and “averaging” of the MBIE monitoring. To demonstrate, we compared the bills of our small commercial customers (SMEs) with those of equivalently sized residential customers. The chart below shows average prices for Meridian customers with annual consumption between 10,000 and 14,0000 kWh. This group is comprised of large residential customers and smaller commercial customers. As seen below the prices paid by each group are broadly comparable:

Figure 8 – Average prices for Meridian residential and small commercial customer sample

[

]

Source: Meridian

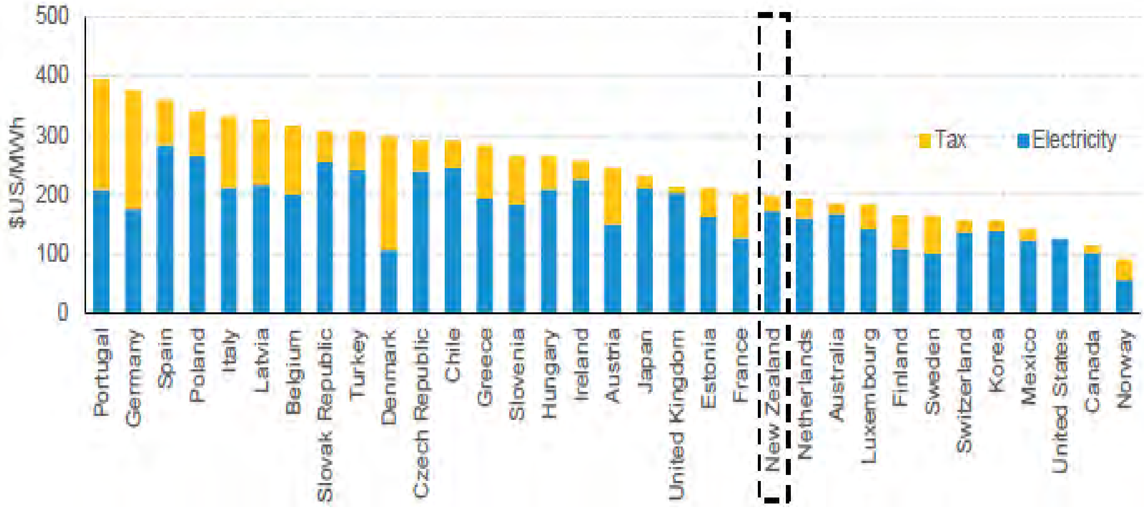
MBIE monitoring of commercial and industrial prices, in addition, excludes GST, partially explaining the difference relative to residential prices.

5. What are your views on the assessment of how electricity prices compare internationally?

How prices compare internationally

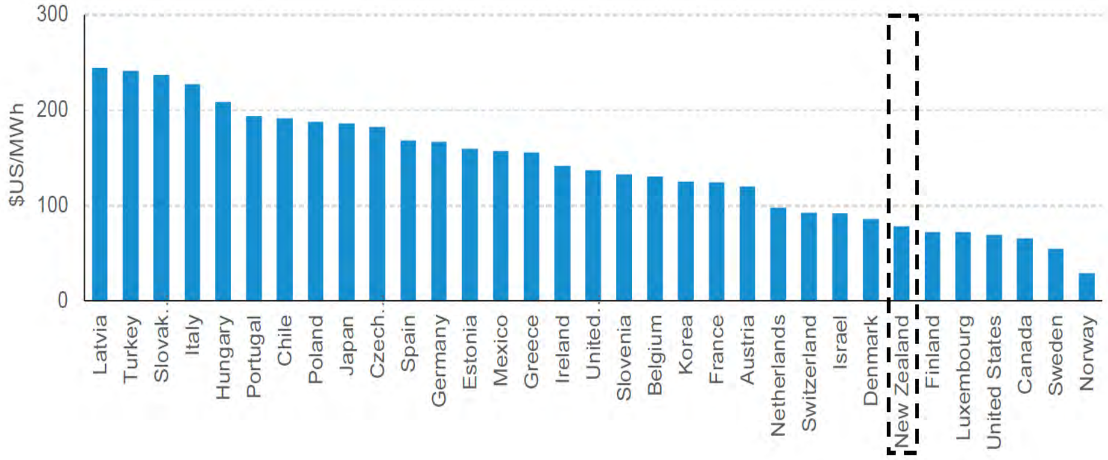
As the First Report's analysis confirms, New Zealand's prices compare favourably to prices internationally. Residential prices are almost 20 percent lower than the OECD average, calculated based on purchasing power parity of the relevant currencies from 2016 data. Based on 2015 data, New Zealand's industrial prices are placed in the lowest quarter.

Figure 9 – Residential electricity prices in OECD countries



Source: First Report, MBIE tables of OECD data.
Figures are US dollars converted at purchasing power parity.

Figure 10 – Industrial electricity prices in OECD countries



Source: First Report, MBIE tables of OECD data.
Figures are US dollars converted at purchasing power parity.

In the case of residential prices, New Zealand's favourable ranking is despite an absence of the subsidies prevalent in other countries. At least 10 of the 11 OECD countries which appear to have lower prices than New Zealand have some form of direct subsidy in place for the industry or for electricity consumers or both. For example:

- In Australia, renewable generation feed in tariffs were criticised by the ACCC and we are aware of some 18 different Government-funded concession entitlements available to customers in the areas supplied by Powershop.
- In the United States the federal government supports the use of fossil fuels, nuclear power, and renewables through tax preferences estimated to total US$18.4 billion in 2016.[27, 28]
- In the EU a 2014 study by the European Commission found that the total value of public interventions in energy (excluding transport) in the EU-28 was €122 billion in 2012.[29,30]
- Electricity use has traditionally been subsidised in Mexico, mostly for households, and this is still the case. The IEA holds subsidy data from 2010 – 2015 showing that in 2015 total subsidies were equivalent to US$5.8 billion.[31] According to S&P Global, and records from Mexico's National Congress, subsidies in 2017 were equivalent to US$6.2 billion.[32]
- Many Canadian provinces have feed in tariffs and tax credits for renewable generation.[33]
- In South Korea, 51% state owned KEPCO is dominant and responsible for almost all generation, transmission, distribution and retailing of electricity. The IEA identified "a significant problem is that present mechanisms for calculating wholesale and retail electricity prices do not reflect the full cost of electricity production, nor do they reflect its market value; in other words, there is a direct subsidy in place in the form of the sale of electricity at prices below costs."[34]
- In Switzerland the IEA has noted that "as end-user prices are regulated close to generating cost and below spot market prices for most of the time, consumption is subsidised and incentives for investing in generating capacity are reduced."[35]

Finally, in relation to our closest neighbour Australia, we note the OECD data runs only up to 2016 and shows Australian residential prices comparing favourably to New Zealand. The table below updates this based on MBIE data and price data in the recent ACCC report to take account of the significant recent price increases recently observed in Australia. As can be seen, the New Zealand market has delivered significantly lower prices and a significantly smaller change in price since 2008.

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[27] Congressional Budget Office: https://www.cbo.gov/system/files/115th-congress-2017-2018/reports/52521-energytestimony.pdf
[28] Department of Energy: https://www.energy.gov/energy-economy/funding-financing
[29] European Commission Directorate-General for Energy: https://ec.europa.eu/energy/sites/ener/files/documents/ECOFYS%202014%20Subsidies%20and%20costs%20of%20EU%20energy_11_Nov.pdf
[30] The EU-28 countries include the Netherlands, Luxembourg, Finland, and Sweden (amongst the 11 cheapest). Note that Switzerland and Norway are not part of the EU-28.
[31] IEA, page 154-155 https://www.iea.org/publications/freepublications/publication/EnergyPoliciesBeyondIEACountriesMexico2017.pdf
[32] S&P Global: https://www.platts.com/news-feature/2017/oil/commodities-in-mexico/cut-power-subsidies-solar-plan-050517
[33] IEA: https://www.iea.org/publications/freepublications/publication/energy-policies-of-iea-countries---canada-2015-review.html
[34] IEA: https://www.iea.org/publications/freepublications/publication/Korea2012_free.pdf
[35] IEA: http://www.iea.org/publications/freepublications/publication/Switzerland2012_free.pdf

Figure 11 – Comparing average prices between Australian and New Zealand

Measure	**Australia** (NEM)	**New Zealand**[36]
Average 2018 prices (c/kWh in nominal terms including GST)	**41.24 c/kWh NZD**[37]	**29.03 c/kWh NZD**
Average increase in residential prices (c/kWh in real terms)	**56% increase** since 2007-08 FY[38]	**17% increase** since 2008 CY
Average increase in network component (c/kWh in real terms)	**46% increase** since 2007-08 FY[39]	**29% increase** since 2008 CY
Average increase in energy and other component (c/kWh in real terms)	**63% increase** since 2007-08 FY[40]	**5% increase** since 2008 CY

Source: Meridian, utilising MBIE and ACCC data.

6. What are your views on the outlook for electricity prices?

How prices might be expected to change in future

In future we expect that competition will likely continue to constrain prices and price increases in those parts of the sector where competition is present.

On the wholesale side, prices should remain stable but may increase if there is too quick a push towards 100 percent renewable generation. Our response to question 14 provides further discussion on this.

Underlying distribution costs may continue to increase. There is anecdotal evidence of a "wall of wire" on the horizon as distribution assets come to their end of life. The Commerce Commissions recent approval of Powerco's application for a customised price path (CPP) indicates the scale of new investment and price increase potentially in store. According to the Commerce Commission "the CPP allows Powerco to spend $1.27 billion on a major network upgrade to replace parts of its network built in the 1950s and 60s and nearing the end of its life". Once the upgrade is complete in 2023 the cost increase to consumers is calculated by the Commerce Commission to be an added 4.5% on customer bills. If other networks make similar applications to increase their revenue increases of the order of the 4.5% approved for Powerco would add $157.5m to consumer bills.

Transpower has signalled that underlying transmission costs and therefore revenue could fall in the next Regulatory Control Period from 2020 to 2025.[41] However, beyond those dates it is unclear what the outlook for transmission prices is.

[36] All New Zealand prices from MBIE QRSS data available at: http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices/electricity-prices/sales-based-residential-prices.pdf
[37] VaasaETT data in ACCC report, Figure 1.20 based on 37.4 c/kWh in AUD at an August 2018 conversion rate
[38] ACCC report page 5 and Figure 1.3
[39] ACCC report page 7 Figure 1.3
[40] ACCC report page 7 and Figure 1.3
[41] https://www.transpower.co.nz/industry/revenue-and-pricing/revenue

Figure 12 – RCP2 and RCP3 transmission revenue path

	RCP2			RCP3				
$'m	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
HVAC	832.6	817.2	825.9	798.0	755.5	824.4	832.1	820.6
HVDC	145.8	149.4	144.7	116.1	109.2	94.7	95.0	96.3
Total	**978.3**	**966.6**	**970.6**	**914.1**	**864.7**	**919.1**	**927.1**	**916.8**

Source: Transpower

Affordability

7. What are your views on the assessment of the size of the affordability problem?

Regardless of whether prices are fair, equitable, and efficient we know that some customers struggle to pay their power bills. There are multiple reasons for this. They relate not just to electricity costs themselves but to factors such as income level, quality of housing and appliances, the customers' overall level of health, and the availability and cost of other household goods and services.

Assessed on a common 'spending in excess of 10% of income' basis, the First Report points to an improvement in energy poverty statistics over the 2012-2016 period.[42] Explained in the report as largely due to the strong growth in incomes for many households, this result comes as a welcome development. However, as the report identifies, increases in incomes have been far less for some, providing little in the way of real impact on the affordability of all their household costs, electricity included.

Identifying those who are most acutely affected by hardship is not a simple exercise. While extensively used, the 'spending in excess of 10% of income' measure has significant limitations. Such measures miss those who under-spend on electricity but also introduces 'false positives' – those for whom electricity is affordable but simply consume high amounts.

A report by PWC for ERANZ:[43]

- Confirms energy hardship as a multi-faceted problem.
- Supports findings of the Panel that size of the household, network area and housing quality (level of insulation) all have a particularly important influence on energy hardship.

The PWC report, in addition, identifies a group of 44,500 consumers most affected by hardship – that is, a group for whom energy costs exceed a 10% of income threshold (this is up to 175,000 households, from the Panel's estimates) and that are also assessed as meeting additional risk factors. By accounting for these additional risk factors, the 44,500 household group provides an estimate of those most severely affected by hardship.

Finally, regarding the First Report's analysis of disconnection rates, we note the Consumer NZ disconnection statistics referenced are significantly higher than those recorded by the Electricity Authority. Depending on household income group, Consumer's statistics suggest that in the order of 4% to 13% of households have been disconnected for non-payment, whether once or more frequently, for an undefined period. The Electricity Authority's statistics in contrast indicate that

[42] First Report, page 25.

[43] PWC *Definition of Energy Vulnerability in New Zealand October* 2018, page 27.

numbers for the previous 5 years average roughly 0.3% per quarter for Meridian and Powershop, and 0.4% per quarter across the industry.

8. What are your views of the assessment of the causes of the affordability problem?

As acknowledged by the Panel, the causes of energy hardship are wide-ranging and diverse. PWC's research, referenced above, provides valuable insights in this regard. In line with the Panel's research[44], thermal properties of the home, the age of occupants (specifically children under 10 or elderly), and higher cost distribution network areas emerge from PWC's analysis as significant contributing factors.

While underlying causes extend beyond what is in the direct control of the industry, we categorically have a role to play in addressing hardship.

Retailers like Meridian go to significant lengths to support financially vulnerable customers. Meridian has a full-time hardship consultant and we work to identify customers in hardship early so that we can offer them individual support to:

- ensure we understand their situation;
- make sure they are on the best plan for their consumption;
- discuss energy management options;
- connect them with budgeting services or Work and Income;
- smooth payments over a year; and
- ensure they retain their prompt payment discounts (now addressed more directly by Meridian's decision to effectively guarantee such discounts, regardless of time of payment – see below).

As an industry, retailers follow the Electricity Authority's *Guidelines on arrangements to assist vulnerable customers*. Retailers have also developed a *Voluntary Practice Benchmark for Electricity Retailer Credit Management* in 2014 to improve outcomes for vulnerable electricity consumers and monitor consistent compliance with the Guidelines. Amongst other important requirements, these embed the principles of early identification of financially vulnerable customers, working with them to identify government and other sources of financial assistance, and disconnection as a last resort.

Meridian is fully compliant with the Guidelines and Benchmark and we believe both have made significant contributions to improving retailer practices in this area. We would support formal codification of these arrangements to ensure that they are appropriately recognised and followed by all retailers.

Meridian agrees the Low Fixed Charge regulations are detrimental to high-use, low-income households. We support their removal. Meridian's response to question 30 provides further discussion on this point.

In addition, Meridian has recently ended the practice of offering prompt payment discounts. Instead we effectively guarantee customers receive their discount, regardless of when they pay – a move we

[44] Ibid, page 29.

would like other retailers to adopt, as a regulatory requirement if necessary. We strongly believe this will help address affordability issues. The findings from the initial analysis of retailer billing data support this view – in particular the finding that the biggest driver of differences in electricity costs across socio-economic groups is the effect of lost prompt payment discounts and that these raise bills for consumers in the most deprived areas by around $50/year on average and up to $250/year or more in some cases.[45]

Distribution charges

Another means of addressing affordability would be via re-balancing of distribution charges from residential customers to business customers. This warrants close investigation.

As previously discussed, distribution components account for approximately 25% of residential bills and, together with transmission, are the primary source of real cost increases for residential consumers since 1990. The process of rebalancing distribution costs away from business and towards residential consumers has undeniably had a large impact on residential consumers. By the Panel's estimates, distribution costs for households have increased some 548% since 1990.[46] For non-residential consumers, distribution costs are estimated to have reduced by 58%.[47]

Assessed by the Panel as having the potential to provide $90 in average annual consumer savings,[48] Meridian considers the scope for re-balancing distribution charges across different consumer groups should be considered. Trends in distribution costs should be further investigated to determine alignment with actual costs (i.e. cost-reflectiveness) to assist with such analysis. Calculated as an average, we note the Panel's estimated savings may very well disguise variation in the scope for re-assignment across different networks.

In our response to question 22 below, we further discuss the potential to re-balance distribution costs while retaining cost-reflective distribution pricing.

Distribution pricing reform must also be advanced to ensure low income consumers are not unfairly penalised by the uptake of new technology by those that can afford it and the associated avoidance of distribution costs that can result. We discuss this further below under the heading 'Distribution'.

9. What are your views of the assessment of the outlook for the affordability problem?

Meridian strongly supports the Panel's premise that affordability is something industry, regulators and Government must work together on.

Consistent with the Panel's views, and as per our response to question 27, Meridian agrees the emergence of new technologies gives important impetus to reforming distribution charges. This is needed to address the adverse effects for low-income consumers from the commonly used volumetric model of charging (as discussed in more detail under the heading 'Distribution' below). As suggested by the Panel, we also support further investigation of wider Government initiatives to:

- Facilitate housing upgrades – implemented for instance through building code changes, or EECA programmes; and

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45 Electricity Price Review *Initial analysis of retail billing data* 15 October 2018, pages 11-12
46 First Report, page 60.
47 Ibid.
48 Ibid.

- Enhance the Winter Energy Payment, to further assist with alleviating energy hardship. To achieve this in a targeted way, payments for instance could be subject to mean-testing and extended to low-income working households.

10. Summary of feedback on Part three.

- Consumers have diverse interests and priorities – encompassing price, reliability and service-related dimensions such as billing options, sustainability credentials, access to customer support, and consumption tools and analytics.
- A 2018 survey indicates that 83% of consumers are satisfied overall with their retailer.
- Operating in a highly competitive market – retailers work hard to earn and maintain the trust of their customers.
- A range of organisations help consumers to engage with the market including, the Electricity Authority, Utilities Disputes Limited, and Consumer New Zealand. There is always more that could be done to promote existing service providers and Meridian is open to exploring the establishment of a consumer advocate.
- On the whole, electricity prices in New Zealand compare well internationally and are well below the OECD average.
- Price increases have been broadly in line with the underlying costs of providing electricity and are comparable to increases in income levels.
- However, when broken down to individual components it is clear that lines costs, and in particular the rebalancing of such costs from business to residential consumers, have driven the majority of the total increase since 1990.
- Since 2011, the competitive generation and retail components of electricity prices have fallen by 2% in real terms, while the costs attributable to the monopoly lines companies have increased by 20%.
- In future, we would expect competition to continue to constrain generation and retail costs. However, indications are that distribution costs will continue to increase.
- Affordability is a real problem for some customers. Meridian takes significant steps to support such customers.
- We recently ended the practice of offering prompt payment discounts.
- Affordability is something industry, regulators and Government must work on together.

11. Solutions to issues and concerns raised in Part three.

- All the solutions proposed by Meridian are set out in the introductory section of this submission.
- In brief, the solutions to issues and concerns raised in Part three include:
  - Discounts that are conditional upon prompt payment should be regulated so that they do not exceed the costs incurred by a retailer as a result of a customer paying late.
  - The low fixed charge regulations are driving inequitable and perverse outcomes and must be removed.
  - Vulnerable customer guidelines and industry benchmarks should be codified to provide minimum regulatory protections.
  - To assist consumers in the process of comparing retailers, an enhanced price comparison and switching website with links to registry and consumption information should be put in place and retailers required to advertise it on their bills. Refer to the heading 'Retail' for further details.
  - Further investigation should be undertaken on:
    i. re-balancing of distribution charges;
    ii. the establishment of a consumer advocate; and
    iii. the scope to better target the Winter Energy Payment for those most acutely impacted by hardship – the payments could be means-tested and extended to low income working-households.

Industry

Generation

12. What are your views on the assessment of generation sector performance?

The First Report finds that:

> Overall, the generation sector is delivering reliable supply, low and falling emissions, and wholesale prices that are reasonable compared to costs of building new power stations.

Meridian agrees the generation sector is performing well. The finding that "wholesale prices have moved broadly in line with the cost of adding more capacity" is also consistent with Meridian's experiences and expectations. Likewise, we agree with the finding that "there is no evidence contract prices have been above costs on a sustained basis in recent years."[49]

The First Report however expresses concern with respect to short-term market power. Reference is made to the May 2017 letter from the Electricity Authority to Meridian. We discuss this further below but note:

- The May 2017 letter related essentially to high prices in 2 trading periods (a total of an hour) on 2 June 2016;

[49] Taking a different approach, investment analysts UBS looked at the total replacement cost for generators' assets and returns on those assets, concluding that "returns for regulatory purposes are 2-3%. This positions them far below WACC…" UBS *Sector Note: New Zealand Electric Utilities* 31 July 2018

- Despite these high prices, the average wholesale prices at Benmore over the full month of June 2016 were $49.82/MWh;

- By way of comparison, average wholesale prices at Benmore in May and July 2016 were $51.92/MWh and $46.03/MWh respectively; and

- Taking a longer timeframe, the average wholesale prices at Benmore in calendar year 2015 were $64.45/MWh, in 2016 were $50.45/MWh, in 2017 were $76.55/MWh and in 2018 (to 1 October) have been $73.20/MWh – i.e. the yearly averages are all higher than the average observed in June 2016.

Allegations relating to market power are invariably linked to spikes in prices. In New Zealand the trading periods over which price spikes are observed are relatively rare. When they do arise, they are generally linked to dry periods when hydro generation is scarce or to transmission constraints which limit supply to particular areas. Further, as illustrated above, such trading periods are too far and few between to have any significant impact on average wholesale prices. The point is well made in advice given by the retailer Flick to its customers in the FAQ section of the Flick website:[50]

> What's a price spike - and do I need to be worried about them?
>
> Short answer - no. A price spike is when the spot price rises above 30c per kWh for one, and occasionally two, 30-minute trading periods. The prices either side of a spike might be higher than you're used to seeing, too, but they'll quickly subside back to normal levels. From 1 Jan 2014 to 30 March 2018, spot prices have only spiked around 0.20% of the time. That's teeny!

Market power, to the extent it exists in the wholesale market, is transient. The handful of high priced periods observed over the years has had no real impact on the average price paid by purchasers in the wholesale market, which has been remarkably consistent over time. As found in the Report, in inflation-adjusted terms "wholesale prices were roughly the same in 2018 as they were in 2004".[51]

This consistency and the relatively benign nature of average wholesale market pricing has prompted at least a couple of retailers to offer residential customers direct exposure to the wholesale electricity market, effectively making the assessment that the wholesale market is likely to deliver the lowest prices to their consumers over time. Again, as Flick say in their FAQ:[52]

> What's an 'average' spot price?
>
> Jolly good question. Spot prices tend to sit below 6 cents per kWh [equivalent $60 per MWh] a whopping 47.99% of the time, and fall between 6-12 cents per kWh [equivalent to $60 to $120 per MWh] 45.04% of the time. From January 2014 through to 30 June 2018, the average spot price was 6.95 cents per kWh [$69.50 per MWh].

While such pricing is not for everyone and some customers may not be comfortable with the occasional price spikes this delivers, providing retail customers with direct exposure is a tangible demonstration of the transparency, fairness, and efficiency of pricing delivered by the wholesale market over time. These qualities have been demonstrated even during periods of system stress such as the dry winter of 2017, following which the Electricity Authority stated that: [53]

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[50] https://flickelectricsupport.zendesk.com/hc/en-us/articles/360000422775-What-s-a-price-spike-and-do-I-need-to-be-worried-about-them-

[51] First Report, page 22.

[52] https://flickelectricsupport.zendesk.com/hc/en-us/articles/360000422755-What-s-an-average-spot-price-

[53] https://www.ea.govt.nz/dmsdocument/22785

> The wholesale electricity market is workably competitive. This has most recently been demonstrated by the wholesale market response to the dry hydro conditions during winter 2017. Wholesale prices rose to levels that incentivised efficient responses, such as the conservation of hydro storage and the use of demand-side response.

The Electricity Authority monitors the wholesale market and has tools to manage market power including:

- A regime for dealing with undesirable trading situations in Part 5 of the Code – this allows the Authority to reset prices in any trading periods where it considers the use of market power has threatened or may threaten confidence in or the integrity of the wholesale market.

- Trading conduct provisions introduced to Part 13 of the Code in 2014 to require generators to observe a high standard of trading conduct – these allow for the imposition of pecuniary penalties and compensation orders against participants found to have breached the Code.

It is important to note that any market participant is free to allege that another market participant is in breach of these provisions. If that happens the Authority has a duty to investigate. In 2011, following complaints from many participants, Genesis were found by the Authority to have caused an undesirable trading situation by raising offer prices at Huntly to $19,000 per MWh during a transmission outage. As a result, the Authority reset the relevant prices to $3,000 MWh. Since then there have been no findings of an undesirable trading situation over the subsequent 7 years and very few cases even of alleged undesirable trading situations. There have also been no cases where breaches of the trading conduct provisions have been found and again, very few cases where such breaches have even been alleged by a market participant.

As already noted, the First Report refers to a May 2017 letter from the Electricity Authority to Meridian as an example of market power being exercised over a short timeframe. The letter relates to a period of an hour and a half on 2 June 2016 when wholesale prices rose to $4,000 per MWh for 30 minutes, fell back to normal levels for the next 30 minutes and then rose to $3,000 per MWh for 30 minutes. The Authority initially investigated whether there had been an undesirable trading situation at that time. It found there had not been saying "there was no evidence that the existing levels of confidence in, or integrity of, the wholesale market were threatened, or may have been threatened, by the situation."[54] Accordingly it found no undesirable trading situation on 2 June 2016. It also said:

- "The Authority considers the situation on 2 June was within the normal operation of the wholesale market";

- "Meridian's offer behaviour was not an unusual response for a market participant facing the risk of financial loss as a result of the tight and uncertain market conditions that existed in the North Island over the relevant trading periods."; and

- "The offering behaviour of other market participants, and an unscheduled generation outage, had equivalent impacts on the market outcomes to Meridian's offer behaviour".

The Authority subsequently investigated whether Meridian's conduct might amount to a breach of the trading conduct provisions in Part 13 of the Code. The Authority's investigator recommended that the Authority discontinue the investigation because, in his view, no breach was established and there was a strong argument that Meridian had complied with a high standard of trading conduct. The Authority accepted this recommendation and discontinued the matter but expressed the view in

[54] https://www.ea.govt.nz/dmsdocument/21184-uts-2-june-2016-decision-paper

passing that Meridian had breached the trading conduct standard. The basis for the Authority saying this was not clear to Meridian and we did not have the right to challenge the Authority's view before the Rulings Panel because the substantive decision was to discontinue. We have since asked that the trading conduct provisions in the Code be clarified. A project to do this has been commenced by the Authority's Market Development Advisory Group.[55] Meridian supports this process and would like to see it progressed to a quick conclusion.

Although not mentioned in the Review Panel's Report, we note that Vector has commissioned an academic paper from Dr Stephen Poletti of the University of Auckland Business school. Academic, theoretical models like Dr Poletti's are interesting but need to be grounded in reality. Dr Poletti's model assumes that wholesale prices only need to cover the short run marginal costs of generation (i.e. the fuel costs). However, this is only half the story – the reality is that generators need to invest over time to match the growth in demand and maintain reliable supply. To provide the necessary investment signals, investors need to be able to recover their full long run marginal costs of investment and not just short run marginal costs otherwise no-one would ever invest and do business. In the electricity sector, Dr Poletti's model would mean under-investment in capacity and an increase in security of supply issues leading eventually to rolling blackouts and higher prices to redress the supply demand imbalance. At the level of returns suggested by Dr Poletti's model it is also likely that a number of existing generating stations would close as they would not cover their fixed costs of business. We don't think this model is realistic or desirable.

Dr Poletti's analysis is very similar to that undertaken by Frank Wolak in 2009, which was widely criticised at that time by, amongst others, the Treasury:[56]

> "Setting aside any flaws in Professor Wolak's methodology, the $4.3 billion figure for "excess profits" is not credible, as it represents over 90% of the total after-tax profits earned by the five major electricity companies. If these profits had not been made, these companies would have earned relatively small amounts on their billions of dollars of assets – certainly far less than their cost of capital - and would have had insufficient cash flows to fund any of the significant investment in new generation that occurred over 2001 to 2007 and the years following that. Without that investment, New Zealand would most likely be experiencing significant shortages of electricity and (ironically) higher prices."

It was also criticised by Dr Brent Layton, the Chair of the Electricity Authority:[57]

> "the 'competitive benchmark' price based on short run marginal costs used by the [Wolak] report to calculate market power rents is not sufficient to cover the costs of building new capacity and ensuring security of supply. The additional costs of, for example, payments to generators to provide capacity have been missed from the calculations."

See also Dr E Grant Read's description of the New Zealand wholesale market:[58]

> …"this market has been designed to operate just like the vast majority of successful markets operating outside the electricity sector, and with similar cost structures, where pricing above SRMC [short run marginal cost] has always been considered absolutely normal."

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[55] https://www.ea.govt.nz/dmsdocument/22983-letter-to-mdag-2017-18-work-plan-request-to-add-trading-conduct-project

[56] New Zealand Treasury *Report to Cabinet: Regulation of the Electricity Market* 8 March 2012

[57] Dr Brent Layton *The Economics of Electricity* 2013, available at: http://media.nzherald.co.nz/webcontent/document/pdf/201323/Electricity2.pdf

[58] E Grant Read *An Economic Perspective on the New Zealand Electricity Market, 2018 at page 50.*

The peer review of Dr Poletti's paper makes essentially the same point: [59]

> "I would like to observe that industry professionals are increasingly coming to the view that an energy only market will need to deliver prices above (short-run) marginal cost to sustain investment returns … In terms of the market power rents calculated by the author, they may indeed be more than adequate to reward investors, but that would require some investment analysis to confirm."

The investment analysis proposed by the peer reviewer has been undertaken in the Review Panel's First Report. By comparing prices and the costs of building new power stations, the Report finds that:

> "Wholesale prices have moved broadly in line with the cost of adding more capacity. There is no evidence contract prices have been above costs on a sustained basis." …
>
> "The key challenge is the potential need to build new grid connected generation to meet new demand. The market can do this provided strong incentives to invest are maintained."

Meridian strongly agrees with these findings and considers that any statements to the contrary need to be closely examined in the light of the observed benefits of wholesale competition:

- Wholesale prices are in real terms the same now as they were in 2004.
- New Zealand generates 85% of power from renewable sources, up from 65% ten years ago.
- New Zealand has a secure supply of electricity, even in dry hydrological years.
- Since 1996, the New Zealand electricity sector has invested in around 20,000GWh of new electricity generation (i.e. equivalent to around half of NZ's current generation production) at a cost of approximately $9 billion in real terms. This investment has been diversified – it is not dominated by any technology or fuel source or by any single company or companies. And the risks of these investments are borne by private investors rather than directly by taxpayers as they were prior to reform of the sector.

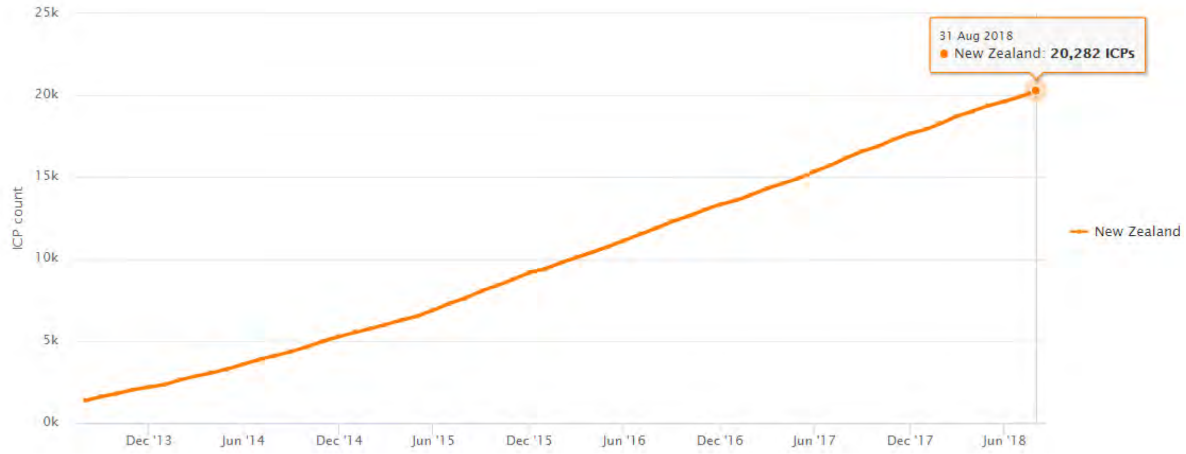
13. What are your views of the assessment of barriers to competition in the generation sector?

Meridian agrees with the statement in the Report that "New Zealand has 34 generators [of more than 1MW], which suggests relatively low barriers to generation competition." The true number of generators in the market is far higher. There are many small scale solar and wind generators and the numbers are growing rapidly. For example, as of September 2018 there were over 20,000 solar generation systems installed in New Zealand:[60]

[59] Professor Derek Bunn *Independent Review of the Report Market Power in the NZ Wholesale Market 2010-2016* July 2018, available at: https://cdn.auckland.ac.nz/assets/business/about/our-research/research-institutes-and-centres/energy-centre/Poletti%20DWB%20Peer%20Review%20on%20the%20Market%20Power%20Analysis%20by%20Stephen%20Poletti.pdf

[60] https://www.emi.ea.govt.nz

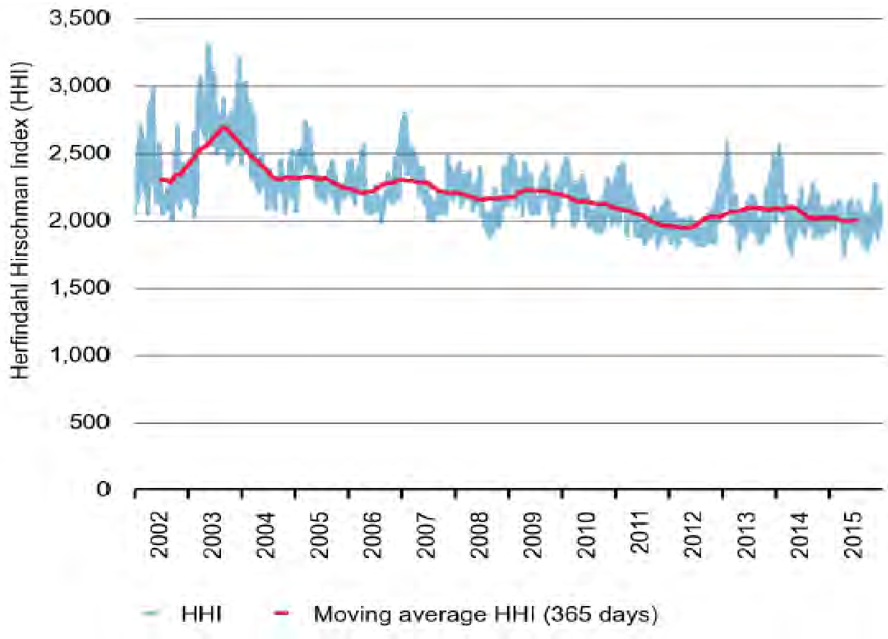
Figure 13 – Installed distributed solar generation



Source: EMI

Anyone can invest in generation in New Zealand and Electricity Authority HHI data shows that the wholesale market is increasingly competitive over time:[61]

Figure 14 – Daily generation HHI



Source: Electricity Authority

The First Report discusses the 'virtual asset swap' agreements between Genesis, Mercury and Meridian that were the result of the 2009 ministerial review of the industry. These agreements, signed in 2010, expire in 2025 and seek to make generators more geographically balanced. We do not consider the virtual asset swaps to be strictly necessary to promote retail competition any longer given subsequent developments in retailing and in volumes traded via ASX and OTC contract markets, which also assist in managing locational risk. To a large extent the virtual asset swaps have

[61] Electricity Authority *Market Performance Review 2015* available at https://www.ea.govt.nz/dmsdocument/20488

achieved their purposes. However, if regulators or the Government considered it necessary for the virtual asset swaps to continue Meridian would be open to this.

Further comment on contract or hedge markets is below under the heading “Vertical integration”.

14. What are your views on whether current arrangements will ensure sufficient new generation to meet demand?

Meridian agrees that a key and welcome challenge for the sector is the forecast need to build a lot of new generation as decarbonisation of the economy results in a widespread electrification of transport and industrial processes.

We also agree that the current market and industry arrangements will ensure sufficient new generation to meet the increased level of demand, provided current strong incentives to invest in generation are maintained. The First Report is correct that large scale grid connected generation will be necessary to meet most of the increased demand. Small-scale renewable generation has a role to play but will not be nearly enough on its own to meet future electricity demand.

As we understand it, Meridian’s view that current market and industry arrangements will ensure sufficient new generation is largely shared by other generators and generation investors. As already indicated, the amount of new generation delivered by private investors since the current market and industry arrangements were put in place is huge, and it seems to us likely that appropriate and timely levels of investment will continue to be made provided current market arrangements are retained.

Stevenson and others, in their work for the Productivity Commission, look ahead to 2050 and ask whether “the current energy only wholesale market [will continue to] deliver resource adequacy in a low emissions environment” over that timeframe.[62] They don’t reach firm conclusions and acknowledge that:

> It is possible that bilateral contracting between major suppliers for capacity may serve to keep stand-by generation available and that has been the case in recent years. However, if lower average annual wholesale prices do result from higher levels of renewable energy lower contract prices may also soften which would, in turn deter investment in flexible plant.

Meridian observes that the increase from a 65% renewable energy system to an 85% renewable energy system in the last 10 years has not brought with it lower average annual wholesale prices. The First Report finds the level of wholesale prices is the same now as it was in 2004. The Productivity Commission characterise the issue raised by Stevenson and others as whether “at some time in the future” New Zealand will require, alongside it’s current ‘energy-only’ market, a market for firm energy to ensure there is sufficient thermal or other firm generation to cover periods of severe hydro shortfall. They say:

> Yet a useful market for firm energy already exists, though it mostly operates among the large generators and gentailers. In particular, Genesis has retained the Huntly Rankine plants for use under a voluntary “swaption” agreement with Meridian (which runs hydro and wind generation) (New Zealand Herald, 2016). Meridian also has demand response arrangements with the Tiwai

[62] Stevenson, T., Batstone, S., Reeve, D., Poynton, M., & Comendant, C. (2018). *Transition to zero net emissions by 2050: Moving to a very low-emissions electricity system in New Zealand*. Wellington: New Zealand Productivity Commission.

> Point aluminium smelter that effectively provides it with firm energy in the event of a dry year. In addition, Huntly provides Genesis with firm-energy cover for its retail base.

We agree. We also agree with the submission of the Electricity Authority to the Productivity Commission who said:

> For over 20 years the spot market has operated effectively in providing signals for efficient generation investment, including to manage dry years. This has been supported in more recent years by well functioning hedge and futures markets that provide parties with the means to enter into forward contracts … without the prescription of a formal capacity mechanism that can be readily gamed. Key Authority initiatives—including the development of cap hedge products, and introduction of more accurate prices and nodal scarcity prices through real-time pricing—will provide further support for parties to forward contract to manage risks, including dry year risk, into the future. These latter initiatives are good examples of how the Authority is able to continue to evolve the design of the market to ensure that it delivers long term benefits to consumers.

There have been a number of recently commissioned or recently announced investments in new generation in the last few months[63] and these, in combination with Methanex's recent commitment to extend gas contracts out to 2029 (thus providing potentially significant upstream gas flexibility) suggest the current investment environment is fundamentally sound and there is no immediate need to consider changes to market arrangements or to tweak the energy-only market design. On the contrary such a move raises risks of unintended consequences. The Authority refers to gaming risks and the experience in other countries is that capacity markets have not performed as expected and where implemented generally have increased costs to consumers.[64]

Meridian anticipates that over the next ten plus years New Zealand can seamlessly transition to a system that is around 95 percent renewable. This is provided the fundamentals of our current market system are maintained. Policy makers should resist calls to add reserve energy capacity or any other "market" that provide subsidies for particular types of generation. New Zealand is in a unique position globally with a wealth of renewable electricity resources and a wide range of competitive renewable electricity generation development options including wind, geothermal, and hydro that can be expected over time and with the right investment signals to progressively displace existing thermal generation.

We also agree with the First Report of the Electricity Price Review and the Productivity Commission that under current available technology, pushing too soon towards 100 percent renewable generation could raise electricity prices and make it harder to achieve net-zero emissions for the country as a whole. Over time, improvements in technology will enable 100 percent renewable electricity generation, the only question is when such technologies will become economically viable. Technologies that enable greater demand side participation in wholesale markets are likely to play a key role. Rather than setting sector specific targets, Meridian supports the use of the Emissions Trading Scheme as the main policy tool to incentivise economy-wide emissions reductions over time in the most efficient manner.

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[63] For example the Te Ahi o Maui geothermal plant – see http://www.eastland.nz/eastland-generation/projects/te-ahi-o-maui/, the Ngawha geothermal expansion project – see http://ngawhageneration.co.nz/background/, Todd Energy's new open cycle gas turbine at Junction Road, and the Waverley wind farm Waverley wind farm: http://www.scoop.co.nz/stories/BU1810/S00485/genesis-and-tilt-renewables-announce-plan-for-waverley-wind.htm.

[64] See for example https://www.greentechmedia.com/articles/read/the-perils-of-electricity-capacity-markets#gs.3B05mHw and https://www.cleanenergywire.org/factsheets/capacity-markets-around-world

Professor Lewis Evans has recently reviewed the suitability of New Zealand's current market arrangements for a future of renewable, intermittent generation that has low operating costs but high capital investment costs at the development stage. He concludes that where storage of generation fuel and electricity are common (as occurs in our hydro lakes), spot markets may continue their role of coordination of real-time supply and demand and, together with hedge markets, deliver an efficient wholesale market for electricity.[65]

Resource Management Act barriers

There is however some scope for delay and increased costs for the transition to a low emissions future in the form of barriers under the Resource Management Act. These will potentially constrain and hold back investment in renewable electricity generation and add costs for renewable developers and consumers.

Meridian believes this needs to be addressed relatively urgently as resource management processes are essentially determined by policy and planning processes which implement change slowly over a decade or more i.e. changes made now may not be felt for a while. A lot of wind generation will need to be built or upgraded in the next few years and critically, New Zealand's two largest hydro schemes will need to go through re-consenting – Waitaki by 2025 and Manapouri by 2031. If the Government wishes to address potential barriers and encourage investment in renewable electricity generation we suggest the following priorities need to be considered:

- A new National Policy Statement for Renewable Electricity Generation to be clearer and more directive about the outcomes the Government wants to achieve for renewable electricity and climate change.
- Populate Appendix 3 of the National Policy Statement for Freshwater Management with significant hydro generation infrastructure such as the Manapouri and Waitaki schemes.
- Move Climate Change and Renewable Generation from section 7 to section 6 of the Resource Management Act.
- Allow for resource consent durations longer than 35 years.
- Increase the default five-year lapsing date for renewable generation consents.
- Develop National Environmental Standards or National Planning Standards that enable renewable electricity generation including zoning and noise standards.
- Define the existing environment for the purposes of planning and reconsenting in areas with existing renewable generation activities.

These priorities are further detailed in our submission on the Productivity Commission's *Low-emissions economy* inquiry.[66]

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[65] Lewis Evans *The electricity sport market: Is it future proof?* The Electricity Journal, Volume 30, Issue 2, March 2017, Pages 25-29

[66] https://www.productivity.govt.nz/sites/default/files/sub-low-emissions-253-meridian-energy-701Kb.pdf

Retailing

15. What are your views on the assessment of retail sector performance?

Switching

The New Zealand retail market is fiercely competitive.

New Zealand is one of the easiest places in the world to compare and switch electricity suppliers and around 21 percent of consumers switch their retailer each year. In 2017 there were more than 439,711 switches between retailers - the highest level on record.

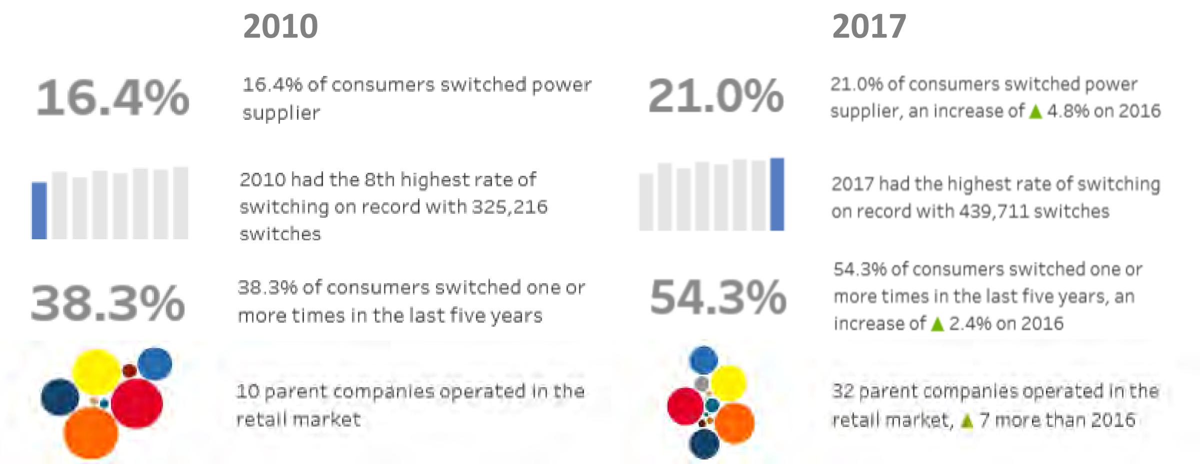
According to the then Chief Executive of the Electricity Authority:[67]

> Around 26% of electricity consumers switch electricity retailer each year.[68] Based on a survey in 2016 we know that 30% of consumers actively investigated switching retailers in that year and decided not to do so. This shows around 55% of consumers are actively shopping around in a single year. A great result.

This is consistent with a 2018 Consumer NZ survey that found around half of all consumers considered changing electricity retailers in the past 12 months.[69] Even if a consumer does not proactively shop around, an Electricity Authority study found that high levels of competitive activity "saw 69% of New Zealand households being approached by a competitor in the past two years, significantly higher than in other markets."[70]

The Authority's statistics below show just how much the industry has evolved over the past seven years with competition increasing and delivering better consumer outcomes every year:[71]

Figure 15 – Retail market snapshots 2010 and 2017



Source: Electricity Authority

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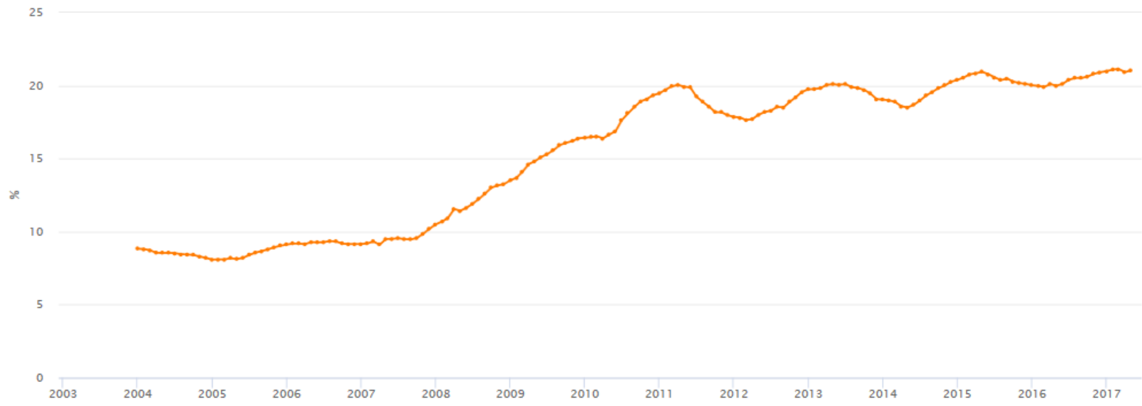
[67] *Market Commentary: Chief Executive's Introduction* 21 June 2018
[68] Taking into account withdrawn switches
[69] Consumer *Energy Provider Retailers Survey* 2018
[70] Electricity Authority *International comparison of activity, behaviour and attitudes towards electricity industry - A quantitative study* August 2014
[71] https://www.ea.govt.nz/monitoring/retail-market-snapshot/

Figure 16 – Switching rate in New Zealand (rolling 12-month rate)



Source: EMI

The First Report acknowledges uncertainty surrounding how many, and what type of consumers do not switch but finds that between 400,000 to 750,000 residential consumers have not switched retailer since 2002. When considering these numbers, it is important to bear in mind:

- The numbers are based on addresses (ICPs) switching and not the actual switching of consumers, for example if the new occupants of a flat happen by chance to choose the same retailer as the former owners this will not show up in the statistics as a switch. This suggests the number of non-switchers may be over inflated.

- Just because someone has not recently switched does not mean that they do not benefit from retail competition. For example, many of these consumers will not have switched because:

  - they are happy with their provider or have received a price or other incentives to stay; or

  - they have made a choice not to bother, despite the ease of switching in New Zealand, as the potential savings are not sufficient to motivate them.

Potential savings

The First Report cites the Electricity Authority estimate of average residential savings of around $200 a year if all consumers switched to the cheapest plan available to them. This figure is an estimate and assumes that every customer switches every month to the best offer in the market, meaning up to 12 switches every year – we question whether this is likely, especially given that for the estimated level of savings on offer ($200 per year amounts to about $17 a month) many people will choose to do other things with their time rather than spend it checking every month whether there is a sharper offer available.

The Price Review Panel's initial analysis of retail billing data suggests a similar but slightly higher level of average saving. It is unclear to us whether the methodology used makes the same assumption about monthly switching. What is clear, is that the analysis takes into account fixed term offers but somewhat problematically does not consider the disadvantages for a customer that might exist when a fixed term is broken. This suggests the level of savings may be over-estimated (i.e. switching each and every month may attract exit fees which have not been factored into the analysis).

The First Report states that those who don't or can't easily shop around are paying more than they need to. It is important to differentiate between those that don't shop around as a matter of choice, and those that can't shop around, for example due to age or financial vulnerability. Meridian supports measures to ensure that vulnerable customers can take full advantage of the benefits of competition. For example, a more heavily promoted enhanced price comparison site could help reduce any consumer confusion or mistrust of the switching process.

Such a site may need to be more heavily funded and promoted than the existing Electricity Authority 'What's My Number' site or other existing price comparison sites such as Consumer Powerswitch. It may also need to be enhanced and expanded to better explain the differences in service and other non-price components of different retailers' offerings. Linking the site to the Registry would ensure that price comparisons are made on the basis of the correct meter configuration for the property and enabling customers to authorise the linking of their consumption information to the site would ensure price comparisons were as accurate as reasonably possible. In addition, retailers could be required to communicate in a standardised format on all customer bills:

- the benefits of switching; and
- the logo and details of the enhanced switching site.

This would ensure that all consumers are better aware of any potential savings available and can make more informed choices about the best option for their needs.

Price differences

The First Report looks at the price difference between the cheapest retailer in each area and the retailer there when retail competition was introduced in the late 1990s (the 'incumbent' retailer) and finds that the price difference increased by about 50 percent between 2002 and 2014. It is unclear from the data whether the incumbents have become more expensive or retail competition means the cheapest offer in an area has become relatively cheaper e.g. because there are more low cost (for example online only) retail options in the market.

Such price differences are not surprising given the extent of competition in the retail market and the increasing range of differentiated service offers available. The benefits of price differentiation in competitive markets are well described in economic literature[72] and have been discussed in recent overseas market investigations. Retailers in any competitive market will make sharp price offers to try and win customers and grow their businesses. This is especially the case in a market like electricity where shopping around and switching suppliers requires some effort compared to continuing a relationship with the existing supplier.[73] A certain level of expected saving is necessary to make it worthwhile for consumers.

Those that switch can benefit from lower prices. However, differentiated price offerings also benefit those that do not switch. The threat of losing a customer to a competitor applies downward pressure on prices in general. If there was no price differentiation it would be much harder to induce customer switching, retailers would become complacent, and competition and innovation would suffer. It is also a myth that prices would coalesce at the level of the lowest price offers currently in the market – you would in fact expect average prices to be higher overall due to reduced competition.

[72] For an overview see CEG *Competition in New Zealand electricity markets* 2018

[73] This is a dynamic that also holds generally for electricity markets around the world, and wider relationship-based service products (other utilities and financial services – banking and insurance for instance).

The Authority, in implementing tariff disclosure requirements in 2016, endorsed these considerations – in particular by opposing mandatory provision of non-generally available tariff information (e.g. special tariffs offered further to retailers contacting consumers directly), with risks of harmful effects on innovation and competition cited as its primary reasons for this.[74] Independent research findings commissioned by the Authority also reinforced this view.

Accompanying this submission are reports by CEG and Stephen Littlechild which provide further analysis in support of positive benefits overall for consumers from differential pricing.

Prompt Payment Discounts

According to the First Report, "analysis of retailer billing data shows vulnerable households are disproportionately affected by prompt payment discounts." The Review's initial analysis of retailer billing data finds that:[75]

> *Consumers living in the most deprived areas pay around $79/year more on average for their power than consumers in the least deprived areas – after adjusting for other differences such as usage levels. This figure almost certainly understates the true level of difference (see main text for reasons).*
>
> *The biggest driver of differences across socio-economic groups is the effect of lost prompt payment discounts. These raise bills for consumers in the most deprived areas by around $50/year on average. Again the average hides a wide dispersion of outcomes. The data indicates five per cent of consumers in the most deprived areas pay additional costs of $250/year or more due to lost prompt payment discounts.*

This is consistent with Meridian analysis. Meridian recently announced that from 1 October 2018 we will remove prompt payment discounts across all customer segments, instead effectively guaranteeing discounts for all customers regardless of whether they pay on time.

We estimate that by taking this step our customers will save $5 million per annum. If all retailers took similar action to guarantee prompt payment discounts, we estimate that it would save consumers (particularly low-income consumers) around $40 million per annum in total. It is likely the Price Review Panel will be able to more accurately estimate consumer benefit based on the two years of billing data made available to them.

Meridian encourages other retailers to eliminate or at least limit the level of prompt payment discounts. Prompt payment discounts were never intended to operate as they do now. Over time the level of discount has been 'competed up'. Now for many consumers the level of prompt payment discount is such that they cannot afford to pay late. This has the potential to be punitive, particularly for vulnerable customers, and should stop. We believe the problem is sufficiently serious that the Price Review Panel should consider recommending the regulation of prompt payment discounts so that they are set no higher than the reasonable costs to the retailer of a consumer paying late.

Meridian's decision to discontinue prompt payment discounts and instead make such discounts available to all customers regardless of whether they pay on time, has predictably provoked a strong reaction from some of our competitors. The New Zealand Herald article of 9 October 2018 states:

[74] Refer for further details: https://www.ea.govt.nz/dmsdocument/20115-access-to-tariff-and-connection-data-decisions-and-reasons-paper

[75] Electricity Price Review, Initial Analysis of Retail Billing Data, 15 October 2018, at page 3.

> Genesis has labelled Meridian's statements regarding prompt payment discounts ''unhelpful'', in a sign of intense pressure felt by power companies facing a pricing review and locked in a heated battle for customers.

Customer satisfaction

According to the 2018 Consumer Energy Provider Retailers Survey, 83 percent of customers are satisfied with their electricity retailer. This is an excellent result compared to other countries and sectors.

On the other hand, the First Report refers to Utilities Disputes Limited (UDL) complaints as an indicator of consumer satisfaction, seemingly suggesting that there are relatively high numbers of complaints, and therefore low levels of satisfaction with retailers.

This is not correct. The 2,233 complaints referred to in the First Report are for all schemes operated by UDL including energy, broadband shared access, and water providers. Only 2,053 of these complaints related to the energy scheme and this covers distributors, gas and LPG providers as well as Transpower. As a point of comparison Meridian received 338,606 calls and emails to its contact centre over the same period. The industry figure would be far greater.

More importantly, the figure of 2,053 complaints covers all complaints which come to UDL's attention, and complaint is defined very broadly as an expression of dissatisfaction where a response is explicitly or implicitly expected. The vast majority of these complaints are never dealt with by UDL but are instead resolved to the customer's satisfaction directly between the energy provider and their customers. The key statistic is deadlock complaints, which are complaints that a retailer has not been able to resolve to the customer's satisfaction and which have gone to UDL for consideration. We are advised by UDL that 77 of these complaints related to retailers in 2017-18 (i.e. around 0.004% of all electricity consumers). The total number of deadlock complaints across all energy providers (i.e. including electricity retailers, distributors, gas and LPG providers and Transpower) was 141 – this was a significant reduction on the previous two years and we believe it compares favourably with the figures quoted in the First Report for banking and insurance.[76]

Innovation

The competitive intensity in the retail market means electricity suppliers are forced to innovate. The result is an array of retail offerings pitched at different customer preferences and providing customers with a wide range of choice including online and traditional service models, pre-payment, smooth pay, spot price, and time of use pricing (including special electric vehicle rates) as well as different approaches to providing customers with billing and usage information and tools. For example, Meridian offers plans for electric vehicle charging with low overnight rates and our online tools help customers track and manage their daily energy use. Meridian's subsidiary Powershop uses a mobile app to inform customers about the electricity they are using and how much it costs as well as offering electricity specials and packs enabling payment in advance, as you go, or set and forget. Powershop New Zealand also took a number of innovative new offerings to market in 2018 such as *Get Shifty*, which is a time-of-use offering for residential customers and *Power for Good*, which allows customers to contribute to a selected charity.

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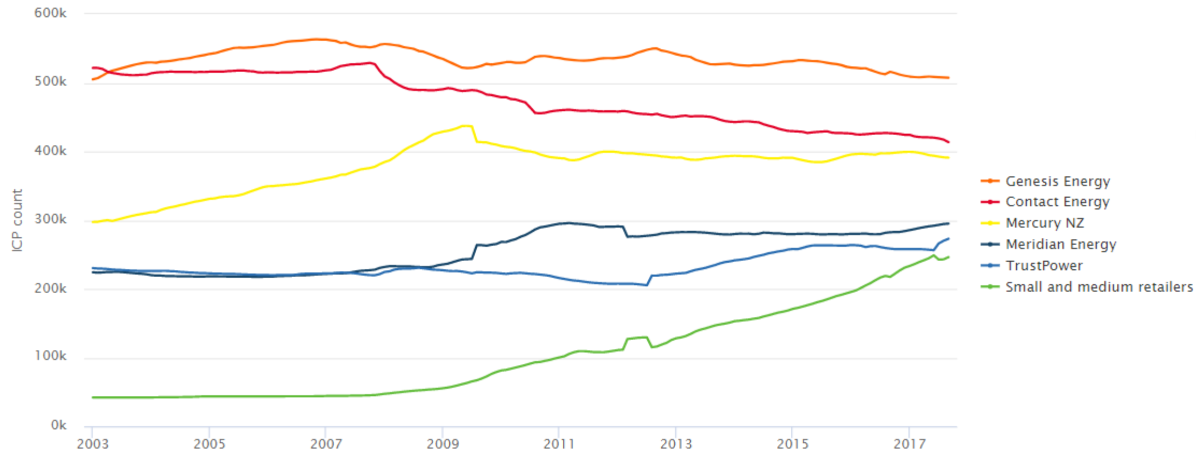
[76] For further details see UDL *Annual Report 2017-18*, page 6. Available at: http://media.utilitiesdisputes.org.nz/media/Annual%20Reports/2018%20Annual%20Report.pdf We understand the figure of 147 cases accepted for consideration includes six broadband shared access complaints or disputes.

As already noted, as well as driving innovation, intense competition is driving good price outcomes for consumers. Since 2011 there has been no real price increase to consumers arising from the competitive parts of the electricity supply chain (generation and retail), in fact, average prices have fallen by 0.35 c/kWh between 2011 and 2018.

16. What are your views on the assessment of barriers to competition in retailing?

Meridian believes that with the two exceptions mentioned below there are no barriers to competition in retailing. We agree with the Price Review Panel that the fact that 28 of today's retailers have entered the market since 2005 is strong evidence against any suggestion otherwise. We also note that small and medium sized retailers have significantly increased their market share since 2009.

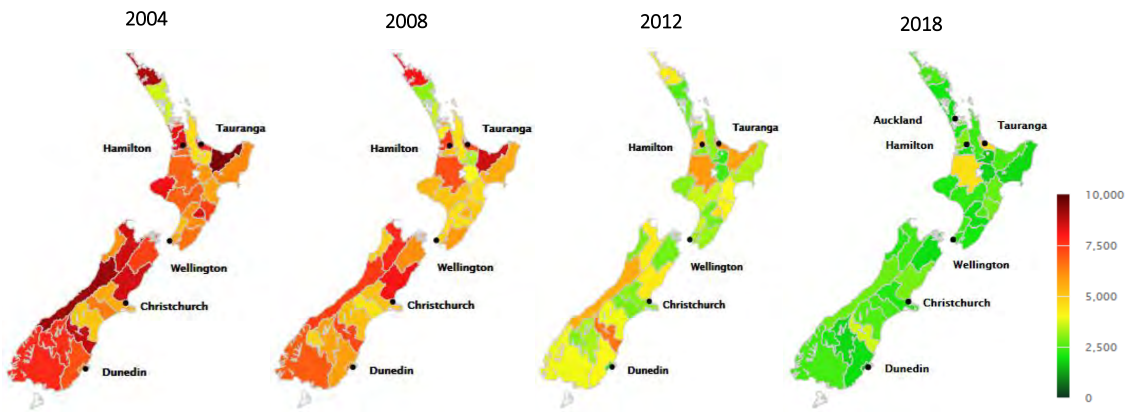
Figure 17 – Market share trends



Source: EMI

As a result, the Authority's data shows that "market concentration in the retail market has significantly reduced over the last 10 years indicating that competition in the retail market is working effectively."[77]

Figure 18 – HHI trend across network regions



Source: EMI

[77] https://www.emi.ea.govt.nz/Retail/Reports/IK41HT?_si=tg|market-structure,v|3

This data undermines claims by some retailers of barriers to entry or competition.

One such claim is that win-back discounts are a barrier to expansion. In reality, win-backs are a product of, and evidence of a highly competitive market where consumers get the direct benefit of competing offers and counter-offers from suppliers looking to win or retain a consumer's business. Meridian cautions against any measure than might restrict this competitive dynamic. All retailers are free to engage in win-back activity and most win-back competition takes place between larger retailers. It is not clear to us that restrictions on win-back activity would benefit customers. The same conclusion was reached in Australia in the ACCC inquiry.[78]

Another claim sometimes made by independent retailers is that they cannot access risk management contracts on competitive terms. We do not believe the evidence supports this claim as we discuss below under the heading "Vertical integration".

One actual barrier to retail competition is the payment of rebates to the customers of some retailers only. In many network regions, network rebates are paid to all customers on the network. While we question the efficiency of network companies charging customers higher lines charges so those customers' own money can be recycled to them in the form of a rebate – there is no impact on retail competition per se. However, consumers who live in Tauranga City or Western Bay of Plenty District only receive a payment from the Tauranga Energy Consumer Trust (TECT) if they are a customer of Trustpower. This gives Trustpower a significant competitive advantage over other retailers and, as a result, the region is comfortably the least competitive retail market in the whole of New Zealand.[79] The TECT payments enable Trustpower to preserve a high market share even though there are many cheaper offers from other retailers.

One final barrier worth mentioning is the requirement for retailers to negotiate use of systems agreements with each of the 29 distribution networks on which they wish to trade. This is discussed further below in our response to question 31.

Vertical integration

17. What are your views on this assessment of vertical integration and the contract market?

Benefits of vertical integration

Some electricity companies combine a retail business with generation or a generation business with retail – so-called vertical integration. Meridian's view is that vertical integration is an efficient business structure and is generally positive for contract markets. This is because, as discussed below, it is not possible for a company to be perfectly integrated. As a result vertically integrated companies still have strong incentives to buy and sell contracts to other participants including stand-alone generators and retailers. We note that vertical integration was considered in the UK CMA inquiry where it was concluded that the benefits of vertical integration significantly outweighed any concerns.[80] In Australia the ACCC has recently remarked on the trend to vertical integration in that market saying "The ACCC accepts that the market trend towards vertical integration likely reflects

[78] ACCC *Restoring electricity affordability & Australia's competitive advantage* 2018, section 6.4.4 https://www.accc.gov.au/publications/restoring-electricity-affordability-australias-competitive-advantage

[79] https://www.emi.ea.govt.nz

[80] CMA *Energy Market investigation* 2016, from page 340. Available at https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf

competitive advantages of such a business structure, and that vertical integration therefore has the potential to be pro-competitive. Indeed, a number of small and medium sized retailers are vertically integrated, or are pursuing vertical integration."[81]

The option of vertically integrating is open to any retailer or generator. Businesses which have up to that point chosen to operate as a stand-alone retail or generation business can decide at any time to do things differently and invest in generation or retail as appropriate. Entry into the generation market need not be done through the physical construction or acquisition of generation assets. Instead a stand-alone retailer could sign a power purchase agreement (PPA) whereby it acquires the generation or a portion of the generation of certain generation assets. Other than access to capital, there is nothing stopping firms competing in this way if they choose. Indeed, there are a number of smaller generator retailers – it is not a business model that is the preserve of large companies. In Australia, where Meridian has a small share of the retail market (2% of residential connections in Victoria, less in other states, meaning we are of comparable scale to Pulse, Electric Kiwi, Flick and Vocus in the New Zealand market) we have recently invested in some small hydro stations and PPAs to support the growth of our Powershop Australia retail business.

Worldwide, vertical integration is common in electricity sector businesses. This is because it delivers efficiencies, enables better management of risk and lowers the cost of doing business. The motivations for maintaining a vertically integrated position with retail and generation include:

- the retail business provides a spot market hedge to the generation business and vice versa;
- larger corporate size and resulting efficiencies of scale, reduced transaction costs, greater internal diversity of thought and initiatives, and increased brand and company recognition; and
- larger balance sheet, reduced cost of capital, and enhanced ability to secure finance and undertake large-scale generation investments.

Retailers that are vertically integrated with generators have a natural hedge because the generation side of the business does well with high spot prices while the retail side of the business does well with low spot prices. Integration therefore reduces risk by insulating the business to some extent against spot market variations caused by climactic conditions, price spikes, and plant outages although, as discussed below, the 'hedge' provided by the other part of the business is never perfect. The resulting earnings stability is important for a listed company as it allows greater certainty of operating cash flows to cover costs and payment of a stable dividend. The reduced risk is also viewed positively by investors and lowers the cost of debt.

A greater level of vertical integration generally reduces any risk of misuse of market power. As shown by Hogan and Meade:[82]

> This is because any extra profits they secure at the wholesale level translate into reduced retail-level profits, given that the wholesale price is an input cost to their own retail arm. Conversely, non-integrated generators with market power, or integrated generators with unbalanced generation and load, do face incentives to manipulate wholesale prices.

[81] ACCC, Retail Electricity Pricing Inquiry—Final Report, June 2018, page 131.

[82] Seamus Hogan and Richard Meade *Vertical Integration and Market Power in Electricity Markets* (February 2007) available at: http://researcharchive.vuw.ac.nz/xmlui/bitstream/handle/10063/3953/180207_VI_and_MArket_RM_an_d_SH.pdf?sequence=1

Claims of limits to competition resulting from vertical integration

Claims are sometimes made that vertical integration limits competition in retail and wholesale markets, and in particular affects the liquidity of contract markets and the ability of participants to secure hedges. These claims do not stack up.

First, and as we have pointed out above, if vertical integration offers advantages, there is nothing to stop a retailer or generator adopting that model.

Secondly, competition at both the wholesale and retail level is intense. The parties growing both retail volumes and customers in the New Zealand market at present are small independent retailers. These parties are likely to be supported by contract markets. It is not obvious that vertical integration is holding them back.

The better view is that vertically integrated businesses also need and benefit from well-functioning contract markets and have a strong stake in their success. Meridian relies heavily on contract markets to manage our business.

As noted by CEG vertically integrated companies need hedge markets because it is not possible for the retail side of vertically integrated business to fully hedge the generation side, or vice versa. As a result, they say:

> …the potential for adverse competition outcomes are small (and smaller than the adverse outcomes that would flow from preventing retailers and generators adopting the most efficient business structure). Ultimately, no party is truly capable of being perfectly vertically integrated (in that the 'shape' of generation output perfectly matches the 'shape' of retail sales).

This is particularly the case in New Zealand because of the high percentage of hydro generation. Unpredictable inflows and their impact on a hydro generator's ability to generate, along with the ever-present risk of a prolonged dry period, mean that hydro generators are strongly incentivised to trade contracts to manage variability. This is part of the reason New Zealand has a healthy contract market that includes the over-the-counter market (OTC), the Australian Securities Exchange (ASX) futures and options market and the Financial Transmission Rights (FTR) market.

ASX liquidity and volume

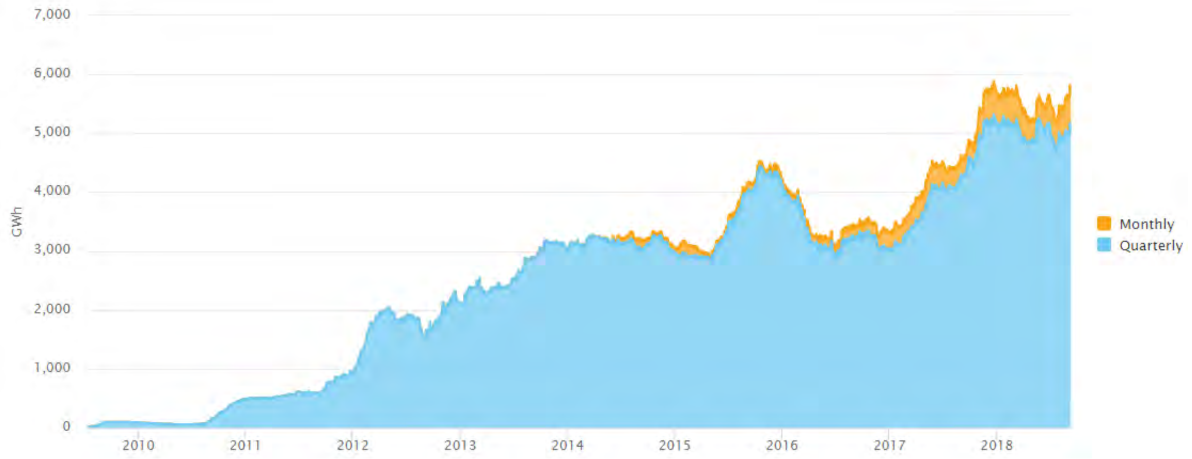
At the end of 2017 the Electricity Authority reported that:[83]

> "The total value at risk on the ASX NZ futures and options market has reached record levels. At the end of November, 'open interest' in ASX contracts reached a peak of around 5,750 GWh, which equates to approximately 65 per cent of the total volume of the physical electricity market, up from around 4,500 GWh in November 2015."

Open interest in this context is the total volume of electricity traded under futures or options which have still to be settled. It is a practical measure of skin in the game and often used as an indicator of liquidity. As seen below, open interest on the ASX has grown significantly over the years and is now at record levels.

[83] https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/market-insights/hedge-market-breaks-records/

Figure 19 – Open interest in ASX products for the New Zealand electricity forward market



Source: EMI

Other measures also demonstrate the strength of the ASX, for example:

- Trading volumes on ASX have grown materially over time, so that over the period from the start of 2017 till now they represent 61% of the NZ market's physical generation sales (or around 2100 GWh a month traded).[84]

- Total ASX volume traded by Meridian over the same period was the equivalent of 55% of the generation produced by Meridian.[85] We note that as a market maker, many of these trades are not in Meridian's interest to hold onto and as a result they cost Meridian money when we trade out of them. Meridian's trades for its Portfolio (i.e. non-market-making trades) still represented 15% of our generation production over that period. If Over-the-Counter transactions are taken into account, Meridian places 31% of its generation production on hedge markets for Portfolio purposes.

The reality is that the hedge market and ASX specifically are fundamental to supporting Meridian's business. We buy and sell material volumes through ASX. This growth in ASX traded volumes has been supported in large part by the voluntary market making commitments of four vertically integrated businesses, Meridian, Mercury, Genesis and Contact Energy (the market-makers). We note that other large, well capitalised, vertically integrated businesses like Trustpower and Nova have not provided this market making service. While we cannot talk for them, our guess is that they do not do this because of the cost of providing market making. These costs are real, and material, but Meridian and others have chosen to voluntarily bear them to date.[86] With a broader group of market makers, ASX traded volumes would be larger again.

Another sign of the strength of the ASX futures market is the substantial number of new participants. ASX data shows that over time the proportion of activity by non-market-makers (non-MM) has increased significantly. Around two thirds of all trades now involve non-market-makers.

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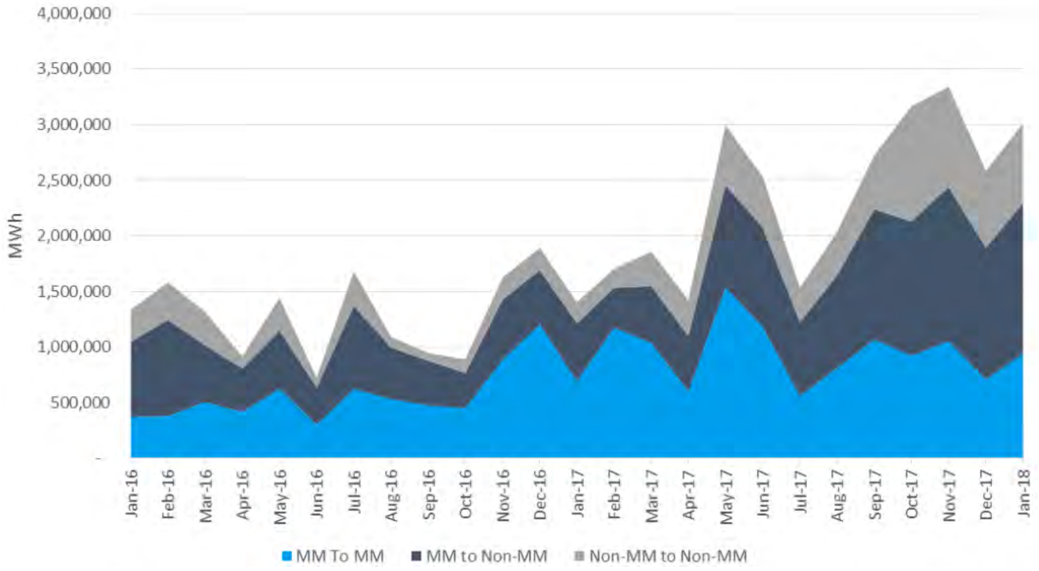
[84] Meridian completed an analysis of all ASX trades since the start of the 2017 calendar year to calculate this figure

[85] Ibid.

[86] Market-making costs Meridian approximately $**[ ]** per annum. Contact's 2018 results presentation indicated that market making cost them $2 million that year.

Figure 20 – ASX trading by counterparty type



Source: ASX

ASX prices

Another claim sometimes made by stand-alone retailers is that prices on the ASX are too high.[87]

Claims that ASX prices make it too difficult for independent retailers to compete have been analysed and rejected by the Electricity Authority.[88] The Price Review Panel refers to the Electricity Authority's findings in its 2017 review of fixed price variable volume (FPVV) offers to commercial customers. The Authority found no "evidence to substantiate the claim that there is systemic discounting in the FPVV market relative to the ASX." The Panel nevertheless remarks that the Authority's finding that FPVV prices were lower than ASX in 12 per cent of cases is a cause for concern. We disagree and note:

- Vertically integrated firms do not 'set' prices on the ASX, there are many ASX participants and ASX prices are a product of their interactions.
- ASX prices are variable and can be especially volatile in the short term. It would not be a surprise if FPVV contracts formed at a date that coincided with high ASX prices, were priced lower than the ASX peak on that date. Similarly given the volatility of ASX there will be times, over the course of an FPVV contract, when the ASX price is higher than the FPVV price. FPVV prices will be set based on an average or smoothed projection of forward prices on the ASX. Meridian's FPVV offers are based on a 'smoothed' view of historic ASX prices that we then project forward over the duration of the proposed FPVV contract (up to 2

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[87] These claims can be contrasted with the claims of some stand-alone generators who believe that spot market prices are too low. The Chief Executive of NZ Windfarms, a stand-alone generator, as quoted in Energy News:

> *'The issue of the "missing bucket of money" for the country's wind generation must be addressed in order to ensure there will be future renewable energy investment" and "… wind receives low revenues when there is wind…"*

See: http://www.energynews.co.nz/news-story/wind/38577/changes-wholesale-market-structure-needed-wind-nz-windfarms?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

[88] https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2017/review-of-fixed-price-variable-volume-commercial-offers and https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2018/2017-winter-review/

years+). The aim is to produce a competitive market offer that includes estimated adjustments for location and profile of the customer's expected load.

- Some larger FPVV customers look to the ASX directly as an alternative to the FPVV offers they get from retailers – trading on the ASX comes with higher costs but there is a degree of substitutability.

- The fact that 88% of FPVV contract offers over the 6-year period analysed by the Authority were above ASX prices indicates that the vast majority of the FPVV market could be contested by an independent retailer also pricing off ASX.

- The FPVV market is very competitive and margins are tight. It is probably to be expected in a competitive market where no one has perfect price foresight that a relatively small proportion of fixed-price, variable-volume commercial offers prove to be less than settlement prices on the ASX.

ASX market-making spreads

The First Report focuses on the wider bid and offer spreads that occurred during winter 2017 and suggests this was a "decline in market-maker performance". We disagree. The voluntary market-making arrangement we have with the ASX provides limited compensation to market-makers for the costs involved.[89] The agreement therefore also allows for the widening of spreads or for market-makers not to market-make at all during times of portfolio stress i.e. if and when they are sustaining significant losses on their ASX book. This enables market-makers to manage the otherwise excessive costs of market-making services during times of unusually high volatility. Analysis by NERA shows that wider buy sell spreads are the standard reaction to high volatility in even the most highly liquid markets. We would argue that during winter 2017 the agreements worked exactly as intended.

A key finding from winter 2017[90] was that retail participants hedged their exposures well in advance of winter and thus were not affected by widening of ASX buy and sell spreads:[91]

> "Electricity purchasers were hedged well in advance of the winter of 2017… This meant that purchasers were not adversely affected when the spreads for exchange traded futures widened during the winter."

We work with many of these purchasers and we concur with that conclusion. The reason for this is purchasers know that hydrology can dramatically affect prices in forward markets and so hedge beyond the hydrology window (more than 3 months in advance). The graph below provides context for this. The blue line shows the spreads on the 'Front Three Months' i.e. futures covering the next 3 months for Benmore on the ASX, which as highlighted by the First Report widened in winter 2017. The red line shows the spreads for all quarterly products beyond the hydrology window (beyond the immediate next three months after lake levels typically revert to mean regardless of whether conditions are currently wet or dry), proving that market makers maintained tight spreads for these longer dated products. It is these quarterly products which are particularly important to purchasers as this is where they hedge.

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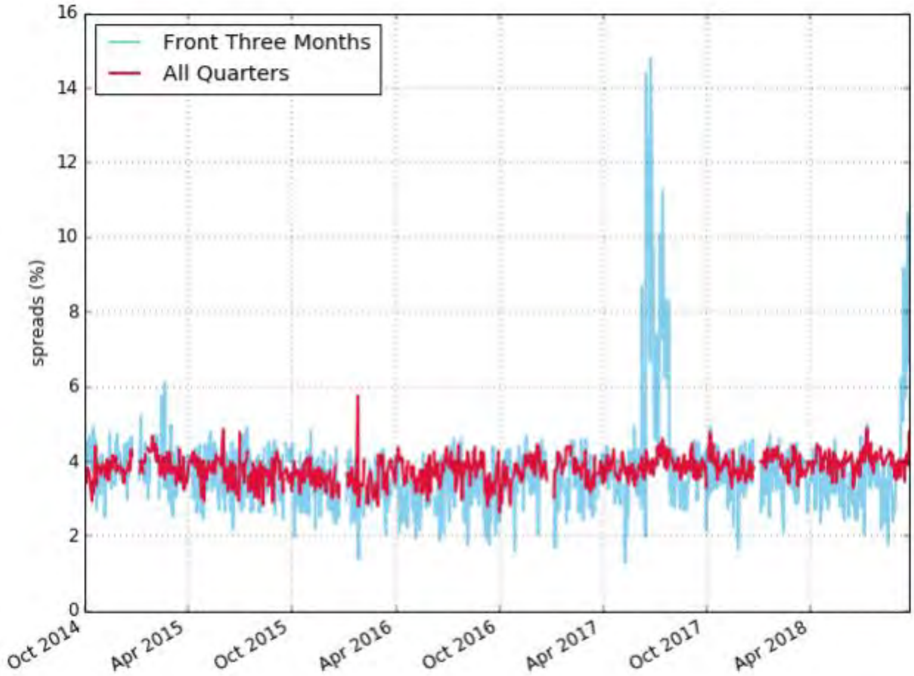
[89] Meridian is paid approximately $**[ ]** per year for making the ASX futures market based on volumes traded.

[90] The Authority made other positive observations in relation to winter 2017, for example, "despite historically bad hydro inflows, there was no suggestion of non-supply". "There is statistical evidence that storage was managed more conservatively than in the past." "Various security of supply measures had the desired effect. Market mechanisms worked well, and Transpower provided regular updates to customers."

[91] https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2018/2017-winter-review/

Figure 21 – Spread between contract buy and sell prices for Benmore ASX Futures



Source: Meridian analysis of ASX data (front three months repeats analysis in Figure 19 of the First Report)

So the question becomes, who was impacted by the widening of market making spreads in 2017 (or at any other time). And, if someone was impacted, is this a problem that requires attention. The parties impacted by the widening of spreads were speculators and other financial intermediaries who were looking to take advantage of volatility in short term ASX futures.

At times of price volatility, we observe that speculators and financial intermediaries can make money from this volatility by 'picking off' the market makers (as the market makers are the only parties who have to provide both a bid and an offer in the market).[92] Some financial intermediaries operating in the New Zealand market are domiciled offshore and trade electricity and other futures markets in a number of jurisdictions so are familiar with how market-makers can act at times of market stress like the winter of 2017. This costs Meridian, and presumably other market makers money, and so we move to limit the risks and costs we face by widening our spread. Meridian has been very open with the Electricity Authority and parties who ask, that we will not unduly expose our balance sheet to financial intermediaries many of whom are capable of market making in their own right but choose not to.

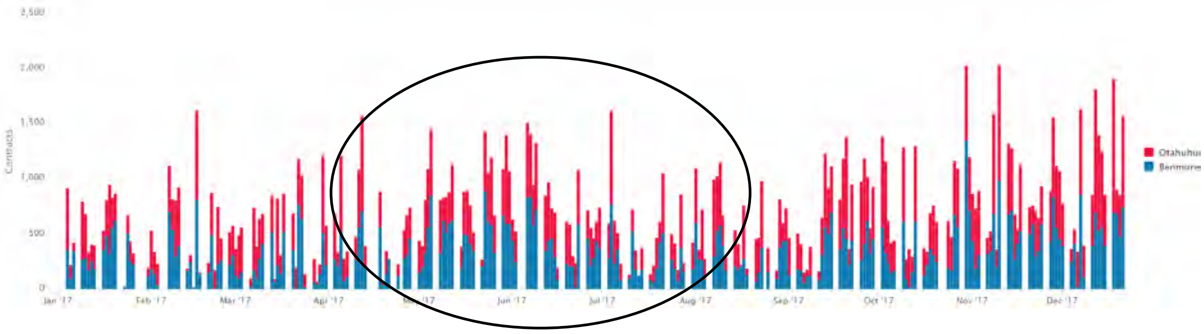
At the same time, we know that physical participants like independent retailers are not impacted unless they too speculate and buy risk management products too late, once they have already seen the physical market conditions tighten. This is equivalent to trying to buy insurance while your house is on fire.

[92] For example speculators tend to "buy a side" (i.e. all 12MW of the offers from market makers in market) in the periods where the volatility exists. Market makers are then short to the market by 12MW. Those same speculators then offer the 12MW (or less to ensure only some market makers can trade out) at a price above the offers posted by market makers initially. Market makers then have a choice – buy at a higher price than they sold (in order to limit the risk that tomorrows prices on ASX are higher than todays) or sit on the short position and hope tomorrow's prices are lower than todays. Many market makers will opt to close their positions at a loss as a result of the capital management processes they run. Their behaviours become well known by financial intermediaries who monitor the market makers using algorithms

Fundamentally, the ASX futures market is there to allow participants (including independent retailers) to hedge their risk – the ASX does not exist to enable short-term speculators to benefit at the expense of market-makers and New Zealand consumers.

To be clear, market-making still occurred over winter 2017 – market-makers continued to make offers available and it was possible to buy hedges, even though some purchasers did not like the price, which reflected the tightening of the physical spot market. The ASX continued to see high numbers of traded contracts:[93]

Figure 22 – Traded volumes for ASX futures in 2017



Source: EMI

Meridian considers the ASX to be a huge success. We do not think changes to the market or market-making are warranted for the purpose of keeping buy sell spreads tight for short-term contracts that will only benefit speculators at the expense of market-makers. However, to the extent that is seen as a desirable outcome, we are open to exploring updated market-making arrangements. The ASX has begun exploring options for an incentivised market-making arrangement. This could draw in a wider group of market-makers beyond the current four and potentially even include specialist financial traders. At a minimum it would be fair to include Trustpower and Nova as the other large integrated firms not currently providing market making services. Features of an updated market-making arrangement could include:

- the current market-maker performance standards for timing and volumes;
- an incentive payment to be split between a fixed monthly fee and a floating portion (based on participation rate compared to other market makers);
- penalties for non-compliance down to the point where a market maker forfeits all the incentive payment for the period (the money that would otherwise have gone to the non-complying participant will instead be spread over those participants that did comply, thus increasing their incentive to continue to market make);
- the ASX together with the Electricity Authority could run a tender to select market-makers – the cheapest of up to eight bids would be the incentivised market-makers. The size of the incentive pool would be set by the last bid, and all market-makers would be paid as described above from that pool;
- funding of the incentive should be by all the beneficiaries of market-making (all ASX participants). This could be achieved through an industry levy or an increased ASX exchange fee.

[93] https://www.emi.ea.govt.nz

We note that an incentivised scheme has been successfully established in Singapore, and for other commodities in Australia. Such a scheme might provide tighter market-making spreads for short-term contracts. However, allocation of market-making cost amongst ASX participants would be contentious.

OTC

Over the Counter (OTC) hedge contracts transacted directly between market participants without going through an exchange are another means of managing wholesale market exposures in addition to the ASX. Trades are disclosed to the Electricity Authority and anonymised on the hedge disclosure site - electicitycontract.co.nz. Traded volumes for August 2018 were 2529 GWh.[94] Meridian policy is to always make an offer to anyone when approached for an OTC contract. We frequently enter into OTC contracts with both integrated firms and independent retailers.

Hedge disclosure

Meridian considers the current hedge disclosure arrangements to be robust and we are pleased to see the ACCC looking to New Zealand practices as a model.

Transparent financial reporting

Something overlooked by critics of vertical integration is that vertically integrated firms are required to provide considerable transparency in their financial reporting relating to their component parts' performance.

Meridian is required to follow International Financial Reporting Standards and N*Z IFRS 8 Operating Segments*. The public disclosure of Meridian's segment performance[95] provides a clear view of the component parts of the company's consolidated annual results. The retail segment is reported independently of wholesale and Meridian's international businesses allowing a consistent view of segment performance over time. This includes the treatment of retail segment energy purchase costs.

Conclusion on vertical integration

Vertically integrated firms are varied and include the mixed ownership model companies (that have Crown and private investor shareholdings) as well as other listed and privately-owned firms. Any attempt to force vertical separation would be highly intrusive and complex and would introduce inefficiencies and costs to the vertically separated businesses that would be ultimately have to be recovered in some way. The results of such a step would do more harm than good to consumers and likely have repercussions beyond the electricity sector.

Without vertical integration electricity market participants would have less options available to manage wholesale price risks, particularly dry years. The removal of the natural hedge would also create new incentives for participants in both retail and generation to attempt to gain and exercise market power. Critically, without integration investors will have less revenue security and will be less willing to commit to long-term, generation investments. This is particularly problematic given the generation investment likely to be required to meet future demand.[96]

[94] https://www.electricitycontract.co.nz/
[95] See for example *Meridian Energy Limited Integrated Report: 2018* from page 90
[96] Transpower, for example, anticipate a doubling of demand by 2050 – see *Te Mauri Hiko* 2018

18. What are your views on the assessment of generators' and retailers' profits?

There is no evidence that generators' or retailers' profits are excessive.

Generation

The profits of listed firms are public and unexceptional assessed against the value of each firm's asset base. Critics generally attempt to show excess profits by insisting that reported asset values should be lower. We do not consider these approaches to be realistic or useful.

Accounting rules allow two approaches to recording the value of property, plant and equipment on a company's balance sheet:

- Cost model: the historical cost of the asset less any accumulated depreciation and any accumulated impairment losses; or
- Revaluation model: the fair value (being price that would be received in an orderly transaction between market participants) less any subsequent accumulated depreciation and subsequent impairment losses.

Once commencing the revaluation model for a class of assets (such as generation assets) revaluations must continue with sufficient regularity such that the carrying value does not differ materially from fair value.

Meridian changed its accounting policy in relation to generation assets from the cost model to the revaluation model in 2003. Since then there have been 8 further revaluations.

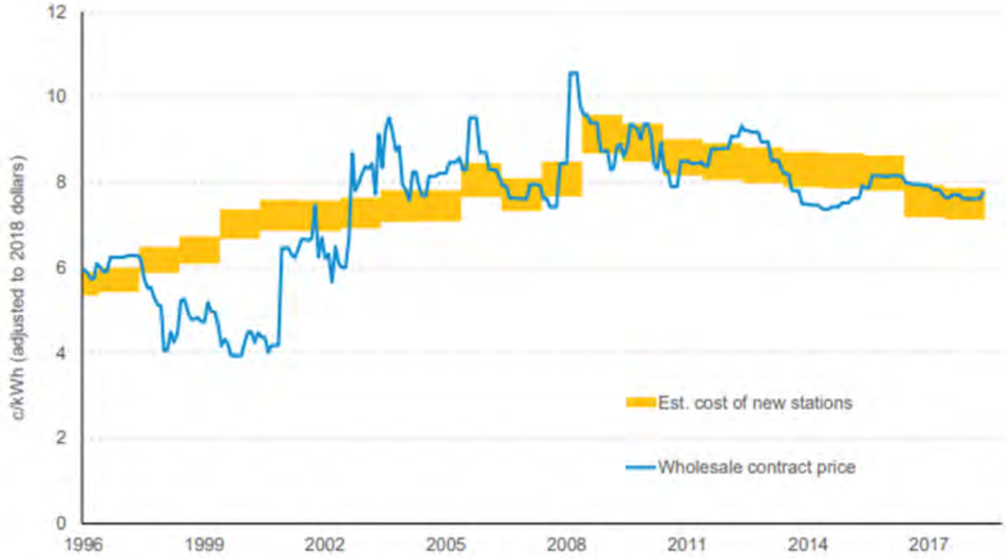
Meridian engages PwC to annually prepare an independent valuation of our generation assets in New Zealand and Australia.

The use of fair value or replacement cost reflects the real world. Consider the investment decision that a firm makes when it enters the market. The firm would enter the market only at the point when its expected revenues from entry equalled or exceeded the expected entry costs, both capital and operating. At the time of entry, the firm's costs include the replacement costs or fair value of the required assets, as replacement cost is the cost the firm must pay to acquire or invest in assets.

The fact that there is a link in competitive markets between replacement cost and price does not mean that the price in a competitive market will always equal that required to exactly cover replacement cost. Real world markets, unlike hypothetical perfectly competitive markets, take time to respond to changes in replacement cost or other shocks, due to factors such as imperfect information, transaction costs and lumpy, long-lived investments. There will be times when the price is lower, and times when the price is higher. However, in the long-run, price will trend towards replacement cost, even as replacement cost moves around, and it is this long-run relationship that should drive regulatory policy.

This view of the world is consistent with the First Report's finding that wholesale contract prices have tracked the cost of new generation plant.

Figure 23 – Wholesale contract prices versus cost of building new power stations (duplicates Figure 14 of the First Report)



Source: Concept Consulting analysis. Prices and costs are adjusted for inflation and expressed in 2018 dollars.

A market-based approach to asset valuation has been used for a long time. Switching to historic costs would be a major change. It would create significant uncertainty and undermine the confidence of those considering building more generating capacity.

A recent paper sponsored by Vector and authored by Dr Stephen Poletti suggests that modelled generator profits above short run marginal costs are significant market rents. We have addressed this paper above in our response to question 12. In short, profits above short run marginal costs are entirely expected in an energy only market and are necessary otherwise no-one would ever invest and do business in the generation sector. If prices are artificially depressed so that they remain at or near short run marginal costs this will ultimately produce security of supply concerns followed by high prices.

Retail

Returns from retailing are volatile. To demonstrate the volatility in retail margins we have looked at MBIE QSDEP retail tariffs on the Orion network and compared them against hypothetical Meridian cost to supply based on the operating costs of the retail business (for example the costs of staff, business overheads, metering and meter reading, marketing, and customer service) plus either spot or ASX wholesale prices. This shows the volatility in retail profits – dry years severely erode available retail margins while wet years can provide for firm retail margins. In the long term, overall retail margins are extremely tight.

Figure 24 – Orion residential tariffs vs cost to service based on spot or ASX

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Source: Meridian analysis, ASX, EMI and MBIE data

Transmission

> ***19. What are your views on the process, timing and fairness aspects of the transmission pricing methodology?***

Transmission costs amount to $1 billion annually and make up about 10.5% of the average residential customer's bill.

The existing Transmission Pricing Methodology is supposed to socialise most of this cost by allocating it to distribution companies (who in turn pass it onto homes and businesses) and large industrial consumers, at a flat national rate. However, the measure by which costs are allocated is Regional Coincident Peak Demand (RCPD). Parties can avoid paying transmission costs and shift costs onto others - the total revenue Transpower is allowed to recover is not actually reduced - by altering their contribution to RCPD in their region (upper North Island, lower North Island, upper South Island, lower South Island). Some parties have been very successful in reducing their contributions to RCPD. The actual incidence of transmission costs paid in fact varies significantly from customer to customer and network to network across the country.

In many cases the transmission costs paid by a party bear no relationship to the actual level of transmission costs their activities drive, or to the actual benefits they derive from the national grid. Some pay considerably more and some pay considerably less. Some pay nothing at all. This fundamental disconnect lies at the heart of the Electricity Authority's efforts to reform transmission pricing.

Currently about $150 million or 15% of the annual transmission costs of $1 billion are not allocated in the above way. These costs, relating to the inter-island HVDC transmission link, are allocated directly to South Island generators and South Island generators alone. North Island generators and consumers nationwide contribute nothing. As with the other transmission costs mentioned above this allocation does not reflect the actual benefits from the HVDC.

The net effect of the above is that:

- There is a substantial disincentive to investment in new generation in the South Island, particularly if you are a new generator to the South Island and not already subject to paying HVDC transmission charges;

- In contrast substantial time and effort is invested by parties in seeking to lower their contribution to RCPD and thereby shift transmission costs onto others;

- The cost of large recent grid upgrades intended to benefit consumers and businesses in the upper North Island are allocated across the country, to consumers and businesses that derive no benefit from those upgrades;

- Costs of the existing transmission grid and any new grid are poorly reflected in investment decisions – both new generation decisions and decisions about where to site new load.

The current TPM has been controversial since its inception. The current reform process, which has been running since 2012, is only the most recent attempt at reform. Previous attempts have all faltered due to the strong vested interests that some parties have in preserving the current allocation of costs.

Transpower is opposed to the Electricity Authority's proposals. Over the course of the Electricity Authority's current process they have responded by making small-scale 'operational' changes, which have belatedly addressed some inequitable aspects of the current TPM. However, the fundamental problems with transmission pricing remain and Transpower does not have the power to address them via the limited 'operational' changes that it is empowered to make.

In the absence of significant reform, transmission cost allocation will continue to be poorly aligned with the actual benefits derived by users of the grid. This will continue to drive significant inefficiency in the use and development of transmission infrastructure, in the development of generation, and in the siting of load generally in New Zealand. This in turn will lead to poor trade-offs and decisions by those businesses looking to decarbonise by substituting away from other sources of energy to electricity.

These inefficiencies will increase the long-term costs to all consumers of electricity and therefore increase the costs but decrease the speed of electrification and therefore the resulting emissions reductions.

In Meridian's view, the Authority should be left to determine the TPM guidelines under the current process. The Authority has the necessary expertise and experience in terms of the impact of the TPM on industry participants and consumers. The suggestion that responsibility for the TPM could be transferred to the Commerce Commission would not alter the fundamental need for reform. Furthermore, the Commerce Commission has never set a pricing methodology analogous to the TPM and would have to build their understanding and restart the reform process from scratch – such delays to the reform process are the likely intention of those advocating for Commerce Commission responsibility.

Meridian is pleased that the Price Review Panel does not intend to enter into the TPM debate and does not seek detailed comment. However, Meridian is concerned with the following statements from the First Report:

- The Price Review Report seems to suggest that a Government Policy Statement (GPS) could be used to guide the TPM review process. Meridian opposes this on the basis that it would either be high-level and not provide any new information or guidance; or else would (deliberately or inadvertently) descend into the difficult issues that the Authority has been grappling with. It would also result in an even more convoluted process for allocating transmission costs – a GPS would guide the Authority in developing a TPM, which in turn would guide Transpower in allocating transmission costs. Greater instability and costs could also result for the industry and consumers as transmission pricing could become subject to the political leanings of the government of the day. Subject to no less than 5 updates over the course of its three-year life span, and with little evidence of any beneficial impact, we note that experiences with the sector's prior GPS reinforce Meridian's strong reservations regarding this course of action.[97]

- The Price Review Panel also comments on whether a fairness objective would lead to a different TPM outcome. We agree with the Electricity Authority that the outcome would be no different – Meridian considers that it is fundamentally fair and efficient that those who benefit from transmission investments should pay for those investments. Entities that stand to pay more under a revised TPM oppose these principles to protect their bottom line rather than the long-term consumer interest.

- The Price Review Report's commentary that "We are unaware of any other country undertaking retrospective reallocation of past grid investments" is not helpful. Meridian is concerned with any suggestion that the difficulties with determining the TPM might be solved by applying the revised TPM to future investments only. This has been the subject of considerable consultation in the process to date. There is nothing unusual or unfair in applying a revised pricing methodology to existing assets. This is exactly what the Price Review Panel seems to be suggesting regarding changes to distribution pricing i.e. a reallocation of the costs of distribution network investments that were in large part made some time ago. It is also what Transpower has already done in its operational reviews of the TPM. It is commonly done in regulating natural monopoly industries in New Zealand.[98] The

[97] Refer for further discussion Sapare 2009 research, available here: https://www.businessnz.org.nz/__data/assets/pdf_file/0007/74716/Regulation-and-governance-of-electricity-sector.pdf. An update to this research is expected shortly.

[98] In fact, based on our research, it would be unprecedented in terms of sector specific economic regulation in New Zealand to implement a regulatory change in a way that only applied the new regime to new assets with the old regime continuing to apply to existing assets. See page 58 and Appendix 3 of the Meridian Submission on the Electricity Authority's Second TPM Issues Paper. Available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15999

benefit of changing current prices is to create the right incentives for future generation and load investment.

- Meridian disagrees with the TPM Group's characterisation that a revised TPM would "attach penalties to sunk investments". One of the key issues in the TPM from Meridian's perspective is how the cost of the HVDC assets that connect the North and South Islands are allocated. Meridian considers that the present arrangements (whereby only South Island generators pay) are arbitrary, inefficient (because they act as a tax on South Island generation) and single out and penalise one group of participants despite the benefits of the HVDC being enjoyed by a far wider group located throughout New Zealand. Correcting these problems cannot be seen as attaching a penalty to sunk investments.

Distribution

> ***20. What are your views on the assessment of distributors' profits?***

The First Report notes that compared to the WACC distributors' profits do not appear excessive. However, Meridian considers there is a strong case, as long argued for by the Major Electricity Users Group, that electricity lines businesses are overcompensated for the level of risk they actually face and that the current setting of WACC at the 67th percentile is too high. We suggest it should be changed so that WACC is set in the middle of the Commerce Commission's estimated range at the 50th percentile. This has the potential to significantly reduce costs to consumers.

The justification generally given for setting regulated WACC (and therefore profit levels) high for lines companies is that the potential harm they may cause by underinvesting is greater than the potential harm from overinvestment. However, consistent breaches of network quality standards by Vector over the past four years demonstrate that even with an over incentive to invest some distributors are failing to deliver, meaning that consumers have the worst of both worlds – they pay more than they should and receive a substandard quality of service in return.[99]

The justification for a high WACC is arguably not applicable to Transpower. As a 100% state owned monopoly transmission service provider that also currently holds the contract for acting as System Operator for the NZ electricity system it seems unlikely that Transpower will "find other things to do with its money" if it is not given an over-incentive to keep investing in the national grid.

More generally the purpose of regulation of natural monopolies like the 29 local distribution networks and Transpower as recorded in section 52A of the Commerce Act 1986 is "…to promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets…". Since about 2008 electricity demand in New Zealand has remained relatively static. Consistent with this, prices in the competitive parts of the sector (generation and retailing) are, in real terms, lower now than they were in 2011. In contrast, prices in the regulated monopoly lines part of the sector have continued to climb year on year. If the purpose of regulation is to ensure that the outcomes produced by the lines businesses are supposed to mimic 'outcomes produced in competitive markets' then the data suggests that current regulation of lines companies is not achieving this.

[99] See https://comcom.govt.nz/news-and-media/media-releases/2018/commission-files-proceedings-against-vector-for-excessive-level-of-power-outages. See also https://comcom.govt.nz/news-and-media/media-releases/2018/commission-to-file-proceedings-against-aurora-energy-for-breaching-quality-standards.

Finally, in relation to Input Methodologies Meridian believes the Price Review Panel is proceeding on a false premise to the extent that it believes that "any suggested changes to the regulation of natural monopoly networks may have a bearing on the gas sector and international airports, which are also regulated under Part 4 of the Commerce Act 1986." This is not inevitably the case and it is perfectly feasible that changes could be made which are specified only to apply to electricity lines businesses.

21. What are your views on the assessment of barriers to greater efficiency for distributors?

Meridian agrees with the Price Review Report in identifying a wide range of areas where there is potential for improved efficiency in the distribution sector. The IEA, the Office of the Auditor-General, and the Productivity Commission have all called for distribution sector reform – in terms of governance structure, capability, open access, and pricing.

For example, the Productivity Commission recently recommended that review is required to:[100]

- develop measures to raise the capabilities of the electricity distribution businesses;
- ensure all power system resources (including distributed energy resources) have competitive access to a well-configured common distribution infrastructure, at a reasonable cost;
- coordinate distributed energy resources (including smart, flexible demand) to meet participants' preferences for security, quality and reliability; and
- provide rewards and allocate costs commensurate with the marginal costs and benefits of each load and generating source.

The Productivity Commission's recommendations are consistent with similar concerns raised by the International Energy Agency:

> New Zealand's electricity distribution sector is facing a period of rapid change, following the widespread deployment of advanced interval metering and the emergence of new technologies (electric vehicles, battery storage, and rooftop solar PV). These developments … have the potential to radically transform the distribution system use and power flows, making the systems far more dynamic and complex to manage in an efficient and secure manner. Distribution businesses will be at the forefront of managing these challenges…
>
> …Concerns have been raised about the financial, technical and managerial capability of the distribution sector to respond effectively to this challenge. Concerns have also been raised about the governance and decision-making capability of the distributors and their capacity to manage this potentially complex transition in an efficient and timely manner that will help to realise the potential benefits for consumers.

Of concern recently is the extent to which some distribution companies are consistently failing to meet the quality standards set by the Commerce Commission. We note in particular the announcement on 10 October 2018 that the Commerce Commission has filed civil proceedings in the High Court seeking financial penalties against Vector for breaching its network quality standards in both the 2015 and 2016 financial years. "The Commission will file proceedings under the Commerce Act alleging Vector failed to adhere to good industry practice in some aspects of its network

[100] https://www.productivity.govt.nz/sites/default/files/Productivity%20Commission_Low-emissions%20economy_Final%20Report_FINAL.pdf

management, which resulted in increased outages over that period."[101] Vector has also reported further breaches of its quality standards for 2017 and 2018 that are subject to a separate investigation.

The 29 distribution businesses in New Zealand range in their size and capabilities. It is questionable whether it is efficient to have 29 distribution companies in a country the size of New Zealand.

Studies noted in the Price Review Report suggest that around 20,000 or 30,000 consumers is the minimum required scale to operate efficiently. Half of New Zealand's distributors are below this figure.

TDB Advisory was recently commissioned by a group of distributors and generator retailers to undertake analysis on the potential efficiency gains of amalgamating distributors. The analysis concluded that:[102]

- the estimated efficiency gain from amalgamating EDBs with fewer than 50,000 customer connections is in the range of $2 million p.a. to $29 million p.a. with a mean value equivalent to $30 p.a. per affected customer; and

- the apparent gains range from $3 million p.a. to $55 million p.a. or $31 p.a. per affected customer on average if the smallest EDB has 100,000 customer connections.

These potential efficiencies are not large when compared to the potential costs of amalgamation. But coupled with significant unexplained discrepancies in the relative costs of distribution business noted in the TDB report[103] they suggest there may be real gains to be made in this part of the supply chain. And regardless of the impact on distributors' efficiency Meridian anticipates that greater standardisation of processes, terms and tariffs across the distribution sector would drive efficiencies for retailers by significantly reducing their costs to serve.

Strata Energy Consulting was similarly engaged in 2014 to provide an estimate of the potential economic gains from restructuring the electricity distribution sector in New Zealand. That analysis indicated a potential present value benefit of between $1.43 and $2.56 billion.[104]

The report compared distribution networks across Australian states with the situation in New Zealand, in particular the number of networks and the number of customers that each serve.

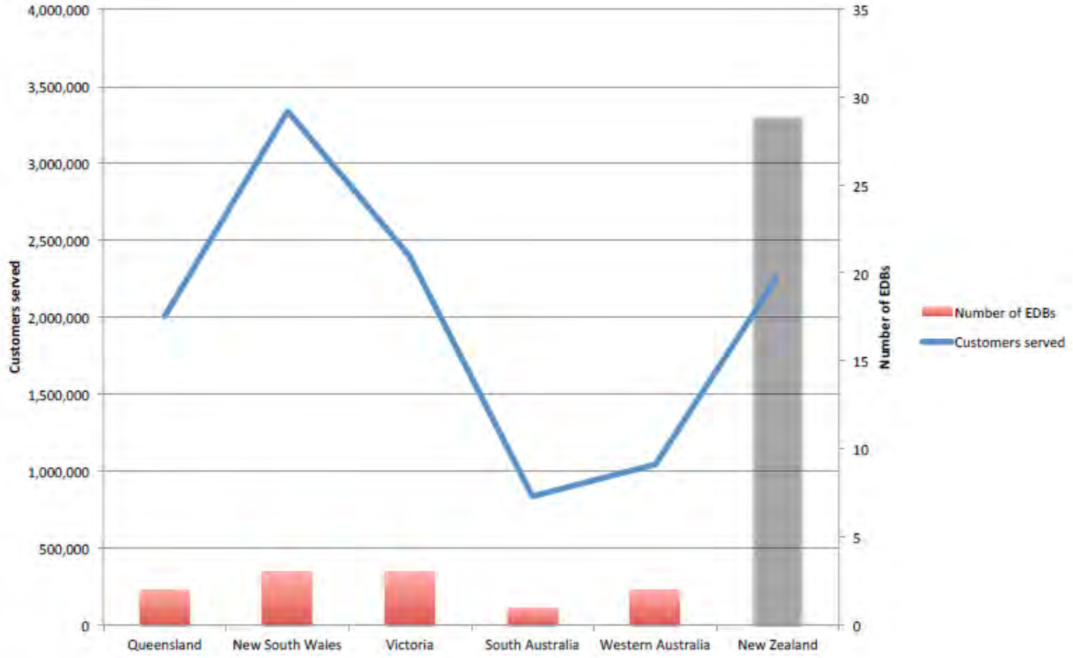
[101] https://comcom.govt.nz/news-and-media/media-releases/2018/commission-files-proceedings-against-vector-for-excessive-level-of-power-outages

[102] TDB Advisory *Estimated Efficiency Gains from Amalgamation of Electricity Distribution Businesses* 2018

[103] Ibid

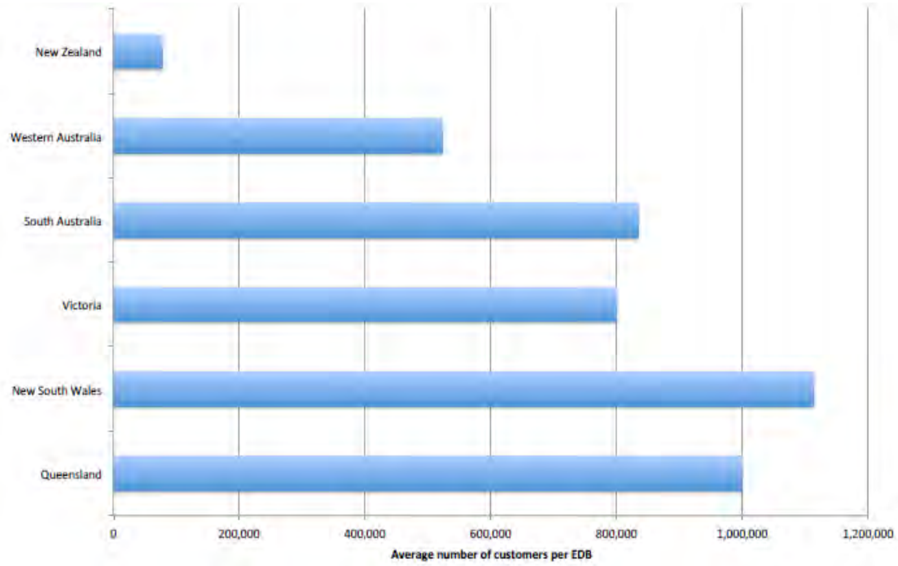
[104] Strata *Summary Report on Potential economic gains from restructuring electricity distribution* 2014

Figure 25 – Customers served by number of distributors in New Zealand and Australian states



Source: Strata

Figure 26 – Average number of customers per distributor in New Zealand and Australian states



Source: Strata

The Strata report then looked at credible and practically achievable structures based on four or five distribution networks in New Zealand and estimated the resulting efficiencies in terms of capital and operating expenditure at between $1.43 and $2.56 billion.

Efficiencies of scale are possible by means other than amalgamation. Regulatory options could encourage more contracting between distributors, joint ventures, collaboration, shared services, or the use of a small number of distribution system operators to more efficiently coordinate and optimise flexible demand response (like EV charging) and other network services.

Metering data

The Price Review Report states:

> "We see some merit in one stakeholder's suggestion of an open-access regime for meter data with standardised terms and conditions for all parties. This could take the form of a virtual central repository for metering data, giving distributors better information to maintain their networks and avoid costly upgrades."

Some distributors are dissatisfied with the meter data they currently receive from retailers. This data is typically supplied for network management purposes in accordance with the use of systems agreements that retailers are required to sign to trade on distributors' networks. Retailers have traditionally only been required to share relatively limited amounts of meter data with distributors. However, distributors have in recent years significantly expanded the amount of meter data they consider necessary for network management or other purposes. In so doing some have been prepared to enter into additional agreements with retailers protecting the privacy and security of the additional meter data they now require. Others have not and have insisted on provision of such data as their right under existing agreements.

A key point to note is that distributors do not typically pay for the meter data they receive from retailers. In contrast retailers contract with and pay metering equipment providers to supply them with the meter data. It may be that the best way for distributors to obtain the data they need is, like retailers, to do so by contracting directly with metering equipment providers.

Against this background Meridian questions the need for an open-access regime for meter data. This would seem to require significant reform and expense, including measures to:

- address customer privacy; and
- administer the open-access regime; and
- fairly allocate metering costs (which are currently paid entirely by retailers) to a broader group of businesses that would benefit from access to an open data pool.

It is not clear to us why commercial arrangements entered into directly between distributors (or other parties that want the information) and metering equipment providers cannot achieve the same ultimate goal of enabling wider, but secure, access to such data. Such arrangements may require consent from retailers but retailers are incentivised to give such consent if in return they are relieved of a portion of the metering equipment provider's costs.

22. What are your views on the assessment of the allocation of distribution costs?

The First Report of the Electricity Price Review notes that distribution costs for householders have risen 548% since 1990 and that householders' average yearly bill could fall by $90 (including GST), or about 4.5 per cent, if business and residential distribution cost allocations were brought into line with usage on all networks. On the same methodology, businesses' average yearly bills would increase by about 5.5% or $525 on average.

Meridian considers there is merit in such an approach. Analysis by Concept Consulting[105] suggests that provided any such re-allocation is confined to residual network costs (as opposed to demand-driven costs that vary with demand) then this re-allocation may well:

- be consistent with a move to more cost-reflective distribution pricing

[105] Concept Consulting *Issues and options for moving towards more cost-reflective network tariffs* 2017, page 61.

- produce fairer outcomes
- be more efficient.

According to Concept Consulting a key design choice for networks is:[106]

> "…whether to alter the cost-allocation approach between residential and business consumers. The significant re-allocation of residual costs to residential consumers during the late '80s and 1990's is considered to be a material factor in consumer (and political) concern with the sector. Future moves to cost-reflective demand-driven tariffs may further increase the proportion of network costs recovered from residential consumers (to the extent that residential consumers consume proportionately more electricity at times of system peak demand).
>
> Against this background, it is not clear that the current approach to allocating residual costs to residential consumers is optimal:
>
> - There is scope for approaches which allocate a greater proportion to business consumers, and still be economically efficient. …
> - To the extent that allocation of residual costs through fixed charges is more likely to result in income-constrained residential consumers to reduce demand, than business consumers go out of business or re-locate, some re-allocation away from residential consumers would actually be more economically efficient. …
> - The social / political dynamic may also favour some re-allocation away from residential consumers, and may make introduction of cost-reflective tariffs less likely to be overturned.
>
> However, a return to the 1970s where residential consumers paid little or no network costs would also be undesirable. If networks want to consider alternative approaches to allocating residual costs in a way which reduces costs to residential consumers, the challenge will be to develop such approaches in a way which is sufficiently rigorous to be robust to the inevitable public scrutiny – particularly from the business community."

Meridian agrees.

23. What are your views on the assessment of challenges facing electricity distribution?

Meridian agrees that emerging technologies may well have the greatest bearing on the future of the distribution sector.

We discuss these challenges in greater detail below under question 32. For the reasons discussed in the First Report, Meridian sees merit in at least considering the establishment of independent distribution service operators to coordinate the more active management of distribution networks. This may already be under consideration as part of the IPAG's equal access project.

[106] Ibid.

24. Summary of feedback on Part four

- The generation sector is highly competitive and wholesale prices have broadly tracked the cost of adding new generation capacity – there has been no increase in real wholesale prices since 2004.
- The wholesale market can support the decarbonisation of the economy and deliver on the expected need for a large increase in generation, provided the existing investment incentives are maintained.

- The retail market is fiercely competitive and delivers a range of innovative options.
- The retail and generation component of electricity prices is lower now than it was in 2011.
- Surveys suggest that 83% of customers are satisfied with their electricity supplier.
- Switching rates are high and around half of all consumers consider switching every year.
- Competition puts downward pressure on all prices.
- Some customers struggle to pay their bills. Reasons for this including income level, quality of housing and appliances, and the cost of household goods and services.
- Prompt payment discounts have become punitive as they exceed the costs of chasing unpaid bills. Prompt payment discounts also tend to disproportionately punish low-income households.

- Vertical integration is an efficient business model open to any retailer or generator. It is consistent with effective contract markets.
- Independent retailers are increasingly entering the market and growing. They can compete with integrated firms by acquiring wholesale contracts through the ASX or OTC markets.
- The ASX market is highly liquid with ever-increasing traded volumes and open interest.

- The Electricity Authority should conclude the TPM reform process as soon as possible.
- Meridian is pleased that the Price Review Panel does not intend to enter the TPM debate and does not seek detailed comment.

- There is considerable scope for increased efficiency in the distribution sector.
- It should be possible to allocate distribution costs in a way that is efficient and fairer to residential consumers.

25. Solutions to issues and concerns raised in Part four

- All the solutions proposed by Meridian are set out in the introductory section of this submission.
- In brief, the solutions to issues and concerns raised in Part four include:
  - Regulation of prompt payment discounts, restricting them to the actual level of the costs actually caused to retailers by customers paying late;
  - An enhanced price comparison site should be established and heavily promoted by the industry;
  - Retailers should be required to advertise in a standardised format and prominent location on all customer bills:
    1. the benefits of switching; and
    2. the logo and contact details of the enhanced price comparison site;
  - Regulatory minimum standards for retailers to apply in their dealings with vulnerable customers, based on the existing *Guidelines on arrangements to assist vulnerable customers;*
  - Remove unnecessary barriers to the development of new renewable generation under the Resource Management Act;
  - Consider a new incentivised market-making scheme for the ASX electricity futures market.

Technology and regulation

26. What are your views on this assessment of the impact of technology on consumers and the electricity industry?

Technology

Meridian agrees that over the next few years the impact of technology on consumers, the electricity industry, and the country will be profound.

The First Report rightly highlights the potential impact and disruption to existing market models of solar panels, batteries, electric vehicles (including self-driving electric vehicles), new price structures, peer-to-peer trading platforms, use of electricity for process heat, and changes to network power flows.

Meridian agrees these will all be important. But other changes may have as much or possibly even greater impact.

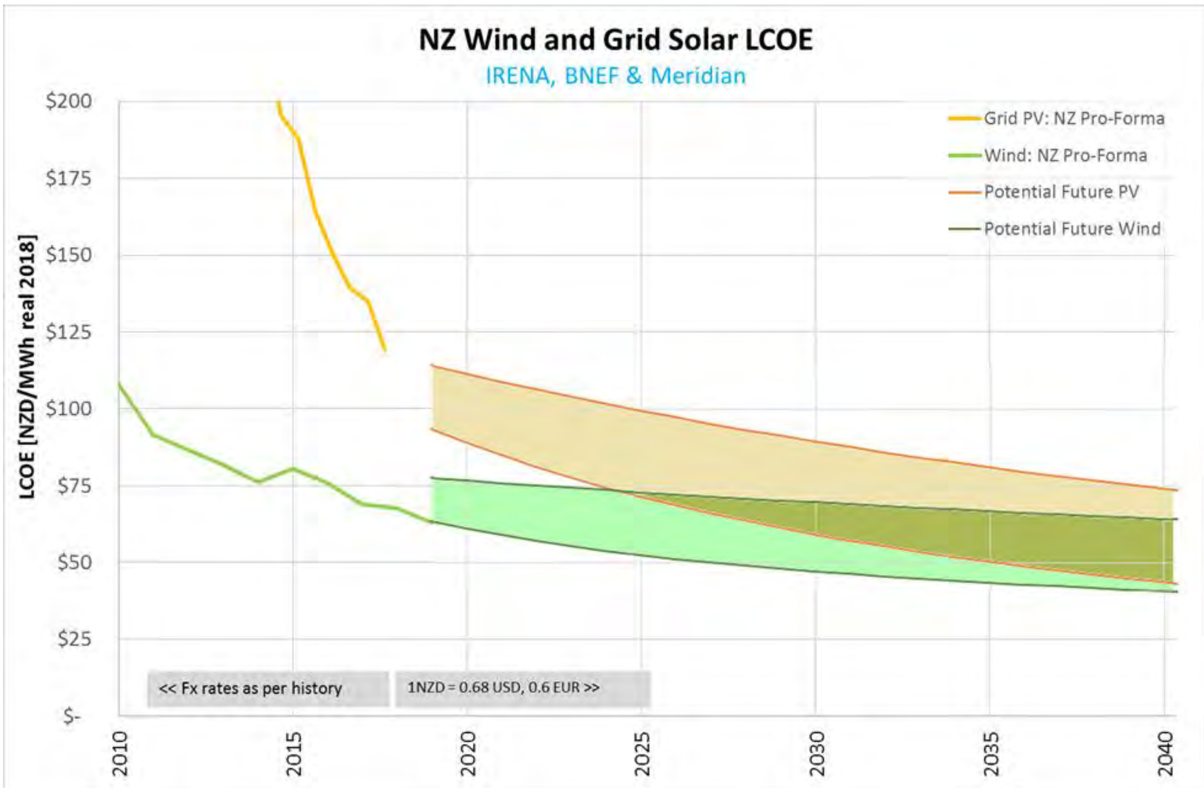
For example, the use of technology to enable more widespread and large-scale demand response at times of network congestion will play an increasingly significant role in how we efficiently manage our electricity system. It will enable individuals and businesses to have a direct impact on price levels within the sector by choosing prices at which they are willing to use less electricity (and be paid the market clearing price for doing so). The Electricity Authority's Real Time Pricing project is critical to enabling this development.

There is also the potential for technology and technology convergence to enable the entry to the sector of large, well-resourced new entrants who have not traditionally participated in the sector.

Already we have seen the acquisition of Flick Electric by oil company Z as part of its strategy to "extend into adjacencies in one of [their] three preferred market spaces – future fuels, mobility and the last mile."[107] Others will follow. We may in future see the entry of multinationals such as Google, with huge data resources and already expert in understanding consumer preferences, who look to capture an increased share of a converged 'home services' market of which 'home energy services' is just a subset.

We also anticipate a significant expansion in the role of some existing technologies as cost reductions make them economic in a wider variety of uses and situations. As the largest wind farm developer in New Zealand Meridian has witnessed a huge fall in the price of wind turbines. We anticipate this will continue and that the Levelised Cost of Energy for wind production and grid-scale solar will continue to fall:

Figure 27 – Levelised cost of energy for wind and solar in New Zealand



Source: IRENA, BNEF, and Meridian

Key to realising the potential of new technologies and the new business models they enable, in a way that delivers the greatest value for New Zealand, will be:

- Ensuring barriers to entry into the retail and wholesale electricity markets remain low.
- Ensuring regulation does not inadvertently give advantages to existing market participants by, for example, allowing distributors to leverage existing monopoly positions in the

[107] See https://z.co.nz/about-z/news/general-news/flick-electric-and-z-energy-announce-partnership/

provision of lines services into new and emerging markets for electricity and electricity-related services.

- Regulators working to lower the existing already low barriers further e.g. by ensuring there are no real barriers to access to consumption data and network-related data.
- Regulators maintaining a 'technology-neutral' approach to regulation of the sector.
- Regulators and Government resisting the temptation to 'pick winners' by subsidising or favouring particular technologies or business models, and instead enabling 'winners' to be picked by consumers via a process of competition between current and new participants providing the services that best meet consumer needs at the best price.

If one particular technology was to be singled out, Meridian agrees that the impact of electric vehicles will be transformative. Assessed on an overall cost basis (inclusive of fuel savings, as compared against Internal Combustion Engine (ICE) alternatives), we believe the economic case for EVs is already compelling and will only become more so with time.[108]

Meridian's fleet of vehicles is already over 50% electric and we are aiming for 90% by 2020. From the beginning of our conversion journey, a key priority has been to ensure the commercial model is financial sustainable. In working to achieve this goal, we've carefully considered our investments end-to-end – from vehicle purchase (directly importing, for instance, where this makes commercial sense) to choices regarding charging infrastructure (dedicated new, utilising existing, or a combination of the two). We have found the total cost of ownership for Meridian's EVs is favourable to fossil fuel equivalents.

Meridian is aware that various organisations currently are petitioning the Government to fund a large-scale programme to support household solar and batteries, at a cost of $78-88 million annually.[109] To the extent the Government may be interested in further investigating this proposal, it is important that other generating technologies are also considered. An alternative, for instance, is to have lower-cost wind generation providing the supply of electricity to these properties, from new or existing plant. Power Purchase Agreements would be entered into by the Government to facilitate this, over an agreed number of years, with the Government buying on behalf of the relevant consumers or tenants. We estimate this could be as much as four times more cost-effective for the Government in terms of the amount of electricity that could be procured for the relevant properties when compared against a rooftop solar scenario.

27. What are you views on the assessment of the impact of technology on pricing mechanisms and the fairness of prices?

Meridian agrees existing distribution price structures do not adequately reflect the costs of providing distribution services and encourage inefficient use of electricity. They also have the potential to result in cost-shifting from those who can currently afford new technologies to those who cannot and thus to drive unfair outcomes.

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[108] Bloomberg analysis, for instance, supports this view, predicting cost parity with ICEs could be achieved for battery capability (BEVs) from as early as 2025.

[109] Refer for further details, September 2018 'Seize the sun' Greenpeace report, available https://storage.googleapis.com/p4-newzealand-production-content/new-zealand/wp-content/uploads/2018/09/80a7f7ed-seize-the-sun-report-greenpeace-nz.pdf

As new technologies become more prevalent this will exacerbate the inefficiencies of existing distribution price structures. Existing distribution price structures over-incentivise the take up of solar panels and hold back the take up of electric vehicles.[110] Meridian also agrees that the Low Fixed Charge regulations are contributing to this problem.

As noted in the First Report at footnote 173 the Low Fixed Charge Regulations may also be incentivising consumers to prefer gas over electricity for cooking or heating as it has the potential to lower a consumer's consumption below the arbitrary 8,000kWh cut off (9,000kWh in the lower South Island) and thus lower a household's overall energy cost. Meridian believes it is inappropriate, particularly in the light of the strong international position that New Zealand has taken against fossil fuel subsidies[111] that the Low Fixed Charge regulations should continue to indirectly subsidise the use of fossil fuel.

Meridian believes distribution pricing reform is urgently required to ensure that:

- distribution pricing adequately reflects the cost of providing distribution services;
- the right price signals are in place to enable efficient technology uptake; and
- costs are not shifted onto those unable to afford new technologies.

The Electricity Authority has been working on distribution pricing reform since 2009. It is encouraging an industry -led approach with distributors asked to publish pricing reform "roadmaps" and next steps every six months. Some distributors have published detailed roadmaps and appear to be making progress. Others are not. The ACCC recently recommended that "steps should be taken to accelerate the take up of cost-reflective network pricing" in Australia.[112] We believe the same should happen here.

Meridian suggests distribution pricing reform should be completed to align with, or start soon after, the next Commerce Commission reset of distribution prices commencing in 2020. We suggest a good starting point for reform would be relatively simple two-part 'Time-of-Use' pricing.[113] If distributors are not visibly committed to making reforms soon we suggest regulatory intervention may be required. The direct financial costs to New Zealand of failing to address this issue in a timely way are estimated in the billions.[114] In addition we will incur the costs of significantly increased greenhouse gas emissions along the way.[115]

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[110] See NZIER *Effects of distribution charges on household investment in solar* September 2015; Concept Consulting *Electric cars, solar panels, and batteries in New Zealand Vol 2: The benefits and costs to consumers and society* (June 2016). The Concept work indicates that indicates that the current flat structure of most retail electricity tariffs, along with low carbon costs, constrains the uptake of electric vehicles because of:

- the electricity cost from charging EVs at off peak times (like overnight) generally being too high;
- the payments which future EVs could earn from injecting power back into the electricity grid at times of peak demand being too low; and
- the carbon price that internal combustion engine owners pay from tailpipe emissions being too low.

[111] See https://www.mfat.govt.nz/en/environment/clean-energy-and-fossil-fuels/

[112] Recommendation 14 at page xix, *Retail Electricity Pricing Inquiry, Final Report,* June 2018.

[113] This is supported in the paper *Issues and options for moving towards more cost-reflective network tariffs*, Concept Consulting, 2 November 2017.

[114] See NZIER *Effects of distribution charges on household investment in solar* September 2015;
Concept Consulting *Electric cars, solar panels, and batteries in New Zealand Vol 2: The benefits and costs to consumers and society* (June 2016).

[115] According to Concept Consulting *Driving change* (2018) New Zealand could expect 37 percent higher emissions from the light vehicle fleet in 2050 under a continuation of non-cost-reflective prices.

> ***28. What are your views on how emerging technology will affect security of supply, resilience and prices?***

Provided current regulatory settings are retained and the focus of regulators is on incremental change aimed at:

- "[promoting] competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers" (in the case of the Electricity Authority); and
- "promoting outcomes that are consistent with outcomes produced in competitive markets" (in the case of the Commerce Commission's regulation of distribution and transmission),

Meridian believes that emerging technology will contribute positively to security of supply, resilience and future prices.

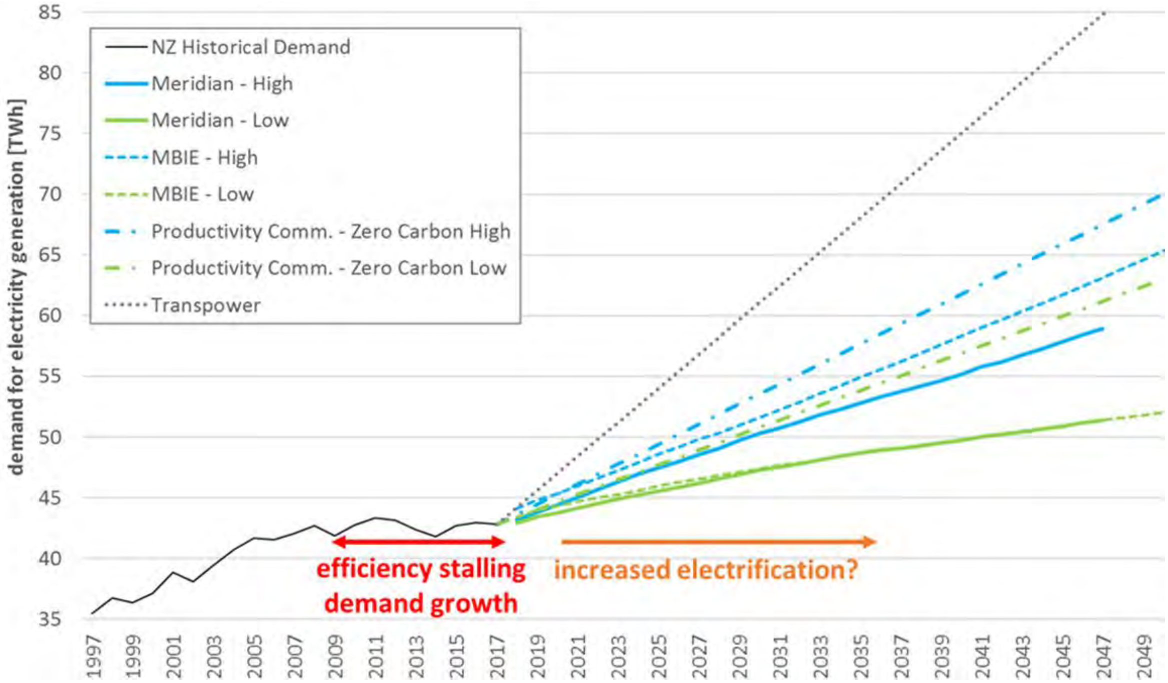
This section of the First Report highlights the crucial role of fast-starting hydro-generation, and its ability to respond quickly and flexibly to demand, enabling the integration of the predicted large amounts of solar generation in future. The same applies to integration of wind power which we expect to play an even larger role, or any other intermittent source of renewable generation that may emerge in future. Meridian has described hydro-generation as a 'super-renewable' because of its dual role in both increasing New Zealand's overall share of generation from renewable sources, and facilitating the integration of large amounts of other sources of renewable generation into the New Zealand power system.

Hydro's crucial role in this regard is sometimes overlooked. Similarly, inappropriate comparisons are sometimes made between New Zealand's hydro-based system and thermal-based systems overseas. We are pleased to see that the First Report recognises the differences between the New Zealand power system and overseas power systems.[116] It is critical, in our view, to New Zealand's future that we ensure that we make best use of our existing hydro resources and are careful to ensure that their contribution to our electricity supply is not inadvertently restricted.

Meridian's modelling of future scenarios also indicates a need for large increase in generation by 2050:

[116] For example at page 67 where the current, likely more-restricted role of grid-scale batteries is noted.

Figure 28 – Demand forecasts (non-Tiwai exit scenarios)



Source: Meridian

In relation to solar panels and other new technologies such as electric vehicles that may potentially increase load and the need for investment in distribution networks, Meridian's current view is that these potential effects can be accommodated within existing market structures and regulatory frameworks. It will however be important that New Zealand does not introduce subsidies of the scale seen overseas and which have led to pressure on distribution networks.

Regulation

29. What are your views on the assessment of the place of environmental sustainability and fairness in the regulatory system?

Meridian agrees with the Productivity Commission and with the First Report's assessment as to the place of environmental sustainability and fairness in the regulatory system i.e. these goals, important as they are, should not be explicitly added to the existing objectives or purposes of the Electricity Authority or Commerce Commission. There are better ways to ensure these goals are appropriately served.

30. What are your views on the assessment of low fixed charge tariff regulations?

Meridian agrees with the First Report's assessment that the Low Fixed Charge regulations:

- are causing unintended harm;
- increase bills for consumers on high-use or standard plans;

- provide unneeded assistance to many people who are well-off;
- inappropriately provide an indirect subsidy for the use of fossil fuel;
- offer no assistance to low-income consumers with high usage (in fact they hurt such consumers because, as noted above, they increase bills for those on high-use or standard plans);
- are poorly targeted;
- discourage efficient distribution pricing by making it harder than it needs to be to flexibly implement cost-reflective and service-based pricing;
- are a poor means of helping those in energy hardship.

We also believe that the Low Fixed Charge regulations add huge cost and complexity to the electricity industry that is not commensurate with the limited benefit that they provide. By requiring retailers to offer a low fixed charge equivalent for every standard tariff they offer, the Regulations at a single stroke double, or close to double, the number of tariffs on offer in the New Zealand market. The costs of administering these tariffs and the extent of resulting consumer confusion should not be underestimated.

Meridian believes the regulations should be repealed as soon as possible.

We note the First Report's concern that about a significant number of households may be on the wrong plan for them e.g. high-use households on low user plans or low-use households on standard plans. It is important to note that retailers do not have the ability to forcibly switch those on the wrong plans. Further the financial impact for those whose consumption is at or around the 8,000kWh cut off (9,000kWh in the lower South Island) is likely to be small. What we can and do advise such customers is that they may be better off on an alternative plan. Some customers read and reject such advice because, for example, they anticipate their consumption will be different next year, making their current plan the right one for them.

31. What are your views on the assessment of gaps or overlaps between the regulators?

Meridian agrees with the First Report that:

- there are no gaps or overlaps between the Electricity Authority and Commerce Commission's roles that would justify changes in their functions; however
- the regulation of access to distribution networks, especially for the provision of distributed energy services, is an area in need of attention.

Meridian has strongly supported the Electricity Authority's long-running efforts to encourage standardisation of, and more recently regulate, the 'use of systems' or distribution agreements offered by the 29 distribution networks to retailers wishing to sell electricity in their respective network areas. Introduction of mandatory or default terms for such agreements has the potential to be transformative, particularly for new entrant retailers, in seeking to reduce costs and expand their geographical coverage, and thereby increase competition.

Even though some networks have voluntarily adopted much of the Electricity Authority's model use of systems agreement, some have refused to do so or have only done so by implementing a heavily modified version of that agreement that bears little resemblance to the original. This means the current costs of negotiating and finalising different agreements with each of the 29 networks on their own preferred terms remain significant.

Vector has legally challenged the Authority's power to impose mandatory terms for use of systems agreements. The challenge was unsuccessful in the High Court but has been appealed by Vector to the Court of Appeal.[117] If Vector ultimately succeeds and it is found that the Authority does not have the power to impose mandatory terms, Meridian suggests that changes to legislation should be made giving the Authority such a power. We also recommend that any default distribution agreement be applied to embedded networks i.e. that each default distribution agreement between a retailer and a distributor should be deemed to apply also between the retailer and any embedded network operator on the distributor's network (with any appropriate adjustments to reflect the differences between the distributor's network and embedded network). Retailers are struggling to put in place contracts to deal with the proliferation of embedded networks and there is no good reason for there to be significant differences in the terms put in place between the distribution network operator and embedded network operators respectively and retailers trading on those networks.

Meridian also agrees that regulation (or at the very least clarification) is needed of distributors' current ability to exploit their natural monopoly positions and foreclose competition in distributed energy-related markets. It seems unlikely that the drafters of Part 3 of the Electricity Industry Act 2010, who were careful to impose limits on distributors' ability to engage in retailing and generation, would nevertheless have considered distributors should be able to provide in-home batteries and solar panels and even supply electric vehicles as part of the regulated "electricity lines service".[118]

Yet that is how the Commerce Commission has interpreted the relevant provisions in Part 4 of the Commerce Act 1986. The possibility that lines companies can include distributed energy-related services (including solar PV, in-home batteries and electric vehicles) in their regulated asset bases and thus earn a guaranteed return on their forays into these emerging markets by allocating the costs to consumers as part of those companies' lines charges should, in Meridian's view, be a cause of some concern. We were particularly concerned to see recent reports that "Vector has spent more than $10 million on Tesla batteries, many of which have sat in storage for more than two years."[119] It is not clear to us whether Vector's spend on these batteries has been included in its regulated asset base.

It has certainly caused concern in other jurisdictions where regulators have required distributors who wish to participate in these emerging markets to do so on an arm's-length basis separate from their regulated network businesses. The concern of regulators in those jurisdictions is that competition in these emerging markets can and should take place on a level playing field. In contrast here in New Zealand the Commerce Commission has been frank with submitters that in relation to these services "…Part 4 [of the Commerce Act] does not directly promote the 'level

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[117] The High Court judgment is available here: https://www.ea.govt.nz/dmsdocument/22420.

[118] Defined in legislation to mean "the conveyance of electricity by line in New Zealand." See section 54C(1)(a) of the Commerce Act 1986.

[119] https://www.stuff.co.nz/auckland/107728375/Claim-Tesla-batteries-worth-millions-gathering-dust-at-Vector

playing field' submitters have referred to…".[120] In making this comment the Commerce Commission referenced section 52T(3) of the Commerce Act which the First Report notes may mean that the Commission does not have a strong mandate to promote competition in distributed energy related markets.

Recently the Commerce Commission has published an open letter on its intention to gather information on emerging technologies.[121] The letter says that with limited exceptions the Commission does not consider that Electric Vehicle chargers form part of the regulated service of conveyance of electricity by line. This is because "the main purpose of EV chargers is to charge cars, not the provision of the regulated service (defined as conveyance of electricity by line). Therefore, our starting point is that we would not expect the costs and revenues associated with EV chargers to be within the scope of the regulated service."[122] This view has however been challenged by distributors some of whom have indicated they are already including EV chargers in their regulated asset bases.[123] How this difference of view between the Commerce Commission and distributors gets resolved and what it means for potential investment by non-network investors in EV chargers and other distributed energy related services in the meantime, isn't clear.

32. What are your views on this assessment of whether the framework and regulators' workplans enable new technologies and business models to emerge?

Meridian agrees that when originally drafted the current legislative and regulatory definitions of key terms such as "generation" and "electricity lines service" probably did not contemplate a number of the emerging technologies and business models to which they are now being applied.

However, provided there is sufficient scope to apply a purposive interpretation of these terms it is not necessarily the case that they will inevitably present barriers to the emergence of new technologies and business models.

Meridian does not at this stage have strong views on the issue of whether some amendments to rules are needed to enable peer-to-peer trading although we note that the Electricity Authority is currently considering the issue of peer-to-peer trading as part of its work on Multiple Trading Relationships.

More generally, Meridian supports open competition in emerging markets for new technologies as the best means to enable new technologies and business models to emerge in a manner that promotes the long-term interests of consumers. Batteries, for example, can flatten demand peaks (assuming the right price incentives) and therefore have the potential to help reduce emissions from the electricity sector in future. They can also be used to support the management of distribution networks. However, they are not "natural monopoly" assets like traditional poles and wires as they

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[120] Para 132 *Input Methodologies Review: Emerging Technology Pre-Workshop Paper*, 30 November 2015.

[121] 9 May 2018 and available here: https://comcom.govt.nz/__data/assets/pdf_file/0023/90581/Open-letter-Our-intention-to-gather-information-relating-to-emerging-technologies-9-May-2018.pdf

[122] See above at para 30.

[123] See for example Vector submission page 6 at: https://comcom.govt.nz/__data/assets/pdf_file/0026/90593/Vector-Emerging-technology-information-request-Submission-25-May-2018.pdf; see also Orion submission at: https://comcom.govt.nz/__data/assets/pdf_file/0031/90589/Orion-Emerging-technology-information-request-Submission-25-May-2018.pdf.

can be provided by a growing number of industry participants and in many instances by consumers themselves.

Allowing these technologies to be treated as regulated monopoly assets enables distributors to guarantee a regulated return in what is otherwise a potentially high-risk emerging market. Meridian believes that distributors should be required to keep new technology services separate from their regulated businesses and that networks should openly tender for network services based on new technology to ensure that:

- network spending on such technologies is subjected to competitive market forces rather than economic regulation;
- consumers benefit in the long-term through greater competition, innovation and reduced costs; and
- potential emissions reductions from these technologies are realised in the most efficient manner.

Meridian believes that the IEA's platform for services model for distribution networks may well be the most suitable to:[124]

> [M]eet the challenges facing the sector because it will increase competition and innovation, reduce transaction costs and more effectively integrate a diverse range of suppliers and new technologies. In addition, it will maintain a more effective separation of contestable and natural monopoly functions.

We note that the Electricity Authority has identified similar risks and has asked the IPAG to undertake an Equal Access project to consider potential options to strengthen the equal access framework for access to distribution networks in order to further promote competition, reliability and efficiency in the provision of electricity and electricity related services. As already alluded to the Commerce Commission is also gathering information from distributors regarding emerging technologies and reminding them of their obligations under the Commerce Act to not take advantage of their substantial market power in emerging markets that they are seeking to enter or are already participating in. Meridian will continue to encourage these regulatory developments and technology uptake that is in the best interests of consumers and will most efficiently reduce emissions.

Regulatory frameworks need to support distributors in providing a platform for the different services and technologies that will rely on their networks. Enabling a competitive environment will benefit customers in the long-term and ensure efficient prices and innovative service offers. In the absence of this shift, there may be a case for government to legislate to ensure investment in new distributed technologies is subject to competitive pressure and in the best interests of consumers. One way to achieve this would be to prevent or limit the ability of distributors to directly own distributed energy technologies on their network. Distributors could still utilise these technologies on their network but would do so through a structurally separate related entity that must compete on a level playing field with other potential providers of the service.

[124] International Energy Agency *Energy Policies of IEA Countries: New Zealand 2017 Review*

33. What are your views on the assessment of other matters for the regulatory framework?

In relation to other matters for the regulatory framework:

- Meridian believes regulators like the Commerce Commission and Electricity Authority are effectively required to act as consumer advocates (the EA's objective is to act for the long-term benefit of consumers) and if some are calling for a separate consumer advocate to be established this perhaps suggest the regulators need to do more. In our experience the Electricity Authority is relatively good at providing an indication to consumers of the bottom line impact to them of proposed reforms. We believe the Commerce Commission has improved in this area and that the information provided to consumers relating to the Powerco CPP application was very good, but it could do more in this regard.

- On 'pace of change' while some stakeholders say things take too long to fix, others will say that reform has been rushed through. The Electricity Authority has in the last few years been sued by parties looking to halt or delay reform. In relation to the TPM, Trustpower's litigation against the EA alleged in part that the EA had failed to allow sufficient time for consultation. Trustpower's case was rejected by the High Court but it is illustrative of the fact that on 'pace of change' regulators sometimes can't win. For some stakeholders, change can't come fast enough. For others, changes will always be seen as happening too soon.

- Meridian does not support a separation of the Electricity Authority into separate rule-making and enforcement bodies. In a small country like New Zealand we should look to avoid a proliferation of different regulators and rule-making bodies with the potential additional costs this involves. In any event Meridian's experience with the Authority is that while decisions are ultimately made by the EA Board, its investigative function operates independently of and separately from its rule-making function. This is appropriate.

- Meridian believes the current relatively limited means of challenging Electricity Authority decisions are appropriate and sufficient. Allowing a non-expert body such as the High Court to carry out a merits review is fraught with difficulty (even if the High Court bench is given the benefit of expert lay members).

- As already indicated Meridian believes it is time for the 12 currently exempt distribution companies to be made subject to price-quality regulation. The assumption that because a natural monopoly distribution company is community-owned it will therefore inevitably act efficiently and in the best interests of the consumers of electricity lines services in its area (despite a complete absence of any competitive pressure on that company) does not bear scrutiny.

- The current level of EA and ComCom spending on regulatory functions and the cost of compliance with that regulation seem to us broadly reasonable.

34. Summary of feedback on Part five

- The industry is poised for significant and fundamental changes, due to the integration of well -recognised new technologies (EVs, batteries, peer-to-peer trading structures etc.), and possible broader developments (more wide-scale demand response, new, large-scale market entrants, decreasing generation technology costs, for instance).
- It is important a technology-neutral stance is maintained through this phase by regulators and Government, to ensure the long-term interests of consumers are served through open competition.
- Regulatory frameworks are largely suitable. Distributor arrangements do require further refinement, however, including to introduce additional safeguards for new technology investments.
- There is much to be positive about in terms of the way emerging technologies are likely to impact the market generally, whether in relation to security of supply, resilience, or future prices.

35. Solutions to issues and concerns raised in Part five

- All the solutions proposed by Meridian are set out in the introductory section of this submission.
- In brief, the solutions to issues and concerns raised in Part five include:
  - The repeal of the Low Fixed Charge Tariff regulations, which add significant cost and complexity, while delivering limited benefits.
  - Distribution pricing reform needs to be progressed with urgency, given the increasing rate of technology uptake.
  - Keeping under review the need to enable the introduction of mandatory use of systems agreements through legislation, should this be determined as outside of the Authority's remit.
  - Amended rules for distributor investments in new technologies to facilitate open market access for other players.

36. Please briefly provide any additional information or comment you would like to include in your submission.

We have provided additional information and comment in the 'Introduction and recommendations' section at the start of this submission.

Retail Lessons for New Zealand from UK regulation and the CMA's Energy Market Investigation, including a critique of Professor Cave's analysis

Stephen Littlechild[1]

8 October 2018

1. Introduction

The New Zealand Government's Electricity Price Review takes place at a time of some concerns about retail energy markets internationally, with some significant changes in regulatory policy. In the UK, for example, the energy regulatory body Ofgem has intervened particularly actively in the retail market since 2008. The Competition and Markets Authority (CMA) completed an extensive Energy Market Investigation in 2016, which found that Ofgem's interventions had reduced competition and required them to be withdrawn. The CMA introduced a cap on PrePayment Meter (PPM) Tariffs in April 2017 and recommended some additional demand-side remedies to stimulate customer engagement. In February 2018 Ofgem extended the scope of this PPM cap to certain vulnerable customers. In July 2018 Parliament passed an Act requiring Ofgem to introduce a much wider retail energy tariff cap, which Ofgem is in the process of implementing.

In May 2018 Professor Martin Cave discussed "Retail lessons for New Zealand from the UK Energy Market Investigation". (Cave 2018) This is a particularly well-informed paper because the author was one of the members of the CMA panel that carried out the Energy Market Investigation. In various places it usefully comments on the CMA's thinking, or spells out the CMA's thinking more fully or more intuitively than the CMA's Final Report does. It is certainly more succinct because, as Professor Cave notes, the Final Report had over 1400 pages plus about 5000 pages of Appendices. The paper also comments on the two years of experience since the Final Report, including the initial implementation of the CMA's remedies. Professor Cave's paper is thus more approachable and more recent than the CMA report, and has the additional benefit of the author's own wide experience of regulatory issues. It makes a useful contribution to the present debate, not only in New Zealand but also around the world.

The paper has particular significance for additional reasons. Professor Cave dissented from the rest of the CMA panel on one important issue. He argued that, because the CMA had identified such a large customer detriment, a temporary but widespread tariff cap was required. In contrast, the CMA majority said that that such a cap would harm competition and customers. In introducing its Tariff Cap Act, the Government in effect sided with Professor Cave. Furthermore, the Secretary of State recently appointed Professor Cave as the new Chair of Ofgem's governing body (the Gas and Electricity Markets Authority), as from 1 October 2018. So Professor Cave's views will continue to be influential for several years to come.

The present paper provides a summary, analysis and critique of UK experience and policy in the retail energy market. Hopefully it will be of relevance to the Review in NZ.

[1] Emeritus Professor, University of Birmingham; Fellow, Cambridge Judge Business School; and former Director General of Electricity Supply (head of the Office of Electricity Regulation OFFER) 1989-98.

- Part I is a summary and critique of Ofgem's retail regulatory policy in the years 2008 – 2014 before the CMA investigation.
- Part II analyses the relevant aspects of the CMA Final Report (CMA 2016), partly arranged as a critique of Professor Cave's paper, with a little more detail about the CMA report to make the paper self-standing.
- Part III notes and comments on the CMA remedies, and on some UK developments since the Final Report, including in the four months since Professor Cave's own paper.
- Part IV comments on the lessons for New Zealand that Professor Cave proposes, and suggests five alternative lessons from UK experience.

In general, I do not take issue with Professor Cave's helpful summaries of the CMA report. But as I have explained at greater length elsewhere (Littlechild 2014, 2015, 2017, 2018), I do have concerns about how the CMA report itself analysed the retail energy market. I agree with its conclusion that Ofgem's regulatory interventions from 2008 to 2014 had an adverse effect on competition. However, I am not convinced that there is "weak customer response" in the UK, or that the retail market is uncompetitive, much less imposes a customer detriment of £1.4 billion pounds a year.

So my concerns about Professor Cave's paper are mostly about the CMA's views rather than about Professor Cave's own views. Having said that, because I do not accept the CMA's calculation of a large customer detriment, I am not convinced by Professor Cave's view that a widespread price cap is required to protect customers. I agree with the CMA majority that such a price cap would be harmful to competition and customers.

Part I Regulatory developments before the CMA Energy Market Investigation

2. **Opening the competitive retail market 1998-2008**

In 1986 British Gas was privatized and restructured; in 1990 the same approach was taken to the electricity sector. Competition was introduced into the wholesale markets and, over time, was phased into the retail markets too. There were some transitional caps on prices to residential customers.

Competition was vigorous, and there were also many takeovers. By the early 2000s the market had consolidated into 5 major electricity suppliers, each having taken over two or three of the 14 former-incumbent supply businesses, plus British Gas. While the former electricity suppliers retained some distribution networks, these were operated quite separately. All six retail suppliers owned some generation plants, and all six sold both gas and electricity (dual fuel). They became known as the Big 6. (The CMA report called them the Six Large Energy Firms or SLEFs.) At this stage, entry of new small-scale suppliers was minimal.

In 2002 Ofgem removed the last transitional price caps. Ofgem's Chairman and CEO said that "the evidence is overwhelming that competition is effective over all social groups and methods of payment", and that "ongoing price controls would pose serious risks to development of competition".

Over the next few years Ofgem announced a programme of work to remove remaining obstacles to competition. It implemented a Social Action Plan "to ensure that the benefits of competition are extended to all customers". It reported vigorous price competition and innovation in terms of tariffs. The switching rate (at which customers changed suppliers) gradually increased from 15% per year in 2003 to 20% in 2008.

3. **Ofgem's Probe 2008 and the non-discrimination condition**

Figure 1 shows that domestic retail prices were increasing rapidly. Having fallen by about one third in real terms over the two decades from the early 1980s to the early 2000s, they doubled in the next five years. The consumer body Energywatch argued in 2007 that energy markets were failing consumers, that "Ofgem has been complacent at best and negligent at worst", and that the competition authorities should step in. The Government expressed concern about mis-selling, vulnerable customers not switching, and charges for prepayment meters.

Figure 1 (Source: House of Commons Library 2014)

On 16 January 2008, responding to such concerns, Ofgem issued a press release entitled "Market is sound, Ofgem assures Chancellor". This statement did not convince others. On 5 February the Select Committee announced an investigation into "Energy Prices, Fuel Poverty and Ofgem" and

urged Ofgem to take action. On 21 February, Ofgem announced a Probe "to address mounting concern among customers" about the domestic (residential) market.

In October, the Probe Initial Findings noted that world fuel prices had increased, and did not find excessive retail profits. It also found high levels of switching. It said "The fundamental structures of a competitive market are in place, and the transition to effective competitive markets is well advanced and continuing." (Ofgem 2008, p. 5)

However, the Initial Findings also noted that relatively few customers were proactively and confidently engaged. (Some years later Ofgem explained that it was drawing on behavioural economics for its new analysis.) The less active customers were suggested to be paying £1bn per year more than active ones. Ofgem was particularly concerned about what it called "unfair price differentials". In particular, each of the five former incumbent electricity suppliers charged an average of about 10% higher prices to its existing customers within its pre-privatisation regional monopoly area, while competing with lower prices to attract new customers in the other areas where they were effectively new entrants.

It is not clear that competitive conditions were significantly different from previous years, but Ofgem's own perspective had changed. Instead of citing the lower prices as evidence of competition, it emphasised the higher prices as evidence of lack of competition.

Ofgem proposed 20 new measures to promote more customer engagement. It also introduced a new Financial Information Reporting licence condition to increase transparency about revenues, costs and profit. It required the six large suppliers to provide annual statements segmenting the results of their generation and supply businesses. Ofgem regularly publishes these so-called consolidated segmental statements.

Most controversial was a new non-discrimination condition (Standard Licence Condition SLC 25A) "to ensure that price differentials are objectively justified by cost differences". (When the market was first opening, Ofgem had publicly considered and rejected such a condition.) Ofgem calculated that, in total, suppliers benefited by about £1 billion per annum from various differentials.

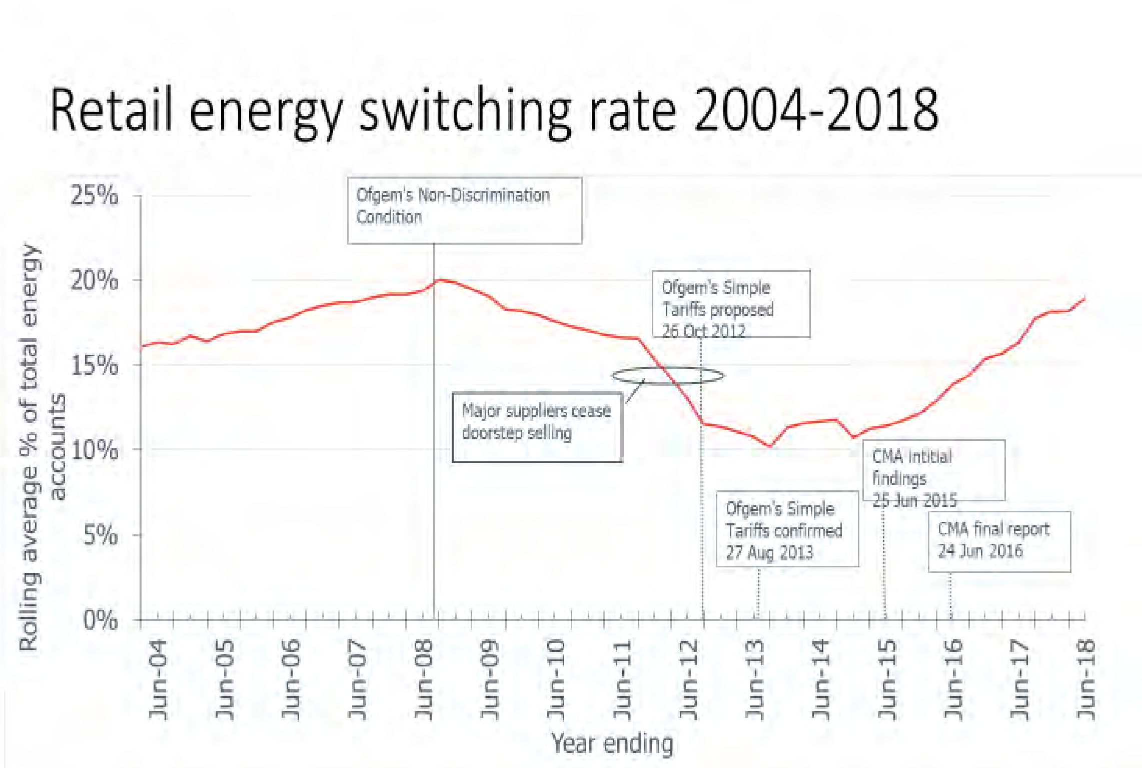
However, Ofgem also noted that this total exceeded the average annual margin earned by the Big 6 businesses between 2005 and 2007. So it accepted (although it did not highlight this) that an erosion of the price differentials might be via a rebalancing between prices rather than a straightforward decrease of the highest prices. Assuming average prices remained unchanged, Ofgem estimated an impact of around £550m a year. This would mean a reduction of some higher prices by about that amount, but also an increase of £40 per year on the average dual fuel bill. Nevertheless, the rebalancing "would disproportionately benefit vulnerable groups".

A number of experienced regulatory economists were very critical of Ofgem's decision as "likely to stifle competition" and "have harmful consequences for consumers". (Vickers 2009, Waddams 2009, Yarrow 2009) Professor George Yarrow resigned from the Ofgem board on this issue.

Ofgem implemented the non-discrimination condition in 2009, for three years. In 2012 it initially proposed to renew it, but then allowed it to lapse with a strong warning to suppliers not to resume differential pricing. Ofgem never did carry out its promised review of the impact of the non-discrimination condition. Others noted lower tariff differentials but also higher prices. Ofgem itself reported a 38% increase in net retail profit margins by 2010.

A year or so later, Ofgem began to crack down on door-to-door selling, which was coming under public criticism, not only of energy suppliers. The Ofgem restrictions were so onerous that all major suppliers abandoned the practice during 2011-12. Although it had problems, doorstep selling had been the most cost-effective way of acquiring new customers. So customer acquisition costs now increased. Moreover, suppliers were now less able to engage customers in the lower socio-economic groups.

Ofgem's two policies had a noticeably adverse impact on the customer switching rate. As Figure 2 shows, it fell from 20% per year in 2008 to 16% in 2011, then more sharply to 10% in 2013. That is, it halved in 5 years.



4. Ofgem's Retail Market Review 2010/11 and its Simple Tariffs policy

In view of the increase in profit margins after 2008, Ofgem decided in November 2010 on a further Retail Market Review (RMR). In March 2011 it found reduced tariff differentials but little else had changed, except that customers were now less active. It attributed this to "complex pricing structures" and an "increase in the number of tariffs available".

Hitherto, retailers had mainly continued to use the Standard Variable Tariff (SVT) that had predated privatisation. This involved a fixed (customer or standing) charge per month plus a charge per kWh used. It was open-ended as to duration and, with 30 days notice, could be changed at the supplier's discretion. On average suppliers changed it about once or twice a year (depending on the stability of underlying costs). Most customers were on such tariffs. But by 2011, no longer able to compete via differential tariffs in different areas or to use doorstep selling, retailers were looking for other ways to compete including via the internet. Retailers could still offer temporary discounts from SVTs. Price comparison and switching websites were now becoming more common, and fixed period tariffs (e.g. for 12 months) were an effective and flexible means to compete.

Ofgem decided that "Further radical actions were required to make it easier to compare prices". This included extensive prescriptions with respect to a Tariff Information Label, bill format and so on.

Initially, Ofgem also proposed to restrict suppliers to one tariff each, comprising a monthly fixed charge and a unit charge. To increase customers' ability to compare tariffs, Ofgem proposed to set the monthly fixed charge itself, which would be uniform over all suppliers, so that suppliers would compete on a single unit price/kWh. I referred to this as "Ofgem's Procrustean Bed" (Littlechild 2012a) In October 2012, after nearly two years of consultation and deliberation, Ofgem abandoned its Procrustean Bed proposal, citing unspecified concerns and practical difficulties.

Instead, Ofgem introduced its Simple Tariffs restrictions. Each supplier would be limited to a maximum of 4 tariffs per fuel. Tariffs could have a maximum of one standing charge and one level of unit charge. Most discounts were banned. 'Dead tariffs' – those no longer available to new customers – were prohibited, and customers on them had to be moved to the supplier's cheapest 'live or open tariff'. With some modifications, these and other restrictions came into effect in January 2014.

5. Consequences for competition of Ofgem's Simple Tariffs policy

The Simple Tariffs policy had serious disadvantages, and was soon criticised. (e.g. Littlechild 2012b) It meant the removal of many competitive tactics such as introductory discounts, cash-back schemes, loyalty discounts and prompt payment discounts. One supplier's new tariff, described by financial commentators as "the best offer in the market", had to be removed because it offered a higher discount in the first year than in the second.

Tariffs with zero monthly standing charges were popular with some older customers who wanted to pay only for what they consumed and could therefore control. These tariffs had to be withdrawn because they were generally only viable with a higher level of unit charges on the first few units, which was now-prohibited. Similarly, E.On's innovative StayWarm tariff involving a fixed monthly bill, regardless of usage, available only to the over 60s, was popular because it too provided reassurance to customers. It was previously highlighted by Ofgem as addressing the needs of the fuel poor. This tariff too had to be withdrawn. Potentially innovative tariffs such as those involving wholesale price trackers were not allowed.

Predictably, suppliers withdrew tariffs with minority appeal (e.g. Green tariffs) and focused on simple, popular and convenient tariffs. Typically, suppliers kept one SVT and offered two or three fixed price tariffs for 12, 18 or 24 months. Amongst other things, this discouraged longer-term customer relationships and focused competition on the price of short-term contracts rather than on designing different tariffs to meet the needs of different types of customers.

6. The CMA's view on Ofgem's regulations

Ofgem's rather speculative exploration of possible further measures following its RMR led to a burgeoning of proposals for other interventions. Some commentators demanded that suppliers be required to put their customers on their best offer. The Prime Minister suggested that suppliers should be required to put customers on the cheapest tariff in the market. The Labour party leader proposed to freeze tariffs until the next election. Consumer organisation Which? advocated a 'petrol pricing' approach with each supplier restricted to a single nationally uniform price per kWh, with no fixed daily or monthly charge. Former Prime Minister Sir John Major suggested a windfall tax on energy suppliers.

More focused political pressures continued. In July 2013 the Energy and Climate Change Committee was very critical of rising energy prices, of the six large energy companies, and of Ofgem's lack of action. (House of Commons 2013) Later that year, with a change of leadership at Ofgem, the Secretary of State announced that Ofgem would work with the competition authorities to assess the state of competition in energy markets. This in turn led to Ofgem referring the energy market to the CMA in June 2014.

The next section deals in detail with that Investigation, but it will be convenient to note here the CMA's evaluation of Ofgem's regulatory policy. First, the CMA was critical of Ofgem's non-discrimination condition: "when Ofgem prohibited suppliers from offering out-of-area discounts for new customers, the effect was to increase prices for out-of-area customers and reduce the strength of competition". (CMA 2016 para 14.44 pp 946-7) Professor Cave comments that the condition "predictably softened price rivalry among the SLEFs (and offered them an object lesson in the mutual benefits of foregoing competition)". (Cave 2018 p 5)

The CMA was also critical of Ofgem's simple tariffs requirement following the Retail Market Review (RMR) and explained why this had an Adverse Effect on Competition.

> "There are few, if any, signs that customer engagement is improving materially, either in terms of direct customer activity (eg switching, shopping around) or their experience and perception (eg views on tariff complexity). … [Suppliers withdrew] a number of tariffs and discounts and changing tariff structures, which may have made some customers worse off. … The RMR four-tariff rule limits the ability of suppliers to compete and innovate and provide products which may be beneficial to customers and competition. … [The RMR rules] dampen price competition by limiting the ability and incentives of suppliers to respond to competition by offering cheaper tariffs or discounts (which means that they, in turn, put less competitive pressure on their rivals)." (CMA 2016, paras 171-175)

As a remedy, the CMA recommended that Ofgem remove its simple tariffs restrictions. Ofgem seemed relieved to do so.

In discussing the RMR rules, the CMA commented that "(a) Given their complexity, the interactions and effects of these rules are difficult to understand and lead to compliance risk for suppliers. (b) More broadly, there is a risk that overly prescriptive rules are counterproductive and encourage game playing, by implicitly legitimising any behaviour that is not explicitly proscribed by the rules." (CMA 2016 para 13.222 p 860) The CMA endorsed Ofgem's new intention (announced in 2015) to move towards principle-based regulation. Ofgem has implemented this recommendation over time, most recently with a proposal to introduce "five new narrow principles" on supplier-customer communications and "remove around 50 pages of detailed rules". (Ofgem 2018f, para 20)

The CMA further concluded that Ofgem's consolidated segmental statements were inadequate, and that lack of sufficient information had caused it to go astray. "Ofgem's inability to address concerns about the Six Large Energy Firms' profitability with the information they currently obtain … was a significant driver of the set of circumstances which ultimately led to those Ofgem policy interventions which have led to Adverse Effects on Competition".[2] As one of its remedies, the CMA recommended that Ofgem require better reporting of generation and retail profits, including balance sheet data as well as profit and loss data.

The CMA also made other findings pertaining to "a lack of robustness and transparency in regulatory decision-making". These related in large part to government responsibilities.[3]

Part II The CMA's Energy Market Investigation

7. The CMA energy market reference

The CMA was required to decide whether any feature of the market "prevents, restricts or distorts competition". Such a feature would constitute an Adverse Effect on Competition (AEC). If the CMA found an AEC, it had to decide whether to take action itself, and/or whether to recommend others take action, "to remedy, mitigate or prevent the AEC or any resulting detrimental effects on customers".

In making the reference, Ofgem excluded the large customer market where it observed "little evidence of harmful features". It identified five issues of concern to itself: weak customer response, incumbency advantage, tacit coordination, vertical integration, and barriers to entry and expansion.

The CMA found no problem with the last four issues, or with wholesale markets generally. It also noted considerable new entry by smaller suppliers after about 2013, who had taken about

[2] CMA (2016), para 18.143. For more detail, see "18.137 … In our view, however, Ofgem's lack of access to suitably specified financial information means it is unable to provide a clear and robust analysis of market trends, prices and profitability. This in turn contributes to a climate where, under the influence of the public and political debate, ill-advised changes to the regulatory regime have been implemented, some of which, we have found, give rise to AECs. 18.138 For instance, we found that some decisions taken by Ofgem over the last few years (eg SLC 25A and the simpler choices component of the RMR rules), which in our view were not based on robust analysis, have had adverse effects on consumers. Both measures were taken in the wake of the Energy Supply Probe, which found that the market was not working in the best interests of consumers but failed to provide a clear narrative in respect of increases in retail prices and energy firms' profitability…. 18.139 In our view, had clearer and more relevant information been available to Ofgem, it would have been in a position to provide a more robust analysis of the markets which would have led to more robust decisions being taken in the best interests of consumers."

[3] In addition to the mentioned point about financial information, this latter finding covered several issues including the downrating of the competition duty in Ofgem's statutory objectives, the absence of a mechanism for transparently addressing disagreements between Government and Ofgem, and the lack of effective communication about the impact of government and regulatory policies on energy bills.

15% of the residential market by the end of the investigation. But the CMA did find ten market features that it considered had an AEC, four of which related to the retail market, viz

"*(a)* weak customer response and lack of engagement with domestic retail energy markets;
(b) price discrimination and tacit coordination on the part of suppliers;
(c) supply-side barriers to entry and expansion in the prepayment segments; and
(d) the regulatory framework governing domestic retail market competition, notably the RMR reforms and the settlement systems for gas and electricity." (CMA 2016 para 124 p 30)

8. Differential prices and a two-tier market

The CMA examined the prices of different kinds of tariffs and carried out a customer survey. It was concerned by certain price differentials and sought to explain these in terms of market power. As Professor Cave explains,

> "Based on the data of the survey, the CMA investigated a theory of harm under which certain firms exercised unilateral market power over certain groups of consumers. By dint of this market power, each firm was able to charge excessive prices on a discriminatory basis to a particular category of consumers – those who were disengaged from the market." (p 5)

> "The theory of harm which the CMA explored was what Ofgem later described as a two-tier market. The competitive tier included households which searched, usually annually, for a new contract – often employing price comparison websites. …. Disengaged customers were generally on the evergreen SVT either because they had never made a positive choice, or because they had defaulted to the SVT at the expiry of a fixed term tariff." (p 6)

So customers that spent time searching found lower-priced tariffs than customers that did not search. But why is that surprising and why is that a problem? The CMA assumed or asserted that this was a problem because, in a competitive market, what it considered to be the "same" product should not sell for different prices. The CMA then focused on the reasons for what it assumed was a problem.

The CMA amassed evidence on the relationship between the various tariff types, with some data going back to 2004. Professor Cave notes "an upward trend in average SVT tariffs … from about 2012" (p 7) and "the widening gap in the period after 2013 between the SVT and fixed-term offerings of the SLEFs themselves" (p 7). He also notes that "over the period between January 2012 to January 2016, the gap between the average SVT price and an industry level benchmark of direct costs grew in similar fashion" (p 9).

Professor Cave writes

> "It is apparent that the balance changed over time among the non-standard tariffs, with the capped and non-standard variable tariffs giving way to fixed term tariffs in mid-2013. This is probably a response by the SLEFs to the almost exclusively fixed term offering of their rivals, which increased their market share from 2% in 2012 to 15% in 2016. In other words the battleground in the competitive tier of the market, between the SLEFs and larger entrants, became fixed term contracts." (p 7)

Certainly the new entrants had an important effect. But surely, a main reason why the balance among non-standard tariffs changed in mid-2013, and why the battleground became fixed term tariffs, was because of Ofgem's new restrictions on tariffs. Its simple tariffs policy – proposed in October 2012 and confirmed in August 2013 – forced suppliers to change the way they competed. In particular, by prohibiting discounts and requiring that each supplier have only one SVT, Ofgem's policy prevented the use of variable tariffs as flexible and aggressively priced acquisition tariffs, and in effect relegated the role of the SVT to that of a default tariff. Mention was made above of "the best offer in the market" having to be withdrawn because of the discounts it offered.

There were other factors too. Ofgem's crackdown on doorstep selling meant that retailers had to find other ways of marketing their tariffs. Price Comparison Websites (PCWs) were developing rapidly, and ranking the offers of competing retailers. Low-priced tariffs were needed to attract customer attention.

In a competitive retail market, suppliers need to be very fleet of foot in adjusting their tariffs to beat or match their rivals. Some offers obtain only for a few weeks or a few days or even hours. With only four tariffs at their disposal, one of which was the default SVT, and no room for minority (e.g. green) tariffs, in order to acquire new customers suppliers were driven to focus on shorter fixed term tariffs.

9. Customer disengagement and weak customer response

Professor Cave notes how the CMA sought to explain the two-tier market, and the changes in tariffs and competition after 2012. Referring to the four CMA concerns listed at the end of section 7 above, he says

> "In terms of identifying the causes of these outcomes, several non-exclusive possibilities were identified in the case of the generality of customers. First, weak customer engagement on the part of some customers with their own SLEF; [second] coordination among SLEFs; [third] the impact of dysfunctional regulatory measures.
>
> The third of these factors was recognised in a decision by the CMA that the regulator-determined reduction in the number of tariffs, and other parallel actions, restricted competition. The second – coordination – was examined and not found to be present….
>
> The spotlight thus fell on the first factor, which was found to be present. More precisely, the CMA 'identified a combination of features of the markets for the domestic retail supply of gas and electricity in Great Britain that give rise to an adverse effect on competition (AEC) through an overarching feature of weak customer response, which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base.'
>
> This was known as the domestic weak customer response adverse effect on competition." (p 10)

As regards the *change* in observed market phenomena that concerned the CMA, it seems implausible that weak customer engagement is the explanation. Human nature evolves over millenia. If there is such a thing as weak customer response, it is unlikely to have suddenly evolved in 2013.

More plausible, as just suggested, is that it was Ofgem's regulatory interventions, including its simple tariffs policy which came into effect in 2013, that changed the way that competing suppliers operated after this time. Although the CMA did indeed find that Ofgem's regulatory interventions had an adverse effect on competition, it does not seem to have realised the full extent of the impact on pricing and tariff type.

What is the evidence for weak customer response? The CMA observed that "there were significant gains from switching that went unexploited by domestic energy customers over the period Q1 2012 to Q2 2015". (para 126 p 30) For example, under the CMA's most liberal scenario 5x, in which customers were able to change supplier, tariff and payment method, the average saving available to all dual fuel customers of the 6 Large energy firms was £164 over this period (14% of the bill). (para 128) The CMA concluded

> "Our finding of material potential savings that are persistent over time, available to a significant number of domestic customers and that go unexploited provides evidence of weak customer engagement in the domestic retail markets for electricity and gas in Great Britain." (para 134 p 33)

The CMA then sought to identify characteristics of energy consumption that it considered were "likely to impede customers' understanding of and engagement in energy retail markets". (p 35)[4] These characteristics themselves are not in dispute. But is there really evidence of weak customer response that needs to be explained? For me, the CMA's argument and figures do not prove this.

For example, the CMA's preferred scenario 5x is based on the assumption that all rational or engaged customers would be able and willing to change tariff type and payment method. This seems unreasonable. Some customers might have a preference not to keep changing fixed tariffs; other consumers are not able to interact only online or to pay by direct debit. If a single basis of comparison is to be used, consider instead the CMA's scenario 3b where customers can change supplier but not tariff type or payment method. Then the average saving to all dual fuel customers of the 6 large energy firms reduces from £164 to £65 (6% of the bill). (CMA 2016 para 8.249 p 418)

Moreover, for the dual fuel customers of the Medium size suppliers – these are customers who have already demonstrated by switching supplier that they are actively engaged - the corresponding average savings are £143 (11% of bill) under scenario 5x and £72 (5% of bill) under scenario 3b. (CMA 2016 para 8.250 p 418) In other words, the active and engaged customers seem not very different from the allegedly less engaged ones. And in both cases, the majority of the allegedly available savings seem to derive from changing tariff type (which customers might prefer not to do) or from changing payment method (which customers might be unable to do), rather than from changing supplier.

[4] One characteristic was the absence of quality differentiation of gas and electricity, another was that conventional meters were not very visible or immediately informative to the consumer. Some customers experienced difficulties in shopping around, and some did not have access to the internet or were not comfortable using it. Some were not comfortable using a PCW. There was a perception that the process of shopping around was more difficult than it actually was.

Furthermore, as explained and illustrated in more detail in a later section of this paper, these savings are uncertain, because tariffs might change, and at best apply to the first year only. If a customer stays with the new supplier and is transferred to that supplier's higher SVT, then the average savings over time can be significantly less than in the first year.

There are many different savings figures in the CMA report, but similar considerations apply. Contrary to the CMA's view, it seems plausible that not changing supplier (or tariff type or payment method) is essentially a rational decision by customers, not a failure to engage in the market reflecting weak customer response. Although some customers are willing and able to actively engage in the market in return for an expected saving in price, other customers consider this risky or worrying or not worth the hassle: they have better things to do in their lives.

Basically, the CMA compared the preferences and actions of actual customers against its own concept of what customers should think and do, and found actual customers wanting. It concluded that customers themselves were the problem because many of them were not capable of, or interested in, sustaining what the CMA conceived to be a competitive market. So the CMA's solution was to try to stimulate customers to be more engaged – that is, to change their preferences and their preferred way of life.

10. Evidence from tariff and customer data

It might be argued that weak customer response is reflected in the continuing high market share of the Six Large Energy Firms. There have indeed been many new entrants in recent years, and at the time of the CMA Final Report they had taken about 15% of domestic customers. So the SLEFs retained 85% of all customers.

In the two years since then the share of the small and medium suppliers has increased to 25%.[5] Now, if the SLEFs retain a 75% market share, it might be argued that most customers are disengaged. But note that the average proportion of the SLEFs' customers on SVTs is 54%.[6] That means that, on average, 46% of their customers have actively chosen other tariffs.

Moreover, a significant proportion of these SVT customers have been with their large supplier for less than three years. Only one third of SLEF non-PPM customers have been on an SVT with their supplier for more than three years.[7] This means that SLEFs have had to compete in the market for two thirds of their present customers, either to keep their existing customers via other tariffs and/or to attract new customers.

Furthermore, the proportions of customers leaving or staying with the SLEFs is not random. It seems to be related to the recent average prices charged by the SLEFs. As the CMA indicates, relative positions of the SLEF SVTs have varied over time. However, in recent years, since the

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[5] Cornwall Insight, Chart of the Week 101, 21 September 2018, data as at 31 July 2018.

[6] Ofgem, SVTs Latest trends as of April 2018. 57% is the simple average of the proportions of non-PPM SVT accounts of the six SLEFs.

[7] Ofgem, Number of non-price protected domestic customer accounts by supplier: standard variable, fixed and other tariffs (GB), data as of April 2018, accessed 2 September 2018. The simple average of the proportions of customers on the six SLEF SVTs for more than three years is 31.9%.

publication of Ofgem data, two SLEF suppliers (BG and SSE) have consistently maintained the lowest SVTs, relative to other SLEFs. Table 1 indicates that over 40% of their present customers have been on SVTs with them for more than 3 years. In contrast, for the three SLEF suppliers that have set the highest SVTs, on average just under 25% of their customers have been on SVTs with them for over 3 years. Thus, even apparently disengaged customers, who prefer SVTs and prefer not to keep switching supplier, respond to differences in prices by switching or staying. This does not look like weak customer response.

Table 1 The impact of SVT price levels on customer retention

Supplier	SVT Ranking by average level of SVT 2016-18 (cheapest to most expensive)	SVT customers over 3 yrs as % of total
BG	1	41.7%
SSE	2	43.0%
E.On	3	33.5%
EdF	4	25.3%
Scottish Power	5	20.7%
nPower	6	27.4%
All SLEFs (average)		31.9%

Source: Ofgem data per previous para fn 6. SVT ranking is my calculation from these data

11. The two-tier market and the competitive level of price?

It might be argued that whether customer response is weak or not could be judged according to whether it leads to a competitive level of price. Professor Cave writes

> "… the CMA found the GB energy market to be characterised by two separate markets: one which delivers competitive prices to engaged customers, while in the other, which contains large numbers of disengaged households, customers of the SLEFs (Six Large Energy Firms) are charged the much higher standard variable tariff or SVT. " (p 12)

There is no doubt that more active customers pay lower prices, hitherto mainly for short-period fixed tariffs that these customers switch relatively frequently, than less active customers pay for staying on SVTs. However, the characterisation of the fixed tariff market as having a competitive level of price, and the SVT market as being non-competitive and reflecting market power, is misleading. There are three main reasons why fixed tariff prices do not represent what might be called a self-standing competitive price level.

The first reason is that, although SVTs and fixed tariffs are separate products, suppliers incur certain overhead costs across all customers. In a competitive market, suppliers need to recover their overhead costs according to the strength and elasticity of demand for each product. A higher margin on SVTs than on fixed tariffs is not inconsistent with competition. By the same token, the lower margin on fixed tariffs is only possible because of the existence of the higher margin on SVTs.

For example, in a competitive market a generating plant might get 10 p/kWh for electricity generated at peak time, and 1p/kWh for electricity generated at nighttime. A key consideration in assessing a competitive market is whether the average price received over the course of the day and year, say 6 p/kWh, is sufficient (and not more than sufficient) to cover the total cost of production. If it is, it would be wrong to argue that the nighttime price of 1 p/kWh is competitive while the higher peak price of 10 p/kWh is not competitive and reflects the exercise of market power. Nor would it be argued that, because the difference in price of 9 p/kWh is greater than the difference in cost of producing during the day rather then during the night, this is a measure of the extent to which generators exploit their market power to charge excessive prices on a discriminatory basis to daytime customers. And although the power can be sold at 1 p/kWh at night because it can also be sold at 10 p/kWh in the daytime, this would not normally be characterised as the daytime users cross-subsidising the night-time users.

The second reason why the fixed tariff market is not "at the competitive level" and the SVT "above the competitive level" relates to an interrelationship that Professor Cave (as well as the CMA) spelled out.

> "It should be borne in mind that the SLEFs expect some of their fixed period customers to default to their more expensive SVT contract, so that profits from such subsequent harvesting of acquired customers might drive their fixed period prices down. On the other hand, entrants with different harvesting expectations offered in many cases even lower fixed terms prices." (pp 7-8)

> "There is a secondary but separate linkage between the two market prices which has already been noted. If a fixed term customer fails to renew her tariff, then according to the regulatory rules she is transferred on the substantially higher SVT. A firm's customer data enable it to forecast the frequency and duration of such transfers. In setting its prices for fixed term contracts it will take this expected subsequent excess return into account." (p 23)

What this means is that the prices of fixed tariffs do not themselves represent the self-standing level of competitive prices. They are at a *discount* to a self-standing competitive level because they are priced lower in order to attract customers who, it is hoped, will become more profitable higher-margin SVT customers in future.

To take another example, suppose that certain magazines competed for readership by offering the first few months' subscription for free. Some relatively engaged readers might be induced to change magazines relatively frequently, thereby paying less over time, or conceivably even nothing; other readers would not want the nuisance of doing this. But one would not argue that the competitive level of price is zero because free subscriptions are available temporarily, and that the readers who paid the full subscription each year were disengaged and were being exploited by the amount of that subscription. Nor would one conclude that the "solution" to this "problem" of disengaged customers was to try to persuade more customers to switch to other magazines and thereby get them free for a few months. And it would surely be realised that, the more customers that kept switching in this way, the more likely it would be that magazines would reduce the length of the free initial subscription, and might cease making such free offers, or would find ways of restricting them to new customers genuinely interested in longer term subscriptions rather than to repeat customers seeking "a free lunch".[8]

[8] For example, The Times in the UK is presently offering a free subscription for one of the first three months, but conditional on the customer signing up for a minimum of 12 months. In the retail energy sector, some suppliers have

The third reason why the lowest fixed tariff prices do not represent a properly competitive level is that they are subsidised prices. The lowest prices are typically offered by small suppliers that are exempt from social and environmental costs levied on the large and medium suppliers. Estimates of the level of these costs vary, but they are significant. The CMA noted that Ofgem "estimates that environmental and social costs will have increased from £62 in the year to 31 December 2014 to £71 in the year to 31 March 2016." (fn 109 p 984) So the small suppliers and their low fixed prices are cross-subsidised by the larger suppliers out of their higher SVT prices which are paid for by their less active customers. (Moreover, if the large supplier has a relatively high proportion of fixed tariff customers and a relatively small proportion of SVT customers, then the burden per SVT customer is relatively high, hence increasing the differential between SVTs and fixed price tariffs.)

The CMA was aware of this small supplier subsidy, and made some adjustment for it (for example, in its calculations about customer detriment discussed below). It considered that "without these exemptions, … entry into the market [would be] more difficult" and that "Given the relative strength of firms above the exemptions thresholds compared with new entrants … we do not believe that the impact of the current exemptions is likely to be market-distorting". (para 8.94 pp 367-8) In my view, this underestimated the impact of the cross-subsidy on market prices and price differentials, and hence on the perception of what constituted "competitive price levels".

The present level of fixed tariffs being below the self-standing competitive means that the public has been given an unrealistically low impression of the competitive level of price, and has been encouraged to believe that SVTs are above that level. Hence the widespread impression that the market is less competitive than it actually is, and that the less active SVT customers are being exploited. And hence the belief that price control is needed to bring SVTs down to the "competitive level", when in fact it will put them below that level.

12. Estimating customer detriment

Professor Cave explains that

> "A key issue affecting the reception of the CMA report was how the customer detriment associated with the retail adverse effects on competition was calculated. It is likely that much of the public debate that followed was influenced by the size of the harm to consumers associated with high SVT prices, which the CMA estimated as averaging £1.4 billion pounds a year over the period 2012-2015. This amounts to an average of more than £50 in each year for every Great Britain household, an uplift in excess of 5%. This annual total is an amount greatly in excess of detriments calculated in earlier CMA market investigations." (p 10)

This comment is spot on: the £1.4bn annual customer detriment figure – together with the estimate of £2bn for 2015 - has dominated public debate. It was cited by Professor Cave himself in arguing the case for an additional wider tariff cap, and has been repeatedly cited by the Secretary of State, and by others in the media, in making the same argument.

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reportedly refused to accept re-applications from previous customers (who are perceived as unlikely to stay), or applications made by entities that are ready to reswitch customers after the initial offer ends.

It is also true that these figures are greatly in excess of detriments calculated in earlier CMA investigation – Professor Cave cites the £40m annual detriment in the cement industry (fn 6 p 10) - and indeed greatly in excess of calculations by the CMA's predecessor the Competition Commission (CC).

My explanation for this is quite simple. It is not that the detriment is any greater in the retail energy sector than in other sectors. Rather, the CMA energy investigation used assumptions and methods that were different from – and more extreme than - those used in previous competition authority investigations.

Professor Cave explains that

> "There are broadly two ways of calculating the customer detriment. One is to identify the profits made in the activity where adverse effects on competition are found to be operating. This requires a comparison between the cost of capital to the firms involved and the rate of return earned. ….
>
> The other approach is to seek out an estimate of the competitive price, and to compare the impugned prices with that estimate. …
>
> The CMA employed both approaches, calling the first the indirect method, and the second the direct method." (pp 10-11)

I found this simple characterisation particularly helpful: it enabled me to understand the logic of the CMA's two methods, a logic that had previously eluded me.

Both methods require judgements as to what would be observed – in the way of profits or prices – in a benchmark competitive market. The next sections examine in turn the two sets of judgements made by the CMA in this investigation, and indicate how they differ from previous approaches.

13. The direct method of estimating customer detriment

The direct method of estimating customer detriment generated the estimate of £1.4bn per year averaged over 2012-2015 and £2bn in 2015. Professor Cave cites the CMA's explanation of how it exercised its judgement in this approach.

> "193. Our direct approach to assessing detriment involves calculating the average prices offered by the Six Large Energy Firms to their customers and comparing these to a 'competitive benchmark price', which is based on the average prices offered by the most competitive suppliers. In establishing the competitive benchmark price, and then making this comparison, we made certain adjustments to observed prices to ensure the comparison is on a broad like-for-like basis. These included adjustments for exogenous cost differences relating to network costs and the costs associated with different payment methods, adjustments to reflect the fact that the suppliers in our benchmark are growing rapidly, and hence incurring higher acquisition and indirect costs but lower obligation costs than they would in steady state, and adjustments to achieve a benchmark level of profitability." (CMA 2016 p 45, cited in Cave pp 12-13)

I have elsewhere set out my concerns about this estimate. (Littlechild 2017, 2018) Because the 'most competitive' suppliers were much smaller and newer and were exempt from some subsidies and were not yet fully profitable, the CMA had to make substantial adjustments to ensure comparability. The CMA ended up comparing actual prices of the six large suppliers with the CMA's guess at what just two of the much smaller mid-tier suppliers would charge *if* they were not exempt from costly environmental obligations and *if* they had reached an efficient scale and *if* they were in a steady state and *if* they were not loss-making and *if* instead they were earning a normal return on capital. It was thus a comparison between actual prices and the CMA's guess at the prices that would obtain in a hypothetical and efficient steady state.

The CMA's competitive benchmark sounds remarkably similar to the concept of perfect competition, or something suspiciously like it. However, that would be inconsistent with the CMA's own guidelines, which explicitly state that its benchmark is "not an idealized perfectly competitive market". (Competition Commission 2013, para 320, p 68)

The CMA's calculation was disputed by the larger suppliers. Oxera advising Scottish Power argued that the correctly calculated average detriment was not £1.4bn but was in the range £755m down to minus £720m. It is not possible to assess the merits of the competing arguments because the CMA's calculations were not made public: there were over 10,000 data excisions in the CMA final report and appendices. Only advisers authorised by the CMA were allowed access to the confidential data rooms. Oxera says that, after final closure of the data rooms, the CMA made two final adjustments that it had not made previously, which Oxera estimates amounted in total to about £1bn. But no one could see and comment on the details of this calculation.

The hypothetical and extreme nature of the CMA's competitive benchmark, and the fact that no one is allowed to see the final calculations, call into question the plausibility of the CMA's £1.4bn and £2bn calculations of customer detriment using the direct method.

14. The indirect method of estimating customer detriment

In the case of the CMA's indirect method, Professor Cave explains that "the CMA's measurement strategy was to estimate a cost of capital to a notional stand-alone retail business, identify a capital base of tangible and intangible assets, and calculate the return on capital employed." (p 11) In fact, none of the six large suppliers operated a stand-alone retail business. So the resulting estimates of capital base, returns and excess profit were particularly conjectural and, again, were challenged by the large suppliers.

Professor Cave notes that "A fact which emerged from the investigation is that the retailing costs of the SLEFs differed markedly." (p 12) He continues

> "Two rival approaches to this issue have been suggested. One is to regard these variations as marks of productive efficiency and to normalise the costs at an estimate of an efficient level. The other is to treat them as a rising supply curve and regard the least efficient producer as indicating marginal cost at the output level observed. The CMA chose the first method. The effect is that its estimate of excess is a combination of realised excess profits and of inefficiently incurred costs.
>
> Over the period 2012-2014, the CMA's detriment figure found by the profit-based indirect method is £1.1 billion (adding together profits in excess of the cost of capital of £650 million and measured inefficiencies of £420 million). If the lowest cost firm [rather than the lower quartile cost firm] were used as the benchmark for productive efficiency, the measure of detriment would increase further to £1.5 billion." (p 22)

These calculations are sensitive not only to the efficient cost benchmark but also to the time periods involved. For example, the CMA focused mainly on the longer but earlier period 2007 – 2014, where it calculated that the detriment averaged about half of that last figure, viz £723m per year equal to excess profits (average £303m) plus inefficient costs (average £420m). The CMA observed that "a large part of the detriment we have observed in the form of high prices is likely due to inefficiency rather than excess profits". (para 252 p 59)

But why should estimated inefficiency be added to estimated excess profits? Why are the higher costs of some companies considered a customer detriment in this or any market? In the real world, all competitive sectors have cost and profit differentials between companies. Profits that reflect superior efficiency are not normally regarded as indicative of the exploitation of market power.

Professor Cave's explanation for choosing the first rather than second of his "rival approaches" is as follows.

> "The second method seems appropriate when there is an objective reason for the 'rising supply curve'. For example, in a wholesale energy market, more costly types of generating capacity are commissioned, in a well established 'merit order', as demand/output rises.∗ But if the variation in generators' costs were due to varying efficiency of operation of the same plant, a regulator would be less willing to fix the strike price on the basis of the costs of the least efficient generator in production." (fn 9 p 12) (∗ Professor Cave's words reordered slightly to clarify what I take to be his meaning)

This second method was used by the CMA in its cement market investigation, that produced the £40m estimate of customer detriment. The CMA assumed that existing cement plants had fixed capacities and ranked them in order of increasing operating cost. This second method seems appropriate there, as well as in a wholesale energy market where plants can be ranked in merit order. But surely differences in efficiency in operating a given type of plant are an equally valid basis for ranking plants in a wholesale energy market? Indeed, in a 'normal' competitive market, is it not usually assumed that the more efficient companies – those that are more efficient than the 'marginal' business - will be "pricing above a level that is justified by the costs incurred in operating an efficient business"?

The approach used in the energy market investigation is not the UK competition authority's conventional approach. The Competition Commission (CC) considered inefficient costs in a couple of previous investigations, but ignored them because in one case they were not sufficiently significant, and in another case the firm in question was making a loss, hence not imposing its higher costs on customers. Although two of the SLEFs were similarly loss-making, the CMA did not set aside their higher costs as the CC did in its previous investigations.

If the CMA's unusual treatment of inefficient costs is set aside, this leaves the CMA's more conventional calculation of excess profit at an average of £303m per year over 2007-2014. The SLEFs disputed these calculations and I am not in a position to assess them. However, if the large customer market is taken as the benchmark of an acceptably competitive market (rather than the CMA's assumption of what a normal competitive profit should be), and if SLEF profits are adjusted for what the CMA estimated to be the higher risk in the residential market than in the large customer market, then the CMA's calculated excess profit in the residential market reduces from £303m to £170m a year. (Littlechild 2017, 2018) This corresponds to an excess profit of about £7 per dual fuel household per year on a bill of about £1100, which is not a very large amount.

Furthermore, in an earlier market investigation, the Competition Commission opined that only if all companies in the market earned excess profits would this indicate market power.[9] In the domestic retail energy market it was far from the case that all major suppliers earned excess profits. On the contrary, Professor Cave cites Ofgem data to the effect that, in 2016, the SLEFs' pre-tax domestic supply margins in gas and electricity averaged 4.5% but ranged from plus 7.2% down to minus 6.3%. (p 12)

Ofgem data also show that, over the period in question, the largest supplier, British Gas (BG), accounted for two thirds of the total sector retail profits, and the largest two suppliers, BG and SSE, accounted for 95% of these profits. Ofgem figures suggest that these two suppliers had the lowest costs in the market, so this profit was in effect a reward for superior efficiency. Two other large suppliers had average profits around the level that the CMA considered competitive. The remaining two suppliers on average had losses throughout the period. This disparity in results does not support the claimed unilateral market power with excess profits, presumed to obtain across all the six large suppliers.

In sum, the remarkable and much-publicised customer detriments of £1.4bn and £2bn per year are not confirmation of weak customer response, nor an indication that the residential retail energy market is significantly worse than other markets. Rather, they are an artifact of two novel and questionable ways of measuring that detriment. In other respects, the CMA report is a valuable insight into the operation of the UK energy sector. But in the event, the customer detriments of £1.4bn and £2bn took on a life of their own, and led the Government to impose a widespread retail price control that the CMA itself advised against.

Part III CMA remedies and developments since the CMA report

15. The household remedies debate

Professor Cave's next section gives "a broader and more thematic account" of the arguments employed in the debate on remedies for the residential sector.

> "The CMA describes its proposed retail remedies as falling into three categories:
> - creating a framework for effective competition;
> - helping customers to engage to exploit the benefits of competition; and
> - protecting customers who are less able to engage to exploit the benefits of competition.
>
> The first category is fairly non-controversial. It involved removing regulation which has an adverse effect on competition, and improving the settlement regime among customers of electricity and gas to improve cost allocation. This process, and the second category of measures too, would be enhanced by the plan for a nationwide roll-out of smart meters, due to be completed by 2020." (p 13)

[9] "6.152 In order to be indicative of a failure of competition, profits in excess of the cost of capital must be persistent, ie there must have been sufficient time for a competitive response (entry or expansion) to have occurred, rather than being just a short-lived or temporary situation relative to the life of the investment. Profits should also not be specific to a particular firm; we would expect that suppliers who are particularly innovative or efficient will realize higher profits than others in the same market." Competition Commission (2009) p 105

I agree with Professor Cave about the desirability of creating a framework for effective competition, and the measures proposed. Remarkably, in the UK the first step has had to be the removal of unhelpful regulation. Regulation that the CMA found had an adverse effect on competition deserves a greater share of the responsibility for any defects in the present market than the CMA identified. Hence, removing such regulation can be expected to have a more beneficial effect (over time) than the CMA recognised. This in turn reduces or removes the share of responsibility attached to 'weak customer response', and similiarly reduces or removes the pressure to find other remedies for such alleged problems.

Professor Cave's discussion of demand-side measures is informative and balanced, and I find little to disagree with. He points out that, by the time of the CMA reference, Ofgem's regulatory measures over bill design had had little effect, at least in reducing the proportion of customers on SVTs. He cites some useful extracts from the recent review by Professor Amelia Fletcher, which concludes that "Getting such remedies right is difficult. We can sometimes predict how customers will act on the basis of past experience, but often we cannot." (Fletcher 2016 p 16)

Professor Cave has a reservation about the use of demand side measures.

> "But regulators do not generally commit to a forecast of what increase in engagement they expect to see in a market, either in total or as a consequence of the demand-side measures which they introduce. Nor do they generally indicate, in the case of such measures, what level of enhanced engagement would qualify as a success. This lack of precision is a disadvantage in the face of a large consumer detriment." (p 16)

This is true. But since it is true of almost all policy measures, whether adopted by regulators, governments or others, this does not seem a major argument against their use, or a basis for invoking more severe measures like price controls.

Professor Cave has a good summary of Ofgem controlled trials of CMA remedies, up to the date of his paper. They show some limited increase in customer engagement following prompts by own supplier, other suppliers or Ofgem. He concludes:

> "This work is still in its infancy. In due course we may derive reliable information from it, and find approaches which can make a real difference to disengagement levels." (p 17)

He also refers to the practice of collective switching, and to Ofgem's then-ongoing Active Choice Collective Switch trial. Since Professor Cave's paper was written, Ofgem has published some initial results of that trial. It shows higher response rates of disengaged customers, in the range 15% to 27%, depending on the source and nature of the prompts, compared to under 3% by the control group. (Ofgem 2018c)

Clearly various kinds of regulatory prompts can have an impact on customer behaviour, at least at the margin. This may in turn impact on supplier behaviour, and on prices and differentials in the market. Nonetheless, I have some reservations, to which I now turn.

16. Some reservations about trying to influence customer behaviour

The drive to "make a real difference to disengagement levels" is driven by the CMA's assumptions a) that there is an exceptionally large customer detriment in this sector, and b) that "weak customer engagement" is the cause of it. As explained above, I am not convinced of either of these propositions. Hence I am sceptical of the need to try to change customer behaviour.

Ofgem's work to reduce barriers to switching, including by improving and speeding up the switching process, is certainly welcome. And by all means let Ofgem alert customers to the ease and benefits of engaging in the market and switching supplier and/or tariff – though I would be surprised if rival suppliers and Price Comparison Websites were not in general more capable of finding ways of persuading customers to engage and switch than competition and regulatory authorities are.

But the additional CMA-inspired demand side measures raise a few additional concerns. As the CMA found, almost all of Ofgem's regulatory interventions since 2008 that were aimed at improving the residential competitive retail market have had unintended adverse consequences that necessitated the removal of the interventions. Is there reason to believe that further such interventions will not be similarly problematic?

For example, Professor Cave cites the conclusions of some University of East Anglia research for Ofgem which suggests that "the effect of reducing prices for disengaged customers may be to raise them for active customers" (p 25). They say this will be the consequence if existing differentials reflect a sharing of fixed costs rather than unilateral market power and inefficiency. This is the argument I have put forward above. In addition, as also explained, if fewer new customers stay on from introductory fixed tariffs to SVTs, then there is less benefit in discounting fixed tariffs in order to attract such new customers.

My concern is that hitherto disengaged customers that are "nudged" to switch to low price suppliers might encounter more difficulties than they envisaged. Several such suppliers have had to leave the market. Most recently, in October 2017, IRESA offered the cheapest price in the market; it recently went into liquidation and Ofgem had to take steps to bail out its customers (at the expense of other customers). The CMA/Ofgem trials have suggested names of cheapest suppliers to customers. One large supplier, engaging in such a trial, "reportedly contacted almost 13,000 customers and urged them to switch to a supplier which is believed to be struggling to pay its debts".[10] Although Ofgem has described its trial methodology in considerable detail, little is known about the identities, reputations and prices of the suppliers whose names have been suggested to customers.

[10] "The regulator has since revealed that SSE wrote to customers and listed Electraphase, a company unable to pay its debts, as one of the alternatives. It has been reported that SSE sent more than 176,000 letters to customers, with almost13,000 of these suggesting a switch to Electraphase." Adam John, *Utility Week*, 14 August 2018.

Ofgem, consumer organisations and price comparison websites not infrequently refer to "annual savings" from switching.[11] I see the need for simplicity of message, but this could be misleading. The savings claimed are actually for the first year only (assuming no further tariff changes). They are not annual. What happens to the switching customers *after* the first year? How do their tariffs with their new suppliers evolve compared to their tariffs with their original suppliers? If these are disengaged customers, it is highly possible that they will stay with their new suppliers for several years. Unless they make a further active effort to switch to lower fixed tariffs, they will likely be transferred to default SVTs that could well be higher-priced. Taken over a period of years their annual savings could well be significantly lower than their first year savings.

To illustrate with recent Ofgem data, an average-usage dual fuel customer on the highest large supplier SVT tariff (nPower £1176) could save £218 by switching to the cheapest mid-size supplier fixed tariff (First Utility £958).[12] But suppose the customer then stays with the new supplier (First Utility) and after the initial year is moved to its fixed term default tariff of £1101 (which is less than its SVT of £1132). This is only £75 lower than the original nPower SVT. The customer's saving over, say, 5 years would average £104 a year, half the initial saving of £218.

In that example, the customer is nonetheless still better off. But this need not be the case. For example, in October 2017 the average-use SVT of large supplier E.On was about £1111 while small supplier Economy Energy was offering its Switch Saver tariff at £811, the second-lowest tariff in the market (after the ill-fated IRESA). This indicated a first year saving from switching of about £300. But Economy Energy's default SVT price was about £1211, hence a customer defaulting to that tariff after the first year would pay about £100 per year *more* than on E.On's SVT. For such a customer, the net saving over 4 years would be zero, after which period the customer still on Economy Energy's SVT would be losing £100 a year.

In the event, all Economy Energy customers suffered more and sooner than that. In September 2018 the supplier suddenly increased its Switch Saver tariff by £311 for an average-use customer.[13]

It seems that, with the demise of the simple tariffs restrictions, the number of variable tariffs has been increasing. For example, in the published sample letter sent out with Ofgem's latest collective switch trial, the three cited cheapest alternative offers are all variable tariffs rather than fixed tariffs. So, the claimed annual savings from switching are dependent on no change in the offered tariffs (as well as the present tariffs), which clearly cannot be guaranteed.

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[11] E.g. "annual savings of around £300 available" (Ofgem website accessed 19 August 2018). "you could save up to £377 a year by switching to a cheaper tariff" (Which? accessed August 2018). "customers could still save an extra £200 to £300 per year by switching supplier" (energyhelpline 7 September 2018)

[12] Ofgem Retail Market Indicators, Average Tariff Prices by Supplier: Standard Variable and Fixed Default vs cheapest available tariffs, data as of June 2018, accessed 7 October 2018. Ofgem provides no details of the tariffs offered by the small suppliers.

[13] Andrew Capstick, MoneySavingExpert.com News, 14 September 2018. Worse, although this tariff had been advertised at launch as variable, many customers were told on signing up that it was a one year fixed price deal. The supplier agreed to honour that commitment for those customers that could prove they were told that.

At any moment in time, it is clear that some tariffs offer considerable savings over the SVTs of the large suppliers. But how reliable are these savings over a longer period of time, and what is involved in maintaining such savings? In citing the cheapest tariffs and the gains from switching, Ofgem and some others typically do not draw a distinction between fixed and variable tariffs, nor refer to the reliability or otherwise of the supplier. And quality of service records vary greatly.

If hitherto disengaged customers are nonetheless persuaded to switch, will they later deem the switch worthwhile? Will their new supplier keep them on a relatively low tariff? If necessary, will they change their lifestyles and henceforth engage regularly? Or will they feel that their earlier stance was probably the better one for them, and that Ofgem or the consumer organisation or the switching site (or their original supplier in the trials) has given incomplete and unhelpful advice?

It seems to me that those customers that are happy to be active in the market are well provided for, including by PCWs and automated energy switching services. And Ofgem can provide information and reveal new options to less active customers that may wish to consider a change of approach. But how far is it desirable and practical to try to change customer lifestyles? When Professor Cave remarks that, despite Ofgem's regulatory measures, "the proportion of customers on SVTs … fell at a stubbornly low rate … even as switching rates rose" (p 14), perhaps these customers are telling us something that we should respect. Contrary to some regulatory arguments, SVTs seem very suited to those customers, perhaps the majority, who (at present) do not wish to go through the hassle and risk of repeatedly monitoring the market and switching tariff or supplier.

If there is a problem with SVTs, it is the level of the prices that some such tariffs embody, rather than the concept of an SVT per se. If SVT prices broadly reflect the costs of the suppliers involved, and over time customers are moving from higher priced SVTs to the lower priced ones, should we really argue that customers are exhibiting weak customer response and making the wrong choices, and therefore need to be reeducated? Or would it be more fruitful to provide them with more information about those suppliers that are building up a better reputation for keenly priced SVTs over longer periods of time, coupled with good customer service?

17. The case for a transitional price cap

Professor Cave makes the case for a transitional price control on the retail market, along with the CMA's demand-side measures.

> "…it is unlikely that cost conditions make retail activities a persistent monopoly. Instead, retail market failure is likely to be situated in a potentially competitive space, somewhere between an effectively competitive market where there is no dominant firm, and monopolistic territory. This suggests that the market failure is possibly a transitional state, capable of being converted to effective competition by increasing customer engagement, or even by the passage of time. … This implies that advocates of price controls on retail activities almost invariably support a

combination of demand and supply-side measures, and hope/expect that as the demand-side measures take effect, the price controls can be removed." (p 18)

He acknowledges the possible adverse effects of a price control on quality of service:

"The evidence from the UK is that even in the absence of price controls the performance of many firms in energy, especially in accurate and timely billing, is variable and often quite poor. [CMA Final Report pp 629-631] But imposing a price control may exacerbate it." (p 19)

Against this, he argues that a price cap would reduce customer detriment, and that a reliable forcast can be made of the extent of this. I examine the evidence on this in the next section. But it should be noted first that other members of the CMA panel did not share this view about the desirability of a price cap.

"251. … The majority of us concluded that the disadvantages of attempting to address the detriment of all customers on the standard variable tariff through a price cap would likely be disproportionate. The majority of us believe that attempting to control outcomes for the substantial majority of customers would – even during a transitional period – run excessive risks of undermining the competitive process, likely resulting in worse outcomes for customers in the long run. This risk might occur through a combination of reducing the incentives of suppliers to compete, reducing the incentives of customers to engage and an increase in regulatory risk." (CMA 2016 p 59)

18. The impact of the PPM tariff cap

Professor Cave notes some effects of the PPM tariff cap, citing Ofgem data on retail market indicators accessed April 2018:

"The trajectory of SVT and pre-payment prices before and after the introduction of the cap in February 2017 shows that between the end of December 2016 and the end of April 2017:
- the average pre-payment tariff falls by about £100 per year
- the cheapest pre-payment tariff is constant
- the average SVT direct debit tariff rises by about £40
- the cheapest direct debit tariff rises by about £40.

These observations are consistent with the cap bringing pre-payment tariffs down by £100 at a time when the cheapest fixed term (which is likely to be an approximation of the competitive price) and the SVT were rising, possibly in the face of rising energy and policy costs. The imposition of the cap has not led to an increase in the cheapest prepayment tariff – though individual suppliers may have increased their prices." (p 20)

Table 2 updates these observations with Ofgem data accessed 27 September 2018.[14]

Table 2

[14] Ofgem explains that the tariff values shown are annual bills for a typical medium domestic dual fuel consumer using 12,000kWh/year for gas and 3,100kWh/year for electricity, averaged across GB regions. The market averages are based on the prices of the ten largest suppliers in each segment (PPM and DD) weighted by their estimated market shares (lagged by a few months to reflect data availability). I have rounded figures to the nearest £1.

Tariff details	Dates observed				Changes in tariff		
	Pre-Tariff Cap		Post-Tariff Cap				
	28/12/15 £	28/12/16 £	28/4/17 £	28/8/18 £	Dec 16 - Apr 17	Apr 17 – Aug 18	Dec 16 – Aug 18
Safeguard tariff cap	n/a	n/a	1050	1089	n/a	+£39	n/a
Ave (SVT) PPM tariff	1163	1123	1032	1086	(-) £91	+£54	(-) £37
Cheapest PPM tariff	1056	986	971	947	(-) £15	(-) £24	(-) £39
Ave (SVT) DD tariff	1092	1060	1096	1175	+ £36	+£79	+ £115
Cheapest DD tariff	771	790	863	842	+ £73	(-)£21	+ £52
Cap – Ave PPM	n/a	n/a	18	3			
Cap – Cheapest PPM	n/a	n/a	79	142			
Ave PPM - Cheapest PPM	107	137	61	139			
Ave DD - Cheapest DD	321	270	233	333			

Although the data in column 6 do not entirely tally with Professor Cave's figures,[15] it is nonetheless the case that, from December 2016 to April 2017, the tariff cap brought down PPM tariffs when the DD tariffs were rising, and the cap did not lead to an increase in the cheapest PPM tariff. Indeed, Table 1 shows that, over a year later, in August 2018, the tariff cap has increased, as have the average PPM and DD tariffs, but the cheapest PPM and DD tariffs have reduced. We return shortly to this phenomenon.

Meanwhile, were the increases in DD tariffs simply to reflect increasing energy and policy costs – or were they also a response to the forced reduction in PPM prices due to the tariff cap? Insofar as suppliers need to cover their total costs in one way or another – what some have called a 'portfolio approach to pricing' – the latter is certainly a possibility.

Professor Cave later (p 22) asks what effect the wider price control will have on other prices, and whether there is a waterbed effect, but he does not answer his question. The answer is surely that the price control on SVTs will increase the prices of fixed tariffs, at least for the large, medium and many small suppliers that presently maintain a significant tariff differential. As explained earlier, if there is a lower margin to be made on an SVT customer, then there will be less reason to reduce the price of fixed tariffs in order to attract future SVT customers.

19. The concept of headroom

Professor Cave's next section is entitled "Choosing the duration of the price control and the degree of headroom, in the light of customer switching behaviour" (p 20) (although in fact he does not discuss the duration of the control). His argument for providing headroom is that, although there would be no reason to build 'excess profits' into a price control for a persistent monopoly, there is a case for doing so where the market is potentially competitive.

[15] From end-December 2016 to end-April 2017, the average PPM tariff fell by about £91 (rather than about £100), the cheapest PPM tariff fell by about £15 (rather than remained constant), the average DD tariff rose by about £36 (rather than £40) and the cheapest DD tariff rose by about £73 (rather than about £40).

He gives two reasons. The first is “as a safeguard against the possibility that effective competition develops more slowly than expected” (p 21) This is not explained: possibly (in the light of the CMA analysis) it means that effective competition requires all suppliers to have efficient costs, and this might take time to eventuate, and it would be inappropriate to penalise inefficient suppliers unduly in the interim.

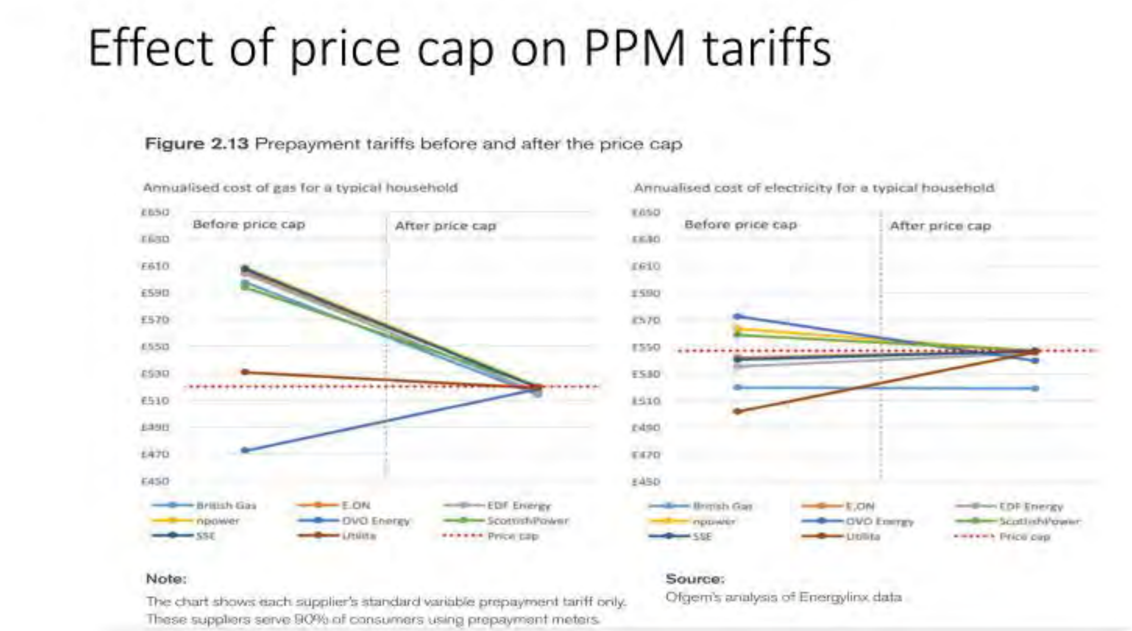
The second reason is that “the control provides headroom over the competitive price in order to provide a continuing incentive for customers to search and switch. Clearly if the regulated price is perceived as being equal to the competitive price, the incentive for households to ‘learn’ engaged behaviour is removed.” (p 21) He notes that the CMA included a headroom of £15 per household per fuel (i.e. £30 per dual fuel) in its PPM tariff cap. And he says that “headroom was also a feature of those [price caps] set prior to the deregulation of retail energy tariffs in the UK”. (p 21)

On this last point, I cannot speak for the tariffs set by other regulators, but when I set the first transitional retail price cap for the Office of Electricity Regulation (Offer) for the first two years (1998-2000) of the newly opened residential competitive electricity market, I did not do so by adding “headroom over the competitive price”. I assumed that suppliers would be able to offer lower prices than before because they were no longer tied into long term contracts with the generators at above-wholesale-market prices. (Such contracts had been part of the ‘deal’ at privatisation in order to facilitate privatisation of the coal industry.) But I did not know what the competitive retail price would be, since the wholesale and retail markets had never been open and wholly unrestricted before. Nor did I try to estimate the competitive price. Nor did I calculate what would be an appropriate headroom. Rather, I took the price cap obtaining at the end of the period before the retail market opened, and subtracted from it the reduction in distribution network charges that were provided by the network price controls. I argued that it was for the competitive market, not the regulator, to discover the competitive price and to deliver price reductions to customers. Which it did.

20. Headroom and suppliers’ prices

Professor Cave’s main point is that providing headroom - setting the cap above the expected competitive price - may be justified in order to continue to incentivise customer switching. He refers to “the trade-off between the scale of switching behaviour (promoted by a substantial headroom) and protection of non-switchers, accomplished by a low headroom level. Unfortunately, the evidence on this question is very limited.” (p 21)

Some evidence from the PPM tariff cap can be brought to bear. The most important outcome, that Professor Cave did not mention, is the clustering of PPM tariffs around the tariff cap. Ofgem’s Figure 2.13 (Ofgem 2017 p 32) shows this quite dramatically (for gas and electricity separately).



The bottom section of Table 2 above, based on more recent Ofgem data, gives more detail. After the introduction of the PPM tariff cap in February 2017, the difference between the cap and the average PPM tariff was only £18 in April 2017. Moreover, it had reduced to only £3 in August 2018. This indicates strong clustering of tariffs around the cap: there is no longer any differential between the average tariff and the cap.

There is nonetheless an odd feature. The differential between the average PPM tariff and the *cheapest* PPM tariff roughly halved from £137 in December 2016 to £61 in April 2017, but then increased back to £139 in August 2018. Correspondingly, the differential between the cap and the cheapest PPM tariff was £79 in April 2017 and increased to £142 in August 2018. This suggests that the cheapest tariff was even further below the cap, but that tariffs offering a saving on the cap were increasingly thin on the ground.

An examination of the tariff savings posted on PCWs sheds some light on the situation. On the morning of 2 October 2018, a day after the tariff cap increased again, a leading PCW listed 28 different suppliers with PPM offers in the market.[16] Half of them, including all 6 Large Suppliers, all 5 Medium suppliers, and 3 Small suppliers, had offers essentially equal to the cap and offering zero savings. Two suppliers offered rather small savings (£11 and £33); nine suppliers offered savings in the range £51 to £77; and three suppliers (Extra Energy, Toto and E) offered higher savings of £110, £118 and £145 respectively.

[16] Figures for 2 October 2018 are based on data from a leading PCW (USwitch) for one location accessed circa 10.15am. They assume dual fuel consumption at average levels.

Further investigation revealed that E's tariff apparently saving £145 required a smart PPM meter, which was not then generally available. Furthermore, E's quoted April 18 tariff data were out of date and, according to the supplier's website, the saving with the October 18 tariff would be only about £35. And within a couple of days, the Toto tariff saving £118 had been removed too.

As of 4/5 October, looking over all ten Ofgem accredited PCWs, there appeared to be 15 suppliers offering 21 tariffs promising savings of more than £80 over the tariff cap, the largest such saving being £165. Further research (still ongoing) reveals that all but two of these are not in fact generally available. The two that may be available appear to save £112 and £92 per year, although both require smart meters (which are not widely available), and both are variable tariffs that could be increased at any time.[17]

Apart from one tariff by large supplier EdF offering a saving of £67, all the tariffs offering savings in the range £50 to £80 are by small suppliers. These (recall) effectively have a subsidy which Ofgem put in the range £62 - £71 in 2016. Thus, with one or two exceptions, all of the unsubsidised Large and Medium suppliers and some of the Small suppliers are pricing at the cap, and almost all the Small suppliers that are pricing below the cap, are doing so by roughly the amount of the subsidy. Further research is needed, but it seems that the apparent competition under the tariff cap is largely an artificiality attributable to the small supplier subsidy.

21. Effects of tariff caps on customer switching

The fact that large and medium-size suppliers are generally not pricing below the tariff cap at all, let alone to the extent of the £30 (dual fuel) headroom that the CMA allowed in setting the cap, suggests one or both of two possibilities. The cap calculations may have underestimated the costs of serving PPM customers, so that suppliers need to use the headroom to cover the shortfall – which some suppliers tell me is the case. Alternative, suppliers may consider that a £30 saving would not be sufficient to attract customers – which is plausible given that the CMA's analysis of its survey data (reproduced in Professor Cave's Appendix Table 12 p 38) found that only 7% of respondents would switch for a saving of less than £50, and three-quarters would require a saving of over £100.

Either way, the reduced tariff differentials have implications for the customer switching rate that the CMA and Professor Cave are keen to increase. Ofgem surveys and empirical evidence indicate that the switching rate is strongly related to savings available. The reduced savings available since the price cap have predictably reduced PPM switching: one large supplier (E.On 2018) has reported a reduction of about one third; another supplier tells me that its PPM customer acquisition rate is down by a half. This reduction also increases suppliers' costs as (for example) sales staff need to make more customer calls to achieve a given level of switching.

[17] Indeed, one of the two suppliers is Economy Energy, which recently announced the £311 increase in another variable tariff, as noted above. And the previously problematic ambiguity is still present: one page on its website says that the available tariff is fixed while an adjacent box says it is variable.

Ofgem's initial impact assessement for the forthcoming wider tariff cap suggested a wide range of possible adverse effects.[18] Its latest impact assessment suggests that, with its preferred level of tariff cap, annual benefits for customers would be £2088m per year, costs for society (mainly reductions in suppliers' revenues) would be £2109m per year, and the net impact would be minus £21m per year. (Ofgem 2018e p 5) The price differential between average SVT of the six large suppliers and the cheapest fixed tariffs would nearly halve (falling from £260 to £145 as of 2017). Ofgem's central estimate is that this would reduce customer switching rate by 30%, that is from 17% to 12% per year. (para 5.66)

However, this reduced switching would in turn allow some suppliers to increase their fixed price tariffs, "meaning that a number of customers could face higher bills than they would in the absence of the cap". (para 5.73) Ofgem estimates that, if smaller suppliers maintain their fixed tariffs at the prices they would charge in the absence of the tariff cap, while large suppliers converge (increase) their fixed tariffs to the tariff cap, then the switching rate would reduce to 8.5% per year in 2019. In sum

> "7.43. There is substantial uncertainty, but our view is it is likely that, other things being equal, switching rates will fall following the introduction of the price cap. Our best estimate is that, by reducing price dispersion, the proposed level of the cap could reduce switching rates by as much as 50%." Ofgem (2018d para 7.43 p 53)

The imposition of a wider tariff cap on SVTs as a supply-side remedy is therefore going to work significantly *against* the CMA/Ofgem attempts to use demand-side remedies to help customers to engage. Furthermore, the tariff cap will make it more difficult for the small and medium size suppliers to challenge the six large suppliers, whose positions will become more entrenched. The tariff cap will thus frustrate the CMA's aim – and the Government's aim – "to move the market to effective competition". (p 21)

22. Removing price controls

Professor Cave asks, "Does the evidence suggest that customer engagement can grow under a price control, so that the control can be removed?" He notes that this has happened in the energy sector and in other sectors, both in the UK and in other countries including Australia.

This is true. But all these cases involve the removal of an initial safeguard price cap in a market newly-opened to competition. Professor Cave does not cite any case where a price control has been removed then reimposed then removed again.

[18] These included: Prices clustering around a focal point, increases in other prices, reduced price differentials, less incentive for customers to switch; Uncertainty among investors, higher cost of capital and risk, greater difficulty in financing investment, less innovation and growth; Higher administrative costs for suppliers; Less engaged customers, with a greater reduction in switching than for PPM customers; Possible exit of high cost suppliers, and lower quality of service as suppliers try to cut costs; An impact on the introduction and continuation of specific business models; A reduced range of tariff types; Impacts on the wholesale market (particularly on hedging, market liquidity and price volatility); And impacts on third party switching services. Ofgem (2018b).

The economic and political dynamics are surely quite different in the two situations. In the previous cases referred to, regulators and/or governments have observed the newly-opened markets and concluded that competition is sufficiently effective to protect customers. There is no longer a need for a price control, and indeed competition will work better without the existing control. In the present case, by contrast, the CMA has concluded that competition is *not* sufficiently effective to protect customers and indeed is imposing a heavy detriment on them. So the Government with the unanimous support of Parliament has determined that only a tariff cap will suffice to protect customers. And although there is provision for lifting the cap, it is not expected that it will be possible actually to observe effective competition before then.

To explain, the Tariff Cap Act enacted in July 2018 provides that the tariff cap will continue for five years, but can be removed earlier if the Secretary of State considers that "the conditions for effective competition are in place". To inform that decision, Ofgem too has to review whether it considers the conditions for effective competition are in place, and "must, among other things, consider the extent to which progress has been made in installing smart meters", and must then advise whether the cap should be removed. Ofgem has said that the wording means "the right market framework is in place for competition to be effective for currently disengaged consumers *once the cap is removed*". It acknowledges that this makes assessment more difficult because the cap will have an adverse effect on competition. Consequently,

> "5.9. When we assess whether conditions are in place for effective competition *should the cap be removed,* we will not be able to monitor these characteristics *when the cap is still in place.* We recognise that with a cap in place, the market is less likely to fully exhibit these characteristics." (Ofgem 2018a, italics added)

This is a critical difference from previous situations when price caps were removed. Once the tariff cap is in place, and tariffs and competition have been reduced, will judgement (or speculation) about a hypothetical counter-factual situation be sufficiently persuasive to politicans?

Professor Cave suggests that "advocates of price controls on retail activities almost invariably support a combination of demand and supply-side measures, and hope/expect that as the demand-side measures take effect, the price controls can be removed." (p 18) But as noted, the PPM tariff cap has removed almost all PPM tariff differentials (other than those associated with the small supplier subsidy) and has reduced customer switching. Ofgem expects the wider SVT tariff cap to have a similar adverse impact, and switching to reduce by half. This seems likely to outweigh any positive effect of (e.g.) Ofgem nudging disengaged customers, particularly since the savings available to them will generally be significantly lower. Competition will seem – and will be – less strong than it was before the price cap was imposed. So why should the public and politicians think that customers would now be better off by removing the tariff cap?

In the short term, the forced reduction of existing SVT tariffs will bring benefits to those customers on them. But, as with price controls generally, the longer term adverse effects on competition and customers will be very great. This is why price controls are no longer employed in modern competitive economies and why the CMA majority argued against them. Removing the tariff cap in less than five years will surely be problematic. Whether an increase in the number of customers on smart meters, and hypothetical conjectures as to how much more active customers would be if the cap were removed, will seem persuasive to politicians and the public, remains to be seen. More likely, the case for removing the cap will have to be based on the obvious damage that it will have done, as exemplified not least in the paucity of choice and opportunities remaining in the market.

Part IV Possible Lessons for New Zealand

23. Professor Cave's proposed lessons

Professor Cave suggests that the UK energy market investigation offers five possible lessons for New Zealand. As summarised at the beginning of his paper, the first lesson is:

> "In process terms, the NZ inquiry can (compared with the UK one) be more agile, and more quickly identify and concentrate on key issues such as customer engagement;" (p 2)

Certainly the NZ inquiry is "an input into wider a governmental process rather than itself being a trigger for the implementation of remedies". (p 33) Whether this means that it can more quickly identify key issues is less clear: the parties to the CMA investigation submitted much new and useful information that needed time to digest, and the same will no doubt be true in NZ. The suggestion that customer engagement is a key issue seems premature, and surprising given that it is not mentioned in the Possible Lessons section in the body of his paper. As argued above, an undue focus on this issue seems to have led the CMA astray.

The second proposed lesson is:

> "In relation to household and SME retail prices (the subject of this paper), it is helpful if the inquiry team can produce (and publish) a reliable snapshot of the shape of the markets, including levels and differences in prices, and search and switching behaviour. A comprehensive customer survey can be very helpful in this regard;" (p 2)

I agree that such a snapshot of the market and consumer survey could be helpful. I would add to the list a reliable snapshot of profitability in the retail market. If there is widespread excess profit that is not being challenged by new entry (though there will be differences of view as to how to measure such profit) then there may be cause for concern, but if there is not widespread excess profit, how serious is the problem? As explained above, my view is that the CMA did not deal adequately with this issue. It claimed to find unilateral market power exploited by the Six Large Energy Firms setting prices above cost, and of those six suppliers, two indeed made relatively high profits over many years. But two made what would seem to be about normal profits, and two regularly made losses. As in any competitive market, the more efficient made profits and the less efficient made losses: this does not look like the exercise of market power.

The third proposed lesson is:

> "There are recognised characteristics of retail energy (and some other) markets which make it likely that some customers will be disengaged and subject to price discrimination by their supplier; vulnerable customers may be particularly prone to this danger;" (p 2)

The body of the paper explains that

> "the problem … is more closely associated with the complexity of the tariff structure which is multi-part and makes price comparisons difficult, as customers have to submit detailed information about their expected or current level of demand (which is particularly difficult if customers are not on smart meters). This puts suppliers in a place where they can offer individual deals to households and differentiate them in the different channels of communication available to them." (p 34)

It is not at all clear that the retail energy market is distinctive in this way. The switching rate for retail energy products is higher than for many other products apart from car insurance.[19] This does not suggest that energy customers are disengaged. Ofgem's earlier belief that customers were not switching because the retail energy tariff structure was so complicated was rejected by the CMA, which found that simpler tariffs had no noticeable effect on switching. Suppliers' websites and PCWs have made price comparisons rather straightforward, given that bills contain details of actual annual usage. (Though there seems to be some question whether the offers therein are uptodate.) Price differentiation and individual deals – and some concerns about them - are common in many markets, perhaps increasingly common nowadays.[20] Indeed, there is some evidence (e.g. Smith 2018) that such price differention is greater in markets where the customer engagement rate is higher. So, I would suggest that the inquiry team, instead of assuming that the retail energy market is characterised by customer disengagement and undue discrimination, take sufficient time to understand the ways in which other such markets work, and to understand the role of price differentiation in competition, so as to put the retail energy market into a broader economic context.

The fourth proposed lesson is:

> "UK retail energy markets differ from NZ ones in many ways, but should the evidence support a disengagement finding in NZ, the inquiry should be able to identify a set of remedies which addresses the problem; these may include demand-side and more intrusive supply-side measures;" (p 2)

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[19] For example, the CMA investigation found that the proportion of customers switching supplier was 27% for energy, about half the level obtaining for car insurance (54%) but greater than for mobile phones (24%) and more than double that for mortgages and current accounts (both 12%). CMA (2015) Fig 10 p 15. This is consistent with earlier evidence. Ofgem (2008) reported the proportion of customers who switched various providers over the five years 2003-2008. Gas and electricity (both 54%) were then only a little less than car insurance (61%) but greater than home insurance (46%), fixed line telephone (44%), mortgages (38%), mobile phones (35%), credit cards (31%), savings accounts (20%) and current accounts (13%).

[20] For example, "Citizens Advice today submitted a super-complaint to the Competition and Markets Authority (CMA) calling on it to identify remedies and recommendations to put an end to the penalty paid by loyal and disengaged consumers. The super-complaint covers several markets, including insurance, cash savings and mortgages" [and also references mobile and broadband]. Financial Conduct Authority, 28 September 2018.

Yet again, the summary draws attention customer disengagement when it is not mentioned in the corresponding section of the paper. My view is that the CMA inquiry focused unduly on engagement, and became obsessed with its recommended solution of more customer switching. (The CMA Final Report and appendices mentioned switching no less than 4785 times.) Hopefully the NZ inquiry will take a more rounded view, and understand that prices in a market can differ for a number of reasons that reflect effective competition rather than the lack of it. But if the inquiry does find a lack of competition, even one associated with customer disengagement, it will hopefully bear in mind that the majority of the CMA expressed the considered view that "more intrusive supply-side measures" – particularly a widespread price control – were *not* an appropriate part of the solution. Such measures would instead likely have an *adverse* effect on customers in the long run.

The fifth proposed lesson is:

> "The balance of such a package may depend on the scale (and hence the urgency) of any correction required, and upon the government's approach to regulatory interventions in general;" (p 2)

It is hard to disagree with this point. Price control and other significant interventions in competitive sectors is not characteristic of recent government policy in New Zealand, so their introduction in the retail energy sector would raise questions about control of the economy generally. New Zealand has established a reputation for a rather level-headed approach to these matters, which will hopefully continue.

In discussing this lesson, the final paragraph of Professor Cave's paper refers to "a spectrum of responses" to any identified problem, in which "a temporary safeguard cap to 'reset' the market" is "in the middle". (p 35) But surely most regulatory economists would consider that introducing any kind of price cap into a competitive market is around the end of the spectrum rather than in the middle.

It is also unclear what meaning can be attached to the claim that a price cap would 'reset' the market. The word has been picked up by UK politicians.[21] But it has no basis in economics. Certainly a price cap would reduce prices in some instances while the cap was in force. But what after that? In his dissenting view in the CMA Final Report, Professor Cave said that "its protective power should outlast the cap, as customer resistance and other factors will prevent energy companies from immediately re-establishing the same level of over-charging as before". (p 1417) However, Ofgem is assuming that customer switching will halve, so customer resistance against price increases will be less than now. Do "other factors" mean a greater reliance on Government or regulatory arm-twisting?

Will suppliers that are required to set low prices or low tariff differentials as a result of a price control somehow continue to set the same prices or differentials when the price control is removed? Will they no longer respond to actual market conditions as they did before? On the

[21] For example, in explaining the Government's tariff cap policy, the Minister said 'It is considered to be a reset of the market. We think this market is moving in the right direction but not fast enough, and we want this to reset.' House of Commons (2018c), Q447

contrary, as explained above, the assumption that "the conditions for effective competition" cannot be observed while the price cap is in place, but instead have to be conjectured, implies that, once the tariff cap is removed, the competitive market will spring back into life. How soon this will happen remains to be seen.

24. Alternative possible lessons for NZ

I would draw different lessons for NZ from the CMA investigation and the events from the previous decade leading up to it. The public are understandably concerned about rising energy prices and blame the companies that announce such price increases. Briefly, the first lesson is that, insofar as the reasons for price increases lie elsewhere – in the wholesale market or the transmission or distribution networks or other aspects of government social or environmental policy - the review needs to make this clear. Shooting the retail messengers won't solve the problem.

In retrospect, the Ofgem (2008) discussion of price increases was relatively technical, and did not drill home the message that the retail price increases reflected cost increases beyond the retailers' control. Nor did it note that, although retail profits were increasing, they were if anything slightly negative in those years. The public did not take in the detail about rebalancing of prices. What they heard – indeed, what Ofgem increasingly emphasised – was that retailers were exploiting some customers by £0.5 billion and Ofgem was going to make the retailers pay it back via a non-discrimination policy. That was politically acceptable at the time, but Ofgem and the CMA later agreed that it was the wrong policy.

Was the error due to inadquate information? As noted above, the CMA found that a problem was "Ofgem's inability to address concerns about the Six Large Energy Firms' profitability with the information they currently obtain. So, a concomitant lesson is to ascertain whether there really are excess retail profits before considering possible actions against retail suppliers.

Second, Ofgem intervened extensively in the retail market between 2008 and 2014. In the face of increasing political pressure, Ofgem repeatedly felt the need to Do Something. It used a mixture of supply side and demand side remedies informed by a behavioural perspective. It restricted suppliers' prices and products, hoping initially to bring about "fair price differentials" and later to increase customer engagement with a view to making the market work better, particularly for more vulnerable and less engaged customers. Quite simply, most of these regulatory interventions did not work. Indeed, the CMA found that they had unintended and adverse consquences for competition and customers, and should be repealed. So the second lesson is that UK experience suggests great caution in proposing further regulatory interventions in New Zealand or, for that matter, in the UK or elsewhere.

Third, analysis and diagnosis need to recognise that price differentials are the norm, not the exception, in competitive retail markets generally. They may well indicate the strength of competition rather than its absence. They enable lower prices to some customers that simply cannot be offered to all customers. They facilitate new entry and innovative products. If some customers pay lower prices, this does not mean that the customers paying higher prices are being exploited or paying an unfair or above-competitive price. In consequence, attempting to prevent or limit price differentials, either because they are thought to reflect market power, or in the name of fairness, may well reduce competition and operate against the interest of most customers. So the third lesson is that the review needs to understand that price differentials are characteristic of competitive markets generally, and explain this to the public.

Fourth, there has been criticism in the UK and elsewhere of some products that are offered in the retail energy market or of the way that the market operates, or of some customers' alleged lack of engagement. However, competitive markets tend to produce what customers want, and to use marketing tactics that customers best understand. There is no reason why this is not the case for retail energy markets too. Some customers are able and willing to switch tariffs and/or suppliers at frequent intervals; other customers prefer more stability and less engagement. If the latter customers are forced or nudged into greater engagement in the market, this may secure them a lower price in the short term but they may not consider that this outweighs the continual hassle and risk in subsequent years. By all means help customers to understand the options that the competitive market provides. But changing customer lifestyles is not straightforward and not necessarily what customers themselves will appreciate. The fourth lesson is to consider whether it might not be better to help the market work better in discovering and providing products and lifestyles that customers actually want, rather than dictating what competitors in the market should provide.

Fifth, the CMA's exceptionally large £1.4bn customer detriment figure, based on a novel and questionable methodology, took on a life of its own. It led to irresistable pressure for a very interventionist policy that the CMA majority expressly advised against. The Government's adoption of this policy, citing the CMA's calculation but overriding its majority recommendation, has therefore undermined the CMA's authority. It is also a setback for the UK competitive retail energy market from which it will take years to recover. So the fifth lesson is to take care in making calculations and presenting the results of the analysis.

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COMPETITION ECONOMISTS GROUP

Competition in New Zealand Electricity Markets

October 2018

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1 Executive Summary

1.1 Competitiveness of the New Zealand energy retail sector

1. Even if the number of active retailers were small, the structural characteristics of the retail electricity market are such that highly competitive outcomes can be expected. This reflects the following structural characteristics of the market:

   - Homogeneous products being sold to a large number of buyers although the services offered with the product may vary;
   - Low barriers to entry and exit;
   - Low transaction costs, particularly switching costs. The cost of switching is very low, since customers can easily switch over the internet or by phone.
   - Easily available price and quality information among buyers and sellers;

2. However, the number of active retailers in New Zealand has risen considerably since early 2011. In April 2011 the sector included 8 active retailers (with at least 0.01% ICP market share) but this increased to 26 active retailers by May 2018. This has been associated with:

   - Material decreases in the market share of the largest retailers. The combined market shares of the largest three retailers has decreased by 12 percentage points since January 2009, while the market share of the non-Big 5 retailers has increased by 9 percentages points from less than 2.5% in January 2009 to almost 12% by May 2018.
   - A fall in the market concentration of the New Zealand electricity retail industry (as measured by the Herfindahl-Hirschman index (HHI))[1].

3. Figure 1-1 shows the HHI of New Zealand electricity retailers based on the number of connections. The HHI has fallen considerably from almost 2200 in January 2009 to 1680 in May 2018. Using the US Department of Justice's classification, the current level of HHI implies that the market for New Zealand electricity retailers is borderline moderately concentrated, and appears to be trending towards becoming "un-concentrated".

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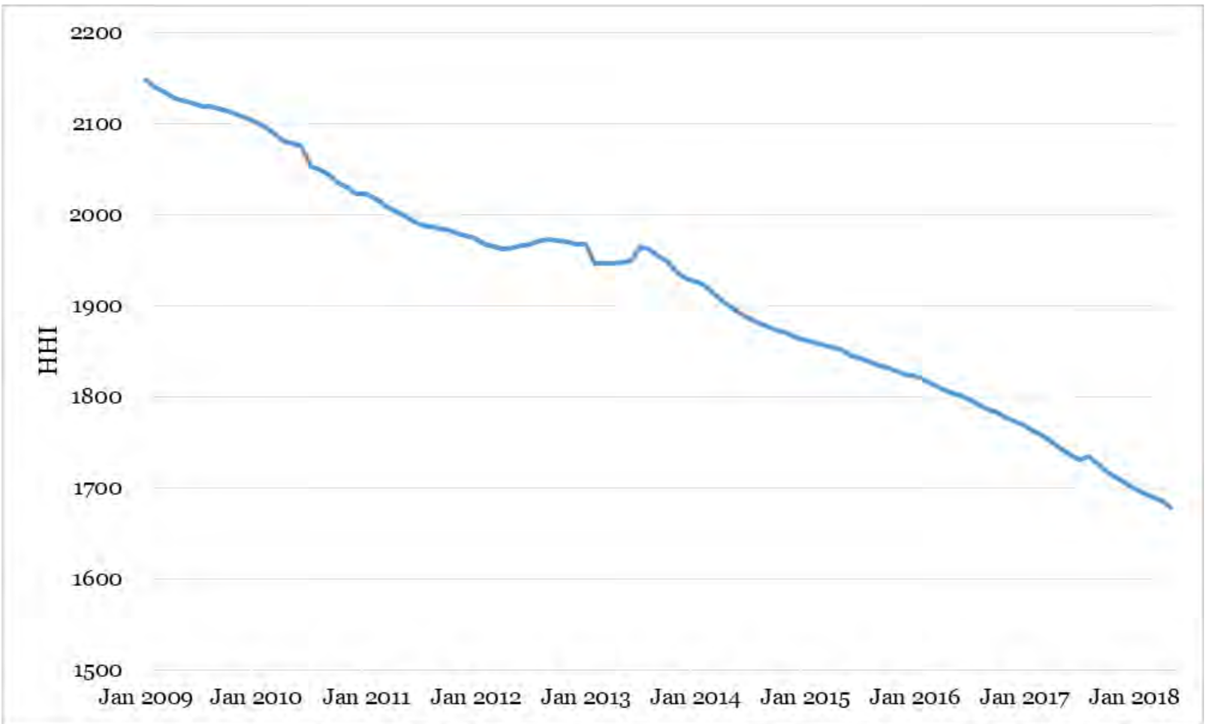
1 Which the U.S. Department of Justice (DOJ) and European Commission both rely on as a screening tool to investigate market competitive effects in merger evaluations See U.S. Department of Justice and the Federal Trade Commission, (2010) "Horizontal Merger Guidelines," August 19th 2010 and European Commission, (2014) "Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings," Official Journal of the European Union, 2014

Figure 1-1: - HHI using number of connections



Source: CEG analysis using data from NZ Electricity Authority

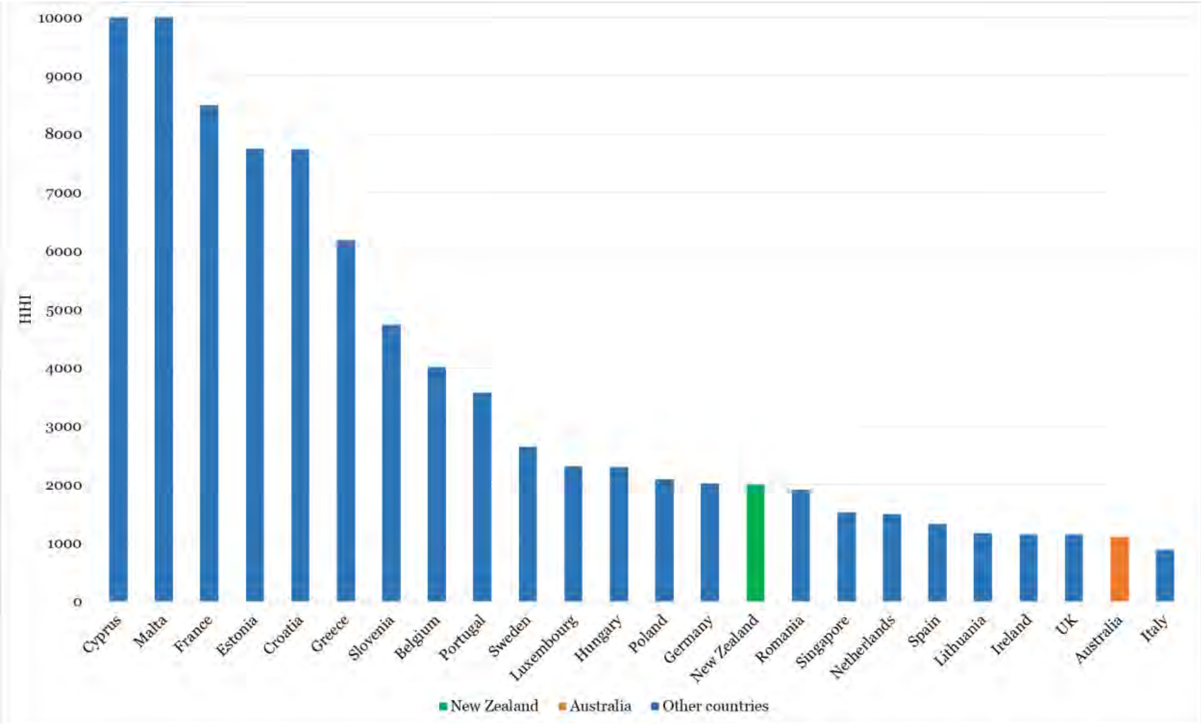
4. It is also notable that, according to data from the Electricity Authority, the 12 month rolling switching rate has increased from 8.8% in December 2004 to a high level of 21.12% in August 2018.

1.2 Competitiveness of the New Zealand wholesale market

5. New Zealand's national wholesale market HHI is broadly in line with that of other countries, which suggests that the electricity generation sector in New Zealand is not overly concentrated relative to the rest of the sample. However, smaller countries tend to have higher HHI (consistent with minimum efficient minimum scale of generation plant making it more likely to find concentration in smaller markets). New Zealand has a materially lower HHI than predicted for a country of its population size.

6. Figure 1-2Figure 5-1 shows the HHI estimates for New Zealand and for other countries for which we have data. New Zealand's HHI is broadly in line with that of other countries.

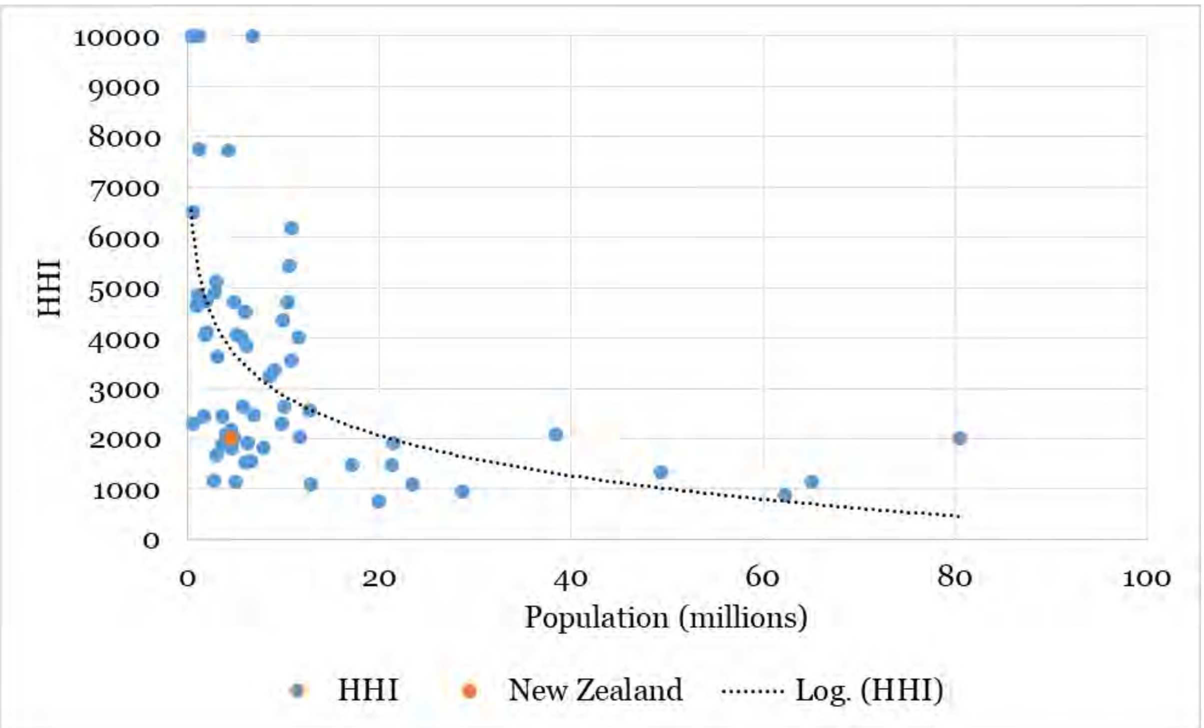
Figure 1-2: International HHI (non-dispatchable excluded)



Source: See Table 5-1, CEG analysis

7. Figure 1-3 shows HHI against population. This shows that concertation is strongly negatively correlated with population size and that New Zealand has a low level of concentration for a small country.

Figure 1-3: International HHI against population



8. The following two reports have recently assessed New Zealand's wholesale energy market.

- APEC, New Zealand: Electricity Retail Services Market Reform, APEC Policy Support Unit, May 2017; and
- Electricity Authority, 2017 Winter review, Final Report, March 2018.

9. Both of these reports found the market to be working efficiently.

1.3 Vertical integration and liquidity of the hedge market

10. The Expert Advisory Panel's First Report (the Report) states that:[2]

> *Vertically integrated companies have no inherent need for contract markets, whereas independent generators and retailers rely on them heavily. If large portions of the generation and retailing sectors have little use for contract markets, there will be low liquidity and muffled price signals, making it difficult and costly for independent companies to manage electricity price risks.*

2 Electricity Price Review, First Report, 30 August 2018.

11. Separately, the Report states:

> *The New Zealand contract market had been developing well and has been on a trajectory of steady improvement since 2010. However, events during the winter of 2017 highlight the fragility of current arrangements. For this reason, we consider improving the depth and resilience of the contract market should be given high priority.*

12. We reach four key conclusions in relation to these issues.

- First, the outstanding value of arm's length hedge contracts is not a reliable indicator of liquidity in hedge markets – where the correct definition of liquidity is the ease with which an investor can trade without moving the market price materially against themselves;
- Second, vertical integration does not cause the merged "Gentailer" entity to have "no inherent need" for contract markets. On the contrary, while the number of external contracts held by the merged entity falls, the merged entity makes the same contribution to contract market liquidity as the two stand-alone entities would absent the merger; and
- Third, it may nonetheless be that hedge market liquidity may be sub-optimal for reasons unrelated to vertical integration. If this is the case (and we don't suggest it is), the least cost policy intervention may involve placing regulatory burdens on the market participants with the strongest balance sheets (i.e., large vertically integrated generators). However, if Gentailers bear the largest burden of regulatory intervention to improve liquidity then they will be 'fixing' a problem that they did not create. This may have important implications in the design and extent of any such interventions.
- Finally, there is no compelling evidence that there is sub-optimal liquidity in New Zealand electricity hedge markets.

1.4 Price levels and trends

13. A cross check on the conclusion that the wholesale and retail markets are competitive and working well is to compare prices paid by NZ consumers with those in other countries. While not necessarily definitive, because cost conditions can vary, it is useful as a means of identifying any 'red flags'.

14. To that end, we have carried out analysis of price levels and price trends in New Zealand's energy market, and make the following key observations.

- Price levels

  a. Residential prices in New Zealand are lower than average for the IEA member countries when adjusted using Purchasing Power Parity (PPP);

b. New Zealand's residential-to-industrial-price ratio is in line with the ratios observed for other IEA members when consumption by the Tiwai Point smelter is removed from 'industrial customers';

c. Energy prices in Wellington are lower than average compared to capital cities in the EU for which data is available.

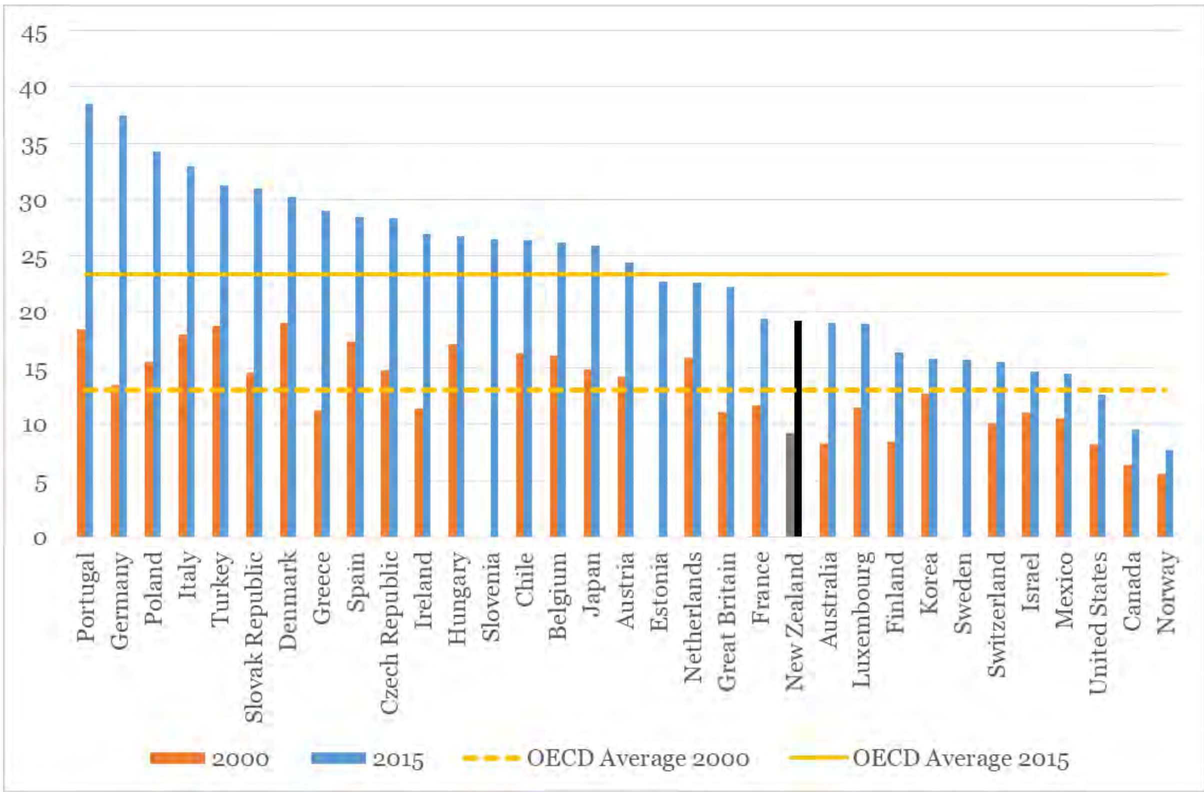
- Price trends

a. Price increases in New Zealand are lower than those observed in Australian cities that are part of the National Electricity Market (NEM);

b. Electricity price changes are consistent with changes in income.

15. Figure 1-4 shows the 2015 household retail prices for IEA members, converted across currencies using PPP. New Zealand's residential electricity price is ranked 12th cheapest among 33 countries in 2015, with a price of US 19c/kWh when converted using PPP. This price level is lower than the simple average household electricity price across IEA members (US 24c/kWh).

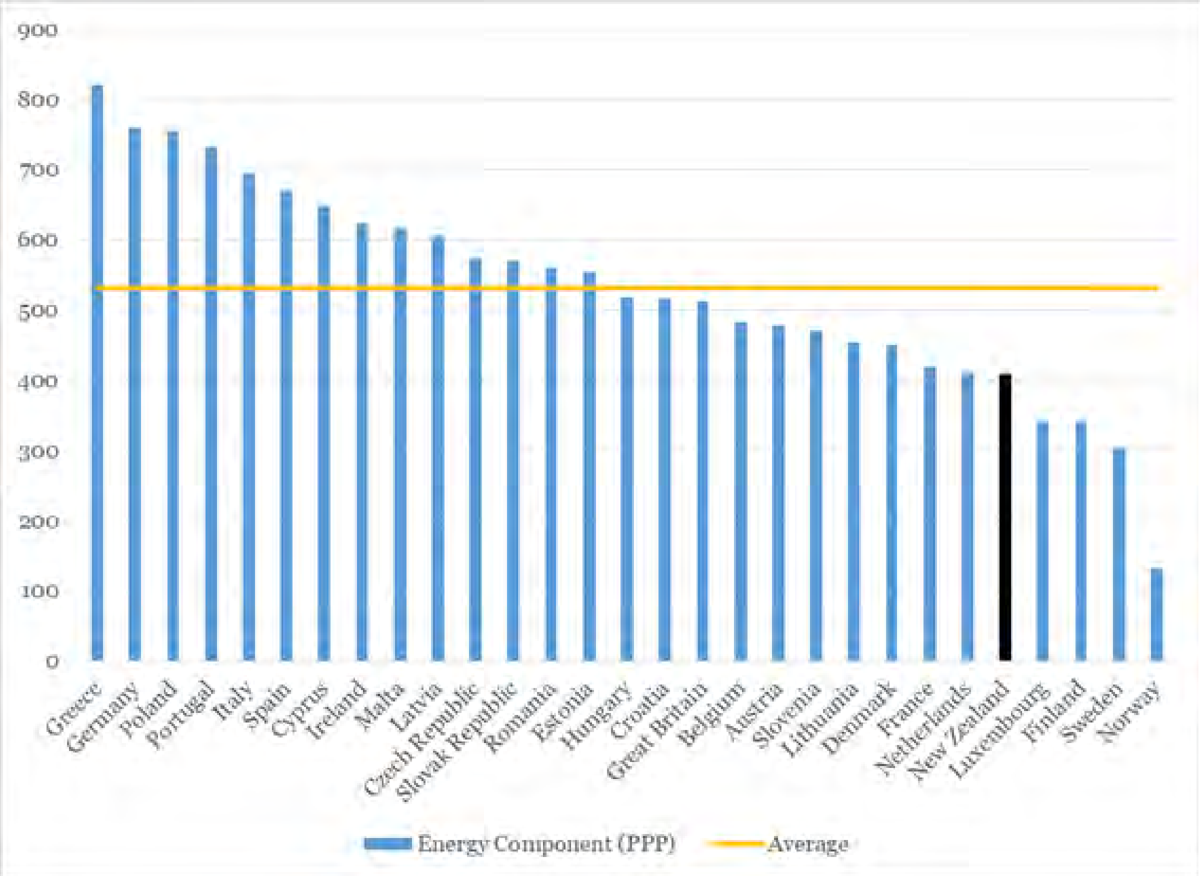
Figure 1-4: IEA Electricity prices for households (2015 Data, US cents/kWh, PPP)



Source: IEA Energy prices and taxes, CEG analysis; Note: Data is missing for Australia, Korea and Spain.

16. New Zealand price relativities are even lower when the comparison is made excluding network costs between capital cities. Figure 1-5 below shows that the "energy component" (i.e, excluding network costs) in Wellington is well below the simple average for the EU estimates.

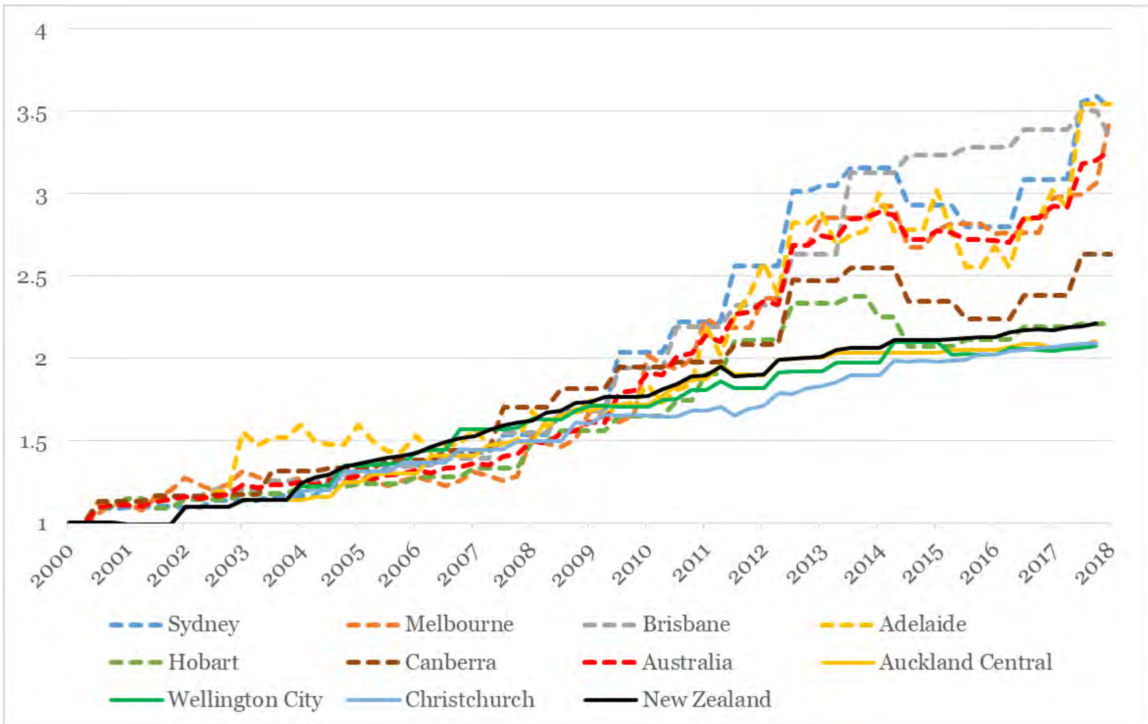
Figure 1-5: EU capitals and Wellington electricity bills (US$ PPP)



Source: MBIE, ACER, CEG analysis;

17. Figure 1-6 shows the pricing for both New Zealand and Australian cities, setting the price in 2000 as 1. We observe that the electricity price increment in the large cities in New Zealand is below the trend for both Australia NEM capital cities and country average since 2000.

Figure 1-6: Australia (NEM) and New Zealand price index



Source: MBIE, ABS, CEG analysis.

1.5 Price dispersion and discrimination

18. A separate issue is the level of price dispersion in retail markets (as opposed to the average price level). Electricity retailing, like most other consumer markets, is characterised by customers with varying degrees of engagement. Consequently, we expect to observe, as we do in most markets, pricing strategies aimed at offering:

- very low (close to marginal cost) prices for new price conscious customers; and
- higher markups to other existing customers (although noting that the higher the markup the more likely otherwise 'inactive' customers will become 'active').

19. The price dispersion that is caused by the existence of disengaged customers is sometimes viewed as a problem by regulators. It is seen as inconsistent with the 'law of one price' that would be observed in an 'idealised' perfectly competitive product markets with 100% well-informed active customers. There are two proposed solutions to this perceived problem which we examine. Namely:

- Banning price discrimination;
  - For example, banning discounting aimed at switching/engaged customers; and
- Increasing the proportion of engaged/well-informed customers.

- For example, requiring suppliers to directly inform customers of lower cost tariffs or to automatically move them to lower cost tariffs, etc.

20. It is not obvious that either of these policies will result in lower prices on average across all customers.

1.5.1 Banning price discrimination will result in higher prices for all customers

21. In most markets there are customers who pay more/less attention to the prices that they are being charged and who will put more/less effort into ensuring that they are receiving the best possible deal. In this circumstance, sellers will attempt to discriminate between these customers and charge a lower/higher price to the more/less active shoppers.

22. It is critical to understand that there is an inter-relationship between the higher/lower prices charged to 'sticky'/'slippery' customers. Specifically, the lower prices to 'slippery' customers constrain the higher prices to 'sticky' customers. This is because there is a continuum between 'slippery' and 'sticky' customers. The bigger the discounts on offer in the market the more likely a 'sticky' customer is to become a 'slippery' one. If the low prices are 'taken away' (e.g., via a ban on discounting) then the high prices would very likely be higher still. That is, 'sticky' customers would become even more 'sticky' if competitors discounted prices were not being offered in the market.

23. That is, the concern that firms tend to charge higher price to their existing customers than potential new customers (or customers threatening to leave) is misplaced. In reality, this conduct makes customers better off – including sticky customers. In reality:

    a. Competition results in greater price discrimination in favour of active shoppers than monopoly (or duopoly). That is, the stronger is competition the more accentuated is the practice of discounting. In other words, the 'issue of concern' is actually a sign of strong competition;

    b. Average prices would be higher if a single price was offered to all customers (e.g., if regulation was imposed to that effect). In other words, if a regulator attempted to 'fix' the 'problem' of price dispersion it would make average prices higher.

    c. Moreover, not just average prices but also undiscounted prices (i.e., prices paid by inactive shoppers) would typically be higher absent price discrimination. That is, the apparent 'victims' of price discrimination (i.e., inactive shoppers) are actually beneficiaries – in the sense that their prices would rise if discounting were not allowed;

    d. Price discrimination in favour of active shoppers is not a sign that excess profits are being earned. Moreover, consistent with points b. and c. above, profits would be higher if discounting was not possible. That is, regulation to prevent discounting would be a 'boon' to retailers; and

e. The theoretical conclusion in point d. is supported by strong empirical evidence from the UK.

1.5.2 A more informed customers base is good for newly informed customers but bad for all other customers

24. The impact of policies aimed at reducing switching costs is more ambiguous. If successful these policies will have short run effects that benefit the customers who become more engaged and, as a result, shift to tariffs closer to marginal cost. However, with a higher proportion of active customers the competitive price for these customers will rise (because the probability that they become profitable inactive customers in the future falls). Thus, customers who would have been active anyway will be worse off – as will customers who remain inactive.

25. In the long run, a smaller fraction of profitable inactive customers will also induce market exit by retailers and a reduction in competition. This will also tend to raise prices. Indeed, it is useful to note that, in the extreme, a universally perfectly informed and engaged customer base would (somewhat counterintuitively) likely lead to monopoly/ collusive oligopoly market structure and all customers would lose as a result.

2 Introduction

26. Meridian Energy has sought consulting advice regarding: the effectiveness of competition in New Zealand's energy market; the impact of vertical integration on hedge markets; and the issue of price dispersion in competitive markets. This report sets out our findings on these issues.

2.1 Report structure

27. The remainder of this report is set out as follows:

- Section 3 discusses the concept of perfect competition and the closely related concept of workable or effective competition;
- Section 4 assesses the competitiveness of the New Zealand energy retail sector, with reference to the number and concentration of competitors, and other factors that facilitate competition in the sector;
- Section 5 assesses the competitiveness of the New Zealand wholesale energy market;
- Section 6 assesses the impact of vertical integration on the liquidity of the electricity hedge market and also considers the potential rationale for policy interventions in that market;
- Section 7 provides an international comparison of price levels and trends; and
- Section 8 analyses the issue of price dispersion in a market with active and non-active customers, as well as evaluating the appropriateness of regulatory intervention in such a market.

2.2 Report author

28. I am Tom Hird and I am the author of this report. I have a Ph.D.in Economics and 25 years working as a professional economist for the Australian Commonwealth Treasury and in private industry. I have been assisted in my research by Jason Ockerby, Johnathan Wongsosaputro, Dr Ker Zhang and Yang Hao. However, the views expressed in this report are mine alone.

29. I have made all the inquiries that I believe are desirable and appropriate and no matters of significance that I regard as relevant have, to my knowledge, been omitted from consideration in this report.

Dr. Tom Hird

3 Participants in workably competitive markets

30. The theoretical concept of perfect competition consists of characteristics including the following:

    a. A large number of small firms;

    b. Selling the same homogeneous product to a large number of buyers;

    c. No barriers preventing entry into and exit out of the market;

    d. No transaction costs, particularly switching costs; and

    e. Perfect information among buyers and sellers.

31. Under such a market, every firm is a price taker because no firm has sufficient size to be able to influence market prices. Should a single firm attempt to charge above-market prices, the absence of transaction costs means that all of its customers would have no qualms switching to other firms selling the same homogeneous product at market price. This would induce the firm to lower its prices back to the market price.

32. Conversely, a firm that charges below market prices would find itself earning a sub-optimal amount of profit (or even incurring an accounting loss), and thus react by raising its prices back to the market price in order to maximise its profits.

33. Perfect competition remains a theoretical concept, however, since the characteristics described above are rarely seen in practice. Economic regulation therefore does not establish perfect competition as its benchmark, but instead refers to the concept of workable competition.

34. One rationale for a workable competition benchmark rather than perfect competition is that regulation should only be implemented if the economic benefits of doing so exceed the costs. Should regulators attempt to go beyond workably competitive markets in order to achieve outcomes that are closer to that of perfect competition, then the marginal cost of doing so is likely to exceed the marginal benefits, due to the increased cost of compliance, and the chilling effect that it would have on innovation and investment.

3.1 Workably competitive markets

35. The *Commerce Act 1986* defines competition as "workable or effective competition".[3] The definition of this term was discussed extensively by the High Court in *Wellington International Airport Ltd and Others v Commerce Commission*:[4]

> *[14] A workably competitive market is one that provides outcomes that are reasonably close to those found in strongly competitive markets. Such outcomes are summarised in economic terminology by the term "economic efficiency" with its familiar components: technical efficiency, allocative efficiency and dynamic efficiency. Closely associated with the idea of efficiency is the condition that prices reflect efficient costs (including the cost of capital, and thus a reasonable level of profit).*
>
> *[15] There is a large body of theoretical literature about the relationship between prices, incentives, efficiency and market outcomes. But the practical context is the existence of sufficient rivalry between firms (sellers) to push prices close to efficient costs. The degree of rivalry is critical. In a workably competitive market no firm has significant market power and consequently prices are not too much or for too long significantly above costs.*

36. The High Court went on to state that workably competitive markets tended to generate certain outcomes that include normal rates of return being earned by firms, as well as prices that reflect such levels of return. However, the Court was careful to stress that workably competitive markets are associated with *tendencies* towards such outcomes, as opposed to actually achieving them.[5]

37. By this, the High Court meant that firms in workably competitive markets may experience returns that deviate from normal rates of return, even for long periods of time, but nevertheless faced tendencies towards normal returns and associated prices, which would in turn incentivise efficient investment and innovation through the process of rivalry:[6]

> *[22] In short, the tendencies in workably competitive markets will be towards the outcomes produced in strongly competitive markets. The process of rivalry is what creates incentives for efficient investment, for*

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3 *Commerce Act 1986* s 3(1).

4 *Wellington International Airport Ltd and Others v Commerce Commission* [2013] NZHC 3289 at [14]-[15].

5 *Wellington International Airport Ltd and Others v Commerce Commission* [2013] NZHC 3289 at [18].

6 *Wellington International Airport Ltd and Others v Commerce Commission* [2013] NZHC 3289 at [19]-[20], [22].

> *innovation, and for improved efficiency. The process of rivalry prevents the keeping of all the gains of improved efficiency from consumers, and similarly limits the ability to extract excessive profits.*

38. The High Court thus cited with approval the following formulation by Donald and Heydon (1978):[7]

> *...workable competition means a market framework in which the presence of other participants (or the existence of potential new entrants) is sufficient to ensure that each participant is constrained to act efficiently and in its planning to take account of those other participants or likely entrants as unknown quantities...*
>
> *Workable competition exists when there is an opportunity for sufficient influences to exist in any market, which must be taken into account by each participant and which constrain its behaviour.*

3.2 Rivalry in workably competitive markets

39. As set out by the High Court in paragraph 35 above, sufficient rivalry is required in order to "push prices close to efficient costs". However, determining exactly how much competition is needed to constitute "sufficient rivalry" is an empirical issue. As stated by the High Court:[8]

> *These terms are admittedly not precise. No two markets are the same and no single market stays the same. Whether workably competitive conditions exist is a judgement to be made in the light of all the information available, rather than something that can be ascertained by testing whether certain precise conditions are satisfied.*

40. We will further investigate the competitiveness of New Zealand's energy retail sector in section 4.Our analysis draws a distinction between the outcomes for active and well-informed customers and those for passive/inactive customers. In any market at any given time there will be customers actively determining their supplier and other 'passive' customers. Naturally, competition is always directed at actual (and potentially) active customers. By definition, if a customer will never 'shop around' then there is no competition for that customer. Of course, all customers are potentially active shoppers and there is competition aimed at turning otherwise

7 Donald and Heydon, Trade Practices Law (Law Book Co, Australia, 1978), approved in *Auckland Regional Authority v Mutual Rental Cars (Auckland Airport) Ltd* [1987] 2 NZLR 647 (HC) at 671; *Fisher and Paykel Ltd v Commerce Commission* [1990] 2 NZLR 731 (HC) at 759; *Wellington International Airport Ltd and Others v Commerce Commission* [2013] NZHC 3289 at [26].

8 *Wellington International Airport Ltd and Others v Commerce Commission* [2013] NZHC 3289 at [16].

inactive shoppers into active shoppers. As the NSW regulator (IPART) points out in its own review of NSW retail prices:[9]

> *Some take the view that 'if you pay more because you don't shop around, the market isn't working'. We consider that if you can pay a lower price by shopping around, the market is working. A number of competitive markets demonstrate this. For example, customers can make substantial savings by shopping around when buying flights, consumer electronics, insurance, cars and mobile plans.*
>
> *Because customers respond to prices differently, ie, have different demand elasticities, there will inevitably be price differentials in the market. We consider these price differentials is a sign that the market is working, and support innovation and dynamic efficiency. By some customers paying more than they need to, retailers are able to offer lower prices to others who do shop around.*

41. In any case, the Electricity Authority (EA) has previously found that New Zealand's energy retail market consumers were relatively active and well-informed:[10]

> *Residents in New Zealand and Texas were more likely to have looked for information in the past year to help them make a decision about switching power companies.*

3.3 Summary

42. Perfect competition is a well-known theoretical model in economic literature, but it is almost never seen in practice. Instead, economic regulation in New Zealand has focused on "workable or effective competition" as defined in section 3(1) of the *Commerce Act 1986*.

43. A market that is workably competitive (though not perfectly competitive) should not be targeted for intervention because the marginal cost of doing so is likely to exceed the marginal benefits, due to the increased cost of compliance, as well as the possible chilling effect that it would have on innovation and investment.

44. The High Court has discussed the definition of the term "workable or effective competition" fairly extensive in its judgments, and concluded that it refers to a market

9 IPART, Review of the performance and competitiveness of the retail electricity market in NSW From 1 July 2015 to 30 June 2016, Energy – Final Report, November 2016, p. 5.

10 Electricity Authority, (2014), "International comparison of activity, behaviour and attitudes towards electricity industry - A quantitative study" August 2014, p. 33.

framework whereby each participant is constrained to act efficiently as a result of the presence of other participants.

45. According to the High Court, sufficient rivalry is required in order to "push prices close to efficient costs", but the extent of such rivalry required is ultimately an empirical issue.

4 Competitiveness of the New Zealand energy retail sector

46. In this section we take the High Court's formulation of workably competitive markets as set out in section 3, and apply it to New Zealand's energy retail sector. We first assess the number of energy retailers in New Zealand and their respective market shares in section 4.2, before evaluating the other factors that affect the competitiveness of the sector in section 4.3.

4.1 Summary

47. Even if the number of active retailers were small, the structural characteristics of the retail electricity market are such that highly competitive outcomes can be expected. This reflects the following structural characteristics of the market:

- Homogeneous products being sold to a large number of buyers although the services offered with the product may vary;
- Low barriers to entry and exit;
- Low transaction costs, particularly switching costs. The cost of switching is very low, since customers can easily switch over the internet or by phone.
- Easily available price and quality information among buyers and sellers;

48. However, the number of active retailers in New Zealand has risen considerably since early 2011 and stands at 26 in May 2018. When we apply the High Court's formulation of workably competitive markets as set out in section 3 to New Zealand's energy retail sector, we find the sector to be workably competitive. We arrive at this conclusion from the following observations:

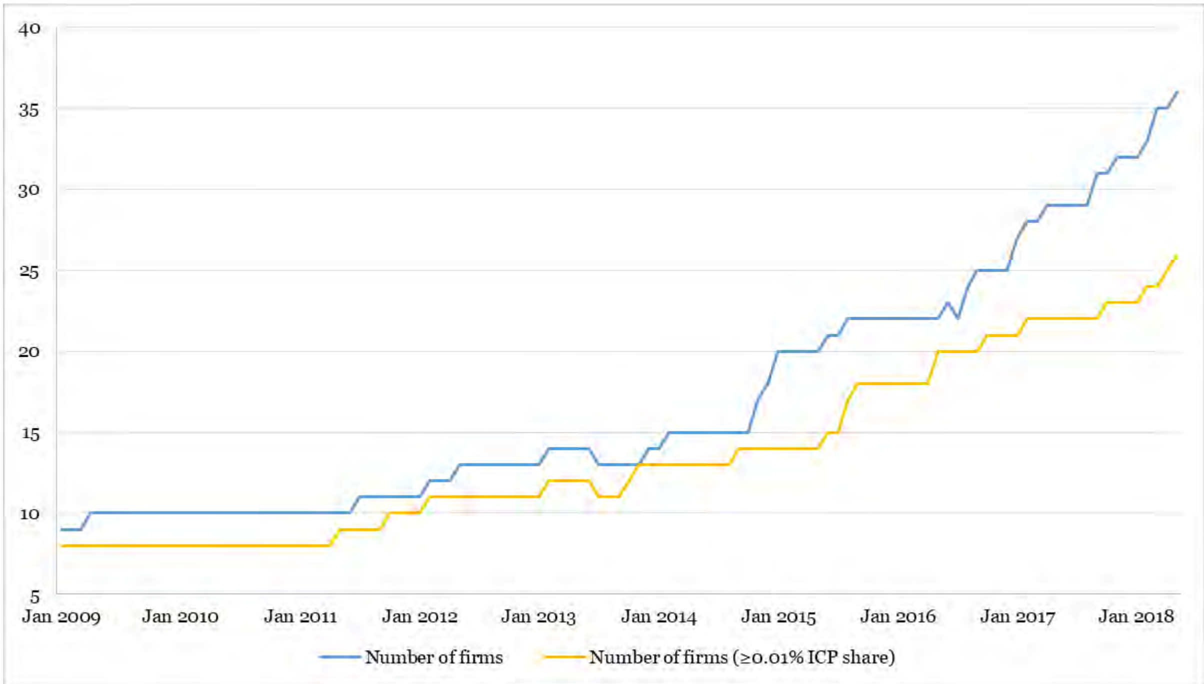
- The number of retailers with at least 0.01% market share increased from eight in April 2011 to 26 in May 2018;
- The combined market shares of the largest three retailers has decreased by 12 percentage points since January 2009, while the market share of the non-Big 5 retailers has increased by 9 percentages points from less than 2.5% in January 2009 to almost 12% by May 2018;
- The HHI of the sector is currently 1680, which is borderline moderately concentrated, and has been on a downward trend towards becoming un-concentrated;
- The 12-month rolling switching rate has increased from 8.8% in December 2004 to 21.12% in August 2018;

- New Zealand consumers are price-sensitive and consider the process for switching retailers to be an easy one;
- New Zealand consumers tend to be active and well-informed compared to their counterparts in other countries; and
- It is easy for New Zealand consumers to obtain information about prices and plans across retailers, with independent price comparison websites being the most common information source.

4.2 Number and concentration of energy retailers in New Zealand

49. The number of energy retailers in New Zealand has risen considerably since early 2011, as can be seen from Figure 4-1. The sector included 8 retailers with at least 0.01% ICP market share in April 2011, but increased to 26 active retailers by May 2018.

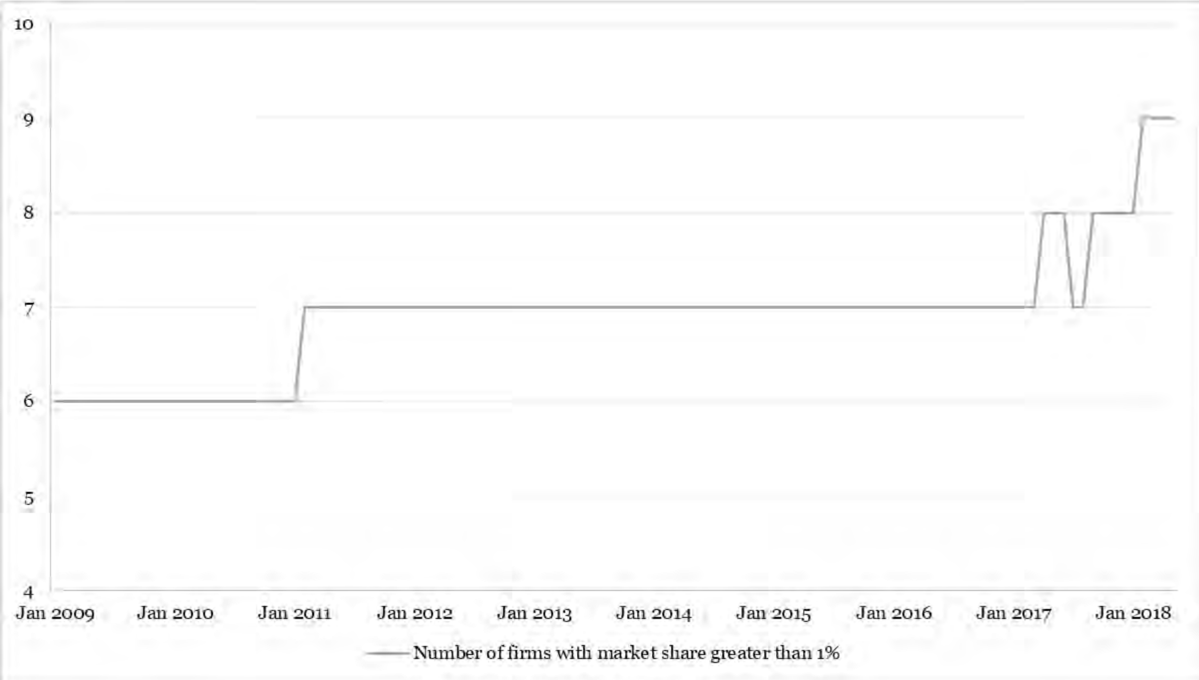
Figure 4-1: Number of energy retailers in New Zealand



Source: CEG analysis using data from the Electricity Authority

50. Figure 4-2 shows the number of retailers with at least 1% market share based on the number of connections. In January 2011, there were only 6 retailers with market share greater than or equal to 1%. By May 2018, that number has grown by to 9 operators with market share greater or equal to 1%.

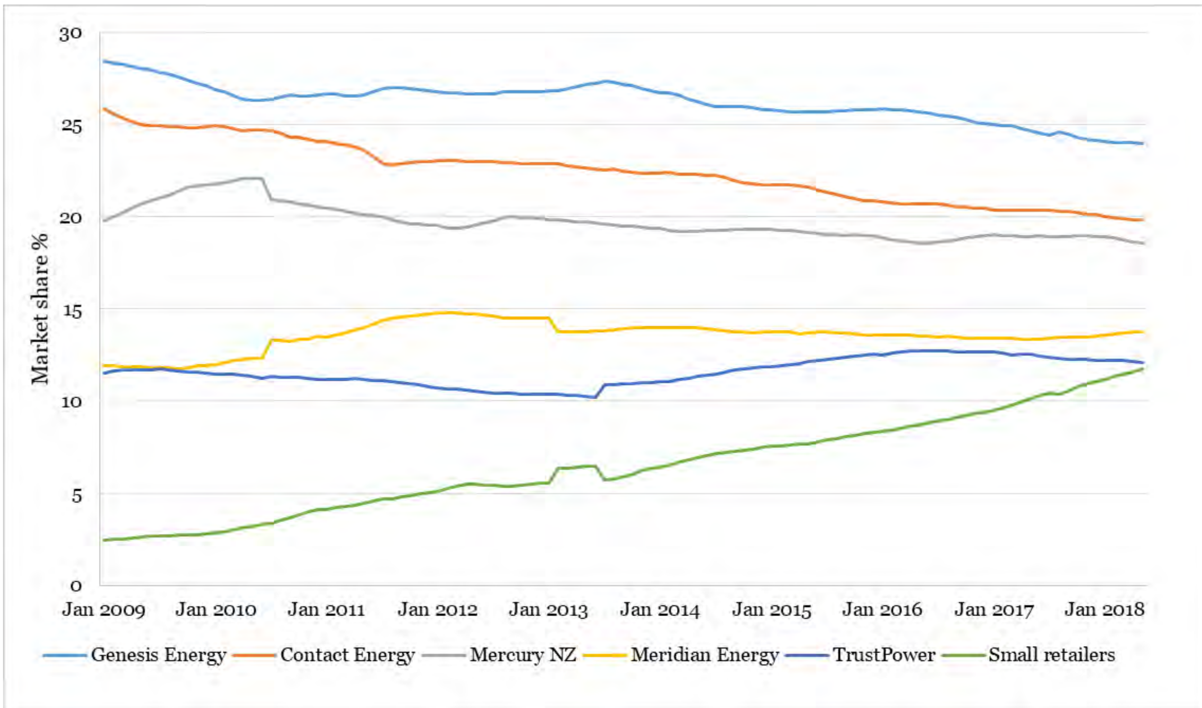
Figure 4-2: Number of energy retailers in New Zealand (connection market share >1%)



Source: CEG analysis using data from the Electricity Authority

51. With the increase in the number of retailers in New Zealand, the largest three retailers in New Zealand have seen dramatic decreases in their market share based on the number of connections. This is shown in Figure 4-3. The combined market shares of the largest three retailers has decreased by 12 percentage points since January 2009, while the market share of the non-Big 5 retailers has increased by 9 percentages points from less than 2.5% in January 2009 to almost 12% by May 2018.

Figure 4-3: Market share trend of New Zealand electricity retailers (connections)



Source: CEG analysis using data from the Electricity Authority

52. With the decline in market share of the Big 3 retailers and increased market share of smaller retailers, the market concentration of the New Zealand electricity retail industry has fallen considerably since 2009. Market concentration is often measured using the Herfindahl-Hirschman index (HHI), which the U.S. Department of Justice (DOJ) and European Commission[11] both rely on as a screening tool to investigate market competitive effects in merger evaluations.

53. The DOJ, for example, classifies markets with HHI between 1500 and 2500 as moderately concentrated, while markets with HHI below 1500 are unconcentrated and markets with HHI above 2500 are highly concentrated.[12]

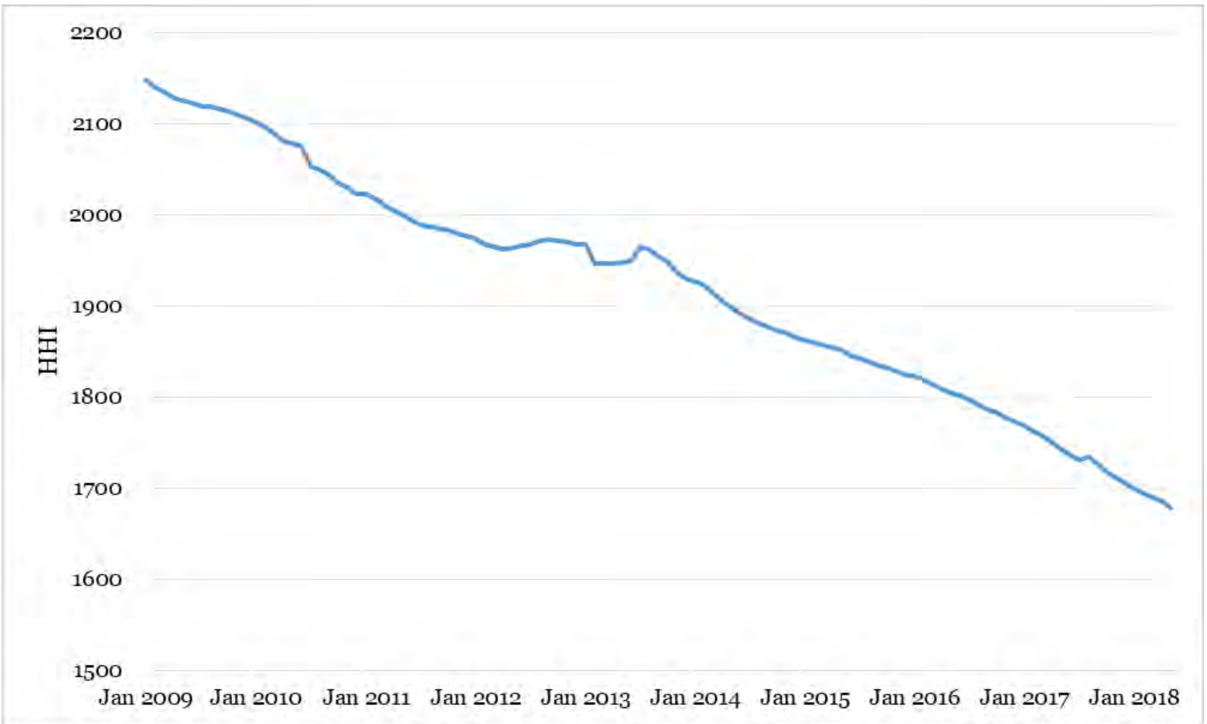
54. Figure 4-4 shows the HHI of New Zealand electricity retailers based on the number of connections. The HHI has fallen considerably from almost 2200 in January 2009 to 1680 in May 2018. Using the DOJ's classification, the current level of HHI implies

11 See U.S. Department of Justice and the Federal Trade Commission, (2010) "Horizontal Merger Guidelines," August 19th 2010 and European Commission, (2014) "Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings," Official Journal of the European Union, 2014

12 Page 19 from U.S. Department of Justice and the Federal Trade Commission (2010)

that the market for New Zealand electricity retailers is borderline moderately concentrated, and appears to be trending towards becoming unconcentrated.

Figure 4-4: - HHI using number of connections



Source: CEG analysis using data from NZ Electricity Authority

4.3 Factors that facilitate competition in New Zealand's energy retail sector

55. The current economic framework in New Zealand's electricity retail market is such that the market will be highly competitive for active well informed customers with only a handful of retailers (requirement in paragraph 30.a). This is reflected in the following facts pertaining to the characteristics set out in paragraphs 30.b to 30.e:

- Paragraph 30.c: Homogeneous products being sold to a large number of buyers;
  - The end product (electricity) is largely homogeneous in nature although the services offered with the product may vary.
- Paragraph 30.c: No barriers to entry and exit;
  - Each retailer has low fixed costs and a marginal cost curve that is mostly flat, such that economies of scale are mostly negligible;

- The marginal cost for each retailer primarily consists of wholesale and transport costs that do not vary according to the number of customers being served; and
- Retailers do not face capacity constraints as they can buy as much/little from the NZEM and transport as much/little as they can sell across the poles and wires networks.

- Paragraph 30.d: No transaction costs, particularly switching costs;[13] and
  - The cost of switching is very low, since customers can easily switch over the internet or by phone.
- Paragraph 30.e: Perfect information among buyers and sellers;
  - Active customers can easily compare prices across retailers by comparing plans over the internet.

56. The fact that the requirements in paragraphs 30.b to 30.e are close to ideal for New Zealand's electricity retail market suggests that the number of suppliers (paragraph 30.a) does not need to be large in order to generate sufficient rivalry to induce them to set competitive prices for active and well-informed customers at levels associated with firms operating in workably competitive markets.

57. As will be discussed in section 8.2.4, Taylor (2003) finds that three firms is enough for the market to be "fully competitive" when the firms are allowed to price discriminate to compete for the active shoppers and the product is fairly homogeneous.[14] The result is due to the fact that when there are three firms, there are two firms competing for the active shoppers attached to the other firm. Neither firm has market power because of the lack of differentiation between the two firms. This satisfies the conditions of Bertrand competition, implying that the equilibrium price should be equal to marginal cost.

58. The characteristics set out in 30.b and 30.c are reasonably self-evident from the nature of the electricity retail market, namely that electricity is a homogenous good, and that generators and networks are required to sell as much/little electricity to retailers as demanded by end-consumers in the NZEM.

59. We further discuss characteristics 30.d and 30.e in sections 4.3.1 and 4.3.2 respectively, since both of these requirements are less self-evident from the electricity retail framework and more dependent on observations for the sector.

13 Aside from switching costs, other transaction costs such as contract enforcement costs are outside the scope of this report and will not be discussed further.

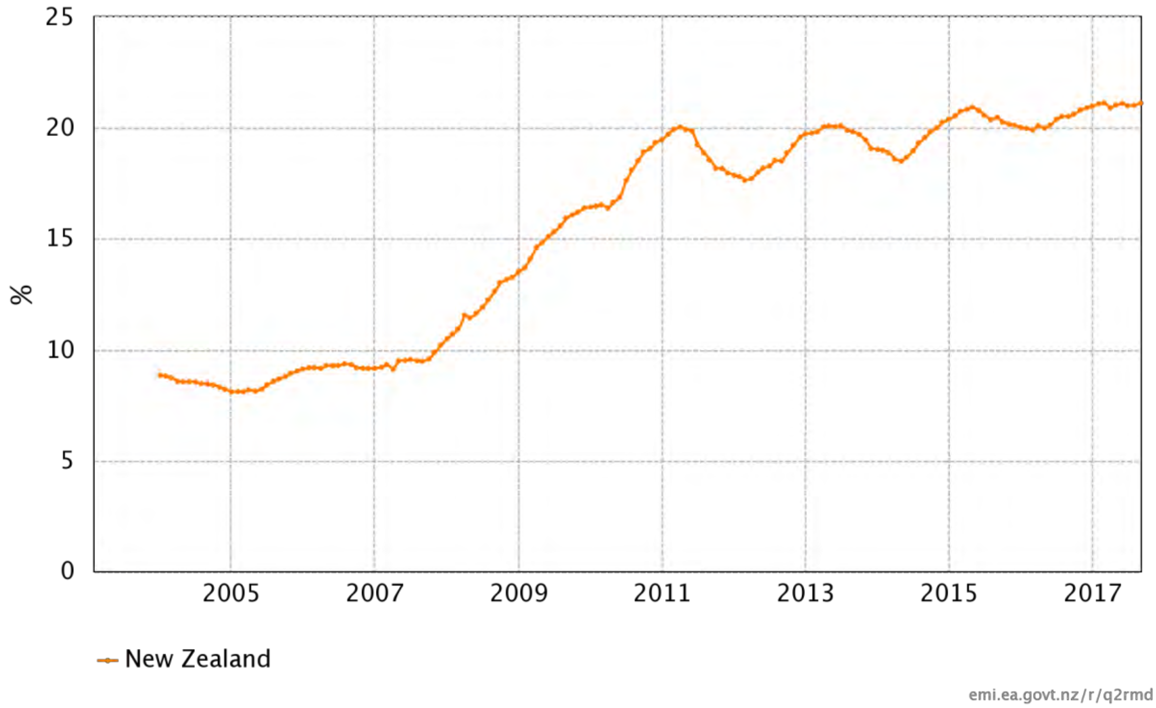
14 Taylor, Supplier surfing: competition and consumer behavior in subscription markets, *RAND Journal of Economics*, vol. 34(2), 2003, pp. 223-246.

4.3.1 No transaction costs, particularly switching costs

60. A high rate of switching is often a sufficient condition for concluding that switching costs are low, though the reverse may not be true. In this regard, there has been a fairly considerable increase in switching among New Zealand energy retail consumers over the last few years, and this has also resulted in an increase in competition within the sector.

61. According to data from the Electricity Authority, the 12-month rolling switching rate has increased from 8.8% in December 2004 to 21.12% in August 2018 as shown in Figure 4-5.

Figure 4-5: Switching rate (12-month rolling rate)



Source: Electricity Authority

62. The above result corresponds with an international survey conducted by the Electricity Authority (EA), which compares New Zealand consumers against Australian, U.S. and Canadian consumers, the study finds New Zealand consumers to be the most price sensitive:[15]

> *New Zealand and Texas residents seem more price sensitive, when asked the level of savings required to make it worthwhile to shop around on an*

15 Electricity Authority, (2014), "International comparison of activity, behaviour and attitudes towards electricity industry - A quantitative study" August 2014, p. 22.

independent price comparison website, a greater proportion from this market were likely to say annual savings of $100 or less would make it worthwhile.

63. The report found that 29% of New Zealand consumers would switch for savings of $100 or less compared to 26% for U.S., 21 % for Canada and 17% for Australia. The report also found that 55% of New Zealand consumers would switch for savings of $200 or less, compared to 48% for U.S., 46% for Canada, and 44% for Australia.

64. The same report later found that 92% of energy consumers found the switching process easy.[16] This has had the added benefit of allowing New Zealand consumers to respond quickly to changing market environments. For example, according to Electricity Authority's 2017 Winter review, 10% of spot exposed residential consumers *"responded to high spot prices by switching away from spot retailers"*.[17]

65. New Zealand customers that elected not to switch retailers tended to do so because they were satisfied with their existing retailer, as opposed to doing so due to actual or perceived lack of choice:[18]

There were differences across the markets when comparing barriers to switching. In New Zealand the key reasons for not switching were satisfaction with the level of service and price they received from their current power company.

In Australia, Alberta and Texas, the key reasons given for not switching were satisfaction with the service from their current provider followed by a perceived lack of choice in their area

66. Such a consumer response shows that the market is operating flexibly and allowing customers to adapt dynamically to changed circumstances by giving effect to their sovereign consumer choices.

4.3.2 Perfect information among buyers and sellers

67. The high switching rate in the New Zealand energy retail market as discussed in section 4.3.1 is paired with consumers who are active and well-informed:[19]

Residents in New Zealand and Texas were more likely to have looked for information in the past year to help them make a decision about switching

16 Page 24 from Electricity Authority, (2014)

17 Electricity Authority (2017), "2017 Winter review – Final report", 22 March 2018, p. 15.

18 Page 7 from Electricity Authority, (2014)

19 Page 33 from Electricity Authority, (2014)

power companies with 33% and 35% having sought information respectively.

In Australia and Alberta, equivalent figures were 29% and 25%.

68. It is also easy for New Zealand consumers to obtain information about prices and plans across retailers, with independent price comparison websites being the most common information source:[20]

Of those that had looked for information in the past year, the most commonly used information in New Zealand was an independent consumer website – cited by 40%. This was lower in Australia and Texas, although still prevalent at 20% and 18% respectively but almost negligible in Alberta reflecting the absence of such a facility.

The most common information source in Australia, Alberta and Texas was general internet searches at 31%, 44% and 38% respectively. This was the second most common source in New Zealand (24%).

Also notable in Australia, Alberta and Texas was information on rates and prices. While general advertisements and power company websites were more widely used in New Zealand.

69. According to the EA report, retailers in New Zealand were also highly active in attempting to lure customers from other retailers, resulting in easier switching:[21]

New Zealand also showed a marked difference on perceived ease of switching, which may be a reflection of the campaign encouraging switching in recent years. It may also be due to a greater level of competitive activity, which saw 69% of New Zealand households being approached by a competitor in the past two years, significantly higher than in other markets.

70. Overall, the increased availability of information has facilitated retailer switching among consumers:[22]

There is evidence that consumers gather information and in the majority of cases switch to another retailer after gathering information from What's My Number or Powerswitch or both websites.

[20] Page 34 from Electricity Authority, (2014)

[21] Page 8 from Electricity Authority, (2014)

[22] Page v from Electricity Authority, (2015) "Consumer switching experiences - Market performance enquiry" 4 August 2015

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5 Competitiveness of wholesale generation in New Zealand

5.1 Summary

71. New Zealand's national wholesale market HHI is broadly in line with that of other countries, which suggests that the electricity generation sector in New Zealand is not overly concentrated relative to the rest of the sample. However, smaller countries tend to have higher HHI (consistent with minimum efficient minimum scale of generation plant making it more likely to find concentration in smaller markets). New Zealand has a materially lower HHI than predicted for a country of its population size.

72. The following two reports have recently assessed New Zealand's wholesale energy market.

- APEC, New Zealand: Electricity Retail Services Market Reform, APEC Policy Support Unit, May 2017; and
- Electricity Authority, 2017 Winter review, Final Report, March 2018.

73. Both of these reports found the market to be working efficiently and that past reforms were effective. Furthermore, the EA report found that there was no danger of non-supply in the system in spite of the exceptionally low hydro input over the 2017 winter period. In this regard, it is useful to reiterate the following principles that guided New Zealand's previous energy reform policies, and that APEC regards as key lessons for reform:

- Learning by doing: the reforms were evolutionary in nature, with governments accepting that market failures may occur and addressing them as they arise;
- Commitment to market based competition, even when addressing market failures: Governments ensured that the policies they enacted were geared towards supporting and encouraging market-based responses;
- No price signals to distort market based responses: Governments did not implement price controls or feed-in tariffs to support alternative energy sources, thus allowing market forces to drive the retail market; and
- Regulatory intervention is only used to improve market efficiency, where competition cannot: Regulators sought to use guidelines instead of prescribing rules.

5.2 International comparison of concentration in energy generation

74. In this section we assess the concentration of New Zealand's energy generation sector when compared with that of other countries. We conduct our comparison using the Herfindahl-Hirschman Index (HHI), which is a well-established (albeit imperfect) measure of concentration.

75. The HHI is calculated as the sum of squared percentage market shares of all firms in the industry. It ranges from zero for a perfectly competitive market where each firm has almost zero market share, to 10,000 for a monopoly where a single firm has 100% market share.

76. We also explore the relationship between the energy generation sector concentration for each country versus its corresponding population. Population is an important variable because the energy generation sector features economies of scale due to the high fixed costs associated with opening a new generation plant. This suggests that countries with small populations may tend to feature higher degrees of concentration in the sector since demand will be insufficient to support a large number of plants owned by different companies.

5.2.1 Data collection and processing

5.2.1.1 Market share and HHI data

77. We obtained energy generation data for each of the countries shown in Table 5-1.

Table 5-1: International data on energy generation market shares

Country	Data type	Data description	Source
New Zealand	Capacity and energy generated	Capacity and ownership of each power station	EMI, Wholesale generation dataset, October 2015
Australia	Capacity	Capacity and ownership of each power station	AER, State of the energy market, May 2017
United Kingdom	Energy generated	Wholesale electricity generation market shares of the eight largest power generators; HHI in power generation	Ofgem, Wholesale Market Indicators (2016), July 2017; European Commission, EU Energy Markets in 2014, October 2014
Singapore	Energy generated	Market share of quantity of sales by seven largest licensees in electricity generation market	EMA, Market Share for Electricity Generation 2005 - 2016, July 2017
United States	Energy generated	HHI of electricity generation in 36 states*	EPA, Electric Generation Ownership, Market Concentration and Auction Size, Docket ID No. EPA-

Country	Data type	Data description	Source
			HQ-OAR-2009-0491, July 2010
Germany	Energy generated	Market share of electricity volumes generated by four largest electricity producers (excluding renewable energies); HHI in power generation	Bundesnetzagentur, Monitoring report 2016, November 2016; European Commission, EU Energy Markets in 2014, October 2014
Estonia, Ireland, Greece, Spain, France, Croatia, Italy, Cyprus, Lithuania, Luxembourg, Hungary, Malta, Netherlands, Poland, Portugal, Romania, Slovenia, Sweden	Energy generated	HHI in power generation	European Commission, EU Energy Markets in 2014, October 2014

**No explanation was given as to why there were no estimates provided for the other states in the US.*

78. We obtain HHI measures in two ways depending on the data source. If the source includes an HHI estimate, then we adopt it as our estimate. If no HHI estimate is provided, then we obtain our own estimation based on the individual market shares of each firm in the dataset. In cases such as Germany's, where a published HHI estimate as well as individual market shares are both available, we use the former as our estimate.

79. One further issue pertaining to HHI calculations is that some countries truncate their data by publishing the market shares of only their largest companies while combining the market shares of all other firms into a single "Other" category. Treating "Other" as a single firm would overestimate the HHI, especially in cases where the "Other" category constitutes a considerable market share. Of all the countries in Table 5-1, only the data for Singapore suffers from this problem since all other countries with truncated data also publish a corresponding HHI estimate. Since the "Other" category in Singapore only constitutes 9% market share, which corresponds to the 6th largest generator, we do not take steps to adjust the data for truncation.

80. There are two further issues that can be observed from Table 5-1. First, the data for New Zealand and Australia both measure the *capacity* at each power station, while all other countries measure the market share of wholesale electricity *generated*. It is difficult to adjust for this difference in the data, and we do not attempt to do so. We note however that, based on the evidence from New Zealand where both sets of data are available, capacity HHIs tend to be modestly higher than generation HHIs.[23]

[23] The New Zealand data includes both "Operating Capacity" and "Typical Annual GWh". Switching from the former to the latter increases the HHI in 10 of 13 regions in New Zealand, while also raising the overall national HHI from 2002 to 2035.

81. Second, the data for some countries does not distinguish between dispatchable and non-dispatchable energy. This is the case for all countries except New Zealand, Australia, and Germany. For the purpose of this report, we present results excluding and including non-dispatchable energy for New Zealand (wind) and Australia (wind and solar), with the former being presented in section 5.2.2.1. Our results are not materially different regardless of whether non-dispatchable energy is included or excluded.

5.2.1.2 Population data

82. We obtain the year 2018 population data for each country from the US Census Bureau.[24]

83. We also obtain intra-national population data from the sources set out in Table 5-2.

Table 5-2: Intra-national data on population

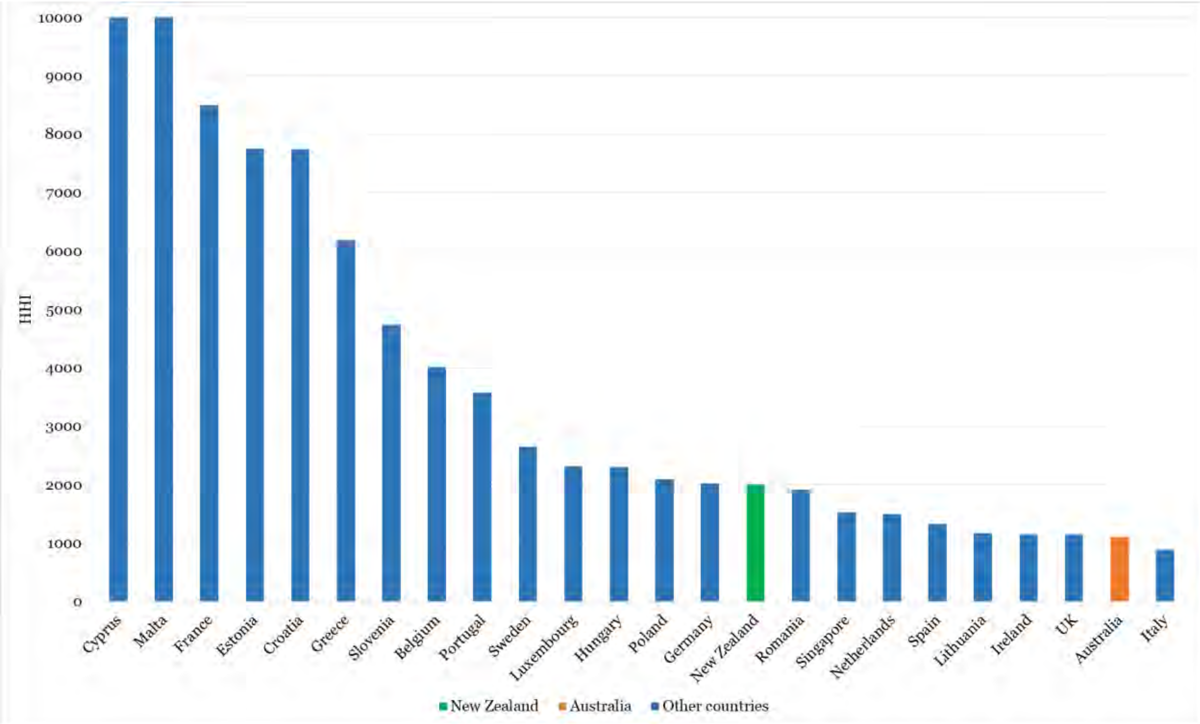
Country	Source
New Zealand	Stats NZ, Subnational population estimates (RC, AU), by age and sex, at 30 June 1996, 2001, 2006-17 (2017 boundaries)
Australia	ABS, 3218.0 Regional Population Growth, Australia, Table 8. Estimated Resident Population, State and Territory Summary, April 2018
United States	World Population Review, US States by Density 2018

5.2.2 HHI

84. Figure 5-1 shows the HHI estimates for New Zealand and for other countries. It can be seen that New Zealand's national HHI is broadly in line with that of other countries, which suggests that the electricity generation sector in New Zealand is not overly concentrated relative to the rest of the sample.

[24] United States Census Bureau, International Data Base, August 2017. Available at: https://www.census.gov/data-tools/demo/idb/informationGateway.php (accessed on 26 June 2018).

Figure 5-1: International HHI (non-dispatchable excluded)

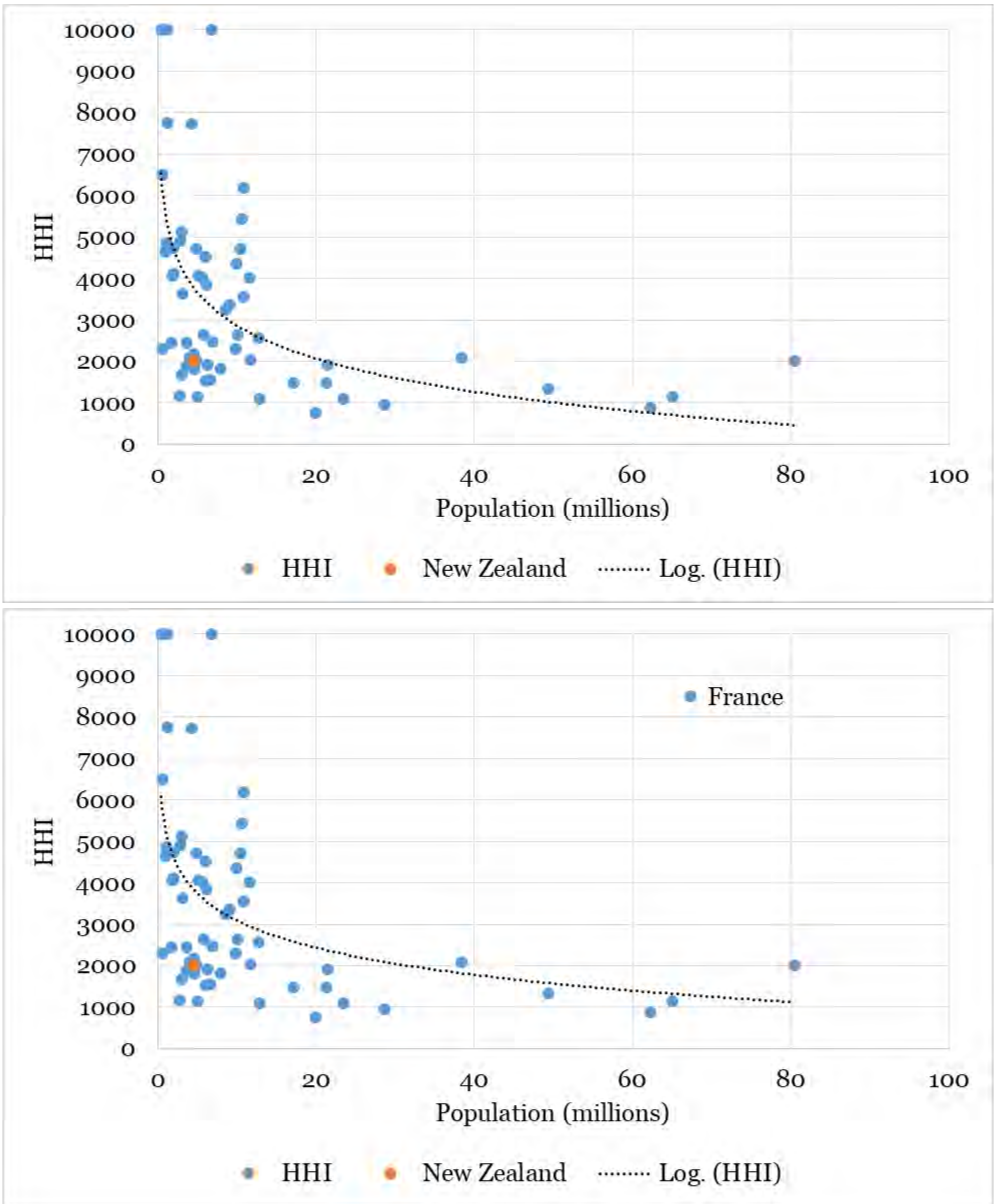


Source: See Table 5-1, CEG analysis

85. Figure 5-2 shows two scatterplots of international HHI against population, with one scatterplot excluding France as a clear outlier. Both scatterplots show clear negative correlations between HHI and population size. New Zealand as a whole is also below the logarithmic trend.

86. Population is an important variable because the energy generation sector features economies of scale due to the high fixed costs associated with opening a new generation plant. Countries with small populations will tend to feature higher degrees of concentration in the sector since demand may be insufficient to support a large number of plants owned by different companies.

Figure 5-2: International HHI against population



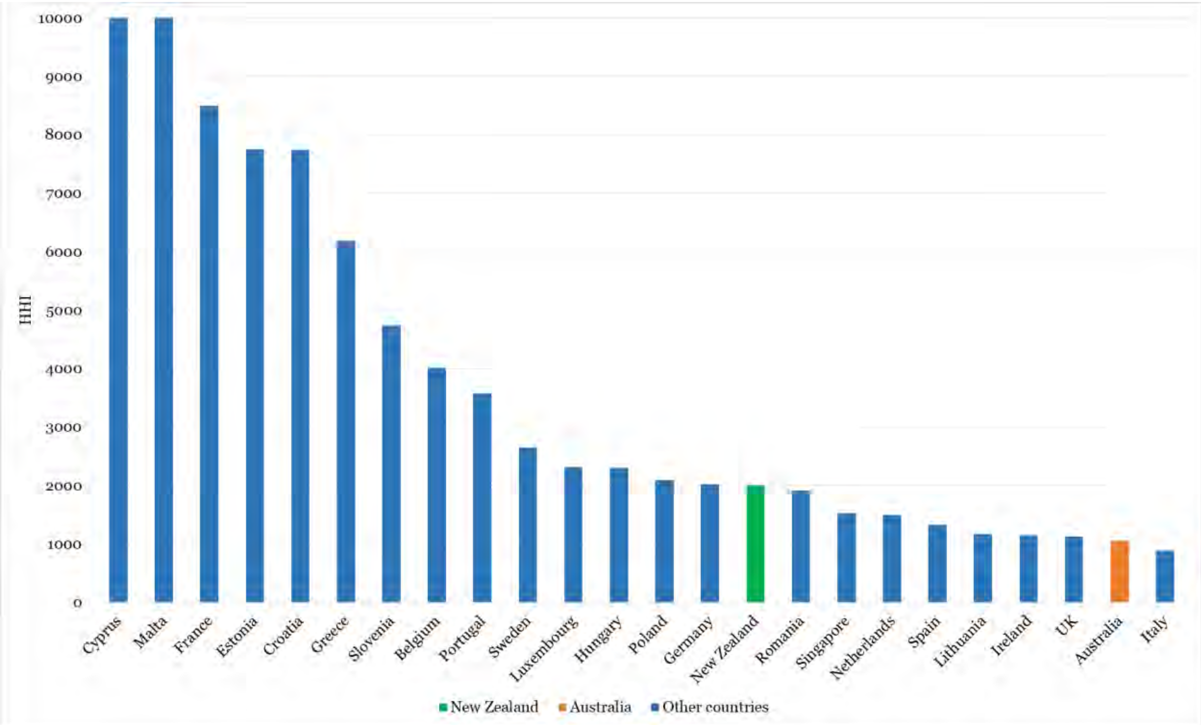
Source: See Table 5-1 and Table 5-2, CEG analysis

5.2.2.1 *Including non-dispatchable generation*

87. This section shows HHI estimates under the alternative specification where non-dispatchable energy is included in the sample.

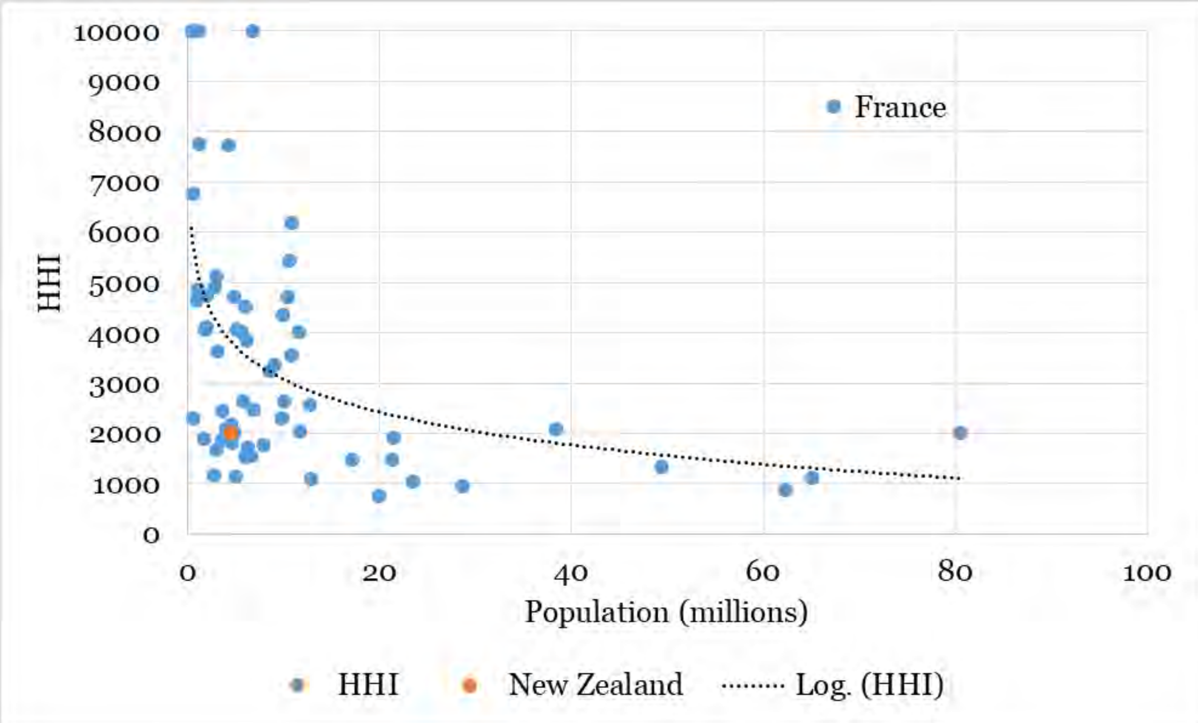
88. It can be seen that the findings under these alternative specifications are not materially different from those observed in sections 5.2.2.

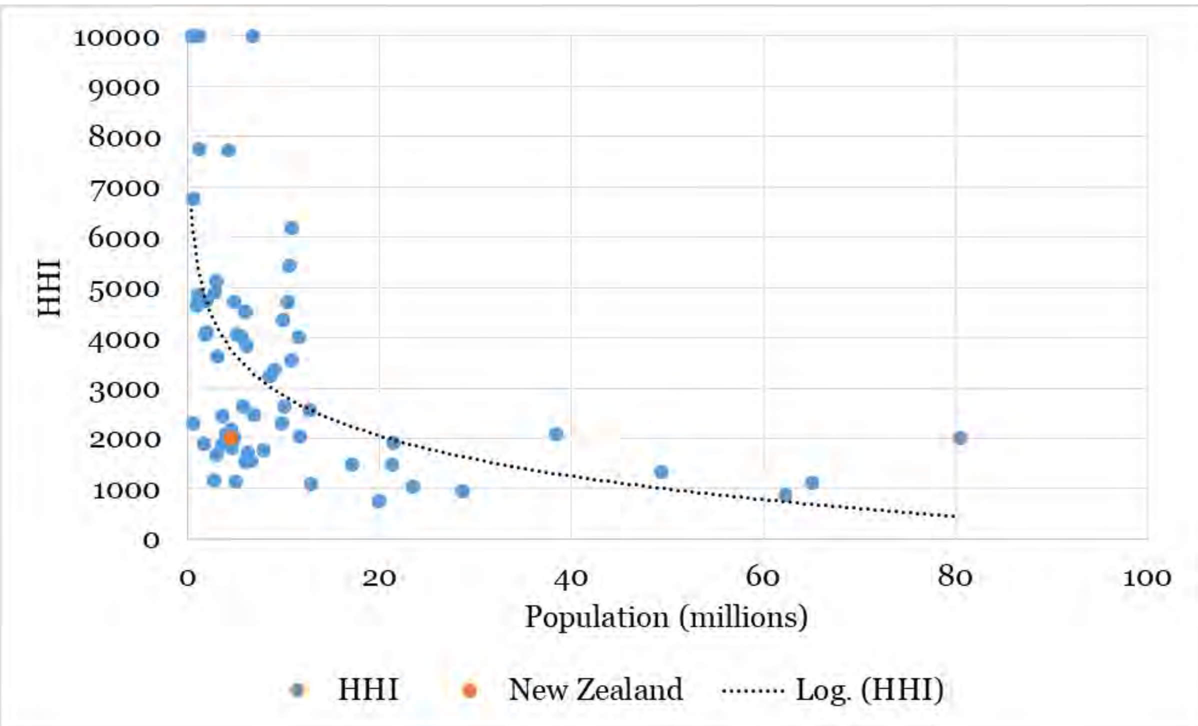
Figure 5-3: International HHI (non-dispatchable included)



Source: See Table 5-1, CEG analysis

Figure 5-4: International HHI against population (non-dispatchable included)





Source: See Table 5-1 and Table 5-2, CEG analysis

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5.3 Third party assessments of energy generation in New Zealand

89. This section reviews the following two reports that assessed New Zealand's energy sector:

- APEC, New Zealand: Electricity Retail Services Market Reform, APEC Policy Support Unit, May 2017; and
- Electricity Authority, 2017 Winter review, Final Report, March 2018.

90. Although the reports focus on New Zealand's energy sector as a whole, both reports also include some commentary that is specific to wholesale energy generation. The reports address two separate aspects of the sector – APEC assesses wholesale energy prices, while EA considers how well the market coped with stresses induced by low rainfall. Both reports suggest that the wholesale energy market is working well in relation to these two aspects.

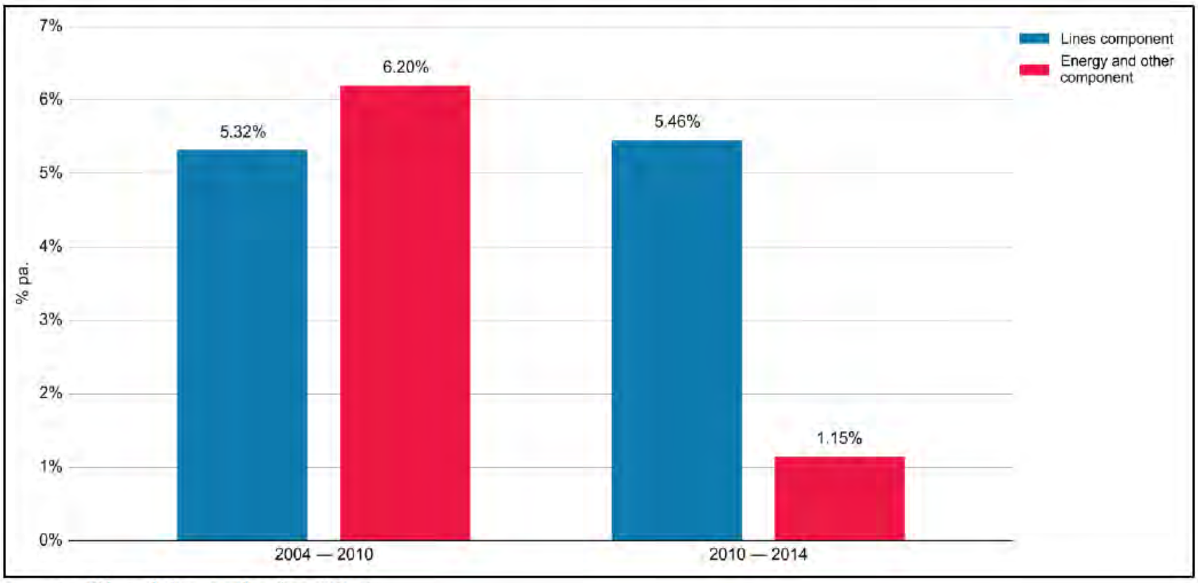
5.3.1 APEC report on New Zealand's electricity retail sector

91. APEC chronicled the history of reforms in New Zealand's electricity retail sector from the early 1980s onwards. Figure 5-5 reproduces Figure 5 of the APEC report, where it can be seen that price growth in the wholesale and retail sector had decreased considerably from 6.20% over the 2004-2010 period to 1.15% over the 2010-2014 period.[25]

[25] APEC, New Zealand: Electricity Retail Services Market Reform, APEC Policy Support Unit, May 2017, p. 43.

Figure 5-5: Average Change in Nominal Electricity Price Components, 2004-2014 (reproduces Figure 5 from the APEC report)

Figure 5. Average Change in Nominal Electricity Price Components, 2004-2014



Source: Electricity Authority, 2016

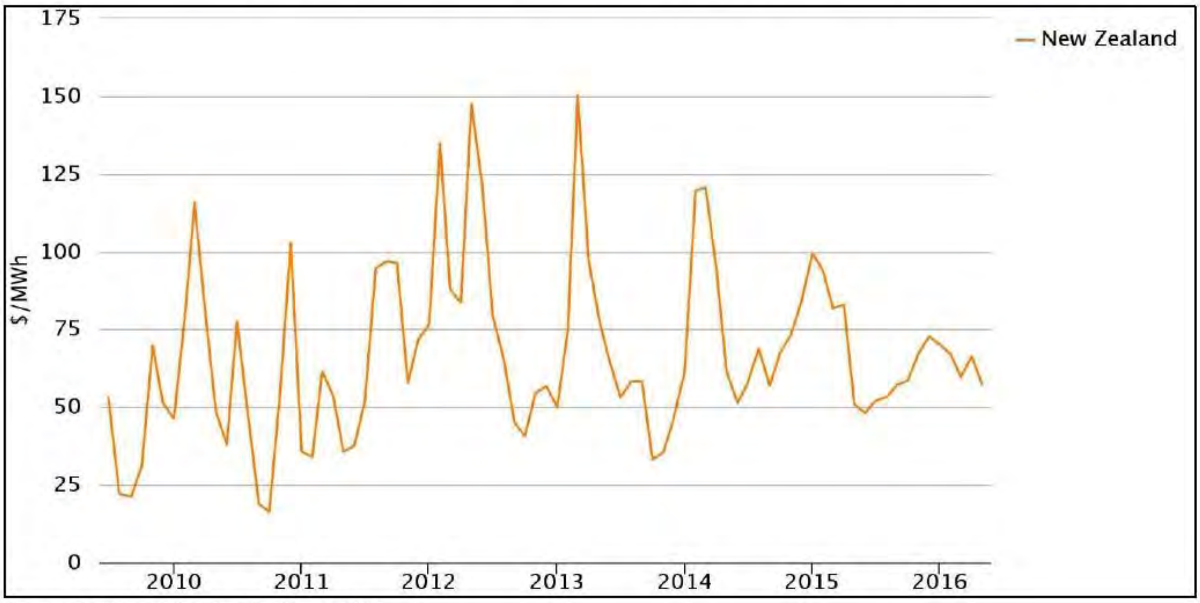
92. APEC attributed the decline in price growth of wholesale prices to increased investment in generation and transmission. APEC also found that the use of virtual and actual asset swaps resulted in greater competition for generation. Coupled with greater liquidity in energy hedge markets, this had the effect of increasing the variety of generation types in the wholesale market, including geothermal, gas, and wind generation.

93. Overall, the reforms "facilitated market responsive pricing and the capacity of generators and retailers to manage risks associated with transmission and supply constraints".[26] Figure 5-6, which reproduces Figure 6 of the APEC report, shows that wholesale energy prices continue to exhibit peaks and troughs since 2010, such as the price spike for the dry year in 2012. Nevertheless, APEC noted that even the dry year in 2012 "did not create concern in the market or public as had occurred in previous years".

26 APEC, New Zealand: Electricity Retail Services Market Reform, APEC Policy Support Unit, May 2017, p. 45.

Figure 5-6: Average of Wholesale Energy Prices, 2010-2016 (reproduces Figure 6 of the APEC report)

Figure 6. Average of Wholesale Energy Prices, 2010-2016



Source: Electricity Authority, 2016

94. The APEC report further included analysis of other issues pertaining to New Zealand's energy system. We do not discuss these issues in this report, but we note that APEC identified the following key principles that guided New Zealand's previous energy reform policies:

- Learning by doing: the reforms were evolutionary in nature, with governments accepting that market failures may occur and addressing them as they arise;
- Commitment to market based competition, even when addressing market failures: Governments ensured that the policies they enacted were geared towards supporting and encouraging market-based responses;
- No price signals to distort market based responses: Governments did not implement price controls or feed-in tariffs to support alternative energy sources, thus allowing market forces to drive the retail market; and
- Regulatory intervention is only used to improve market efficiency, where competition cannot: Regulators sought to use guidelines instead of prescribing rules.

95. We discuss each of the above principles in sections 5.3.2 to 5.3.5.

5.3.2 Learning by doing

96. APEC stated that successive governments understood that reforms to the energy sector would be evolutionary, in that there would be iterative successes and failures that would be used to modify the next set of measures.

97. Such a mindset was appropriate due to the absence of successful precedent that could be followed, and was especially important for circumventing risk aversion to imperfect change.

5.3.3 Commitment to market based competition, even when addressing market failures

98. APEC found that hedge markets were sufficiently liquid and accessible hedge to allow competition from non-vertically-integrated retailers and asset swaps between generators also reduced barriers to competition as did removing restrictions preventing distributor activity in retailing.

99. Second, market participants were required to compensate customers for unreliable supply. This increased market accountability for managing the security of supply in dry years, with less emphasis on energy conservation schemes that were dependent on government sponsorship.

100. Third, funding was provided for public awareness campaigns in response to low levels of customer engagement in the sector. Consumers thus became more aware about the possible benefits of switching retailers. Retailers were also required to fund and engage with an independent complaints Commissioner, which helped to build up public trust in the dispute resolutions process.

5.3.4 No price signals to distort market based responses

101. APEC pointed out that reforms in New Zealand did not feature price controls or other market distortions such as subsidies and rebates, be it for consumers, market participants, or technological developments.

102. Specifically, governments did not attempt to favour alternative energy sources or renewable energy technologies through subsidies or feed-in tariffs. Neither did they implement price controls to address scarcity in generation, nor cap retail prices in response to price increases. Concessional pricing for consumers was also kept to a minimum. This ensured that non-market based policies would not distort pricing signals in the market.

5.3.5 Regulatory intervention is only used to improve market efficiency, where competition cannot

103. Governments accepted that regulation should primarily be used to reinforce market efficiency. Intervention was only used when market efficiency could not be achieved through competitive markets.

104. Examples of the above approach include the use of an Electricity Code instead of a prescriptive licensing regime, as well as a preference for guidelines over making changes to market rules. The Commerce Commission also eschewed pricing controls in favour of default price quality paths for regulating natural monopolies.

5.3.6 EA 2017 Winter review

105. The 2017 Winter review focused on the issue of low hydro inflows in the South Island. Specifically, the EA reviewed the effectiveness of its measures in terms of incentivising the effective management of periods with low inflows.

106. The EA had previously implemented a broad range of measures to manage the risk of low inflows, including:

- Instituting objective triggers for commencing conservation campaigns;
- Customer compensation schemes; and
- Stress testing.

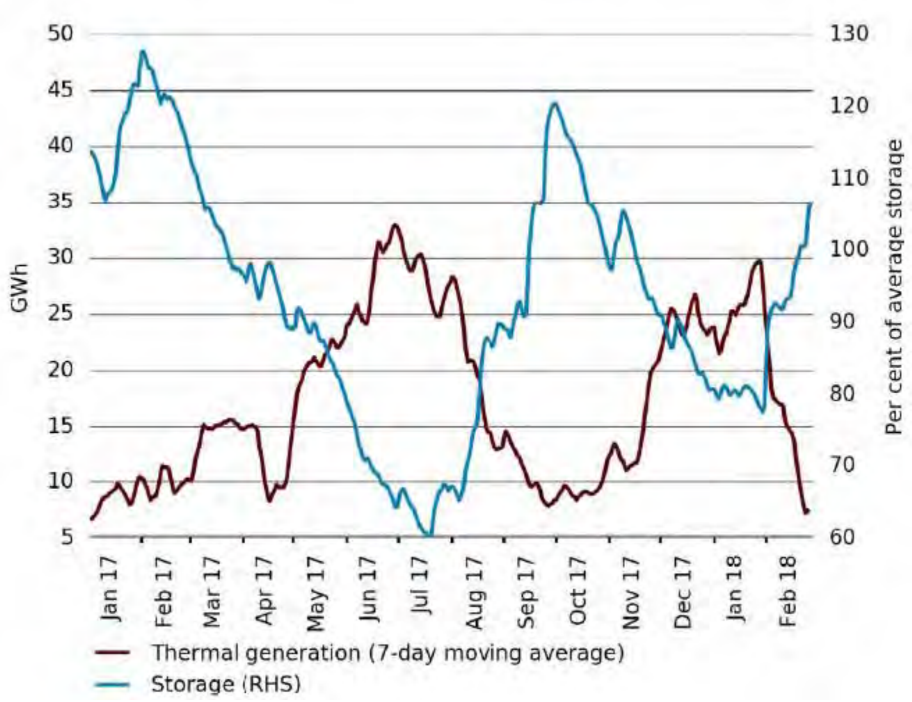
107. The 2017 Winter review concluded that the measures put in place since 2010 are working well, such that the problem of non-supply did not crop up in spite of the bad hydro inflows over that period.

5.3.6.1 Thermal generators increased their output in response to high energy prices caused by low hydro inflows

108. The EA's analysis showed that the low inflows over the 2017 winter period led to low energy storage and high energy prices. However, as shown in Figure 5-7 (reproduces Figure 5 of the EA report), when as storage fell and prices rose, thermal generators reacted by increasing their output, which partially compensated for the problems caused by low inflows.

Figure 5-7: Daily thermal generation and New Zealand storage (reproduces Figure 5 of the EA report)

Figure 5: Daily thermal generation and New Zealand storage



109. Furthermore, the EA found that there was no risk of non-supply issues at any point, since there was always sufficient spare capacity in the system throughout the 2017 winter period.

110. The 2017 Winter review further considered a few other issues that we discuss briefly in sections 5.3.6.2 to 5.3.6.6.

5.3.6.2 Hedge market performance

111. The EA's analysis found that the hedging market sustained high volumes in the winter of 2017 but that bid-ask spreads for contracts that expired in 2017 were elevated in June and July of 2017. However, the EA notes that:

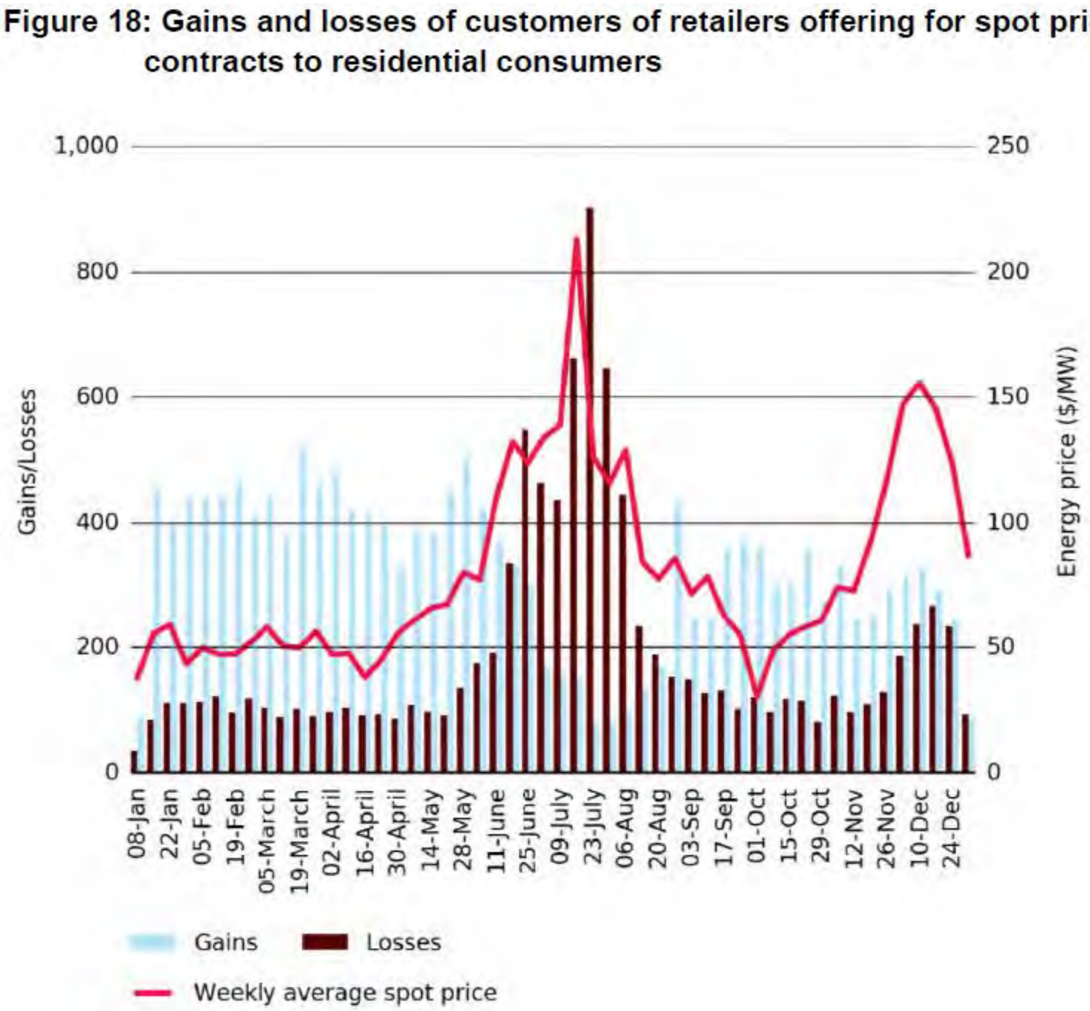
> *Longer dated contracts and quarterly contracts were not affected to anywhere near the same extent.*

112. We discuss this aspect of hedge market experience in more detail in section 6 on vertical integration and liquidity in hedge markets.

5.3.6.3 Retail switching among spot priced residential consumers

113. The EA assessed how residential consumers on spot price contracts reacted to the high spot prices observed during the 2017 winter period. As seen in Figure 5-8, there was an increase in residential customers switching away from spot priced contracts during periods of high spot prices from the third of week of June to the last week of August, as well as at the end of 2017. According to the EA, approximately 10% of residential consumers switched retailers.

Figure 5-8: Residential customer gains and losses for retailers offering spot price contracts



114. The EA followed up with larger retailers and found that retailers opted not to impose special conditions on the customers that were switching away from spot priced contracts. This, the EA concludes, shows that the large retailers were able to accommodate the extra load from new customers. The EA also stated that it would

continue to monitor retailers offering spot price contracts to ensure that consumers are well-informed of their risks and options when adopting spot price plans.

115. We note that the above patterns illustrate that wholesale and retail market interaction are such that customers are able to choose the level of, and effectively manage, exposure to wholesale market prices.

5.3.6.4 Management of storage

116. The EA commissioned a report to investigate the relationship between spot price and hydro storage.

117. The report concludes that:[27]

a. Real spot prices—deflated using the producer price index (PPI)—have declined over the period of the study (1999–2017).

b. There has been a significant decline in the volatility of spot prices since September 2009.

c. There has been a significant reduction in the volatility of hydro storage since September 2009 and storage has not fallen as low since 2009.

d. When the data are split into seasons, and price and storage are combined into a regression model, since September 2009:

i. prices change more in response to changes in storage in the spring (Sept–Oct–Nov)

ii. prices change less in response to changes in storage in the autumn (Mar–Apr–May).

5.3.6.5 Demand response

118. High spot prices can induce a reduction in demand. The EA analysed two aspects of such demand reduction: demand at non-conforming nodes; and demand from spot exposed residential consumers.

119. Nodes are non-conforming if they serve a small number of consumers, which tend to be large industrial consumers. As shown in Figure 5-9, demand at non-conforming nodes did respond to high spot prices, although the effect was smaller than the EA's expectations.

27 Electricity Authority, 2017 Winter review, Final report, March 2018, p. 19.

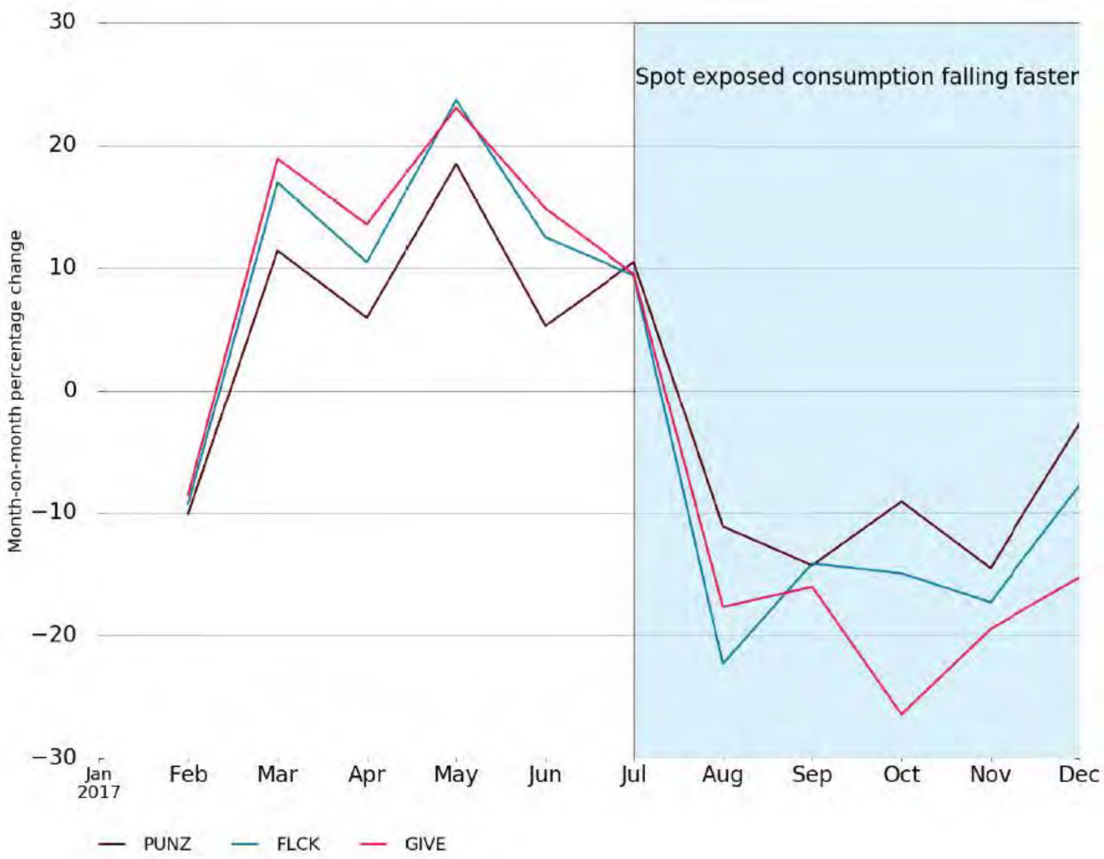
Figure 5-9: Difference in consumption between 2016 and 2017 at non-conforming nodes (reproduces Figure 24 of EA report)

Figure 24: Difference in consumption between 2016 and 2017 at non-conforming nodes

120. The higher spot prices also induced demand responses among spot-exposed residential consumers, although the effect was once again small. As seen in Figure 5-10, the spot-exposed customers of Flick and Giving Energy reduced their consumption at a faster rate than the mainly fixed-price customers of Pulse.

Figure 5-10: Demand responses (reproduces Figure 26 of EA report)

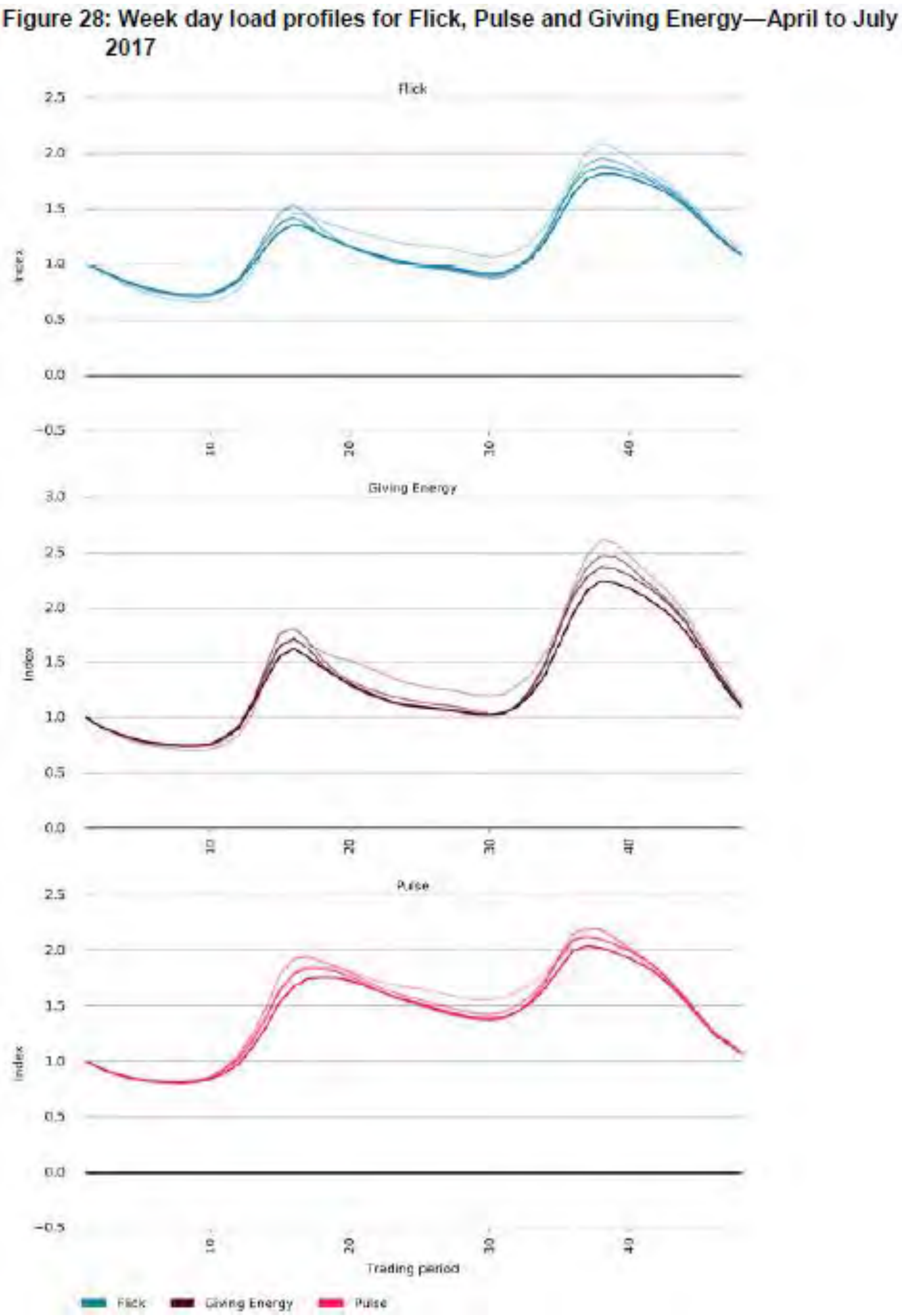
Figure 26: Demand response for Flick, Pulse and Giving Energy



121. Figure 5-11 also shows that spot-exposed customers of Flick and Pulse tended to have earlier morning peaks and later evening peaks than the mainly fixed-priced customers of Giving Energy during the 2017 winter period, possibly in an attempt to shift their loads towards times with lower prices. Though small, this effect shows that consumers did have the capability to respond to spot price signals.

122. The EA suggested that there was further scope to use demand side bidding and forecasting in order to obtain more precise forecasts of loads and prices. This would enable consumers to make better consumption decisions when managing their loads.

Figure 5-11: Week day load profiles (reproduces Figure 28 of EA report)



5.3.6.6 Security arrangements

123. There were a number of security arrangements in place for the 2017 winter period. These included an emergency management policy and a rolling outage plan.

124. Coupled with daily reporting by Transpower, these security arrangements worked well over the winter period, as evidenced by public discourse that focused more on price discussions instead of physical shortage. Furthermore, according to the EA, the fact that there was no uncertainty regarding when a public conservation program would commence was a success in itself.

5.3.7 Summary

125. Table 5-3 summarises the issues considered in the EA's report. The EA's conclusions on these issues suggest that New Zealand's power system is working well overall, and that the reforms introduced in 2010 managed to achieve the desired impact.

Table 5-3: Summary of other issues in the 2017 Winter review

Issue	Conclusion
Thermal generation	Thermal generators increased their output in response to high energy prices caused by low hydro inflows. There was no risk of non-supply issues at any point, since there was always sufficient spare capacity in the system throughout the 2017 winter period.
Hedge market performance	There was a widening of bid-ask spreads, but the effect was not severe due to sufficient volume. However, the EA is still concerned that more severe winters could cause market makers to withdraw.
Retail switching among consumers	Around 10% of spot-exposed residential consumers switched retailers. Large retailers did not impose special conditions for consumers switching from spot priced retailers, indicating that the large retailers were able to accommodate the extra load from new customers. The EA will continue to monitor retailers offering spot price contracts to ensure that consumers are well-informed of their risks and options when adopting spot price plans.
Management of storage	Storage has been managed more conservatively since 2009.
Demand response	Demand reduced slightly in response to high spot prices, which confirms that consumers can respond effectively to price signals. The EA also found that demand side bidding and forecasting produced price forecasts that were more accurate.
Security arrangements	The security of supply arrangements worked well over the winter period. These arrangements include emergency management policies, a rolling outage plan, daily reporting from Transpower, grid reconfiguration, and an official conservation campaign.

6 Vertical integration and liquidity in hedge markets

126. The Expert Advisory Panel's First Report (the Report) states that:[28]

> *Vertically integrated companies have no inherent need for contract markets, whereas independent generators and retailers rely on them heavily. If large portions of the generation and retailing sectors have little use for contract markets, there will be low liquidity and muffled price signals, making it difficult and costly for independent companies to manage electricity price risks.*

127. Separately, the Report states:

> *The New Zealand contract market had been developing well and has been on a trajectory of steady improvement since 2010. However, events during the winter of 2017 highlight the fragility of current arrangements. For this reason, we consider improving the depth and resilience of the contract market should be given high priority.*

6.1 Summary

128. This section has the following structure:

- Section 6.2 focusses on defining what 'market liquidity' means generally but especially in the context of electricity hedge markets.
- Section 6.3 examines the impact, if any, of vertical integration between retailers and generators on hedge market liquidity (properly defined).
- Section 6.4 considers potential policy interventions to raise hedge market liquidity should it be concluded that current liquidity levels are sub-optimal. Section 6.4 also questions whether there is any evidence of sub-optimal liquidity in hedge markets.

129. There are four key conclusions.

- First, the outstanding value of arm's length hedge contracts is not a reliable indicator of liquidity in hedge markets – where the correct definition of liquidity is the ease with which an investor can trade without moving the market price materially against themselves;

[28] Electricity Price Review, First Report, 30 August 2018.

- Second, vertical integration does not cause the merged "Gentailer" entity to have "no inherent need" for contract markets. On the contrary, while the number of external contracts held by the merged entity falls, the merged entity makes the same contribution to contract market liquidity as the two stand-alone entities would absent the merger; and
- Third, it may nonetheless be that hedge market liquidity may be sub-optimal for reasons unrelated to vertical integration. If this is the case (and we don't suggest it is), the least cost policy intervention may involve placing regulatory burdens on the market participants with the strongest balance sheets (i.e., large vertically integrated generators). However, if Gentailers bear the largest burden of regulatory intervention to improve liquidity then they will be 'fixing' a problem that they did not create. This may have important implications in the design and extent of any such interventions.
- Finally, there is no compelling evidence that there is sub-optimal liquidity in New Zealand electricity hedge markets.

6.2 Defining liquidity in energy financial markets?

130. This section defines liquidity in financial markets and also provides an analytical basis for thinking about the effect of vertical integration in electricity markets on liquidity of the market for financial hedge contracts. This issue (the impact of vertical integration on liquidity of financial hedge contracts) is addressed, using more formal/mathematical analysis, in Appendix A.

6.2.1 What is liquidity?

131. The term 'liquidity' is sometimes used in economic discussions without a very clear definition. In this report, we adopt the standard definition from the finance literature where liquidity is defined as the degree to which an asset or security can be quickly bought or sold in the market without affecting the asset's price. The more liquid a market the easier it is to observe the 'fair' market price and the less likely it is that an individual trader will move the market price against themselves by the act of trading in the instrument.

132. This definition is consistent with that commonly used in financial markets. For example Governor Kevin Warsh of the US Federal Reserve System defines liquidity as follows:[29]

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29 Governor Warsh, Speech, Market Liquidity: Definitions and Implications, March 2007. Available at <https://www.federalreserve.gov/newsevents/speech/warsh20070305a.htm>.

> *The traditional concept of liquidity relates to trading: An asset's liquidity is defined by its ability to be transformed into another asset without loss of value. ...*
>
> *As noted, 'liquidity' in the sense of "trading liquidity" reflects the ability to transact quickly without exerting a material effect on prices.*

133. Another simplistic definition of 'liquidity' is the volume of trading in an asset. This simplistic definition is typically strongly correlated with true liquidity (as defined above). This is because, as discussed in section 6.3.2 below, high levels of aggregate trading are typically correlated with high levels of sensitivity of supply and demand to (marginal) changes in price. However, as also discussed in section 6.3.2 below, it is important to keep in mind that this correlation is not causation. Specifically, that certain changes in market structure/conditions might reduce aggregate trading while simultaneously having no effect (or even increasing) true market liquidity. Vertical integration in electricity markets is one such change that can be expected to reduce aggregate trading without reducing liquidity.

6.2.2 Liquidity in asset markets is achieved by traders altering their portfolio in response to price changes

134. Liquidity in an asset market depends on the willingness of buyers and sellers to adjust their portfolio for small changes in price. That is, a change in the desired portfolio of one party must be matched by offsetting changes in the portfolio of other parties. This is how a market achieves equilibrium in response to a change in one party's desired portfolio. For example, if one party wants to hold more US Treasury bonds, it follows that other parties must, in aggregate, hold fewer (or the US Government must issue more (have a more negative portfolio)).

135. The question then becomes, how much do prices have to change in order to elicit the offsetting change in portfolios of other parties? In a liquid market, prices have to change only modestly. In an illiquid market, other parties require a large price change in order to elicit the offsetting change in their (aggregate) portfolios.

136. By way of illustration, imagine that a market was made up of buyers and sellers who had fixed ideas of what their portfolio must look like. In the context of electricity hedge markets this would involve:

- each generator taking the view that they must issue a specific number of base load futures; and
- each retailer taking the view that they must hold a specific number of base load futures; then

- let those specific numbers be insensitive to the price at which the base load future is struck (in the sense that very large price changes are required to cause participants to change, even modestly, their desired portfolio);[30] and
- for the purpose of illustration, let the total number of base load futures that generators want to sell and that retailers want to buy happen to be 1,000 each such that the market was in balance.[31]

137. This market would be illiquid. If one market participant, say a retailer, wanted to increase their holdings of base load futures then other market participants must adjust their portfolio in an offsetting manner (other retailers have to hold fewer based load futures and/or generators have to issue more base load futures). The way that the market achieves this is by the base load future's price rising; giving other participants the incentive to accommodate the desired trade by selling base load futures.[32] If all market participants' desired portfolios are insensitive to price then a large price increase is required to elicit the necessary reduction in holdings that will accommodate the retailer who is seeking to increase their holdings.

138. By contrast, if all market participants' desired portfolios of base load futures are very sensitive to the price of base load futures then the market will be highly liquid. In this case, the price of futures only has to rise by a small amount in order to elicit the necessary accommodating increase in supply by generators and/or reduction in other retailers' holdings.

6.2.3 Liquidity is determined at the margin in response to price changes (not by the aggregate level of infra-marginal trading)

139. It is important to clearly understand that the above examples of an illiquid and a liquid base load futures market do not rely on any fact or assumption about the total volume of trading required for all parties to achieve their desired portfolio. Indeed, the above example is constructed so that both the liquid and the illiquid market have the same base level of trading required to achieve retailers' and generators' initially desired portfolios (1,000 units).

140. What matters for market liquidity is not the size of this 1,000 units of infra-marginal trading. Rather, what is important is the sensitivity of the desired portfolio to changes in market prices. That is, what is important is the marginal sensitivity to price of each

30 In fact, if each market participant's desired number of base load futures issued/bought was truly perfectly insensitive to price then the market would not clear – because there would be no mechanism to equate supply and demand.

31 Of course, this can only have been achieved in reality by the price of base load futures having adjusted until supply and demand were in equilibrium as discussed in the previous footnote and also in the text below.

32 Generators issuing more and/or other retailers reducing their net holdings of base load futures.

participant's desired portfolio. If this marginal sensitivity is high then the market will be liquid. If this marginal sensitivity is low then the market will be illiquid.

6.3 Vertical integration and liquidity in electricity hedge markets

141. The Expert Advisory Panel's First Report (the Report) states that:[33]

> *Vertically integrated companies have no inherent need for contract markets, whereas independent generators and retailers rely on them heavily. If large portions of the generation and retailing sectors have little use for contract markets, there will be low liquidity and muffled price signals, making it difficult and costly for independent companies to manage electricity price risks.*

142. We explain that, while in some sense intuitive, it is not correct to claim that vertical integration reduces market liquidity (properly defined).

6.3.1 Vertical integration does not reduce marginal incentives to trade in response to price changes

143. The difference between marginal and infra-marginal trading is important to understand in the context of this report because vertical integration:

- will reduce the infra-marginal trading in base load futures (e.g., the creation of a natural hedge might reduce the number of base load futures desired to be sold/bought from 1,000 to 900); and
- will not reduce, at least in any obvious way, the sensitivity to price of the vertically integrated supplier's portfolio (relative to the sensitivity to price of its constituent parts were they stand-alone).

144. In order to understand the second dot point, consider the impact of a 1% increase in the base load futures price for a quarter. Holding constant market participants' expectations of the future spot price distribution, this makes issuing/holding futures contracts more profitable/expensive. This will, in turn, incentivise all parties to sell base load futures (the effect of which for retailers is to reduce their net holdings). The size of this adjustment, in response to a change in price, defines the liquidity of the market. Small adjustments in quantities are associated with illiquid markets and large adjustments are associated with a liquid market.

145. The critical question for this report is whether vertical integration between a generator and a retailer causes the vertically integrated entity to have a smaller

33 Electricity Price Review, First Report, 30 August 2018.

adjustment to a 1% price increase than the sum of the adjustments if the entities were they stand-alone. There is no obvious reason to believe that this would be the case and one could easily imagine that, if anything, the opposite would be true.[34]

146. Let the following describe the base-case stand-alone scenario:

- At a futures price of 80 $/MWh, expected spot prices and the futures price are aligned.
  - At this price the hypothetical stand-alone generator would issue 100 futures contracts with the sole objective of minimising volatility of profit.
  - Similarly, the hypothetical stand-alone retailer would hold 100 futures contracts with the sole objective of minimising volatility of profit.

    (There is no gain in terms of the level of actuarially expected profit from futures trading because, by assumption, the futures price matches the actuarially expected spot price.)
- At a higher futures price 90 $/MWh (and holding expected spot prices constant):
  - the generator/retailer would expect to raise expected profits by selling more futures contracts; however
  - this will also raise the volatility of expected profits.

    (Recall that the volatility of expected profits is minimised when each party issues/holds 100 contracts (which is what they would issue/hold if the futures contract price was aligned with actuarially expected spot prices));
- Let both hypothetical parties respond to this increased incentive to sell futures contracts by issuing 10 additional futures contracts (20 in total). The effect of this is to raise/reduce the net portfolio of the generator/retailer from 100 units to 110/90 units.
- This 20 unit increase in net supply is their stand-alone contribution to market liquidity. That is, their contribution to the supply of additional futures contracts in a market where rising prices signal a need for additional supply.

147. Now, consider whether there is any reason to believe that, if these entities merged, the vertically integrated entity would respond any differently? Is there any reason to believe that the vertically integrated entity would not also increase the supply of futures contracts by 20 units in response to the same 10 $/MWh increase in futures prices relative to expected spot prices?

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34 For example, vertical integration may have the effect of strengthening the overall balance sheet of the entities, allowing the vertically integrated firm to take on more risk in responding to price signals than the two stand-alone entities combined.

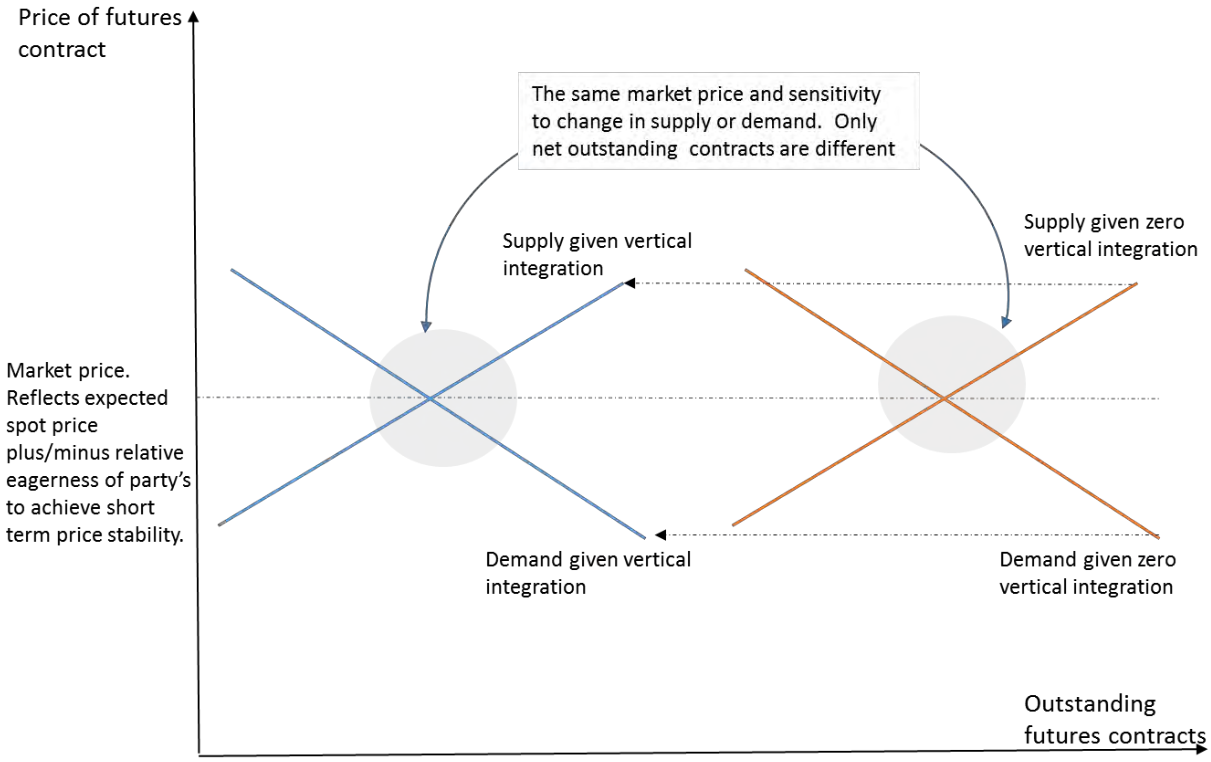
148. It may well be that, at the initial futures price of 80 $/MWh, the hypothetical merged entity would rely on the existence of a natural hedge such that it would neither issue nor hold futures contracts. However, as the price rose above 80 $/MWh, the new firm would have the same incentives to increase supply as its stand-alone constituent elements had. There is no obvious reason for the merger to have any effect on the marginal propensity to trade in the face of changing prices:

- The expected profit from issuing an additional 20 contracts would be the same as the aggregate impact across the stand-alone entity (20 times the $10 differential between futures prices and expected spot prices);
- The expected impact on volatility of profit would be the same (20 times the expected variance in future spot prices relative to the expected mean);
- The combined ability of the new entity to absorb such profit variation would be the same as the combined ability of the stand-alone entities (the new entity would have the combined balance sheet of the stand-alone entities).

149. In short, there is no obvious reason to believe that the merger will result in any change in the marginal sensitivity of supply and demand of futures contracts to changes in price (i.e., market liquidity). The merger will result in a reduction in the total number of observed trades (e.g., at a price of 80 $/MWh the number of observed trades will be 100 units lower). However, this reduction is purely a reduction in the infra-marginal trading (trading that is not driven by price). There is no reason to believe that price sensitive trading, of the kind that supplies liquidity, will change.

150. This is illustrated in the stylised supply and demand diagram at Figure 6-1 below. This figure illustrates a market for hedging products with and without vertical integration. The only difference is that, in one case, one or more generation portfolios are combined with one or more retail portfolios.

Figure 6-1: Illustration of markets with identical liquidity but different size



151. The impact of vertical integration is to reduce the outstanding futures contracts in the market. In the above figure, the reduced need for outstanding financial futures as a result of vertical integration is illustrated by the shift in the market supply and demand curves to the left.

152. However, there is nothing about this leftward shift of demand and supply that alters the slopes of the curves (i.e., that alters market liquidity). Market liquidity is driven by the combined slope of the supply and demand curves around equilibrium and there is no reason (at least no obvious reason) that this will be altered. The leftward shift in supply and demand should be thought of as swapping one form of infra-marginal hedging (financial contracts) for another (a natural hedge).[35] This leaves

[35] Something is infra-marginal if it is not the subject of optimisation. In this context, imagine that a generator, given its balance sheet, would always sell 50% of its output on the hedging market irrespective of the price in the hedging market. Similarly, imagine that a retailer, given its balance sheet, would always buy 50% of its energy in financial markets. The firms will optimise hedging above these levels as market conditions change (e.g., sometimes choosing 90% and sometimes choosing 60%) but never below. The 50% hedging position is a 'set and forget' position. It contributes nothing to market liquidity or price discovery because trading in these volumes is not sensitive to market conditions.

Now imagine that these two firms merge. Let the merger create a level of 'natural hedge' of, say 60%. The combined entity no longer needs to source is baseline 50% hedge position in financial markets. Its the combined firm's ongoing optimisation, using financial contracts, to its hedge position unchanged. This ongoing optimisation (adjustment to market prices/conditions) is what delivers financial market liquidity. A vertically integrated firm has the same needs and desires to adjust to changes in circumstances/prices as its constituent parts. Therefore, a vertically integrated firm will make the same contribution to market liquidity that its constituent parts would have made had they been standalone operations.

153. Indeed, to the extent that there is any reason to believe that liquidity would be affected then it would seem most plausible that it would be increased. This would be the case if the natural hedge provided superior hedging properties relative to external contract hedges. In this case, the merger would reduce the overall risk of the merged entity relative to the (hedged) stand-alone entities. This in turn would improve the merged entity's ability to pursue profits in the hedging market by responding more aggressively to deviations of futures prices from expected spot prices

6.3.2 Distinguishing correlation (between infra-marginal trading and liquidity) with causation

154. True market liquidity and the level of aggregate trading are, typically, very strongly correlated. That is, typically the more of one in any given market the more of the other. For example, the US Treasury bond market has daily turnover measured in the hundreds of billions of dollars. It is also a very liquid market in the true sense of the term. That is, only small changes in price are required to elicit large changes in aggregate supply and demand – such that even large individual trades do not need to materially raise/lower prices in order to elicit the desired supply/demand for the trade.

155. This correlation between trading activity and liquidity is not purely coincidental. High trading activity is a sign that there are many market participants, many of whom have very large balance sheets, who are constantly monitoring prices and responding with countervailing trades as prices change.

156. However, the amount of trading activity should not be taken as the cause of liquidity. The driver of liquidity is the aggregate willingness of traders to respond to higher/lower prices with more sales/purchasers. Other things equal, this will be correlated with the aggregate turnover of the asset. However, it is perfectly possible to imagine a reduction or rise in the aggregate turnover in a market that is not associated with any change in the aggregate willingness of traders to respond to higher/lower prices with more sales/purchasers.

baseline holdings of financial contracts will fall dramatically. However, its need to continually trade and optimise its hedge portfolio between 50% and 100% is unchanged. This will be achieved via day-to-day trading in financial markets just as it would have been had the two operations remained standalone. The contribution to market liquidity from the combined entities is the same.

157. For example, imagine that the interest rate environment changed from one with a large amount of uncertainty to one with only minimal levels of uncertainty. In this case, there would be less scope for differences in valuation of US Treasuries between market participants and, consequently, less reason to trade. Aggregate trading in US Treasuries would fall but this would not be associated with a reduction in true liquidity. Indeed, true liquidity would likely increase because, with the same number of traders backed by the same balance sheets, and more commonly shared valuations of the underlying asset, the aggregate response to a change in price (true liquidity) will be larger.

158. There is a clear parallel here with the impact of vertical integration on aggregate trading. Vertical integration will tend to reduce the amount of aggregate trading in contract hedges by virtue of the replacement of some financial contracts with a natural hedge. However, vertical integration will not alter the aggregate level of monitoring of market prices, nor will it obviously alter the sensitivity of market participants' aggregate supply/demand response to changes in price. As already noted, if anything, vertical integration may well raise that sensitivity (if it supplies a superior hedge to financial contracts).

6.3.3 Common valuations are an important driver of liquidity

159. Assets do not need to be heavily traded to be liquid. By way of example, I might offer to sell bundles of 10,000 in NZD notes on Ebay for 10,000 NZD bank transfer. It is unlikely that I will ever trade that asset at that price – precisely because there is a perfect common understanding of what its value is. There is no scope for differences in valuation and therefore no reason to trade. Yet, the asset is highly liquid. If I were to drop/raise the price by a fraction of a percent, there would be flood of orders/sales.

160. As already noted, liquid assets do, typically, tend to also be heavily traded assets. However, it is important to understand the direction of the causation. Liquid assets are heavily traded because they are liquid. It is not the case that liquid assets are liquid because they are heavily traded. US Treasury bonds are heavily traded in financial markets because the common valuations amongst traders mean that they can fulfil something like the role of "money" in the financial system (with the added benefit over actual cash of being interest-bearing). (The valuations are not identical (as in my Ebay example above) such that there will still be scope for disagreements about value and, therefore, scope for trading.)

161. In order for an asset to be liquid, market participants need to have a common valuation technique leading to broadly similar valuations. That is, unlike a piece of art or an individual suburban house, a large number of potential buyers and sellers must share a (broadly) common view of what the asset is worth. There also must be no material 'inside information' such that the act of buying/selling does not signal that the true valuation of the asset is different to the counterparty's valuation (e.g., the true value of used cars is often inside information to the seller). If there are

common valuations then the price of the asset cannot diverge materially from the common valuation without a large number of parties wishing to trade. It is this sensitivity of buyers and sellers to changes in prices that creates a liquid market.

162. Once more, consider the market for US Government Treasury bonds. This market is highly liquid because all potential traders have a more or less common valuation technique applied to the asset. Specifically, the value of a bond is equal to the net present value of expected coupons plus principal. The discount rates that investors use to value the cash-flows on the bond may differ slightly (investors may expect interest rates to change in different ways over the course of the bond's life) and this may give rise to some differences in valuations. However, if a particular trader decided that Treasury bonds were undervalued and wanted to buy $100m, she would only have to offer a tiny fraction above the price that would have prevailed without her order. That is, a tiny fraction increase in price is all that is necessary to bring forward the necessary supply to match her demand (other things equal).

163. There is no obvious reason to believe that vertical integration in electricity markets has any effect on market participants' distribution of valuation of futures contracts. That is, there is no obvious reason to believe that marginal valuations across participants become less common post vertical integration. It follows that there is no reason to believe that this is a mechanism by which vertical integration would affect hedge market liquidity.

6.4 Policy response to perceived sub-optimal market liquidity

6.4.1 Policy response

164. We understand that four large New Zealand Gentailers already voluntarily make binding offers to buy and sell base load futures - with a limited spread between the buy and sell price. A similar practice is also followed in the UK. It would be wrong to justify an impost on Gentailers on the grounds that they are somehow responsible for the perceived sub-optimal market liquidity. This is simply not the case. It would also be wrong to ignore the real costs that such a policy imposes on Gentailers when calibrating any changes to the current policy.

165. Finally, incorrectly blaming Gentailers for lack of liquidity may lead to any policy intervention being focussed too narrowly on imposts for Gentailers. Large Gentailers are, inevitably, going to bear the majority of the burden of policies that require market participants to provide liquidity (make trades that they otherwise would prefer not to). However, it is not obvious that no other market participants should similarly be required to make a contribution.

166. Conceivably, all generators and retailers above a threshold size could be required to provide periodic binding offers for hedge products - where the required volume was

in some sense proportion to their size. Alternatively, market participants could choose to opt-out and, instead, make a dollar contribution to those willing to make binding buy/sell offers.

6.4.2 Perception of problem

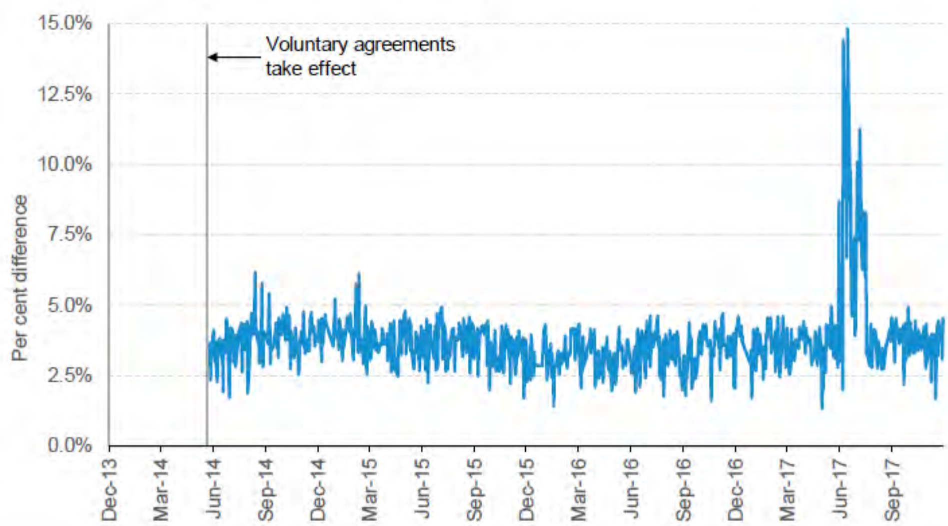
167. The Report states that:

> *The New Zealand contract market had been developing well and has been on a trajectory of steady improvement since 2010. However, events during the winter of 2017 highlight the fragility of current arrangements. For this reason, we consider improving the depth and resilience of the contract market should be given high priority.*

168. In relation to the events of winter 2017 the Report states:

> *Some aspects of the contract market's performance have faltered recently. We were told of a "steady decline in market-maker performance," as evidenced by buy-sell price spreads routinely wider than 5 per cent, and the absence at times of any quoted prices for some contracts during parts of the 2017 winter. As shown in figure 19, the buy-sell price spreads often exceeded the minimum of 5 per cent during the winter of 2017.*

Figure 19: Spread between contract buy and sell prices



Source: ASX. Note: average spread at the end of each trading day for the nearest three-monthly futures contracts for Benmore on the ASX.

169. While this chart shows a material increase in measured bid-ask spreads (at the end of each trading day for the nearest three-monthly futures contract) in the winter of 2017 it is not obvious to us why this is regarded as reflecting a sub-optimal response

from market participants to the heightened uncertainty about the future path of wholesale prices in that period.

6.4.2.1 Rising bid-ask spreads is normal when uncertainty rises

170. The winter of 2017 was a period when the near-term level of wholesale prices was highly uncertain. Consequently, the value of a futures contact linked to those prices will also have heightened uncertainty. In this context, one expects bid ask spreads to be at elevated levels.

171. In order to see why, imagine that a financial institution was actually attempting to be a market maker at that time. That is, imagine that the financial institution was attempting to profit (cover its costs) by providing liquidity in the form of offers to both buy and sell futures contracts. The financial institution does this by being willing to accept trades that have the effect of temporarily exposing it to future electricity prices (making it either long or short on electricity prices) until it can negate that exposure by making the opposite trade with subsequent customers.

172. The financial institution is only willing to do this if they expect to earn a premium to cover them for the risk that they are exposed to. The way that they earn a premium is by buying at a lower price, on average, than they sell. That is, by having a positive bid-ask spread. Naturally the size of the bid-ask spread increases with the amount of risk that they are exposed to.

173. In the winter of 2017 that risk was elevated due to perceived volatility in future wholesale prices – implying a greater risk for any short or long exposure. The risk would also be exacerbated if the types of trades being taken by customers were asymmetric (e.g., mostly buy futures or mostly sell futures) causing the financial institution to take on a larger short/long position on electricity prices.

174. The above description is couched in terms of an independent financial institution trading in the hedge market in order to clarify the exposition of risk. It may be that independent financial institutions are only small players in electricity hedge markets. However, this exposition is still relevant because, at the trading margin, the same calculus is faced by all market participants. [36]

6.4.2.2 Bid-ask spreads are only one measure of liquidity

175. The report focusses on bid-ask spreads reported at the close of trading for the nearest 3 monthly base load contract. We have attempted to access this same data from

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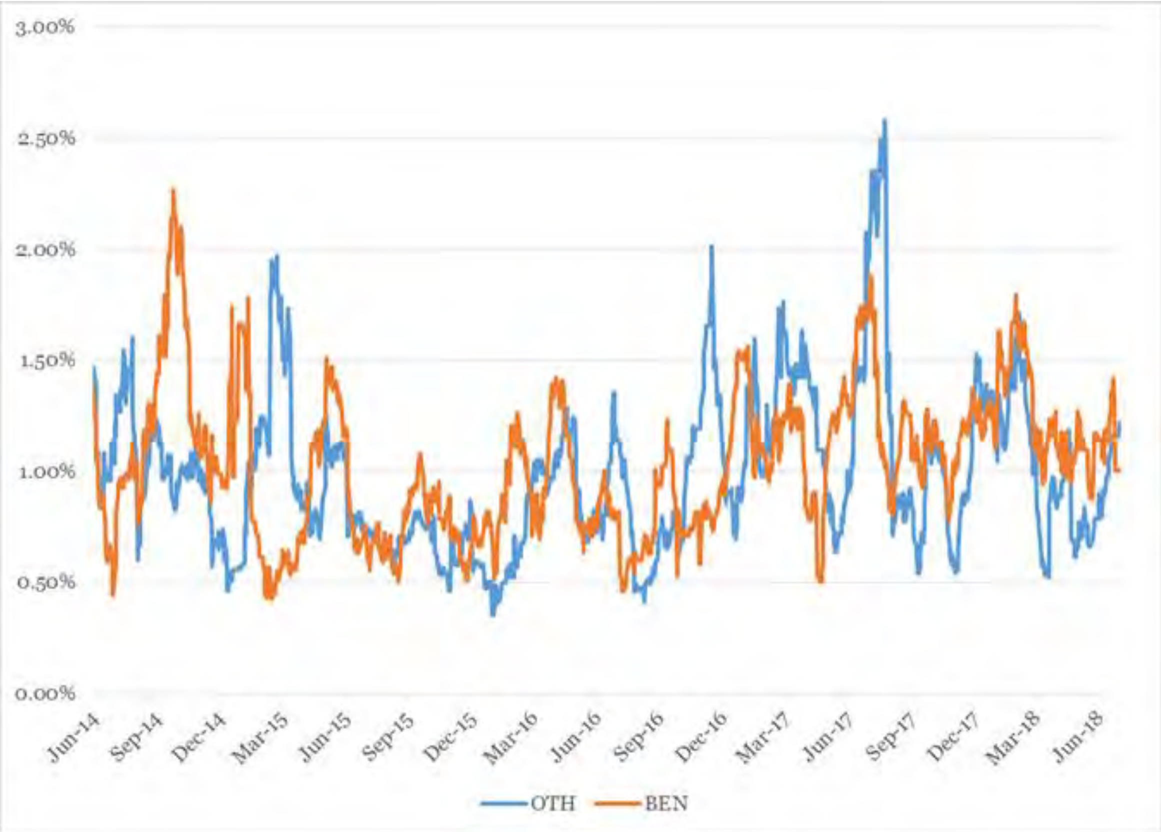
[36] Few, if any, market participants enter hedge markets solely to fix the price of their physical sales/purchases (as is discussed in detail in Appendix A.3). The vast majority will decide what level of hedging (be that more or less than 100%) to undertake based on their view of the market price of hedge contracts and their view of the risks of being under/over hedged. (Indeed, absent such conduct the market could not clear.)

Bloomberg but have been informed that Bloomberg does not currently keep such data beyond March 2017.

176. However, we have created a separate measure of 'liquidity' which is the intraday range in prices for quarterly base load contracts expressed as a percentage of the daily highest price. Intraday price volatility is a measure of illiquidity given that, in an illiquid market, buy/sell orders will tend to push prices up/down in order for the trade to be executed. (Indeed, intraday price volatility will reflect a market maker's bid ask spread if the market maker maintains that spread throughout the day and is not undercut by another market maker.)

177. In order for a day to have an observation it is necessary that the same contract is traded at least twice. If more than one contract is traded twice (e.g., a December 2017 and a March 2018 contract are both traded twice) then the average of the intraday percentage spread is taken. We have taken a 30 day trailing average of the resulting average daily intraday spread.

Figure 6-2: Daily intraday spreads for quarterly base load contracts (30 day trailing average)

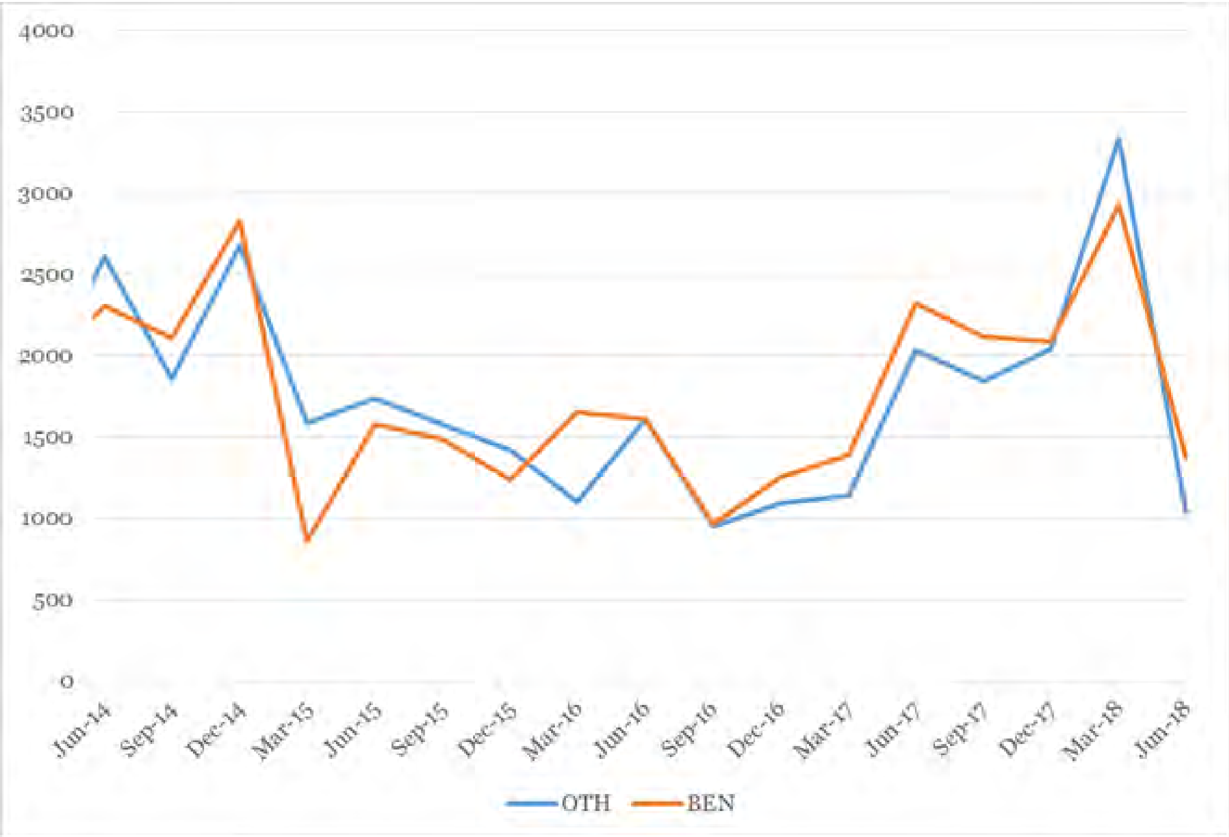


Source: Bloomberg, CEG analysis

178. This figure suggests that intraday price volatility was heightened in June and July 2017. However, it was not particularly unusual in the context of the 4 year period investigated.

179. Moreover, it is not the case that the heightened intraday volatility deterred trading in quarterly base load futures. Figure 6-3 below shows the trading in quarterly futures confined to only include trades that occurred one month prior to the beginning of the contract (e.g., for the September 2017 contract this only includes trades from 1 June 2017 onwards).

Figure 6-3: Quarterly futures trading volumes (one month ahead)



Source: Bloomberg, CEG analysis

180. It can be seen that the month ahead volume of trades of the September 2017 contract (trades from 1 June 2017) were high relative to most other months as were month ahead trades of the December 2017 contract (trades from 1 August 2017).

181. In summary, whatever the cause of the heightened bid-ask spreads in mid 2017 reported in Figure 19 of the Report, they did not:

- Result in unusual intraday price volatility; nor
- Depress actual traded volumes.

182. It is not obvious that the reported spike in bid ask spreads (at the "end of each day") in Figure 19 of the Report is symptomatic of any underlying problem in the functioning of the hedge market.

7 Price levels and trends

7.1 Summary

183. A cross check on the conclusion that the wholesale and retail markets are competitive and working well is to compare prices paid by NZ consumers with those in other countries. While not necessarily definitive, because cost conditions can vary, it is useful as a means of identifying any 'red flags'.

184. To that end, we have carried out analysis of price levels and price trends in New Zealand's energy market, and make the following key observations.

- Price levels

  a. Residential prices in New Zealand are lower than average for the IEA member countries when adjusted using Purchasing Power Parity (PPP);

  b. New Zealand's residential-to-industrial-price ratio is in line with the ratios observed for other IEA members when consumption by the Tiwai Point smelter is removed from 'industrial customers';

  c. Energy prices in Wellington are lower than average compared to capital cities in the EU for which data is available.

- Price trends

  a. Price increases in New Zealand are lower than those observed in Australian cities that are part of the National Electricity Market (NEM);

  b. Electricity price changes are consistent with changes in income.

7.2 Analysis of price levels

7.2.1 Residential prices in New Zealand are low when compared internationally

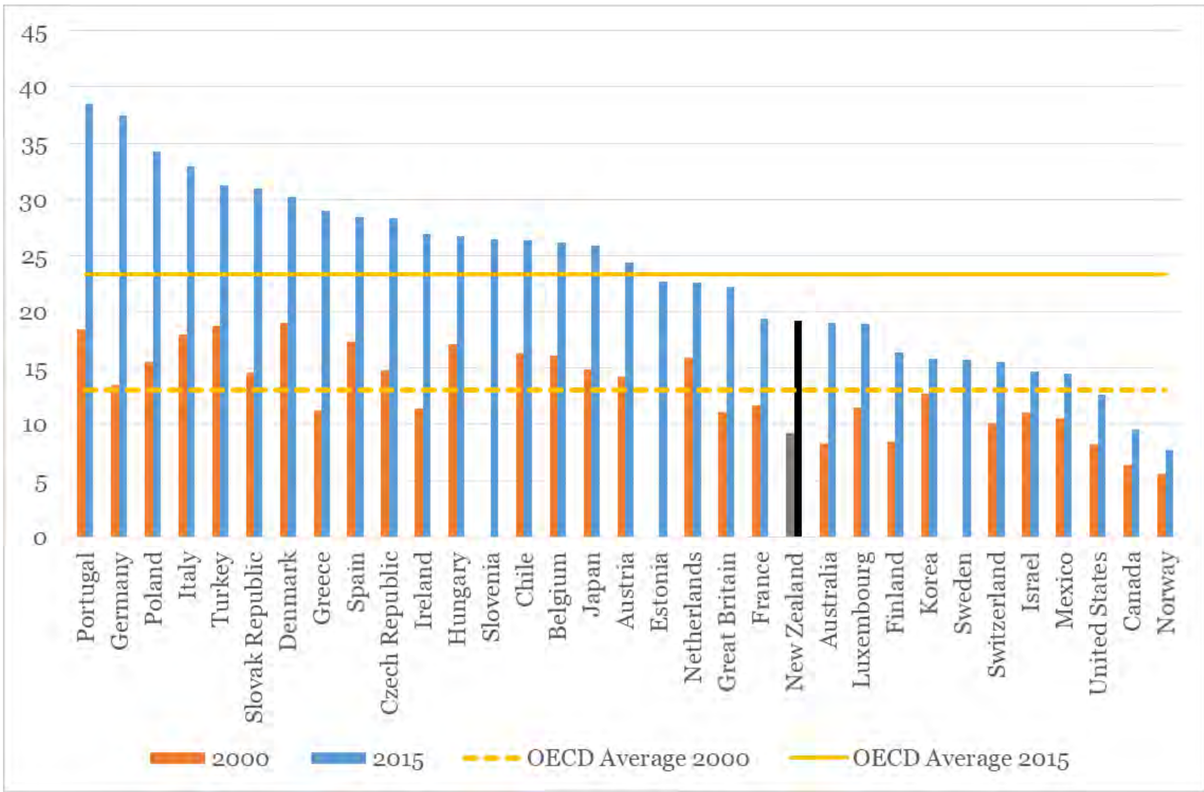
185. International comparisons of prices at market exchange rates are problematic because they fail to take into account the purchasing power of each currency. A more appropriate comparison would involve calculating prices converted with purchasing power parities, which can be found in Table 2e of the IEA's Electricity Information report.[37]

[37] IEA, Electricity Information (2017 edition), p. IV.9, Table 2e.

186. We note as well that the IEA reports estimates for the “OECD Total” in its Electricity Information report, but these estimates do not appear to be simple averages across IEA members. If it is the case that the “OECD Total” estimate refers to a weighted average across IEA members, then this estimate is likely to be disproportionately influenced by prices in larger countries with characteristics that may not be directly comparable to New Zealand.[38] As such, our analysis compares New Zealand’s prices against the simple average of IEA members instead of using the IEA’s “OECD Total” estimates.

187. Figure 7-1 shows the 2015 household retail prices for IEA members, converted across currencies using PPP. Our analysis shows that New Zealand’s residential electricity price is ranked 12th lowest among 33 countries in 2015, with a price of US 19c/kWh when converted using PPP. This price level is lower than the simple average household electricity price across IEA members (US 24c/kWh).

Figure 7-1: IEA Electricity prices for households (2015 Data, US cents/kWh, PPP)



Source: IEA Energy prices and taxes, CEG analysis; Note: Data is missing for Australia, Korea and Spain.

38 The IEA did not confirm how it derived its “OECD Total” estimate.

7.2.2 New Zealand's residential-to-industrial-price ratio is the median when compared internationally

188. New Zealand's basic metal sector – predominantly the New Zealand Aluminum Smelter at Tiwai Point – takes up 37% of industrial electricity consumption at a price that is well below that of the other industrial sectors, as seen in Table 7-1. The lower prices at the Tiwai Point smelter are not, in our view, an appropriate reflection of the industrial average price that should be used when comparing New Zealand to other jurisdictions.

Table 7-1: Industrial Electricity prices (2015 Data)

Non-residential Sector	Price (US $ PPP /MWh)	Consumption (GWh)	% of total consumption
Commercial	11.81	9,394	35%
Agriculture, Forestry & Fishing	13.47	2,669	10%
Mineral and Petroleum Extraction	8.39	447	2%
Food Processing	9.17	2,313	9%
Wood Pulp, Paper and Printing	6.91	2,677	10%
Chemicals	6.02	738	3%
Basic Metals	6.02	6,550	25%
Building and Construction	14.24	1,676	6%
Industrial average	9.75	26,463	-
Industrial average excluding the Smelter	10.98 (↑13%)	19,913	-

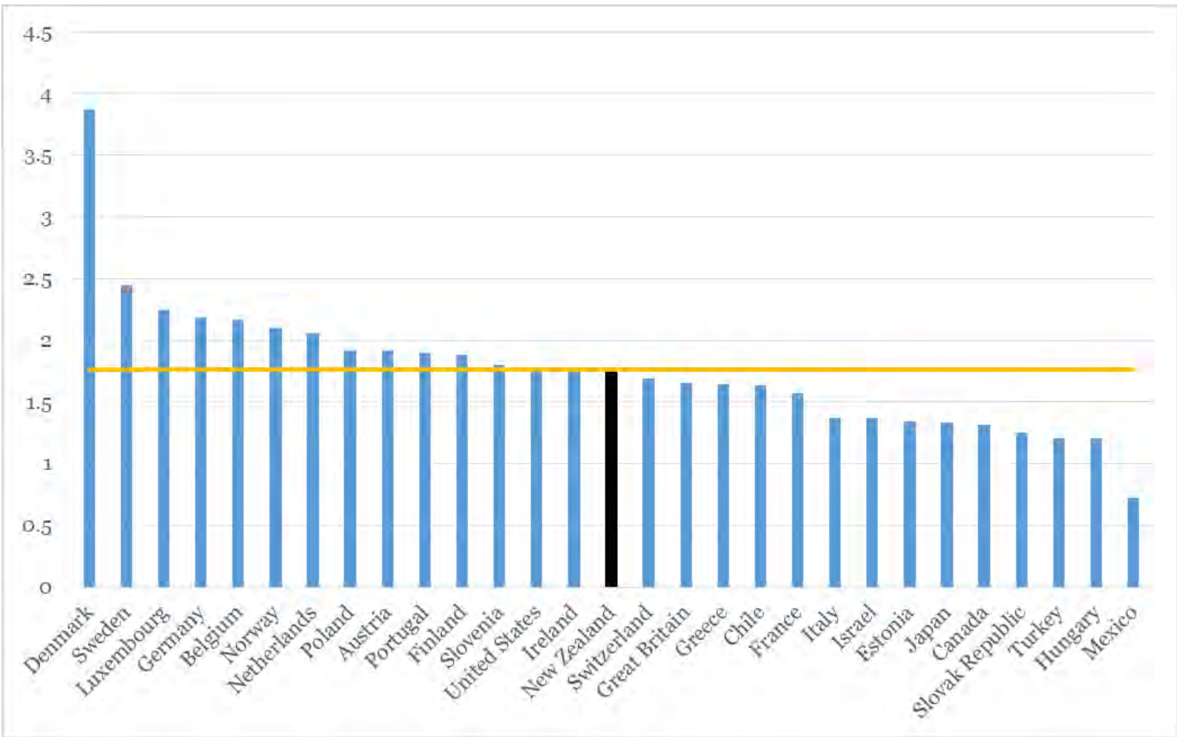
*Source for PPP: World Bank; Source for price: MBIE, Energy Prices, Nominal annual average fuel prices; Source for consumption: MBIE, Electricity graph and data tables, Table 2: Yearly Electricity Generation, Consumption, & Lines Losses (GWh); CEG Analysis. * MBIE's consumption data lists agriculture, forestry & fishing as a separate category from the rest of the industrial sector. We combine these categories in order to maintain consistency with price data. ^ We assume that the "Building and Construction" category in MBIE's pricing data is equivalent to the "Other Minor Sectors" category in MBIE's consumption data.*

189. MBIE data suggests that removing the Tiwai Point smelter increases the estimated industrial average price by 13% (from US PPP 9.75 to 10.98).

190. According to the IEA, the price for New Zealand residential customers in 2015 divided by the price for industrial customers in 2014 is at approximately 1.97 before making an adjustment to remove the impact of the smelter. This ratio is marginally higher than the average level among IEA members (1.76).

191. After making the adjustment, the NZ ratio reduces to 1.74. As shown in Figure 7-2. This ratio is now in line with the average, and ranks 15th among 29 IEA member countries with data available.

Figure 7-2: IEA Residential/Industrial price



Source: IEA, MBIE, CEG analysis; Note: Data is missing for Australia, Korea and Spain. The Smelter has been excluded in the analysis. Specifically, the industrial average price for New Zealand is the consumption portfolio weighted average price excluding the Basic Metal category.

7.2.3 Energy prices in Wellington are lower than in most other capital cities in the EU

192. New Zealand faces relatively high network costs as a result of its low population density and its long, stringy geography. Both factors necessitate the construction of a more extensive network in order to serve the entire population. These increased costs will be passed through to the final retail price, which tends to make New Zealand prices higher in country-to-country comparisons of retail prices.

193. One possible alternative approach would be to restrict the comparison to Wellington and other capital cities in the EU. This could help to ameliorate some of the geographic heterogeneity observed among the countries.

7.2.3.1 Capital city data

194. In an October 2017 report, the Agency for the Cooperation of Energy Regulators (ACER) and Council of European Energy Regulators (CEER) analysed the breakdown of the standard incumbent electricity bills available to household consumers in EU

capital cities based on an annual consumption profile of 3,500 kWh for electricity at the end of 2016.[39]

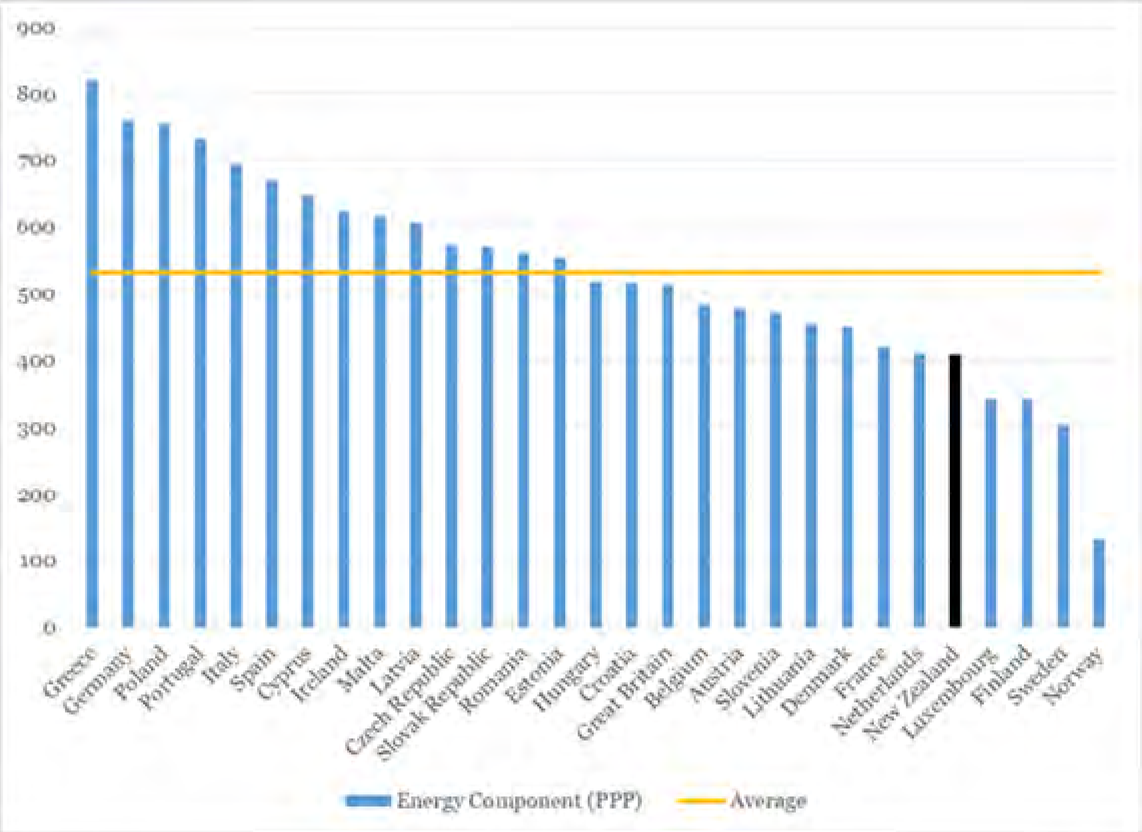
195. Using this data from the EU, we compare the combination of yearly electricity cost per customer in the EU capital cities to the capital city Wellington based on an annual consumption profile of 3,500 kWh. This involves making a number of adjustments to the MBIE survey in order to maintain comparability with the EU estimates, such as converting the data to the same currency using PPP exchange rates.

7.2.3.2 Results

196. Figure 7-3 below compares the MBIE figure (adjusted as noted above) with the estimates from EU countries. Figure 7-3 shows that the MBIE estimate for Wellington is slightly below the simple average for the EU estimates.

39 ACER and CEER, Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016, October 2017.

Figure 7-3: EU capitals and Wellington electricity bills (US$ PPP)



Source: MBIE, ACER, CEG analysis; Note: Electricity bills are based on an annual consumption profile of 3,500 kWh.

197. According to this metric New Zealand is at the bottom end of the sample.

7.3 Analysis of price trends

7.3.1 New Zealand has had lower price increases than Australia

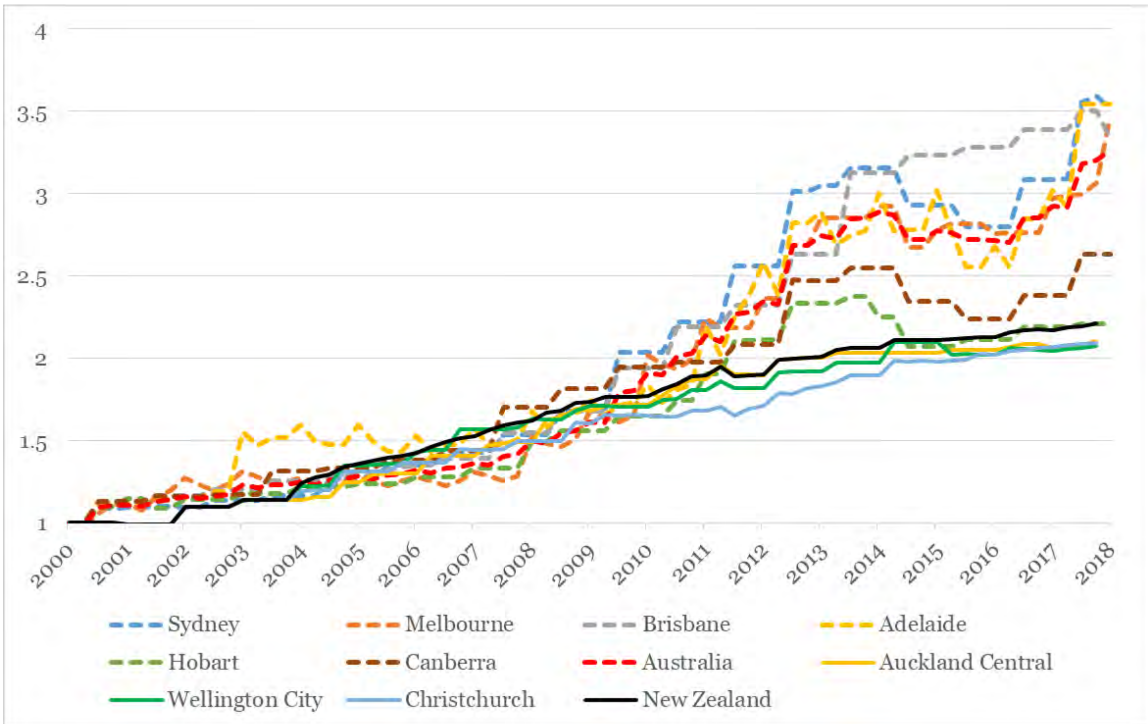
198. We obtain New Zealand's historical energy prices using MBIE's Quarterly Survey of Domestic Electricity Prices (QSDEP). The QSDEP monitors tariffs publicly advertised in the retail electricity market to measure of how the residential electricity tariffs have changed over time.[40] For each retailer in each town or city, the Ministry calculates an average price based on the QSDEP model household based on data sourced from Consumer Powerswitch.

[40] MBIE, Electricity cost and price monitoring, http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices/electricity-prices

199. Australia does not have a historical series of residential electricity retail price in dollar term. Instead, the Australian Bureau of Statistics (ABS) provides the % change in electricity prices among National Electricity Market (NEM). Hence, we compare the electricity price change based on the ABS price level index from 2000 for NEM cities (Sydney, Melbourne, Brisbane, Adelaide, Hobart and Canberra)[41].

200. Figure 7-4 shows the pricing for both New Zealand and Australian cities, setting the price in 2000 as 1. We observe that the electricity price increment in the capital cities in New Zealand is below the trend for both Australia NEM capital cities and country average since 2000.

Figure 7-4: Australia (NEM) and New Zealand price index



Source: MBIE, ABS, CEG analysis.

7.3.2 Electricity price changes are consistent with changes in income

201. According to NZ Stats,[42] the weekly median household income increased from $690 in 2004 to $1208 in 2017,[43] which is a 75% increase over 13 years. This is equivalent

41 ABS, CPI: Group, Sub-group and Expenditure Class, Index Numbers by Capital City, http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/6401.0Mar%202018?OpenDocument

42 NZ Stats, Household income by region, household type, and source of household income

43 The MBIE data only extends as far back as 2004.

to a 34% increase in real terms. This compares with a 22% increase in real GDP per capita, as well as a 34% increase in the real minimum wage.

202. The New Zealand average price prior to 2004 is drawn from MBIE[44]. Quarterly data is available for New Zealand average and 40 town and cities from 2004 onwards, based on MBIE Quarterly Survey of Domestic Electricity Prices (QSDEP).

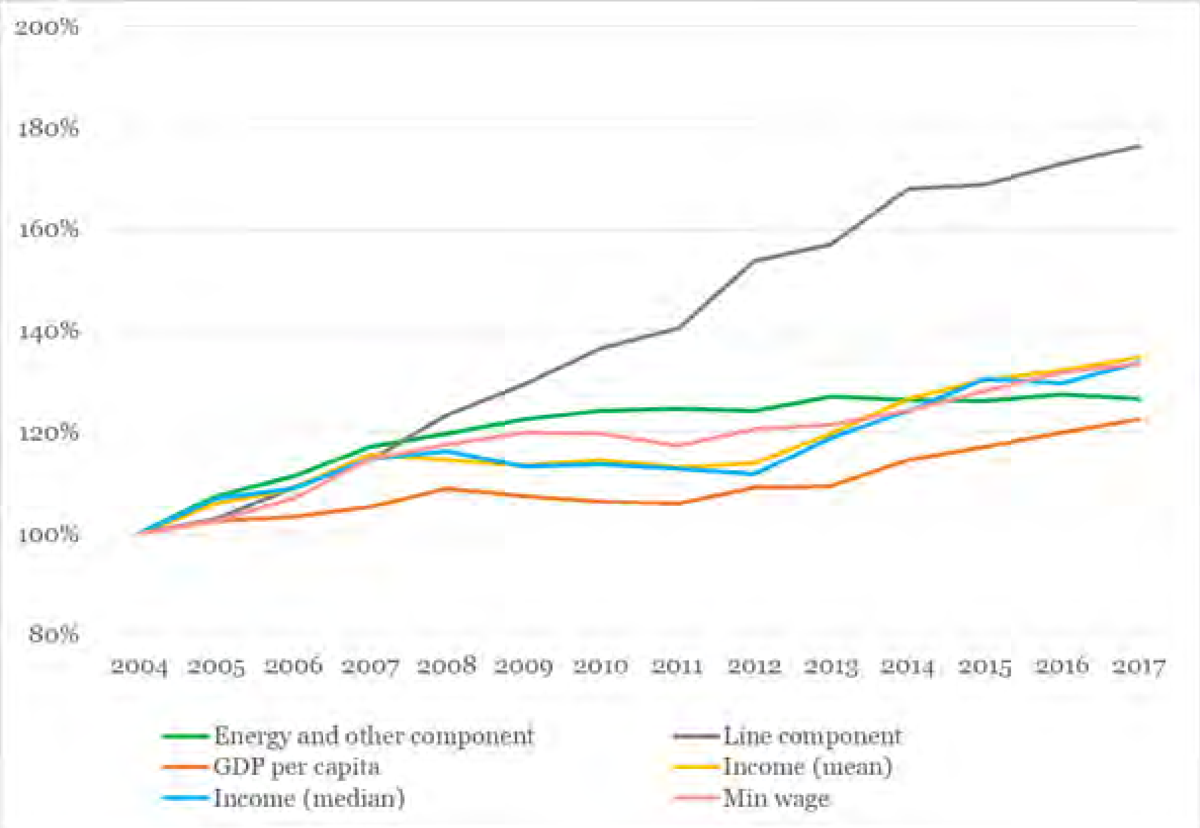
203. The electricity price change since 2004 is broadly in line with the change in household income, increasing from 14.85 to 20.04 NZ cents (35% increase) in real terms during the same period.

204. Figure 7-5 shows the historical electricity price series decomposed into the Lines component and the Energy and other components, along with changes in domestic GDP per capita, household income (mean and median), and the minimum wage. The series have all been indexed to 1 in year 2004.

205. We observe that although the line component of energy retail prices appears to have outstripped the growth in other income measures over the 2004-2017 period, this is not the case with the price trend for Energy and other components, which have remained consistent with the domestic income measures.

44 MBIE, Energy Prices, Nominal annual average fuel prices - Residential electricity

Figure 7-5: NZ electricity price and household income (in real terms)



Source: MBIE, NZ Stats, CEG analysis.

Table 7-2: Summary of method and findings

Comparisons	Findings
Price levels	
Residential prices	New Zealand's residential electricity price is 12th lowest among 33? IEA countries (for which we have data) in 2015, with a price of US 19c/kWh when converted using PPP. This price level is around 20%? lower than the simple average household electricity price across IEA members (US 24c/kWh).
Residential-to-industrial price ratio (used to gauge whether excessive cross-subsidisation is occurring, if any)	New Zealand's residential-to-industrial price ratio is 1.74 after omitting the Tiwai Point smelter from the industrial price estimate. This is in line with the 1.76 average ratio observed among IEA members, and is 15th among 29 countries with data available.
Prices in capital cities	The MBIE estimate for Wellington is slightly below the simple average for the EU estimates. The countries with lower prices are dominated by eastern European countries, which may be less comparable with New Zealand. Energy retail prices in Wellington are lower than the average observed in the EU capital cities.
Price trends	
New Zealand price trends compared to Australian price trends	The electricity price increment in the capital city in New Zealand is below the trend for both Australia NEM capital cities and country average since 2000.
Electricity price trends and trends in income measures	Although the line component of energy retail prices appears to have outstripped the growth in other income measures over the 2004-2017 period, this is not the case with the price trend for wholesale and other components, which have remained consistent with the domestic income measures.

8 Price dispersion and discrimination

8.1 Summary

206. A separate issue is the level of price dispersion in retail markets (as opposed to the average price level). Electricity retailing, like most other consumer markets, is characterised by customers with varying degrees of engagement. Consequently, we expect to observe, as we do in most markets, pricing strategies aimed at offering:

- very low (close to marginal cost) prices for new price conscious customers; and
- higher markups to other existing customers (although noting that the higher the markup the more likely otherwise 'inactive' customers will become 'active').

207. The price dispersion that is caused by the existence of disengaged customers is sometimes viewed as a problem by regulators. It is seen as inconsistent with the 'law of one price' that would be observed in an 'idealised' perfectly competitive product markets with 100% well-informed active customers. There are two proposed solutions to this perceived problem which we examine. Namely:

- Banning price discrimination;
  - For example, banning discounting aimed at switching/engaged customers; and
- Increasing the proportion of engaged/well-informed customers.
  - For example, requiring suppliers to directly inform customers of lower cost tariffs or to automatically move them to lower cost tariffs, etc.

208. It is not obvious that either of these policies will result in lower prices on average across all customers.

8.1.1 Banning price discrimination will result in higher prices for all customers

209. In most markets there are customers who pay more/less attention to the prices that they are being charged and who will put more/less effort into ensuring that they are receiving the best possible deal. In this circumstance, sellers will attempt to discriminate between these customers and charge a lower/higher price to the more/less active shoppers.

210. It is critical to understand that there is an inter-relationship between the higher/lower prices charged to 'sticky'/'slippery' customers. Specifically, the lower prices to 'slippery' customers constrain the higher prices to 'sticky' customers. This is because there is a continuum between 'slippery' and 'sticky' customers. The bigger the discounts on offer in the market the more likely a 'sticky' customer is to become a

‘slippery’ one. If the low prices are ‘taken away’ (e.g., via a ban on discounting) then the high prices would very likely be higher still. That is, ‘sticky’ customers would become even more ‘sticky’ if competitors discounted prices were not being offered in the market.

211. That is, the concern that firms tend to charge higher price to their existing customers than potential new customers (or customers threatening to leave) is misplaced. In reality, this conduct makes customers better off – including sticky customers. In reality:

a. Competition results in greater price discrimination in favour of active shoppers than monopoly (or duopoly). That is, the stronger is competition the more accentuated is the practice of discounting. In other words, the ‘issue of concern’ is actually a sign of strong competition;

b. Average prices would be higher if a single price was offered to all customers (e.g., if regulation was imposed to that effect). In other words, if a regulator attempted to ‘fix’ the ‘problem’ of price dispersion it would make average prices higher.

c. Moreover, not just average prices but also undiscounted prices (i.e., prices paid by inactive shoppers) would typically be higher absent price discrimination. That is, the apparent ‘victims’ of price discrimination (i.e., inactive shoppers) are actually beneficiaries – in the sense that their prices would rise if discounting were not allowed;

d. Price discrimination in favour of active shoppers is not a sign that excess profits are being earned. Moreover, consistent with points b. and c. above, profits would be higher with if discounting was not possible. That is, regulation to prevent discounting would be a ‘boon’ to retailers; and

e. The theoretical conclusion in point d. is supported by strong empirical evidence from the UK.

8.1.2 A more informed customers base is good for newly informed customers but bad for all other customers

212. The impact of policies aimed at reducing switching costs is more ambiguous. If successful these policies will have short run effects that benefit the customers who become more engaged and, as a result, shift to tariffs closer to marginal cost. However, with a higher proportion of active customers the competitive price for these customers will rise (because the probability that they become profitable inactive customers in the future falls). Thus, customers who would have been active anyway will be worse off – as will customers who remain inactive.

213. In the long run, a smaller fraction of profitable inactive customers will also induce market exit by retailers and a reduction in competition. This will also tend to raise prices. Indeed, it is useful to note that, in the extreme, a universally perfectly

informed and engaged customer base would (somewhat counterintuitively) likely lead to monopoly/ collusive oligopoly market structure and all customers would lose as a result.

8.2 Price dispersion in a market with active and non-active customers

8.2.1 'Sticky' customers and price dispersion are ubiquitous in competitive markets

214. In most markets there are customers who pay more/less attention to the prices that they are being charged and who will put more/less effort into ensuring that they are receiving the best possible deal. In this circumstance, sellers will attempt to discriminate between these customers and charge a lower/higher price to the more/less active shoppers.

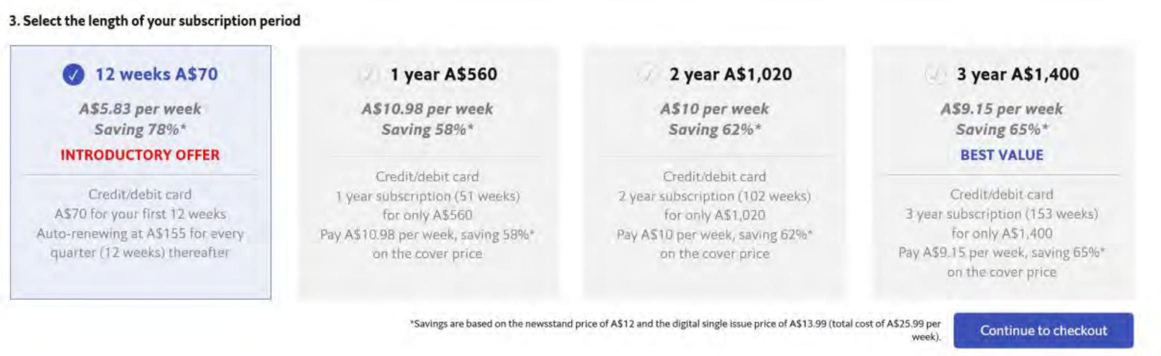
215. This is a form of price discrimination that is commonly observed in competitive markets. In order for it to be practiced successfully sellers require a method for distinguishing between the most and least price sensitive customers (which often will be the same customer just purchasing at different times). Typically this is achieved by offering a discount to new customers switching from other suppliers or actively threatening to switch to new suppliers. These customers will receive low prices with profit margins close to zero.

216. Customers who are not actively pursuing the lowest prices will tend to end up paying higher prices. For example, a customer who actively pursues the lowest price at one time may be signed to an 'evergreen' contract (perpetual but with no exit fees). That customer may be offered a material discount to the base tariff in the first year after switching. However, unless the customer actively engages with the retailer at the end of that year the customer will cease to earn those discounts and pay the higher price until they once again re-engage with the market.

217. The same basic approach is used in a wide range of retail markets. For example, in telecommunications customers typically sign onto evergreen contracts. However, falling costs (due to technological change) only get transmitted into lower prices (or improvements in offering in the form higher free download limits etc.) if/when a customer actively engages with suppliers again.

218. Similarly, magazine subscriptions are typically advertised on a heavily discounted basis for a given period with the prices reverting to 'standard rates' thereafter. This practice is applied by the Economist Magazine, which presumably has one of the better informed/engaged customer groups when it comes to price discrimination practices. By way of example, the Economist Magazine was offering a 73% off 'introductory offer' on Google on 20 June 2016.

Figure 8-1: Introductory offer on the Economist Magazine



Source: "https://subscription.economist.com/offers/subscription" accessed on 20 June 2016.

219. If one selects the $45 (78% discounted) 12 week introductory offer then, after 12 weeks, the subscription auto-renews at $155 – unless the subscriber cancels the subscription and re-subscribes at a new discounted price.

220. Such introductory offers are common across a range of industries – from banking to gym memberships. When the introductory offer runs out customers revert to the higher 'non-discounted' offering. Unless the customer re-engages with the supplier or a competitor they will stay on that higher priced subscription. However, if the customer does, or threatens to, switch supplier (cease subscription) they can commonly enjoy a discounted price again.

221. The OECD has noted in the context of financial (and postal and telecommunications) markets that the same strategy of 'discount to win then revert to higher prices' is common. The OECD also notes (and as we shall discuss further below) that switching costs can promote fierce competition to win customers.[45]

> *Switching costs represent therefore an important source of market power in retail banking. The competitive effects of switching costs are twofold. On the one hand, they lead to the exercise of market power once banks have established a customer base which remains locked in. On the other hand, they induce fierce competition to enlarge the customer base. In this sense there is a strong element of competition for the market. Thus, switching costs may lead banks to offer high deposit rates initially to attract customers and to reduce them subsequently, when consumers are locked in. This pattern seems consistent with empirical observations and stylized facts.* [37]
>
> [37] See Matutes and Padilla (1994) and also Degryse (1996) for similar conclusions for postal or telephone services.

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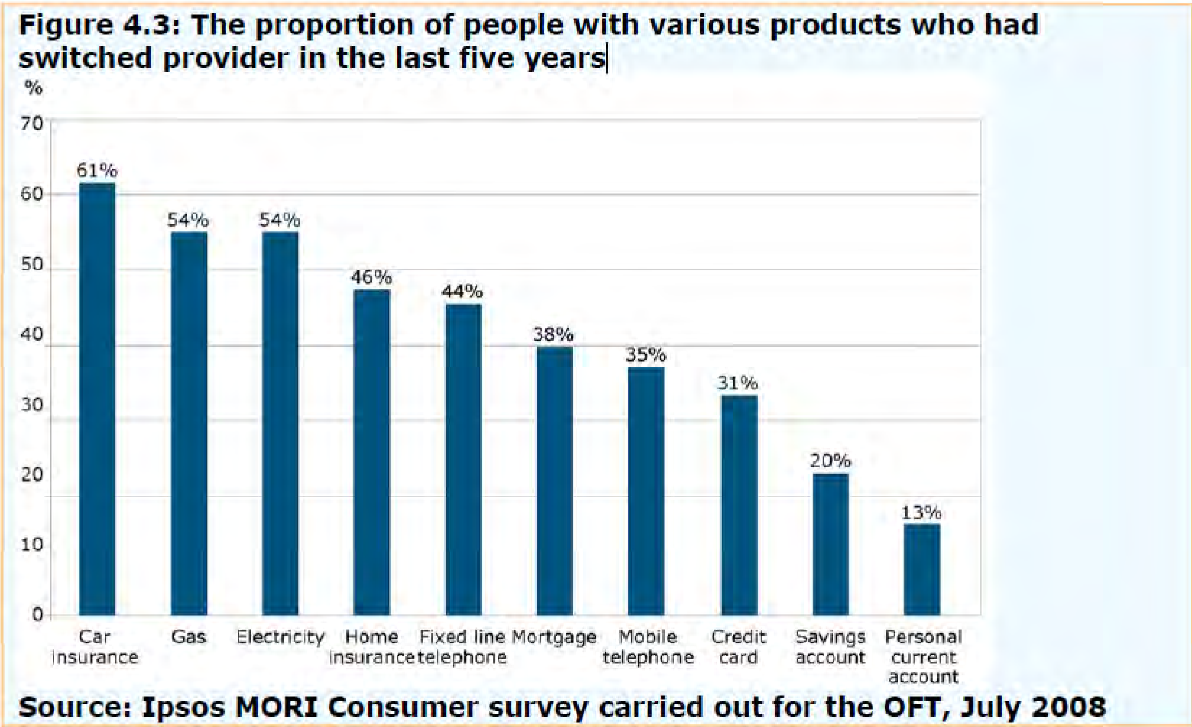
[45] OECD, Competition and Financial Markets, Key Findings, 2009.

222. The following figure, published by Office of Gas and Electricity Markets (Ofgem) in 2008, shows switching rates by product. All of these products will have an element of 'ongoing subscription' where suppliers commonly use an initial discount to attract customers and subsequently the discount lapses absent sustained engagement by the consumer. It can be see that switching rates were higher for retail electricity suppliers than for most other products surveyed.

Figure 8-2: Switching rates



223. It is not just in consumer markets where this conduct is observed it is also in business markets. For example, in professional services (e.g., legal advisers), successful suppliers will build a level of trust with clients and the clients a level of comfort with their existing advisers. As a result, the client faces a 'switching cost' in moving to a new adviser. This means that existing providers can, and will, raise the prices charged to the client above the prices that they would offer to work for new clients.

224. Such competitive conduct is ubiquitous in all markets characterised by 'sticky customers' – which is most markets. That is, in markets where customers, having made a decision to take a service from a supplier, face some form of 'switching cost' (be that monetary or psychological) in moving to a new supplier.

225. In these markets, suppliers will find whatever mechanism are available to offer low prices to customers currently served by their competitors (or at imminent risk of being 'stolen' by competitors).

8.2.2 Does price discrimination to sticky customers raise or lower prices?

226. It is critical to understand that there is an inter-relationship between the higher/lower prices charged to 'sticky'/'slippery' customers. Specifically, the lower prices constrain the higher prices. If the low prices are 'taken away' (e.g., via a ban on discounting) then the high prices would very likely be higher still.

227. That is, the concern that firms tend to charge higher price to their existing customers than potential new customers (or customers threatening to leave) is misplaced. In reality, this conduct makes customers better off – including sticky customers. In reality:

   a. Competition results in greater price discrimination in favour of active shoppers than monopoly (or duopoly). That is, the stronger is competition the more accentuated is the practice of discounting. In other words, the 'issue of concern' is actually a sign of strong competition;

   b. Average prices would be higher if a single price was offered to all customers (e.g., if regulation was imposed to that effect). In other words, if a regulator attempted to 'fix' the 'problem' of price dispersion it would make average prices higher.

   c. Moreover, not just average prices but also undiscounted prices (i.e., prices paid by inactive shoppers) would typically be higher absent price discrimination. That is, the apparent 'victims' of price discrimination (i.e., inactive shoppers) are actually beneficiaries – in the sense that their prices would rise if discounting were not allowed;

   d. Price discrimination in favour of active shoppers is not a sign that excess profits are being earned. Moreover, consistent with points b. and c. above, profits would be higher with if discounting was not possible. That is, regulation to prevent discounting would be a 'boon' to retailers – enforcing what would, from their perspective, be a desirable collusive agreement.

228. This conclusion is strongly supported in the economic literature and also in empirical case-studies. However, it is nonetheless, in some ways, counterintuitive. An intuitive, but typically wrong, logical chain of reasoning is as follows:

   - Informed and active customers currently benefit by receiving lower discounted prices;
   - If retailers are prevented from offering discounted prices then, if they want to continue to compete for new customers, they will have to offer the same lower prices to all their existing customers too;
   - Therefore, banning discounts will lower prices to existing (inactive) customers because the lower prices demanded by active shoppers will be shared by all customers.

229. The problem with the above logical chain is in the emphasised element. Taking away the least cost/most targeted method of competing for new customers will reduce suppliers' desire to compete for new customers. Put simply, they will not want to compete as vigorously for new customers because it will be more costly to do so (i.e., lower prices will have to be offered to existing customers). This, in turn, will entrench each suppliers' 'grip' on their existing customer base (because other suppliers have lost their most effective weapon for 'stealing' customers). As a result, all suppliers will find it easier (not harder) to raise prices to their existing customers.

230. The fatal flaw with the logical propositions that we set out at paragraph 228 above can be informally illustrated by breaking up the analysis into first and second round effects. In the first round, discounted prices are removed from the market and we are left with the higher undiscounted prices - active shoppers are worse off and inactive shoppers are no better or worse off. What matters is what comes next. Specifically, do retailers lower, raise or leave unchanged their undiscounted prices?

231. The answer in the theoretical economic literature is that, except in very unusual circumstances, the undiscounted price increases. That is, all customers are worse off – including the inactive customers. The reason for this is that the loss of discounting as a competitive weapon makes all retailers more secure 'owners' of their existing customer base. This raises the profit maximising price that they can charge them. Thus, banning price discrimination based on active/inactive shopping profiles actually raises prices to all customers – both active and inactive customers.

232. The logic expressed in paragraph 228 would be correct if there was a binary distinction between 'active' and 'inactive' customers – with the former never at risk of switching even if the price gains were enormous (e.g., in the thousands of dollars). However, this is not realistic. In reality the number of active consumers will be a function of the potential savings available from switching. If savings were $1,000 per year then it is likely that close to 100% of currently 'inactive' consumers would become active. As Ofgem has noted:[46]

> *"the single largest factor affecting a supplier's churn rate is its relative price"*

233. Ernst and Young has also reached the same conclusion in the UK market.[47] The Australian Energy Market Commission (AEMC) surveys also place the value of discounts as the most important factor in customers switching.[48]

234. Retailers would obviously be well aware of any such a relationship. Given that competition for active customers will typically be based on marginal cost, this

46 Ofgem, Energy Supply Probe - Initial Findings Report, 6 October 2008, para 4.14

47 Ernst and Young, Cash on the meter, electricity and gas utility receivable, 2009.

48 AEMC, 2016 Retail Competition Review, p.70

relationship determines how much above marginal cost they can profitably set their 'standard' tariff. If they set their standard tariff too high then they will turn too many inactive customers into active customers and the price rise will be unprofitable.

235. This result has been set out informally above. However, it is a strong result from the theoretical literature which we summarise in section 8.2.4 below. This theoretical result is borne out by the experience of regulation of retail tariffs in the UK as set out in section 8.3 below.

8.2.3 The intuition behind the theoretical literature

8.2.3.1 Why an intuitive understanding of the literature is important

236. Simshauser and Whish-Wilson (2015)[49] have taken a broad look at economic theory on price dispersion/discrimination and have found *"price dispersion will increase, not decrease, as competition intensifies … and price dispersion is common in capital-intensive industries and deregulated markets such as … energy."* The literature covered by Simshauser is broad and covers the full range of economic forces leading to divergences from marginal cost based prices in competitive industries – from joint production costs[50] in the competitive beef industry to competition with differentiated products.[51] Simshauser and Whish-Wilson demonstrate that price dispersion and discrimination is not just common, but is, in fact, the norm in competitive markets.

237. However, in this report we focus in detail on the relevant part of the literature that deals with competition between suppliers of homogenous goods in markets with less than perfectly informed customers (or, equivalently, customers who face some form of 'search' or 'switching' costs). Most of the literature that we cover is also referenced in Simshauser and Whish-Wilson. However, our objective is to explain both intuitively and rigorously the nature of competition in such markets as set out in the literature.

238. We feel this is important because some of the predictions of the literature are not, immediately, intuitive. For example, the conclusion that all customers, including customers not actively shopping around, are better off if firms are allowed to 'exploit' customer switching costs by charging higher prices to inactive shoppers. However, this conclusion does become intuitive once the nature of competitive dynamics is understood in these markets.

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49 Simshauser, P. and Whish-Wilson, P. (2015), "Reforming reform: differential pricing and price dispersion in retail electricity markets," Working paper June 2015

50 Simshauser, P. and Whish-Wilson, P. (2015), p. 6.

51 Simshauser, P. and Whish-Wilson, P. (2015), p. 8.

239. This is why we recommend policy makers spend some time understanding this literature before making decisions. We note that Ofgem clearly did not do so before it put in place regulations the effect of which was to limit dual pricing (discounting to active shoppers). The effect of this was consistent with the predictions of the literature in that prices rose to all customers (including the inactive shoppers).

8.2.3.2 A simple stylised example

240. Consider a simple model where there are two customers and two firms – with each firm serving one customer. For simplicity, let the marginal costs supply be zero for each supplier. Let customers face a $1 switching cost in that, other things equal, each customer prefers to be served by their existing supplier[52] and would require a slightly more than a $1 price cost saving to switch.

241. If the firms must charge a uniform price then the equilibrium price (without collusion) will be $2. To see this, imagine both firms start by pricing at marginal cost (zero in this example). This cannot be an equilibrium because if Firm A is charging zero then Firm B can charge $1 without losing its customer (due to the $1 switching costs). This establishes that each firm will always charge at least $1 and make $1 profit (before accounting for fixed costs).

242. However, if Firm A is charging $1, the profit maximising price for Firm B is $2. This raises the revenue from the existing customer without causing them to switch (the price differential still does not exceed $1). Firm A can respond by raising its price to $2 (in which case it earns of profit of $2 on a single customer) or reducing its price to $0.99 (in which case it earns a profit of $0.99 on both customers). Raising price to $2 is the dominant strategy.

243. However, price rises above $2 are not profitable because if Firm B raises price above $2, say to $3. Now Firm A will be more profitable if it offers a lower price rather than price matching. For example, at a price of 1.99 (a $1.01 discount to Firm B's price) Firm A steals Firm B's customer (because the price differential is greater than $1). Firm A has profits before fixed costs of 3.98 (=2*$1.99) which is more than it if price matched (=1*$3.00). This is true for all Firm B prices in excess of $2.00. Therefore, $2.00 is a stable "Nash" equilibrium.

244. In this simple example with uniform pricing, the profit maximising mark-up on marginal cost ($2) is double the switching costs of customers ($2=2*$1). However, it is relatively easy to demonstrate that if firms can offer price discounts to new customers relative to existing customers then this will lower prices for all customers.

52 This might be because they prefer the service but it might simply be because of the actual/perceived 'hassle' of changing suppliers.

245. Let us run through the same logical thought experiment as above but this time allow each firm to set two prices – one for existing customers and one for new customers. Once more, imagine both firms start by pricing at zero (=marginal cost) to all customers. This cannot be an equilibrium for the prices charged to existing customers because, as set out above, these customers will only switch if the price differential exceeds $1. Therefore, the minimum price that each firm will charge their existing customers is $1 (a mark-up of $1 on marginal cost).

246. However, unlike the scenario with uniform pricing, this also the final equilibrium price. If Firm B raised price to its existing customer above $1 then Firm A would be able to profitably offer Firm B's customer (without offering their own customer) a greater than $1 discount thereby inducing them to switch (and vice versa). That is, allowing Firm A to price discriminate means that Firm A can (and will) be more **aggressive in its pursuit of Firm B's customers**. The same is, of course, true of Firm B. This then constrains the prices that each firm can profitably charge to their existing customers.

247. For some readers this will be a counterintuitive result. Giving firms the flexibility to discriminate against their existing 'sticky' customer base actually results in lower prices to the 'sticky' customers. However, this is a more intuitive result when it is recognised that that the flipside is that price discrimination gives firms the flexibility, and incentive, to discriminate *in favour of competitors' customers* by offering them prices close to marginal cost. With all firms doing this to their competitors' customers then all firms are limited in the markup on marginal cost they can successfully charge to their existing customers.

8.2.3.3 Realism of the example

248. In the above example, a retailer's ability to set high prices to their existing customers is constrained by the prices that their competitors are willing to offer those customers. The way this is modelled in this simple example is that each of the 'two' customers has a unique switching cost and will change suppliers as soon as the price difference (between their supplier's offer and the competing supplier's discounted offer) exceeds their switching cost.

249. This formalised modelling may be criticised on the basis that it does not reflect reality - in that most customers do not have a well-defined 'switching cost' and are not constantly monitoring retail prices to compare these to their switching costs. However, this would be an unreasonable criticism in that all this stylised example really relies on is that a customer is more likely to switch at high price differentials than low price differentials. Thus, the existing retailer knows that as they raise their price to existing customers they are more likely to lose customers to competing suppliers.

250. The 'single customer' and 'single switching cost' stylised example is simply used to make the underlying economic principles intuitive and the results tractable/simple

to understand. The literature that we describe below includes more complex analysis where rising price differentials result in gradual loss of customers rather than the sudden 'tipping point' used in this section. However, the results in that literature are essentially the same as in this stylised example.

251. In this context, it is important not to hold a simplistic binary distinction between 'active' and 'inactive' shoppers. While we ourselves use these terms in this report what we are referring to is customers who are more likely to switch and lower price differentials and customers likely to switch at high price differentials. This terminology should not be taken to mean that there is a class of inactive customers that is 'fixed' and independent of the savings available from switching.

252. Of course, firms will still be able to charge above marginal cost to their existing customers given the existence of switching costs. However, the equilibrium price is materially lower with price discrimination because the baseline level of competition for new customers is stronger.

8.2.4 The theoretical literature

8.2.4.1 Thisse and Vives (1988)

253. The stylised example in the previous section is actually a simplified version of the model used by Thisse and Vives (1988).[53] In that model the authors assume a two firm Hoteling model with customer preferences uniformly distributed in linear product space – some customers preferring one firm and some the other with varying degrees of intensity for this preference.

254. This is equivalent to a model where some customers are loosely attached (low switching cost) to their existing supplier and some are strongly attached (high switching costs). Thisse and Vives (1988) compare a scenario where each firm can perfectly price discriminate. That is, each firm knows each customers preferences perfectly and can set a unique price to each customer.

255. Thisse and Vives (1988) compare the prices charged under this perfect price discrimination scenario to the prices charged if only uniform pricing is allowed. They show that the uniform price is above all of the discriminatory prices. That is, not only is the uniform price greater than the average of discriminatory prices it is above the maximum discriminatory price.

256. While the mathematics and sophistication of the analysis is more complex, the basic economic forces behind this result are the same as in our simplified example.

53 Thisse, J.-F., Vives, X. (1988), "On the strategic Choice of Spatial Price Policy," American Economic Review, Vol 78, pp. 122-137.

8.2.4.2 Bester and Petrakis (1996)

257. Bester and Petrakis (1996)[54] essentially take Thisse and Vives (1988) model and impose a restriction that price discrimination is limited to each firm only being able to charge two prices (rather than bespoke prices for each customer). This is essentially one price for existing customers and one price for competitors' customers. This is likely a more realistic assumption in the context of electricity retailing competition.

258. Bester and Petrakis (1996) show that the key results of Thisse-Vives (1988) stand. The prices under price discrimination are all below the price that would be set if only uniform pricing was allowed.

8.2.4.3 Chen (1997)

259. Chen (1997)[55] builds on the work of Bester and Petrakis (1996) and Thisse-Vives (1988) but makes a number of modifications. Bester and Petrakis (1996) and Thisse-Vives (1988) model treated each customer as having a preference for one or the other firm – which the competition firm had to 'defeat' by offering a discount. This worked well as a model of 'switching costs' because competition was assumed to be a 'one period' event.

260. Chen (1997), by contrast, set out to establish a multi-period model where customers 'won' in the first period became 'sticky' in the second period. In order to do this he formally introduced the assumption that customers faced switching costs from their existing supplier (i.e., switching cost "followed" customers to whatever supplier they chose).

261. Chen (1997) retains the assumption that there are only two firms. He follows Bester and Petrakis (1996) in allowing for variation in the level of switching costs each customer perceives and also in only allowing firms to set two prices (one for its existing customers and one for the competitor's customers).

262. Chen (1997) demonstrates that firms will price below marginal cost in order to win customers in the first period given that some fraction of them will be 'sticky' in the second period. Chen (1997) shows that, assuming that each firm is the same size, then the Bester and Petrakis (1996) and Thisse-Vives (1988) results stand. That is, the uniform price is above all the discriminatory prices.

[54] Bester, H., Petrakis, E., (1996), "Coupons and Oligopolistic Price Discrimination," International Journal of Industrial Organization, Vol 14, pp. 227-242

[55] Chen, Y., (1997), "Paying customers to switch," Journal of Economics and Management Strategy, vol. 6, pp. 877-897

263. Chen (1997) does find that there is a possibility that some customers will be better off under uniform pricing if there is a large difference in size between the two firms in its model. Specifically, high switching cost customers of the smaller firm can be better off under uniform pricing. (All customers of the larger firm and all low switching cost customers of the smaller firm are better off with discriminatory pricing – such that the average customer is better off.)

264. In Chen's model with two firms each firm is an 'alternative supplier' to the customers of the other firm. Because there is variation in the switching costs of customers each firm faces a downward sloping demand curve. Under uniform pricing this is a single demand curve (comprised of demand of the competitor's customers to switch and the demand for existing customers to stay). Under price discrimination, where different prices are offered to existing and new customers, there are essentially two demand curves one for customers to switch and one for customers to stay.

265. The position of the demand curves each firm faces depends on the price charged by its competitor to each subset of customers (e.g., Firm A's demand for customers to switch to it depends on Firm B's price to customers to stay with it). Each firm then sets the 'monopoly price' (such that marginal revenue equals marginal cost) for each demand curve it faces.

266. The equilibrium result (based on uniform distribution of switching costs) is that each firm sets:

- the price for competitor's customers at marginal cost plus one third of the distribution of switching costs; and
- the price for their own customers at marginal cost plus two third of the distribution of switching costs.

267. However, under uniform pricing the profit maximising price for each firm is to set a price at the top (100%) of the distribution for switching costs. This is for essentially the same economic forces we set out in our simple example in section 8.2.3.2. Indeed, the result in our simple example where the uniform pricing average mark-up is double average switching costs is repeated in Chen (noting that the top of a uniform distribution is double the average of the distribution).

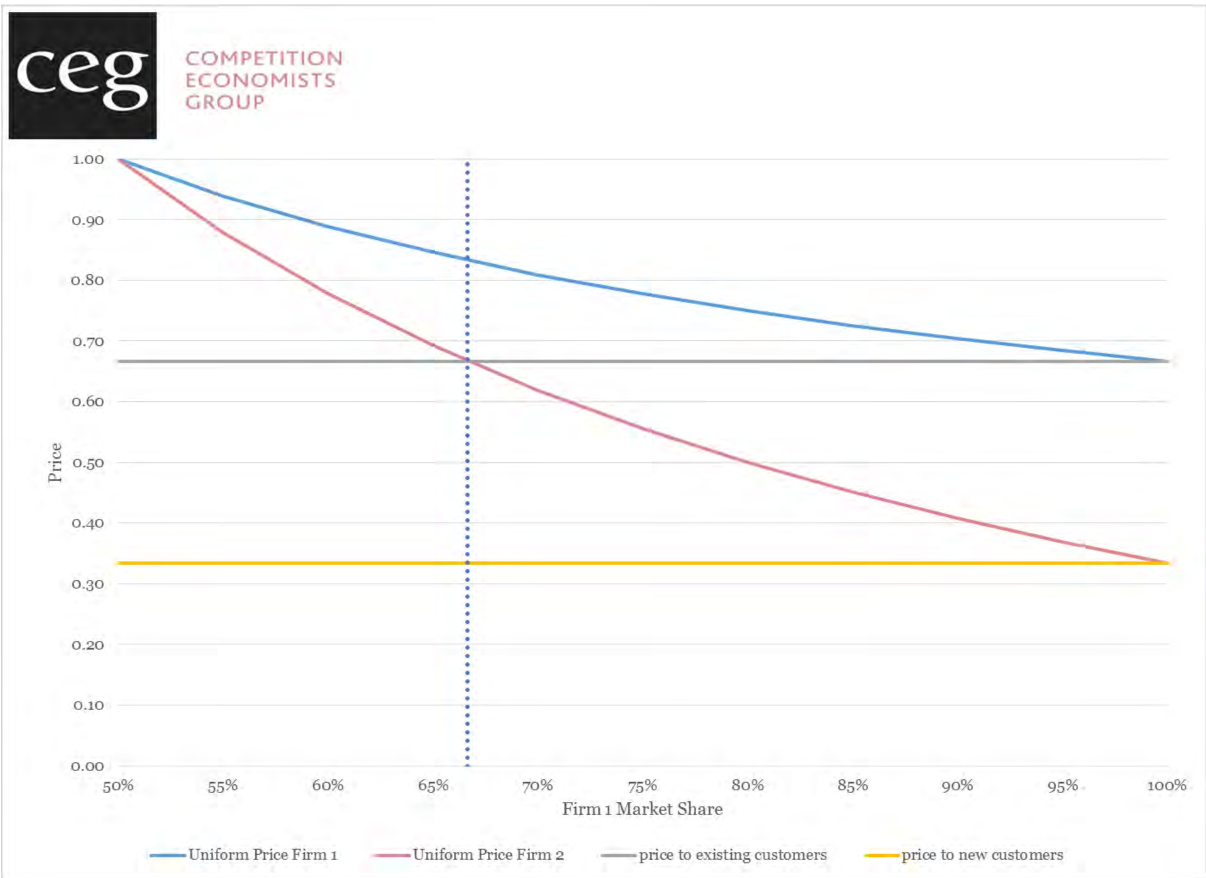
268. Chen does find that a small firm's customers can be better off under uniform pricing. This reflects the fact that, under uniform pricing, small firms have the strongest incentive to compete for new customers. This is because they have the smallest base of existing customers and, therefore, the least to lose from lowering prices to them (while they have the most to gain from winning customers from their larger competitor).

269. Figure 8-3 summarises Chen's result in this regard. It shows that when firms are symmetrical (50% located at the left most point on the horizontal axis) then the uniform price of each firm is $1.0 (assuming uniform distribution of switching costs

between $0.0 and $1.0). However, as we move right on the horizontal axis (i.e., one firm's market share increases relative to the other), the uniform price equilibrium for both firms fall.

270. This is because moving rightward on the horizontal axis makes Firm 2 lose market share and become more aggressive. They then lower their uniform price offering. Firm 1's response is to lower its optimal uniform price – but by less reflecting the fact that Firm 1 has a larger existing customer base and therefore loses more by lowering its price. In the extreme, if the Firm 2 had no existing customers it would set its uniform price equal to the lowest of its discriminatory prices and Firm 1 would respond by setting its uniform price at the highest of its discriminatory prices. However, even in this extreme, the average uniform price is higher than the average price under price discrimination.

Figure 8-3: Impact of price discrimination on prices



Source: CEG simulation using Chen (1997) model.

8.2.4.4 Taylor (2003)

271. Taylor (2003)[56] extends Chen's results in two ways. Taylor allows for there to be more than two firms and extends the number of periods of analysis beyond two. Taylor demonstrates that with multiple periods the market will converge to symmetry under the long run (i.e., the symmetric market shares model is the relevant model in the long run). This is because the smaller firm will grow in size as it is the more aggressively priced firm. Taylor (2003) also finds the equilibrium prices under price discrimination will be more dispersed and lower with 3 or more firms compared to the two firm scenario in Chen (1997).

272. That is:

- increasing the number of competitors leads to greater price dispersion not smaller price dispersion; and
- greater price dispersion is associated with lower average prices.

273. In fact, with three or more firms, Taylor (2003) finds that market becomes *"fully competitive and all firms earn zero economic profit"* under price discrimination.

8.2.4.5 Shaffer and Zhang (2000)

274. Shaffer and Zhang (2000) extends Chen (1997) in a different direction by allowing for one firm's customers to have a different distribution of switching costs to the other firm's customers. That is, one firm may have more strongly 'sticky' customers than the other firm.

275. In terms of our simple in section 8.2.3.2, this would be 'as if' Firm A's customer had a \$2 switching cost and Firm B's customer had only a \$1 switching cost. In our simple example the equilibrium uniform price would be \$4 (double the higher customer's switching cost) and the equilibrium discrimination prices would be \$2 and \$1 (equal to the average switching costs of each customer base).

276. This is also essentially the result in Shaffer and Zhang (2000) where each firms are of the same size (as they are in our simple example). However, Shaffer and Zhang (2000) also explore the implications where there are asymmetries in the size of the customer bases. They find that:

   a. if the larger firm also has the stickiest customers then this will lower average equilibrium prices under price discrimination;

   b. if the smallest firm also has the stickiest customers then this will raise the average equilibrium prices under price discrimination.

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56 Taylor, C.R. (2003), "Supplier Surfing: Competition and Consumer Behavior in Subscription Markets," The RAND Journal of Economics, Vol 34, pp. 223-246

277. A key conclusion from Shaffer and Zhang (2000) is that it can be profitable to offer a lower price to your own customers than to your competitor's customers. This can be the case if you have a large customer base that has low switching costs (scenario b above). That is, if the large firm has the least sticky customers then the large firm can be better off 'paying to stay' rather than 'paying to switch'.

278. It is also the case that, under this scenario, price discrimination may actually raise average prices relative to uniform pricing. However, for this to be true the average switching cost of customers from the smaller firm needs to be 4 to 5 times, depending on market share, greater than the switching cost of the larger firm.

279. Clearly, this is not the case in electricity retailing where the smaller 'new entrant' firms will typically have lower not higher stickiness than the larger retailers who substantially gained their customer bases from the breakup of Electricity Corporation of New Zealand (ECNZ) (rather than won them from competitors).

8.2.4.6 Stole (2007)

280. Stole (2007)[57] is not an original piece of research but is a summary of the literature. Stole authors a chapter in the Handbook of Industrial Organization focussing on price discrimination. The relevant section of this Chapter is section 4 "Price discrimination by purchase history" and, in particular, section 4.1 "Exogenous switching costs and homogeneous goods".

8.2.4.7 Collusion is easier with a single price

281. All of the models surveyed above assumed that there was no collusion (tacit or otherwise) between retailers. We note that collusive prices would be much simpler to agree on, and punishment for cheating simpler to implement, the more simple the offering from each retailer. It is a clear finding in the literature that market transparency facilitates collusion.[58] Specifically, collusion is more likely to be successful in a world where simple uniform pricing was enforced by regulation because monitoring of each suppliers overall pricing would also be simpler.

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57 Stole, L. (2007), "Price Discrimination and Competition", Handbook of Industrial Organization, 64. Edited by M. Armstrong and R. Porter Vol 3, Chapter 4.1 "*Exogenous switching costs and homogeneous goods*".

58 See Ivaldi, Jullien, Rey Seabright and Tirole, The Economics of Tacit Collusion, 2003, Final Report for DG Competition, European Commission. In particular, section III, 5.

8.3 Empirical evidence

8.3.1 UK case study

282. Prior to 2008, the energy retail sector in the U.K. was deregulated. The market was dominated by the 6 largest suppliers who accounted for 99%[59] of residential consumers. In 2008, Ofgem began a probe into the energy supply market to investigate whether the market was working effectively after the deregulation. Ofgem (2008)[60] found:

> *There are now greater levels of competitive activity and consumer switching than almost every other energy market in the world and most other UK consumer services markets. The fundamental structures of a competitive market are in place, and the transition to effective competitive markets is well advanced and continuing.*

283. However, Ofgem was concerned with the price dispersion within the industry and considered it "unfair". The Ofgem report found that, in terms of switching suppliers, "*the vulnerable consumers more generally have lagged behind other consumers*." The report also found the *"use of internet to compare prices is particularly low amongst vulnerable consumers."* As a result, Ofgem adopted policies that required differentials in charges to be cost-reflective on the basis that price differentials between more and less active consumers was unfair.

284. According to Littlechild (2014), Ofgem's decision to ban price discrimination is based on the following reasoning:

- Differentials in prices is unfair as it indicates ineffective competition amongst non-switchers;
- It expected a zero net revenue impact as a result of non-discrimination conditions;
- Based on these assumptions, the revenue from non-switchers was expected to decrease by approximately the same amount as the increase in revenue from switchers.

285. In essence, Ofgem considered the non-discrimination requirement as a redistribution of income without changes in the overall revenue of the retailers.

59 Littlechild, S. (2014), "Promoting or restricting competition?: Regulation of the UK retail residential energy market since 2008," University of Cambridge, Energy Policy Research Group, EPRG Working Paper 1415

60 Ofgem, Energy Supply Probe- Initial Findings Report, 140/08, 6 October 2008

286. Littlechild finds the result of the policy is a large decrease in the number of customer switching as shown in Figure 8-4. Littlechild (2014) finds the number of electricity and gas transfers between suppliers decreased from 2.6 million in third quarter 2008 to 1.1 million in third quarter 2013. There was a large spike in the number of switches in the 4th quarter of 2013 due to "*media and political attention*" [61] on energy prices. Littlechild (2014) also shows that the dramatic decrease cannot be explained by the end of doorstep selling in 2011 and 2012. Littlechild cites from a detailed empirical analysis from Waddams Price and Zhu which finds:

> *"the non-discrimination condition has changed the nature of competition, that the constraint on incumbent price increases has weakened and that each regional market is now closer to a duopoly between the regional incumbent and British Gas."*

Figure 8-4: Customer switching in the U.K.

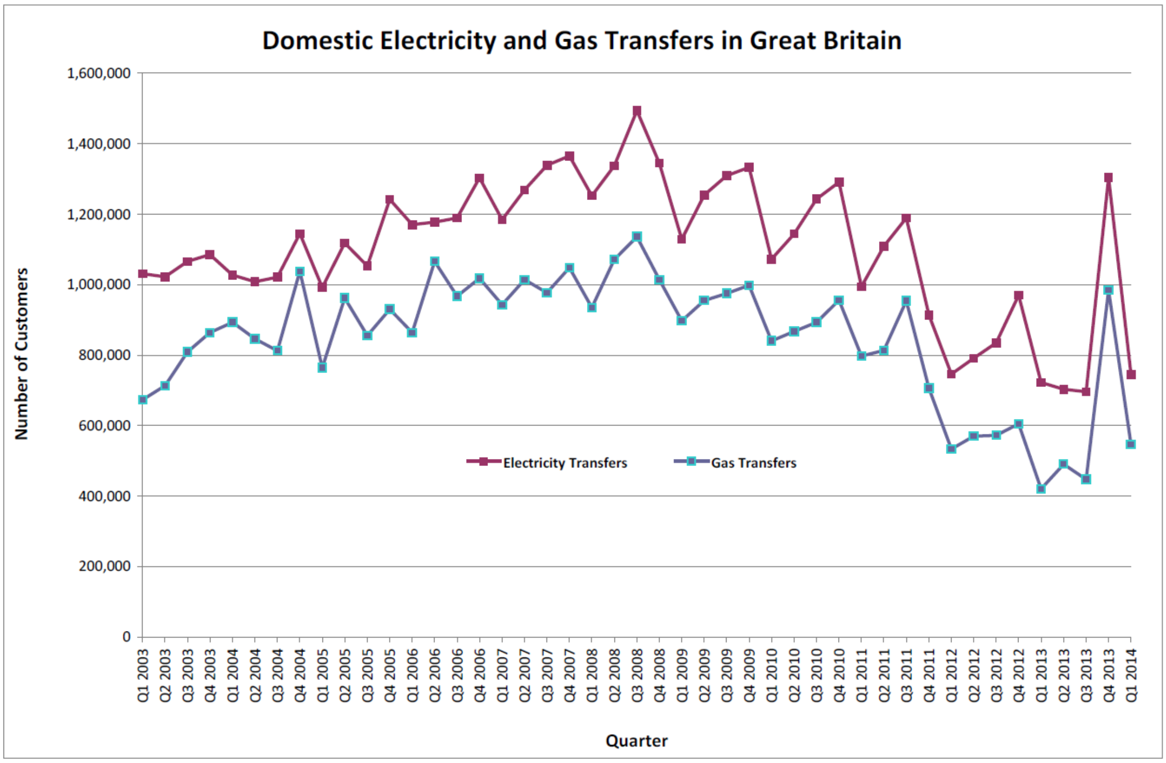


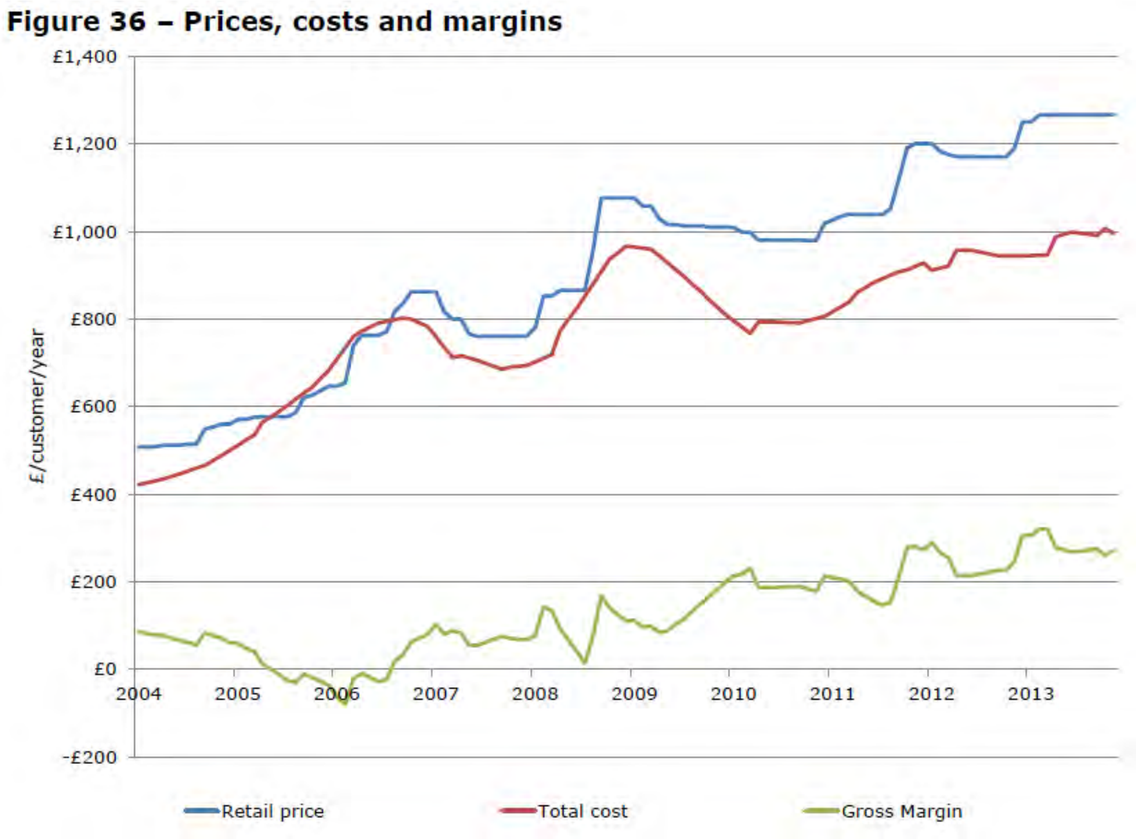
Figure 1 **The increase then decrease in customer switching**[58]

Source: Littlechild (2014)

[61] Ofgem 2014, State of the Market Assessment, 27 March 2014

287. Littlechild (2014) also finds that the restriction also dramatically boosted the EBIT margins of retailers from 0.9% in 2009 to 3.9 % in 2013. Analysis by Ofgem (2014)[62], shown in Figure 8-5, shows an increase in the gross margin from approximately 100 pounds per customer per year in 2008 to approximately 300 pounds per customer per year by 2013 for dual fuel customers.

Figure 8-5: Energy retail margin in the U.K.



Source: Ofgem (2014)

288. Ultimately, Ofgem recognised that its ban on price discrimination was counterproductive and it *"[wrote] to suppliers to confirm that SLC 25A [which prohibits price discrimination] had lapsed and that suppliers were not bound by it in any way*."[63] In fact the prohibition was heavily criticised by CMA (2016).

62 Ofgem 2014, State of the Market Assessment, 27 March 2014

63 CMA (2016), "Energy market investigation – Final Report" Competition & Market Authority 24 June 2016

8.3.1.1 Energy market investigation by Competition & Market Authority

289. Between 2014 and 2016, the U.K. Competition & Market Authority undertook a detailed investigation in the U.K. energy market. One component of the investigation focused on the price discrimination amongst the U.K. energy retailers.

290. CMA (2016) is highly critical of the decisions made by Ofgem, it *"found that some decisions taken by Ofgem over the last few years (e.g. SLC 25A [which prohibits price discrimination]...) which in [CMA]'s view were not based on robust analysis, have had adverse effects on consumers.'*

291. CMA (2016) concludes *"evidence appears to be consistent with a potential weakening of competition concerning [Standard Variable Tariff (SVT)] over time as the gap between the SVT and underlying costs appear to widen. This is particularly apparent from 2009 which broadly coincides with the introduction of the prohibition on undue regional price discrimination."*[64]

292. In fact CMA (2016) determined the impediment to a more competitive energy retail market is not the presence of price discrimination but the *"weak customer response"* to rival offers. CMA (2016) found *"customers have limited awareness of and interest in, their ability to switch energy supplier."*

293. We return to this alternative solution to the perceived 'problem' of price dispersion in section 8.4 below. In short, while we agree with the CMA's criticism of Ofgem's policy on price discrimination, it is not obvious that the CMA's 'solution' to the same 'problem' is necessarily any better. Specifically, increasing the proportion of active and well informed customers need not lower average prices. In fact, in the extreme, a perfectly informed and perfectly active customer base would almost certainly lead to higher (monopoly) prices.

8.4 Does the existence of price dispersion warrant regulatory intervention?

294. The previous analysis addressed whether, given the existence of sticky customers, the practice of discounting was harmful to customers. The answer is unequivocally that it is not. Discounting benefits all customers – and not just active shoppers.

295. This section addresses a separate but related question. Rather than taking the existence of sticky customers for granted, what if policies were put in place to reduce the number of sticky customers and/or make individual customers less 'sticky'. Specifically, could we expect such policies to lower the competitive equilibrium

64 Other than British Gas, the remaining 5 large energy retailers are regional based. Therefore regional price discrimination is equivalent to poaching rivals' customers.

average retailer's markup on marginal cost? Would customers as a group be better off if they all, or a greater proportion, became more active shoppers?

296. The answer is, in fact, ambiguous.

8.4.1 CMA (2016)

297. The CMA clearly was of the view that increasing the proportion of active customers would be beneficial. CMA (2016) was concerned with the *"complex information provided in bills and the structure of tariffs which combined to inhibit value for money assessments of available options."* Another concern raised up by CMA (2016) is the opportunity for *"erroneous transfers which have the potential to cause material detriment."*

298. CMA (2016) recommended several changes to reduce the switching cost of consumers and increase in the ability of consumers to take advantage of offers made by rivals. Its recommendations are

- Establish an Ofgem led program to improve consumer engagement in the retail sector through
  - changes to the information in domestic bills and how this is presented;
  - changes to information provided to customers on cheaper tariffs available across the markets;
  - changes to the specific messaging that domestic customers receive in bills once they move, or are moved, on to an SVT and/or other default tariffs; and
  - changes to the name of the default tariffs.
- Require energy retailers to maintain and disclose to Ofgem a database of consumers who has been on the SVT for three years or more. Through the database, Ofgem should actively engage with these consumers to provide *"marketing letters"* on cheaper tariffs and how to switch suppliers; and to provide the data available to rivals such that the rivals can actively market towards these customers.

299. Ultimately, instead of stifling competition by limiting retailer's ability to poach consumers, the CMA (2016) determine the solution is *"helping customers engage to exploit the benefits of competition."*

8.4.2 What does the literature predict

300. Holding the competitiveness of the market-place constant, making customers better informed must improve outcomes for customers. Well informed and engaged customers are able, in a competitive market with a large number of suppliers, to negotiate supply at marginal cost. The more engaged customers are the more

customers that will be receiving the lowest possible price. This is the first round effect.

301. However, the caveat for this to be true is that *competitiveness be held constant.* This caveat will not typically hold. Put simply, all customers cannot access supply at marginal cost because, if they did, no supplier would be profitable. The market dynamic is quite simple. The first round effect of increasing the proportion of well-informed and engaged customers is increasing the proportion of customers on low priced marginal cost tariffs. However, the second round effect is exit from the market by some retailers, a softening of competition, and higher markups on all tariffs (to all types of customers).

302. Gu and Hehenkamp (2010)[65] develop a model to examine the impact of increases in "the share of informed customers in the market" which is their measure of "transparency". Their abstract summarises the first and second round effects described above in their specific model as follows.

> *Including the entry decision in a Bertrand model with imperfectly informed consumers, we introduce a trade-off at the level of social welfare. On the one hand, market transparency is beneficial when the number of firms is exogenously given. On the other, a higher degree of market transparency implies lower profits and hence makes it less attractive to enter the market in the first place. It turns out that the second effect dominates: too much market transparency has a detrimental effect on consumer surplus and on social welfare.*

303. Overgaard and Mollgaard (2008) note that consumer advocates of better informed customers tend to take a static approach when thinking about the implications of better informed customers:[66]

> *Consumer protection advocates tend to take a more static perspective.... The archetypical example du jour is online shop-bots, which allow potential buyers to compare a multitude of different market offerings by pressing a few keys (thus, at low cost). This allows buyers to shop around easily, turning competition between suppliers of close substitutes into something akin to intensive Bertrand-style competition. Consequently, proponents of this view have not only suggested that information should be allowed to flow freely, but even that the gathering, processing and dissemination of the information to potential buyers should be subsidized*

65 Gu and Hehenkamp, The Inefficiency of Market Transparency– A Model with Endogenous Entry, RUHR Economic Papers, #219, 2010.

66 Overgaard and Mollgaard, "Information Exchange, Market Transparency and Dynamic Oligopoly", published in Issues in competition law and policy / Wayne Dale Collins, editor in chief, American Bar Association. Section of Antitrust Law. (2008). Working paper form is also available on SSRN.

by the public purse or by levying a duty on firms to foot the bill. Thus, government-sponsored or -funded information-transmission mechanisms have been set up.

304. However, the authors counsel not to let the analysis stop at a static (first round) effect. They state:[67]

> *From the perspective of static modelling, it is a relatively robust result that improved consumer information tends to promote the efficiency objective. However, it remains an open question whether this qualitative result is robust to embedding the basic static models in an explicitly dynamic model of oligopoly competition. The reason for this is straight forward: if improved information on the consumer side makes it easier for a firm to steal customers from its rivals, it must also make it easier for these rivals to "steal" them back again! So, the result might just be that no one tries to steal customers from rivals in the first place.*

305. That is, even holding the number of competitors constant (as Overgaard and Mollgaard (2008) do), increasing the proportion of well-informed customers may lead to less competition because, essentially, the benefits from winning customers is reduced. Of course, if this does not happen and the newly 'slippery' customers are the recipients of low "Bertrand" marginal cost pricing, then the inevitable result is less entry/more exist from the industry (which is the mechanism Gu and Hehenkamp (2010) focus on.)

306. More generally, it is ultimately a 'pipedream' to shift all consumers onto today's lowest tariffs by making them all well-informed and engaged. The attempt to do so would cause those tariffs to evaporate in the process. Heavily discounted tariffs, that make no or low contributions to fixed costs, are only made possible by virtue of intense competition for 'sticky' customers who, once acquired, can, in subsequent periods, make a contribution to fixed costs. If all customers are always and everywhere 'slippery' then marginal cost tariffs will disappear because, if they did not, all customers would be on them and no supplier would cover their fixed costs. (This is true in any industry where a supplier's marginal cost is constant (or falling) even when market share approaches the entire market.)[68] The mechanism by which this occurs will be market exit and a consequent softening of competition.

307. Indeed, if all customers were everywhere and always perfectly well-informed (and there are constant or declining returns to scale) it is relatively simple to show that the resulting equilibrium market structure would be monopoly (or collusive oligopoly).

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67 Ibid.

68 The classic 'perfectly competitive' markets are those in commodities where each supplier marginal costs rise steeply as production approaches a fixed capacity (e.g., based on land owned (e.g. agricultural commodities) or proven reserves of for oil and mineral commodities).

This is because in the presence of perfectly informed customers who always choose the lowest price all firms will compete prices down to marginal cost (absent collusion). This will lead to all but the lowest marginal cost firm leaving the market.

308. Moreover, once this monopoly is established it will be secure from new entry. This is because, unless they expect some form of collusive accommodation, no firm will enter a market where 100% of customers are perfectly informed because they know that the incumbent's rational response will be a price war based on marginal cost.

309. The fact that 'Bertrand competition' with homogenous products and constant/declining marginal costs leads to monopoly absent collusion is well established in the literature. For example, Dasgupta and Stiglitz (1988)[69] showed that potential competition is ineffective in constraining an incumbent monopolist if post entry pricing will be based on pure Bertrand competition. More generally they conclude:

> *'...'the fiercer competition after entry, the less effective is potential competition".*

310. In short, fierce competition is only good for consumers when it results in stable fierce competition. If fierce competition leads to exit (or failure to enter) then the long run effect may be bad for consumers.

311. That is not to say that marginal increases in the proportion of well-informed/engaged customers will necessarily lead to a dramatic reduction in competition and worse outcomes for all customers. The economic literature predicts that it will improve outcomes for the customers who, as a result of the intervention, are now are more likely to switch suppliers. However, the intervention will make outcomes worse for the remaining customers (those who would have switched anyway and those who continue to not switch).

312. There is no 'free lunch' in a competitive market. An objective of shifting more customers onto today's lowest cost tariffs is a mirage. The more customers who shift to those tariffs, and stay permanently on them, the higher the markup on those tariffs will be.

313. In our view the most important conclusion is that it would be a mistake to have a policy goal of eliminating price dispersion by making customers perfectly informed/engaged. If this objective was actually achieved then the result would be that all customers paid the same price – but that price would be the monopoly (or collusive oligopoly) price. More generally, shifting the balance to increase the

69 Dasgupta, P., Stiglitz, J., 1988. Potential competition, actual competition, and economic welfare. European Economic Review 32, 569–577.

number of well-informed/engaged customers would benefit those newly informed/engaged customers. However, it would hurt other customers.

314. There is a separate question about whether there is a distributional/fairness justification for shifting a specific subset of consumers onto low tariffs (e.g., particular, 'vulnerable customers'). This may not be a warranted policy goal. However, if this is accepted as a desirable policy goal it is important not to confuse it with a more general policy goal of shifting all consumers onto the lowest tariffs (which is not possible for the reasons set out above).

8.4.3 What is different about consumer as opposed to commodity markets?

315. The conclusion set out above may seem odd to the reader who is familiar with the idealised 'perfectly competitive' market of many firms, a homogenous product and perfectly informed customers. In this 'text book' market, the 'rule of one price' holds with price set equal to marginal cost across all suppliers. It may reasonably be asked: why would not perfectly informed retail electricity customers give rise to this equilibrium?

316. The answer is relatively simple, in the 'text book' model of perfect competition all suppliers have increasing marginal costs – such that if any one supplier were to attempt to serve the entire market they would have materially higher costs than a new entrant. This increasing marginal cost condition ensures that there is competition in equilibrium.

317. This assumption reflects reality in many markets. These markets do fit the stylised 'perfectly competitive' market structure. For example, consider the market for crude oil or bulk wheat. In these markets each supplier controls a limited share of the essential inputs (e.g., arable land or proven oil resources). Consequently, no supplier can expand without limit at a constant (or declining) marginal cost. A farming corporation, even the very largest in the world, is constrained to the extent that they can profitably increase wheat production at a given price. The largest oil companies will, constrained by the limited reserves that they own, ultimately face severe limits in their annual output beyond a certain point.

318. Consequently, fierce competition can simultaneously push prices down to marginal cost while still allowing for the recovery of fixed costs. This is because rising marginal costs at each supplier allows marginal cost pricing to equal average cost pricing. Thus, fierce competition, marginal cost pricing and a large number of suppliers are all mutually achievable in these markets.

319. Electricity retailing, and, indeed, most other markets are, different. In electricity retailing a single firm does not face material constraints in expanding output at something like the prevailing marginal cost. The main input into electricity retailing is wholesale energy and this can be traded relatively simply – with increasing market

share simply matched by higher purchases in the wholesale market (contract and/or spot markets).

320. The other inputs to electricity retailing have large components of fixed costs that are scalable at low marginal cost (such as billing systems, trading operations, management of bad debts etc). Consequently, with the exception of difficulty in acquiring 'sticky' customers, any individual retailer faces few, if any, rising costs associated with expanding the scale of their operations.

321. Now consider what would happen if all customers were perfectly well-informed and engaged. Any individual supplier could acquire the entire market simply by having the lowest price – and any supplier that did not have the lowest price would lose their entire customer market. Unlike the wheat or crude-oil markets, there would be no cost based limitation on how small the number of supplies could fall to. Consequently, the end result would be fierce price competition (based on marginal costs) until market exit occurred that softened competition sufficiently for fixed costs to be recovered. In fact, assuming no collusion the end result would be "Bertrand competition" until a monopoly was established.[70]

322. The fact that customers are not perfectly well-informed/engaged is what prevents electricity retailing from this long-term anticompetitive fate. It is the existence of 'sticky' customers that prevents a marginal cost price war from creating a monopoly (or oligopolistic collusive market structure).

323. It should be noted that the same analysis applies in most markets. That is, commodity markets, not electricity retailing, are the exception. The same analysis applies to any market where:

- The products sold by suppliers are perceived as 'homogenous' by customers (i.e., close substitutes) ;
- Customers are atomistic (as opposed to customers with countervailing size and ability to coordinate/vertically integrate/sponsor entry with long term contracts);
- Suppliers have constant (or falling) marginal costs of supply over the size of the market; and
- There are fixed costs of supply that are scalable over the size of the market.

324. Where these conditions hold then perfectly well informed/engaged customers will lead to a 'price war' between suppliers that will ultimately end with monopoly (or

70 Moreover, a monopoly would be secure because no credible threat of entry exists into a market where the new entrant expects a price war at marginal cost after entry – which would be the rational response from the incumbent.

collusive oligopoly). It is for this reason that companies put so much effort into differentiating what would otherwise be regarded as homogenous products.

325. Consider Pepsi and Coke and other fast moving consumer goods (FMCG). These products will typically satisfy all of the above characteristics with the possible exception of the first. Indeed, the reason that FMCG suppliers compete so heavily on branding/product differentiation is in order to avoid the kind of price war that will inevitably mean exit from the industry by most suppliers.

326. Alternatively, consider consumer finance. A home or car loan should, to a well informed and engaged customer, be perceived as something close to a homogenous service. If all consumers had this view then the financial institution with the lowest 'comparison rate' would win all the customers. A monopoly (or collusive oligopoly) would be quickly be established as all financial institutions fought to be the last one(s) standing. This does not happen because consumers are either not perfectly well-informed (engaged in sifting between offers) or simply do not regard products as homogenous (which maybe another way of saying the same thing).

327. Of course, the above conclusions do not imply that the current level of customer engagement/information in electricity retailing is optimal. It may be that marginal improvements in customer engagement from where it currently stands will not result in a material exit of suppliers from the industry and the gains (in terms of shifting more customers to marginal cost tariffs in the short run may not be fully offset by higher average tariffs in the long run).

328. However, the clear conclusion from the literature is that a goal of all customers being 'perfectly informed/engaged' is not, in fact, desirable. Unless electricity retailing can be turned into a differentiated product market, then successfully pursing such a goal would ultimately lead to monopoly (or collusive oligopoly).

Appendix A Mathematical exposition

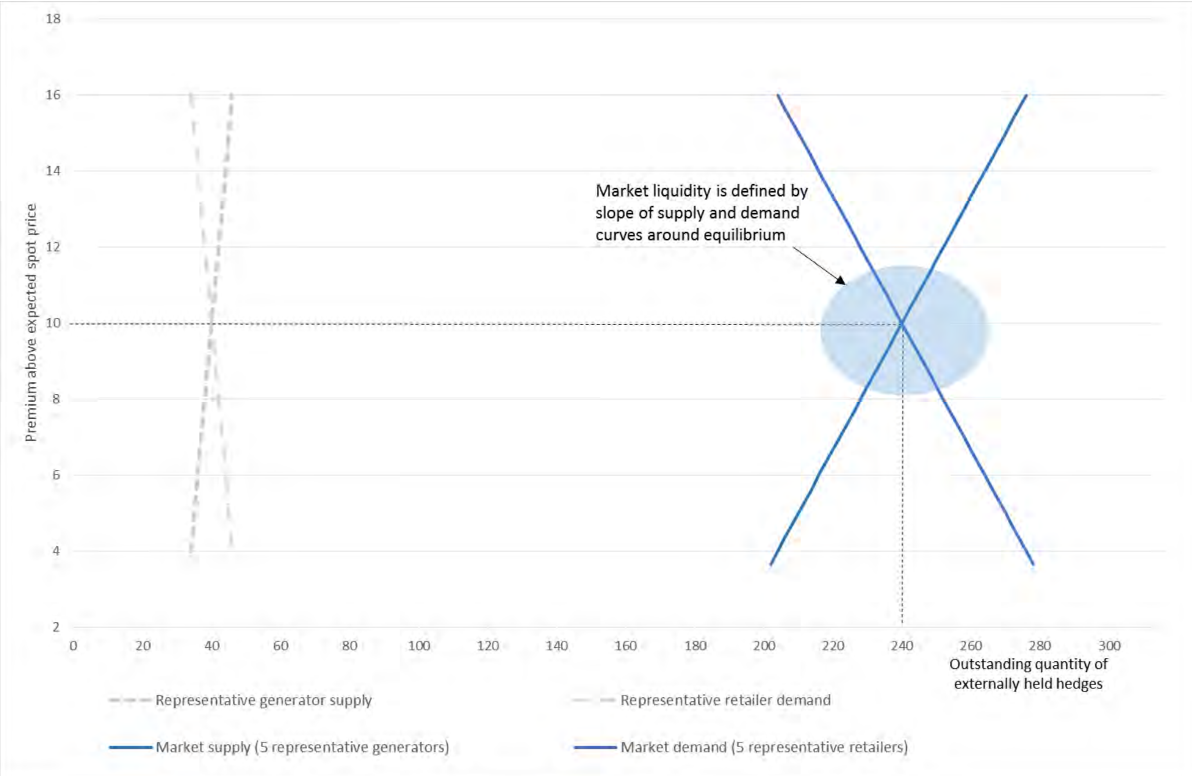
A.1 Market liquidity from individual firm supply and demand responses

329. The market supply and demand curves are simply the (horizontal) sum of individual firm supply and demand curves. For the purpose of illustration, let there be six identical 'representative' generators and retailers. The slope of the market supply and demand curves will be flatter than the individual representative generator supply curve because it represents the cumulative response of all six firms to a change in price. Under these conditions, the market supply and demand curves will:

- be six times further to the right than the representative demand and supply curves; and
- be one sixth of the slopes (six times flatter).

330. This is illustrated in Figure A1 below.

Figure A1: Representative firm and market supply and demand



Source: CEG illustration

331. In the above illustration, the representative firms' supply and demand curves have a constant slope of +1.0 and -1.0 respectively and intersect with the vertical axis (zero supply and zero demand) at prices of -30 and +50 respectively. (Note the scale of the X and Y axis are very different which makes the curves look steeper than they would if the same scale was used.) That is, a generator (retailer) would prefer to have zero hedging if the hedge price was 30 $/MWh below (50 $/MWh above) the expected spot price. (Section A.3 in Appendix A provides a discussion of the practical determinants of supply and demand for hedge contracts by generators and retailers).

332. This is captured by the below equations:

$$Representative\ standalone\ supply = \ Hedge\ premium + 30$$

$$Representative\ standalone\ demand = \ -Hedge\ premium + 50$$

$$Market\ standalone\ supply = \ 6 \times Hedge\ premium + 180$$

$$Market\ standalone\ demand = \ -6 \times Hedge\ premium + 300$$

333. The end result of these assumptions is a market hedge price (where supply equals demand) of 10 $/MWh[71] above the expected spot price (this is true irrespective of the number of representative firms). Each representative firm is counterparty to 40 contracts and, with a market made up of six representative generators and retailers, the equilibrium quantity of hedges outstanding is 240 (six times the outstanding hedges that would be held by the representative generator and retailer).

334. However, what is critical for liquidity is neither the equilibrium price nor the equilibrium quantity. Rather, the liquidity of the market is defined by the slope of the market supply and demand curves. This defines how much the price of a hedge contract can be expected to move in the face of one party seeking to buy or sell (to increase/reduce the number of outstanding hedges to which they are a counterparty). This, in turn, is defined by the slopes of the aggregate supply and demand curves.

335. The slopes of the aggregate supply and demand curves provide the formal measure of the ease with which the market adapts to one party's desire to change their portfolio. All positions in the market must, in aggregate, sum to zero. Therefore, if, say, a retailer wishes to increase the quantity of baseload futures that they hold then other parties must either increase the supply of these (e.g., generators issue more expanding their portfolio or retailers sell more reducing their net portfolio). The slopes of the market supply and demand curves define the price changes necessary in order to bring forth the necessary counterparties to any trader's desired trade.

[71] $Market\ Supply \ = Market\ Demand \ \rightarrow \ 6 \times Hedge\ premium + 180 = -6 \times Hedge\ premium + 300 \ \rightarrow$ $12 \times Hedge\ premium = 120 \ \rightarrow Hedge\ premium = 10$

336. Specifically, starting in equilibrium a unit increase in price will bring forward counterparties wishing to trade a volume equal to the sum of the (absolute) slopes of the supply and demand curves. In this context, the supply and demand curves are expressed as quantity supplied/demanded as a function of price (as is the case for the equations at paragraph 332) and this is the inverse of the slopes (rise over run) in Figure A1.

$$Liquidity\ is\ proportional\ to:\ abs\left|\frac{d(Demand)}{d(P)}\right| + abs\left|\frac{d(Supply)}{d(P)}\right|$$

337. The intuition behind this measure is simply that markets are more liquid the smaller the increase in price required to bring forth more net supply. Or, equivalently, markets are more liquid the larger the increase in net supply as a result of a unit increase in price. The net supply brought forth is equal to the sum of additional hedges issued by generators plus fewer net hedges held by retailers.

338. In our example, the slope of the market supply (and demand) curve is such that for a unit increase in price (relative to the expected spot price), 6 additional hedges are sold by generators and 6 are sold by retailers. That is, a unit increase in price causes 12 hedge contracts to be available.

$$Liquidity\ is\ proportional\ to:\ abs|-6| + abs|6|$$

$$Liquidity\ is\ proportional\ to:\ 12$$

339. Thus, if, say, a retailer sought to buy 12 additional units of hedging it could expect to have to pay one dollar more than the equilibrium price that would have prevailed absent their trade. Clearly, the higher this number the more liquid is the market (the greater the net increase in supply for a given increase in price and/or the greater the net increase in demand for a given reduction in price).

340. Clearly, the above analysis with linear demand curves and identical representative generators/retailers is a simplification of reality. However, the fundamental point holds in the more complex dynamic real world market. That is, market liquidity is provided by firms adjusting their usage of hedges to any given changes in hedge prices. The more readily firms adjust their usage of hedges to a given change in the price of hedges, the more liquid will be the market.

A.2 Implications of vertical integration

341. A critical question becomes, is there any reason to believe that the vertically integrated entity would, in aggregate, respond differently than would its generation and retail operations if they were standalone?

342. For the reasons set out in this section, there is no reason to believe that this would be the case. The vertically integrated firm has precisely the same incentives to respond to rising futures prices by:

- reducing the amount of generation it buys through futures contracts as would a standalone retailer; and/or
- increasing the amount of generation it sells through futures contracts – just as would the standalone generator.

343. The above conclusions can be shown to hold mathematically. Let us start with the standalone market structure used to illustrate market liquidity in section A.1 above. Then, let us see how market liquidity would be affected if, instead of the six standalone representative generators and retailers (12 firms in total), we merge these firms into 6 'gentailers' – some of whom have retail loads less than generation and some who have more retail loads than generation. For simplicity, let the amount of generation in each representative firm be the same as in the previous example. However, instead of their being six standalone retailers of equal size let each generation firm have a retail arm:

- three of which have load that is only 50% generation; and
- three of which have load that is 150% of generation.

344. Assume that these mergers result in 'perfect' natural hedges. That is, put aside important considerations why perfect natural hedges do not, in reality, exist. With these assumptions made, we have:

- three firms that have 50% of their generation that is not naturally hedged; and
- three firms that have unhedged retail load of the same magnitude (i.e., equivalent to 50% of the generation).

345. That is, there are two sets of three firms with each set being made up of firms that have a representative standalone generator from paragraph 332 plus:

- 50% of a representative standalone (SA) retailer from paragraph 332; or
- 150% of a representative standalone (SA) retailer from paragraph 332.

346. It follows that the new vertically integrated (VI) representative supply and demand curves are:

$$Repr.\ Supply^{VI} = Repr.\ Supply^{SA} - 0.5 \times Repr.\ Demand^{SA}$$

$$Repr.\ \ Demand^{VI} = 1.5 \times Repr.\ Demand^{SA} - Repr.\ Supply^{SA}$$

347. Substituting the equations from paragraph 332 into the above results in the following representative supply and demand curves:

$$Repr.\ Supply^{VI} = 1.5 \times Hedge\ price + 5$$

$$Repr.\ \ Demand^{VI} = -2.5 \times Hedge\ price + 45$$

348. There are now only 3 firms in each set (as opposed to six in the standalone market structure) so the market supply and demand curves are only 3 times the representative supply and demand curves.

$$Market\ Supply^{VI} = 4.5 \times Hedge\ price + 15$$

$$Market\ Demand^{VI} = -7.5 \times Hedge\ price + 135$$

349. Thus, the market supply of hedges in this example has a lower absolute slope than in the standalone market, but the market demand for hedges has an absolute slope that is higher by an exactly offsetting amount. Consequently, the measure of liquidity defined at paragraph 336 is the same with and without vertical integration. The "with vertical integration" liquidity is as set out below.

$$Liquidity\ is\ proportional\ to\!:\ abs\left|\frac{d(Demand)}{d(P)}\right| + abs\left|\frac{d(Supply)}{d(P)}\right|$$

$$Liquidity\ is\ proportional\ to\!:\ abs|-7.5| + abs|4.5|$$

$$Liquidity\ is\ proportional\ to\!:\ 12$$

350. The without vertical integration liquidity was also 12, as set out at paragraph 338 above.

351. Similarly, when we solve for equilibrium by setting market demand equal to market supply, the equilibrium market price remains at a 10 $/MWh premium to expected spot prices.[72] Thus market price and market liquidity are unchanged. This is because the only effect of vertical integration is that infra-marginal contract hedges have been swapped for infra-marginal natural hedges. The marginal propensities to trade have been unaffected and, thus, price and liquidity are unaffected.

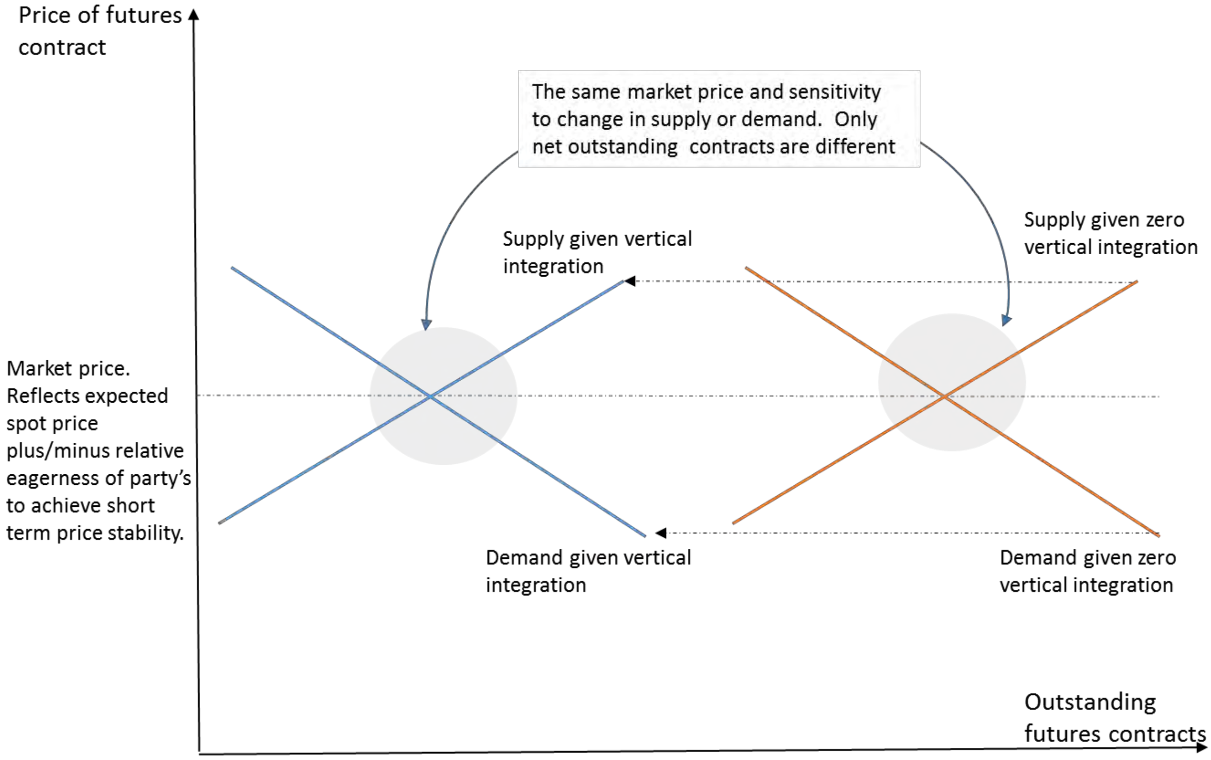
352. At this price the equilibrium outstanding amount of external hedge contracts is 60 (this can be seen by substituting a hedge price of 10 into the equations at 348). This involves a reduction from 240 to 60 outstanding hedge contracts held in equilibrium. It follows from the fact that each firm now holds half as many external hedge contracts on average (consistent with the 50% natural hedge assumption) and there are now half as many independent firms. However, despite the number of outstanding hedge contracts falling to a quarter of the original number, the resulting price and liquidity in the market are unchanged.

353. This is illustrated in the stylised supply and demand diagram at Figure A2 below. This figure illustrates a market for hedging products with and without vertical

72 $Market\ Supply^{VI} = Market\ Demand^{VI} \rightarrow 4.5 \times Hedge\ price + 15 = -7.5 \times Hedge\ price + 135 \rightarrow 12 \times Hedge\ price = 120 \rightarrow Hedge\ price = 10$

integration. The only difference is that, in one case, one or more generation portfolios are combined with one or more retail portfolios.

Figure A2: Illustration of markets with identical liquidity but different size



354. The impact of vertical integration is to reduce the outstanding futures contracts in the market. In the above figure, the reduced need for outstanding financial futures as a result of vertical integration is illustrated by the shift in the market supply and demand curves to the left.

355. However, there is nothing about this leftward shift of demand and supply that alters market liquidity. Market liquidity is driven by the combined slope of the supply and demand curves around equilibrium and there is no reason (at least no obvious reason) that this will be altered. The leftward shift in supply and demand should be thought of as swapping one form of infra-marginal hedging (financial contracts) for another (a natural hedge).[73] This leaves the combined firm's ongoing optimisation,

73 Something is infra-marginal if it is not the subject of optimisation. In this context, imagine that a generator, given its balance sheet, would always sell 50% of its output on the hedging market irrespective of the price in the hedging market. Similarly, imagine that a retailer, given its balance sheet, would always buy 50% of its energy in financial markets. The firms will optimise hedging above these levels as market conditins change (e.g., sometimes choosing 90% and sometimes choosing 60%) but never below. The 50%

using financial contracts, to its hedge position unchanged. This ongoing optimisation (adjustment to market prices/conditions) is what delivers financial market liquidity. A vertically integrated firm has the same needs and desires to adjust to changes in circumstances/prices as its constituent parts. Therefore, a vertically integrated firm will make the same contribution to market liquidity as its constituent parts would have if they were standalone operations.

A.3 What determines each firm's supply/demand response?

356. The above discussion starts from the position that each generator/retailer has a supply/demand curve for hedges. This section discusses the likely determinants of what these supply and demand curves actually look like. In order to understand the source of liquidity in financial hedge markets (or, indeed, any market) it is necessary to have a model of how parties value hedge contracts at the margin and how that marginal valuation changes with the number of hedge contracts sold/bought.

357. Imagine that a market participant always valued hedge contracts based on the expected future spot price (i.e., there was no positive or negative risk premium built into their valuation). Under this scenario, if the participant perceived that the actuarially expected average baseload spot prices in a relevant quarter was going to average 60 $/MWh then the participant would:

- buy hedges whenever the hedge price was above 60 $/MWh; and
- sell hedges whenever the hedge price was above 60 $/MWh.

358. However, in reality, most individual market participant will not be prepared to buy or sell an unlimited amount of hedge contracts – even if their perception of future spot prices is different to the market price of hedges. The reason is that market participants are limited by the size of their balance sheets as to how much exposure to future spot prices they can incur before also being exposed to the potential for financial distress.

359. One can see this for a generator in Figure below. This figure plots the marginal cost to a generator of selling a hedge contract against the number of hedge contracts sold.

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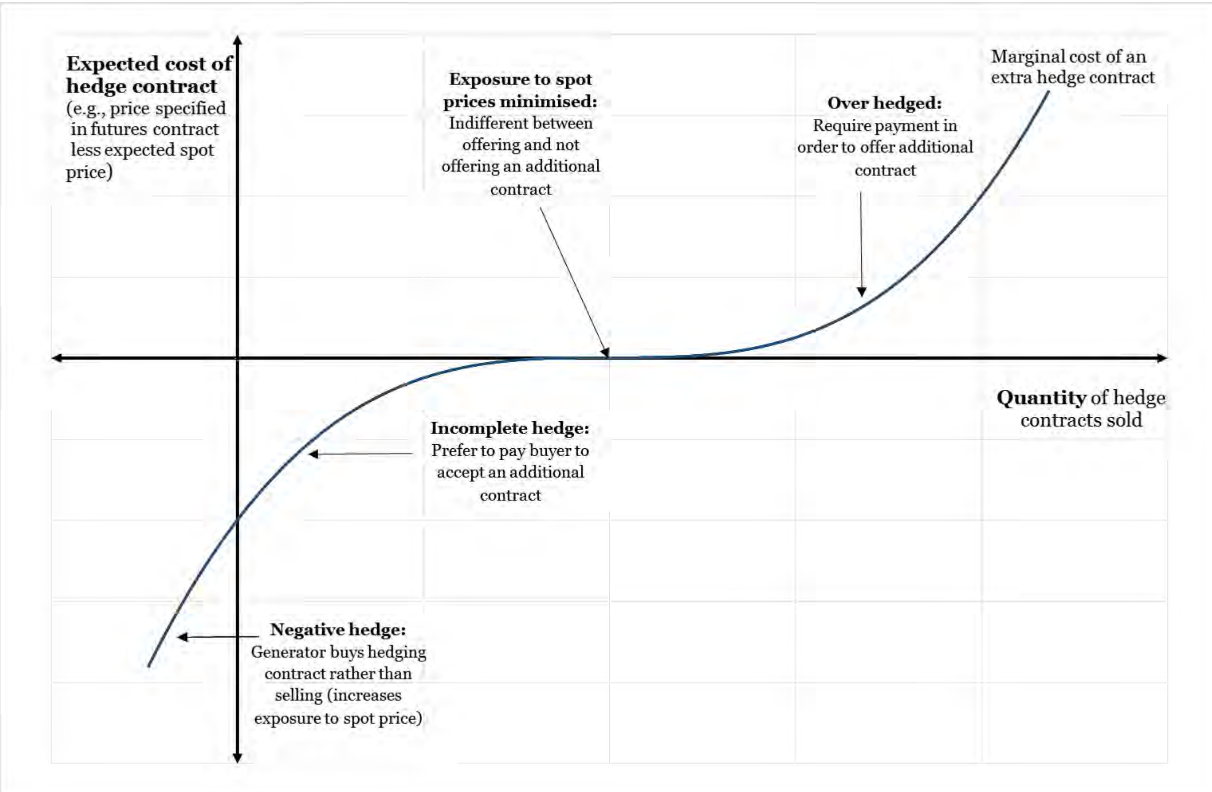
hedging position is a 'set and forget' position. It contributes nothing to market liquidity or price discovery because trading in these volumes is not sensitive to market conditions.

Now imagine that these two firms merge. Let the merger create a level of 'natural hedge' of, say 60%. The combined entity no longer needs to source is baseline 50% hedge position in financial markets. Its baseline holdings of financial contracts will fall dramatically. However, its need to continually trade and optimise its hedge portfolio between 50% and 100% is unchanged. This will be achieved via day-to-day trading in financial markets just as it would have been had the two operations remained standalone. The contribution to market liquidity from the combined entities is the same.

360. The vertical axis is a measure of 'price' of a hedge contract defined as the difference between the price specified in the futures contract and the actuarially fair (i.e., probability weighted) expected spot price. Thus, if the contract price was 60 $/MWh and the expected future spot price was 50 $/MWh then the 'price' of the hedge contract would be 10 $/MWh. At this price, the expectation is that the generator will be paid 10 $/MWh by the retailer). Similarly, if the contract price was 60 $/MWh and the expected future spot price was 70 $MWh then the 'price' to the seller would be negative 10 $/MWh (the expectation would be that the retailer will be paid by the generator).

Figure A3: Illustration of marginal cost curve for an individual generator



Source: CEG

361. Initially, with zero hedge contracts sold, the generator has a strongly negative marginal cost for the first contracts sold. That is, the generator would be happy to sell contracts at a negative premium to the expected spot price. This reflects the fact that with zero hedging the generator is 100% exposed to the spot price. Unless they have a very strong balance sheet,[74] having zero hedging will mean that there is a significant exposure to very low spot prices, causing negative cash-flows and

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74 That is, access to liquid assets in excess of the potential negative equity cash-flows that could result from 100% exposure to the spot price for an extended period.

triggering financial distress. Consequently, the generator would, if necessary, be prepared to sell hedge contracts at a discount to the expected spot price in order to reduce the risk of financial distress and, therefore, reduce the expected costs of financial distress.

362. However, as the number of hedge contracts issued increases, the probability of lower spot prices causing future financial distress is reduced. Consequently, the generator places a lower marginal valuation on selling each incremental hedge contract. Thus, the marginal value/cost of issuing a new hedge contract rises (becomes less negative).

363. At some point, the sale of incremental hedge contracts will cease to provide any further hedging benefit. That is, the sale of one more contract will not reduce (or increase) the volatility of cash-flows. This is the point at which exposure to spot prices is minimised. (This can be thought of as a position that is 'fully hedged' – although this is potentially misleading given that a true complete hedge is not possible due to outages and other factors.) At this point, the marginal cost of issuing another contract is zero and the generator is indifferent between issuing and not issuing the contract.

364. In order to be convinced to sell additional contracts beyond the quantity that results in a 'fully hedged' position, the generator must expect to be paid a premium relative to the expected spot price. This is because, beyond this point, selling additional hedge contracts increases the generator's exposure to spot prices. That is, the generators becomes 'over hedged' in that the additional liabilities under hedge contracts, in the event of high spot prices, exceed the additional spot market revenues it receives. Consequently, selling additional hedge contracts increase the probability of future financial distress and, therefore, increases the expected costs of financial distress.

365. It follows from the above analysis that the marginal valuation/cost curve for the generator's supply of hedging contracts is directly derived as:

- The change in the probability of reaching various levels of financial distress as a result of selling the contract; multiplied by
- The costs associated with the levels of financial distress.

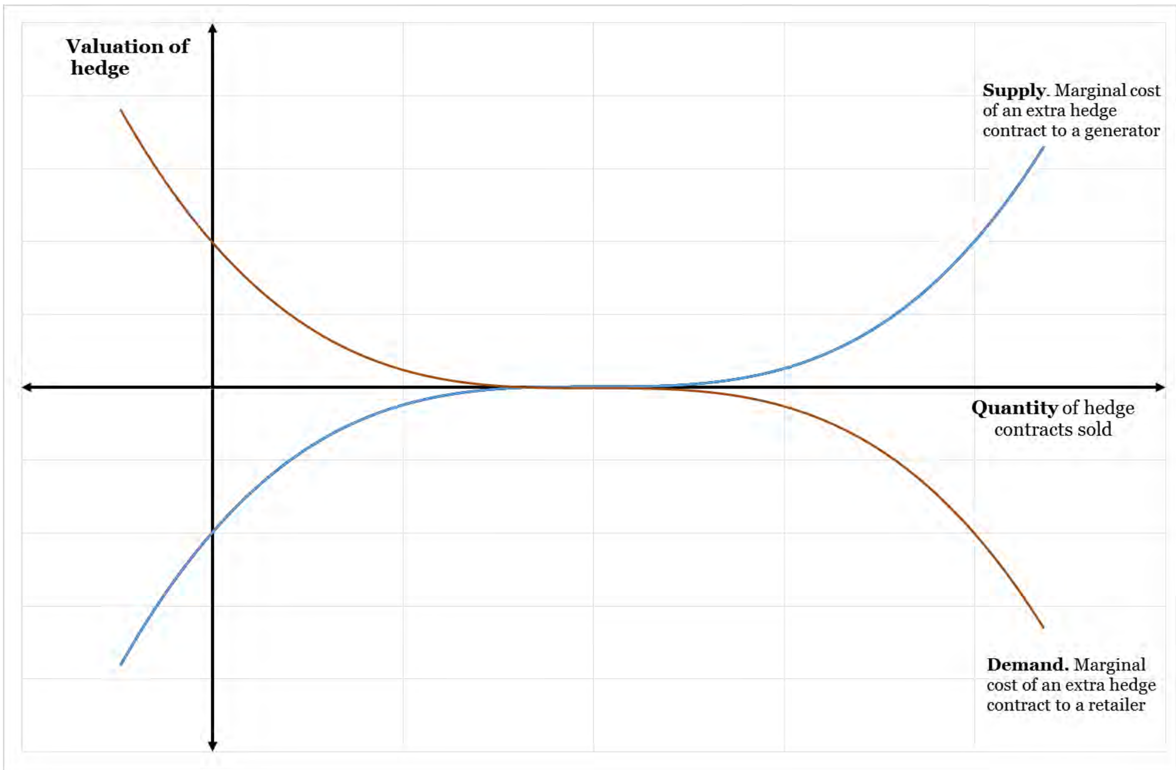
366. The marginal valuation/cost curve has been drawn with a 'sideways S' shape to reflect the fact that, beyond a given point, the costs of financial distress increase rapidly with incremental losses in cash-flow. The middle of the curve is drawn relatively 'flat' to reflect the fact that, starting with even a modest balance sheet, some additional spot market exposure does not materially increase the probability of high cost financial distress. However, as one moves away from the middle of the curve, the probability attached to high cost financial distress increases more and more rapidly – which is why the slope of the marginal cost curve is steeper the further away from the 'fully hedged' middle position on the curve.

367. The entirety of the above logic applies in reverse to retailers. That is, absent an extremely strong balance sheet, a retailer with zero hedging will place a very high

valuation (willingness to pay) for a marginal hedge product. However, this marginal valuation will decline as the number of hedge contracts bought increases. Eventually, the marginal valuation will turn negative as additional hedge contracts actually increase exposure to spot price volatility rather than reducing it.

368. On the assumption that a retailer was otherwise identical/symmetrical to a generator (e.g., had the same balance sheet, the same load and profile etc. and also faced the same costs in the event of financial distress), then the retailer's marginal valuation curve would simply be the "mirror image" of the generator's marginal valuation curve. This scenario is illustrated in Figure A4 below.

Figure A4: Generator and retailer marginal valuation curves



Source: CEG

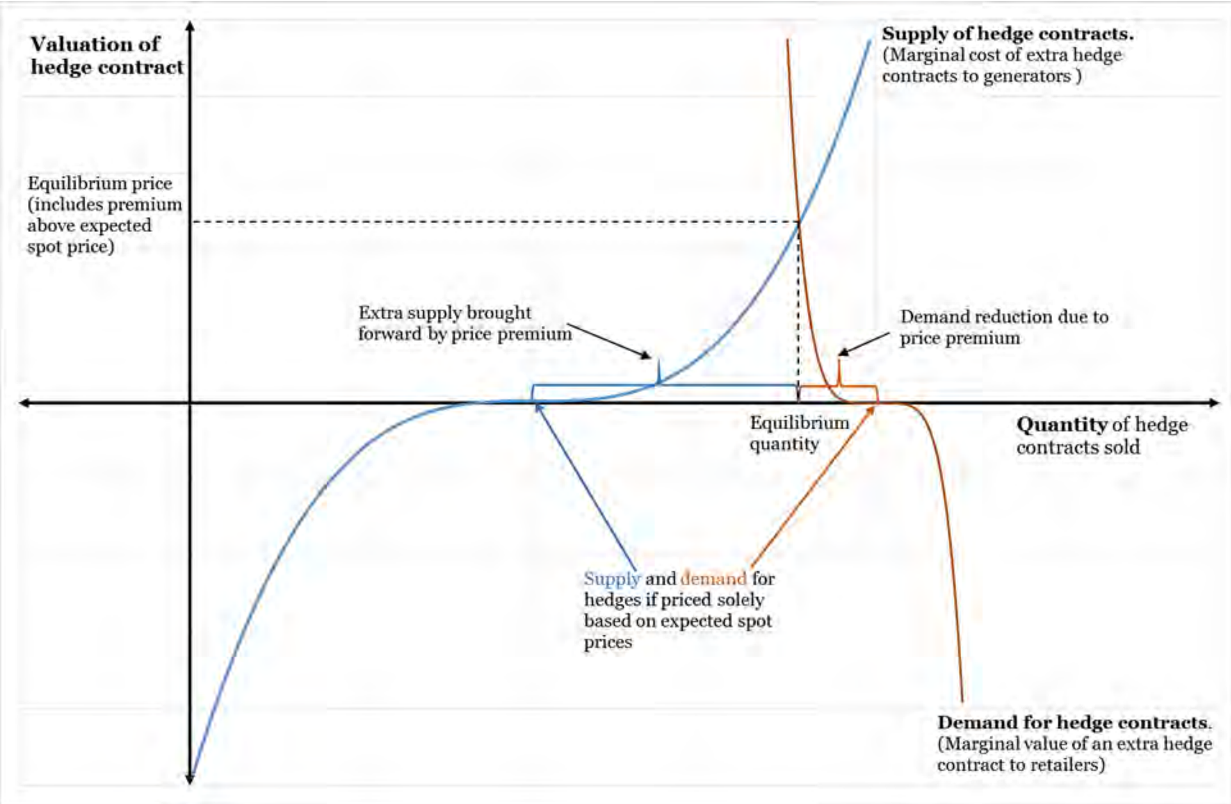
369. This diagram is useful in that one can easily see hedge market dynamics operating. Imagine that the above cost curves were typical of all generators and retailers. In which case, before any hedge contracts were sold, retailers would have a high valuation on hedge contracts and generators would have a very low valuation. Consequently, market forces would 'kick in' and generators would sell hedge contracts to retailers. However, the more contracts sold the lower the gap between valuations would become. Eventually, enough contracts would have been sold for the gap in valuations to fall to zero, at which point equilibrium is achieved.

370. As drawn in Figure A4, based on the assumption of symmetry between retailers and generators, equilibrium is achieved at a 'price' of zero (where the contract price equals the expected spot price). However, other equilibrium outcomes are possible and, indeed, likely.

371. For example, assume that retailers typically chose to have a lower level of exposure to spot prices than generators. This may, in turn, reflect a decision to enter with a relatively weaker balance sheet than generators and also that the downside for retailers of not being hedged during extreme high price events is worse than the downside for generators of not being hedged during low priced events. (Noting that it is downside events that trigger financial distress and the associated costs of that financial distress.)

372. The net result is that the marginal valuation curve for retailers will be shifted to the right relative to that of generators. This is illustrated in Figure A5 below for a 'typical generator' and a 'typical retailer'.

Figure A5: Asymmetrical generator and retailer marginal valuations



Source: CEG illustration.

373. Given the assumptions underpinning this scenario, if hedge contract prices just reflected expected spot prices then there would be excess demand. This would cause a premium to be built into the price of hedge contracts with the effect that:

- generators would increase their supply of hedging products by becoming 'over hedged' and accepting more exposure to the spot price (the price premium providing the incentive to do so); and
- retailers would reduce their demand for hedging products by becoming under hedged (i.e., accepting more exposure to the spot price rather than be fully hedged using contracts that include a positive hedge premium).

374. In this equilibrium, retailers are effectively shifting some of their risk to generators. Generators are better able to bear this risk given their stronger balance sheets, and the hedge market provides a means for retailers to, in effect, make use of generators' balance sheets. However, retailers must pay generators for this privilege – with the premium in hedge contracts relative to expected spot prices effectively a 'rental charge' for using generators' balance sheets (convincing generators to over hedge in aggregate).

375. It appears to be well accepted that hedge prices in wholesale electricity markets typically are struck to include a premium on the expected spot price. If this is correct, then the market is characterised by something like Figure A5.

NERA
ECONOMIC CONSULTING

Vertical integration and competition in the New Zealand electricity markets

Meridian Energy

23 October 2018

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1. Introduction and conclusions

1. The New Zealand Government's Electricity Pricing Review (**"EPR"**) first report ("**EPR first report**") states the EPR has been asked to consider: [1]

> *... whether vertical integration limits competition across the supply chain. Vertical integration simply means, in our context, companies that generate electricity and also retail it. The five big companies that dominate generation and retailing are vertically integrated. Some smaller retailers, such as Nova Energy, are also vertically integrated.*

2. We have been asked by Meridian Energy Limited (**"Meridian"**) to comment on whether vertical integration has impacted entry or limited competition in the New Zealand electricity generation and retail markets.

3. We note at the outset that public policy should be concerned with the competitive process and outcomes, not whether particular competitors with specific business models are able to compete. Furthermore, when assessing whether competition has been "limited", the relevant standard is workable competition, not perfect competition. The Commerce Commission has summarised the concept of workable competition as follows:[2]

> *"Workable competition exists when there is an opportunity for sufficient influences to constrain the market power of suppliers (e.g. rivalry amongst existing suppliers, the threat of substitute goods and services, the threat of new entrants, or the buying power of consumers)."*

4. Addressing the questions posed by Meridian concerning vertical integration requires comparing the state of competition in the electricity markets today (the **factual**) with the state of competition that would exist if there was no (or perhaps less) vertical integration (the **counterfactual**).

5. In the factual/today, the evidence is that:

   a) Entry has occurred at generation and retail, and has been sustained;

   b) At retail, switching rates are at historical highs and the market share of the incumbent firms has and continues to be eroded with firms outside the "big 4" now having a national market share of 24.41% (split between 12.84% for Trustpower (which is short on generation) and 11.58% for other firms);[3] and

   c) At generation, wholesale prices have largely tracked long run marginal cost (LRMC).

6. Electricity is a product with unique features that result in volatile wholesale prices.[4] Therefore risk management is fundamental to competing in electricity supply, and is a cost of doing business, incurred by both incumbents and entrants.

7. The risk situation in New Zealand is (materially) exacerbated by a high degree of hydro generation and limited storage. Therefore, in addition to volatile prices, New Zealand is also

[1] *EPR first report*, p.43.

[2] Commerce Commission, *Input Methodologies (Airport Services): Reasons Paper*, December 2010, X8.

[3] EA EMI database, as at 31 August 2018.

[4] In theory if this risk could all be passed to consumers, e.g., with spot pricing at retail, then retailers and generators would not bear spot price risk. However, at present we understand only Flick and Paua to the People offer spot pricing and they have a combined market share of 1.23%. Therefore, the majority of New Zealand electricity consumers 98.77% pay fixed prices for electricity. Source: EA EMI Retail market share trends report. Accessed 19/10/18.

subject to what is known as "dry year risk" – sustained periods of high prices during "dry periods".[5]

8. Globally, vertical integration is a commonly-observed strategy to manage risk in electricity markets, including in markets widely regarded as being competitive. Vertical integration between generation and retail provides a natural hedge (a good day for the retail business is a bad day for the generation business and vice versa).

9. However, two commonly-cited concerns regarding vertical integration are that:

   a) Hedges may not be offered to competitors, preventing entry and dampening competition (**foreclosure theory of harm**); and

   b) Vertical integration may reduce liquidity and therefore increase the transactions costs of hedging risks (**liquidity theory of harm**).

10. Regarding the foreclosure theory of harm:

   a) Foreclosure is typically only a concern if there is market power at one vertical level – there can be no *ability* to foreclose if a buyer of hedges can shop around for suppliers. As already noted, there are multiple generators and retailers in New Zealand, and there has been successful entry and expansion by non-integrated players.

   b) Furthermore, the competitiveness of these markets means firms are unlikely to have an *incentive* to foreclose by withdrawing hedges. For example:

      i) The entry of a stand-alone retailer which acquired customers from a fully internally-hedged vertically integrated gentailer would result in that gentailer becoming longer on generation. The gentailer would then become more exposed to risky spot prices;

      ii) By selling a hedge to the retailer, the vertically integrated gentailer would manage its risk. If instead it attempted to foreclose the retailer, the vertically integrated gentailer would miss out on that hedge, and so face the risk;

      iii) This cost of foreclosure might be justified if the vertically integrated gentailer could be confident the foreclosed retailer's customers would switch to it. But the more competitive the market, the less likely this diversion would be; and

      iv) Furthermore, a rival vertically integrated gentailer or generator might sell the hedge anyway.

   c) To the extent that generators do not hedge their full generation output, this is likely the result of New Zealand's high hydro share and limited storage. Signing contracts with fixed prices and quantities in the face of dry year (i.e., material inter year price and quantity) risk would expose generators to additional risk they may efficiently not wish to bear:

      i) Thermal generators may not offer hedge contracts covering their full dry year output, as the SRMC of peaking plant will be above the retail/hedge price, thus exposing them to price risk; and

      ii) Hydro generators will not offer firm contracts equal to their wet year output, as this would expose them to price risk in dry years.

   d) Trustpower is short on generation and yet it has been increasing its retail market share. Furthermore, the large gentailers are long on generation and yet they still appear to sign contracts with other retailers, including independent non-integrated retailers.

[5] The extreme version of dry year risk is when there is not sufficient peak/reserve generation to come online and there would be sustained period of black outs or conservation campaigns because supply cannot meet demand.

e) Independent retailers with little/no generation now account for 11.84% of ICPs,[6] giving them a combined retail share close to that of Trustpower or Meridian.

f) We also note the EA's recent review of the 2017 dry winter[7] found that retailers were hedged well in advance of winter and therefore were not adversely exposed to price spikes.[8] While the *EPR first report* notes that spreads widened materially in June/July 2017, given the EA's finding that retailers were largely hedged in advance, this would have only affected speculators.

g) Relatedly, the widening of spreads was likely caused by the extreme volatility in hedge contract prices that occurred in June/July 2017, and not by vertical integration[9] – the link between volatility and bid-ask spreads is well established in the empirical finance literature.

h) Accordingly, we do not think the evidence supports a concern about vertical integration leading to foreclosure.

11. Regarding the liquidity theory of harm:

a) There is no generally accepted definition of liquidity, but broadly the concept represents the ability to buy and sell quickly without altering market prices.

b) Low liquidity can occur in the absence of vertical integration, due to the underlying features of the market. For example, as already noted, dry year risk may mean that hydro generators do not fully hedge their output and therefore this generation does not participate in the hedge market.

c) The *EPR first report* is wrong to state that, *"Vertically integrated companies have no inherent need for contract markets"*.[10] We observe vertically integrated firms hedging with other players, either through standardised financial contracts on the ASX, over-the-counter contracts (OTC transactions) or through contracts such as the "swaption" between Meridian and Genesis. Even if vertically integrated firms make an internal allocation of all their generation to the retail arm of their business, they still have the incentive to trade hedge contracts in the secondary market:

i) To arbitrage contract prices;[11]

ii) Because their own generation and their customers' retail demand will be unlikely to match in any given half hour;[12]

[6] Although we note that Nova accounts for 3.7% of ICPs and it also owns generation assets.

[7] Electricity Authority, *2017 Winter Review*, 22 March 2018.

[8] As we note elsewhere, hydrology risk may result in the market being structurally short of hedges, so this statement is one of degree, i.e. it is unlikely any party will be completely hedged. Furthermore, there are financial speculators in the hedge market who provide contract volumes unrelated to physical generation capacity.

[9] Contracts that did not experience increased volatility, being contracts for energy outside of the 2017 winter months, did not experience increased spreads.

[10] *EPR first report*, p.43.

[11] E.g., it would be profit maximising for the retail arm to sign contracts with generators whose SRMC is lower than the vertically integrated firm's expected cost of generating during the contract period.

[12] E.g., a firm that has lots of solar generation could be structurally long on generation during the summer months and short on power during the winter months, despite its total generation over a year being equal to the consumption of its retail customers.

iii) Because their generation and customers' demand needs can change independently of each other;[13]

iv) The generators in New Zealand have quite a different fuel mix and hedging between firms can be used to manage that risk; and.

v) Because the valuation that any player places on a hedge is a function of the financing and risk management of each business and the specific supply and demand risks that each business faces. Accordingly, the valuation of hedges will differ between generation and supply businesses.

d) There are markets with high vertical integration and high liquidity (measured by contract turnover), such as the NEM[14] outside South Australia and the UK. Furthermore, vertical integration is a common structure in high liquidity markets such as Germany and the Nordic countries;

e) A counterfactual world with no vertical integration would likely involve attempts to replicate vertical integration by contract (i.e., retailers and generators signing longer term hedge contracts). Under the theory of harm posited for vertical integration, this would also lower liquidity, which raises the question of how different liquidity would be with less vertical integration;

f) The UK CMA did not find any evidence to suggest liquidity is causing competitive distortions in the UK, despite a similar level of vertical integration there to that in NZ.

g) Even if the hedge market would be more liquid under the counterfactual, consumer outcomes would likely be worse than under the factual. That is because the fact we observe vertical integration in so many electricity markets across the world strongly implies this market structure is efficient, and in particular that it is an efficient risk management mechanism.

12. Therefore, in our view, vertical integration is unlikely to be inefficiently resulting in material barriers to entry or limits on competition in the New Zealand electricity markets. Rather, vertical integration is an efficient and competitive response to underlying conditions that make contracting hard.

13. The rest of this paper proceeds as follows:

a) Section 2 discusses the unique risks faced by participants in electricity markets more generally, the unique situation in New Zealand that results in dry year risk, and that vertical integration is a commonly observed strategy for managing these risks.

b) Section 3 documents evidence concerning the current competitiveness of the generation and retail levels of the market (i.e. the factual/status quo).

c) Section 4 addresses the question of whether an alternate world with less/no vertical integration would result in lower prices and/or better outcomes by considering the two commonly posited theories of harm for vertical integration in electricity markets.

[13] For example, in winter a vertically integrated firm may experience a period of warm weather where its customers are located, reducing demand for heating, while simultaneously experiencing windy weather in the area where it has wind turbines. I.e., supply and demand might receive independent shocks.

[14] The NEM is the acronym commonly used to reference electricity markets in Australia and stands for the "National Electricity Market".

2. Risk management is fundamental to competing in electricity supply

14. In this section we make three key points:

a) The unique features of electricity markets mean that all electricity markets face volatile prices and therefore risk management is important;

b) Due to a high hydro share and low storage, New Zealand faces both the *within* year volatility experienced in other markets and the *between* year risk of a dry year; and

c) Vertical integration is an efficient, commonly observed, way to manage risk in electricity markets.

2.1. Electricity markets are characterized by unique risks

15. Electricity is a product with unique features that result in volatile prices, including that:

a) Demand on the grid must be balanced in real time, which means that electricity produced at different times may have very different value to consumers (or large retailers on their behalf);

b) Both demand and supply can vary in unpredictable and unrelated ways, which combined with the costs of committing units to generation ahead of time, increases volatility and exposes both generators and retailers to price and volume risk;[15]

c) The demand side is largely passive in the short run and very inelastic (although this is changing with, e.g., the advent of smart meters and retail spot pricing); and

d) The costs of the storage that would flatten prices are prohibitive (albeit falling).

16. Given this backdrop of volatile prices, both retail and generation need to manage risks. In other words, risk management is a cost of doing business, incurred by both incumbents and entrants.

17. Regulatory concerns about vertical integration in electricity are typically that small retailers short of power must pay an excessive price for hedging these risks because:

a) Menu costs[16] are high and metering technology has historically not allowed retailers to bill customers based on the cost of electricity they actually consume, such that retailers typically cannot effectively pass these risks through to end-users in the short term;

b) The pooled nature of the wholesale market means there is open access to the underlying physical commodity, which means that regulators' concerns about vertical integration are rarely absolute input foreclosure; and

c) Generation investment is lumpy, long-lived and capital intensive which prevents small retailers (or generators) from easily hedging their own customers demand by building plant (or output by acquiring customers) and therefore small market participants need to rely on the wholesale market to mitigate wholesale price risk.

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[15] E.g. both demand and supply can be affected by the weather, but the effect on each will not always be the same if the weather is different where generation and demand are located.

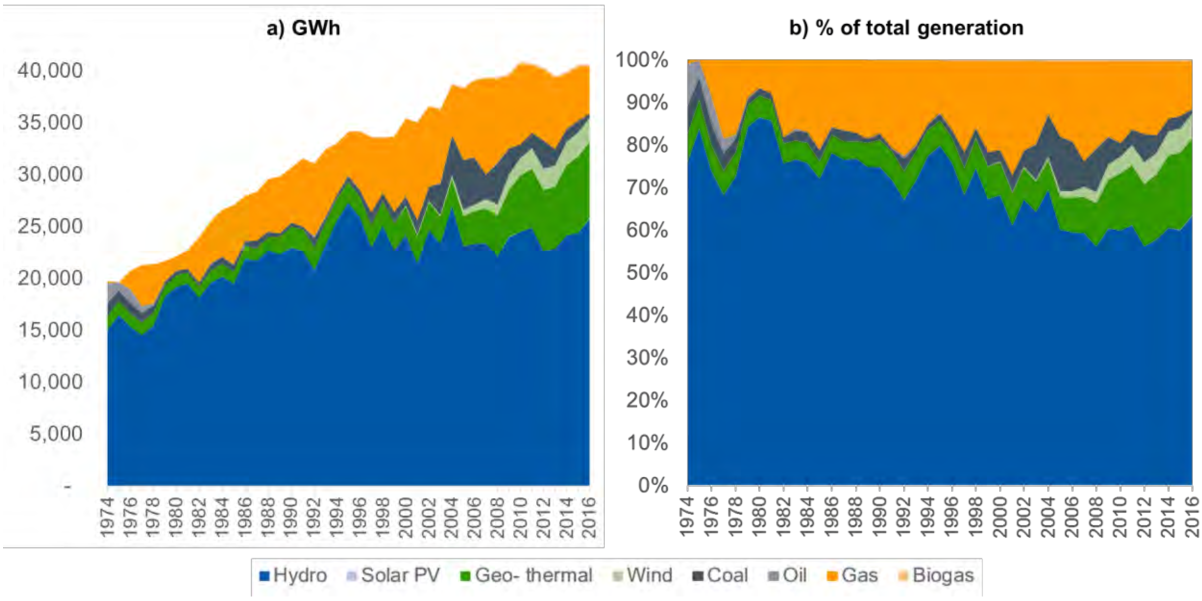
[16] I.e. the transaction costs associated with changing prices. If menu costs were low, suppliers could simply update their retail prices if there was a shock to wholesale prices.

2.2. Risk is exacerbated in NZ due to large hydro share and lack of material storage

18. Most electricity markets experience significant *within year* price volatility. In this section we demonstrate that New Zealand's combination of a high proportion of hydro generation and lack of long term hydro storage results in an additional risk to be managed: *between year* or what is known as dry year risk.

19. Figure 1 below shows annual total generation by fuel type in energy (GWh) terms and as a percentage of the total. As at 2016 (which is the year of the latest data), hydro generation provided around 60% of annual generation.

Figure 1: New Zealand: Generation Output Mix (excluding cogen) (1974-2016)



Source: NERA analysis of MBIE electricity data file

20. Regarding the generation portfolio of the main gentailers, some companies rely much more heavily on hydro generation, while others rely more heavily on generation from thermal sources.[17] However, even though Contact and Genesis have the largest non-hydro share in their generation portfolios, hydro still makes up approximately 40% of their generation capacity (see Figure 2).

21. The large proportion of New Zealand generation that is hydro (~60%), combined with low storage and volatile inflows,[18] means that the New Zealand wholesale market is subject to material hydrological risk.[19] As shown in Figure 1 New Zealand's annual generation in 2016 was around

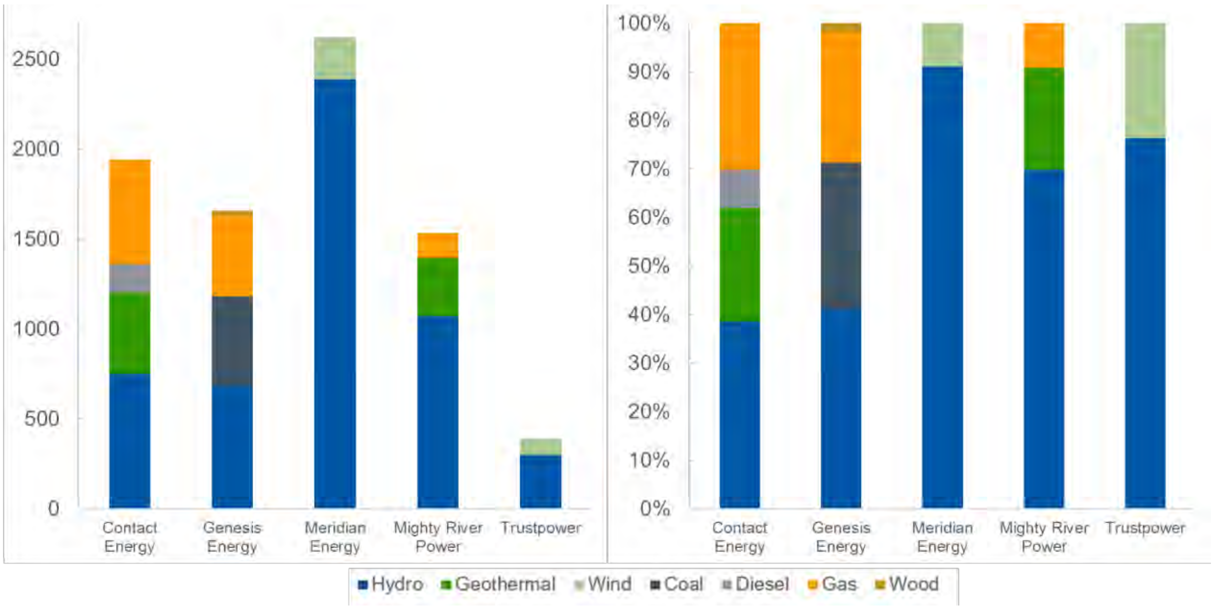
[17] In 2015, Meridian, Mighty River Power and Trustpower generated 65-85% of their output from hydro sources, and 15-35% from thermal sources, while Contact and Genesis generated only around 40% of their output from hydro sources and around 60% from thermal sources.

[18] See, e.g. the hydro inflows on Transpower's website https://www.transpower.co.nz/system-operator/security-supply/hydro-storage-information

[19] Hydrological risk curves for New Zealand are available on the EA's website at: https://www.emi.ea.govt.nz/Reports/Environment/Chart/3UN1KD

40,000 GWh.[20] Average national hydro storage is around 3,000 GWh,[21] or slightly less than one month of average consumption. The current level of hydro storage in New Zealand is insufficient to smooth out fluctuations in inflows, so "dry years" have a material impact on electricity spot market prices.

Figure 2: New Zealand: Current grid Connected Generator Capacity Mix



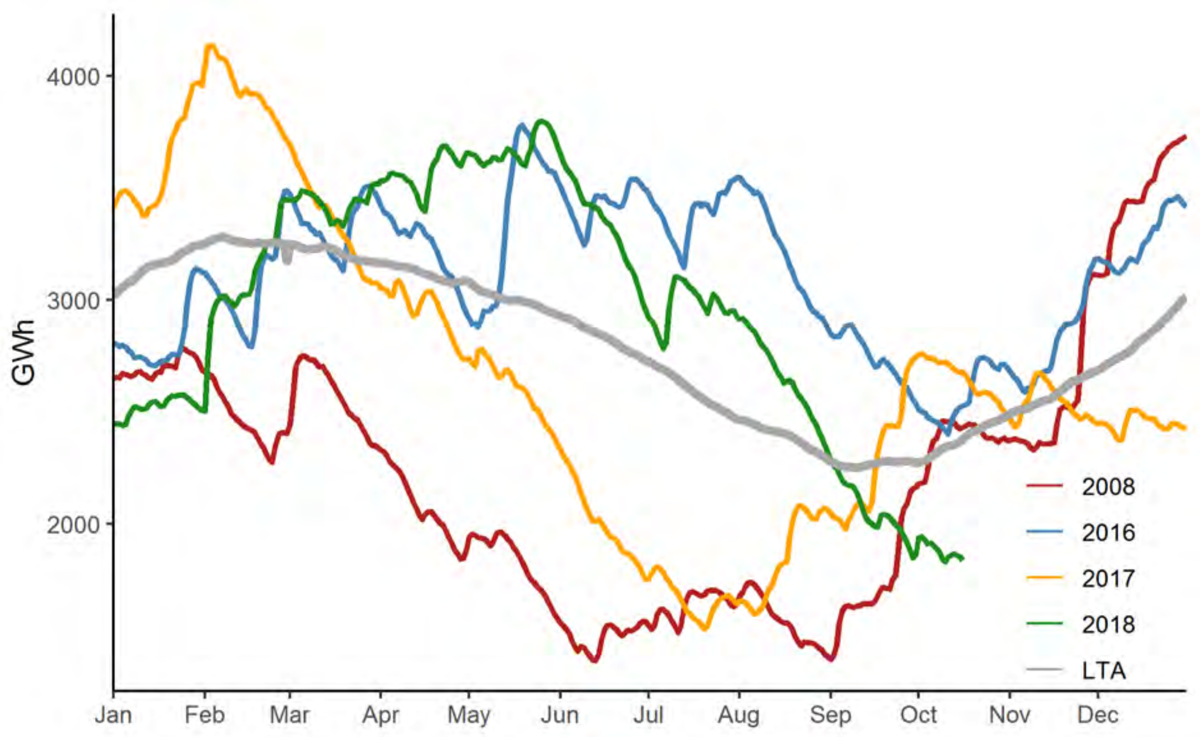
Source: NERA analysis of EA EMI "Current Generation Fleet" dataset

22. Figure 3 below shows New Zealand's national hydro storage over the past three years, as well the long- term average and the curve for 2008, which was a particularly bad "dry year".

[20] According to Electricity Authority statistics, grid based generation for the 2016 calendar year was 40,0074.35 GWh. See https://www.emi.ea.govt.nz/r/hxnnj.

[21] See the 83-year average storage level on page 4 of the report available at: https://www.meridianenergy.co.nz/assets/Investors/Reports-and-presentations/Monthly-operating-reports/2018/July-2017-mo nthly-operating-report.pdf

Figure 3: New Zealand national hydro storage

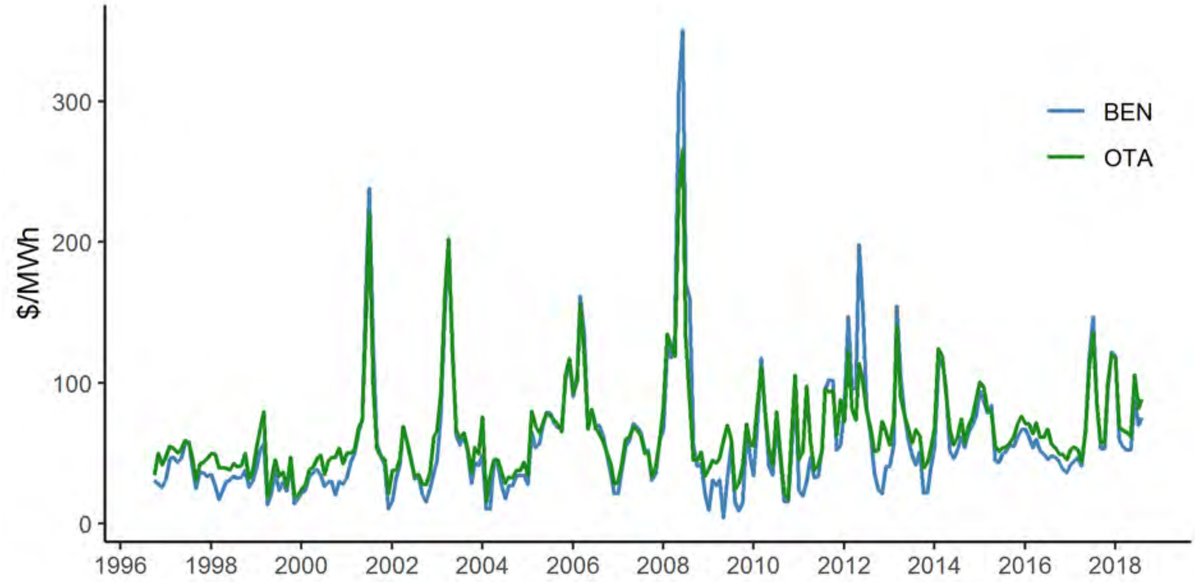


Source: NERA analysis of NZX hydro data

23. This chart demonstrates that 2016 and 2017 had almost opposite storage patterns, with 2017 being materially below average during the winter months and 2016 being materially above average in the winter months. Similarly, despite 2017 being a dry year, storage levels for 2018 (the green line) began the year well above the long-term average and are currently tracking below the long-term average. This variation between years can result in significant price variation *between* years.

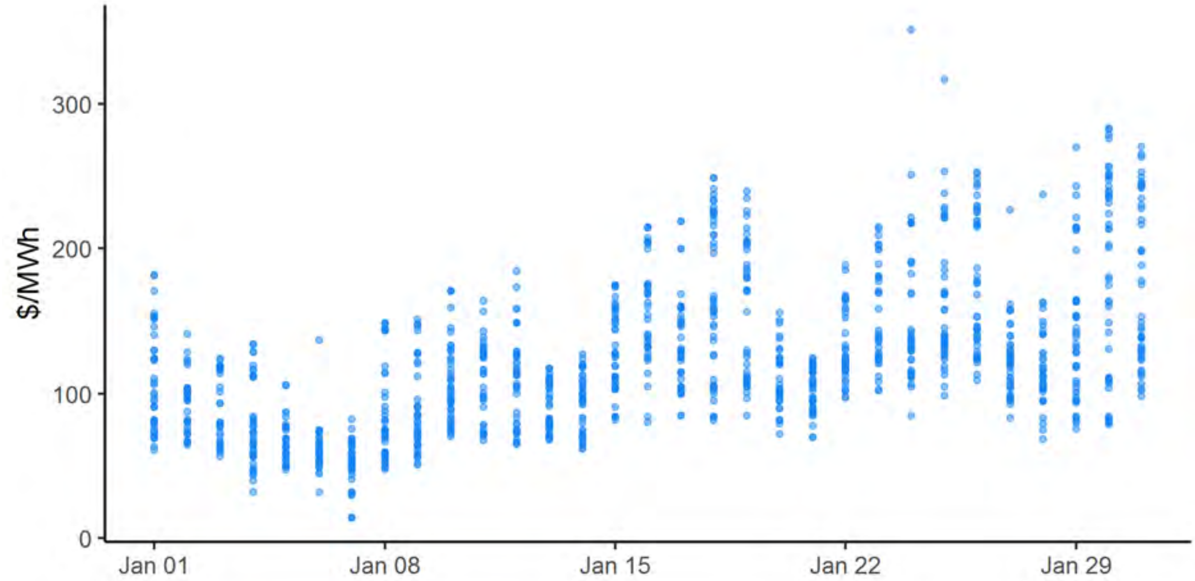
24. During dry years wholesale spot prices can rise materially, as shown in Figure 4 below, which charts historic wholesale spot prices in New Zealand over the period 1996-2018. Each major "spike" in price corresponds to a dry year (i.e. to a period of below-average precipitation).

Figure 4: New Zealand: Monthly Average Wholesale Spot Price (1996-2018)



Source: NERA analysis of Electricity Authority EMI final pricing dataset.
Note: Calculated using daily average prices at the Otathuhu and Benmore grid reference points.

Figure 5: Half hourly spot prices at Benmore node: January 2018



Source: NERA analysis of EA Final pricing dataset.
(https://www.emi.ea.govt.nz/Wholesale/Datasets/Final_pricing/Final_prices/)

25. While Figure 4 shows monthly averages, like all electricity markets, even in the absence of dry year risk, participants in the New Zealand electricity markets also experience material volatility on a short term (i.e. half hourly basis). Figure 5 shows that prices vary materially within a day.

2.3. Vertical integration is an efficient and commonly observed strategy to manage these risks

26. Vertical Integration provides an internal hedge and therefore can be a more efficient means for managing wholesale electricity price variability, both in terms of the flexibility it offers to

respond to changing market conditions and from a transactions costs perspective. As the ACCC notes (citing NERA):[22]

> *In essence, the ability to increase or decrease generation output facilitates a more flexible hedge against the retailer's change in demand. This flexibility is difficult to achieve through contracts, which typically specify a fixed volume.*
>
> *The reduction in transaction costs from vertical integration may be significant. Establishing and maintaining a portfolio of contracts is a significant undertaking that requires ongoing management and negotiation. Vertical integration may alleviate these costs. However, vertically integrated retailers continue to participate in contracting markets to some degree, so these costs are not entirely avoided.*

27. Vertical integration is a commonly observed strategy in electricity markets globally, including those that are generally regarded as being competitive, such as Germany, Nordpool and the UK.

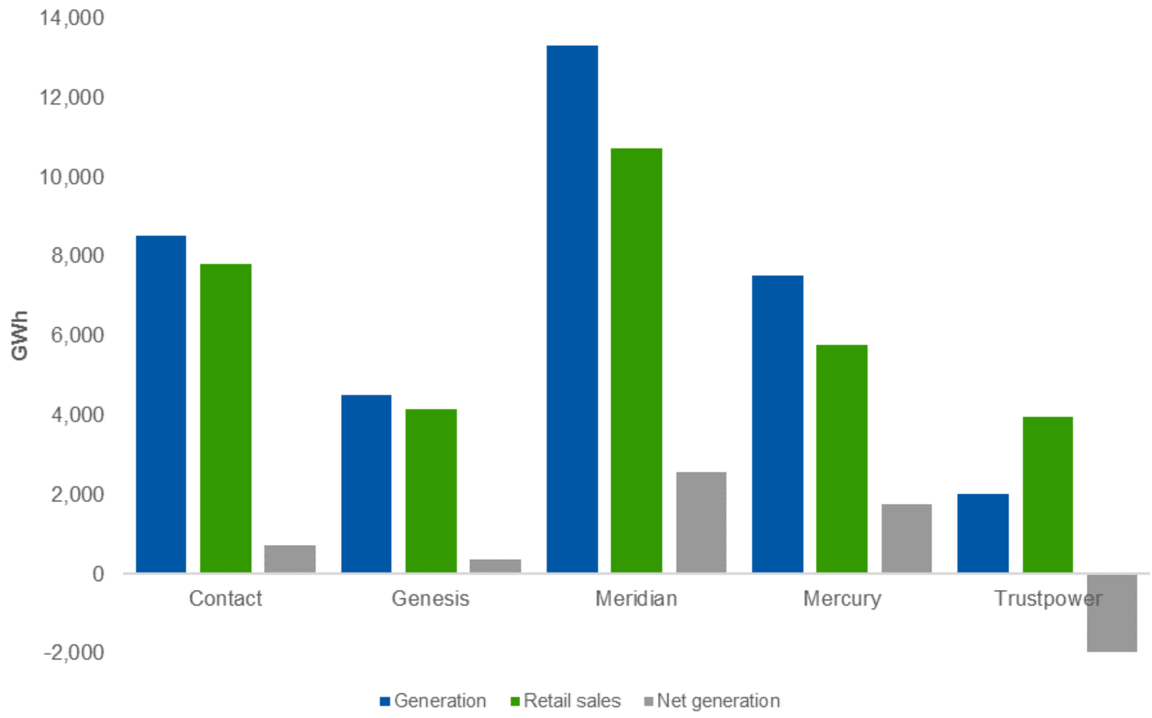
28. Turning to New Zealand, generation is provided mainly by five vertically integrated generator-retailers ("gentailers"), with only 7% of generation capacity owned by other firms.[23] Overall, the vertically integrated "gentailers" have broadly balanced portfolios of generation and retail sales[24] (see Figure 6 below). This is at least consistent with the view that the desire for hedging provides a motivation for vertical integration, when contract markets cannot meet the need as efficiently.

[22] ACCC, *Retail Electricity Pricing Inquiry: Final report*, June 2018, p.123.

[23] As at December 2015. See MBIE Electricity data file. We understand that no major grid connected generation has been commissioned since 2015 so this data is current.

[24] The portfolios of generation output and retail sales are still not perfectly balanced in geographical terms, since the majority of hydro generation is in the South Island while the majority of thermal generation, and load, is in the North Island. See Figures 10 and 11 of MED and ETAG, *Improving Electricity Market Performance – Volume 1*, August 2009. Hedging this geographical imbalance requires derivative contracts known as Financial Transmission Rights (FTRs), which were launched in New Zealand in 2013. That is not to say that the current FTRs perfectly hedge locational risk. The Electricity Authority launched a consultation process in March 2017 on further improving the FTR market. See https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/consultations/#c16389

Figure 6
New Zealand: Generation/Retail Sales Balance (FY2017)



Source: Generator Annual and operational reports

29. Despite the top four gentailers being long power over the year as a whole, this should not be taken to imply that vertical integration provides a perfect internal hedge within the year. Indeed, with intermittent renewables like wind and solar, volatile hydrological inflows and volatile demand, we might expect that within a year there will be times when each gentailer's generation does not match its retail sales. To unpick this, we can use the EA's data on "matched sales", which it refers to as a measure of the degree of vertical integration.[25]

30. This measure calculates on a volume weighted or value weighted basis, the extent to which, in a given month, sales (i.e. electricity injected into the grid) and purchases (electricity withdrawn from the grid) "match". In our view, it is perhaps more technically a measure of how effective vertical integration is at providing an internal hedge throughout the year.[26]

31. This figure is shown below for each of the "big 5" and an aggregate measure for small and medium retailers. The following are apparent from Figure 7:

    a) While there is material volatility for all firms, it is notable that Contact, Genesis and Mercury are frequently between 90 and 100% matched;

    b) Trustpower has increased the extent to which its injections and offtake match over time;

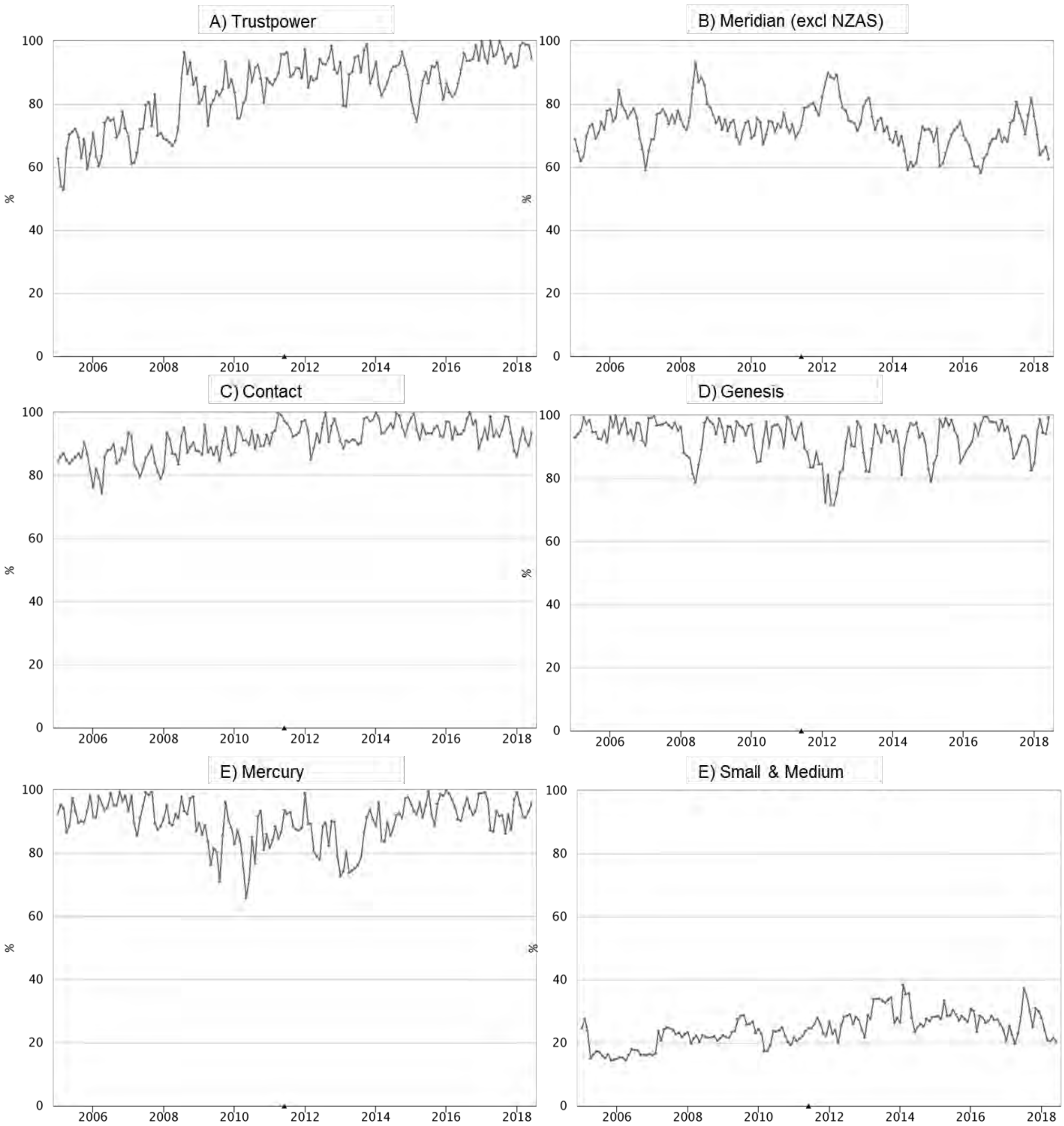
[25] https://www.emi.ea.govt.nz/Wholesale/Reports/BLKL4U?Include=All_NZAS&Show=MWT&_si=v|3#tabs-3

[26] This measure is not contingent on the hedge contract trading behaviour of the generators concerned but shows the net position based on *physical* offtake and injections. Accordingly, it measures months in which, each supplier could have supplied its needs entirely from power it generated itself. In practice, the generation and retail businesses concerned may have traded further contracts with third parties. Moreover, given that suppliers' needs for electricity fluctuate on a half-hourly basis, the generation and retail businesses shown would have traded either with each other or with the TSO in order to match their real time positions.

c) Small and medium firms are only ~20% matched; and

d) Meridian rarely has more than 80% of its injections and offtake matching.

Figure 7: Extent to which injections and offtake match (monthly, by firm)



Source: NERA analysis of Electricity Authority EMI data

Note: The EA describes this metric as follows: "If a firm, or trader, has total purchases that precisely equal its total sales, we say that sales and purchases are matched. If total purchases exceed total sales then only a portion of the trader's purchases are matched by its sales, and vice versa. In other words, if S denotes sales and P denotes purchases, the matched volume is equal to min(S, P). The VI measures expressed as a percentage, whether volume or value, are defined as: 100·2·min(S, P)/(S + P). "

32. The fact that Meridian, as the largest generator, is generally not more than 80% matched, while the rest of the big four are, is particularly interesting. This may reflect the fact that Meridian has a relatively large share of its generation portfolio made up by hydro and thus has less control over

its generation than a firm with a thermally dominated portfolio. We return to the impact of hydrological risk in Section 4.

33. We also note that the “small and medium” players are not very “matched”. Despite, this, as we show in section 3.1, these players have been successfully gaining market share. Likewise, Trustpower appears to have historically been short on generation, yet is has increased the proposition of its sales that are matched in recent years and gained market share.

3. The Factual: Evidence suggests no market power in generation and retail

34. The question we address in this report is whether vertical integration has impacted entry or limited competition in the New Zealand electricity generation and retail markets. This requires comparing the state of competition in the electricity markets today (the factual) with the state of competition that would exist if there was no (or perhaps less) vertical integration (the counterfactual).

35. As we set out in the remainder of this section, the evidence suggests that in the factual/today:

a) Entry has occurred at generation and retail, and has been sustained;

b) At retail, switching rates are at historical highs and the market share of the incumbent firms has and continues to be eroded; and

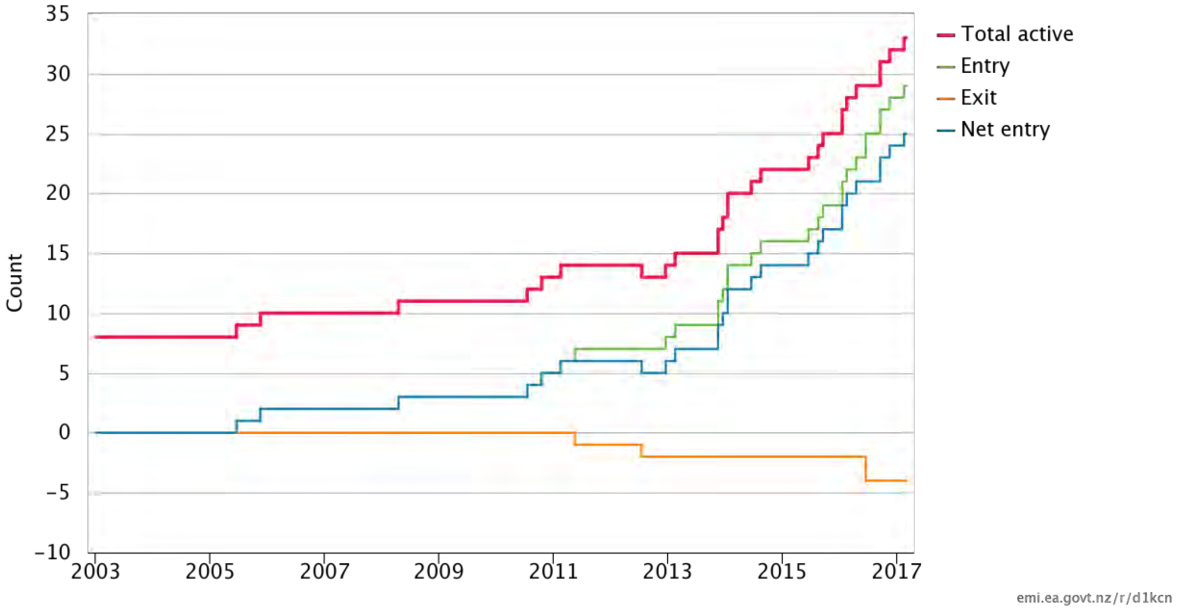
c) At generation, wholesale prices have largely tracked long run marginal cost (LRMC), suggesting the market is delivering efficient outcomes.

3.1. Evidence of retail market entry

36. Retail prices for residential customers have been rising over time, which the *EPR first report* largely attributes to a combination of retailer charges rising[27] and a reallocation of distribution costs from business and industrial customers to residential customers.[28]

37. Figure 8 shows entry and exit by new firms (as opposed to brands) since 2005. There has been material entry in recent years, with the number of firms competing in the retail market more than doubling in the last five years.

Figure 8: Entry by new retailers (parent companies) since 2005



Source: Electricity Authority

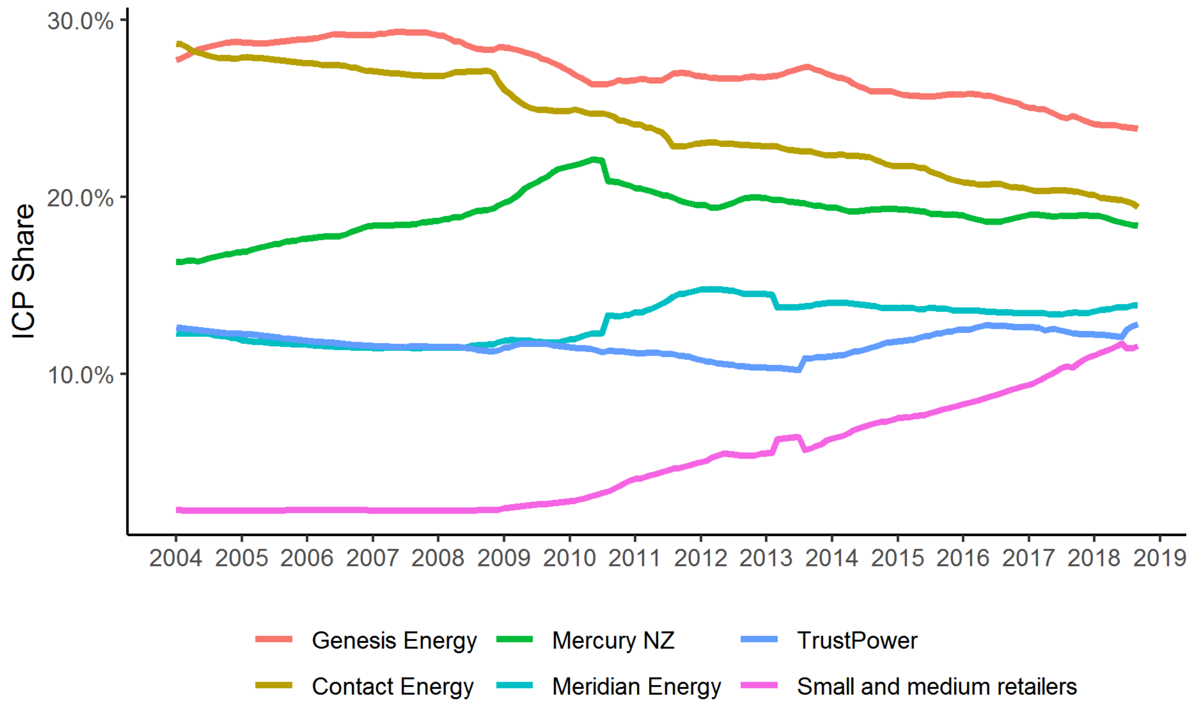
[27] *EPR first report,* p.22.

[28] *EPR first report,* p.21

38. In terms of the impact this has had on market share, the market share of firms outside the "big 5" has been steadily increasing since 2009, with the combined market share (measured by number of customers) of these firms of 11.58% now at a similar level to Trustpower (12.84%) and Meridian (13.87%).

39. Also of interest is that both Meridian and Trustpower, being the smallest of the big 5 with respect to retail market share, have increased their retail share over the same time period. Although Meridian has been relatively flat since 2013 and Trustpower was actually falling prior to 2013. The gains of independent retailers appear to have largely come at the expense of Genesis, Contact and Mercury.

Figure 9: National market share by ICPs



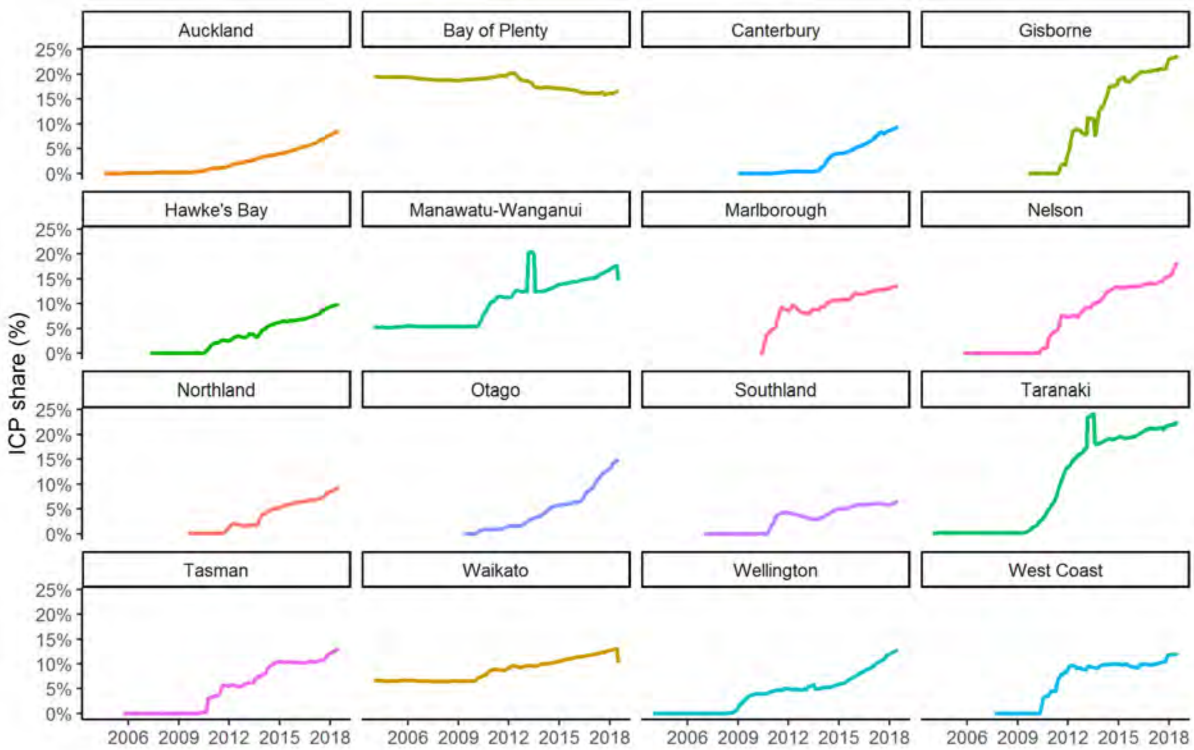
Source: Electricity Authority EMI dataset

40. The impact of these smaller firms is particularly pronounced in certain regions. Figure 10 below shows the combined ICP market share by regional council area for firms outside the big five.

41. The inroads made by independent retailers has resulted in, and reflects, a material increase in switching. Figure 11 below shows the 12-month moving average of the switching rate since 2005, and shows that prior to 2009 roughly 10% of ICPs changed supplier in a given year and this figure has doubled and is now over 20%. We acknowledge the point raised by the *EPR first report* that 42% of customers have never switched.[29] However, in the context of whether vertical integration is a barrier to entry/expansion, this lack of switching by a class of customers doesn't appear to have impeded entry.

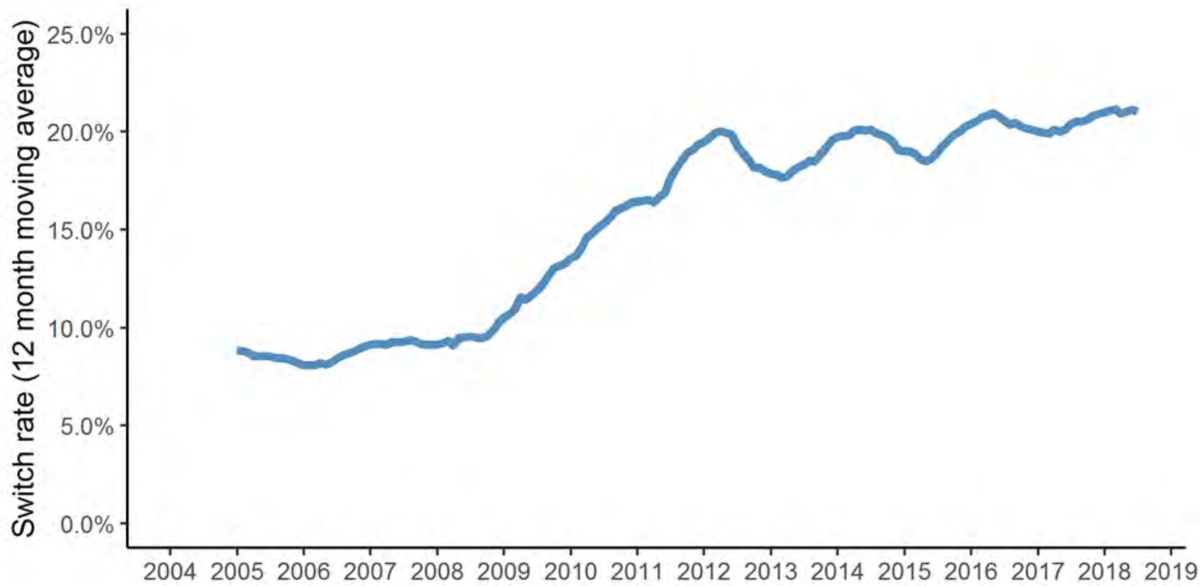
[29] *EPR first report,* p.36.

Figure 10: Market share of small and medium retailers by region



Source: NERA analysis of Electricity Authority EMI dataset

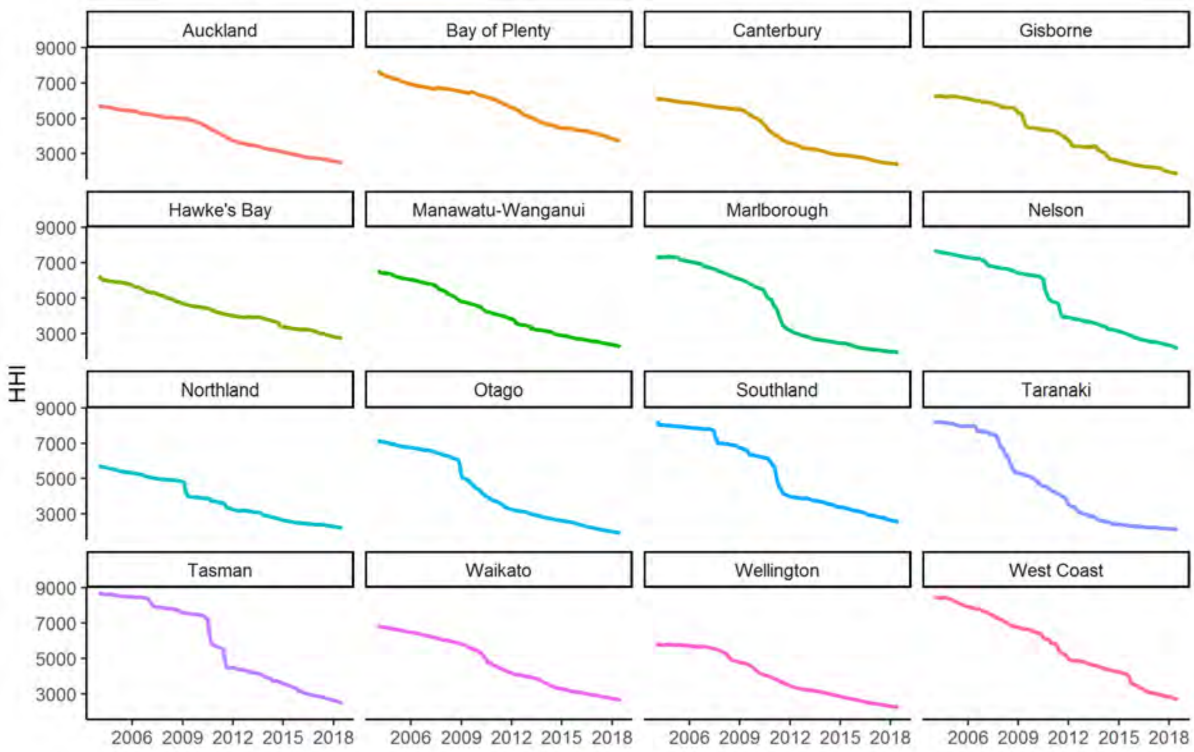
Figure 11: National switching rate (12-month rolling average)



Source: NERA analysis of Electricity Authority EMI dataset

42. Another measure of concentration is the Herfindahl-Hirschman Index (HHI). Analysis of regional HHIs shows that while the increase in competition has been particularly stark in some regions, there is an across the board reduction in concentration.

Figure 12: Regional Herfindahl-Hirschman Index (HHI)



Source: NERA analysis of Electricity Authority EMI dataset

3.2. The wholesale generation market is generally competitive

43. The EPR first report concludes:[30]

> *Overall, the generation sector is delivering reliable supply, low and falling emissions, and wholesale prices that are reasonable compared to costs of building new power stations. However, we have some concerns about short-term market power.*

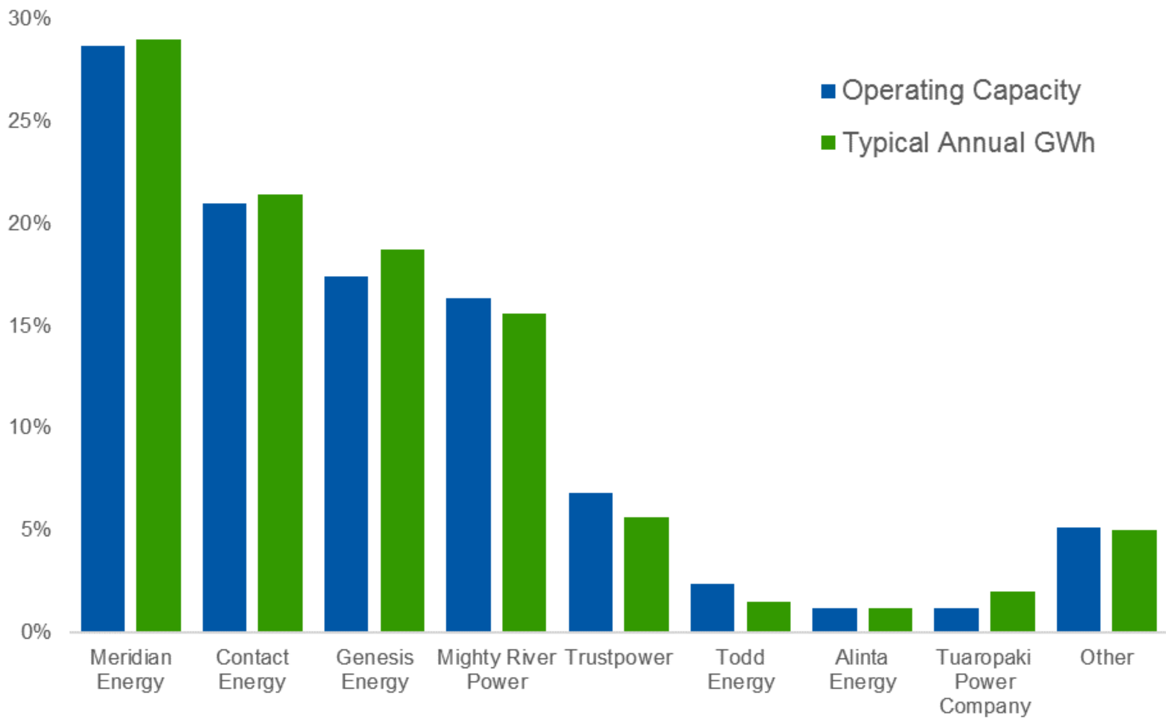
44. This is on the basis that the wholesale prices have generally tracked the long run marginal cost (LRMC) of new generation (see Figure 14 of the *EPR first report*). This is strong evidence that the generation market is delivering efficient outcomes.

45. In the context of this report, we are primarily interested in whether there is *sustained* market power in the generation market that could be leveraged by vertically integrated firms into retail markets.

46. Given the EPR's finding that price tracks LRMC and the fact that there are five large generation firms and a long tail of smaller firms (market share in generation is shown in Figure 13 below), we agree with the first report's conclusion that the only issue is whether there is transient market power.

[30] *EPR first report,* p.33.

Figure 13: Generation market share (capacity and typical output)



Source: NERA analysis of EA Existing Generation fleet dataset (https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_fleet/Existing)

47. It also seems that any concerns about transitory market power are not impacting retail competition to a material extent. Prior to introducing a trading conduct remedy for pivotal situations in 2014, the EA noted that *"retail competition may suffer if retailers constrain their geographic coverage due to concerns about exposure to pivotal supplier risk"*.[31]

48. Similarly, the EA's Wholesale Advisory Group (WAG) noted that, while not clear cut, net pivotal status appeared to coincide with regions that had concentrated retail markets.[32] The panel below presents regional HHI calculations in May 2012 and May 2018 and demonstrates that while some pockets of high concentration remain, there has been a material improvement over time.

49. The *EPR first report* notes (page 33) that the presence of short term spikes in wholesale prices makes a functioning contract market important. The fact that retail concentration has improved across regions implies that the contract market is functioning effectively and/or the EA's trading conduct remedies provide sufficient protection for non-integrated retailers in these areas.[33] We also note that the presence of short term price spikes does not require insurance via contract – to the extent that firms have customers and generation in these regions, vertical integration will also provide a natural hedge against the exercise of transient market power.

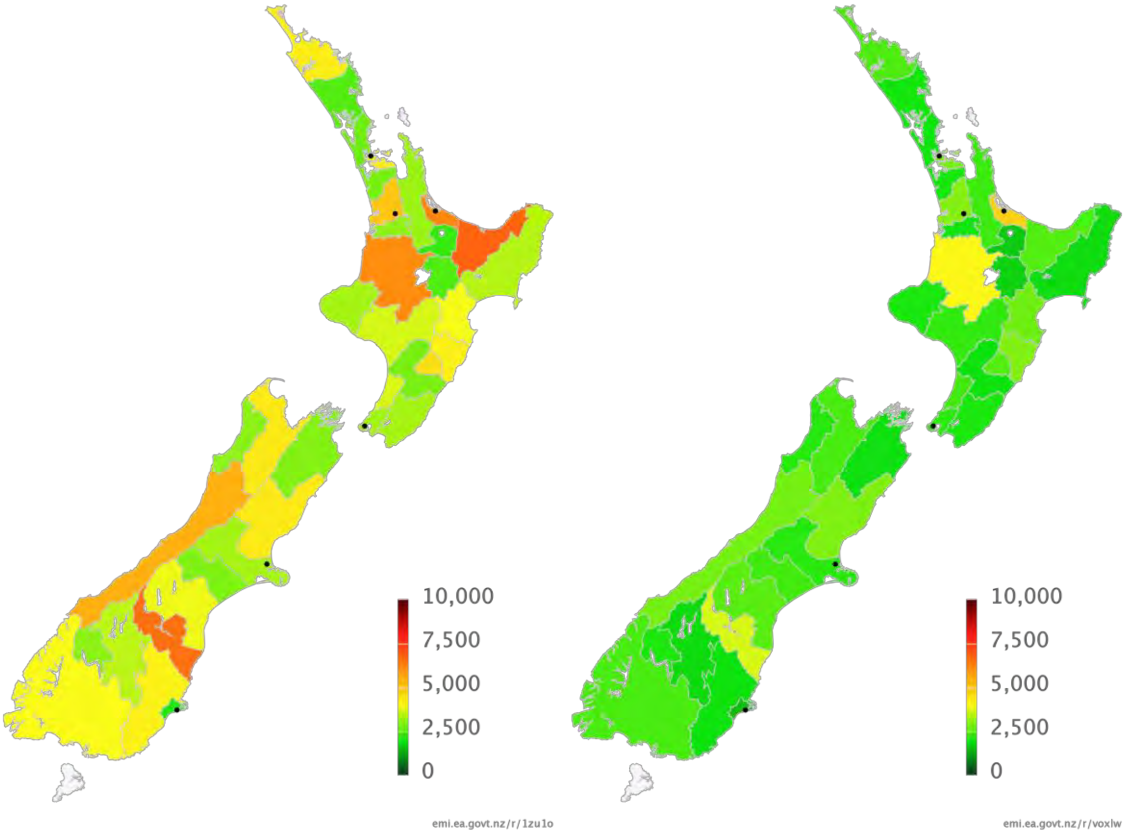
[31] Electricity Authority, *Improving the efficiency of prices in pivotal supplier situations*,18 February 2014, par.5.3.1

[32] Wholesale Advisory Group, *Pricing in Pivotal Supplier* Situations, 27 May 2013, B.2.2-B2.2.6.

[33] It is also possible that transmission investments have alleviated localised constraints.

Figure 14: Regional Retail HHI: 2012 vs 2018

(A) 2012	(B) 2018



Source: EA EMI dataset

4. The Counterfactual: Would prices be lower (or more generally, would outcomes be superior) in the absence of Vertical Integration?

50. Because vertical integration replaces contracts *between* firms with management *within* a firm, it prompts concern over two topics which, although often confused, are in fact distinct:
    a) Access to contracts for managing risks ("access"); and
    b) Liquidity of the market for hedge contracts (liquidity).
51. The two theories of harm we discuss concerning vertical integration relate directly to these two concepts:
    a) The first theory of harm, which relates to *access*, is that hedges may not be offered to competitors (or they may be offered at a relatively high price), preventing entry and dampening competition (**foreclosure theory of harm**); and
    b) The second theory of harm is that vertical integration may reduce liquidity and therefore increase the transactions costs of hedging risks (**liquidity theory of harm**).
52. We define *access* and *liquidity* in more detail in the sections below in conjunction with an assessment of each theory of harm.

4.1. Theory of harm 1: Vertically integrated players foreclose via hedge market

53. The concept of *access* to a hedge is simply that a retailer (or generator) who wishes to obtain a hedging contract for an upcoming trading period, is able to do so at a reasonable (i.e. competitive) price. This is effectively the same concept as "Market access and costs" discussed by the ACCC in the 2018 Retail Electricity Pricing Inquiry, where the ACCC noted *"Accessing hedging markets means being able to trade on the ASX or through OTC contracts*".[34]
54. Because the New Zealand wholesale electricity market is a mandatory pool, retailers can access electricity to serve their end customers and, so long as generators are "in merit", they will be dispatched[35] and therefore are able to sell their power. The design of the electricity markets make foreclosure in relation to the underlying physical commodity (electricity) impossible.
55. We have already discussed in section 2 that risk management is a key input for competing in electricity markets. Therefore, the specific concern in electricity is foreclosure through a refusal to trade (at a competitive price) hedge contracts.
56. While mentioned in the context of *liquidity* as opposed to *access,* the ACCC summarises this theory of harm well in the Australian context:[36]

    Vertical integration in the NEM is likely to have reduced market liquidity as more generation capacity is tied up with retail businesses and reserved to manage risk internally. The big three retailers have acquired the majority of the NEM's thermal generation capacity, which are natural suppliers of many fundamental hedging products. Without sufficient competitive pressure in wholesale and retail markets,

[34] *ACCC Retail electricity pricing inquiry: Final Report,* June 2018, p.112.

[35] Unless of course other generators bid below their true cost or transmission constraints result in a generator not being dispatched.

[36] *ACCC Retail electricity pricing inquiry: Final Report,* June 2018, p.114.

these vertically integrated players may have the ability and incentive to withhold contracts from rival retailers, or to discriminate against them regarding price.

57. The AEMC also describes why access to hedging contracts is important:[37]

> *Wholesale contracts, in the form of hedging products, provide protection for retailers from volatile and uncertain wholesale spot prices. Access to risk management products helps retailers to stay in business, even when there are high price events in the wholesale spot market. Where a liquid contract market exists, the value of vertical integration is viewed as less important.*

58. Denying access to an essential input (in this case hedge contracts) is what economists refer to as vertical foreclosure. In the context of assessing vertical mergers, the Commerce Commission notes that vertical foreclosure can take two broad forms:[38]

    a) **input foreclosure** – where the merged firm refuses to supply an input to a downstream competitor or raises the price of the input; or

    b) **customer foreclosure** – where the merged firm disadvantages an upstream competitor in the sale of that competitor's products by limiting access to customers.

59. To be concerned about foreclosure, the firm in question needs to have both the *ability* and *incentive* to foreclose its rivals. To have the *ability* to foreclose requires market power at one vertical level. As the Commerce Commission notes:[39]

> *A firm is generally only able to foreclose competitors if it has market power at one or more level(s) of the supply chain. If a firm does not have market power, its competitors could switch to other suppliers or purchasers. This would mean that the firm is unlikely to have the ability to foreclose its competitors.*

60. Relatedly, for retailers like Flick, whose business model does not rely on hedge contracts, hedge contracts are not an essential input.

61. More generally, as set out in Sections 3.1 & 3.2, it seems unlikely there is sustained market power in the generation and retail markets.

62. In a competitive market, vertically integrated firms are unlikely to have an incentive to foreclose:

    a) The entry of a stand-alone retailer means a vertical integrated gentailer would now be longer on power and exposed to risky spot prices.

    b) By selling a hedge to the retailer, the vertical integrated gentailer would manage its risk. If instead it attempted to foreclose the retailer, the vertical integrated gentailer would miss out on that hedge, and so face the risk.

    c) This cost of foreclosure might be justified if the vertical integrated gentailer could be confident the foreclosed retailer's customers would switch to it. But the more competitive the market, the less likely this diversion would be.

        i) Also, a rival gentailer might sell the hedge anyway.

63. In the UK, the CMA examined the impact of vertical integration and the availability and liquidity of hedge products. In the context of Theory of Harm 1, the following finding by the CMA is relevant:[40]

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[37] AEMC, *2018 AEMC Retail Energy Competition Review*, FINAL, 15 June 2018, p.35.

[38] 5.5, *NZCC merger guidelines*.

[39] 5.7, *NZCC merger guidelines*.

[40] UK CMA, *Energy Market Investigation: Final report,* 24 June 2016, par.7.29

...our conclusion is that vertical integration is unlikely to have a significant impact on the extent to which products are available to trade on the wholesale electricity market. That is, vertically integrated firms still have to trade externally to a significant extent in order to hedge their exposure to wholesale market volatility.

64. In this context, the Electricity Authority's findings in the Winter 2017 review are informative:[41]

Electricity purchasers were hedged well in advance of the winter of 2017. This includes the swaption between Meridian and Genesis. This meant that purchasers were not adversely affected when the spreads for exchange traded futures widened during the winter

65. Accordingly, it appears that firms had *access* to hedging contracts.

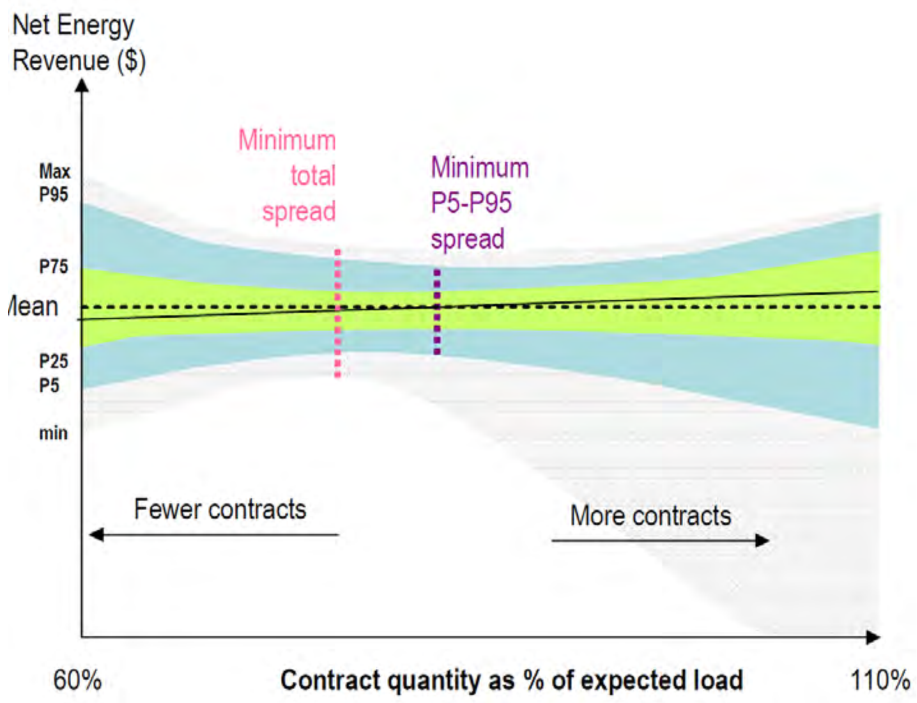
66. To the extent that the vertically integrated gentailers do not fully hedge their generation output and it is hard for standalone retailers to obtain hedge contracts, this may actually be a structural feature of the market caused by the high share of hydro and lack of material storage. The variation in hydro inflows and lack of storage results in material price and quantity risk for both thermal and hydro generators, known as "dry year" risk. The result of this is that:

    a) Thermal generators will not offer hedge contracts covering their full dry year output, as the SRMC of peaking plant will be above the retail/hedge price, thus exposing them to price risk; and

    b) Hydro generators will not offer firm contracts equal to their wet year output, as this would expose them to price risk in dry years.

67. This explanation is consistent with descriptions that Meridian has given to analysts about its hedging of hydrological risk. For example, Figure 15 below shows what Meridian refers to as the "bow-tie".

Figure 15: Illustrative contracting bow-tie



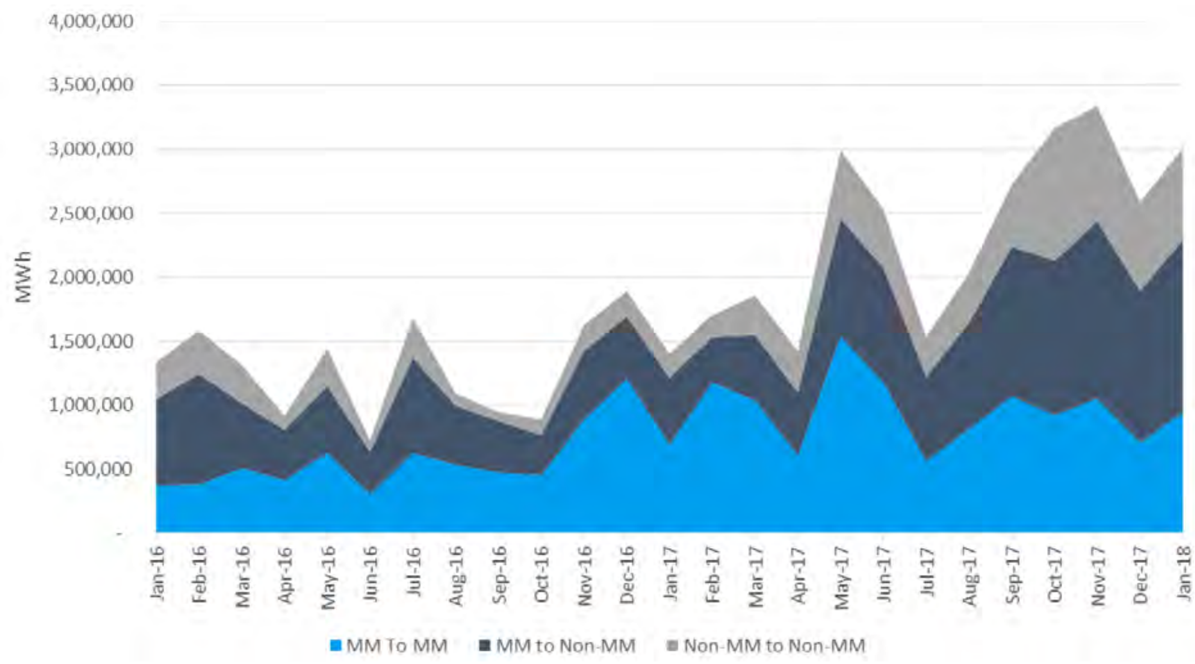
Source: Meridian Analyst Presentation: Managing Hydrology Risk, 17 August 2011.

[41] Electricity Authority, *2017 Winter Review*, 22 March 2018, p.2

68. This graph illustrates that, according to Meridian's modelling, past a certain point, increased hedging actually increases net revenue volatility. Furthermore, consistent with our conceptual point, revenue variability is minimised with a contract quantity as a % of expected load of less than 100%.

69. Data from the ASX on the identity of traders also shows that an increasing number of trades involve non "market makers" (i.e., firms besides the big four gentailers).

Figure 16: ASX hedge contracts: trading by counterparty type



Source: ASX New Zealand Electricity Users Group Meeting -Wellington, 14 February 2018

70. This shows that the majority of trades for hedge contracts on the ASX involve a firm besides the big four gentailers, suggesting independent parties have access to hedge contracts.

4.1.1. Summary

71. Foreclosure can't occur without market power, thus concerns about vertical foreclosure are actually concerns about market power at one level of the market, rather than concerns with vertical integration per se.

72. Entry has occurred in a sustained way at retail by non-integrated players, which suggests the vertically integrated gentailers are unable to foreclose their non-integrated rivals by denying access to hedge contracts. Entry has also occurred by firms such as Flick that pass wholesale spot price risk onto consumers and therefore have no need to hedge.

73. The generation market appears to be competitive and any market power concerns are only transient. This transient market power does not appear to be hindering the development of retail competition.

74. Vertical integration does not in and of itself reduce *access* to hedges – demand and supply are reduced in equal parts.

75. The experience of Winter 2017 suggests that independent retailers were able to obtain *access* to hedges in advance of the price spikes.

76. The market may be structurally short of hedges due to dry year risk, but this has nothing to do with vertical integration.

4.2. Theory of Harm 2: Vertical integration leads to low liquidity

4.2.1. What is liquidity and why does it matter?

77. Liquidity is a difficult concept to define or measure, but generally refers to the degree to which an asset can quickly be bought or sold in the market without affecting the asset's price. As the AEMC notes:[42]

> *Importantly, liquidity is not in itself about increasing the volume of energy supplied to the market, though it can facilitate this outcome. It is about increasing the traded volume of energy in the market. That is the number of times electricity is bought and sold between different entities before being consumed.*

78. There is no consensus on how to define and measure liquidity, as noted by the ACCC:[43]

> *No single metric is generally agreed to provide a complete picture of hedge liquidity, and different metrics have their own strengths and weaknesses. The ACCC does not consider it necessary to form a specific view about market liquidity, but broadly agrees with the AEMC's approach that a liquid wholesale contract market is typically characterised by:*
>
> - *no single transaction being likely to move the price excessively*
> - *individual trades that are able to be easily executed*
> - *an ability to trade large volumes of energy in a short period of time*
> - *a market that can recover towards its natural equilibrium after being exposed to a shock.*

79. Similarly, the Single Electricity Market Committee (SEMC) in Ireland defined liquidity in a recent consultation as:[44]

    a) Parties can "trade 'reasonable' volumes without significantly moving market prices"; and

    b) Parties are "readily able to trade out of positions as well as to acquire those contractual positions".

80. Regarding how this concept is measured, the UK CMA considered four proxies in the energy market inquiry: the volume of trades, churn, spread between the buy and sell price and depth available of these spreads.

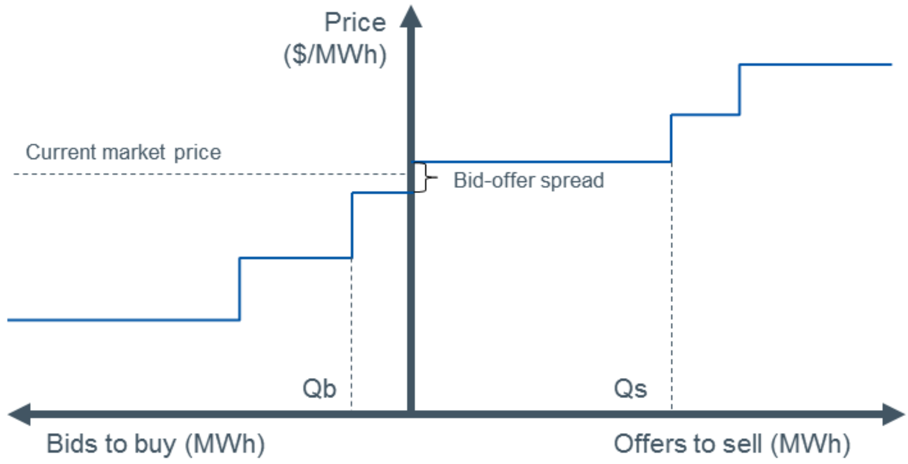
81. The volume of trades is typically measured relative to consumption of electricity in the market in question. Churn is the turn-over of contracts relative to demand for the product in question. The concepts of market depth and bid-offer spreads are explained in Figure 17 below.

[42] AEMC, *2018 AEMC Retail Energy Competition Review*, FINAL, 15 June 2018, p.35.

[43] ACCC, *Retail Electricity Price Inquiry: Final Report,* June 2018, p.113.

[44] SEM committee, *Measures to promote liquidity in the I-SEM forward market: Consultation Paper*, 17 June 2016

Figure 17: Market depth and bid-offer spreads



Spreads: In the figure above, offers to sell are shown to the right of the central axis, whilst bids to buy are shown to the left. The lowest price offer is more expensive than the highest price bid. The difference between them is the "spread" (variously, **bid-offer spread** or **bid-ask spread**), which provides a margin for traders and brokers. Wider spreads tend to discourage trading and to indicate less liquid markets.

Market Depth: The lowest price offers cover the volume Qs on the right hand side, beyond which quoted prices start to rise. The highest price bids cover the volume Qb on the left hand side, beyond which quoted prices start to fall. These changes in quoted prices may reflect imperfections in the market, or else just differences in the cost of production from different sources (e.g. the fuel costs at different generators). Small trades – purchases up to Qs, sales up to Qb – can be made at the prices being offered and bid at present. However, larger sales would exhaust the volumes available at these prices and shift the price to a new level. The gap between Qb and Qs indicates the "depth" of the market, i.e. traders' ability to buy and sell at current market prices.

Source: NERA

82. In the electricity industry, liquid contract markets offer two main advantages: they allow firms to adjust their contract portfolio as their forecast production and sales change ("risk management"); and they produce market prices which act as a guide to efficient operations ("price discovery").

83. Illiquid markets do not offer the same benefits. The absence of liquidity acts a transaction cost on market participants adjusting their contract portfolio over time. As a result, market participants pay a premium to manage their risks and may therefore remain inefficiently exposed to risk, resulting in an artificially high cost of capital and higher prices for consumers. Illiquid markets do not provide the price discovery function either. Illiquid markets with infrequent trading means that market signals are blunted. Market prices move not only because market fundamentals change, but may also shift purely as a result of small changes in the volume being bought or sold, such that a single market participant may move recorded market prices substantially buying a routine quantity of power.

84. The definition of liquidity adopted by the first report does not mandate a particular volume of trade, but instead that that market participants should be able to trade easily at transparent market prices.[45] In principle, it may be possible to meet this definition of liquidity with very limited trade

[45] I.e., at page 43 the *EPR first report* notes: *"An effective contract market, in contrast, supports ready access to contracts on reasonable terms, and sends clear price reference points for buyers and sellers."*

actually taking place. For instance, if all market participants placed the same value on a product, then new information would cause both buyers and sellers to revise their price expectations upwards and no trade would occur. In practice, markets in which very limited trade takes place are unlikely to allow market participants to trade without substantially affecting market prices because traded prices themselves are an important signal of information to the wider market of expectations over the value of a commodity. As a result, much of the economic literature focuses on the circumstances which must hold for trading itself to be frequent. These circumstances include that:

a) information is progressively revealed to the market, such that different market participants have different views about the value of the commodity at any point in time; or

b) market participants have asymmetric risk-exposure or preferences such that they have different valuations given the same information; and

c) market participants are able to write standardized, complete, tradable contracts that capture commodities or risks they intend to trade.

85. Economists usually regard symmetrical information sets as important for underpinning liquidity. For instance, as Vavanos and Wang (2012) put it:[46]

> *An increase in information asymmetry […] generates an illiquidity spiral. Because illiquidity increases, liquidity demanders scale back their trades. This raises the signal per trade size, further increasing illiquidity. When information asymmetry becomes severe, illiquidity becomes infinite and trade ceases, leading to a market breakdown.*

86. “Information asymmetry” is the phenomenon whereby one trader possesses “private information” about a market, i.e. information that others do not possess. That trader is better able to estimate the true value of the product and can profit from the ignorance of others through insider trading (by selling to those whose valuation of the product is too high, or buying from those whose valuation is too low). Competition can only blossom where participants do not fear that insider trading may go against them (e.g. because producers and consumers have better information about current conditions of supply and demand).

87. Uncompetitive markets, dominated by a single firm or small selection of firms, are likely to be illiquid. Firms have superior information over their own future bidding behaviour and the operation of their facilities to the information available to third parties. Where any firm knows that its own unilateral action is sufficient to move the market price because it has market power, placing an order to sell power provides information to the market about the likely future value of power. As a result, generators will tend to sell fewer hedges in order to avoid sending pessimistic signals to the market that would depress their value (and conversely buyers tend to under-hedge for the same reason).

88. Regulating the behaviour of a dominant firm does not overcome this problem, since it only creates a new kind of information asymmetry. First, the bidding strategy of the dominant firms becomes a matter for privileged discussions with their regulator over the rules governing their behaviour. Second, even if the rules are published, their interpretation is often unpredictable (albeit within certain bounds), giving a dominant firm the advantage of knowing better than others how it will behave in the market and what prices will emerge. Therefore, regulation of dominant firms does not remove the underlying problem of information asymmetry.

89. Uncompetitive market conditions therefore do not provide the conditions necessary for the growth of liquid trading.

[46] Vayanos and Wang (2012), *Liquidity and Asset Returns under Asymmetric Information and Imperfect Competition*, p.20.

4.2.2. Regulatory concerns over vertical integration and liquidity

90. The common concern expressed about vertical integration and liquidity is summarised by the Australian Energy Regulator (AER):[47]

> *Vertical integration provides a means for generators and retailers to internally manage risk in the spot market, reducing their need to participate in hedge (contract) markets. Less participation in contract markets can reduce liquidity in those markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.*

91. Similar concerns have been expressed by the ACCC,[48] and the AEMC[49] in Australia, and the CMA in the UK.[50]

92. While the concern is intuitively easy to understand, it is based on the premises that:

    a) Vertically integrated firms have no/little need or incentive to trade externally; and

    b) The market would be more liquid in the absence of vertical integration.

93. Indeed, the *EPR first report* asserts that:[51]

> *Another drawback of vertical integration is that it can result in less use of contract markets – where companies buy and sell electricity ahead of time to lessen their exposure to wholesale price volatility. Vertically integrated companies have no inherent need for contract markets, whereas independent generators and retailers rely on them heavily. If large portions of the generation and retailing sectors have little use for contract markets, there will be low liquidity and muffled price signals, making it difficult and costly for independent companies to manage electricity price risks.*

94. As we now discuss, the *EPR first report* is incorrect to conclude that vertically integrated firms have no inherent need for contract markets and that vertical integration therefore has a material impact on liquidity.

4.2.3. Evidence and first principles suggest vertical integration does not have a material impact on liquidity

95. Vertical integrated firms do have the incentive to trade externally, even if on average over a year their generation matches their retails sales. This is because:

    a) Arbitrage/profit maximization:

        i) If another generator offers a contract below the vertically integrated firm's expected cost of generation, it will be cheaper for the vertically integrated firm to meet its obligations using that contract;

---

[47] AER, *State of the Energy Market 2015,* p.43

[48] The ACCC *Retail Electricity Price Inquiry: Final Report* notes at page 104 notes:
"there is a trend towards vertical integration, which has reduced liquidity and lessened the ability of participants to effectively manage their risk"

[49] As the AEMC notes at page 21 of the *2018 Retail Energy Competition Review:*
"A consequence of vertical integration is that the volume of trading a retailer or generator needs to perform in the wholesale contract market is less than would be the case if it were stand-alone. Vertical integration reduces the need to enter into forward (hedge) contracts and may affect the level of liquidity in the wholesale contracts market. This in-turn impacts on how stand-alone retailers compete and manage their exposure to wholesale spot market risk."

[50] The CMA in the *Energy Market Investigation: Final report* states:
"*vertical integration could raise barriers to entry and growth by new suppliers if they were unable to secure sufficient wholesale electricity."*

[51] *EPR first report*, p.43.

ii) If a retailer is willing to sign a contract at a higher price than the vertically integrated firm's expected retail price, it would be profit maximizing to sign that contract;

b) The forecast pattern of a firm's generation output rarely matches the forecast pattern of its retail sales. Even if the total volumes are the same, their forecast timing (and value) will differ (see Figure 7 above demonstrating this);

c) Those forecasts may also change during the year, and the changes to demand and supply can occur independently of each other (i.e., demand and supply can receive independent shocks);[52]

d) The valuation that any player places on a hedge is a function of the financing and risk management of each business and the specific supply and demand risks that each business faces. Accordingly, the valuation of hedges will differ between generation and supply businesses; and

e) The generators in New Zealand have quite a different fuel mix (see Figure 2) and hedging between firms can be used to manage that risk (an example of this is the "swaption" between Meridian and Genesis).[53]

96. Accordingly, even if vertically integrated firms make an implicit internal allocation of hedging contracts between the generation and retail businesses at the start of a year, they will still have the need and incentive to engage in trading throughout the year.

97. The AEMC in Australia recognized that vertically integrated firms have a need to trade:[54]

> *Generally, vertically integrated businesses are imperfectly hedged in a particular region as they may own more or less generation than their retail load in that jurisdiction. For this reason, the businesses participate in wholesale contract derivatives (futures) markets to manage outstanding wholesale spot exposure.*

98. The findings of the UK CMA are consistent with this. Indeed, the CMA found that the levels of trade are unlikely to be affected by vertical integration as the Six Large Energy Firms externally trade at much higher levels than their own generation. This is different from how the EPR first report has characterised the CMA's conclusions. At page 45 the *EPR first report* notes:

> *An effective contract market is critical to mitigating the potential adverse effects of vertical integration and short-term generator market power. Our view is reinforced by the recent review in the United Kingdom, which concluded vertical integration was not adversely affecting competition, in part because the contract market had sufficient liquidity "for independent firms to hedge their exposure to wholesale market risk in a similar way to vertically integrated firms.*

99. That is to say, the *EPR first report* characterizes the CMA as not being concerned about vertical integration *because* there is sufficient liquidity. In fact, the CMA's findings are subtly, but importantly different. For example, at 7.28 – 7.30 the CMA discusses whether vertical integration reduces liquidity - we have reproduced the discussion in full below:[55]

> *We consider in the section below on benefits arising from vertical integration whether vertically integrated firms have an in-built natural hedge against wholesale market volatility, and whether they may therefore trade less as a result. If we found that vertical integration was leading to a*

[52] For example, in winter a vertically integrated firm may experience a period of warm weather where its customers are located, reducing demand for heating, while simultaneously experiencing windy weather in the area where it has wind turbines.

[53] See, e.g. https://www.nbr.co.nz/article/genesis-extends-life-coal-fuelled-power-station-2022-b-188271.

[54] AEMC, *2018 AEMC Retail Energy Competition Review*, FINAL, 15 June 2018, p. 21.

[55] UK CMA, *Energy Market Investigation: Final report,* 24 June 2016, pars. 7.28-7.30

lower level of trading, it is possible that vertical integration could reduce wholesale market liquidity, potentially to the detriment of independent suppliers and generators.

However, our conclusion is that vertical integration is unlikely to have a significant impact on the extent to which products are available to trade on the wholesale electricity market. That is, vertically integrated firms still have to trade externally to a significant extent in order to hedge their exposure to wholesale market volatility. We found that all of the Six Large Energy Firms externally trade multiples of their combined generation and supply volume in electricity (and therefore make a net positive contribution to liquidity). We also saw similar patterns of trading behaviour between gas and electricity, even though there is a much lower degree of vertical integration, and liquidity is generally held to be better, in gas than in electricity.

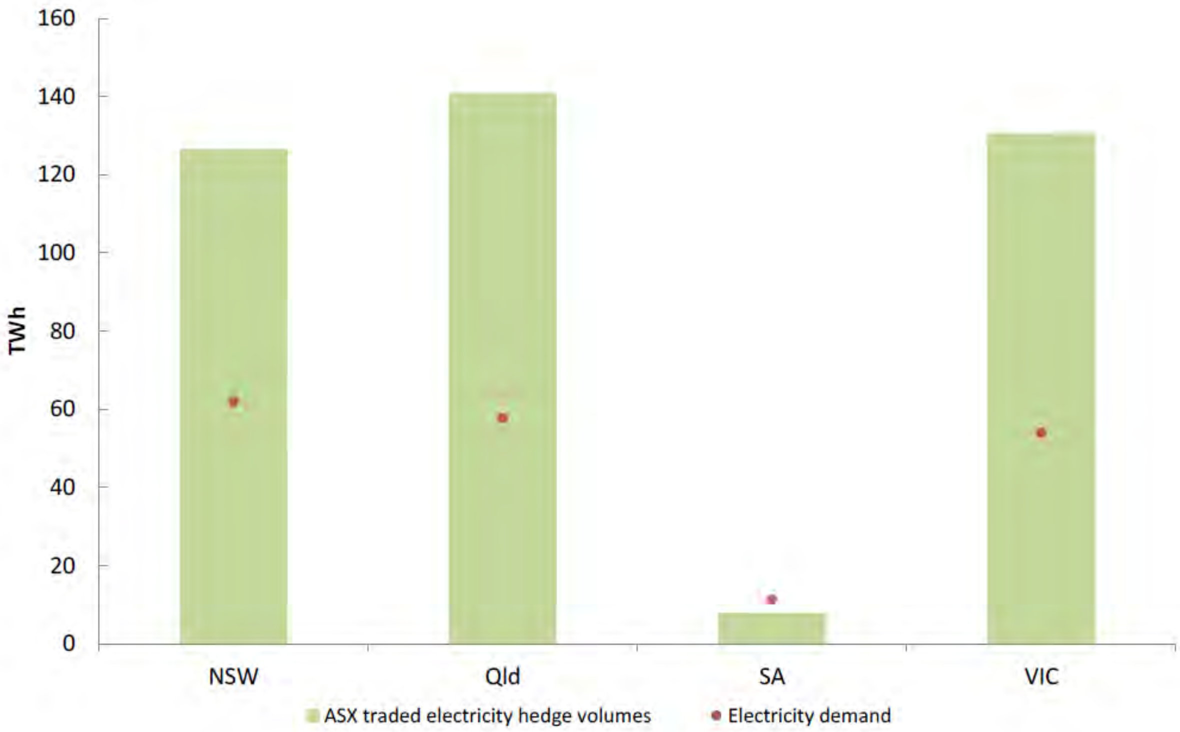
As a result, we consider that vertical integration does not appear to affect liquidity in a way that would prevent an efficient independent supplier or generator from being able to trade basic products that are necessary to participate in upstream or downstream electricity markets.

100. Therefore, rather than not being concerned about vertical integration *because* there is liquidity, the CMA conclusion is that vertical integration does not appear to materially affect liquidity as vertically integrated firms still have a need to trade.

101. We also note that Australian states other than South Australia appear to have high vertical integration and liquidity. For example, Figure 18 below is taken from the *ACCC Retail Electricity Pricing Inquiry* preliminary report and shows that in New South Wales and Victoria, where vertical integration between generation and retail is also high, annual contract volumes are far in excess of annual electricity demand. The same pattern of hedge trades to demand is true in Queensland, where vertical integration is much less of a feature in the market due to government ownership of the main generation assets. In South Australia, the market is less liquid by this measure, although South Australia also has a high penetration (close to 50%) of wind generation,[56] which may contribute to lower liquidity for the same reasons as in a hydro dominated market like New Zealand.

[56] In the nine months to 31 March 2017, the wind generation supplied 50 per cent of South Australia's electricity. See AER, *State of the energy market 2017*, May 2017, Figure 1.11.

Figure 18: Annual contract trade volumes and NEM turnover, 2014–2016 average



Source: ACCC, Retail Electricity Pricing Inquiry: Preliminary report, 22 September 2017, Figure 3.11

While the ACCC found that vertical integration has reduced liquidity in the NEM, the issues were only significant enough in South Australia to warrant action. The ACCC recommended implementing market making obligations in South Australia:[57]

> *However, the ACCC considers that the combination of vertical integration and concentration in the NEM has reduced contract market liquidity and is making it harder for all parties to effectively manage their wholesale price risk. The issue is most acute in South Australia, where contract market activity is infrequent and dispatchable generation sources are limited. The ACCC is therefore recommending market making obligations be introduced in South Australia in order to boost market activity and provide access to trading partners for smaller retailers (recommendation 7) … Should these market making obligations prove to be highly effective in South Australia, they may be expanded to include other NEM regions if liquidity concerns are identified.*

102. In our view the Australian evidence indicates that the "problem" is high, intermittent wind penetration in South Australia, not vertical integration.

103. Vertical integration is also a common strategy in markets generally held up as having a very liquid forward markets, such as the Nordic markets (Nordpool[58]) and Germany[59]. For example, in Nordpool, one of the major players is Vattenfall, which accounts 22% of generation in Nordpool as a whole and 50% of generation and 30% of retail sales in Sweden.[60] As shown in Figure 19, in

[57] ACCC, *Retail Electricity Price Inquiry: Final report,* June 2018, p.150

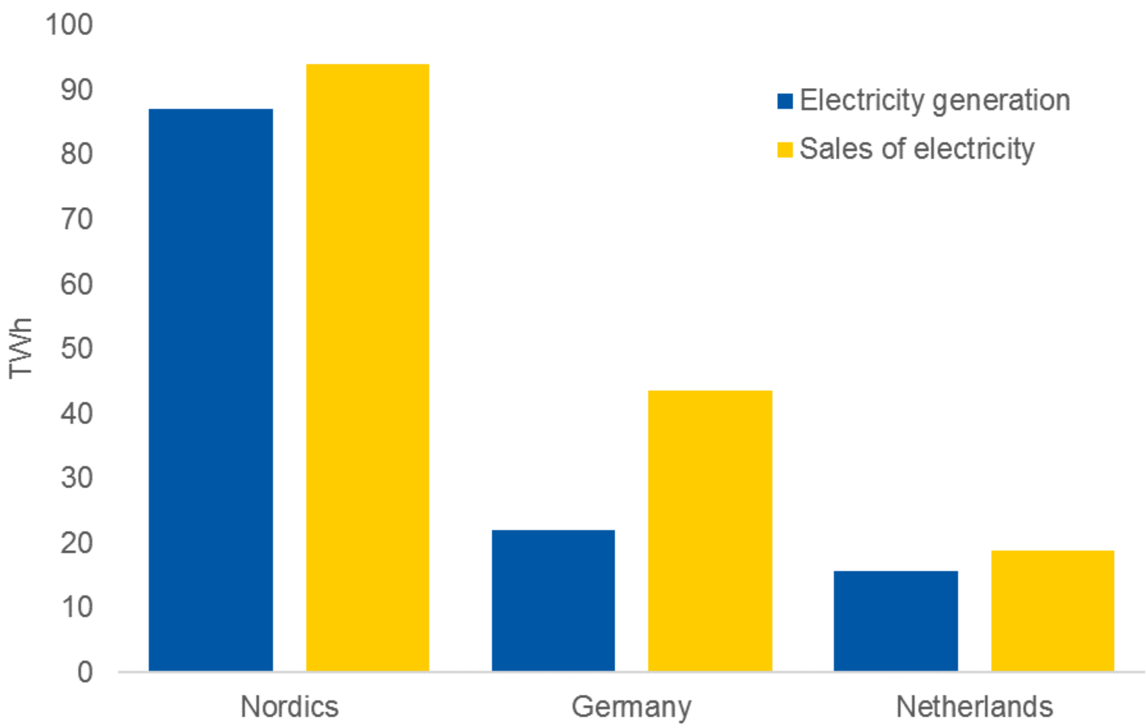
[58] Nordpool has a turnover ratio of around 400% between 2014 and 2016.

[59] Germany had a turnover ratio of between 500% and 800% between 2014 and 2016.

[60] https://corporate.vattenfall.com/about-vattenfall/our-operations/markets/nordic-countries/

the markets Vattenfall operates in, it has a relatively balanced generation and retail portfolio, though retail sales in Germany were roughly double its generation in 2017.

Figure 19: Vattenfal's 2017 generation and retail balance in European markets



Source: https://corporate.vattenfall.com/about-vattenfall/our-operations/markets/

104. The German market is quite different to the other markets we have considered. While there are five main national generators who have a market share of generation of ~76.5% (in 2016)[61] that also generally also operate at retail, there are currently also over 800 municipal distribution system operators (DSOs)[62] that own generation and retail activities (i.e. are vertically integrated), as noted by Deloitte in 2015:[63]

> *In 2013, more than 900 DSOs (distribution system operators) were operating in Germany. The distribution networks are often run by vertically integrated utilities, companies that own generation assets as well as supply and distribution businesses. The country's four dominant companies hold shares in many of these DSOs.*

105. Turning to New Zealand, Figure 20 shows annual generation and contract volumes for New Zealand.

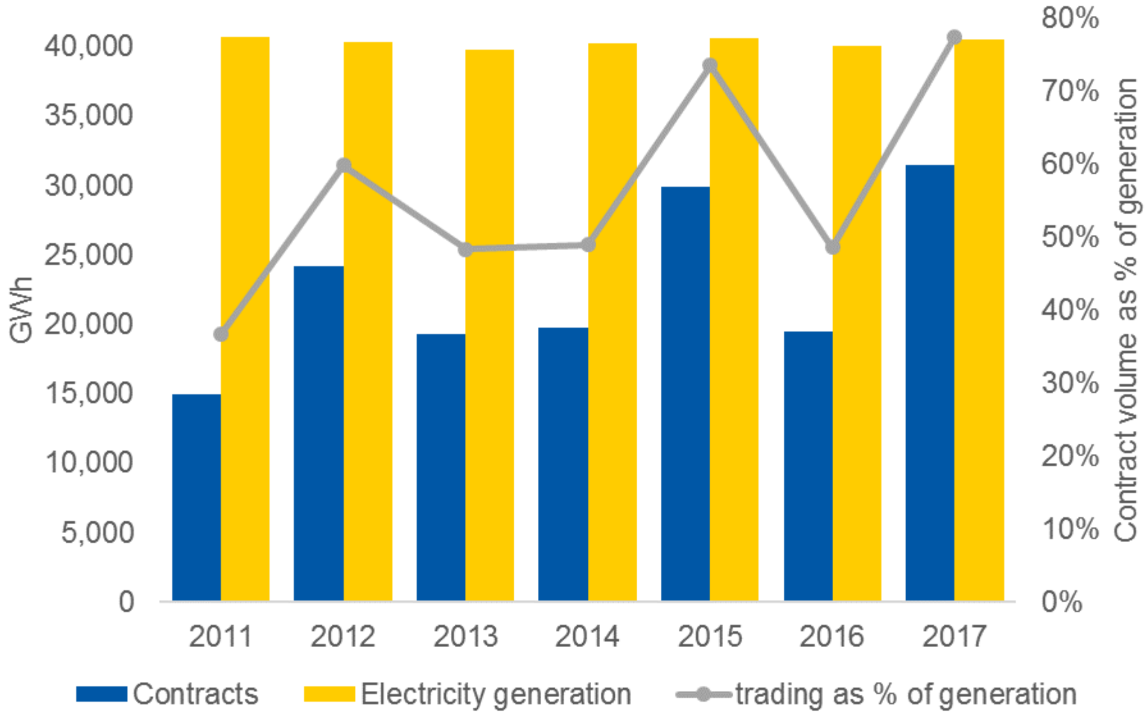
---

[61] BNetzA, *Monitoring Report 2017 – key findings*, p.2.

[62] https://uk.practicallaw.thomsonreuters.com/5-524-0808, Accessed 19/10/18.

[63] Deloitte, *European energy market reform Country profile: Germany.*

Figure 20: New Zealand: Annual contract volumes and grid generation



Source: NERA analysis, Electricity Hedge Disclosure System, EA EMI data on grid injections.

106. This demonstrates that while liquidity, as (imperfectly) measured by comparing annual contract volumes to generation, has been increasing in recent years, it is less than historically experienced in, e.g. New South Wales and Victoria, but greater than South Australia. However, the discussion above implies this might not necessarily be caused by the level of vertical integration in New Zealand. Rather a relatively low level of liquidity in New Zealand might be caused by the underlying conditions in the market.

107. In particular, we have already explained in section 4.1 above that hydro and thermal generators may not wish to sign fixed price/fixed quantity contracts covering their full output due the presence of dry year risk in New Zealand.

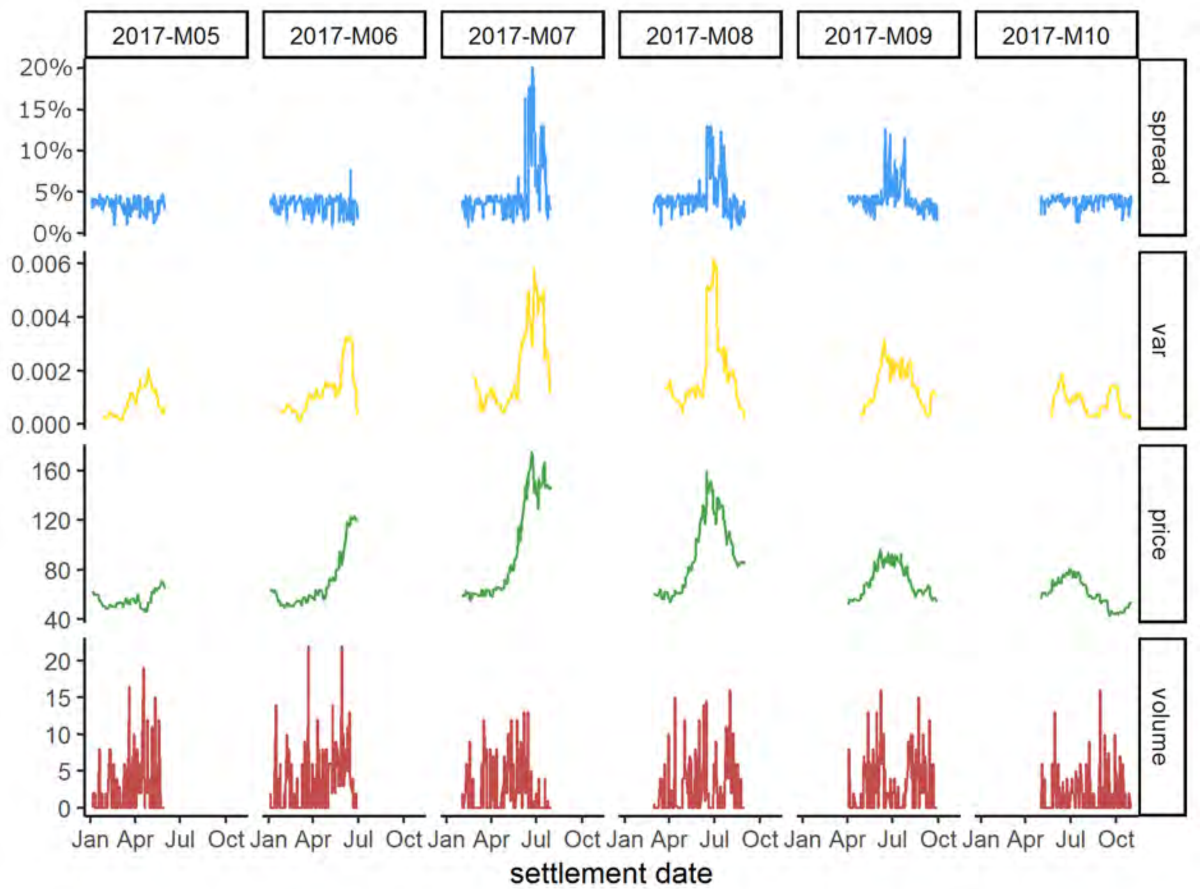
108. It is also important to consider what would happen in the absence of vertical integration. In this situation it would appear likely generation and retail business would seek to sign long term hedge contracts (equivalent to the initial internal allocation made by a vertically integrated firm) and then engage in trading to manage exposure and arbitrage opportunities. As we discuss in section 4.3 below, the fact firms would attempt to replicate vertical integration via contract, and that this would come at increased cost and complexity relative to vertical integration, was one of the reasons the 2006 New Zealand government review rejected vertical separation.

109. The *EPR first report*'s concern with vertical integration and liquidity appears to be driven by the widening bid-ask spread during winter 2017 (e.g., the discussion of spreads on pages 44-45 in the Vertical Integration section).

110. In attributing the widening of spreads to vertical integration, the *EPR first report* does not consider whether wider spreads are a natural response to the large volatility in contract prices that was occurring at the time. There is an established link between volatility and bid-ask spreads in

the finance literature.[64] We therefore consider that it is incorrect to necessarily attribute the widening of spreads to vertical integration. For example, analysis of ASX contract prices at the Benmore node during 2017 demonstrates that wide spreads coincided with periods of high volatility in settlement prices and that spreads for longer term contracts did not widen during June and July 2017 (see Figure 21 below). This suggests the "problem" was isolated to short term contracts and that the only parties who were disadvantaged were those that did not hedge in advance of winter 2017. According to the EA, retailers were generally hedged in advance of winter 2017,[65] which implies it was only financial speculators that were affected. That is, to the extent a problem exists, it did not affect independent retailers with prudent risk management policies.

Figure 21: ASX Benmore monthly futures trading data: high spreads coincided with high volatility in winter 2017



Source: NERA analysis, ASX data.
Note: graph displays the percentage bid-ask spread and the 15 day rolling variance of the log price change for monthly futures contracts maturing in May, June, July, August, September and October 2017 (months 05-10 respectively). I.e. each vertical column is the trading data for a separate contract.

---

[64] See, e.g., Stoll, Hans R, "Friction", The Journal of Finance, vol. LV, no. 4, August 2000, Harris, Lawrence E., "Minimum Price Variations, Discrete Bid-Ask Spreads, and Quotation Sizes", *The Review of Financial Studies*, vol. 7, no. 1, Spring 1994, Holden, Craig W., "New low-frequency spread measures", *Journal of Financial Markets*, vol. 12, 2009, pp. 781 – 782. Figueiredo, Antonio and Parhizgari, A.M., "Currency volatility and bid-ask spreads of ADRs and local shares", *Global Finance Journal*, vol. 34, 2017 and Frank, Julieta and Garcia, Philip, "Bid-ask spreads, volume, and volatility: Evidence from livestock markets", *American Journal of Agricultural Economics*, vol. 93, issue 1, 1 January, 2011, p.209.

[65] Electricity Authority, *2017 Winter Review*, 22 March 2018, p.2.

4.3. Vertical Integration is actually likely to be pro-competitive

111. Vertical integration is an efficient and competitive response to underlying conditions that make contracting hard. In the New Zealand context, the high share of generation made up by hydro is a likely driver of vertical integration, though as we have already noted vertical integration is a common strategy in electricity markets across the globe. As outlined above, vertical integration is likely to provide a more efficient and lower transaction cost method of managing risk.

112. When vertical integration is the efficient response to underlying conditions in the electricity industry, it creates companies that are able to offer generation and retailing services at a lower cost than two standalone businesses. Competition among vertically integrated firms can then drive prices down to a level that would be impossible without vertical integration.

113. There may be countervailing inefficiencies to vertical integration – this is why vertical integration is not ubiquitous in markets across the economy.[66] The vertical boundaries of firms will evolve to reflect the balancing of the costs and benefits of vertical integration in a particular market. While standalone generators and retailers may miss out on the risk management benefits of vertical integration in the New Zealand market, they may have countervailing efficiencies or innovative business models that enable them to profitably compete.

114. In this way, vertical integration drives efficiency throughout the market and drives down prices for consumers.

115. Consistent with this, the AEMC in Australia has recognized that to the extent vertical integration reduces costs, it may be a beneficial market structure for consumers.[67]

116. The Thwaites review in Victoria discusses a number of benefits of vertical integration, including a lower cost of financing and economies of scale, which benefit consumers:[68]

> *Vertical integration can provide key competitive advantages such as:*
>
> - *Ability to self-hedge against electricity and gas price volatility, reducing reliance on liquidity of hedging markets or unaligned suppliers*
> - *Lower earnings volatility (generation earnings balancing out retail earnings)*
> - *Investment-grade credit rating, providing the ability to borrow and to support market to market hedge exposures in volatile markets more readily and cheaply*
> - *Lower cost of financing – demanding lower returns than an ungeared competitor*
> - *Economies of scale (more customers)*
> - *Economies of scope (multiple products to offer like gas, large business services)*
> - *Customer information and billing systems that are generally more sophisticated, allowing for differentiation of customers (customers' credit quality, their usage volume, or churn propensity)*

117. Previous reviews of the electricity sector in New Zealand have considered and rejected vertical separation on the basis of the costs that such a ban would impose on consumers. The Cabinet

[66] For a (non-electricity specific) discussion of the benefits of market procurement as opposed to vertical integration, see chapter 16 of Paul Milgrom and John Roberts (1992) *Economics, Organization & Management*, Prentice-Hall.

[67] AEMC, *2017 AEMC Retail Energy Competition Review,* FINAL, 25 July 2017, Sydney. p.55

[68] *Thwaites review*, p.24

Paper resulting from the government review in 2006 specifically noted these costs [69] and stated that: [70]

> *Separating generation from retailing is unlikely to materially enhance competition in the wholesale and retail markets because:*
>
> i) *To the extent that generator market power exists in the wholesale market from time to time, vertical separation is unlikely to fix it*
>
> ii) *Generators and retailers are likely to seek to replace their current arrangements through contracting (albeit at a higher cost and complexity compared to vertical integration).*

118. The Cabinet Paper produced at the end of the government's 2009 review reached similar conclusions. Once again, the government considered and rejected a ban on vertical integration as it would *"increase transaction costs and the riskiness and costs of both generation and retailing"*.[71]

[69] NZ Cabinet Paper (2006), *Electricity Market Review: Improvements to Current Arrangements (Paper Two)*, by the Office of the Minister of Energy (undated), par.97.

[70] NZ Cabinet Paper (2006), par.98.

[71] NZ Cabinet Paper (2009), *Ministerial Review of the Electricity Market*, Office of the Minister of Energy and Resources, (undated), footnote 14.

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An Economic Perspective on the New Zealand Electricity Market

E Grant Read

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EGR Consulting Ltd.

CONTENTS

Executive Summary

1. This paper has been prepared at the request of a group of market participants who are making submissions to the Electricity Pricing Review. It reflects on the lessons learned from 40 years of experience developing, implementing, and working within a variety of economic frameworks for the New Zealand electricity sector, including the development of optimisation models for reservoir management and planning, close involvement in the Energy Plan process within the old Ministry of Energy, and extensive participation in the market reform and design process, in New Zealand and elsewhere.

2. From time to time, considerable public concern has been attached to assessments of the degree of "market power" that might, or might not, be exercised by generators in the NZEM wholesale spot market. That is, in the extent to which highly volatile "spot prices" might deviate from the Short Run Marginal Cost (SRMC) of generation. We consider that concern to be largely misplaced because:
    - The general public has very little exposure to these spot prices, which are primarily used as internal transfer prices, coordinating the activities within and between industry participants.
    - Spot prices are largely driven by hydrology, and can vary greatly from year to year without indicating any trend at all in retail pricing.
    - The larger industrial/commercial consumers who are exposed to these prices should have the tools and understanding to mitigate any risk involved.

3. We believe that public concern, if any, should rather be focussed on the alternative measure known as Long Run Marginal Cost (LRMC) which provides a much more stable measure of industry costs, and does eventually determine retail pricing.
    - The extent to which spot prices deviate from SRMC is still an important topic, though, inasmuch as it impacts on the efficiency of operations within the industry and of those consumers who are exposed to spot prices.

4. This paper considers some basic questions that need to be addressed before considering the kind, and extent, of market power that might be considered appropriate, or inappropriate, in the NZEM, and describes a conceptual framework within which the relationship between the SRMC, LRMC, and historic cost recovery paradigms can be understood, and an idealised market design described that would, theoretically, allow all three to operate simultaneously.

5. We adopt an "economic" perspective, in which all power available in any particular dispatch period is valued equally, irrespective of the age or historical cost of the assets producing it. We explain the basic theory, which centres on the concept of SRMC-driven spot prices forming an optimal Price Duration

Curve (PDC) the shape of which is controlled by the LRMC entry cost of the mix of technologies best suited to meeting the national Load Duration Curve (LDC).

6. This implies an optimal plant mix for the system, and generalises and reconciles the SRMC and LRMC concepts by clarifying that, in equilibrium, LRMC should be the long run average of SRMC, but with LRMC controlling SRMC, in the long run, not vice versa.
   - Thus, if the NZEM "energy only" market design is working properly, we should see the PDC sitting at a level which just induces sustainable entry of the optimal plant mix.
   - Other markets achieve a similar effect by regulating spot prices to lie close to SRMC, but with capacity is at least partly paid for by explicit capacity payments.
   - Adding contracting to the framework allows the forward looking SRMC/LRMC pricing paradigm to be made consistent with a traditional backward-looking focus on historical cost recovery.

7. Conceptually, this creates and idealised market design, either a high degree of forward contracting, presumably at prices matching the LRMC of entry; and minimal deviations from SRMC pricing, in the short run. Theoretically, this could allow both short and long run efficiency to be maximised, simultaneously.
   - The transaction costs of imposing such a regime would be significant, though, as would the efficiency loss due to intrusive regulation.
   - In particular we would be concerned if contracting was centralised by a "single buyer", because we believe that such a role would become politicised, leading us back to eventually repeat the mistakes of the past, when excessive investments were made in over-priced and unnecessary plant, for essentially political reasons.
   - So, the market design instead relies on multiple participants making their own judgments about may things, including entry economics, and making their own arrangements, including finding their own balance between contracting ahead and relying upon spot revenue

8. We particularly focus on the conceptual and practical difficulties arising in markets relying heavily on renewables, and/or dominated by reservoir-based hydro. The general theory still applies, and optimal SRMC-based pricing should, theoretically, still cover LRMC entry costs, on average in the long run, for each technology in the optimal plant mix. But we identify three issues that will only become more important, as greater reliance is placed on intermittent renewable supply options, in future.
   - It is actually quite difficult to determine what participants actually believe the SRMC of hydro to be, though, let alone identify the motives behind any deviation from it, because a wide range of market behaviours and outcomes which might be thought to have something to do with market power are also quite likely to arise in a perfectly competitive market, or in a centrally planned environment.
   - Thermal SRMC can actually be hard to define with any real precision, too, given the fixed costs involved, and the upstream constraints in a

closed system making its SRMC opportunity cost co-dependent with that of hydro.

- Long term contracting for specific delivery volumes becomes difficult, too, because neither hydro nor thermal generators actually know how much they will be able to produce, or called on to produce, very far in advance.
- An initial empirical analysis suggests that, theoretically, more than 25% of industry revenue would need to be collected from periods of sustained high prices, mainly in very dry years. In other words, several years' worth of normal annual revenue would have to be collected in a single year, perhaps every 20 years or so.

9. We consider that such large sustained price spikes would not be allowed to occur, in practice. This threat of possible price capping in such circumstances implies a significant potential loss of revenue, which can be expected to discourage entry by potential entrants, particularly in extreme peaking plant. In any case, no commercial operator would enter solely in the hope of receiving such a risky and infrequent payment stream.

    - A healthy plant mix will only be sustainable if generators can supplement their income in wet, normal, and moderately dry years, in order to compensate for the expectation of not being able to recover the theoretically optimal requirement in extremely dry years.

10. Contracting, including retail sales commitments, can be used to greatly reduce the risk faced by generators, and to smooth revenue streams between wet and dry years. But it will not be practical for participants to sell their expected output under contract, though, when their real capacity and output is so unpredictable from year to year. So, their exposure to spot prices will be significant, but varying greatly from year to year.

11. That implies significant risk, but also opportunities and incentives to manage that risk by "exercising market power"; that is, by moving output levels closer to contract level than might be implied by a perfectly competitive analysis.

    - This will shift SRMC up, in wet to normal years when the aggregate generation sector will be contracted to supply less than potential output.
    - But it will shift SRMC down, in very dry years when the aggregate generation sector will be contracted to supply more than its potential output.

12. Alignment between prices and SRMC is still theoretically desirable, inasmuch as it provides more accurate signalling for efficient operation, both within the sector, and to consumers. But some deviation from SRMC pricing is likely to be one of the means used to sustain acceptable revenue streams through the long periods of relative surplus expected in a hydro dominated market.

    - This market has been designed to operate just like the vast majority of successful markets operating outside the electricity sector, and with similar cost structures, where pricing above SRMC has always been considered absolutely normal.

- Other sectors with similar cost structures, such as hotels and airlines typically recover costs via charges that are very different from SRMC partly, we suggest, because forward contracting is quite difficult in those sectors.
- The average price paid for electricity, though, has a strong contract component, just like the average price paid for "accommodation", or "transport", more broadly defined. Thus, both generators and consumers can protect themselves from the impact of spot prices, and any distortion of spot prices, should they see fit.
- The level of price distortion will reduce as the contracting level increases, because participants incentives to put upward pressure on prices falls off as contract levels approach perfectly competitive output levels, and then reverse above that.

13. Assuming current technology, and a diminishing contribution from thermal plant, pressure to achieve cost recovery by pricing above SRMC will become increasingly acute as the proportion of renewable generation increases, and (in theory) SRMC may alternate between zero and demand response values for extended periods of time.

    - But storage facilities, including hydro and potentially batteries and other emerging technologies will moderate that situation, and may allow the energy-only market to keep functioning much as it does today.

14. In our view, alignment of the PDC with LRMC entry costs, across the spectrum of plant types, is a much more important issue than alignment with SRMC, because:

    - Costs in the New Zealand electricity sector have traditionally been dominated by investment costs, rather than fuel costs, and this will become even more true, as the role of thermal generation options recede. So, the key issue must be to provide appropriate LRMC signals to guide investment decisions.
    - LRMC is not a "limit", though, because prices must equal LRMC, on average, being above that level for long enough to balance periods of excess supply, when competitive pressure may force prices below LRMC.

15. Thus, we argue that the most important measure of market performance, is the degree of alignment between the market Price Duration Curve and assessed entry costs for each plant type, as calculated for potentially risk-averse investors.

    - A simple empirical study on NZEM 2010-16 data concludes that the degree of alignment seems remarkably good, with most technology types slightly under-recovering entry costs for.
    - This is not surprising, in a market where LRMC is declining, with little entry occurring.

16. The results for extreme backup capacity are less encouraging, with Whirinaki only recovering very little of the revenue required to support entry of that kind of backup capacity:

- This is not too surprising, given that our analysis shows that Diesel OCGTs do not form part of the optimal plant mix, so long as gas is available at moderate prices.
- It may just be that the sample does not include any years dry enough to really require much contribution from Whirinaki, and/or there may just be excess capacity in the market, due to low growth in recent years.
- But it suggests that the focus of concern, if any, should probably still be more on mechanisms to incentivise adequate capacity provision than on the possibility of "gaming" producing excessive profits, a concern that is not supported by the empirical evidence anyway.

An Economic Perspective on the New Zealand Electricity Market

1 Introduction

Several questions have been raised, over the years, about the design of the New Zealand Electricity Market (NZEM), and particularly about the potential exercise of market power within that market, and specifically in the wholesale spot market, on which we focus here. It seems evident, from some discussions, that there is a divergence of view about what the market design actually is, or was intended to be, and perhaps about what it should be. And there is perhaps also confusion and/or disagreement as to how standard theory might be applied in a market dominated by hydro, and increasingly other renewables. This raises a particular risk that situations and behaviour may be assessed from a perspective derived from other markets, with different design philosophies, and that inappropriate and incompatible conclusions and "solutions" may then be imported from such markets.

Much public attention has sometimes been focussed on claims and counter-claims with respect to the extent to which "market power" has, could, or should be observable in the NZEM. The answers to such questions hinge crucially on the way in which market power is defined, and on the distinction between "exercise" and "abuse" of market power. But there is also evident tension between conclusions drawn from studies and concerns focussed on a narrow Short Run Marginal Cost (SRMC) perspective, and those derived from a broader Long Run Marginal Cost (LRMC) perspective.

This report is extensively based on an earlier report, originally commissioned by Mighty River Power.[1] That report was intended to assist in developing greater understanding, and awareness, of some key issues related to the design and expected performance of the New Zealand Electricity Market (NZEM) at that time. A similar discussion seems to have again come to the fore, though, perhaps in response to the recent First Report of the Electricity Price Review.[2] New issues are emerging, too, as New Zealand faces the challenge of not only increasing the contribution of renewable to meeting existing electricity demand, but expanding electricity production to meet new demands arising from the desire to increase electricity's contribution to other sectors, including transportation and heating. It may now be appropriate to ask, not only whether the current market design has been "fit for purpose" over the last 20 years or so, but whether it will still be fit for purpose over the next 20 years or so.

---

[1] *Economic Behaviour in a Hydro-Dominated Electricity Market* EGR Consulting Report for Mighty River Power, March 2009

[2] *Electricity Price Review: First Report for Discussion*, NZ Government, 30 August 2018

This report does not really attempt to answer either question, but it seems appropriate to update what was written a decade ago, in light of new experience and emerging challenges. Thus, before considering any market power or performance issues, we start by reviewing the basic concepts underlying the New Zealand market design, the kind of pricing and behaviour patterns that might be expected (even) if market power were NOT being exercised. Specifically:

- In Section 2, we ignore hydro and other renewables entirely, and discuss some basic market design concepts, noting the difference between the "one part" market design adopted in New Zealand, and several other jurisdictions, and the "multi-part" designs used in some other parts of the world. We particularly focus on the difference this makes to expectations about the shape of the SRMC-based Price Duration Curve (PDC) for an optimally planned system, under realistic risk and regulatory assumptions, and discuss how that optimal PDC can be determined, and used to assess system performance.

- In Section 3, we consider some particular issues arising from the way in which hydro and other renewables affect the shape of the PDC, and the timing and risk associated with cost recovery requirements, particularly for long-lived hydro assets.

- Then, in Section 4, we turn to consider what might be considered legitimate, or illegitimate, exercise of market power in that kind of market context, and focus on the compromises that might be required to actually make this kind of market workable, for a hydro dominated electricity sector, in a real socio-political context. Finally, we summarise the conclusions from some very preliminary analysis of the actual performance of the NZEM, focussing on entry economics and cost recovery.

Three Appendices provide more detailed discussions of:

- The rationale behind the uncapped, LRMC focussed, locational market design philosophy of the NZEM, and the reasons why various modifications to that design were not adopted, even though they may seem attractive in the short term.

- The inherent difficulty of defining SRMC in hydro dominated electricity markets, and the kind of behaviour and price patterns that may be expected to arise in such markets, assuming perfectly competitive, or centrally optimised, responses to varying hydrological conditions.

- An LRMC focussed perspective on how we believe the performance of the NZEM should be assessed, illustrated by applying a simple spreadsheet analysis to approximate NZEM data.

Much has been written on some of the points touched on here, and much more could be written. Thus, a comprehensive treatment is not possible in this context, or timeframe. Our aim has been to provide a reasonably accessible overview of the issues, rather than an in-depth development of any one of them. Accordingly, we focus on the issues that are most pertinent, and perhaps most controversial, and do not attempt to "prove" any of the assertions made here, at either a theoretical or empirical level. No attempt is made to reference the large academic literature which might be brought to bear on these issues, either. However, the perspective presented here is based on an extensive personal history of involvement with, and research on, electricity sector issues, particularly in New Zealand, before, during, and after the market reform process. So, reference is made to earlier commentaries and studies by the current author and his colleagues, in the New Zealand context, many of which expand upon the points made here.

In particular the reader is referred to Culy et al [1996][3] for an economic perspective on the history of the New Zealand electricity sector prior to establishment of the current market. Read [1997][4] provides a perspective on the goals of the current market design, and a commentary on initial experience with it. Read [2010] [5] provides an informal discussion of the properties and relative merits of a variety of mechanisms that could be used to provide adequate cost recovery for peaking/backup plant, in particular, in the NZEM context. And Read et al [2012][6] provides a high-level perspective on "gaming" issues in electricity markets, arguing that the "games" that matter most are the highest level games involving not just market participants, but Governments, Regulators and voting consumers, in establishing the regulatory regime under which the sector operates.

---

[3] J.G. Culy, E.G. Read, and B. Wright: "Structure and Regulation of the New Zealand Electricity Sector", in R Gilbert and E Kahn (eds.) *International Comparison of Electricity Regulation,* Cambridge University Press, 1996, p. 312-365.

[4] E.G. Read: "Electricity Sector Reform in New Zealand: Lessons from the Last Decade" *Pacific Asia Journal of Energy* Vol 7, No 2, 1997, p. 175-191

[5] E.G. Read: *Scarcity Pricing for New Zealand: A Personal Perspective* EGR Consulting report. Released by the New Zealand Electricity Commission, October 2010

[6] E.G. Read, P.R. Jackson & S. Dye: "Gaming, Risk and Investment in Electricity Markets: An Antipodean Perspective" Presented to the *Energy Centre Workshop*, Auckland, August 2012

2 Market Design Concepts

2.1 Market Clearing Prices

The NZEM is a locational market, and electricity spot prices vary significantly between locations due to both transmission constraint and marginal loss effects. The principles discussed in this report can be generalised to apply to the interaction between supply and demand at the locational level and, with some modifications, to transmission between locations. We ignore this complication, though, and assume a hypothetical national market, in which all power generated and consumed is traded at a single node, without any restraint on transmission to, or from, that node.

At the most basic level, the NZEM is an "energy-only", or "one-part", market[7], in which all participants buy and sell at Market-Clearing Prices (MCPs). Thus, it is based on the principles that:

- All participants providing (or purchasing) energy at the same location should be paid (or should pay) at the same rate, irrespective of their offers (or bids);
- The entire remuneration for generators should be provided by these spot market energy payments, or derived from them by way of financial contracts written against them; and
- Competitive discipline is largely relied upon to discipline offering behaviour, and hence to control prices, with limited regulatory interventions in extreme circumstances.

This design has important implications for the pricing patterns we should expect to see arising from the market.

First, it is often loosely stated that, under "perfect competition" participant offers should be expected to reflect Short Run Marginal Cost (SRMC), and that MCP should thus reflect the marginal cost of generation at the industry level. That expectation is examined in greater depth later, but here we note that SRMC "offering" is not the same as SRMC pricing. It does not mean that individual plant, or firms, sell at their own SRMC, but that they all sell at the industry SRMC: That is, at the SRMC of the marginal producer at any particular time.

Second, in this kind of market, MCP is not determined solely by the industry supply curve, but by the interaction of supply and demand curves, either explicitly or implicitly. If there was no (voluntary) elasticity in the demand curve, MCP would

[7] We will use the former term, because "multi-part" offers may be employed in markets which are essentially "energy-only" in the sense that energy prices are capped only at very high levels, and there is no separate market for long term capacity investment.

(theoretically) equal the marginal cost of production until a capacity constraint was reached. But, at that point, the MCP should theoretically rise to very high levels, reflecting the cost to society of the involuntary load shedding needed to match demand to the available supply. In general, that cost would be much higher than for voluntary reductions of the type that might be expected in response to market price signals. This would be reflected in the "shadow prices" calculated by a centralised optimisation, and the same price pattern should be expected from a hypothetical perfectly competitive market.[8]

In the real world, demand will be somewhat elastic across the entire price range, though. Even if consumers do not submit a "demand curve" to the market, consumers who are exposed to MCP can be expected to respond to it, and that response should really be accounted for in a centralised optimisation, or evident in the market when plant capacity limits are reached. So, prices should sometimes be set by load reduction at levels below the SRMC of the most expensive generator, and expected to exceed the SRMC of generation, often by a very large margin when supply is short. And we expect such situations to become more frequent in future.

As discussed in Section 3.3, the expected marginal water values computed by reservoir management models inevitably account for the prospect of future load reduction interchangeably with generation. Thus, for several decades now, most New Zealand discussions have extended the definition of "SRMC" to include demand reduction costs, thus making it natural, but potentially misleading, to refer to MCP as the "SRMC price". But some parts of our discussion will need to distinguish between SRMCG(eneration), and SRMCD(emand).

2.2 Energy vs Capacity Pricing

Second, as an "energy-only" market, the NZEM differs significantly from markets in which participants receive supplementary payments for "capacity" in various forms.[9] As such, it should be expected to produce patterns of "energy" prices, which differ from those arising in such markets, and also from many traditional forms of regulated electricity pricing, in which explicit capacity payments (or peak) charges often feature

8 Technically, a centralised optimisation may report "infinite" shadow prices, but these over-state the severity of the situation.

9 This discussion ignores ancillary service market(s). In New Zealand, these are "co-optimised" with the energy market, and ancillary service sales provide some additional revenue to support capacity investment. But this does not materially alter any of the discussion here. Ancillary service payments are only made to participants providing ancillary services, and only for the MW provided. This is not the same as providing a capacity payment to all capacity in the market, as occurs in markets that employ capacity pricing.

prominently.[10] What we might hope to see, though, is a pattern of energy prices in the NZEM broadly matching the optimal pattern of energy/capacity prices, in combination, in a centrally optimised electricity sector.[11]

A traditional centralised optimisation model would compute an SRMCG-based price corresponding to the MCP, so long as the optimally planned system was able to meet demand. There would be periods, though, in which an optimally planned system would be unable to meet demand, forcing some form of rationing to occur.[12] Provided the optimization model includes an economic representation of the costs incurred when load is not supplied, it will compute a shadow price limiting demand to equal total available generation capacity. In the optimisation logic, that shadow price represents an extra payment, over and above the SRMCG-based prices, to all capacity available at that time, reflecting the economic value each unit of capacity delivers by being available to limit shortage to the optimised level.

Ignoring economies of scale, this traditional optimisation problem is convex, and it can be shown that the costs of all capacity in the optimal plan will be covered if (and only if) this (notional) capacity payment is added to the (notional) payments calculated from SRMCG-based prices. Conversely, the SRMCG-based prices alone will always be insufficient to cover the investment cost of any plant, after fuel and variable maintenance costs are accounted for.

The same result applies equally in a hypothetical perfectly competitive market, with prices theoretically "spiking" up to the levels required to ration demand. In real life, this same price pattern may be approximated in two ways:

- By a combination of energy and capacity prices in a "two-part" market; or
- By energy prices alone in an "energy-only" market

In the first case, we might hope to see <u>energy</u> prices approximating the SRMCG of supply at all times, complemented by <u>capacity</u> prices approximating the capacity constraint shadow prices in a hypothetical centralised optimisation. In the second case,

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[10] For many years, before there was any significant thermal generation in New Zealand, the wholesale "Bulk Supply Tariff" consisted entirely of such peak charges, meaning that "energy" was implicitly charged at a per unit price of zero. (This might be thought to be the SRMC of a pure hydro system, although that is generally not correct, as will be seen from later discussion.) A 50% energy component was introduced later. (See Culy et al [1996].)

[11] Traditional capacity charges have at least partly reflected the cost of the transmission and/or distribution systems, and other overheads. In this discussion, though, it is only the "generation capacity" component of these charges which is relevant.

[12] Put another way, there will always be a probability level beyond which it would be more economic to risk the possibility of non-supply, rather than to incur the cost of building supply facilities which will almost certainly never be used. A sufficiently detailed probabilistic optimisation will reflect this by determining an optimal trade-off between supply and non-supply, implying a finite probability of non-supply.

we might hope to see energy prices approximating the SRMCG of supply much of the time, but supplemented by moderately frequent (energy) price "spikes", reflecting SRMCD. And the value implicit in those price spikes should approximate the value which would be recovered from capacity charges under a "two-part" energy/capacity market design. In other words, the aggregate should equal the value of the capacity constraint shadow prices in a hypothetical centralised optimisation.

2.3 The PDC and Entry Economics

The simplified discussion above can be generalised in a way that fits more naturally with discussions of market economics. While the precise chronological pattern of loads is important for some purposes, much can be learned by analysing the cumulative distribution of loads over, say, a year, known as the Load duration Curve (LDC).[13] We can summarise the distribution of market prices, similarly, by creating a Price Duration Curve, or PDC, indicating the proportion of time for which prices are observed above each price level. Option Values (OV) for any plant type "x" can be determined from such curves, being the net operating profit to be made by that plant type, assuming that it operates at full capacity throughout the period for which the MCP exceeds its SRMC.

OV(x) is the value of a call option, with a strike price set at SRMC(x).[14] MCP is assumed to equal SRMC(x) all the time when plant x is partially loaded and hence "on the margin". So, the call option would actually have no value to x, during that period, in this hypothetical pure SRMC market. It does have value when x is operating at full capacity, since the MCP is being set by some more expensive plant, so we define:

- U(x) as the proportion of time[15] for which plant x is running at full capacity, which it will do whenever MCP exceeds SRMC(x).
- RV(x) as the revenue collected by x, while it is running at full capacity, so it is the sum of all prices in the PDC above SRMC(x)

Then we have:

$$OV(x) = RV(x) - U(x)*SRMC(x)$$

In words:

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13 Normally the LDC specifies the number of hours for which load levels exceed each load level, over some period. But, more generally, we can think in terms of the percentage of time involved.

14 We will ignore variations in operating efficiency across the output range, and note that, under competitive assumptions, plant will make no net operating profit when it is itself marginal, because the price will be set by its own SRMC.

15 Or the number of periods if the LDC is defined that way. The formulae developed below assume that U is expressed appropriately for each context, so that annual running costs are compared with annual capital costs, etc.

OV(x) = Expected revenue for x assuming SRMC-based MCP prices
MINUS Fuel and variable operating costs for x, over the time it operates

Generalising the definition of SRMC to include load reduction costs, as above, a notional PDC for an energy-only market can be produced under competitive assumptions. Prior to the market, in the latter days of the Ministry of Energy, the New Zealand electricity sector was planned using OVs determined from a PDC defined in exactly this way, but created using shadow prices from the PRISM/SPECTRA models. It is not difficult to show that more capacity of each plant type should be introduced if, and only if, its SRMC-derived OV exceeds its Fixed (Capital + O&M) Cost, which we will refer to as FC.[16] This holds true in a centralised optimisation, but also for a market.

In other words, subject to some caveats discussed below, investors should have commercial incentives to introduce new capacity of each type when its MCP-derived OV exceeds its FC. The threat of such entry thus "disciplines" the PDC by ensuring that the total (OV) value of the PDC above the SRMC of each viable entry option matches FC, the LRMC entry cost of that option. If the OV at an SRMC level associated with plant x rises above FC(x) then we expect more capacity of type x to enter, thus depressing the upper part of the PDC until OV(x) reduces to match FC(x). If the OV at the SRMC for plant x falls below FC(x) then we expect no more capacity of type x to enter, while load growth, plant retirement etc raise the upper part of the PDC until OV(x) increases to match FC(x). So, in expectation, we should have:[17]

$$OV(x)=FC(x)$$

That is:

Fixed Cost for x = *Expected revenue for x assuming SRMC-based MCP prices*
MINUS Fuel and variable operating costs for x

This can then be re-arranged to form a relationship which should hold on average, over the long run:

Long Run Marginal Cost (LRMC) for x
= Fixed Cost for x + Fuel and variable operating costs for x
= Expected revenue assuming for x "SRMC-based" MCP prices

Scaling units appropriately, we get:

$$LRMC(x) = F(x) + SRMC(x) = OV(x)$$

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16 In reality, investment is lumpy, and this matching is not exact. But this does not really affect the principles discussed here. In practice, we will compare annual cost recovery requirements with annual OVs.

17 Strictly, the "expectation" referred to here is the expectation of a generic potential entrant.

2.4 The Optimal PDC and Plant Mix

Many discussions seem to assume that there is a single well defined LRMC for the electricity sector as a whole. Each technology has its own LRMC, though, and we have just seen how that LRMC "disciplines" the PDC, in the sense that FC(x) determines RV(x), the total value of prices in that part of the PDC above SRMC(x). In reality, we may expect SRMC(x) and/or FC(x) to change over time, due to technological progress, resource depletion etc. Ignoring that possibility, though, the relationships above actually define a long run equilibrium PDC that is driven entirely by the economics of the entry technologies potentially available in a particular market. It also defines the optimal plant mix, in the following way:

- Generation technologies are often ranked in a "merit order", from the lowest running cost, up to the highest. The next plant up in the merit order, after plant x, will be x+1, with SRMC(x+1) greater than SRMC(x).
- But there would be no point even considering building plant of type x+1, with its higher running cost, unless its fixed cost FC(x+1) was lower than FC(x).
- This means that plant x+ 1 is more suited to meeting load levels closer to the peak that occur less often, while plant x is more suited to meeting load levels that occur more often.
- In fact, there will be a critical utilisation factor U(x), below which savings on capital cost more than offset the extra SRMC cost, making it cheaper to invest in plant x+1 than plant x, to meet higher, less frequent, load levels.
- It is not hard to see that:

  $U(x) = (FC(x)-FC(x+1))/ (SRMC(x+1)-SRMC(x))$

  Or, in words, with appropriately scaled units:

  The extra annual fixed cost of investment in pant type x (rather than x+1

  Divided by:

  The extra annual running cost of using pant type x+1 (rather than x

At one extreme, we may be prepared to pay quite a high fixed cost for base-load plant like wind or run-of-river hydro, with an essentially zero SRMC. At the other extreme, we have "shortage" for which we pay no fixed cost, but face an SRMC set by the "shortage cost" or "Value of Lost Load", VoLL. In between, we can apply the formula above to each successive pair of technologies in the merit order, and find a range of technologies, each of which is best suited to meeting incremental load levels occurring with a frequency between U(x) and U(x-1). This same set of critical utilisation factors:

- Defines the optimal long run equilibrium PDC because, with SRMC pricing, we should have MCP= SRMC(x) over the hours when plant x is "on the margin", i.e. between U(x) and U(x-1).
- And, when applied to the LDC, determines how much MW capacity of each type should actually be built, and hence the optimal plant mix to meet that LDC.

These mathematical formulae, developed here in a market context, are exactly the same as those applying in a centralised optimisation. In fact, the approach described here was developed and applied to electricity sector planning by the New Zealand Ministry of Energy in the mid 1980's. And note that the first relationship, defining the optimal PDC, is actually independent of the LDC. Thus, while entry will keep occurring if the LDC grows over time, or to replace retiring plant, the equilibrium PDC itself should only change in response to changes in the fixed or variable costs of the potential entry technologies.

Markets are seldom really in equilibrium, and the actual PDC is unlikely to exactly match the optimal PDC calculated above. The entry dynamics discussed here, though, imply that market forces should be consistently acting to move the real PDC towards the optimal PDC determined by the entry costs expected in any particular year. When we talk about SRMC/LRMC alignment, then, we are not just talking about matching two specific values. Rather, we are talking about the alignment between two distributions of prices: the *observed* PDC in any year, and the *optimal* PDC determined by the entry costs that were expected in that year.

The relationship between FC and OV also implies an equivalent interpretation in terms of option valuation.[18] Thus, this optimal PDC concept plays a central role in electricity sector economics, and implies the following test that can be applied to each plant type in that optimal mix:

- The (own-generation weighted) average SRMC-based MCP received by base-load plant must match the LRMC of such plant;
- The (own-generation weighted) average SRMC-based MCP received by "shoulder" plant must match the LRMC of such plant;
- The (own-generation weighted) average SRMC-based MCP received by "peaking" plant must match the LRMC of such plant.

2.5 Cost Recovery

In discussing the alignment of LRMC with cost recovery requirements we need to specify which LRMC we are talking about. Some studies seem to focus solely on the LRMC of base-load entrants such as geothermal, and arguably wind and run-of-river hydro, and the theory above implies that should align with the Time-Weighted Average Price (TWAP). But the actual cost of meeting loads is higher than that, and corresponds to the Load-Weighted Average Price (LWAP), because the cost of covering peak and shoulder loads is higher than that for base loads. Under our simplified single node

[18] That relationship rests on the observation that, provided both are available, plant x, with its lower SRMC, will be fully dispatched, and operating at a profit, whenever plant (x+1) is dispatched. Thus it will receive all the revenue x+1 does, and make more profit per unit on it, because its SRMC is lower. This means that OV(x) is always greater than OV(x+1), and it is that difference in option values that justifies the extra cost of building capacity of type x, rather than type x+1, to meet load levels occurring more often than U(x).

assumption LWAP is equal to the Generation-Weighted Average Price (GWAP).[19] The discussion above applies to each plant type in the optimal mix, but it can be generalised to apply to each load class, too, or to the whole LDC:

- The (industry load/generation weighted) average SRMC-based MCP paid for any pattern of peak/shoulder/base load should match the LRMC of meeting such load, as determined by the optimal plant mix and PDC discussed above.
- The load weighted average SRMC-based MCP paid by any load class or component, should match the LRMC of the optimal mix of plant required to supply that load.

Accordingly, the alignment of the SRMC/MCP-based PDC with entry costs provides an important test of market performance. This alignment means that, if all plant expect to recover their LRMC costs when they enter, they actually should be able to cover their costs, on average, unless the market is disturbed in ways that were not expected at the that time of entry. Surprises always will occur, and the whole market may under- or over-recover as a result, and some projects will have unexpected cost over-runs, too. Entrants are assumed to account for all such possibilities in their decision-making, though, and should not enter unless they expect to cover their costs, on average. Individual expectations may differ but, unless aggregate industry expectations are biased, we should expect to see SRMC prices matching LRMC on average, across the PDC, over the long term.

Oddly, though, many discussions treat LRMC as if it were an upper bound on SRMC prices. Thus, it is common to see market price projections tracing a rising curve of "SRMC prices" up to the point where they equal LRMC, after which it is assumed that entry will occur and limit prices to LRMC thereafter. This may be a reasonable picture of the actual performance of many markets, including the NZEM in its early years, but it should be recognised that it can only be a valid picture of a market in disequilibrium, starting with excess capacity. From an economic perspective, it can not represent a typical, or sustainable, long term pricing pattern.[20]

What we should really expect to see, in the long term, is that aggregate annual SRMC-based prices sometimes lie above LRMC, and sometimes below it, equalling LRMC on average. Regulators seem generally comfortable with periods when SRMC prices lie below LRMC, and some may even try to force prices down in situations where they are above SRMC, even if that implies cost recovery below a long-term sustainable LRMC level. But it is by no means clear that the same regulators will look so benignly on extended periods when SRMC prices rise above LRMC. Rather than force prices up in

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19 Otherwise, the two would differ due to transmission losses and constraint rentals.

20 Prices may also rise, over time, because LRMC itself is rising, perhaps due to resource depletion and increasing environmental pressures. But that issue is discussed in Section 3.5.

tight market situations, it seems more likely that prices could be capped below their theoretically optimal demand-rationing levels.[21]

Any restraint on SRMC pricing in such circumstances surely implies, though, that prices would have to rise above SRMC during surpluses, if a sustainable long run equilibrium is to be maintained, on average. Otherwise the market design had failed in one of its primary objectives: That of setting prices to sustainable levels, on average. More exactly, the issue is not whether prices will actually be restrained by some direct cap or indirect influence, which may be unknowable in advance, but whether potential entrants now think there is a possibility they will be restrained, and account for that possibility in making their operational/investment plans. The greater the perceived probability of capping, and the tighter the possible caps, during shortage periods, the greater the deviation from "SRMC" required to balance the books during surplus periods.

Attitudes towards that outcome may be seen as reflecting a fundamental conflict between the forward-looking perspective of economics, with its emphasis on finding the best use of resources irrespective of what they may have cost to develop; and the backward-looking perspective of accounting, with its emphasis on paying for resources already committed, whether or not they were economically justified in retrospect. They also reflect a conflict between the desire to provide efficient SRMC-driven signals to consumers operating installed electrical appliances etc, and the desire to provide efficient LRMC-driven signals to consumers as they consider investing in electrical appliances etc.

In Section 2.7, we discuss the kind of contractual mechanisms that could, theoretically, allow all three goals to be achieved simultaneously. But first we should discuss the possible impact of risk aversion.

2.6 Risk Aversion and PDC Inflation

As discussed in Section 3.4, risk is a rather more significant issue in hydro dominated markets, than it is for typical electricity markets, and it may not be easy to provide risk averse investors with sufficient assurance that they will be able to obtain an adequate return for the risk involved. But participants in all markets face the risk of strategic response from other participants, regulatory intervention, technical failure, and changes to load growth, technology or fuel prices. Accordingly, risk and risk aversion are important factors.

All of the above discussion may be thought of as assuming risk-neutrality, though. Thus, when we say that peaking plant will enter if its "OV exceeds its FC", this may be

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[21] In principle, some kind of price restraint has occurred whenever physical rationing, or shortfalls, occur. Arguably it also occurs when reliance is placed on public campaigns, aimed at encouraging individuals to sacrifice their own price-driven interests for the community good.

interpreted in NPV terms. But we have not actually said what discount rate is to be used when determining OV or, for that matter, FC. In reality, a potential entrant realises that investment in a peaking plant is naturally risky, and that any threat of intervention is likely to increase that risk. So, the potential entrant will presumably apply a risk adjustment to the discount rate used for project evaluation, thus raising FC by a potentially significant amount. Read et al [2007][22] argue that this could have a significant impact on the effective PDC expected in long run equilibrium, particularly in an energy-only electricity market:

- In a market which provides guaranteed payments for "capacity", the providers of that capacity should be expected to determine FC at a moderate discount rate, and this should be equivalent to the OV for such capacity determined from an optimal SRMC based PDC;[23] but

- Since participants in an energy-only market receive no such guarantee, they must determine FC at a "risk-adjusted" discount rate, and that FC should be equivalent to the OV for such capacity determined from a PDC with higher prices occurring with a higher probability.

One may argue about how significant this effect actually is, particularly in a market dominated by vertically integrated "gentailers" who are exposed to the risk of not being able to meet customer obligations if they can not access sufficient capacity in extreme conditions. In theory, though, if an energy-only market were reliant on stand-alone entry by independent generators, the PDC could be inflated to significantly higher levels than might be calculated on a risk-neutral perfectly competitive basis. The issue is whether those higher prices occur more often because market prices exceed SRMC, or whether it is that SRMC itself must be higher, more often. But it must occur somehow.

PDC inflation of this type is not necessarily inconsistent with "SRMC pricing". If market rules were to enforce SRMC pricing, but prices were not capped, potential entrants would simply refuse to enter, thus "withholding capacity" in the ultimate sense, until the PDC rose high enough to support entry, with an appropriate risk premium. In part this may occur because the lack of investment forces less efficient, and hence more expensive, plant onto the margin, more often. Thus, peaking plant may be required to generate more as "shoulder" or "peak support" plant, and shoulder plant as base-load plant. In part it may occur because shortages eventually become

[22] E. G. Read, M. Thomas and D. Chattopadhyay "The Impact of Risk on Capacity Investment in Electricity Markets" keynote presentation, *IAEE Proceedings*, Wellington, 2007

[23] Such a guarantee does not eliminate supply-side risk, but probably reduces overall risk below normal commercial levels.

acute enough to force SRMC/shortage cost prices up to a level entrants find acceptable, given the risks involved.[24]

Read et al argue that the result will be a plant mix with less capital investment, higher running costs, and more shortage than may seem optimal, when assessed from a traditional central planning perspective, where aversion to commercial risk is not normally considered to be a significant factor. Alternatively, though, an equilibrium involving more entry, less shortage and a more balanced plant mix, could be sustained if potential entrants believe that their risks can be reduced by pricing above SRMC at peak times, and/or during surplus periods.

2.7 The Impact of Contracting

The market for trading financial contracts settled against NZEM spot prices has become much more active since the original paper was written, in 2009, and there is a danger that a focus on relatively short-term contract trading activity could obscure four fundamental things about the nature of such contracts:[25]

- First, the ultimate value of every contract will ultimately be determined by spot prices in the period when it matures.
- Second, no matter how many intermediate trades, or traders, are involved, contracts will only reduce risks of the original issue, or ultimate purchaser if backed, directly or indirectly, by the capacity to physically generate, or desire to physically consume, electricity.
- Third, under-contracted generators are effectively selling generation in excess of contract quantities at spot prices, so they still have some incentives to reduce output toward the contracted level, so as to increase the price at which they sell. But over-contracted generators are effectively buying in power to make up the contract quantities at spot prices, so they have some incentives to increase output toward the contracted level, so as to lower the price which they pay.[26]
- Thus, even though these contracts are not "physical", they do give participants incentives to align physical production/consumption, on the day, with contract quantities.

Thus, while there may be many steps in between, the fundamental role of contracts is to bridge from the LRMC-dominated world of physical (investment in) generation capacity, through the SRMC-dominated world of spot market trading, and on to the

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[24] Price capping merely removes this second option and forces more reliance on the first, as discussed in Section 5.5.

[25] Except where "options" are referred to the contract here are assumed to be "Contracts for Differences" (CfD's), effectively specifying a buy/sell agreement for a fixed volume, at an agreed "strike price".

[26] Totally uncontracted generators, having no guaranteed income and relying solely on spot market prices to recover costs, represent an extreme case, and always have incentives to withhold generation in order to increase prices.

LRMC-dominated world of physical (investment in) consumption capacity, both industrial and domestic.

Provided contracts trade at a freely determined price, rather than being imposed on one side of the market or the other, the logic described above remains valid, with three major differences:

- Contracts have a direct impact on risk, and hence on the economics of entry and the long run equilibrium PDC. Entrants who can secure a significant part of their forward revenue via a contract[27], should be prepared to enter at a rate of return less inflated by risk (as discussed in Section 2.6), and hence discipline the PDC at a price point reflecting that lower rate of return requirement, ultimately lowering the average price charged to consumers.

- Contracts also alter behavioural incentives, so that some approximation to the equilibrium conditions discussed in previous sections may still apply, even in situations where the perfectly competitive assumptions underlying that discussion do not quite apply: that is in situations where participants may have the ability to profitably affect prices by the way they offer. But discussion of that issue will be deferred to Section 4, which discusses market power

- Because contracts re-define and re-assign risk between participants, but also over time, they can also allow the backward and forward looking perspectives to be reconciled, as discussed below.

Theoretically, a potential entrant should be able to sell a contract for the expected output pattern of a unit at around the expected value of that output pattern in the spot market, which it will be matching to its LRMC. Thus, looking forward, it will try to time its entry so that the OV of such a contract corresponds to the FC of its proposed plant. So, the economic optimality conditions described in Section 2.3 should be expected to hold, in prospect, at the point when a participant commits to building a new plant, at least when evaluated from that participant's perspective.

Looking back, though, participants may have quite different views, both about what their costs actually were, and about market performance. Thus, they may find a significant discrepancy between their cost recovery "requirements", and SRMC-based prices. If they have sold a contract for all their expected capacity, the forward-looking value of that contract may be higher or lower than expected, depending on these updated spot price projections. If their project is performing, though, in the sense that they can still generate that amount, then the price they receive will still be the contract price, not the MCP.[28] If that contract price met their expected LRMC-based cost recovery requirements at the time it was agreed, it will continue to meet those expected requirements as conditions change. Contracted entrants would then only have to deal

[27] Perhaps implicitly though vertical integration.

[28] Projects never perform exactly as expected, but that is a normal commercial risk, rightly borne by the developer, and presumably accounted for in their rate of return requirements.

with any discrepancy between the actual and expected cost and/or performance of their own plant.

In reality, a perfect match between contracted and actual capacity, or perfectly competitive output levels, is unlikely, and virtually impossible for a hydro generator. But the perfectly contracted case describes the opposite end of the spectrum from that at which many analyses start; with a pure spot market and no contracts at all. Reality will lie in between, and generators will find themselves more exposed to spot prices as their optimal perfectly competitive generation levels deviate from contract levels. The closer the real world lies to the perfectly contracted case, though, the closer revenues will lie to cost recovery requirements, and to LRMC, as it was expected to be when the contract was signed. Ignoring any risk premia, the effect should be just to narrow the distribution of outcomes, rather than to alter expected values.

3 Cost Recovery Issues for Renewables

3.1 Introduction

The theory discussed in the previous section was largely developed in the context of systems dominated by thermal generation, but it mostly applies to renewable generation too. Renewable generation technologies often introduce new technical issues, though, and/or represent special or extreme cases of the standard theory. So, the application of some aspects of the theory may be challenging in the context of a move toward a 100% renewable system. Thus, this section highlights some issues of particular importance when analysing the behaviour and performance of renewable generation options, and of systems with a significant renewable component.

3.2 PDC for Renewables with no Storage

Discussion in the previous section focuses strongly on the concept of an optimal long run equilibrium SRMC driven PDC. Traditionally, that PDC has been assumed to consist of a set of steps, each representing the SRMC of some thermal plant type. But the SRMC of all non-storage renewables, including wind, solar, geothermal and run-of river hydro is extremely close to zero[29], until their capacity is fully utilised, at which point it becomes infinite.

This does not exactly cause the theory to break down, but it does require some re-thinking of how these technologies might complement one another, over various time cycles, and why the aggregate market might want to invest in a range of plant types, rather than in some single technology, when all have the same SRMC. But, in the non-storage case, the key thing to note is that applying the traditional analysis based on the SRMC of generation implies an optimal PDC where:

- The price is always zero, whenever any of these technologies is spilling energy due to lack of demand.[30]

- The price spikes to the shortage cost because demand exceeds the combined output available from all plant.

But the analysis implies that shortage, or demand response, would have to occur quite frequently in this non-storage 100% renewable system, because no plant can recover any costs except during shortage/demand response periods. During those periods the

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[29] Except geothermal plants, which face a non-zero steam royalty to resource owners, and may incur variable charges for carbon dioxide emissions.

[30] Spilling energy because a capacity limit is reached is another matter. In that case, the SRMC of that plant becomes infinite, but the market SRMC will be set by some other plant, most often at zero.

price should be expected to vary, too, and as the price must be set high enough to depress unconstrained demand (i.e. the demand at the "normal" SRMC price of zero, in this case) down to the volume that can actually be delivered, on a real-time basis.

This is not just a commercial issue, but an economic one. A perfect central optimisation, perhaps managed by a "single buyer" should actually come to the same conclusion as a perfectly competitive market with respect to the level of capacity to build, and the frequency of shortage. And while that agent might want to recover costs via charges structured in a different way, it would face a dilemma:

- It would have to physically limit demand in the periods where its chosen price was less than the shortage cost price required to supress demand down to capacity.
- Consequently, it would need to recover the revenue foregone in such periods by another charge, implying some other distortion, or by raising prices above SRMC in other periods, thus also suppressing demand below optimal levels in those periods.

Hopefully, participants would realise the advantage of maintaining a high degree of contract cover when facing this level of spot price variability, and sale of such contracts could still support entry at reasonable risk-adjusted discount rates. Even so, this theoretically pure SRMC pricing regime may be difficult to sustain. It seems likely that participants would learn to "exercise market power" by setting offers up in such a way that prices frequently rose above the SRMC of zero, even in periods when there was actually still some spare capacity.

Some level of demand response might be expected at any non-zero price level, though. So, if we broaden the definition of SRMC to include all forms of demand response (as has been traditional in New Zealand) including reactions to market prices, there is a sense in which the MCP would always equal "SRMC", in this case SRMCD. But non-zero prices would always be the SRMC of demand response, rather than of any generation technology, both above and below the nominal "shortage cost" level on a traditional PDC.

3.3 Treatment of Storage

Introducing hydro reservoir storage into the system raises some complex issues which are discussed in Appendix B, to which the reader is referred for more detail.

As noted there, many of these same issues actually arise in thermal power systems too, and especially in power systems dependent on small isolated, and relatively uncompetitive fuel supply sectors, as in New Zealand. Similar issues will also arise in power systems where battery storage plays a significant role, albeit over a much shorter time scale. Thus, the effective SRMC of solar or wind generation linked to a battery system will not necessarily be zero, but determined by the opportunity cost of using that power, rather than storing it to provide incremental supply at any time in the next day.[31]

Here, though, we focus on hydro storage systems, and just emphasise a few significant points that may easily be overlooked in a more detailed discussion.

Complexity

First, the determination of SRMC for hydro systems really is both complex and subtle. It is easy to say that the hydro SRMC is determined by the "expected marginal water value", EMWV, and that is true, at a high level. Reservoir management models generally only assess expected marginal water values for a few major reservoirs and, at that level, subtle differences in assumptions can have a major impact. This is particularly true with respect to the treatment of shortage costs and risk, both of which have a major impact on EMWV, and hence SRMC in the periods which matter most from a cost recovery perspective.[32]

Such EMWVs are often used to infer the SRMC of hydro generation but, at a more detailed level, most hydro generation in New Zealand comes from power stations forming part of a river chain. The SRMC for such stations is really determined by the difference between the upstream and downstream MWVs, and those MWVs can both change repeatedly across each day. Thus, at an hourly level, it is not clear that any New Zealand generator could actually compute hydro SRMCs to the level of detail discussed in Appendix B, let alone compute optimal deviations from that SRMC.

Retrospection

Second, the actual MWV of hydro can really only be known in retrospect. Looking back, we can determine how an incremental unit of stored water would actually have been used, and hence what the opportunity cost of releasing it earlier actually was. In retrospect we can trace the actual storage trajectory, and see that that incremental unit would have been used to displace a unit generated from a specific thermal power station at some point along that trajectory. Or we may see that the increment would have been carried in storage for some time, but eventually spilled, or used to meet demand that otherwise would not have been met.

31 Over time (e.g beyond 2035) it is conceivable that new technologies such as extensive demand side management, bio diesel, solar-thermal storage, etc may also have the potential to add meaningful marginal information back into system SRMC, and allow the energy-only market to function much as it does today. As yet, there does not appear to be an urgent problem that needs fixing.

32 Our discussion here, like most reservoir management models, assumes that equal weight is placed on all possible future hydrology sequences when computing the "expected" MWV. Intuitively, though, risk averse reservoir managers would like to put more weight on those sequences most likely to result in high future shortage costs. Doing so creates mathematical difficulties, so many modellers prefer to add buffer zones, or penalty functions to achieve a similar effect. Either way, the effect can be to greatly increase the assumed SRMC of hydro, in these critical situations.

What reservoir management models compute is the expected value of these true MWVs, because that is the best estimate that can be made at the time of computation, and the best basis for release decisions made at that time. And that expected MWV is also the appropriate value to be used in making offers to a perfectly competitive market, and hence (if marginal) in setting prices for that market.

Thus, a perfectly competitive market PDC should contain significant ranges of periods in which market prices lie between the SRMCs of the various thermal/demand response blocks. As discussed in Section 6.1, the prospect of high prices due to a possible future energy shortage, for example, feeds back into high opportunity cost–based offers from hydro, and typically high prices, for many periods before that event is projected to occur. Strictly speaking, though, this does not cause the PDC to inflate above SRMC levels. What it does is to cause the SRMC of hydro, as determined by these opportunity cost calculations, to rise, and this is reflected in the PDC.

But, if an expected MWV is created as a probability weighted sum of the true MWVs, then it can be decomposed back into its constituent elements. And those same weights can then be used to assign a proportion of the hours for which that source was on the margin to the PDC. Hence the stepped shape appearing in our PDC projection, vs the more continuous PDC shape that would normally be seen in a real market PDC, or one based on simulated expected MWVs.

Circularity

Third, there can be a significant degree of circularity in MWV computation. The MWV is defined as an opportunity cost of releasing water rather than saving it for future use. The best future use of an extra unit of water stored in one reservoir, though, may well be to displace a unit that would otherwise have been released from another reservoir at some future date. And the value assigned to that reservoir's release may correspond to displacing generation from another, and etc. So, all of these marginal water values are highly co-dependent with each other, and also often with the opportunity cost of using constrained (thermal) fuel stocks.

In the end, though, the extra increment of water will be seen to displace either a unit of generation from fuel imported into the system, or a unit of load reduction. Even now, while thermal generation remains possible, the probability of future load reduction rises as storage levels fall, and the "Value of Lost Load" (VoLL) soon comes to dominate in the EMWV calculation.

The true value of VoLL has been endlessly debated, and it clearly varies greatly with circumstances. Thus, it really should be replaced by a more sophisticated representation of the various types and depths of demand response and curtailment occurring in these very tight market conditions. Even if it were known with certainty, though, VoLL is obviously not a measure of any kind of supply side marginal cost. Consequently, EMWV hardly represents a traditional supply side SRMC either, when it has a high VoLL component.

Experience suggests that the reservoir management policy, across the entire storage range becomes quite sensitive to quite small variations in the assumptions made about VoLL. But this influence obviously becomes very important when EMWV reaches high levels, in those relatively rare situations that dominate any calculation of entry economics and cost recovery. In those circumstances, though, EMWV is almost entirely a mathematical construct, used to trade off the probability of some level of demand response/curtailment in some period against the probability of some other level of demand response/curtailment in some other period.

This interpretation of EMWV will become increasingly pervasive as the role of thermal generation diminishes. Ultimately, EMWV will always be determined by the opportunity cost of some form of future demand response, right across the storage range. That opportunity cost may not be determined by any explicit offer, though, but by an inferred response to a possibly "gamed" market price. And that seems to introduce potential circularities, and raise questions about benchmarking any analysis of market power that can only become more critical in future.

The issue of circularity seems even more important if EMWV is not calculated from an optimisation model, but inferred from market data, as in Tipping and Read [2012], and the various papers on which that was based.[33] That study assumed that market participants (in aggregate) were operating on the basis of a (national) EMWV curve of a specified simple form, and set out to find the curve parameters providing the best fit to market outcomes. In doing so, the authors implicitly assumed that all risk aversion and gaming considerations were already accounted for in the fitted curve. In other words, they assumed that participants based their offers directly on that curve, just as they would with a (hypothetical) true SRMC-based EMWV curve in a perfectly competitive market, without any further adjustments to lower risk, or influence prices.

In fact, a surprisingly good fit to market outcomes was provided by simulating market operation with participants making what they believed to be perfectly competitive offers based on that curve. That might be taken to imply that perfectly competitive hypothesis is at least plausible, as an explanation of NZEM behaviour. It certainly does not prove that there is no exercise of short run market power in the NZEM, though, and we would actually be surprised if that were the case. Thus, it may well be that an even better fit to market data could be found by re-estimating the EMWV curve, assuming that participants were marking up offers relative to SRMC determined by that curve.

The goal would be to determine the most plausible combination of EMWV curve, and level of gaming. Tipping and Read proposed to do this for the New Zealand market, but did not complete it.[34] This leaves us unsure as to how to interpret a study such as

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33 J. Tipping & E.G. Read "Hybrid bottom-up/top-down modelling of prices in hydro-dominated power markets" in S. Rebennback, P.M. Pardalos, M.V.F. Pereira & N.A. Iliadis (eds) *Handbook on Power Systems Optimisation* Springer, 2010, Vol II, p213-238.

34 Although the same paper calibrates a Cournot model of the Australian market in exactly that way.

that of Polleti [2018][35], where inferences are drawn about market power on the basis of simulations that assume a hydro SRMC determined by an underlying EMWV curve fitted to market data, using a method similar to that of Tipping and Read.

3.4 Risk

Section 2.6 has discussed the impact of risk on electricity market investment, in general, but participants in, and potential entrants to, markets with high renewables penetration face additional risks, at both operational and investment levels.

At the operational level, reservoir mangers have to adopt storage strategies that will see them covered across the range of possible future hydrologies. Section 6.5 discuss the issue further but, in New Zealand, risk aversion mainly implies withholding generation from the market over summer, in order to be sure of having enough water stored to get through the next winter. Since that also implies maintaining higher prices over summer, the implications are discussed further in the next section, on market power issues. Here we focus on investment issues faced by all participants in such a market.

For a start, investors must try to assess the true underlying supply/ demand balance, and the whole price probability distribution, from observation of prices in a relatively small sample of recent hydro years, which may have been significantly wetter, or dryer than average. Since extremes play a major role in determining expected values and risk, it might take several decades to collect an adequate sample, from a hydrological perspective. At the same time, though, observations of market conditions, as opposed to the hydrology distribution, will be rapidly outdated by changes to the system, fuel prices, market design and political conditions.

Then, once built, generation designed to provide the last increment of capacity to meet the 1:20 security standard used in traditional capacity planning might be expected to generate significant power in only one year out of twenty.[36] In fact, there is a non-zero probability that it will not be called upon ever, during its entire technically viable life-time.[37] In our view, this changes the situation with respect to competitive entry to such an extent that it becomes qualitatively different, and may require different regulatory and design approaches.

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[35] S. Poletti *Market Power in the NZ wholesale market 2010-2016*, Working Paper, University of Auckland, released September 2018.

[36] Our discussion will focus on that standard because it the loosest adopted in pre-market times. For many years a 1:25 investment standard was applied, while ECNZ adopted a 1:60 standard for operational purposes.

[37] This characterisation is obviously simplistic, but actually not far from the historic experience of stations such as Marsden B, or the original Whirinaki station. Short term price spikes will tend to provide more frequent revenue opportunities under current market arrangements, but the data presented in our final appendix suggests that the current Whirinaki peaker is not making any substantial return on its replacement cost, either [

Theoretically, all the standard theory discussed earlier, with respect to the adequacy of the PDC to support entry still applies. Theoretically, a perfectly competitive market with pure SRMC pricing, should still produce a PDC capable of supporting (i.e. recovering the cost of) an optimal mix of plant types. But we should pause to consider the realties implied by that theoretical statement. First, consider the equilibrium situation with strict SRMC pricing, and no contacting:

- The PDC we are talking about can no longer be thought of as representing an annual price distribution, corresponding to an annual LDC. It now summarises a price distribution representing performance of a particular system configuration over at least 20 hydrological years. But, in reality, participants know they will experience that distribution as a sequence of prices over 20 or more actual years, during which a great many factors other than hydrological variation will add to their risk.
- Theoretically, a fully diversified risk neutral international investor might be prepared to take a bet on this basis, in the belief that hydrology risk in New Zealand is unlikely to be correlated with anything else. But even that bet rests on the assumption that the theoretical dry year payouts implied by the optimised PDC will actually occur. And that assumption seems dubious, because the implied payouts seem large enough to potentially destabilise not just the electricity market, but the national economy and political equilibrium.
- Section 4.4 suggests that the proportion of cost recovery that needs to come from periods in which prices exceed the SRMC of a Diesel fuelled OCGT must lie somewhere over 25%. In Australia, we understand that similar calculations have led to price caps being set to a level at which OCGT plant can recover their annual costs in just 4-5 hours. And investors in the Australian market are probably fairly relaxed about that, in a situation where prices peak because of hot weather, which is more or less guaranteed to happen every year.
- In a hydro dominated system, though, we may expect to see very little cost recovery from periods in which MCP exceeds the OCGT SRMC, in normal years. As discussed in Section 2.2, this represents "missing money" not just for the OCGT, but for all capacity in the system. Over these years none of them would have been getting the revenue component that theoretically should be covering over 25% of their LRMC cost from this source, as they should under a pure SRMC market arrangement, in long run equilibrium.
- Thus, in this theoretical pure-SRMC market, the industry might collect, say, only 75% of its LRMC revenue requirement, in most years. Then, when a super-dry year does occur, the industry would typically need to collect something like 20 years' worth of "missing money" in a single year: Say an additional 500% of its average LRMC revenue requirement, or around 670% of its "normal year" revenue.

This theoretical super-dry year payoff is surely implausible, though. No government or regulator is likely to countenance a nearly 10-fold increase in electricity prices in a single year, so the electricity sector, as a whole, could not achieve such a result. At that point, then, it would become apparent that the "missing money" foregone in normal years would truly be missing. And any investor who understands and predicts this kind of outcome, will realise that the theoretical promise of full cost recovery from a strict SRMC market is highly unlikely to eventuate in practice.

Further risk would arise as a result of errors in predicting load growth or under/over-investment, which would have a disproportionate impact on extreme peaking. Risk aversion would surely be significant in this situation, but even a risk neutral investor will be unwilling to invest in a situation where they can reasonably expect that regulatory intervention will deny them the opportunity to even recover their expected costs. Instead they will:

a. Hold off until prices become so high that they can reasonably expect to recover costs from revenue received in (fairly) normal years, and/or
b. Seek other ways to recover costs in normal years

As discussed in Section 2.7, the most obvious mechanism that could be used to achieve ahh steadier revenue stream is via contracting. Vertical integration by way of selling into retail markets has a broadly similar effect, and it is worth noting that vertically integrated "generators" will be largely locked into fixed price variable volume retail contracts for the duration of any likely dry year crisis. Thus, any rise in spot prices would have to be absorbed by transactions between their generation and retailing arms.

Section 4.3 also notes that generators will have incentives to maintain prices above SRMC levels, though, in periods when they have excess capacity, not contracted, or committed to retail sales. And that would cause the "bottom end" of the PDC to inflate, thus helping to support cost recovery, and hence entry, at least of the kind of capital-intensive plant best suited to meeting base/shoulder loads.

3.5 Non-Linear Cost Structures

The basic discussion of entry economics applies most clearly to "linear" cost structures, in which each unit of capacity or generation costs the same, across the entire planning horizon. Relaxing that assumption opens up a number of ways in which costs could vary, some of which have significant implications for renewable generation, in particular.

Economies of scale affect all generation technologies, to some extent, and it is well known that cost recovery can be an issue when the marginal cost of capacity is less than its average cost. In principle, that could be a significant issue for large scale hydro developments, but that now seems to be a largely historical issue. It is not a major issue for likely future, wind, solar or geothermal developments, though, and will be ignored here. Three other non-linear pricing issues may be relevant, though, in a situation where it is sometimes suggested that "old plant" may be receiving excess rents.

First, the cost of technologies such as wind and solar are declining over time, independently of any development in the New Zealand market, and Figure 14 from the EPR report[38] shows how this is affecting both LRMC estimates and market prices. Theoretically, potential investors in those technologies may actually respond to the

[38] Figure 4.1 in this report

expectation of falling costs by delaying investment in that plant type until costs fall further. In the long run, though, falling costs must imply a steady decline in the prices that can incumbents can charge, without triggering entry. This figure suggests that, currently, older plant in the NZEM are unlikely to experience rising revenue streams, and may now expect to receive a lower total return than was anticipated at the time when their plant was built.

Second, though, the LRMC of new hydro typically rises over time, despite any technological progress. This is partly due to a continual process of tightening various regulations affecting hydro, pushing up the cost of new development. This raises the value of older developments, although that effect is countered, and possibly reversed, if the maintenance costs of older developments rise, due to refurbish/ retro-fit requirements.

The rising hydro LRMC cost curve also reflects a kind of depletion effect, though, as the cheapest and best sites are developed first. At first glance it is not actually obvious how the PDC analysis of Section 2.4, can be extended to allow representation of the various hydro development options that might be available in a particular context. If they were all assumed to have an SRMC of zero, the option with lowest capital costs would appear to dominate all others. But it will not even be possible to meet all requirements with this single project. So how can the total cost curves of all hydro options be adjusted to allow several hydro developments to appear in the optimal the mix?

c. First, assuming a zero SRMC implies unrealistically high generation for almost all hydro. So, for each potential hydro development, we must find the non-zero SRMC that will just use the water available, over a year.[39] Some will then appear as potential base-load plant, and some as potential peakers etc, and each may, or may not appear in the recommended optimal plant mix
d. Second, though, as hydro sites are developed they can no longer be included as development options. To be exact, they are now development options that have already been exercised, so their fixed "entry cost" is no longer relevant. Instead the PDC analysis itself will determine the option value (i.e. OV) of each project, and those option values will adjust, over time, with SRMC being tuned to keep output at a sustainable output level, as above.
e. Then, these existing projects will remain in the optimal plant mix, unless or until their OV falls below their fixed O&M cost, which can be expected to rise over time.[40]

It should be recognised that the process described above can not be used to define a "long run equilibrium" PDC, independently of the LDC. In fact, other things being

[39] Ideally, this should be done for a variety of hydro years, implying a different OV for each year. The probability-weighted average of those OVs can then be compared with FC.

[40] The same is true, actually of existing thermal plant, with the difference being that their SRMC is normally assumed to be well defined, and to determine their energy contribution, whereas hydro is in the opposite position.

equal, it implies that the PDC must gradually rise as the LDC grows, and cheaper development options are exhausted.

Theoretically, rational investors would predict this phenomenon, though. If the opportunity to develop all sites were to be put up for auction in the same year, we should expect the sites that promised to deliver better value for money to attract premiums that investors would then see as part of their fixed entry cost. Poorer sites would attract lower premiums that would be further discounted because of the possibly very long delays, before development would actually occur, and the risks that might occur over that extended period.

Historical reality has obviously been very much messier than this, but theoretically, there should be no such thing as "cheap old hydro power". All power generated at the same time, and delivered to the same point is of equal value. What should be expected to differ is the wealth of the site owners. Then, whenever any asset is bought by a willing buyer from a willing seller that asset is implicitly re-valued in light of the knowledge and expectations available at that time. Such valuations may rise over time, or fall, or fluctuate, but hydro projects are no different from other assets, such as housing, in that regard.[41]

Finally, a technology like geothermal might suffer from a "site-depletion" effect, like hydro, but also a declining international technological cost curve, like wind and solar. The latter will be counteracted, though, by a third, local "learning curve" effect as each development increases understanding of the New Zealand geothermal environment. At a national industry level, that implies some incentive to bring investment forward (i.e. to enter when OV is still somewhat below FC), so as to benefits from whatever learnings may arise.

3.6 Long Lived Assets

Although many electricity sector assets have long lives, this is particularly true for hydro power stations and transmission/distribution lines. In both cases it is sometimes suggested that since certain assets were "paid for long ago" they should not now be expected to earn an economic return, and that perhaps some way should be found to discount charges (supposedly) intended to recover their costs.

During the reform process, we expressed concern that any increase in the valuation of transmission and distribution assets would increase the economic distortions inevitably

[41] Historically, the "ownership" of development rights may be debatable, and many "sellers" may not have been willing. This obviously raises a large and complex set of historical, legal and social issues that lie well beyond our present scope. But, whatever the rights and wrongs of that debate may be, the practical outcome in New Zealand was that, in almost all cases, the State or some other public body obtained or assumed the right to develop, and whatever value might be assigned to that right has either been implicitly retained by taxpayers or ratepayers, or explicitly passed back to them, or at least their collective agent, when the asset was sold.

inherent in pricing regimes required to recover costs in a situation where the optimal SRMC price signal is essentially zero. We were particular concerned that "variabilising" fixed cost recovery charges would create artificial incentives to reduce consumption at times when such reduction actually saved no costs, and eventually to encourage uneconomic network bypass of various kinds. Our view was, and is, that the motivation behind much of the debate reflected much more on the social, organisational, and political history of the sector than it did to the underlying economics. [42]

Similar comments apply to some extent, to some extent, to the generation sector, where some discussions seem to involve a curious amalgam of forward-looking economic and historic accounting concepts, often mixed with strong doses of selective historical reminiscence, and social policy concern. Scale economies are much less significant in this sector, though, and the case for forward looking valuations, based largely on the economic value delivered by displacing the need for power from alternative sources always seemed much clearer for generation assets.

The actual historic record on "cost recovery" seems quite mixed. Culy et al [1996] reported that tariffs had actually under-recovered capital cost for long periods in the pre-market era. And, while some hydro projects clearly were "paid for years ago", the final round of pre-market hydro developments (e.g Clyde, and the Tongariro scheme) were passed into the ECNZ asset base at values well below their construction cost, while others (e.g. Marsden B and Whirinaki) were deemed to have essentially only salvage value.

In 2014, an extensive analysis by the New Zealand Electricity Authority concluded that, over the period from 1974 to 2013:

> *Based on the modelled generation costs presented in this paper, while the early- to mid-2000s saw retail charges increase relative to generating costs on average across all consumer types, at no time did average total charges exceed estimated costs. The cumulative under-recovery resulting from the negative margins shown above has been borne by a mix of taxpayers, and company shareholders. This*

[42] In particular, we saw no economic logic behind the seemingly arbitrary approaches taken to cost recovery for essentially similar networks serving households: Low fixed charges and high mark-ups on variable charges on the electricity network; High fixed charges with no variable charging for local calls on the telecoms network; and fixed charges bundled into local rates for other networks, such as wastewater disposal. At that time, though, it was easy to theorise about alternatives, because virtually all the assets were in some form of public ownership, and being transferred into new structures whose value would be retained by the public, either through direct or community ownership, or through the proceeds of asset sales based on any new valuation. Now, though, asset values are entrenched into a diverse set of organisations, under a range of ownership structures, making change much more difficult.

> *analysis finds no evidence of windfall gains over historical generation costs accruing to generators or retailers.*[43]

It seems to us that any logic behind accounting for "windfall gains" in power pricing should apply equally to "windfall losses", and those may well be greater. But, even if there had been "windfall gains", on average, that would not make the electricity sector any different from any other.

Standard economic theory would hold that what was paid for assets, and when, has no bearing on their current value, which is determined entirely by the net value of the services they will be able to deliver in future. Since the power produced by "old" assets is interchangeable with power produced by "new" assets, it seems obvious that the economic value of these assets is also the same, after accounting for their remaining useful life, maintenance cost and so on. Attempting to create a market in which "old power" was priced higher or lower than new power would be both complex and distortionary. At best, it would just shift rents into different pockets.

Some commentators seem to mis-read the intent of economic studies focussed on cost recovery. The issue has never been about whether this or that historic investment proved profitable, or not, or whether particular parties have received a "fair return" on their investment, in this sector or any other. The record above shows that some projects paid for themselves relatively quickly and have made a steady profit ever since, others suffered major cost over-runs and may never pay for themselves, and a few failed completely.

Of itself, though, the analysis of options that are no longer available is not relevant to potential entrants. The economic issue is really whether the historical evidence will convince them that they will receive a fair return, in future. So, they will focus most on whether the market returns being experienced by recent investments of the type they are actually in a position to make themselves, is covering entry costs, or not. Hence the relevance of the LRMC comparisons discussed elsewhere. But the longer-term historical record is also important inasmuch as it indicates the sort of risks they may face in future.

We expect the planning horizon over which entry assessments are performed to approximate a conservative lower bound on the expected asset life. Major hydro schemes may be expected to remain productive beyond the planning horizon, but that is mainly just a matter of computational convenience. The prospect of economic returns beyond the chosen horizon may still be recognised as a likely upside, though, as for investments in any sector. A realistic commercial discount rate may place little weight on the prospect of such returns, but investors will surely pay more for an asset they expect to own, and earn revenue from over the period beyond the planning horizon.

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[43] From Page ii of: *Analysis of historical electricity industry costs: Final report*. NZ Electricity Authority, January 2014

And surely no-one would be surprised if investors were to demand a higher rate of return if they suspected that a future regulator might intervene in ways which reduced profits over that period. If so, it should be recognised that the implicit prospect of making profits on "old" assets which "have already been paid for" has a significant impact on entry economics. Regulators may find it attractive to retrospectively change the rules, and appropriate some of the rents expected by the original investors for other purposes, e.g by capping prices. But they need to weigh the one-time gain from doing that. against the long-term impact such action may have on the rates of return that will be required by future investors, and hence on the price levels faced by future consumers.

3.7 Public Focus

Finally, we should note one aspect of the situation that is seldom mentioned, but seems to apply more strongly to renewable electricity generation assts than anything else in the sector, or probably the wider economy.

We suggested that the motivation behind different approaches to pricing of transmission/distribution assets reflected more on the social, organisational, and political history of each sector than it did to the underlying economics. The same is true, now, of developing renewable technologies such as wind and solar where, for many, the underlying issues are as much about the fate of the planet, and/or local landscapes, as they are about economics. But it seems particularly true for hydro assets, which seem to occupy a very special place in the hearts and minds of the New Zealand public.

Throughout our lifetimes, older New Zealanders, at least, have consciously or unconsciously developed a relationship with these assets which is quite different from the relationship we have with probably any other "productive facility". We have protested and mourned the loss of natural landscapes, while simultaneously celebrating and enjoying the benefits of new lakes, roads, and landmarks. They appear in our photographs, and family memories, and influence the environments we relate to, far downstream from the projects themselves. But the promise of "cheap hydro power", economic development and even "think big", are all part of our national heritage and mythology.

Deep down, then, we are all "invested" in these projects, and all feel they are "our" assets in some sense quite different from what the legal documentation might define. And this colours debates about what are supposedly "economic" issues, in ways that are seldom explicitly recognised.

In our view, it is this feeling, rather than any economic logic, that underlies the arguments advanced over the years that ways should be found to pass the emotively labelled (and perhaps illusory) "windfall gains" on historic hydro projects through to the general public. So too, to some, extent the concern about the prospect of "market power rents" being earned, perhaps at our expense, on what we feel to be "our" assets".

Comparison with other sectors seems enlightening, in this regard. The social logic is actually much stronger in housing sector, where there arguably have been major "windfall gains" over recent years. Even though national attention is now focussed on a "housing affordability crisis", though, we just do not see impassioned public pleas to solve the housing affordability crisis by requiring owners of older hotels, or houses, that were "paid for long ago" to charge lower rents, or to sell them at historic/discounted prices to the deserving younger generation. Nor do we see detailed studies of exactly how much might be at stake, or how it might be transferred.

Nor, in the electricity sector, do we see impassioned public pleas to lower the prices paid by the major commercial electricity users, who also draw power from old hydro assets. We do not see pleas to pass on the "windfall losses" implied by the historic cost of some hydro developments, and of thermal stations like Whirinaki and Marsden B in power pricing either. Since the economic logic, if any, seems the same, there is surely another social logic at work here. Indeed, the arguments we have seen on this topic seem to be less about whether there is an economic rent, but about whose pockets that rent should ultimately be assigned to.

To be clear, though, we are not actually rejecting the validity of that social logic, just arguing that it should be explicitly acknowledged, and not presented as some arcane re-interpretation of standard economics. During the reform process, our view was that, if the objective was to return some value to the general populace, then lowering wholesale prices to all, including industrial/commercial users, did not look like the most effective option. Other options were considered during the market design phase, including creation of a special "bonus" mechanism for hydro profits[44], giving away shares, retaining assets in public ownership, or simply returning the value realised from asset sales to the public funds.

The broad impact on the welfare of the New Zealand public was expected to have been much the same, given that all assets were in public ownership at that time. So, the debate ended up being mostly about economic efficiency, and pragmatism. As it happens, some assets have been retained in some form of public ownership, and some sold at what seemed to be fair market valuations at the time. Asset values will have changed since then, creating some subsequent benefit or loss to those private shareholders who took on that risk. A rising LRMC would imply upwards revision of old asset values, while the current experience of falling LRMC will presumably imply downwards revision. But that is true throughout the economy, and it is not valid to single out any specific sector or transaction for retrospective analysis.

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[44] G. Bertram, I. Dempster, S. Gale and S. Terry *Hydro New Zealand: providing for progressive pricing of electricity* Wellington: Energy Reform Coalition, 1992.

4 Market Power and Market Design

4.1 Definitions and Perspectives

Section 3.7 discusses some of the emotions underlying economic debates in the electricity sector, and the term "market power" clearly attracts attention from many quarters, ranging from the halls of academia to the wider public. It is by no means clear that all those who use the term have the same thing in mind, or use the term consistently across their various spheres of involvement, though.

At one extreme, analytically inclined academics often use a precise mathematical definition, and state that market power is being "exercised" whenever market prices deviate from the SRMC of the marginal provider[45]. The recent growth in literature studying deviations from SRMC pricing in the electricity sector partly reflects its economic importance, its critical supporting role in modern society, and fears that the sector provides an environment where "gaming" may be facilitated. It should be said, though, that much analytical attention has also been driven by the fact that, at least from the advent of electronic computing, it has provided analysts with perhaps the richest, and most precise centralised "hard" dataset available for analysis.

- From the 1950's it has been a major testing ground for the development and successful deployment of centralised optimisation techniques, and large-scale hydro systems, in particular, still challenge the capabilities of stochastic optimisation algorithms. At the operational level, that paradigm focusses strongly on the calculation and equalisation of SRMC, over space and time. It is hardly surprising then, that we analysts trained in that tradition have a strong focus on SRMC.

- More recently it has been a major testing ground for the development and successful deployment of "smart market" ideas, in which decentralised operation, is still coordinated by essentially the same optimisation techniques, just deployed in a slightly different way. In that context, though we see "deviations from SRMC", and it is hardly surprising that analysts from essentially the same tradition now express strong concerns.

- Now, the sector is proving to be a major testing ground for the development and testing of theories about the role of both risk aversion and market power in motivating deviations from SRMC pricing, and in developing the software required to analyse such issues. Amongst things, the sector provides a

[45] We have already seen that there is a sense in which market prices may always equal the "SRMC of demand reduction", and that becomes important in hydro dominated systems where Expected MWVs often reflect the assumed SRMC of demand reduction more than anything else. But, reflecting its origins in thermal systems, the analytical literature often ignores that potential circularity, and thinks of SRMC as being the SRMC of generation.

conveniently computable SRMC benchmark, and a wealth of historical data against with which performance can be compared.

At the other end of the spectrum, the general public seem very clear that they do not like “market power”, in the electricity sector, but appear to have very little idea as to how “deviation from theoretically optimal spot pricing” might be defined, how it might affect them, or how to recognise it in real life. At the highest level, this public fascination with the topic is actually very odd, and seems more reflective of the emotional factors discussed earlier than of any understanding of, or rational response to, the real economics of the sector.

Larger scale commercial/industrial consumers can be somewhat exposed to spot prices on which academic studies focus. and some may be fully exposed. But those consumers are well able to explicitly protect themselves against spot price volatility by contracting. Indeed, some will be in a position to profit from price spikes by reducing consumption, so as to effectively sell contracted quantities back into the spot market.

Only a very small part of domestic load is actually exposed to spot prices, though, and even their charges are significantly distorted, and even dominated, by an overlay of charges recovering the essentially fixed costs of the distribution and retailing sectors. In reality, then, spot prices could vary over a very wide range, and most domestic consumers would be totally unaffected. So far as they are concerned those prices should logically just be seen as transfer prices within organisations, and perhaps between organisations, which just happen to operate in a much more transparent manner than most other sectors they deal with. In particular, because the fundamental drivers of most spot price volatility are short term events such as wind or inflow variations, the occurrence of high prices at any particular time really gives no meaningful signal, to the general public, of a likelihood that retail prices will rise in future.

While it seems reasonable that the general public should be concerned about trends in their electricity costs, their logical focus should be on LRMC and long-term cost recovery, not on spot prices which may or may not deviate from SRMC. In fact, the same public that seems so easily excited when academics release results about electricity prices being “inflated by market power rents” seems quite oblivious to the reality that “deviation from SRMC pricing” is absolutely pervasive throughout the economy.

Every day, we are all actually paying prices above SRMC, and often involved in setting them too. No business owner thinks that “adding a mark-up” is anything but a routine, and probably automated, operation. And surely business owners realise that the wholesale price they pay for goods is already well above SRMC, due to mark-ups already added further up the supply chain. Everyone surely understand that mechanics, plumbers, lawyers, and consultants are routinely charged out at rates that often amount to a 100-200% mark-up on their wages. And, while those wages may reflect some kind of opportunity cost to the worker, they are generally well above the “true supply-side SRMC” of actually staying in the office for another hour. In many cases they are not even a <u>short run</u> marginal cost to the employer, either, because staff are on contract for fixed hours.

We may all seek ways to avoid these mark-ups, if we can, and so receive some goods or services at prices a little closer to their true SRMC. But most of us also understand three things:

- First, we understand that, in the long run, businesses will simply not survive to provide us with services unless they are able to recover their full costs in some way. We may complain about the high rates we are charged by sub-contractors, but the constant stream of bankruptcies arising in that sector must surely give us pause to consider whether we are really being "ripped off" on average. Perhaps we will conclude that substantial excess profits can be made in the sector, but the ultimate test is surely whether we would be willing to invest themselves.

- Second, we understand that, while those who possess some particular skills may be able to charge an extra premium because they are in temporary short supply, those rates will ultimately be disciplined by the prospect of new entry. We may complain about the rates we are charged by lawyers (or whatever). But the lawyers will tell us that, if we think their sector offers abnormally high rewards to those with the requisite underlying abilities, there is no reason why we, or our children could not go to law school ourselves, become trained, build up experience, and ultimately charge similar rates. We may protest that such a course of action involves long term commitments of time and money, and that it carries the risk that, by the time we are trained the market might not support the high charge-out rates we hoped for, particularly if many others enter with a similar hope. But that is precisely the point. Entering a competitive market is a long run investment with uncertain outcomes, and no-one will do it unless the returns look substantially better than those of more certain alternatives.

- Third, we at least implicitly understand that, while it may be academically useful to label the pervasive economy-wide "deviation from SRMC pricing" as an "exercise of market power" or "collection of market power rents", that labelling does not turn it into the kind of "abuse of market power" a Commerce Commission would, should, or could be concerned about. If it were, it would be investigating and intervening in virtually every sector, virtually all the time. That kind of concern, and action, must surely be reserved for situations where behavioural rules have been broken, or normal market disciplines do seem to have broken down in a sector, over an extended period. For example, it would be concerning if market outcomes did not seem consistent with the LRMC/entry barrier tests discussed in other sections.

Section 4.3 discusses analogies with other sectors, whose capital-intensive cost structures may be more closely analogous to that of the electricity sector. In all cases, though, the conclusion is the same: The normal test of sectoral performance, across the whole economy, is not whether prices deviate from SRMC, which is not even readily knowable in most cases, but whether prices match the LRMC entry cost. If prices are below LRMC we should expect to see more firms exiting (or downsizing) than entering (or expanding), until prices pick up (or the whole sector disappears). If prices are above LRMC we should expect to see more firms entering (or expanding) than exiting (or contracting), until prices fall to LRMC. Or, if that does not happen we should look to see what barriers might be preventing entry, and what might be done about it.[46]

The fundamental direction of electricity sector reform in recent decades is based on the realisation that modern communications/optimisation technology makes it possible to efficiently coordinate multiple generators in the same power system, and provide them with the ancillary service support they need to allow independent operations, and entry. Thus, the contention is that, now, the electricity sector can be treated much like any other. So, in the next section, we ask why, at least some parts of the world, there is still a very strong desire to treat it very differently from the rest of the economy, and particularly to focus on SRMC rather than LRMC perspectives.

4.2 Complementary Pricing Paradigms

The electricity sector has long attracted more than its fair share of attention from analytical economists of various schools. This is partly due to the fact that this kind of analysis is just not possible in other sectors, but also its economic importance, and critical supporting role in modern society. There has been widespread concern, too, that the electricity network, at least, is a natural monopoly, whose owner might, unless restrained, hold society to ransom, and extract monopoly rents, at whim. Thus, the whole sector has typically been either publicly owned, or heavily regulated, in most jurisdictions, with much attention devoted not only to its "optimal" operation, but to its optimal interaction with the wider society, particularly via pricing.

From an early date, the SRMC focus noted above lead naturally to a desire to see consumers facing "SRMC prices", so that they could coordinate their own activities optimally with the optimised centralised dispatch, or market. But real time SRMC pricing was not possible, in the past, and nor would it have been socially acceptable, at least in a hydro dominated system like New Zealand's.

An optimally planned (and priced) system, should produce essentially the same volatile SRMC pricing pattern as an idealised perfectly competitive market. But that reality has historically been obscured by both pragmatic and political factors. Rather than raise prices to SRMC levels high enough to choke off demand during times of relative shortage, reliance has been placed on public appeals and physical restrictions. Prices have not been forced down to SRMC levels during times of relative surplus either, and certainly not to zero in systems where water spills in wet years.[47]

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[46] E.g by relaxing limits on training schemes in the examples above.

[47] In New Zealand, prices charged to the generality of loads were held constant, in nominal terms, over long periods with significant inflation, and then sometimes increased very abruptly. It is true that the system also veered between really quite significant under- and over-supply, but these price changes were generally driven by politics, and government revenue requirements, more than the underlying sectoral economics ,though. In fact, some of the largest price increases occurred during times of relative surplus. .

There was also a long-standing debate, though, between this SRMC paradigm, and two alternative paradigms:

- First, there has always been a strong economic argument that really it should be LRMC that guided consumer decision-making, and that principle was accepted (if not necessarily acted on) by the New Zealand Ministry of Energy in its later years.
- Second, though, it was widely accepted that assets built to meet public electricity demand must be paid for, preferably by electricity consumers, leading to widespread regulatory focus, particularly in the United States, on defining and determining what those costs actually were, typically in historical accounting terms.[48]

This may be seen as reflecting a fundamental conflict between the forward-looking perspective of economics, with its emphasis on finding the best use of resources irrespective of what they may have cost to develop; and the backward-looking perspective of accounting, with its emphasis on paying for resources already committed, whether or not they were economically justified in retrospect. And some discussions about "cost recovery" suggest that the fundamental conflict between these forward and backward-looking perspectives still remains.

We also see, though, a conflict between the desire to provide efficient real time SRMC-driven signals to consumers operating installed electrical appliances etc, and the desire to provide efficient LRMC-driven signals to consumers investing in electrical appliances etc. In other words, there is a tension between achieving productive and allocative efficiency in the short run, versus dynamic efficiency in the longer run.

Those debates dogged the sector for some decades. Ultimately, though, it was realised that all three views are complementary, not conflicting. In fact, the unified framework discussed in Section 2.7 resolves the conflict by showing that, if scale economies can be ignored, the expected value of SRMC prices should equal forward-looking LRMC, in the long run and, looking backward, that alignment should also recover the costs anticipated at the time of entry.

In principle, then this framework would allow long term investment decisions, including generator entry, to be based on LRMC contract prices, while deviations from contract volumes would face SRMC-based spot prices. It was hoped, then that markets would succeed, where centralised planning had obviously failed, in allowing more SRMC price signals to be passed through to consumers who could respond, while also

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[48] It may seem odd, to the inheritors of that tradition, but this cost-based focus was largely absent in some systems, where assets were directly owned by the government. In New Zealand, construction costs were incurred in a different Government department, and the legislation only placed a very loose limit on the contribution to capital requirements expected to come from electricity revenues. Implicitly, within the Government's accounts, there was very wide discretion for electricity sector losses or profits to be transferred to or from taxpayers. Nor was there much concern, given their assumed commonality of interest.

minimising fluctuations around the LRMC benchmark, and recovering costs, or at least ensuring that the cost recovery risk was faced by investors, rather than by the electricity consumers or taxpayers.

So far as we know, this theory is not seriously in dispute between the advocates of LRMC and SRMC based approaches to evaluating market performance. At least in principle, all would like to see a pattern of market prices aligning with both, across hydrology years, and time periods within each year. Presumably all realise that costs must ultimately be recovered from, too, and most will agree that recovery should be electricity consumers.[49] The conflict, if any, relates to the relative weighting that should be placed on alignment with each principle, if compromises must be made. And, specifically, the extent to which prices might need to deviate from SRMC in order to achieve sufficient cost recovery, with acceptable risk, in practice.

4.3 Design Alternatives

Probably all would agree that the NZEM market design is not perfect, but there would be far less agreement about what changes might improve it. Most would agree, though, that it is better to have an imperfect market design that works, and produces broadly acceptable outcomes, than one that is theoretically perfect, but impractical, or implies unacceptable outcomes. Thus, the NZEM market design is inevitably a compromise, the perfection of which is limited by two key factors:

- The fact that, with New Zealand's population approximating that of a large suburb in a major international city, it is simply not worthwhile to devote the same level of resources to debating, designing, implementing, operating, or monitoring market design features that might seem desirable in larger markets overseas. It also makes it much more difficult to achieve the levels of competition that might be expected elsewhere, particularly given the discrete nature of large-scale hydro generation projects.

- The fact that the market is isolated, dominated by hydro, and served by a relatively sparse transmission network. This means that participants must manage more risk than elsewhere, and face a potentially major problem in maintaining acceptable cashflows, as discussed below. And it makes it even more difficult to achieve a high level of competition at particular locations. It also means, though, that each major participant's situation is really quite different from any other, making it very difficult for a regulator to understand all the issues involved, let alone design or implement common "solutions" that work effectively equitably across all participants.

Both factors have, quite reasonably in our view, lead to a situation in which participants have been left to sort out a variety of arrangements for themselves, or between

[49] Although some older New Zealander's may still recall the days when that did not seem to be the case, as noted elsewhere.

themselves, that might have been specified by a regulatory process elsewhere. We should reasonably expect the trade-off to be acceptance of a lower degree of "optimality" and/or certainty about optimality with respect to some aspects of market performance.

Still, the original market design was undertaken with some care, albeit in an environment with few established international precedents to follow, and it has been refined over time. Appendix A discusses a number of alternative design features that were considered and, rightly or wrongly, rejected during that process. We did not, and do not, necessarily agree with all the choices made, but we do consider that those choices were made in a reasoned and reasonable manner. Only time will tell whether they should be re-visited, in light of market experience, or changing conditions.

As discussed in Section 5.2, though, we do agree that, if compromises must be made, long term alignment of wholesale prices with LRMC (or more exactly with the optimal PDC determined by LRMC entry costs) is more important than short term alignment with SRMC, in a capital-intensive industry. In fact, Section 3.4 suggests that the extreme volatility of strict SRMC pricing in a hydro-dominated sector is very unlikely to be socially acceptable if passed straight through to consumers, and that constrains the extent to which strict SRMC pricing can be implemented through the various levels of the industry.

SRMC alignment is still highly desirable, though. While Section 3.7 argues that the attention sometimes focussed on this issue by the general public is unwarranted, it does have an impact on both the internal efficiency of the industry, and the accuracy of the price signals provided to incentivise efficient utilisation of electricity by consumers. And Section 2.7 explains how a high degree of contracting could theoretically allow long term decisions, including generator investment, to be guided by LRMC, while short term decisions respond to SRMC prices.

Is the "ideal" achievable (or ideal)?

Some may see the discussion of contracting in Section 2.7 as grounds for arguing that all generation, and hence all load, should be contracted for its expected output at all times, and over all time scales. In theory, it might be thought that would minimise risks, remove the need for prices to deviate from SRMC, and allow both long and short-term markets to operate with minimum distortion, and maximum efficiency.

We believe that "ideal" is not actually achievable, though, particularly in the volatile environment of a hydro dominated sector, where participants can not sell all their output via long term contracts, because they do know, in advance, how much they will be able to produce. Perhaps more importantly, it could really only be implemented by creating a "single buyer", who would establish, or oversee establishment of, contracts with all generation capacity.

Section 5.3 discusses several reasons why that option was rejected in the WEMS market design phase. Perhaps the most important, is that it would re-create the situation which lead the New Zealand electricity sector into so much trouble before the market reforms. The investment pattern of the entire sector would then be driven by the judgements of a single entity, thus increasing national risk, relative to a market situation where the judgments of multiple parties contribute to a self-correcting incremental response to changing conditions and perceptions. Most damagingly, that entity would inevitably become captured by an essentially political imperative not to quickly abandon announced plans that were becoming inappropriate, and also become subject to political influence to distort planning choices in one direction or another, depending on the party in power.[50]

Accordingly, preference was given to less centralised alternatives that might appear less "perfect", but promised to be more robust in the long term. Those alternatives involve somewhat messy looking compromises, though. So, it seems pertinent to ask:

- What kind of market design compromise might be reached? And also, what degree of deviation from SRMC pricing might be inevitable, acceptable, or even desirable, in such a market?

Conversely: Is the observed level of deviation in the market and something that could or should be "corrected"? Or is it perhaps optimal, when seen from the context of some broader theoretical framework?[51]

How are costs recovered in capital intensive industries?

In a hydro dominated electricity sector, we face three closely related problems:

- The need to ensure adequate cost recovery for enough peaking capacity to cover LDC requirements in very dry years, which occur quite infrequently

- The fact that the natural SRMC pricing structure of the sector implies that all generators should recover a substantial part of their costs from revenue, in those years, that is not likely to be socially acceptable,

- The implication that, not just potential peakers, but all participants may see a serious enough risk that they will not actually recover costs, that they become reluctant to enter except at high rates of return that will raise costs to consumers.

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[50] Note that the evidence presented in Section 4.4 suggests that, in this critical respect, the New Zealand electricity sector has performed markedly better during the NZEM era, than it did during the era of State control, under the NZED or MoE.

[51] We make no comment here, on the level to which prices might actually be deviating from SRMC, because we have not studied that question. But we have no doubt that they will deviate, if only because even a large and diverse electricity market will become un-competitive when supply is tight in particular times and places, and partly because the true SRMC pricing pattern is probably too extreme to be acceptable.

Read [2010] discusses a wide range of alternative arrangements that might be used to deal with this situation in the electricity sector. But, first, it might be helpful to see how this kind of situation is dealt with in other sectors whose cost structures are similar.

There are, in fact, many industries with basically similar, capital-intensive cost structures to electricity. So, the critical question to consider is this: If regulation to force a high level of contracting, and/or SRMC pricing is the right answer for electricity, why is it not adopted more widely throughout the economy?

The cost structure of the electricity sector is actually little different from that in many other industries, where prices routinely exceed SRMC, because prices need to be maintained at such levels in order to provide an adequate return on investment, given the risks involved. But we will focus on two sectors with which we are all very familiar: airlines, and hotels. The extra weight of a passenger really makes very little difference to the fuel consumed by an airliner, and a hotel really only faces an incremental room cleaning cost, plus the cost of some tea, coffee and toiletries. In both cases SRMC is very low, except on rare occasions when all capacity is fully booked.

In both cases, though, SRMC pricing is a rare exception, typically linked to what might be considered a pseudo-contractual deal designed to secure customer loyalty. Prices in both industries are moderately volatile, in both the short and long term, once special offers are taken into account. But "worse", from an economic perspective, there will often be empty seats that could easily have been filled by grateful passengers, had they been offered at the "true SRMC price", of close to zero. Hotels routinely charge positive prices, even quite high prices, on nights when there are actually spare beds, and SRMC close to zero.[52]

In fact, we have already argued that deviation from SRMC pricing is ubiquitous in the everyday world of business, even in sectors which can be reasonably considered "competitive". So why do regulators not intervene to force SRMC pricing in all of these industries? Clearly, regulators are taking a wider and longer-term perspective. They understand that what is really most important, particularly in capital intensive industries, is that the market facilitates efficient investment over time, in the form of new aircraft, hotels, software packages etc. Accordingly, they rightly focus on the existence of possible barriers to entry, and accept that short run pricing will be routinely distorted, with consequential impacts on short run efficiency.

Let us be clear: These deviations from SRMC pricing do impose real costs on the economy. There really are people sleeping under bridges when beds are free at the Hilton. There really are empty seats in planes and movie theatres that would have been filled if tickets were free. And consumers, every day, go without all kinds of goods that they find too expensive at retail prices, but which they would readily buy and use if available at the SRMC of production and distribution. The aggregate cost of all these

[52] The software industry is "worse", because a download really has no SRMC at all, and there are no capacity limits either, so no reason why SRMC prices should ever be much more than zero.

distortions must be very great indeed. Our point here is not to criticise such practices, though, but to note that, despite the obvious distortion and inefficiency, pricing above SRMC has long been considered legitimate, indeed necessary, if not desirable. In fact, many, if not most, desirable economic outcomes require investments, the fixed costs of which can not realistically be recovered without "distorting" prices away from, and often well above, SRMC.

These situations are not quite analogous with the electricity sector. The services delivered by hotels differ in various ways, and they each strive to create their own niche market, within which they are shielded somewhat from competitive pressure. And they each charge their clientele what they are prepared to pay, or more exactly what enough of them are prepared to pay to keep the hotel full enough, on average, to cover its LRMC cost in the long run. There is no centralised market-place dispatching bed-nights, capacity is not filled in strict merit order, and they do not all receive a price set by the SRMC of the marginal provider.[53] If we imagined a whole collection of hotels , though, differentiated only by SRMC, with bed-nights assigned centrally, each would actually be less able to charge prices much above their own SRMC, because all their SRMCs would be low, until all bed capacity was filled.

That scenario is obviously unrealistic, and no-one would invest in hotels if required to recover costs in that way. It is not much different from the emerging situation in an increasingly renewable electricity sector, though, with the distinction that reservoir storage does at least allow a physical trade-off between providing services in one period, vs another.

What role do contracts play?

There is another common factor at work here, though. What these industries have in common is that perfect forward contracting is not possible, or more exactly that the transaction costs of such contracting would exceed the economic costs of living with the distortions implicit in the current regime.

We have referred to the hotel sector, above, but it should be recognised that this is actually just a small subset of a much broader accommodation sector. In that broader sector, it is actually quite possible to contract forward, and most people actually do manage it, with respect to the vast majority of their person-night requirements. The most common form of forward contracting is called "home ownership", and home-owners spend most of their person-nights in their own homes, paying only SRMC per additional night. But they still pay LRMC, in total, because they also pay the fixed cost of purchasing a home, which is ultimately disciplined by the cost of construction. Those with term rental agreements are in much the same situation.

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[53] Arguably, if a merit order were to be formed, accommodation might be ranked more by quality of service than by SRMC, but we can not say that customers would pay the Hilton price at a backpackers, just because the Hilton is full. So, the analogy is not exact.

The hotel sector just represents an extreme outlier in the distribution of accommodation contracting arrangements, from ownership though rentals, time shares etc, to hotels. And hotel accommodation works out to be the most expensive, per night, mainly because it is unrealistic to expect customers to enter into contracts to book hotel beds for anything like the term over which the fixed costs of building a hotel must be recovered. So, the hotel supplier must often run with spare capacity, and recover all of their costs, with a considerable risk element, from "spot sales".

Even though their SRMC is low, their role is, in effect, similar to that of a peaker in the electricity sector. Theoretically, they might set prices at SRMC most of the time, and then try to recover the shortfall on their entire LRMC cost by charging extremely high prices for the few nights when all accommodation in town is at capacity. But they know that would be both risky and socially unacceptable. So, instead, they must recover their LRMC cost, by charging prices far above SRMC for all the bed-nights they can actually sell, even when there is spare capacity. Even so, we expect they face higher risk than "base-load" accommodation providers, and thus require a higher rate of return, thus pushing the prices they must charge to achieve cost recovery even higher.

Similar comments apply to the "transportation" sector, in which airlines and taxis also lie at one extreme of a wide spectrum of arrangements, covering that part of the demand which customers can not reasonably foresee, or arrange for themselves, and hence can not make long term arrangements for, by buying a car, for instance. In these cases, what we should expect to see, and in fact do see, is a whole spectrum of arrangements being offered; ranging from arrangements in which the customer takes full responsibility for the fixed costs, e.g by outright purchase of a house or car, and then obtains per unit "service" at SRMC; through to arrangements in which the customer takes no responsibility for the fixed costs, and can only obtain "service" at prices that recover LRMC, with a suitable risk-adjusted rate of return. In fact, any one customer, at different times and for different reasons, is likely to access "accommodation", or "transport" via a mix of any or all of these arrangements. The less flexible those terms are, the more firm the contract, and the more nearly the contract price approaches (the fixed cost portion of) a low-risk LRMC, and the per unit consumption price approaches SRMC.

Similarly, too for the ideal electricity market. The theory lying behind an energy-only electricity market like the NZEM is that loads should be sufficiently motivated to contract forward to ensure that a reasonable balance is struck, with the majority of load covered by contracts, and thus hedged against spot market risk, but with suppliers also free to extract a reasonable risk-adjusted rate of return from that part of the load that opts not to contract forward, thus forcing suppliers to take all the risk of providing for a load which may not even eventuate.

This is the way effective markets generally work, and customers in most markets know and understand that, if they leave their bookings to the last minute, they might get a bargain, but they may equally be left out, or end up paying a premium price for the last bed in town. This point may not be well understood by consumers in the electricity sector, though. Understandably they compare contract prices, retrospectively, with the spot prices that actually eventuated. Much of the time, it turns out that spot prices were low, and they may feel that they paid "too much" for the contract. But this retrospective assessment ignores two important effects:

- First, a CfD on electricity prices, particularly in a hydro-dominated system, includes a significant component of "insurance" against the possibility of very high prices. And the very nature of insurance contracts is to provide a negative return, when assessed retrospectively, in most periods.

- Second, the proper comparison is not against the prices that actually did occur, but against those that would have occurred, had the contract not been in place. Collectively, consumers should recognise that the less they are prepared to contract forward, the higher the risks faced by generators, and the higher spot prices will have to be to provide an adequate rate of return. For most individual consumers, the effect of their contracting will be insignificant, but some major electricity users will be large enough to have a noticeable impact in a small market like New Zealand, and particularly in transmission constrained regional sub-markets.

How do contracts change behaviour?

There is another factor coming into play here, though, because contracting materially affects the incentives larger participants in the electricity market have to influence prices away from SRMC.

Using conventional CfD contract forms, hydro generators will have to find a compromise between being under contracted in wet years, and over-contacted in dry years. Thermal generators will have to make the opposite compromise.[54] Both will then find themselves incentivised to maximise output to minimise the price and cost of power bought in when they are over-contracted, and to reduce output so as to increase the price of extra power sold, when under-contracted. Both actions will move prices away from SRMC, and both may be interpreted as "exercise of market power" in the spot market. Both are also ways to smooth revenue streams, and achieve acceptable cost recovery, with acceptable volatility, over the hydrological cycle.

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[54] In theory, thermal generators can largely avoid being under- or over-contracted by selling "call options", with a strike price set at their own SRMC. The value of such a contract should be OV, as discussed above, and that can be matched to FC, as discussed. Scott and Read [1996] (T.J. Scott & E.G. Read: "Modelling Hydro Reservoir Operation in a Deregulated Electricity Sector", *International Transactions in Operations Research*, vol.3, no.3-4, 1996, p. 209 221) showed how such contracts can be assigned in a way that produces perfectly competitive industry outcomes, even when participants have Cournot incentives. In theory, such contracts should be attractive to loads looking for peak power, and to hydro producers looking for dry-year backup power. In reality, the market for such contracts may be thin, and generator output may need to be sold in some bundled form more suited to consumer requirements, and backed by a portfolio of plant and/or contracts. If so, potential thermal entrants may find it difficult to compete with vertically or horizontally integrated incumbents, and this may create barriers to entry. But that does not alter the principles discussed here.

In part, competing pressures will move MCP in opposite directions. In wet years, over-contracted thermal may seek to keep prices down, while under-contracted hydro seeks to keep them up, and vice versa in dry years. Typically, though, the whole industry will be under-contracted, in aggregate, relative to what could be produced in a wet year, especially when wind speeds are high and loads are low. The aggregate pressure will thus be towards keeping spot prices up and cost recovery up, rather than dumping the entire potential surplus on a demand side which will not be prepared to pay much for it, because it will not be geared up to find short term uses of any great value for such intermittent supply.

The aggregate pressure may be in the opposite direction in very dry years, though, when the supply side may seek to damp down the prices that it needs to pay to (implicitly) "buy back" contracted output from those consumers who can respond to price signals, so as to meet obligations contracted for delivery to less flexible consumers.

What balance should be struck?

Finally, returning to the original question, we re-iterate our view that the natural structure of SRMC prices in a hydro dominated market will not support anything like an optimal plant mix, without significant modification to create much less volatile payment streams for all parties. In particular, most generators will somehow need to receive revenues above SRMC prices in order to cover their costs, during periods of relative surplus.

To a large extent, participants may achieve the required stabilisation by contracting. It seems impossible, though, that generators would be able to sell their entire potential generation capacity in such a way as to end up with contract positions exactly matching perfectly competitive outcomes, in real time. In a world of imperfect contracting, though, generators may not be financially viable unless spot prices also exceed SRMC during extended periods of relative surplus. So, they can be expected to "exercise market power", so as to influence prices in that direction during periods when they are under-contracted.

Against that, though, we also expect them to "exercise market power" so as to restrain price rises during periods when they are over-contracted. In any case, we expect that the sector understands that it simply could not recover costs by charging very high prices for sustained periods in very occasional super-dry years. And the calculations in the next section suggest that the inability to do so implies a quite substantial expected shortfall, probably exceeding 25%. So, we suspect that an energy-only market of the NZEM type can only work if prices are allowed to settle significantly above SRMC on average, in wetter hydrology years.

Relying on ill-defined mark-ups and mark-downs like this may be considered a less than perfect way to run a market, but this is, in fact, the normal way in which most other markets operate, with considerable success. If that is not deemed to be acceptable, Read [2010] canvasses a number of other options that could be considered, but concludes that no option is perfect, or clearly better than the status quo.

The current design gives participants more freedom than in some markets, particularly those with a pre-market heritage of close regulatory supervision, but it is by no means clear that the cost of closer supervision would be justified, in terms of better outcomes, overall. As it stands, this market has been designed to operate just like the vast majority of successful markets operating outside the electricity sector, and with similar cost structures, where pricing above SRMC has always been considered absolutely normal.

Given the current market design, then, the more participants can rely on contracting the less they must rely on marking up offers above SRMC, and the less incentive they have to do so. But determining the optimal balance between these two mechanisms goes well beyond our current scope, a does estimating the extent to which each may be relied upon in the current market. Thus, we are not in a position to say that the market has “got the balance right”. But we certainly could not say that the market has “got the balance wrong”, either.

Indeed, we are not sure how that question could definitively be addressed. A first step, though, might be to ask whether the rates of return being sought by potential investors in various technologies are sustaining a plant mix approximating what we might expect from a centralised optimisation, with an acceptable shortage risk. Thus, an initial analysis along those lines is presented in the next section.

4.4 NZEM Evidence[55]

The discussion above suggests that the broad health of the market, in terms of supply/demand balance and price/ entry equilibrium can actually be assessed very easily, without recourse to detailed simulations or complex gaming models. Or, At least, such high-level analyses can be used to put the results of such detailed modelling into a proper perspective.

If the high-level analysis suggests that the market is not performing well, then more detailed studies can help to identify more exactly what is going wrong, and perhaps how to fix it. But if the high-level analysis suggests that the market is performing well, then negative results from more detailed studies need to be understood and interpreted in that light. If the outcomes seem good, even though detailed modelling indicates that “something is going wrong”, we may need to ask whether the detailed problems identified are actually as real or material as they may seem.

Market outcomes

Some very useful analysis has already been performed, and summarised by Figure 4.1, which reproduces Figure 14 from the EPR report. This actually suggests that the market is performing very well, in terms of aligning average spot prices with LRMC, but it

[55] All data discussed in this section supplied by S. Batstone

compares base load contract prices with base load LRMC estimates. Although other analyses in that paper highlight how the costs of meeting different load profiles differ, it does not directly address the key issue of incentives for investment in peak/support plant. Accordingly, we have undertaken a very preliminary indicative analysis of that issue in Appendix C, the results of which are summarised here.

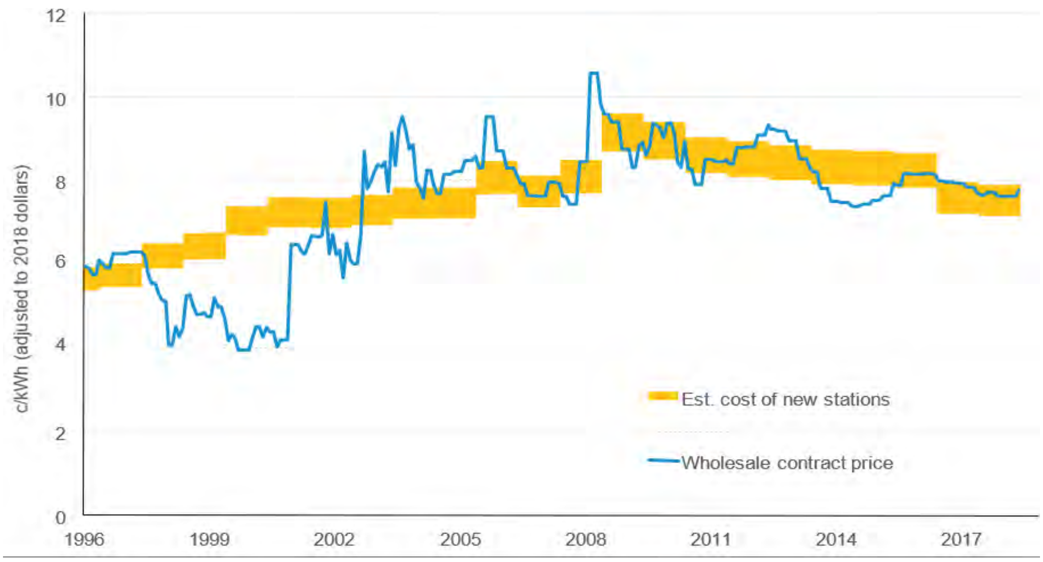

Figure 4.1 Wholesale contract prices versus cost of building new power stations

First, the theory developed in Section 2.4 suggests that we should check the alignment between the market PDC and entry costs, right across the spectrum of entry options. In order to do that, we need entry cost data, and the following table has been supplied by the participants in this study.[56]

PLANT TYPES	Shortage	Diesel OCGT	Gas OCGT	CCGT	Geothermal
Fixed ($/MWy)	$ -	$ 128,500	$ 138,500	$ 184,000	$ 556,000
Variable ($/MWH)	$ 1,648.00	$ 308.00	$ 67.00	$ 53.00	$ 7.00
Reliability (%)	100.00%	95.00%	95.00%	94.00%	95.00%

Table 4.1: Entry Cost Data

[56] The shortage cost has been set to a rather low value for technical reasons, but that can be ignored for the illustrative purposes of the present discussion. The effect of the reliability estimate is just to scale the effective fixed cost component up. In this simplistic analysis, the "geothermal" entry represents base-load renewable capacity whose output is not correlated with the LDC, and hence can expect to receive a "base-load" price. Geothermal has been used in this illustrative analysis, because it is the simplest example to analyse.

Then, Figure 4.2 shows the number of hours for which the spot price exceeded the assumed SRMC of several plant types, over the months of 2010 to 2016.[57] Figure 4.3 then sums these values and compares them with the standing costs for the respective technologies, as discussed in the previous section.

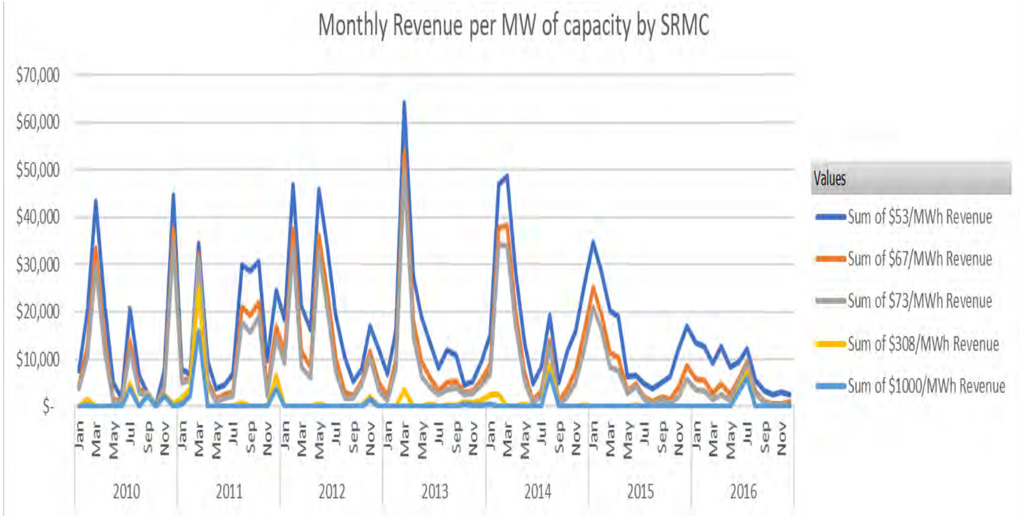

Figure 4.2: Spot price contours

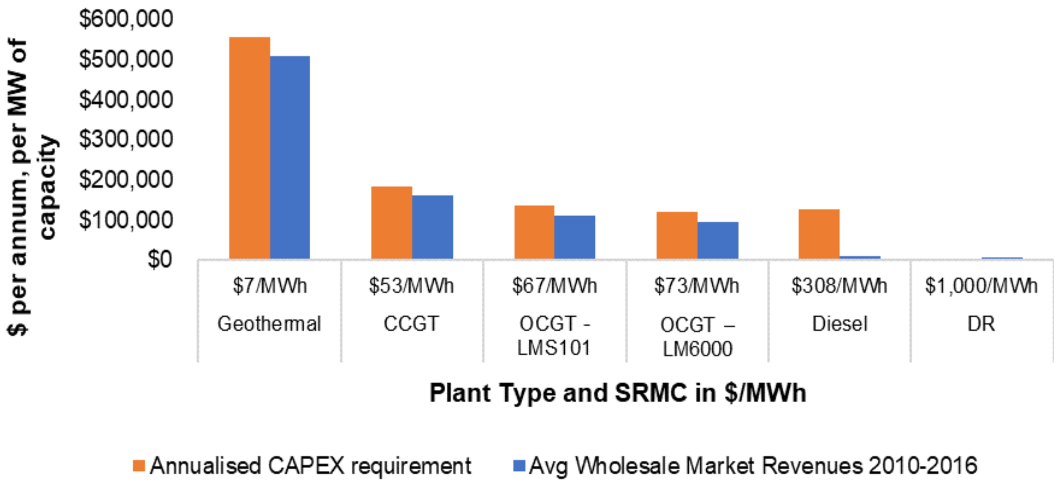

Figure 4.3: CAPEX vs Operating Profit

Basically, this analysis expands on that in the EPR report, to paint a picture of an electricity market exhibiting perhaps surprisingly good alignment with the theory outlined in Section 2.4. No thermal plant type seems to be quite recovering its costs, but that is not surprising, in a market where LRMC is declining, and only limited entry occurring. Most plant types seem to be very nearly recovering costs, though. That could be taken to indicate that the threat of competitive CCGT/OCGT entry was still disciplining the PDC effectively in this 2010-16 period, or that other competitive

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[57] This is an upper bound because operators may not always be able to predict price spikes and dispatch their plant to exactly capture them.

pressures (e. g from coal) applied. At least, even if generators are pushing prices up, there is certainly no evidence of overcharging, here, relative to an LRMC standard.

Nor do we see evidence of anything likely to be characterised as "overcharging", in any other sector. It may be that thermal plant, in particular, are pricing their offers up in ways designed to recover as much of their LRMC cost as they can. And it would surely be astonishing if any other business, in any other sector, did not take some advantage of such opportunities as they arise.

Some years ago, the Electricity Technical Advisory Group (ETAG) wrote that "*Using the LRMC benchmark, there is no clear evidence of the sustained or long-term exercise of market power* [in the NZEM]".[58] We might phrase that slightly differently, because we expect that under-contracted generator participants must often have both incentives and opportunity to make offers above SRMC. We also expect that, when supply is tight, over-contracted generator participants will have both incentives and opportunity to offer below SRMC. And both practices may be characterised as <u>exercise</u> of market power, <u>in the spot market.</u>

We find it hard to see how that unilateral exercise of market power could be characterised as abuse though. As discussed elsewhere we would have thought that it was normal business practice, and also probably necessary to make the current market design work with a socially acceptable degree of price volatility, and at commercial rates of return that deliver acceptable costs to consumers on average, over the long term. The relative merits of some alternative market designs are discussed in Appendix A, but the evidence considered here seems entirely consistent with the ETAG conclusion, if we interpret it as applying to the exercise of market power <u>in the market for generator entry and/or long-term contracts</u>. Thus, we see no evidence, emerging from this LRMC driven analysis, of the sustained or long-term exercise of market power in that entry market.

Nor do we see evidence of market power being abused in the spot market to produce price spikes that are higher or longer than they need to be, if the criterion is a requirement to sustain an optimal plant mix with an acceptably low probability of shortage. The evidence we would cite is the situation faced by the diesel fired OCGT at Whirinaki, which seldom runs and would seem to be recovering very little of the entry cost for that technology. This is broadly consistent with the analysis discussed below, which suggests that, so long as spot gas is freely available at a modest price in dry years, this kind of liquid fuelled development would not form part of the optimal plant mix. So perhaps it is not surprising that this station was not constructed in response to market signals. The degree of under-recovery here is much greater than even that analysis would suggest, though.

[58] *Improving Electricity Market Performance Volume One: Discussion paper* A preliminary report to the Ministerial Review of Electricity Market Performance by the Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009 (p40)

Based on this evidence, market prices would have to spike to much higher levels and/or for much longer, in order to support such entry. So, taken at face value, this evidence tends to reinforce the concerns we have expressed elsewhere, that the potential for over-charging during times when prices spike above the SRMC of liquid-fuelled OCGT capacity is really not the biggest potential problem with the New Zealand market. If anything, the evidence suggests the reverse, that more extreme spot market price patterns would be needed to support the backup capacity required by a market increasingly dependent on renewables. Or, that other market mechanisms may be needed if that kind of pricing pattern proves to be socially and/or politically.

This observation does needs to be interpreted with considerable care, though. It could be that the market environment is restraining participants from making aggressive offers when the supply/demand balance is tight, and that action may therefore be required to refine the market design in order to provide the backup likely to be required in future. But other factors may have been at work during this period, too:

- Perhaps other features of the market arrangements, including the impact of any potential dry year compensation in a vertically integrated industry means that a station of this type can deliver value to participants by means other than spot market sales.
- Perhaps, despite the concerns of some critics, capacity really was in excess supply over this period. That would not be surprising, given the lack of load growth, and would be expected to correct itself as new capacity is required to meeting increasing demands, e.g from electrification of transport.
- Or perhaps we have yet to see the "super-dry" conditions under which this capacity will eventually pay for itself, both physically and commercially.

Peaker Support Recovery Requirements

Table 4.2 below calculates the levels to which prices would have to spike in order to justify the capital cost of the last MW of OCGT peaker capacity required to limit the number of hours of shortage to the values shown.[59] The first row corresponds roughly to the standard applied in setting price caps for the Australian market. If we imagine market prices spiking to these levels for 4 hours every year, then the last peaker MW would just cover its annual fixed cost of around $130,000/MW over those 4 hours, and require no further revenue for the rest of the year.[60]

But all other MW available during those 4 hours would receive the same revenue, and that revenue would be required to cover a significant proportion of their fixed costs for

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[59] This table has been prepared using the Diesel OCGT data, but the gas OCGT gives very similar values for the last MW of capacity which, in both cases, is only utilised for the number of hours shown, making the fuel cost almost irrelevant.

[60] Note that this is for the last MW. The station may well run at less than full capacity during other hours of the year. But, in a strict SRMC market, it will not make any profit from doing so, because the MCP would be set to its own SRMC during those hours. The only hours that contribute any profit are the 4 hours for which the full capacity is utilised.

the year, in a strict SRMC market. Thus, the CCGT, for example, would also receive around $130,000/MW over those 4 hours, making a slightly greater profit than the OCGT because its SRMC is lower, and then need to make up the remaining $56,000 or so, over the rest of the year.

annual hours	percent of time	VoLL ($/MWh)	hours every 20 years
4	0.046%	$ 34,124	80
8	0.091%	$ 17,216	160
16	0.183%	$ 8,762	320
32	0.365%	$ 4,535	640
64	0.730%	$ 2,421	1280
87.6	0.999%	$ 1,852	1752

Table 4.2 VoLL requirements for peaker cost recovery

If the same shortage probability standard was applied in New Zealand, though, it might (very simplistically) occur as a pattern of 80 hours over a few weeks in the middle of a very dry winter, once every 20 years. In that case, the last MW of peaker capacity should theoretically receive no return at all until those events occurred, then collect around $2.6m in the 20th year. Importantly, all other capacity in the system would have the same experience, with respect to this significant revenue component, in this pure SRMC market.

Reality will obviously be more random than this. Cost recovery would probably be spread over more years and, given the amount of notice that might apply to a developing hydro crisis, New Zealand might well feel that a lower VoLL could be applied. If so, though, it would still need to be spread over enough hours to support the last MW of peaker capacity. So, by construction, the net effect, in terms of industry cost recovery patterns, should be much the same.

Industry Cost Recovery Proportions

As discussed in Section 2.4, the entire optimal PDC can actually be derived from the technology parameters in Table 4.1 alone, irrespective of the LDC. This determines the range of utilisation factors over which each technology would be the least cost way of meeting incremental load. Applying this approach to the thermal data alone produces a simple PDC consisting of one step for each thermal SRMC, and representing the way in which the thermal system would be used to meet the net LDC after accounting for the contributions from renewables with variable output, such as hydro. In this case, those contributions were not optimised, but taken direct from market data, and formed into a monotone "Generation Duration Curve" (GDC).

The utilisation factors defined by the optimal PDC can then be projected onto the residual LDC remaining, after hydro contributions have been accounted for. A tool has been developed to allow various implications of that breakdown to be calculated and displayed graphically. For example, the data above, applied to an LDC and GDC drawn from 2010-2016 data, suggest the LDC being met by the plant mix illustrated in Figure 4.4.[61]

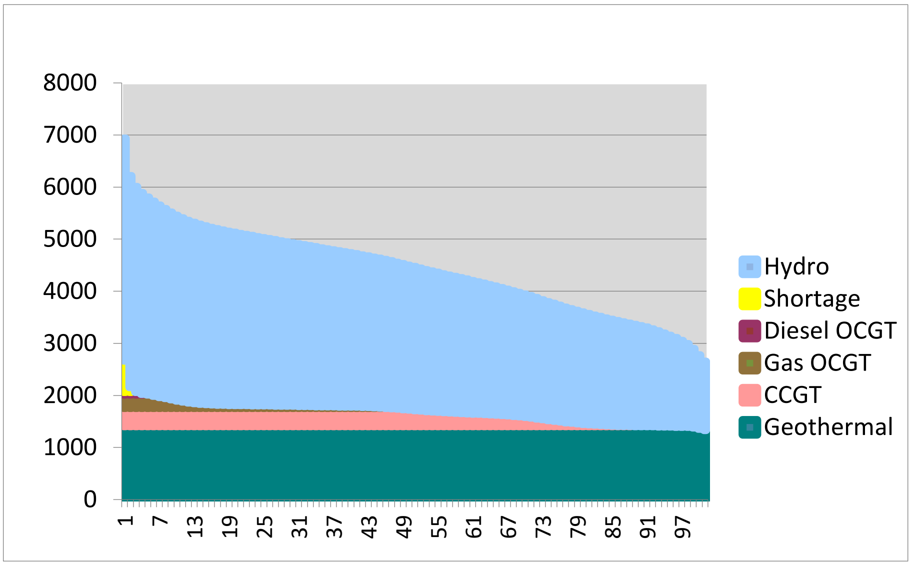

Figure 4.4 Optimal LDC filling Plant Mix

We stress that this analysis is purely illustrative of the kind of analysis we suggest could be performed to provide guidance as to the likely optimal plant mix and PDC against which real market data could be compared. We have not had time to treat the hydro sector properly, and note the market PDC will definitely not be a simple step curve, because some hydro generator will often be on the margin, setting the MCP at a level related to its own Expected MWV. That expected MWV is a weighted average of the true MWV, determined by the SRMC of the technology which a stored unit of water will ultimately displace, in the hydrology scenario that actually occurs. The true MWV can only be known in hindsight, but must correspond to one of the steps in our hypothetical optimal stepped PDC.[62]

Results are also naturally sensitive to assumptions made about both shortage and demand response options that could appear both above and below the SRMC of an OCGT in the merit order, and that can cause some instability, because the prototype

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[61] This LDC has been adjusted by adding a peak oriented component to represent the probability of breakdowns occurring, because those are the situations in which extreme peak capacity would most likely be called upon.

The Hydro contribution is input data representing the observed distribution of output from existing plant.

The "Geothermal" contribution really represents all base-load renewables, including wind.

[62] Section 7.5 discusses a hypothesis about the relationship between the observable PDC, in which the expected MWV of hydro, plays a major role, and this hypothetical stepped PDC, but also expresses some significant caveats.

tool used here can not make fine distinctions within the first 1% of the LDC: That is, in the range covered by the estimates in Table 4.2.

Still, despite all these caveats, it seems worth noting that, over a wide variety of parameter settings, this very preliminary analysis suggests that in a pure SRMC market, the sector as a whole would have to rely on receiving at least 25% of its total cost recovery requirements from periods when prices are spiking above the SRMC of the last MW of peaking capacity in the system. Significantly higher proportions are reported for many parameter settings, particularly if investors in extreme peaking capacity are assumed to be risk averse.

These estimates seem quite consistent with those we have seen previously, all the way back to the original WEMS market design process. In fact, they can be checked directly against the data in Table 4.1. As discussed in Section 7.5 of the Appendix:

- Clearly the extreme peaker itself, whether gas or Diesel fired, must recover 100% of its costs when prices are above its SRMC.
- And, since the peak revenue component is common to all MW capacity available at the time the extreme peaker is running at full capacity, only the residual fixed cost of any other capacity will be recovered over the rest of the year.
- So, the proportion of its fixed cost which technology x recovers during the time the peaker is running at full capacity must be close to FC(peaker)/FC(x).
- Those proportions work out to be 75% for the CCGT and 25% for geothermal, if the extreme peaker is gas-fired, as implied by this data.
- Thus, recovery proportions in excess of 25% seem entirely plausible for the generation sector as a whole.

5 APPENDIX A: NZEM Market Design Choices[63]

5.1 Background

The history of the New Zealand electricity sector prior to establishment of the current market is surveyed by Culy et al [1996], while Read [1997] provides an update, with commentary on initial experience with the current market design. That design evolved in several stages, starting with corporatisation of the Government's electricity sector assets as the Electricity Corporation of New Zealand (ECNZ). The key electricity market design options, including much of the theory discussed in the previous section, were then debated extensively during the late eighties and early nineties, with the current author being heavily involved in those debates. The detail of those debates, or of subsequent history, is not important, but the following summary may be helpful in trying to understand the reasons why the current design was adopted. In particular, it is important to understand that these design choices were made consciously, after careful consideration, and based on a reasonably complete grasp of the theoretical options, and the consequences likely to follow from the design choices available.

From a wholesale electricity market design perspective, the first major step was establishment of a simulated SRMC-based market pricing framework by the Electricity Corporation of New Zealand (ECNZ). That pseudo-market could be described as an exercise in self-regulation by what was then a (near) monopoly. As described by Read and Sell [1987],[64] the development introduced the key elements of the market pricing framework described in previous sections, including half-hourly spot pricing combined with longer term contracts defined as financial "contracts for differences" (CfDs). The key difference was that the half-hourly "spot prices" were not determined by competing market offers, in real time, but by running ECNZ's optimisation models, a week in advance. This was an early attempt to simulate the operation of a perfectly competitive market, with strict SRMC pricing. But the "market" also operated within quite tight limits, because there was a requirement for the distribution companies, who bought ECNZ's output at that time, to be contracted for a very high proportion of their load. Importantly, cost recovery required the addition of an "up-lift" payment, called the Pool Price Margin, which effectively played the role of the "capacity payments" discussed here.

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63 This appendix is based on Section 3 of Read [2009.

64 E.G. Read and D.P.M Sell: *A Framework for Electricity Pricing.* Arthur Young report, released by the Electricity Corporation of New Zealand, November 1987.

The current market design was basically established by the Wholesale Electricity Market Study (WEMS) of 1992, in which the current author played a major role.[65] So far as the wholesale market is concerned, it recommended three major changes to the ECNZ pseudo-market. First, the ECNZ assets were to be broken up, and strict model-based SRMC pricing was to be replaced by a more normal market arrangement, in which prices would be determined by competing offers, in an un-capped market. Second, requirements to contract for a high proportion of load, via cfd "energy" contracts were to be relaxed. But, third, a requirement was to be imposed that load serving entities cover a high proportion of their load with "capacity tickets" defined as call options, and providing protection against extreme price spikes. Thus, this would effectively have been a "two part" market.

WEMS was then followed by the Wholesale Electricity Market Development Group, WEMDG [1994][66]. The WEMDG group included extensive representation from the industry, as for WEMS, but also from consumer groups, and it deliberately employed different consultants, so as to benefit from a wider perspective. Still, it basically endorsed the WEMS design, with one key difference. Whereas WEMS had advocated what was basically a two-part energy/capacity market, WEMDG rejected the capacity ticket proposal, thus creating the energy-only NZEM design, which we have described here. That design was then implemented in 1996, following separation of TransPower and partial divestiture of ECNZ generation assets to form Contact Energy, as a competitor to ECNZ.

The WEMDG wholesale market design remained basically unchanged when the remaining ECNZ generation assets were divided between competing SOEs, and full retail competition establishment, with vertical integration, in 1999. Since that date the most significant events have been Government intervention to build dry year backup capacity at Whirinaki, and the establishment of the Electricity Commission. But neither change affected the fundamental structure of the market.

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[65] See, in particular:

J.G. Culy, E.G. Read, and F.T. Baird *A Managed Transition Toward a Facilitated Market: Rationale*, New Zealand Wholesale Electricity Market Study Report, WEMS/4 October 1992

and

Towards a Competitive Wholesale Electricity Market, New Zealand Wholesale Electricity Market Study Report, WEMS/5 October 1992.

[66] WEMDG *New Zealand Wholesale Electricity Market, Wholesale Electricity Market Development Group, Final Report.* 1994

5.2 LRMC-Focussed Design Philosophy

Much of the literature on electricity market behaviour uses SRMC pricing as a reference point. The designers of the NZEM also had a thorough understanding of that SRMC perspective, having previously been involved with, and advocated, a market design based on strict SRMC pricing. Nonetheless, WEMS and WEMDG placed greater emphasis on a long run perspective, to the likely detriment of SRMC pricing, and thus short run efficiency. So, it seems pertinent to ask why.

In part, the decision was motivated by the difficulty of objectively determining what SRMC might actually be, in a hydro dominated system, as discussed in Section 6. In part, it reflected an aversion to intrusive regulatory intervention, as discussed in Section 5.4. But the WEMS/WEMDG/NZEM market design also emphasised an LRMC perspective, primarily because it was believed that what really mattered most in the electricity industry, like any other capital-intensive industry, was to get the long run signals right. And this decision was made despite a realisation that it could imply sometimes significant deviations from SRMC pricing, with consequent economic distortions:

- It was never expected, at least by the designers, that the market would be seen to produce optimal short run operational outcomes, for the capacity mix actually available. If one thinks one has full knowledge of the costs involved, it should always be possible to show that a theoretically superior outcome could have been produced, particularly in hindsight. But the point is that such "knowledge" is essentially an illusion, because the costs are not necessarily even well defined, let alone agreed. The market outcome should therefore never appear optimal, from any one perspective, but should hopefully be more robust, being produced by the interaction between a variety of participants, with different perspectives, each informed by intimate knowledge of their own situations, at least.

- Nor was it expected, at least by the designers, that the market would produce spot prices that were particularly "low", for the capacity actually available. As we have seen spot prices must be high enough, on average, to cover the full fixed and variable costs of whatever investments are actually made. But the point is that competition and innovation in a de-regulated <u>investment</u> market was expected to provide a better national portfolio of investment options, implemented at lower development costs, and this was believed to be the key factor in keeping average price levels, including spot prices, lower than they would otherwise need to be to cover the cost of the required level of capacity investment.[67]

This long-term emphasis seemed particularly important in New Zealand, where costs have traditionally been dominated by the investment costs of transmission, and of renewable generation. Section 6 discusses the difficulty in defining SRMC for such sources, but the point here is that, even when it is defined, that SRMC is not, of itself, a real cost to the economy.

The SRMC assumed in traditional analyses is primarily a “fuel cost”, and that is typically assumed to be a real marginal cost to the electricity sector, without much consideration of cost structures in fuel supply sectors. But renewable generation capacity has (virtually) no real SRMC at all. As argued elsewhere, the gas sector fuelling much of New Zealand’s thermal generation is in a not very different situation, either, because it is isolated from international markets. In both cases, costs are dominated by large scale exploration, development and construction, with very low variable operating costs.

As discussed in Section 6.3, internal calculations within those sectors can determine an “SRMC-like” opportunity cost which is useful for coordinating operations over time and space. But, looking at the situation from the perspective of the New Zealand Government, the only true short run marginal costs seemed to be:

- On the supply side, the cost of imported fuels, and some aspects of domestic coal production.
- On the demand side, the cost of reducing electricity or gas supply available for other uses, perhaps at other times.

Accordingly, it was thought that the impact of price/dispatch distortions on total supply costs would be proportionately much smaller than in a typical thermal-dominated electricity sector. The SRMC concept still has a significant role within that framework, in terms of coordinating operational decisions within the supply sector, and perhaps between demand and supply sectors. Thus, the main focus of concern with respect to “distortion” of any actual or implicit SRMC was in terms of its impact of short-run economic efficiency.

Conversely, it was thought the bulk of power sales would occur via mid- to long-term contracts, the price of which would and should align with LRMC entry costs, with moderate variation in both directions as the demand/supply balance shifted from year

[67] There was never any reason to expect that prices would be lower than they had been historically, either. As explained by Culy et al, electricity pricing in New Zealand, particularly for domestic consumers, had been historically driven as much by politics as by a requirement to recover costs, and it was not considered desirable that that situation should continue. And of course development costs were expected to rise, because cheap accessible hydro development options had either been exploited or protected from development, while the introduction of the Resource Management Act meant that environmental concerns would have significant cost impacts on new projects, rather than being over-ridden by statutory declarations, as had often happened in the past.

to year. So, it was also well understood that the actual degree of any short run distortion, and also of any short run wealth transfer, would be heavily dependent on the level of contracting. In a perfect world, all loads might be contracted for 100% of their expected requirements, using option contracts which ensured that they were fully hedged for that expected requirement, but also 100% exposed to spot prices for any deviation. Under those conditions it can be shown that the incentives of producers to deviate from SRMC offers is actually minimal, so distortion becomes a non-issue, and risk is also minimised.[68]

On the demand side, it was also believed that, while low demand elasticity may imply significant short run volatility of SRMC prices, and possibly allow significant deviations from SRMC prices, it also suggests that the actual economic impact of such deviations will be small.[69]

In any case, even if spot prices are highly distorted, heavily contracted loads will have minimal real risk exposure. Theoretically, their marginal decisions should still be affected, but this is only true if spot prices are actually passed through to them. In reality, the vast majority of retail customers in New Zealand, accounting for a significant proportion of the load, do not face spot prices in real time. In fact, they may not see any change to price signals at all, even when spot prices are elevated for several months.

This has obvious implications for any consideration of the wealth transfer effects of these prices. But it also has significant implications for market design choices. To the extent that the economic rationale for enforcing SRMC pricing in the spot market rests on the belief that this will enhance allocative efficiency by reducing distortion to consumption patterns, that rationale is undermined by the observation that the prices charged to decision-makers controlling consumption do not reflect the dynamic structure of spot prices anyway. Accordingly, it was considered that the inefficiency due to deviation from SRMC in the spot market, while still significant, would probably be less than that arising from other distortions in the sector.[70]

In summary, then, it was considered that if a compromise had to be achieved between short and long run efficiency, it was better to err on the side of fostering long run efficiency. Thus, the key issue was believed to be reducing barriers to entry, and avoiding intrusive regulation, not just because of the direct expense involved, but also

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[68] See T.J. Scott and E.G. Read: "Modelling Hydro Reservoir Operation in a Deregulated Electricity Sector", *International Transactions in Operations Research*, vol.3, no.3-4, 1996, p. 209-221.

[69] That is, consumers will not curtail their normal activities by much when prices rise, at least in the short term. They may suffer a personal or commercial loss as a result of paying higher power bills, but that is not a welfare loss to the nation, merely a wealth transfer.

[70] Historically, a much greater distortion resulted from the fact that, under central planning, electricity prices were not varied in response to changing hydrological conditions at all. And, in the current context, one would also think that a much greater distortion arises, at least for domestic customers, as a result of limits being placed on fixed charges, thus forcing fixed costs to be recovered by adding substantial mark-ups onto the energy price component, whether or not it reflects SRMC.

because of its likely negative impact on productive efficiency. The implication is that, in this market design, fostering allocative efficiency by aligning prices with SRMC was, at best, to be a secondary consideration. In fact, we have argued that the design actually relies upon prices deviating significantly from SRMC, on a regular basis, to provide a sustainable environment for long run capacity investment.

Our goal here is not to argue for a particular market design, or to explore options for what the NZEM design could, or should be. But the extent to which prices should be allowed, or expected, to deviate from SRMC depends partly on market design choices. Thus, the next few sections briefly consider the rationale behind design choices made in three key areas, and examine the implications of those choices, in terms of their expected impact on behaviour in the market, and performance of the market. Those choices relate to four key questions, namely:

- Why is there no central buyer?
- Why are offers not regulated?
- Why are prices not capped?
- Why is there no capacity component?

5.3 Why is there no central buyer?

For some time, consideration was given to a market design in which a central buyer determined how much capacity was required, and conducted competitive tenders for that capacity. That central buyer might then have entered into long term physical contracts covering the standing costs of the purchased capacity, in return for the right to dispatch that capacity at its assessed SRMC, or to offer it into a market dispatch at that price. Alternatively, the central buyer might have avoided any involvement in dispatch, by entering into long term financial contracts covering the standing costs of the purchased capacity, in return for corresponding call options with strike price set to the assessed SRMC.

Theoretically, this kind of arrangement might seem ideal, in that it is designed to incentivise, or enforce, strict SRMC bidding, and hence achieve “perfect” intra-sector coordination and perfect operational price signalling to consumers, while also guaranteeing recovery of actual investment costs. Indeed, this kind of arrangement may well prove to be the best compromise approach to the purchase of extreme dry year back-up capacity, for example. It should be recognised, though, that this type of “solution” has problems of its own:

- First, it would involve the central buyer in all the problems of determining a “fair” SRMC for each plant type, and adjusting that over time. In reality, the hydro SRMC would vary constantly, so the central buyer would effectively have to buy the right to determine short/mid/long term hydro dispatch, or to optimise the timing of its calls on an equivalently complex and flexible financial contract.[71]

- Second, in a small and locationally diversified sector like New Zealand's it would actually be very hard to determine what the central buyer should be buying. Is it "energy capacity", or "peak capacity" or "storage capacity", or some combination of them all? Is it "anywhere in the South Island", or "anywhere in the North Island", or somewhere locationally more specific? And how to account for seasonality, reliability, variability, and correlation with existing sources?
- Third, given all those possible variations, how much competition would there actually be in each tender, and what rules and exceptions might have to be created to deal with situations where there really only one option met any specific requirement; and/or each option met parts of several requirements? It seemed inevitable that the central buying process would become heavily politicised. Potential entrants would have strong incentives to lobby for purchasing to be biased toward capacity of the type they could offer, and other lobby groups would seek active involvement, too.
- Fourth, the central buyer would obviously have to determine how much capacity of each type it needed to buy, and how much it was prepared to pay; thus implicitly determining an "acceptable" LRMC, and PDC. Many felt that there was little point in developing a market if such fundamental parameters were ultimately set by bureaucratic processes rather than by market interaction.
- Last, but perhaps most importantly, the creation of a central buyer seemed unlikely to solve the central problem that had plagued the New Zealand electricity sector for more than a decade: That the Government itself had become politically invested in perpetuating construction programmes that were adding excessive over-priced capacity, largely to maintain employment, while seeking to sell that over-capacity at a heavy discount to overseas interests. That specific scenario had, by then, been dealt with by creating ECNZ and giving it commercial incentives. But it was thought implausible that future governments could be restrained from responding to any perception of capacity inadequacy by putting pressure on a central buyer (or ECNZ had it continued in that form) to raise capacity targets, and probably to bias electricity sector development in directions designed to serve other interests. That concern remains valid, in our view.

5.4 Why are offers not regulated?

Despite the emphasis on achieving long run efficiency, consideration obviously could, and was, given to mechanisms designed to achieve maximum short run efficiency as well, thus providing the best of both worlds. One obvious option would be to try to force offers to match SRMC. But that option was rejected, for two main reasons.

[71] See: E.G.Read & P.R Jackson "Financial Reservoir Models: Supporting Competition in Integrated Hydro Systems" Presented to ORSNZ conference, Wellington 2014

First, the decision was partly motivated by the difficulty of objectively determining what SRMC might actually be, in a hydro dominated system. Those difficulties, which are elaborated in Section 6, were very much appreciated by the designers of the NZEM, who had extensive experience with the development of computer models to perform such assessments. Thus, it was thought wise to avoid a market design in which alignment with SRMC was a primary goal, implying a requirement to make, justify, and debate such assessments a major focus of activity.

More generally, the idea that intrusive regulatory intervention might lower costs was considered to fly in the face of conventional regulatory wisdom, at least as understood in most sectors other than electricity. Productive efficiency gains seemed most unlikely at the organisational level, where the transaction costs involved in that whole process, including the de-motivating and distracting impact of intrusive investigations and interventions, would most likely outweigh any benefits. Efficiency gains would be conceivable at the sectoral level, though, if it could be shown that the loss in coordination (allocative) efficiency, due to distortions away from SRMC pricing under the status quo, were greater than the increased transaction costs, plus losses in productive efficiency within firms, and dynamic (investment) efficiency, due to regulatory intervention. After much debate, though, the WEMS study concluded that this was not likely, partly because the actual impact of SRMC pricing at the wholesale level would often not be passed through to the retail level (because of contracted prices), as discussed in Section 5.2 above. The overheads of establishing such a function in the small New Zealand market were also considered to be a significant issue.

Second, though, it was considered that forcing offers down to SRMC levels would actually not be desirable, in terms of maintaining a long run equilibrium, with acceptable capacity margins, for the reasons already discussed in Section 2.5. As discussed in Section 4.3, it was believed that the electricity sector should evolve toward a paradigm which has proved successful in other sectors, under which prices might deviate significantly from SRMC. In the absence of a perfect contract market, this was thought necessary in order to support sufficient entry by risk averse investors, and also to provide discipline to that contract market, and encourage consumer contracting, as discussed in Section 4.3.

In most sectors, it is also clearly understood that the market simply will not work if the supplier is restrained from charging premium prices to customers who refuse to book ahead. What incentive would anyone have to book ahead if they knew that a regulator would force suppliers to make seats/rooms available at a near zero SRMC to last minute purchasers?[72] And what incentive would a potential hotelier have to invest, if they suspected that a regulator might intervene in this way? The overall effect would surely be to delay investment until accommodation shortages became common enough that

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[72] In reality there would still be some incentive, but only at peak times when customers may fear there will not be enough capacity, in aggregate. But that motivation would also be largely removed if a regulatory authority were to impose “capacity standards” and “supply obligations” on these sectors, as is not uncommon in the electricity sector.

hoteliers could reasonably expect to make an acceptable profit, given the risks, by charging premium prices when all accommodation was fully booked.

Similarly, a requirement to force electricity suppliers to offer SRMC prices in the spot market could reasonably be expected to kill the contract market for electricity, and thus to make entry riskier, and less attractive. The overall effect would again be to delay and distort investment, raise prices, and increase the frequency of shortages, as discussed in Section 2.6. Consumers may find such measures attractive, in the short term, because they depress prices temporarily, and have the appearance of "controlling market power" by banning "capacity withholding". But, while one may be able to force incumbents to make existing capacity available, forcing potential entrants to create new capacity is another matter. Such measures will not really serve consumer interests, in the long run, if their effect is merely to ensure that the capacity needed to meet consumer requirements is "withheld" from the investment market.[73]

Of course, another option would be to regulate contract prices, rather than spot market offers or prices. Simply regulating prices would not suffice, though, unless contracts were actually available. Thus, consideration was given to requiring generators to offer contracts at regulated prices. If the entry market is reasonably competitive, this kind of intervention seems unnecessary, since contract prices should ultimately be disciplined by the contracts offered by competitive entrants. Still, the prospect of driving prices down will always seem attractive in the short run. There would be limited value in pursuing such a policy, though, unless it could be effective in depressing prices over the long run. And we have already argued, in Section 2.6, that forcing prices down below a level capable of supporting risk averse entry will distort investment patterns and imply a greater likelihood of shortage than would be considered optimal under central planning paradigm. In fact, Section 2.6 argues that, without an explicit capacity payment, entry of peaking plant could never be supported at all, if prices could never rise above the SRMC of such plant.[74]

Still, it might be thought that at least such intervention could produce a sustainable long run equilibrium with lower prices, so long as the reduced security standard was considered "adequate" by the regulator and/or entry of sufficient peaking plant could be subsidised. Unfortunately, this is not true, though, unless demand is actually declining faster than the rate at which existing capacity fails. If any new, or replacement, capacity is to be built at all, prices must eventually rise to the level where

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[73] Ironically, though, consumers may continue to support such short-sighted policies, even in the long run, because their reference point is the capacity that has actually been built, and the efficient utilisation of that capacity. Unfortunately, they have no way of knowing what investment opportunities have been deterred, and how much this has driven prices up.

[74] Technically, entry might not be deterred if the potential entrant could be assured that the allocation of discounted contracts was a one-off event, never to be repeated. But, once such intervention has occurred, it is hard to see how anyone could be certain it would never happen again. And the prospect of such intervention poses a two-fold threat for an entrant, who must consider the probability of later finding their own position being undercut by new discounted contracts issued by other parties, or being forced to issue discounted contracts of their own.

that capacity becomes economic. Thus, for example, the regulator could insist on contracts being available at expected SRMC prices, and this may depress prices temporarily. But the long run impact must be to delay entry until the capacity situation is tight enough that the SRMC based PDC, including shortage components, is high enough to finance that new plant. In other words, the long run PDC may be distorted, but average price levels must be essentially the same, despite the intervention. In fact, we should expect the PDC to be higher, if regulatory action increases perceived risks for potential investors.[75]

Overall, routine regulation of spot or contract offer prices did not, and does not, seem a particularly attractive option, and was rejected by both WEMS and WEMDG. Given the emphasis, on long run efficiency, it was felt that regulatory attention would be better directed to reducing entry barriers, for example.[76]

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75 Although the PDC could be lower, if the intervention was implemented in a way that reduced perceived risk, e.g by guaranteeing contracts for potential entrants.

76 The offering pattern of incumbents is not irrelevant in that context, since it may form part of an entry deterrence strategy. Such gaming strategies relate to market power issues that are not considered here, but the plausibility and likely effectiveness of that type of strategy in the New Zealand context was considered speculative, and pervasive regulation did not seem justified simply as a precautionary measure.

5.5 Why are prices not capped?

Most other electricity markets impose some kind of cap on prices, although that cap may be set at very high levels in other energy-only markets, such as Australia. Obviously, this is an option that could be, and was, considered for implementation in New Zealand, too. In part it was rejected because of a general aversion to regulatory intervention. But it is also not consistent with the general market design paradigm, and theoretical framework described in previous sections.

Market price or offer caps obviously have a direct impact on the PDC, and hence on the economics of entry. Any (actual or prospective) capping of market prices implies a diminution of (actual or prospective) revenue to both incumbents and potential entrants, and thus implies a prima facie risk of deterring entry, leading to under-supply of capacity in the long run.[77] In theory, the optimal plant mix, under perfectly competitive or centrally optimised assumptions, must imply a finite probability that generation capacity will be fully utilised. And that implies a finite probability that prices will have to rise high enough to reduce demand, without any form of physical intervention, in those situations of full capacity utilisation.

Accordingly, if price caps were to be imposed, or if potential entrants think that there is any possibility of such caps being imposed in future, capacity adequacy could only be assured by one of two mechanisms. Either:

- Some means must be found to reward capacity by payments additional to those received from the energy market; or
- Participants must be allowed recover the deficit by pushing prices above their perfectly competitive SRMC levels when capacity is less than fully utilised.[78]

As discussed in Section 5.6*,* WEMS actually proposed a two-part energy/capacity market in which participants would have received payment for capacity, as well as for energy. But that proposal was not implemented, and the point here is that, if no capacity payment is provided, the value taken out of the market by capping the price must be replaced by some other means, if optimal entry is to be supported. The only way this can occur, in an energy–only market, is by allowing the sub-cap PDC of energy prices to inflate, as discussed in Section 2.5. That is, the lower the price cap, the greater the extent to which prices must be allowed to settle above SRMC at other times. The

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[77] Here we interpret "capacity adequacy" in terms of the optimal economic level of capacity, that is the level at which the marginal benefit of extra capacity equals its marginal cost. Of course, this may differ significantly from public/political perceptions of capacity adequacy.

[78] Read [2010] discusses the Australian regime more fully, and suggests that, while the market price cap obviously stops prices rising above a certain level, it arguably also acts as a kind of "target" to tacitly coordinate offers at prices just below the cap. Thus, it is unclear whether it reduces or increases revenue, overall.

alternative, if SRMC pricing is enforced right across the PDC is to accept greater distortion of the long run entry profile.

Thus, no explicit price cap was imposed in the WEMS design. It was widely felt, though, that the industry was subject to an implicit "threat of regulation", and that this threat would inevitably impose limits on how high prices could rise, and how long high prices could be sustained, during any real crisis. In other words, it was thought likely that if a serious and prolonged crisis occurred, most likely in a dry year, the Government of the day would not sit idly by and let the industry raise prices to their theoretically optimal level: That is to the level at which price alone was sufficient to reduce demand back to a level that could be met by available capacity. Instead measures would most likely be introduced to subsidise entry of alternative supplies, and/or to force prices down, while rationing demand by other means.

An implicit price cap of this nature has much the same impact on the top end of the PDC as an explicit cap, and thus implies a similar requirement to inflate prices above SRMC over the lower part of the PDC. Similarly, retail price caps have obvious political attractions, but even the prospect of such caps would have a chilling effect on investment. Basically, if market participants have any reason believe that there may be limits on their ability to charge what the market will bear during periods of extreme short supply, they must compensate by charging more than SRMC during other times and/or withhold investment.

As it happens, the scenario that unfolded was that, rather than introduce a capacity market, entry of one particular peak-lopping plant (i.e. Whirinaki) was subsidised, without making equivalent capacity payments available to other market participants. That may have seemed like an attractive short-term expedient, but it should be recognised that using a subsidised peak-lopping plant to effectively cap the top end of the PDC creates similar issues to imposing a price cap. The price capping potential of Whirinaki was demonstrated by the Electricity Commission during the winter of 2008 when market prices were affected by the offering of Whirinaki below SRMC, with unrecovered costs in the market being recovered by the EC levy.

Such "subsidised" entry could actually be economically optimal, if timed so that the plant might be expected to operate profitably, at a reasonable commercial discount rate, on the basis of receipts from spot market sales.[79] If so, the resultant PDC could also be optimal, and entry by other plant types would not have been unduly discouraged. But

[79] This does seem possible if entry is otherwise being deterred by factors that made it too risky. For example, it may be that loads are reluctant to contract, perhaps because they believe that they may not secure the benefits of contracted capacity for their own exclusive use, physically or commercially, if a real crisis occurs, and/or prefer to rely on the political process for protection. In that case, the "subsidy" required may be more in the form of guaranteeing expected revenues so as to reduce the risk premium, than increasing expected revenues. Effectively, the regulator would be contracting on behalf of all consumers, collectively, because the transaction costs of doing so are lower than the transaction costs of each individual trying, and probably failing, to negotiate an acceptable contract on their own.

if a genuine subsidy does need to be paid, in expected value terms, it must be that SRMC prices, at the top end of the PDC, are not enough to cover the FC of this entry. In other words. OV is less than FC, for the subsidised plant. But that would also then be true for all other plant.

Conceptually, imposing a cap on the energy market price may be thought of as equivalent to allowing the market price to find its natural level, above that cap, but then automatically issuing every MW of load with a (retrospective) 1 MW call option, the strike price of which is set at the cap. If that cap/strike price were to be set at the SRMC of the most expensive plant in the system, then that plant could never make an operating profit from spot market sales. In order for the plant mix to be optimal, the OV of the equivalent call option (as determined by that part of the PDC where prices exceed this maximum supply-side SRMC) must still equal the FC of that plant. But the market can now only be in long term equilibrium, with sustainable entry of peaking plant, if that plant, at least, receives a capacity payment to cover its FC.[80]

Recall, though, that the OV for any plant is just the value of a call option applying in all periods where the MCP exceeds its SRMC, including those periods when it also exceeds the market price cap. In other words, the optimal (uncapped) OV for plant with lower SRMC equals the optimal uncapped OV for peaking plant, plus the value of a call option based on capped market prices, and applying all the time when MCP exceeds that SRMC. So, a market price cap that reduces the OV of peaking plant will reduce the OV of all capacity by exactly the same amount. Thus, whatever subsidy is required to make investment in peaking plant profitable, the market must also pay the same amount, per MW, to all other capacity, if an optimal plant mix is to be maintained.

In particular, capping prices at the SRMC of peaking plant would reduce its OV to zero, thus requiring a subsidy equal to the full investment cost of peaking plant, FC_{peak}, in order to maintain an optimal investment level for such plant. And the same will be true for all other plant types in the optimal plant mix. In the absence of a capacity market, these cost recovery requirements can only be met by allowing a markup on SRMC

80 This follows because no markup is possible on its SRMC price, which forms the market price cap. More generally, the cap could be set to some higher level, so that some operating profit is made, and only a partial subsidy is required. The same will be true if the market price is only capped by a subsidised entrant, because the market prices can then be expected to rise above the "cap" on some occasions.

prices, set so as to restore the PDC to a level that is just sufficient to support optimal entry for each plant type in the optimal capacity mix.[81]

In other words, capping the PDC carries with it the implication that the remainder of the PDC must somehow be inflated in a similar manner to that discussed in Section 2.6. This is not to suggest that price capping, or subsidised entry, will allow, or facilitate incumbents to raise prices in the short term. If incumbents have insufficient market power they may well have to accept a loss in value in the short to medium term. Thus, consumers may benefit from lower prices over that period, too. But the point is that, in the long term, entry will be deferred until it can be supported by the capped market PDC: That is, until the uncapped portion of the PDC rises high enough above its optimal level to offset the loss in value from capping at the top end.[82]

In summary, market price caps are employed in many markets, for fairly obvious reasons, but they seem problematic, and were not favoured by WEMS or WEMDG. In principle, capping market prices distorts the PDC, and leaves us with the option of subsidising plant to operate during the time when the market price binds, or perhaps accepting a sub-optimal plant mix. Thus, even the Australian market, which sets its market price cap to a very high level, also retains a "reserve trader" concept, under which some plant is contracted to operate only when the price cap binds.

81 Specifically, assuming that FC_{peak} is expressed in terms of an annuity, a plant operating for H hours per year, on average, must receive an average price premium of FC_{peak}/H \$/MWh, over and above the SRMC price which might be expected assuming an optimal plant mix, under perfect competition. The logic of Section 2.5 suggests that, in order to sustain entry of plant near the top of the merit order, these mark-ups would have to be concentrated near the peak period, when that plant operates, and this may not be possible if the SRMC of that plant is close to the market price cap. Thus, it may be necessary to set the price cap well above the highest SRMC. Otherwise, a range of high SRMC plant may still need to be partially subsidised, even if they are able to price right up to the market cap, when operating.

82 It has sometimes been suggested that intervention of this form risks starting the market down a "slippery slope" scenario, under which more and more capacity, of all types, must be subsidised to enter. Provided enough peaking plant continues to be subsidised, though, it should be possible to keep the probability of shortage to an optimal level, or less, and to keep prices below their optimal level, if not down to the SRMC of peaking plant, at the top end of the PDC: That is in those periods when the peaking plant operates. But, even with SRMC pricing, the PDC can still inflate by deferring entry, and shifting investment from more to less capital intensive plant, including the subsidised peaking plant. Indeed it must inflate in this way if long run equilibrium is to be maintained. The result is a sub-optimal plant mix, with higher costs, and of course higher prices are required to cover those costs but, although no formal proof has been attempted, it does seem possible that a sustainable equilibrium could exist. There is still an incompatibility, though, between maintaining SRMC pricing and maintaining an optimal plant investment pattern, in an energy-only market:

5.6 Why is there no capacity component?

Finally, many jurisdictions have adopted some form of market, or centralised contracting, for capacity. One way to do this would be to require loads, or load serving entities, to buy "compulsory insurance", in the form of "capacity tickets", or "cap contracts",[83] as proposed by WEMS. The implication would be to force the price of such contracts up until it is high enough to underpin entry of whatever capacity is needed to meet a security standard considered "acceptable" by the regulator.

This was the original WEMS design and, under that proposal, it was hoped that the price of capacity tickets could eventually be set entirely by market forces, both on the supply and demand side. Thus, it was hoped that, ultimately, the provision of such an instrument would allow trading to reach an economic equilibrium, in which purchasers of capacity tickets were satisfied that they had bought an adequate level of "insurance", at a price which allowed capacity ticket suppliers to recover their costs.

It was expected, though, that the market would have to be "managed", at least initially, by setting a capacity ticket coverage requirement to be met by load serving entities. Thus, the level of security, and corresponding demand for capacity tickets, would be set by some non-market process and could, in principle, be made arbitrarily high. But the market could still reach a sustainable equilibrium to supply that amount of capacity, even if the capacity standard was actually excessive in economic terms.[84]

This kind of market design imposes some overheads, but reduces the risk for potential entrants, and particularly for peaking plant. So, it may be expected to lead to greater competition, lower risk premiums, and lower prices, in the long run. Many North American markets include some form of capacity payment mechanism, and some academics have recently recommended designs very much like the original WEMS design.[85]

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[83] In other words, "call options", with a relatively high strike price, effectively creating a market price cap, from a load perspective.

[84] Despite the hopes expressed by WEMS in this regard, it was clearly felt that the capacity level which any regulatory authority might set was likely to be higher, even in the long run, than the "economic: capacity level: That is, the capacity level that customers would freely choose, if faced with the true cost of meeting the standard, assuming they had sufficient understanding of the situation, could contract robustly enough to secure the benefits of contracted capacity, and had no incentive to game the political process. If so, that would exacerbate many of the problems discussed here, but does not really change the nature of those problems, or of those conclusions.

[85] P Cramton and S Stoft: *The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem* A White Paper for the Electricity Oversight Board 25 April 2006

H-P Chao and R Wilson : *Resource Adequacy and Market Power Mitigation via Option Contracts* Electric Power Research Institute 03/18/2004

There is no universal agreement on this issue, though. It would be fair to say that, while WEMS concluded in favour of a two-part energy/capacity market design, opinion within the WEMS study group was actually fairly evenly balanced. After further consideration, the more broadly representative WEMDG group clearly favoured the energy-only design. And it should be said that, when the effect of dry years, ad hoc intervention, and supply side shocks is stripped away, we are not aware of any convincing evidence that this market design actually has produced a capacity shortfall in New Zealand.[86]

It should be recognised, too, that this market design is by no means unique to New Zealand. A number of other markets, including Australia and Singapore, have adopted energy-only designs with apparent success. Most recently, Texas has adopted a design very similar to the New Zealand market, after many years of experience with alternative market paradigms, and extensive observation of alternative market designs operating elsewhere in North America.

Of itself, neither option is really ideal. Theoretically, customers in an energy-only market may expect to face higher prices, greater price volatility, and more frequent outages than might be considered "ideal", and then they would face in a market with capacity payments, or traditional regulation. But society may prefer to opt for this market design if the transaction costs of contracting, or establishing more elaborate and/or intrusive market regulation to avoid this situation, exceed the benefits from doing so. Thus, the energy-only market design may be optimal if the costs imposed by the obvious dis-benefits are less than the transaction costs of adding a capacity component to the market design, and/or imposing more rigorous regulation.

In particular, concern may be expressed that this arrangement gives the body setting capacity requirements considerable power to set requirements in excess of what market participants would willingly pay, if contracting on their own behalf. The resultant distortion to the plant mix could well be greater than that implied by not having a capacity market in the first place, and the cost would ultimately have to be borne by consumers. WEMDG, which included significant consumer representation, obviously found these arguments persuasive and, while alternative proposals have been raised from time to time, consensus in the industry probably still supports that position, on the grounds that:

S Oren "Generation Adequacy via Call Options Obligations: Safe Passage to the Promised Land" *The Electricity Journal* Volume 18, Issue 9, November 2005, Pages 28-42

86 Appendix C outlines a preliminary study which finds, if anything, evidence of surplus capacity, in the recent past, although it remains to be seen whether prices can rise high enough to support development of the new peaking capacity that may be needed to complement future development of renewables.

- The transaction costs of imposing a contracting regime, or establishing more elaborate and/or intrusive two-part market arrangements, may well be more than the costs of persisting with an energy-only market design; and

- Despite public perceptions many analysts believe that the energy-only market design is actually performing well enough, in terms of providing sufficient capacity, and reasonable prices.

The point here, though, is not to debate whether WEMDG's judgement was, or is, correct, or to promote any alternative design. The point is merely that the NZEM now operates according to an energy-only design. As such, it relies upon prices deviating significantly from SRMC, on a regular basis, so as to provide a sustainable environment for long run capacity investment.

5.7 Conclusions

It should be clear, from our discussions that we consider the NZEM design to be predicated on the assumption that significant deviation from SMRC pricing is not only acceptable, but necessary, at least in some situations. Without that freedom, we consider it unlikely that participants would be able to obtain sufficiently high spot or contract prices to underpin the economics of sustained new entry, particularly for peaking plant. This is particularly so when one considers the inherent risk involved in investing in such plant. Thus, in opting for an energy-only market design, WEMDG acted consistently by not placing limits on offers or market prices.

If prices or offers were to be limited, the likely intent would be to force prices down and/or capacity provision up, in the short run. In the long run, though, these two goals seem incompatible. If a sustainable equilibrium is to be maintained in the market, intervention must be accompanied by, or expected to induce, a balancing reaction:

- Intervention to force market prices down, on any occasion, must be offset by an expectation that, in the long run, prices will rise on other occasions, either because participants withdraw existing capacity when it becomes uneconomic to maintain that capacity in the spot market, or because potential entrants withhold potential capacity from the investment market, until average prices cover entry costs, with sufficient certainty.

- Intervention to force capacity provision up is really only possible if the regulatory authority itself enters the market as a buyer of capacity, or requires market participants to do so. If that occurs, though, prices must ultimately rise to induce, or at least cover the costs of, extra capacity provision.

In particular, capping prices, or requiring electricity suppliers to offer SRMC prices in the spot market, or the threat that this could happen in future, can be expected to have a negative impact on the contract market for electricity, and to delay competitive entry until the expected PDC, and the risk of shortage, rise higher than is likely to be considered desirable. Selectively subsidising entry may serve to keep the probability of shortage down to an acceptable level, and this has actually occurred in the NZEM. Theoretically, though, it implies the likelihood of distortion to the remainder of the plant mix, and raises issues which, in our opinion, remain unresolved in the NZEM at this time.

One possible market design would force spot prices down to SRMC, while guaranteeing capacity payments in some way. The regulator could run a competitive tender for capacity contracts, or require loads to do so. WEMS proposed the latter, using "capacity ticket" contracts for peaking (or more exactly in the NZEM context, "dry year backup") capacity. This kind of market design might improve both long run and short run efficiency, but it might not perform significantly better than the current design. It does impose overheads, and create problems of its own and thus it was ultimately rejected by the NZEM designers.

As a result, the NZEM became a simple unconstrained energy-only market. Theoretically, if risk were not an issue, and/or contracting perfect, such a market might produce a perfect alignment between both short and long run economics, with spot prices at SRMC and contract prices at LRMC. But risk is an issue, and contracting imperfect, in this market as in any other. Thus, adequate entry is expected to be partially supported by allowing spot prices to exceed SRMC, particularly at peak times, but also in other circumstances. The threat that prices will significantly exceed SRMC is also a fundamental part of the market design, since that threat is supposed to motivate forward contracting by loads, and hence entry by alternative suppliers.

In other words, this market has been designed to operate just like the vast majority of successful markets operating outside the electricity sector, and with similar cost structures, where pricing above SRMC has always been considered absolutely normal.

6 APPENDIX B: SRMC for Hydro and Energy-Limited Thermal[87]

Discussion of economic behaviour in electricity markets often focuses on the extent to which prices are considered to deviate from SRMC. The previous sections have suggested that prices may actually have to deviate from SRMC, perhaps significantly, in order to produce a sustainable equilibrium, particularly in an energy-only market design such as the NZEM. But this section focuses on the other side of that question, namely determining what SRMC might actually be in a system dominated by hydro and energy-limited thermal plant.

It will be seen that this is actually quite a complex question, and that the SRMCs of hydro, gas, and coal plant can be expected to exhibit quite complex patterns, correlations, and connections, over daily, weekly, monthly and annual time scales.[88] We should make it clear, though, that none of the discussion in this section relates to deviations from SRMC pricing, let alone market power. In this section we assume SRMC pricing, and merely:

- Explain the kind of price patterns, correlations and connections that would arise, internally, within any sufficiently detailed centralised optimisation;
- Note that exactly the same patterns, correlations and connections should be expected in a hypothetical perfectly competitive market; and
- Argue that the same general conclusions should (hopefully) apply in real markets, if they are working properly, even though participants may not be able to clearly articulate or analyse how all of these factors interact.

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[87] This appendix is a very lightly edited version of Section 4 of Read [2009]. As such, it reflects the conditions of that time, particularly wrt respect to the role of thermal generators, and their fuel supplies.

[88] Strictly speaking, SRMC is actually difficult to define in thermal systems too, even without consideration of energy limits. This is because unit commitment decisions must be made, perhaps on a daily or weekly basis and, once committed, plant may not wish to shut off even when market prices are below their fuel costs for a few hours. Similarly, once de-committed, plant may not wish to start up, even when market prices are above their fuel costs for a few hours. This implies variation in the effective SRMC over a daily or weekly cycle. This observation applies to some plant in the New Zealand system, too, but it will be ignored here because it is a relatively less important feature, and is also relatively well understood from studies in other markets.

6.1 SRMC for Major Reservoirs

Although our discussion has already referred to conditions in the hydro-dominated NZEM market, most of that discussion is not actually specific to hydro systems. Electricity markets are inherently risky, and all markets face the central problems of coordinating short run supply and demand side activities, while incentivising efficient entry by risk averse investors in the long run. Thus, the basic market design considerations are the same. But some of the problems discussed above are exacerbated in a hydro market setting.

Obviously, hydrological risk is a major factor in such markets. In the absence of any storage capacity, hydro generation could only utilise flows as they arrived, and load would have to be curtailed to match those flows. It may be argued that the SRMC of hydro generation would be zero in such a market, but this would only be true when flows exceeded what was required to meet the load level which might be induced by a zero price. The rest of the time, the effective SRMC of hydro would effectively be infinite, or at least indeterminate, and the "SRMC" market price would actually be set by the marginal cost of curtailing load to the level which could be generated, given the real-time inflows. So, the market could be expected to experience a volatile bi-modal price distribution, alternating between zero, during times of surplus, and shortage cost levels, during times of relative shortage.[89]

This price pattern may be thought of as similar, on average, to that in a variant of the traditional regulated pricing regime that relied entirely on capacity/peak payments, with no "energy" charge at all.[90] All the standard theory still applies, though, and the expected long run average price level should still be that required to induce new entry, given the market risk.

Introducing thermal generation, still with no hydro (or fuel) storage, would reduce price volatility by introducing intermediate price steps, corresponding to the SRMC of each thermal unit, with a significant probability that the price would lie at one of those levels. But this does not fundamentally change the situation and, again, the above theory still holds.

Introducing hydro storage has a more radical impact, though. Clearly, it will mitigate uncertainty by allowing flows to be stored for use in the most needy periods, and this will reduce short run price volatility. But this means that the SRMC of hydro is no longer zero (or infinity), but is given by a "marginal water value" (MWV), which is the "opportunity cost" or "option value" of a marginal unit of water stored for future use. In a pure hydro system, that marginal unit of stored water may ultimately be spilled, in

[89] The frequency of shortages would probably be quite high, in such a system, although the price implications of modest shortages may also be modest.

[90] And that is exactly the way the "Bulk Supply Tariff" was structured in New Zealand, for many years, while the system was purely hydro.

which case the opportunity cost of using it today will turn out to be zero. Or it may ultimately help to reduce a future shortage, in which case the opportunity cost of using it today will be some kind of load reduction, or shortage cost, and may be very high. But the effective SRMC for hydro generation is given by the expected marginal water value at any time, and this will not normally lie at either extreme, but vary continuously as storage levels, and expectations, change.

The calculation of these expected MWVs lies at the heart of reservoir management optimisation, in a centrally planned system.[91] In New Zealand, the old NZED STAGE model, and the PRISM/SPECTRA models developed by the MoE, both made that calculation explicit, and this is also true of newer models such as SDDP. In other models the MWV calculation is implicit, but mathematically equivalent. Thus the "SRMC" of releasing water from a storage lake is almost always the "expected opportunity cost" of not having that water available for use in some future period.[92]

If there is no thermal generation in the system, that expected opportunity cost will be a weighted average of the spill value (zero) and the shortage cost arising when demand can not be fully met. Thus, it will vary as a function of the calculated probability of spill occurring before the next time the reservoir is empty; or conversely of the reservoir being empty before the next time it is full. And that varies as the state of the reservoirs varies, over time, but will clearly be lower if the reservoirs are relatively full, for the time of the year, thus reducing the probability of future shortage.

The addition of thermal generation to the system does not fundamentally change this, but tends to mitigate the effect. As the proportion of thermal increases, so does the probability that prices will be set directly by the SRMC of some thermal generator, rather than by the expected MWV of some hydro generator. Thus, the weight given to expected spill and shortage events may actually be quite small in determining MWVs, most of the time. Instead, expected MWVs will normally be set by the likelihood that a unit of water saved now will eventually be used to displace generation from some

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[91] Extensive discussion of the theory of MWV calculation for the deterministic case may be found in E.G. Read [1982a]: *Economic Principles of Reservoir Operation I: Perfect Foresight*, International Short Course on Reservoir Scheduling, University of Tennessee, Knoxville, (CBA Working Paper No. 151. E.G. Read [1982b] *Economic Principles of Reservoir Operation II: Uncertain Future*, International Short Course on Reservoir Scheduling, University of Tennessee, Knoxville, (CBA Working Paper No. 152) extends it to the stochastic case.

[92] The only exceptions are when the reservoir is either empty or full, in which case, the "expected opportunity cost" relates to the marginal cost of the thermal generation, or load shortfall, in the current period, because the optimal policy is to release whatever inflows arrive, for a while, and the MWV equals avoided by passing through those inflows. Where water must be released, or spilled, because is not possible to store any more water for the future, this MWV may be zero.

thermal generator at some future date, the value of which will be determined by the SRMC of operating that thermal generator.[93]

6.2 SRMC in River Chains

It should be recognised that the theory discussed above applies to all reservoirs and "head ponds"[94], at all levels in the system, and over all time periods. In all cases, the relevant opportunity cost is calculated over the period until the reservoir storage bounds are next expected to be reached.[95] And in all cases the MWV must change when such a bound is reached. Specifically, Read [1982a] explains why, somewhat counter-intuitively, the MWV must rise whenever an upper storage limit is reached, and must fall whenever a lower storage limit is reached.[96]

If the reservoir is large, then it will typically reach its upper and lower limits, or at least threaten to reach its limits, around the same time each year, thus operating under an annual cycle in which MWV rises at one time of the year (prior to winter for most New Zealand reservoirs) and falls at another (after winter for most New Zealand reservoirs). But a small reservoir will exhibit exactly the same kind of behaviour over a shorter period, often operating on a weekly or daily cycle. So, it may typically reach its upper limit, or at least threaten to reach its upper limit, before the morning peak, then reach its lower limit, or at least threaten to reach its lower limit, after the evening peak. And

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[93] Or at least that is the conventional wisdom, derived from markets in which it can be assumed that the SRMC of operating a thermal generation is itself well-defined. As discussed in Section 6.3, though, that is not necessarily the case where thermal plant is "energy limited", as may often be the case in New Zealand.

[94] These are small storages, immediately above a hydro station, often with only a few hours storage capacity.

[95] It is easiest to think about a deterministic problem here, where we know the inflows, and can determine the optimal time at which storage should next reach one or other limit. The stochastic version of this theory, as described by Read [1982b], is quite complex. The principles discussed here carry through to that case, though, except that changes occur more subtly and continuously, as expectations change over time.

[96] This result, and the timing of the change, is clear-cut in a deterministic optimization model. In reality, because of uncertainty, operators try to avoid having reservoirs actually reach their storage bounds, and the MV change occurs a little more gradually, over several periods, as the threat of reaching the bound builds up, and then recedes. But this requirement to try to avoid actually reaching the limits means that the effective bounds on storage range are actually tighter than a deterministic model would imply, and managing storage to those tighter effective limits means that the total MWV change over the periods involved must actually be greater than for a deterministic model. Thus, consideration of a deterministic model still provides a reasonable guide to real-world behaviour.

this means that its MWV must also cycle daily, rising before the morning peak, then falling after the evening peak.[97]

When reservoirs are linked into river chains the situation becomes much more complex. While it is common to talk, for example, about the MWV of "the Waikato river chain", this is not a well-defined concept. Each reservoir, or head pond, has its own MWV, fluctuating in accordance with its own optimal operating cycle. And, while river chain optimisation seeks to keep all stations operating on synchronised cycles, this is often not possible, due to capacity imbalances and flow delay times. In such a chain, the SRMC of release is not determined by the MWV of the releasing reservoir, at the time of release, either. It is determined by the difference between the MWV of the releasing reservoir, at the time of release, and the MWV of the downstream reservoir, at the time that incremental release is expected to arrive there, which may be several hours later.

Conversely, the MWV of the upstream reservoir must be determined by a trade-off between the opportunity cost of not keeping water in that reservoir, for later release, and the opportunity cost of not having that water arrive at the downstream reservoir, for release there, after some delay. In each case, though, the opportunity cost must be calculated on the basis of the opportunities available before that reservoir next reaches a storage bound. And the periods involved may be very different for the two reservoirs because they may be of very different size, and (given the delays) at very different stages of their daily cycle.[98]

The point of this discussion is not to develop an optimisation algorithm to resolve these issues, but to note their complexity. That complexity becomes much greater once it is realised that one can not resolve the issue by considering just two stations. One would have to iterate both up and down a whole chain of stations, to find a generation dispatch solution, and MWV pattern, that was simultaneously optimal for all stations in the chain. Overlaying uncertainty about both inflows and market prices does not make the

[97] A really small reservoir may have two cycles in each day, one for each peak. In the limit, a station with no storage becomes a so-called "run-of-river" station, for which the MWV for each trading period is effectively determined by the market price in that trading period. (As noted earlier, the SRMC of increasing supply from such a station is not zero, as is sometimes asserted, but indeterminate, because it can not produce any more than the minimum of its capacity or the inflows it receives.)

[98] Suppose, for example, that the delay time is 2 hours, peak load is at 6pm, and both reservoirs actually hit their storage minimum soon after, say at 7pm. Then the MV in both reservoirs will be high until 7pm, but then drop suddenly. But the SRMC of release from the upstream reservoir is not determined by the MWV, but by delayed MWV difference. And that difference will actually rise suddenly at 5pm, because water released after 5pm will arrive too late to also be released to meet the evening peak from the downstream reservoir. After 7pm the SRMC will drop abruptly, though, because water in the upstream reservoir is then too late to be released to meet the evening peak from either reservoir. This example is over-simplified, though. The optimal solution may well avoid having SRMC rise so high at the peak time by having the upper reservoir reach its minimum at 5pm. But that would mean that the daily output cycle of the two reservoirs was offset by the delay time, which means that they can not both be in synch with the load cycle.

situation any less complex, either. Read [1979][99] illustrates the kind of operational patterns that may emerge, using the Waikato river chain as an example. That thesis developed MWV-based methods for optimisation of major long-term storage reservoirs, but found the river chain optimisation problem too complex to tackle in this way. Other attempts in the literature have been similarly abortive, and river chain optimisation packages generally solve a "primal" version of the problem, in which the MWV is only implicit, and generally not reported.

Thus, many hydro system operators may not even be aware of the theory discussed here, or conscious of the MWV patterns implicit in their dispatch solutions. Those MWV patterns are potentially quite complex, though, and the SRMC of generation will generally differ between stations in the chain, and between periods of the day. It is quite possible, for example, that the SRMC of generation from one station in the chain may be zero at exactly the same time as the SRMC of release from another is very high.[100] If generation can be drawn from anywhere in the chain, the SRMC of generation from the chain as a whole will be less volatile, but it will rise as increasing requirements must be met by release schedules of decreasing efficiency, and should be expected to vary over the daily cycle, perhaps significantly.

Despite all this, many discussions assume that we can think of the entire chain as having a single piece-wise linear SRMC "supply curve". Conceptually, and ignoring uncertainty, such an SRMC "curve" could be derived by a technique known as "parametric programming", in which an optimization model representing the river chain, with all of its downstream storage, generation, flow, and delay time restrictions is asked to produce more and more output. Conceptually, we could expect that such an SRMC curve might start out fairly constant, while the output requirements can be met without fully utilizing the chain's capacity in any respect, and then rise in progressively steeper steps as various constraints start to bind. But the situation is actually much more complex than this, because the inter-temporal linkages implied by the storage and delay terms mean that the SRMC curve for any period depends directly on the output requirements in all other periods. Thus, we can not actually derive a piece-wise linear SRMC supply "curve" for any one period. Instead we must determine a multi-dimensional piece-wise linear "surface" for all periods simultaneously. Uncertainty about future demand and supply conditions also means that this surface will evolve continuously, as expectations change over daily, weekly and longer cycles.

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[99] E.G. Read *Optimal Operation of Power Systems*, Phd Thesis, University of Canterbury, 1979.

[100] If there are limits on spill, or on river flows, MWV can actually be negative at some points in the river chain, particularly during flood conditions. And SRMC, which is a difference between successive MWVs can be zero, or even negative, if water must be released to meet minimum flow requirements at some point in the chain.

6.3 SRMC of Energy Limited Thermal

Section 6.1 discusses the conventional wisdom on MWV determination for hydro systems, on the assumption that SRMC of thermal generation is itself well-defined. Unfortunately, in New Zealand, that is not always the case either, because much of the thermal capacity is actually "energy-limited", and not in a very different situation from hydro. Conceptually, gas "reservoirs" actually have similar characteristics to hydro reservoirs, except that they are not replenished, and drawdown occurs monotonically over many years, rather than in daily, weekly, or annual cycles. Thus, the same general theory applies, except that the MWV is replaced by a "Depletion Related Opportunity Cost" (DROC), and (under deterministic assumptions) this rises steadily over the years at the discount rate, until the reservoir is empty. [101]

Of itself, this physical analysis does not imply any significant extra constraints on the power system. Nor does it imply any difficulty in determining SRMC for gas-fired generation, because DROC changes over such a much longer time horizon than MWV, and is not much affected by year to year variations in the demand for gas-fired generation, e.g due to hydro fluctuations. In reality, though, gas producers also have cashflow requirements, and often sell gas via "take-or-pay" contracts that require purchasers to make annual contract payments, and then impose restrictions on the extent to which gas "purchased" in one year can be rolled over for later use, and the extent to which gas to be "purchased" in later years can be used earlier. Maximum and/or minimum restrictions may also be placed on daily, weekly or monthly quantities.

The problem is that when any of these restrictions bind, or threaten to bind, optimal utilisation of this (perhaps artificially) limited resource implies the need to adopt an opportunity costing methodology that is conceptually very similar to that for hydro. And the true opportunity cost-based SRMC of gas-fired generation will then cycle on a daily, weekly, monthly or annual basis, just as for hydro.

To see this, first consider a very simple hypothetical case, in which there is only one gas-fired generator, in a hydro-dominated system, and that generator is supplied under an annual "take-or-pay" contract with no provision at all for roll-over, or purchase of extra gas, and no opportunity to trade. So, this generator's annual gas purchase must be used, or lost, within a year, and the generator faces very much the same situation as a hydro generator with a stock of water than must be used, or lost, within a year. The supply, in this case, is not (normally) at risk, but the demand, being the residual not supplied by hydro, certainly is. And the "per unit cost" is, in principle, irrelevant in determining the SRMC for gas supplied under a contract that effectively involves

[101] DROC can never fall, because the reservoir is never full after the first period, whereas MWV does fall, every time an upper storage limit is approached. Strictly speaking, MWV should rise, like DROC, at the discount rate, over the hours, days or months when storage is not approaching either limit. But this effect is generally ignored on those relatively short time scales.

payment of a lump sum, agreed in advance, for a fixed quantity of gas. Once agreed, this becomes a fixed cost, just like the capital cost of hydro plant.[102]

Such a generator is "energy limited", and must ration its use of its limited gas resource entirely on the basis of opportunity costs, calculated so as to just use up that resource over the annual time horizon. A centralised optimisation model, optimising the dispatch of such a plant in the context of a hydro-dominated system, would ignore the purchase cost of the gas, and endogenously determine an opportunity cost, and hence an SRMC for gas generation, so as to achieve that goal. But that same model would also have to determine opportunity cost based MWVs for each hydro reservoir in the system. Thus, the SRMCs for hydro and gas would be jointly determined, and very closely related, and neither would be determined by the contractual "purchase price" of gas. In a wet year, the opportunity cost SRMC of gas would have to fall low enough to ensure that the annual gas quantity was used, despite the hydro surplus, and the correspondingly low MWV. In a dry year, the opportunity cost SRMC of gas would have to rise high enough to ensure that only the annual gas quantity was used gas was used, despite the hydro shortfall, and the correspondingly high MWV.

In reality, such a system is unlikely to exist, because such inflexible gas-fired generation actually does nothing to complement annual fluctuations in hydro output. If the system were that inflexible, the SRMC of both gas and hydro would probably fall to zero in wet years, leaving water to spill and/or gas unused. And the SRMC of both gas and hydro would have to rise high enough to produce electricity prices high enough to choke off demand in dry years. In reality, gas–fired generation would have to provide greater flexibility than this, in order to play a swing producer role in a hydro-dominated system. This flexibility could be provided by contract provisions to purchase, anticipate, or defer, the supply of incremental gas. Or flexibility could be provided by arrangements to trade gas with other users, as (expectations with respect to) hydro inflows vary, on a short to mid-term basis.

Either way, the per-unit costs relating to such incremental trading, purchase, anticipation or deferral, will become relevant to the opportunity cost calculation. They do not render that calculation irrelevant, though.

First, in the limit, if the gas market is flexible enough, and this generator is physically and commercially unrestricted in trading its gas in that market, the opportunity cost of using gas purchased under its take-or-pay contract for generation will still not depend

[102] There are logical connections, in the longer run, because participants will not enter into contracts to purchase gas that they think is over-priced, on average, relative to the prices they can obtain for gas-fired generation in the electricity market. This impacts on the LRMC of gas-fired generation, but the discussion here relates to determination of SRMC, as hydro output varies, in a time-frame where contract provisions will already have been agreed.

on the price it paid for that gas at all. Instead it will be the market traded price for gas at that time.[103]

Also, in the limit, if variations in electricity generation account for a sufficiently small proportion of the gas market, the market traded price for gas will not fluctuate much as a function of inflow conditions in the hydro sector. This may well be the situation in the US or Europe, say, where there are many alternative uses for gas, and a relatively liquid market will be able to absorb the fluctuations induced by hydrological variations in their, comparatively small, hydro generation systems. And under those circumstances, the daily, weekly, monthly and annual quantity provisions normal in gas contracts may turn out to have very little influence at all on the calculation of gas opportunity costs, and hence SRMC.

We have not investigated current conditions in the New Zealand gas market but, at least historically, the situation in this small isolated market has been rather different from that in the US.[104] Any trading flexibility will serve to mitigate the effects discussed here, but only unlimited trading would eliminate them entirely. And the gas market has not been liquid or flexible enough to allow unrestricted trading within daily, weekly, monthly or annual time frames.[105] Gas-fired generators have faced physical and/or commercial restrictions on their trading; and the range of variation in electricity generation required to fully match fluctuations in hydro generation has been a significant proportion of the total gas market. Unless the daily, weekly, monthly and annual quantity restrictions in gas supply contracts were to become so relaxed that they could be ignored, we consider that the opportunity costing of gas for electricity generation must remain a significant issue.

Those opportunity cost calculations may be relatively more complex than for hydro, because the opportunity cost of using gas now might be determined by the implied need to trade more or less gas on the market, purchase incremental gas from the supplier now or later, bring forward gas usage planned for a future day, week, month or year, or defer gas usage to a future day, week, month or year. Just as for hydro, though, the calculations must be continuously revised, as expectations change with respect to the future requirements for gas-fired generation, due to variations in load, hydro inflows,

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103 As above, the contract price for gas may align closely, on average over the long run, with traded prices, but that is because the traded price determines the contract price, not vice versa. Thus, one price may be substituted for the other, for the purposes of long-term studies. But it would be a mistake to use (historical) contract prices as a proxy for (forward looking) market prices, when determining the SRMC for gas generation on a time scale of moths or shorter.

104 Isolation is not complete, because gas can be indirectly exported as methanol, for example, and imports remain a long-term options. But the New Zealand situation is still very different from that in the US, for example.

105 That is of hourly quantities within a day, daily quantities within a week, weekly quantities within a month, or monthly quantities within a year.

or plant availability. And the calculations should really consider a wide range of possible future scenarios, looking forward.

In fact, the theoretically correct opportunity cost calculation may be so complex that it is not actually performed, explicitly, by the managers of gas-fired generators. But that is not the point. The point is that the implied SRMC of gas-fired generation must actually be changing whenever the manager adjusts output so as to avoid violating any kind of daily, weekly, monthly or annual quantity restriction, irrespective of how that manager may conceptualise, or rationalise, that decision.[106] In particular, if the manager (wrongly) thinks of the per quantity price in the contract as setting "SRMC" then he or she may think that what they are doing is adjusting offers to reflect something other than SRMC. But that is not actually the case. What is really happening is that the effective SRMC itself is varying, in accordance with daily, weekly, monthly and annual cycles. Since those variations are strongly linked with the dynamics of, and fluctuations within, the hydro sector, the SRMC of gas is also strongly linked to the SRMC of hydro, and vice versa, and both vary jointly, but not identically, in all of those time scales.

The above discussion suggests that gas-fired generation is significantly less flexible, and its SRMC correspondingly less obvious, than it is assumed to be in many studies and models of the New Zealand electricity system.[107] This in turn, means that greater flexibility must be found from other sources, and that further complicates the SRMC calculation, unless those sources themselves are fully flexible. Neither geothermal nor wind add any significant controllable flexibility to the system, and their SRMC might best be described, like that of run-of-river hydro, as indeterminate. Perhaps oil-fired generation, which is seldom used, might be considered flexible enough that a well-defined (if considerably uncertain) SRMC can be determined from the world traded price of the relevant grade of oil, adjusted for transport. Shortage costs may also be considered to provide a clear SRMC component, free of any opportunity cost considerations, although the level of that component is a matter of debate.

The situation faced by coal may be a little different from that of gas, though. In this case, there will be a genuine SRMC element in the calculation, if there are options to increase supplies at extra cost, and unrestricted by daily, weekly, monthly or annual limits. There may also be a genuine SRMC element if there are options to trade coal between electricity generation and alternative uses, either in New Zealand or

[106] Hourly restrictions are different, and can be properly accounted for in electricity market offers without any inter-temporal opportunity cost calculations.

[107] Including SPECTRA for example, where these restriction are ignored for algorithmic convenience.

overseas.[108] Historically, though, those options have been limited and, while we have not investigated current market conditions, we suspect that the bulk of the coal supplied to generation plant is still supplied from relatively inflexible sources, on contracts with significant take-or-pay elements. And we suspect that there will not be a sufficiently liquid market for the grade of coal used in electricity generation, or significant alternative users outside the electricity sector, with enough flexibility to absorb the wet/dry year swing. At least, we think it unlikely that the market will be so liquid that generators can assume no limits to their trading. So, a very similar opportunity costing logic applies to coal, too, particularly if there is a coal stockpile involved.

Again, we suspect that the opportunity cost calculations theoretically required here may not be performed, explicitly, by the managers of coal-fired generators. But, again, that is not the point. Conceptually, and analytically, the effective SRMC of coal-fired generation is changing whenever the manager adjusts output so as to avoid violating any kind of daily, weekly, monthly or annual quantity restriction, irrespective of how that manager may conceptualise, or rationalise, that decision. The manager may even think that they are adjusting offers to reflect something other than the "SRMC" implied by the per quantity price in the contract, but that is not actually the case. What is really happening is that the effective SRMC is varying, in accordance with daily, weekly, monthly and annual cycles. Once more those variations are strongly linked with the dynamics of, and fluctuations within, the hydro and gas sectors. So, the SRMC of coal is also strongly linked to the SRMC of hydro and gas, and all probably vary jointly, but not identically, in all of those time scales.

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[108] Unlike gas, (as at 2009) nearly half of New Zealand's coal is exported, suggesting that fluctuations in the requirements of coal-fired generators could possibly be accommodated by varying export quantities. This option is only relevant, though, to the extent that coal intended for these two uses is actually substitutable, in the time frame necessary to deal with variations in hydro availability. If coal is being diverted from export, the export coal would have to be an acceptable input, chemically and physically, for generation purposes, and the physical infrastructure would have to be in place to transport it from the export mine to the station. Export contracts would also have to be flexible enough to allow variation in quantity, or substitution of alternative coals, sourced internationally. Similarly, if coal is being diverted to export, it would have to be an acceptable input, chemically and physically, for its intended purpose in the export market, and the physical infrastructure would have to be in place to transport it from the mine supplying the station to the export port. But, while we have not investigated this market, we understand that much of New Zealand's coal exports consist of metallurgical coking coal, from mines in the South Island, whereas coal-fired generation capacity is situated inland, in the North Island. In any case, the opportunity cost of diverting metallurgical coking coal to be burned in power stations is likely to be very different from the SRMC of their normal fuel.

6.4 Locational Issues

While Section 76.2 talks about several generation stations in a river chain, and flow delays between them, it has nothing directly to do with locational issues. In fact, it assumes that generation from all stations in a chain is interchangeable, in the sense that it can be sold at the same price, in each period. Similarly, the discussion of SRMC/price interactions between hydro and gas/coal "reservoirs" implicitly assumes that "the market" exists at a single location, so that a single price applies to all capacity.

This is a reasonable approximation if there are no transmission limits between the locations involved, as will often be the case for stations in a single river chain, for example. But the NZEM is a locational market, and we should consider locational issues, too.

Basically, all of the logic above applies at each location, but the prices, and implied opportunity costs at those locations are not independent. Thus, the state of South Island hydro storage will still affect the assessment of SRMC for North Island hydro, and for North Island coal/gas stations, too. But the effect may be attenuated by marginal losses and/or transmission limits, on intervening lines. In the absence of losses, it can be shown that the MWV in similar reservoirs will often be exactly equal, in equivalent energy terms. But the presence of losses means that equality will only be maintained within an error bound given by +/- the marginal losses. Transmission limits may further limit the system/ market's ability to trade-off storage in one reservoir against that in the other, thus leading to a greater divergence in MWVs.

In a perfectly competitive market, the prices in various regions will be set by the opportunity cost-based SRMC of the generation capacity that can meet incremental loads in that region, in the period concerned. These prices will be equal across the system, +/- marginal losses, if no transmission limits apply, but may diverge more strongly when transmission limits apply. MWVs will also tend to diverge more strongly where transmission limits apply, but this effect will be significantly less extreme, because the MWV of a reservoir reflects the opportunity cost of being able to use water to meet load requirements at any time up until that storage is next expected to reach, or at least threaten, its bounds. Even if transmission is limiting, many of those opportunities may relate to future periods in which free trade will be possible, and that will tend to align MWVs through all earlier periods, back to the present. But, if MWVs are tending to diverge, due to surplus inflow in one region, say, one reservoir will tend to release at its maximum, and the other at its minimum, during periods when inter-regional trading is possible. In that case, the SRMC of hydro generation is no longer set by the MWV, and will be indeterminate.[109] The implication is that local prices are

[109] Theoretically, it will be +/-infinity, depending on the release bound involved.

not set by this hydro station, and may be much higher (if release is at its maximum), or much lower (if release is at its minimum).[110]

None of this really changes the conclusions reached above, though. While the transmission system may limit the strength of some interactions and linkages, in absolute terms, the complexity of those linkages, and the corresponding SRMC patterns, is increased. In the limit, MWVs may diverge significantly, as one region becomes increasingly isolated from the other, in terms of electricity market trading, on the margin. At other times, though they will be closely linked, as above. As noted earlier, then, opportunity costing means that each participant's SRMC, in any period, may change as a result of changes in variety of factors other than that participant's own supply position, in that period. But now the factors which might affect SRMC estimates in this way include (expected) changes in the status of transmission constraints. And, so long as a generation station is not marginal, its marginal production cost may consistently be above or below the nodal MCP there.

6.5 Risk Aversion

Finally, while the theory discussed in previous sections relates to uncertainty, and hence may be thought to imply some consideration of "risk", we have not actually considered "risk aversion" at all. It should be recognised that risk is a rather more significant issue in hydro dominated markets, than it is for typical electricity markets. We have noted that it may not be easy to provide risk averse investors with sufficient assurance that they will be able to obtain an adequate return for the risk involved, but risk aversion also plays a major role at the operational level. The impact of risk aversion on the management of energy-limited generation seems to have been almost entirely ignored in the international literature, but bears further examination.[111] It should be obvious that a contracted hydro generator can be expected to err on the side of caution, by setting water aside so as to be available to meet future contractual and/or retail commitments under a wide range of possible hydrological and/or market outcomes. Similarly, for an energy-limited coal or gas generator.

This is not wrong, and it is not new. Indeed, while public sector reservoir management was always based on a balanced sample of historical hydrological years, it was also biased in the direction of caution by adding "buffer zones", "safety factors" etc. Realistically, the general public expects a high degree of reliability in its electricity supply, which means that it will almost always be found, in retrospect, that "too much" water was retained early in the season, only to be released later when, on average, the

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[110] Actually, the same will often be true for reservoirs with differing storage/inflow/release characteristics, even without transmission limits. So long as a generation station is not marginal, its marginal production cost may consistently be above or below the nodal MCP there. As discussed earlier, this will often be the case for stations in a river chain, even when no transmission limits apply.

[111] One exception is: A L Kerr, E.G. Read and R.J. Kaye "Reservoir Management with Risk Aversion", *ORSNZ Proceedings* 1998, p167-176.

market supply situation will actually be less tight. This is optimal, and it occurs because there is considerable asymmetry between the costs and risks involved in under-supply, and those involved in over-supply.

The key point here is to note that this pattern of behaviour will involve setting a price on hydro (or coal/gas) generation that differs significantly from the SRMC that would be calculated by a centralised optimisation model that assumes risk neutrality.[112] Specifically, generators will typically be retaining supplies (with upward price pressure), prior to the winter season, only to release more later, when, on average, market prices may actually be lower. This may seem irrational, or perhaps manipulative, from a risk neutral perspective.[113] But the need to behave in this way is dictated by the desire, indeed the effective requirement, to operate cautiously. Risk aversion may also be expected to amplify the response to events that, in themselves, may not seem major, but that might be considered as indicators of an increased likelihood that more severe problems will arise in future periods.

6.6 Conclusions

The above discussion provides a reasonably comprehensive guide to the difficulties of determining SRMC in a hydro dominated market environment, with energy-limited thermal plant. In practice there are a great many "reservoirs" involved, operating over a wide variety of time scales. Effectively, coal and gas stocks form extra "reservoirs", and this further complicates the assessment of opportunity costs, and hence of "SRMC".

In principle, and to a large extent in practice, the SRMC of production from any one of these sources can not be determined independently from that of any other. But the theoretical linkages described above are not created by the market, and have nothing to do with "market power". A sufficiently detailed centralised optimisation model would account for them all endogenously, and internally compute SRMC "shadow prices" for all of these resources, jointly, in the course of determining its optimal dispatch solution. Those shadow prices may not be reported but, if examined, they are likely to exhibit quite complex patterns of variation, and connection, on daily, weekly, monthly and annual time scales. Most importantly, whether reported or not, these internally

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[112] That is for virtually all centralized optimization models of which we are aware.

[113] Consideration may usefully be given to whether profits could actually be increased, on average, by such a practice, but that is not our concern here. As noted above, participants withholding water early in the season may actually be forgoing a profit on the marginal unit withheld, when assessed at market prices. But this does not actually tell us whether such withholding increases or decreases overall profits, once price impacts are accounted for. In fact, profit maximising oligopolists generally appear to be forgoing profitable sales on marginal units, in order to push up the price received for the units actually sold.

calculated SRMC prices would determine and explain the dispatch solution produced by the centralised optimisation model.[114]

Theoretically, a perfectly competitive market should be able to perfectly account for all of these linkages, and reproduce all of these subtle SRMC interactions. In reality markets are not that perfect, and nor are the information sets or models available to market participants. So, they must account for many of these effects subjectively, using their best judgement, rather than through formal analysis. This makes it rather hard to say, objectively, what SRMC actually is, for any participant, in this kind of market situation. One would expect individual judgements to differ, for a great variety of reasons.

Broadly, though, opportunity costs will depend on future market prices, which depend on the offers expected to be made by other participants, which depend on the SRMCs assessed by those other participants which, in the case of hydro or energy-limited thermal, are also opportunity costs. Of course, these opportunity costs will be assessed, internally and privately, by competing generators. Thus, each participant must determine the MWV in their own reservoir(s)/stockpile(s), taking account not only of the probability distribution of their own inflows, or supply contract provisions, but also the assessments which they expect each of their competitors to make with respect to the opportunity costs of operating their own hydro/coal/gas resources, given their own private data and probability assessments. And each of those assessments is, itself, equally complex, and also dependent on each of those other parties' assessments of one's own situation.

The general effect is that changes in (perceptions about) the likely supply situation of any plant, whether energy-limited or not, must cause all energy-limited participants to re-assess their SRMCs, in ways which tend to reinforce one another. Thus, a developing dry year, or a major plant failure will, and should, immediately cause all hydro/gas/coal participants to raise their SRMC assessments. All of this means that SRMC values for hydro, and for energy-limited fuels, will regularly rise to quite high levels, possibly every autumn, in anticipation of a possible crisis, long before the period in which the crisis is predicted to (potentially) occur, and while storage is still relatively high. And they can be expected to remain at such levels, often for several months. Occasionally they will continue to rise until an actual shortage occurs. But most often they will just fall back to more normal levels because the looming crisis dissipates

[114] Once stochasticity is accounted for, the true complexity actually becomes too great for many optimisation models to handle. For example, although its PRISM predecessor once had a coal stockpiling module, SPECTRA does not model annual energy limits on either gas or coal. So, it can not capture the kinds of interaction described here, and must assume an exogenously determined SRMC for both fuels. This approximation is not correct, but it is required because the optimization methodology employed in that model can not readily be generalized to handle a larger number of "storage reservoirs". If managers employ such limited models, and take them as a guide to "SRMC", they will then need to "adjust" SRMC for opportunity cost effects, outside of the model, and perhaps iteratively adjust model inputs, to achieve an acceptable outcome. But that does not change the fact that it is really the SRMC itself that is changing, as above.

and/or is averted. Thus, in a hydro dominated power system, and particularly one with energy-limited thermal plant, a properly operating market can be expected to exhibit quite significant variations in average price from year to year, depending on hydrological conditions. And prolonged periods of elevated prices can routinely be expected, even in years which, in retrospect, turn out not to have been particularly dry.[115]

Since it is the change in expectations, rather than any change observed in the current period, that is supposed to drive MWV, the impact on behaviour can also be counter-intuitive. It might be thought, for example, that a tightening of the demand/supply balance causing prices to rise in the current period would always induce an increase in output, or at least no decrease. That would be the case for plant that is not energy-limited, and also in cases where a single, short, one-off, event, such as short generator outage or dry period, has no discernible impact on longer term MWVs, and thus on the SRMC supply curve. The situation may be radically different for energy limited plant, though, if such an event creates the expectation of an ongoing trend, or extended situation. As soon as the likelihood of an extended outage or drought becomes apparent, hydro and energy limited gas/coal generators should re-assess their opportunity costs, and raise offer prices, so as to reduce output, and conserve water/fuel to be used in later periods when the or drought may create an even tighter supply/demand balance. That is, their SRMC curves should rise to such an extent that their output actually <u>reduces</u>, even though the demand for output, and the prices obtainable, have <u>increased</u> in the market. This may occur over a period of months, for a prolonged outage or anticipated drought. Or it may occur over a period of hours, for relatively short outages, or load increases, for example. [116]

Finally, it might be thought that all of these correlations and connections between the effective SRMCs of energy-limited plant have something to do with "market power", or even "collusion". But, while, both market power and collusion could certainly arise in such an environment, this discussion of correlations and connections actually has nothing inherently to do with either. Nor is there anything particularly unusual about what is going on here. The revaluation of contracted gas, or stockpiled coal, due to a change in the expected availability or price of hydro power in the local electricity market is no different from the revaluation of those same resources due to a change in the expected availability or price of oil on world markets. And nor does it differ from the routine revaluation of shares, or of hotel rooms or airline seats due to changes in perceptions about likely supply or demand.

In all cases the opportunity cost, and hence the SRMC, do actually change, at least when these concepts are properly defined in economic, rather than accounting terms. And

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[115] Noting that New Zealand has relatively small reservoirs, which do not allow much storage carryover from year to year.

[116] See P Stewart, E.G. Read and R James: "Intertemporal Considerations for Supply Offer Development in Deregulated Electricity Markets" *IAEE Proceedings*, Zurich 2004

that re-assessment may imply an initial reduction in output as part of the optimal response to a developing crisis. This is merely an optimal reaction to changing expectations, such as would occur in a sufficiently sophisticated centralised optimisation, or in a perfectly competitive market. All that is different here is that the interactions are more obvious and more explicit, when considered in the context of a relatively small and inflexible system, and applied to commodities such as water, electricity, gas, and coal, for which liquid international markets may not be readily accessible from New Zealand, in the required time frame. In this context, many feedback loops which might normally be considered "open" in many analyses elsewhere, must be treated as "closed", implying a need for something more like a general equilibrium type analysis to calculate opportunity costs jointly, and simultaneously, rather than applying partial equilibrium analyses sequentially and/or independently.

To repeat, then, we are merely explaining the kind of price patterns, correlations and connections that would arise, internally, within any sufficiently detailed centralised optimisation, and arguing that exactly the same patterns, correlations and connections should be expected in a hypothetical perfectly competitive market. Real markets may not exhibit all of these patterns, correlations and connections quite so explicitly, and participants may not even be able to clearly articulate or analyse how all of these factors interact. But a market in which such patterns, correlations and connections were not evident should be judged to have fallen short of the ideal, perhaps significantly so, and that should be a matter of concern.

Real markets may also provide opportunities for the exercise, and perhaps abuse, of market power, and this may distort pricing patterns away from the perfectly competitive ideal discussed here. That is another matter, and not our concern here. We would say, though, that the complexity of the underlying situation does make it difficult to determine whether, and to what extent, market outcomes might actually have deviated from the perfectly competitive ideal, on average, or in any instance.

7 APPENDIX C: Market Performance and Entry Barriers

(prepared in association with Dr S Batstone)

7.1 Discussion[117]

We have argued that attempting to enforce SRMC pricing would be inappropriate in the NZEM context, and that makes assessment of deviations from SRMC of limited relevance. Instead, we suggest that the emphasis should be on whether the market is fulfilling its intended function which is, primarily, to provide appropriate long run signals, while facilitating short run coordination between alternative suppliers, and between them and consumers. Thus, we should really be asking:

- Does the PDC align with the LRMC of relevant plant?
- Are there any barriers to competitive entry by alternative suppliers which might allow prices to persist above LRMC?
- Are there problems in the contract market, and/or the wholesale/retail "contracting chain" which are leading to sub-optimal results, such as excessive risk for entrants, leading to increased risk of non-supply?

In principle, ignoring the possibility that incumbents may raise barriers to entry, it is actually very easy to determine whether NZEM prices are, or have been, "too high" in recent years:

- If entry has been excessive, and we now have "too much" capacity, then we might conclude that prices (or price expectations), if anything, have been too high over the period when that excessive entry was occurring. And we might expect to see market forces now pushing prices below LRMC level, as a result of excessive entry.
- If entry has been inadequate, and we now have "too little" capacity, then we might conclude that prices (or price expectations), if anything, have been too low over the period when that inadequate entry was occurring. And we might expect market forces perhaps now pushing prices above LRMC level, as a result of inadequate entry.

This simple test indicates the basic direction which investigations of market pricing should be directed, either to discover why prices have been too high, or why they have

[117] This section is basically the Appendix of Read [2009], with minor editing. The next section builds on this by providing some illustrative numerical assessments of capital recovery proportions, based on NZEM price and cost data.

been too low. Thus, it is pertinent to ask where the current NZEM PDC lies with respect to long term entry costs.

Read [2009], from which the above text was drawn, did not attempt any numerical analysis of these issues, a deficiency which will be remedied in the remainder of this appendix. Looking at Figure 7.1 below (Figure 14 of the EPR report) we see that 2009 was actually the peak year, in terms of both market prices and estimated LRMC for new plant. Since then, both have trended down, more or less in synch, over a period where load growth has also fallen drastically.

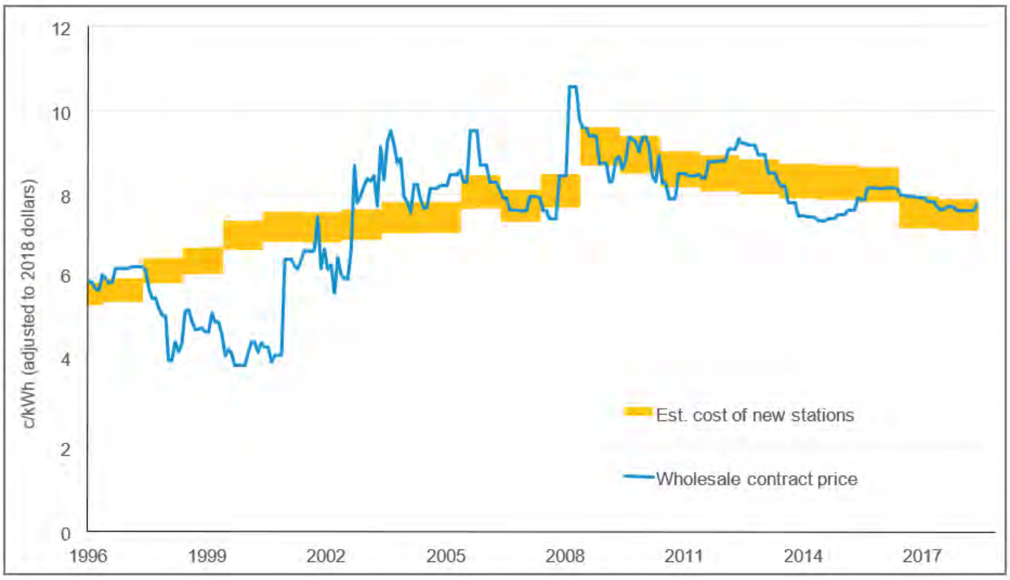

Figure 7.1 Wholesale contract prices versus cost of building new power stations[118]

Arguably, Figure 7.1 suggests that the conditions observed back then, which so alarmed some commentators at the time, really were just a case of "temporary overshoot", of the type discussed in our report at that time. Thus, the historical discussion provides an interesting illustration of the way in which perceptions may change over time, and of the way in which, despite the inevitable "noise" induced by hydrological variations, the market has adapted in a relatively robust and timely fashion to those changing perceptions.

Our 2009 report stated that:

[118] Original *Source: Concept Consulting analysis.*
Prices and costs are adjusted for inflation and expressed in 2018 dollars.

We note that entry has been occurring over recent years, which suggests that the PDC should be matching FC for at least some plant types. There are three complications to consider, though.

- *First, there are other reasons why investment might have been too low, if it has. For example, the new SOEs formed by the breakup of ECNZ, had a limited set of feasible development options and the lead times to develop options have extended significantly. Also, there has been a significant learning curve with respect to technologies like wind generation over that period. So, investment could lag market demand, for those reasons.*

- *Second, a rational investor, or central planner, should be asking what the PDC looks like over the whole range of hydrological conditions, not just what the PDC has looked like over the very small sample of hydrological conditions that actually occurred in the past few years. One does not, or should not, build new capacity in response to high prices driven by dry year conditions, but in response to a shift in the underlying probability distribution from which that price sample was drawn. Thus, it is quite possible to observe (temporary) high prices and (underlying) excess capacity in the same year, in a perfectly competitive or centrally planned system. The study by Tipping et al [2004/2010]* suggests *that the NZEM seemed to have experienced a higher than average number of dry years* (in its early years)*, with correspondingly higher prices. This can be expected to have raised public awareness, and concern, to levels which are probably not justified by the underlying supply/demand balance.*

- *Third, it is the expectation of future prices that should drive investment, and that expectation may turn out to be significantly in error, if the market experiences some kind of shock. In this case, the NZEM has recently experienced a series of shocks, all in the same direction. Apart from the ongoing impact of local "environmental" resistance to developments, the system has seen an unexpected reduction in gas availability, rising world fuel prices, the sudden imposition of policy driven restrictions on capacity investment, and possibly inflow reductions due to climate change. These will all have raised expected LRMC levels, and we should expect to see prices rising now, reflecting an upward shift in the (expected) long run equilibrium PDC, with a higher probability of shortfall, to account for these factors.*

  Further, because these changes were not expected, we should expect to see price overshoot, with prices lying above even the new (higher) LRMC levels for a few years while the market adjusts to the new situation. Basically, if the market was (thought to be) in long run equilibrium prior to these effects becoming evident, we should now expect to see the market out of equilibrium, and experiencing *relative shortage.*[119] *Conversely, if the market now appears to be in equilibrium, and if the PDC is not now lying above the new LRMC levels, we should really be concerned to explain why there was excess capacity investment, relative to expectations, in prior years."*

Leaving aside the weight of public opinion and political concern, we are not trying to express any opinion here as to whether there actually is "too much", or "too little" capacity in the NZEM, or whether prices have been "too high", or "too low". But, if there is, a regulatory response might be envisaged:

- *In the first case, regulatory intervention may be justified to place downward pressure on prices, perhaps by tightening offer rules if, but probably only if, it can be shown that this is not just a temporary situation resulting from a "shock", but a long-term structural problem, presumably arising out of a lack of competition in the market for entry.*

- *In the second case, regulatory intervention may be justified to place upward pressure on prices, perhaps by adding capacity payments or loosening offer rules if, but probably only if, it can be shown that this is not just a temporary situation resulting from a "shock", but a long-term structural problem, arising perhaps out of fear of a political intervention in response to higher prices.*

These are not the only possible conclusions, though. While this market design perspective does suggest a lesser degree of concern about deviations from SRMC pricing, it does suggest that the market for entry may be a legitimate focus for concern. At the national level, we are concerned, primarily, about whether entry into the generation market is competitive, or whether incumbents might raise barriers to competitive entry:

- *One possible way of deterring entry would be for incumbents to refuse to provide necessary supporting "ancillary services", but the NZEM market design makes this quite difficult.*

- *Another obvious strategy would be for incumbents to block access to desirable development sites, or resources, and this possibility may be worthy of examination in the NZEM context. This would not produce a PDC which was "too high" relative to actual entry costs, but would imply that entry costs, and hence the PDC, were too high.*

- *But there is another, less obvious, way in which incumbents might raise barriers to entry. A central concern in the literature about "entry deterrence" is that incumbents could deter entry by building too much plant, then pricing high, but*

[119] *The issue here is not whether any of the factors have really changed, but whether market analysts today employ more, or less, optimistic cost/availability assumptions than they did a few years ago, when performing their FC/OV comparisons.*

> *threatening to price low for long enough to drive out any competitor which might be tempted to enter.*

This hypothesis was advanced in an early NZIER study of NZEM design issues,[120] *but its relevance to current conditions is debateable. If the strategy were being played effectively, it seems possible that there could be too much capacity, and prices which are also too high, on a sustained basis. Or, if the strategy failed, and did not actually deter entry, we could see entry followed by a period in which there could be too much capacity, but with prices which are too low to sustain further entry, possibly falling to SRMC levels.*

Again, we come back to the very basic question, though: "Is there too much capacity in the NZEM?" If not, it seems unlikely that this entry deterrence game is being played. And, if the entry market is deemed to be reasonably competitive, we must then ask whether market power is really a major problem in the NZEM, given its design goals.

But this discussion has been focussed on entry to the generation market, at the national level. All of these issues become more critical at a regional level, and for retail markets. At that level, entry may require being able to:

- *Build generation capacity in the right place, and/or*
- *Gain physical access to generation elsewhere via transmission system enhancement, and/or*
- *Gain commercial access via some form of transmission capacity right.*

The first will obviously be difficult, in many instances, while the last is not possible under current market arrangements (i.e. in 2009*), and opinions vary with respect to the effectiveness of current transmission planning processes. Thus, barriers to competitive entry into regional retail markets could possibly be a legitimate focus of concern. Still, while many of those barriers may create an environment in which the exercise, and potential abuse, of market power is more likely, most are not likely to have been created by market power, or for the purpose of enhancing market power. Nor does the existence of potential barriers prove that market power exists, or has been abused.*

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[120] *See SJ Gale & AE Bollard "A Theoretical Approach To Electricity Generation Restructuring" NZIER Report to the Officials Working Group, July 1990*

7.2 Analysis[121]

7.2.1 Introduction

The discussion above suggests that the broad health of the market, in terms of supply/demand balance and price/ entry equilibrium can actually be assessed very easily, without recourse to detailed simulations or complex gaming models. Or, At least, such high-level analyses can be used to put the results of such detailed modelling into a proper perspective.

If the high-level analysis suggests that the market is not performing well, then more detailed studies can help to identify more exactly what is going wrong, and perhaps how to fix it. But if the high-level analysis suggests that the market is performing well, then negative results from more detailed studies need to be understood and interpreted in that light. If the outcomes seem good, even though detailed modelling indicates that "something is going wrong", we may need to ask whether the detailed problems identified are actually as real or material as they may seem.

At first glance, Figure 7.1 actually suggests that the market is performing very well, in terms of aligning prices with LRMC, but two cautions need to be considered:

- First, we need to distinguish between the possibility that "gaming", for example, is increasing long term profits at the expense of consumers, and the possibility that it might be increasing costs. While the first concern might be dismissed by simply assessing whether market participants seem to be receiving excess profits, the second might increase costs to consumers without increasing profits at all. And that should arguably be of more serious concern to society. Thus, the concerns raised by Philpott and Guan [2018][122] deserve serious consideration, but they can not be addressed by the simplistic analytical approach pursued here.[123]

- Second, though, Figure 7.1 has been prepared using base load contract prices and base load LRMC estimates. Although other analyses in that paper highlight how the costs of meeting different load profiles differ, it does not directly

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[121] The analysis reported in this section has been prepared with the assistance of Dr Stephen Batstone, whose input is gratefully acknowledged.

[122] A. Philpott and Z. Guan *Fine Tuning Frank: Electricity Market Benchmarking Experiments* Presented to EPOC Winter Workshop, August 2018 http://www.epoc.org.nz/ww2017.html

[123] Briefly, Philpott and Guan suggests that significant inefficiencies are occurring because the market is managing reservoir storage differently from the way their optimisation model suggests to be optimal. And other studies suggest a similar imbalance: Specifically, that South Island reservoirs are being managed more conservatively than might seem optimal. That obviously raises the question of how conservative reservoir management should be, and what priority should be placed on keeping the lights on in the South, under dry conditions. But that debate can not be resolved here.

address the key issue of incentives for investment in peak/support plant. So, we have undertaken a preliminary analysis of that issue here.

7.2.2 NZEM Entry Data

We can look at the entry cost/price equilibrium issue in two ways:

- We can determine the actual PDC from market data, and then ask whether it is structured in a way that looks like it is being disciplined by ongoing entry by the plant types required to support the LDC of consumer demand requirements.

- Or we can construct the optimal PDC from entry cost data, and then ask how well the actual PDC matches that optimal PDC.

The key input required for both analyses is the entry cost data for a realistic range of plant types. Traditionally, this kind of analysis has been performed using a range of thermal plant types, including coal, entry of which seems unlikely in the current policy environment.

Theoretically, that does not stop us performing a traditional analysis to determine whether entry would be economic, if it were permissible. But the significance of that analysis seems moot, if it computes a signal to which no plant can actually respond. Conversely, if there is no plant able to enter at, say, SRMC(x), there is no market discipline acting to keep its option value, OV(x), equal to its fixed cost, FC(x), and so no reason to expect that relationship to hold in future market PDCs[124].

Also, while this PDC-based analysis can be generalised to assess the viability of hydro developments, each such development contributes a different mix of energy capture, peak capacity, and storage, making it difficult to determine a generic impact of hydro in terms of shaping the PDC. Recent experience suggests that further development of hydro capacity will face very stiff opposition from environmental groups in New Zealand, and may even be offset by reductions in the effective capability of existing plant. So that possibility will be ignored here. The prospect of new generation development, and of demand side response, will continue to shape future PDCs, though, in the sense that equilibrium implies a requirement for the cumulative PDC above their SRMC to match their fixed costs. So:

- The CCGT entry cost still seems relevant, at least for historical comparisons, as does gas-fired OCGT entry. In fact, we understand that significant gas-fired capacity has already been granted consent to enter the NZEM, and such entry

[124] Here we continue to use the abbreviations of Section 2.2. We refer the reader to that section for definitions. But recall that OV(x) is determined by the difference between the sum of prices in hours above its own SRMC and the per unit cost of running plant x, for that number of hours at SRMC(x).

may be accepted as a necessary support to support the pursuit of increased reliance on renewables, by electrification of sectors such as transportation.

- The entry cost of liquid fuelled OCGT (referred to as Diesel below) is arguably relevant for the future, too, as an extreme dry year backup option. Studies elsewhere suggest that it may be very difficult to maintain reliable supply in an insular hydro-based system without such backup. Arguably, too, an OCGT that is (almost) never used is (almost) as renewable as any technology, and the overall environmental impact largely depends on other factors, including the impact of its physical presence, and manufacturing processes.

- Above that, "shortage" is still a relevant option, even though the actual fixed and variable costs for that option are always a matter of debate.

- But, as thermal generation options are withdrawn, other forms of demand response are likely to become increasingly important, as a routine feature of market operations, across the price spectrum.

- Wind is far from a conventional "reliable" base-load plant, but its impact in terms of disciplining the PDC shape will effectively be that of base-load plant, unless its output pattern is correlated with the PDC.[125] But note that the PDC under discussion here should really be interpreted as a probability distribution over all seasons and hydrology years. So, the seasonal pattern of wind contributions, and any correlation between wind and hydro contributions will have an impact. Accordingly, we suggest that some adjustments may need to be made when using wind entry cost data in this highly simplified context.

- Solar differs from wind, in that its contribution is strongly correlated with the LDC and hence PDC. Thus, while its viability could be assessed in a similar way, its potential contribution to shaping the PDC has been ignored in this preliminary analysis.

- Geothermal is a still a major contender for competitive entry in the New Zealand context. Since geothermal is the simplest base-load option for analytical purposes, we will use this as our base-load entry option in this initial analysis. Because entry opportunities are locationally specific, care is required to account for the impact of locational price differentials and transmission pricing on entry economics. But that is true, to some extent, for all technologies in this kind of broad-brush national analysis.

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[125] In New Zealand, energy contributions from wind do not seem strongly correlated with the LDC. But we understand there is some evidence suggesting a drop-off in wind contribution at the very top of the LDC, and hence probably of the PDC. We also understand that market prices tend to fall when wind generation is high. Both effects would reduce the commercial viability and economic contribution of wind power, but will be ignored here.

Accepting the caveats above, and ignoring the possibility of demand response at prices below that of a Diesel fuelled OCGT, the indicative data in Table 7.1 has been provided by the participants to this study, for the purposes of this very approximate preliminary assessment. Note that shortage costs are notoriously difficult to estimate, and depend strongly on factors such as the duration and depth of the shortage, and the amount of notice given. So, the value displayed here is only indicative of a range of values to be discussed later.[126]

PLANT TYPES	Shortage	Diesel OCGT	Gas OCGT	CCGT	Geothermal
Fixed ($/MWy)	$ -	$ 128,500	$ 138,500	$ 184,000	$ 556,000
Variable ($/MWH)	$ 1,648.00	$ 308.00	$ 67.00	$ 53.00	$ 7.00
Reliability (%)	100.00%	95.00%	95.00%	94.00%	95.00%

Table 7.1 Indicative Entry Cost Data

A critical issue here is the WACC to be used in assessing the FC component of entry costs. As a base level the above estimates use 8%. But as discussed in Section 2.4, investors in peak/support capacity, such as OCGT plant, are likely to require a higher rate of return to compensate for their income stream being much more volatile, and almost certainly riskier. So, following Read et al [2007], an alternative set of results is presented below using a "utilisation risk premium" of 50%. This implies a risk-adjusted return requirement ranging from 8% for base-load plant up to 12%, for extreme peaking plant with a utilisation factor close to 0%.[127]

7.2.3 Actual PDC and Cost Recovery

First, we should compare the cost recovery requirements specified above with actual results from the NZEM. In doing so, we emphasise several caveats:

- First, the entry cost data from the previous section, which will be used again here, should be treated as only indicative. As discussed in Section 6.3, for example, the true SRMC of gas-fired plant may vary quite considerably, and in complex ways, depending on upstream constraints, the availability of spot gas, the drawdown of contracts, and other factors such as the value of any associated condensate.

[126] The shortage cost has been set to a rather low value for technical reasons, but can be ignored for the purposes of the present discussion. (The illustrative value of 1648 is et so that, with this data, the probability of shortage sits at exactly 1%). The effect of the reliability estimate is just to scale the effective fixed cost component up. In this simplistic analysis, the "geothermal" entry represents base-load renewable capacity whose output is not correlated with the LDC, and hence can expect to receive a "base-load" price. Geothermal has been used in this illustrative analysis, because it is the simplest example to analyse.

[127] This adjustment allows us to explore the implications of relying on merchant investment in peaking plant. In reality such investment may always be undercut by vertically and/or horizontally integrated portfolio players, who may be prepared to accept rates closer to their portfolio norm.

- Second, all of this discussion relates primarily to potential independent generators, entering on a "stand-alone" basis. It takes no account of contract commitments, retailer obligations, or the EA's requirement to compensate customers when shortage is threatened.

- Third, real life complications will reduce participant's ability to actually capture all the potential benefits implied by the OV calculation. In about 1% of periods the analysis is implicitly assuming that a CCGT could switch on and off just to grab a single trading period of positive margin, despite there being mostly low prices either side. This seems unlikely, especially after accounting for startup costs. We have, somewhat crudely, accounted for this effect by reducing the availability of CCGT by a further 1% in the calculation of OV, and have used an average heat rate (supplied by the participants based on actual data) in the calculation of the SRMC.

- Fourth, we are assuming that participants can accurately predict the periods for which generation would be profitable

- Finally, we assume no correlation between price and plant unavailability whereas, in reality, high prices will often be triggered by unit breakdowns.

Accordingly, Figure 7.2 effectively shows an upper bound on the OV available for to each of several plant types, differentiated by their assumed SRMC.

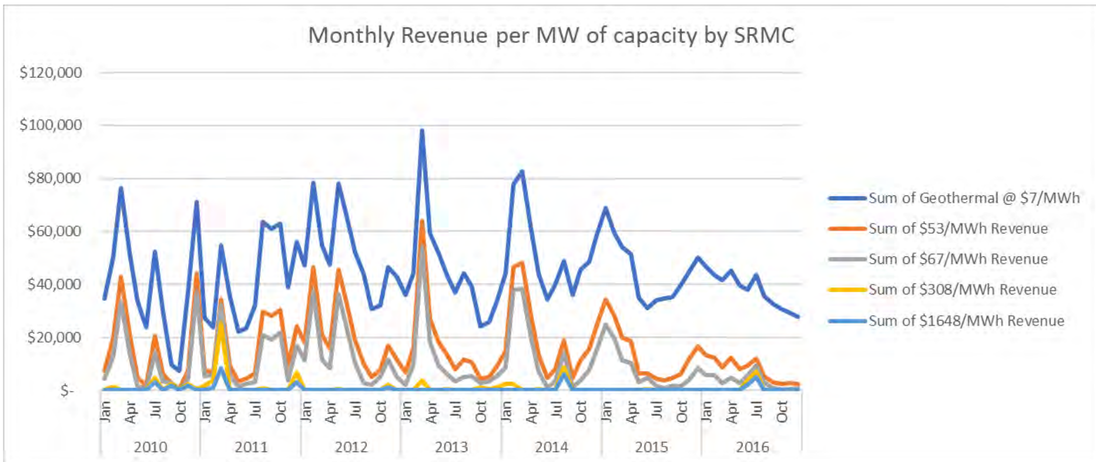

Figure 7.2: Spot Revenue Contours for Differing SRMCs

Then, Figure 7.3 sums these values and compares them with the standing costs for the respective technologies, as discussed in the previous section. Basically, this analysis expands on that in the EPR report, to paint a picture of an electricity market exhibiting perhaps surprisingly good alignment with the theory outlined in Chapter 2.

No thermal plant type seems to be quite recovering its costs, but that is not surprising, in a market where LRMC is declining, with only limited entry occurring. The caveats above suggest that the degree of under-recovery is probably rather greater than that shown here. Ignoring that possibility, though, most plant types seem to be very nearly recovering costs, and that could be taken to indicate that the threat of competitive CCGT/OCGT entry was still disciplining the PDC effectively in this 2010-16 period[128].

Removing potential entrant technologies must (other things being equal) increase sector costs, and raise the equilibrium PDC. So, we would expect to see upward pressure on prices across the mid-range of the PDC in future, even in a perfectly competitive market. We see no such reliable trend in this period, though.

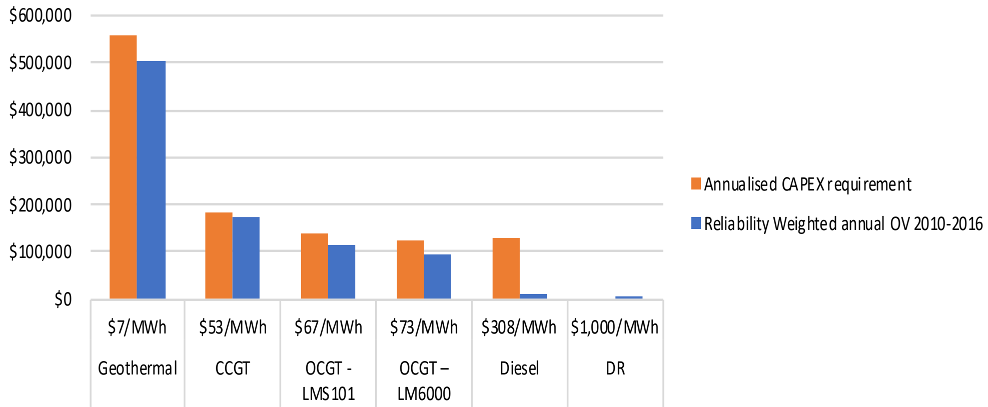

Figure 7.3: CAPEX vs Operating Profit

Nor do we see evidence of anything likely to be characterised as "overcharging", in any other sector. It may be that thermal plant, in particular, are pricing their offers up in ways designed to recover as much of their LRMC cost as they can. And it would surely be astonishing if any other business, in any other sector, did not take some advantage of such opportunities as they arise.

Some years ago, the Electricity Technical Advisory Group (ETAG) wrote that "*Using the LRMC benchmark, there is no clear evidence of the sustained or long term exercise of market power* [in the NZEM]".[129] We might phrase that slightly differently, because we expect that under-contracted generator participants must often have both incentives and opportunity to make offers above SRMC. We also expect that over- contracted generator participants will have both incentives and opportunity to offer below SRMC. And both practices may be characterised as <u>exercise</u> of market power, <u>in the spot market.</u>

We find it hard to see how that unilateral exercise of market power could be characterised as abuse though. As discussed elsewhere we would have thought that it was normal business practice, and also probably necessary to make the current market

[128] Although competition with coal fired generation, which has been ignored here because it is not an expansion option, was a factor in this period, too.

[129] *Improving Electricity Market Performance Volume One: Discussion paper* A preliminary report to the Ministerial Review of Electricity Market Performance by the Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009 (p40)

design work with a socially acceptable degree of price volatility, and at commercial rates of return that deliver acceptable costs to consumers on average, over the long term. The relative merits of alternative market designs are discussed in another appendix, but the evidence considered here seems entirely consistent with the ETAG conclusion, if we interpret it as applying to the exercise of market power <u>in the market for generator entry and/or long-term contracts</u>. Thus, we see no evidence, emerging from this LRMC driven analysis, of the sustained or long-term exercise of market power in that entry market.

Nor do we see evidence of market power being abused in the spot market to produce price spikes that are higher or longer than they need to be, if the criterion is a requirement to sustain an optimal plant mix, with an acceptably low probability of shortage. The evidence we would cite is the situation faced by the diesel fired OCGT at Whirinaki, which seldom runs and would seem to be only recovering about 1/10th of its entry cost. This is broadly consistent with the analysis above, which suggests that, so long as spot gas is freely available at a modest price in dry years, this kind of liquid fuelled development would not form part of the optimal plant mix. So perhaps it is not surprising that this station was not constructed in response to market signals.

The degree of under-recovery here is much greater than even that analysis would suggest, though. As discussed above, the ongoing availability of well-priced flexible gas for occasional use seems uncertain, and gas fired options may not be available at all in future. So, liquid fuelled OCGTs may well need to play a greater role in future, and supporting such entry may become a significant issue. Based on this evidence, though, market prices would have to spike to much higher levels and/or for much longer, in order to support such entry.

This observation does needs to be interpreted with considerable care, though. Perhaps the market environment is not encouraging offer behaviour to be aggressive enough when the supply/demand balance is tight. In which case, action may be required to refine the market design in order to provide the backup required in future. But other explanations seem plausible, at this stage:

- Perhaps other features of the market arrangements, including the impact of any potential dry year compensation in a vertically integrated industry means that a station of this type can deliver value to participants by means other than spot market sales.
- Perhaps, despite the concerns of some critics, capacity really has been in excess supply over this period, although we note that during the study period, two gas plants were fully decommissioned, and half of Huntly's Rankine capacity was retired. But overcapacity is perhaps unsurprising, given the lack of load growth, and would be expected to correct itself as new capacity is required to meeting increasing demands, e.g from electrification of transport.
- Or it could just be that we have yet to see the "super-dry" conditions under which this capacity will eventually pay for itself, both physically and commercially.

Still, taken at face value, this evidence tends to reinforce the concerns we have expressed elsewhere, that the potential for over-charging during times when prices spike above the SRMC of liquid-fuelled OCGT capacity is really not the biggest potential problem with the New Zealand market. If anything, the evidence suggests the reverse, that more extreme spot market price patterns will be needed to support the backup capacity required by a market increasingly dependent on renewables. Or that other market mechanisms may be needed if that kind of pricing pattern proves to be socially and/or politically unacceptable.

7.2.4 Peaker Support Recovery Requirements

Actually, the cost recovery requirements for peaker support can be deduced directly from the peaker entry cost in the table.[130] Table 4.2 below calculates the levels to which prices would have to spike in order to justify the capital cost of the last MW of OCGT peaker capacity required to limit the number of hours of shortage to the values shown.[131] The first row corresponds roughly to the standard applied in setting price caps for the Australian market. If we imagine market prices spiking to these levels for 4 hours every year, then the last peaker MW would just cover its annual fixed cost of around $130,000/MW over those 4 hours, and require no further revenue for the rest of the year.[132]

The critical thing to note here is that all other MW available during those 4 hours would receive the same revenue, and the mathematical relationships imply that they if they do not get that revenue they will not meet their fixed cost recovery requirements for the year, in a strict SRMC market. Thus, the CCGT, for example, would also receive around $130,000/MW over those 4 hours, making a slightly greater profit than the OCGT because its SRMC is lower, and then need to make up the remaining $56,000 or so, over the rest of the year.

annual hours	percent of time	VoLL ($/MWh)	hours every 20 years
4	0.046%	**$ 34,124**	80
8	0.091%	**$ 17,216**	160
16	0.183%	**$ 8,762**	320
32	0.365%	**$ 4,535**	640
64	0.730%	**$ 2,421**	1280
87.6	0.999%	**$ 1,852**	1752

Table 7.2 VoLL Requirements for Peaker Cost Recovery

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[130] This table has been prepared using the Diesel OCGT data, but the gas OCGT gives very similar values for the last MW. In both cases, this last MW is only utilised for the target number of hours shown, making the annual fuel cost almost irrelevant.

[131] The formula here is just: *VoLL(target) = SRMC(peak) + FC(peak)/((Availability(peak)*target)*

[132] Note that this is for the last MW. The station may well run at less than full capacity during other hours of the year. But, in a strict SRMC market, it will not make any profit from doing so, because the MCP would be set to its own SRMC during those hours. The only hours that contribute any profit are the 4 hours for which the full capacity is utilised.

If the same shortage probability standard was applied in New Zealand, though, it might (very simplistically) occur as a pattern of 80 hours over a few weeks in the middle of a very dry winter, once every 20 years. In that case the last MW of peaker capacity should theoretically receive no return at all until those events occurred, then collect around \$2.6m per MW in the 20th year. Importantly, all other capacity in the system would receive this same revenue flow component, in this pure SRMC market: being significantly short for "19" years, then receiving 20 years' worth of this shortfall in one year.

Reality will obviously be more random than this. Cost recovery would probably be spread over more years and, given the amount of notice that might apply to a developing hydro crisis, New Zealand might well feel that a lower VoLL could be applied. If so, though, it would still need to be spread over enough hours to support the last MW of peaker capacity. So, by construction, the net effect, in terms of industry cost recovery patterns, could be much the same.

7.2.5 Peak Period Cost Recovery Proportions by Technology Type

Perhaps surprisingly, the data in Table 7.1 can be used to infer what proportion of its fixed cost recovery requirement each MW of capacity available at the time the extreme peaker is running at full capacity should theoretically receive during those hours.

- Clearly the extreme peaker itself, whether gas or Diesel fired, must recover 100% of its costs when prices are above its SRMC.
- And, since the same revenue component is common to all MW capacity available at the time the extreme peaker is running at full capacity, each other MW will only need to recover its residual fixed cost over the rest of the year. [133]
- So, the proportion of its fixed cost which technology x recovers during the time the extreme peaker is running at full capacity must be close to FC(peaker)/FC(x).
- Those proportions work out to be 75% for the CCGT and 25% for geothermal, if the extreme peaker is gas-fired, as implied by this data.

The proportion of aggregate generator fixed cost recovered during the time the extreme peaker is running at full capacity must then be a capacity weighted average of these individual cost recovery proportions. So, it must be something greater than the minimum proportion calculated here, which is 25%.

A base-load generator with an SRMC of zero would only have fixed costs, while an extreme peaker running for only a few hours a year is actually in a very similar position. Intermediate plant types also have significant annual fuel costs, which are at least covered by SRMC pricing over the hours they run, so this contributes to capital cost recovery. But the total cost to be recovered, for each MW of capacity installed, falls

[133] Ignoring the SRMC running cost differential, which is a relatively small component, for the small number of hours involved.

monotonically as we move from base to peaking plant. So, the proportion of cost recovery occurring over the peaker running period increases monotonically, implying values greater than that for base-load (25% on this data).[134]

That estimate aligns well with estimates we have seen previously, all the way back to the original WEMS market design process. It also aligns well with results from the more sophisticated analysis discussed below.

7.2.6 The Optimal PDC and Base-Load Cost Recovery

A more sophisticated approach would be to try to estimate what the optimal equilibrium PDC might actually be, and what cost recovery might be expected from it. As discussed in Section 2.4, the entire optimal PDC, and plant mix, can also be inferred from the technology parameters in Table 4.1 alone, irrespective of the LDC. This determines the range of utilisation factors over which each technology would be the least cost way of meeting incremental load. Applying this approach to the thermal data alone produces a simple PDC consisting of one step for each thermal SRMC, representing the way in which an optimal mix of these technologies would be used to meet any LDC, or net LDC after accounting for the contributions of renewables, or whatever.

Section 2.4 develops the following formula for U(x) the utilisation factor below which plant x should be fully loaded, and plant with higher SRMCs should be running too, and setting the MCP.

$$U(x) = (FC(x+1)-FC(x))/(SRMC(x)-SRMC(x+1))$$

As noted there, this relationship, which defines the optimal PDC, is actually independent of the LDC. Thus, while entry will keep occurring if the LDC grows over time, or to replace retiring plant, the equilibrium PDC itself should only change in response to changes in the fixed or variable costs of the potential entry technologies. So, when we talk about SRMC/LRMC alignment, we are really talking about the alignment between the observed PDC in any year, and the optimal PDC determined by the entry costs that were expected in that year.

Some years ago, a prototype spreadsheet tool was developed to perform this kind of analysis, in order to explore and illustrate the theory advanced by Read et al [2007]. Effectively, the tool just performs the simple algebra described in Section 2.4 to determine the range of utilisation factors over which each technology would be the least cost way of meeting loads, that is U(x+1)-U(x) in the terminology of Section .2.4. The tool computes these “Optimised LDC Classes”, and various implications of that breakdown are then calculated and displayed graphically. This prototype uses a

[134] The last MW installed, for each plant type, has a lower total cost to cover than the first and, in equilibrium, the cost to be recovered on the last MW of capacity type x equals the cost to be recovered on the first MW of the next (higher SRMC) plant type in the merit order, x+1.

relatively coarse discretisation of the LDC into 1% steps, though, and only allows for a limited range of technology types.

According to that tool, Diesel OCGT capacity of the type appearing in Table 1, should actually not appear in the optimal plant mix at all. Examining the analysis, we see that this occurs because, it is really not much cheaper to build than gas-fired OCGT capacity, and significantly more expensive to run. So, at these relatively low shortage cost levels, shortage becomes preferable once Gas fired OCGT capacity is exhausted.[135]

In our view. the trade-off between gas and diesel fired OCGT capacity is less clear than it may appear. A critical factor that is often overlooked in this kind of analysis is the need to compare plant, like for like, and MW for MW, when playing exactly the same role, or at least having exactly the same utilisation factor. But this simplified analysis assumes that fuels are freely available, at the SRMC price quoted, right across the range of utilisation factors determined for each plant type.

In this case, the utilisation factor below which gas-fired OCGT capacity becomes more economic than gas-fired CCGT capacity is around 45%, and it seems quite plausible that such plant would be able to buy reasonably priced gas, as required. But the utilisation factor above which shortage is preferable to gas-fired OCGT capacity is only 1%, so that is the utilisation factor expected by the "last MW" of OCGT entry. Such infrequently used capacity might really need to be pay a significant premium to buy large quantities of flexible "dry year gas", as required, potentially making its SRMC much closer to that of a liquid fuelled OCGT. Alternatively, the cost of some kind of flexible gas option contract might need to be added to its capital cost, making the comparison with liquid fuelled OCGT capacity look quite different.

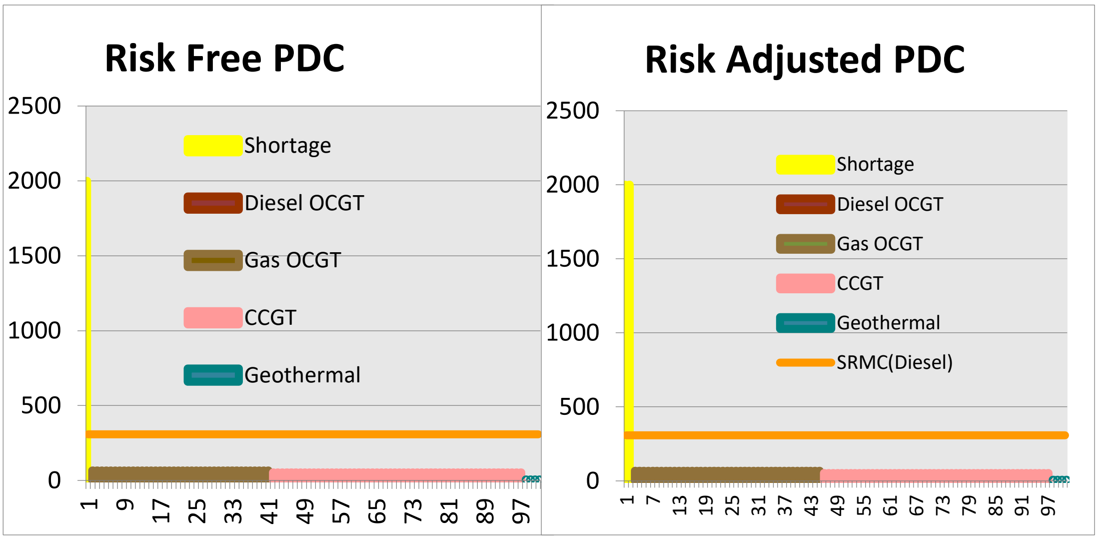

Figure 7.4: Risk Neutral and Risk Adjusted PDCs

135 The diesel SRMC is shown, though, as a reference point.

The two PDC's shown here were formed using the data in Table 4.1, but with the shortage cost set a little higher, at VoLL = $2000. In the risk neutral case, shortage actually occurs in 1% of time periods, and in 2% of time periods when a 50% risk premium is applied to investment in extreme peaking capacity. That aligns with the theory put forward in Section 2.6, but suggests that the VoLL value is really too low. The values derived in Table 4.2 may be considered more realistic, but notice that the lowest of those values implies a shortfall probability of 1%, which is the discretisation level used in his prototype tool. Thus, VoLL has been chosen here largely for illustrative purposes.

Theoretically, we can compute the proportion of time a base-load plant would be recovering its costs at each PDC price level, directly from these PDCs, irrespective of the LDC. Figure 7.5 displays this, for the two PDCs above, suggesting that 26% of a base-load generator's revenue would be recovered during times of shortage, rising to 41% if peak capacity investors are risk averse. This large jump reflects the 1% discretisation interval referred to above, but the direction of change is valid. Other experiments show that increasing the capital cost of the gas-fired plant brings the Diesel OCGT into the mix, and that actually reduces the proportion of costs recovered in shortage periods. But it increases the total collected at prices of SRMC(diesel) or above.[136]

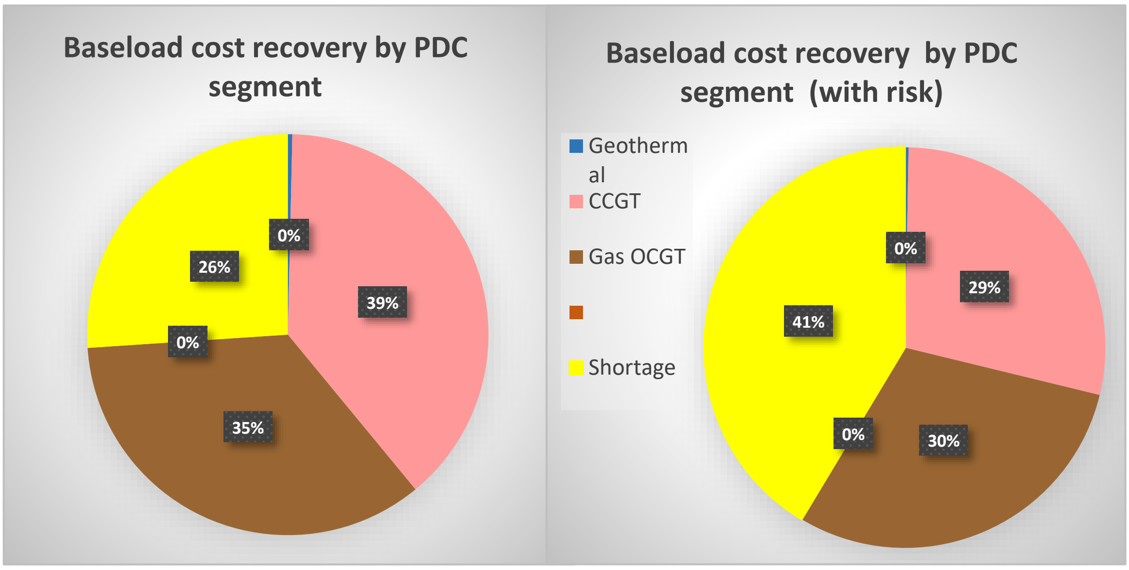

Figure 7.5 Risk Neutral and Risk Adjusted Baseload Cost Recovery

Ideally, we should be using a much finer discretisation, and experimenting with much higher VoLL values, but the point of this discussion is really just to illustrate the kind of analysis that can be done using very simple data. It is worth noting, though, that the

136 There is also a small proportion of cost recovery shown here in periods when geothermal is on the margin: That is because our base-load generator s assumed to have an SRMC of zero marginal cost, whereas Geothermal, in this dataset, has a positive SRMC

cost recovery from shortage periods here is quite compatible with the 25% minimum estimate derived above.

There is another issue here, though. These PDC and pie charts do not depend on the LDC, so they will always come out the same, no matter what LDC we might want to determine an optimal thermal plant mix for. In particular, we get these same results when using this data with the residual LDC for the NZEM, after subtracting the hydro generation. And we believe that would be valid if hydro was, like wind or geothermal, a largely passive contributor to meting loads in each period, as implicitly assumed when forming a hydro "Generation Duration Curve" (GDC) as is done below.

NZEM prices would not really change this abruptly between discrete levels, though, and one of the reasons is that, even if the sector was perfectly competitive, hydro generators will submit offers based on expected MWV's that represent a probability weighted bundle of possible outcomes. So, we should expect to see prices varying continuously between the levels marked.

The fact that expected MWVs, and market prices, are varying continuously between these discrete SRMC levels theoretically makes no difference to the operation of any of those generation options, in our idealised SRMC-driven market. What determines their operation is just whether the market price is above, or below, their SRMC. The intermediate price levels occurring when hydro is on the margin, do make an apparent difference, though, to the OV of all plant generating at that time.

Note, though, that the true value delivered by each MW generated in any of these periods is actually unknown, at the time of generation. It just saves a unit of hydro generation, the true marginal value of which will only become apparent over time. Retrospectively, though, the true MWV actually can be known, as discussed in Section 3.3, and will always equal either zero (if the extra water is eventually spilled), or the SRMC of some type of generation or load reduction. So, each expected MWV can be decomposed as a probability weighted sum of the underlying SRMC values in this equilibrium PDC, or spill. Conversely, the actual market PDC will look like a "fuzzy" version of the hypothetical stepped PDC, but still with the same basic shape, peaking to the same (shortage cost) levels. The question is whether it has the same expected value.

If the MWV-based price received in the period represents the weighted average of all these possible PDC prices we could imagine this payment being withheld until the valuation of each contribution becomes clear. Or we could think of it as the price to be paid now, for a contract whose ultimate value will later be discovered by the purchaser.

We may hypothesise that if the expected MWV is an unbiased estimate of the ultimate PDC values, the expected value of the OV contribution should just be the expected value of the contributions calculated from the stepped PDC. And we could interpret the PDC as representing the distribution of the true MWVs, which will only be known in hindsight. In other words, we could take it as defining the proportion of time for which each technology will be marginal, either directly, in that period, or indirectly because hydro was on the margin, offering its expected MWV, which implicitly includes a probability that the unit of water used today will be made up by using this technology some future period, when it will be on the margin.

This interpretation is very tentative, though, and should be treated with caution. We have not attempted a proof, but suspect that whatever proof may be advanced we expect that some rather heroic assumptions may be required.[137] Ultimately, we suggest that a somewhat more explicit treatment of reservoir limits and management would be desirable. In the meantime, we stress that the results presented here should be treated as indicative and illustrative.

7.2.7 Optimal Plant Mix and Sectoral Cost Recovery

NZEM load/hydro data

In order to discuss the optimal plant mix for a particular system, we must determine the LDC that plant mix needs to cover. In this case, the thermal system being optimised must cover the residual LDC after accounting for hydro contributions. Thus, we need the New Zealand LDC, and a corresponding hydro "Generation Duration Curve" (GDC).

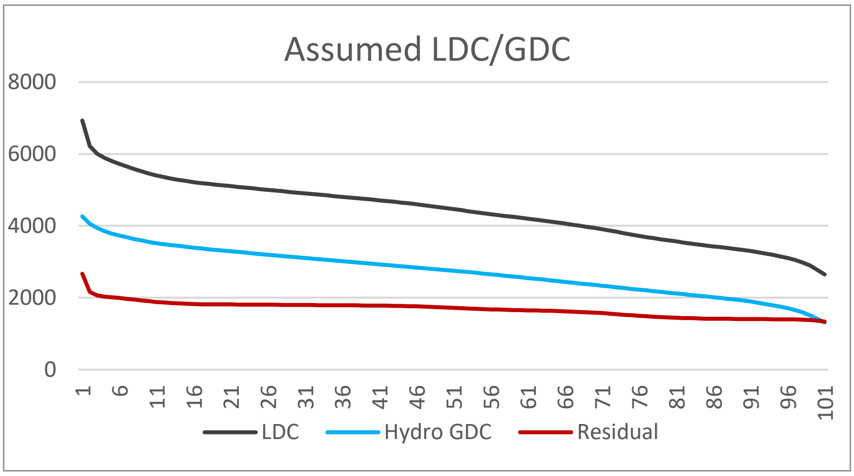

Figure 7.6 Illustrative Duration Curve Data 2010-2016

The data we have used is summarised in Figure 7.6, which also reports the Residual LDC formed by subtracting the GDC from the LDC. Ideally, the entry economics analysis should actually account for GDCs fitted and filled for say, wet, normal, and dry hydro years, with some accounting for limits on inter-seasonal reservoir capacity.

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[137] In particular, the possibility of reservoir storage limits forcing spill seems likely to affect the expected ted value. We note that, while the hydro GDC is based on real performance, and thus reflects the effects of all constraints, and the analysis models the possibility of "geothermal spill" at times of low load, the analysis has no representation of hydro spill due to reservoir limits being reached. Thus, it implicitly assumes that energy can be optimally scheduled into the residual LDC as required, even across and hydrology years, which is obviously unrealistic.

But our prototype tool uses a single GDC, effectively representing the whole range of hydro generation levels over the group of years studied, in this case 2010-16. Similarly, for the LDC.

Subtracting that GDC from that LDC thus effectively assumes that the sector will somehow have managed to schedule the peak hydro output over that entire period to match the peak load level over that entire period. Not surprisingly, this very coarse assumption creates some minor non-monotonicities in the residual LDC, and that creates some significant issues for an analytical approach that matches thermal plant entry to a residual LDC assumed to be monotone. So, a minor adjustment was performed to create an LDC that is very similar to the original, but implies a monotone Residual LDC, shown as "mono resid" in Figure 8.3.

That Residual LDC is slightly peakier than the original, but it still does not fully represent the peak demands that would be placed on the thermal backup system. Traditionally, the peak demand on the thermal system was likely to occur if breakdowns occurred when load was high and hydro flows low. Increasingly, though, a combination of low solar and wind output will greatly add to those factors, creating a potentially much larger spike in thermal backup requirements when heating loads peak on still winter nights.

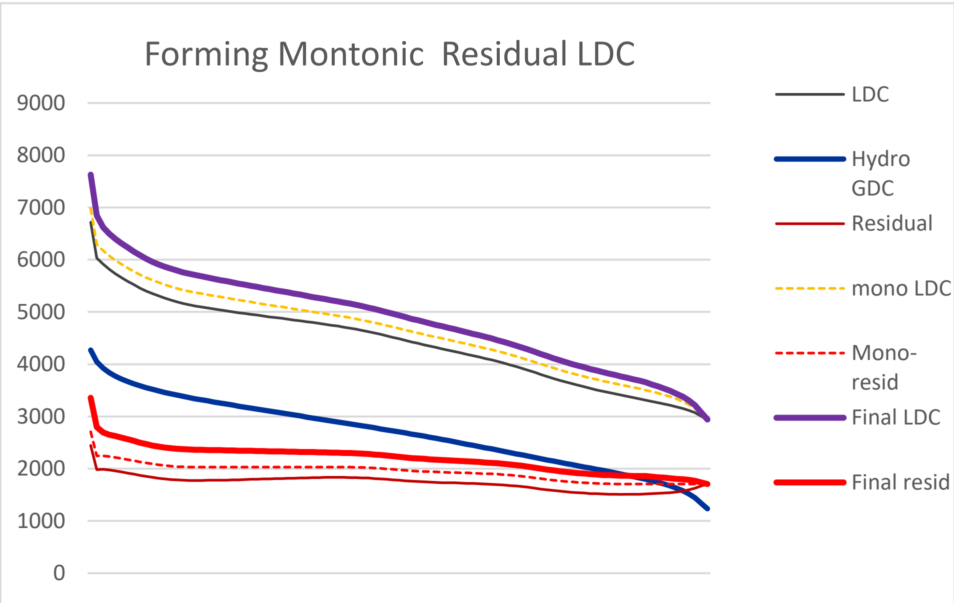

Figure 7.7 Forming the Illustrative Residual Load Duration Curve

This effect has traditionally been represented by creating a convolved "effective LDC" to be faced by each successive plant type, working up the merit order, after accounting for breakdowns. The result can not be exactly represented in a composite sectoral LDC like those shown here, but the broad effect is to add a "pseudo-load" component on to the LDC which increases strongly toward the extreme peak.[138] No attempt has been made to assess the appropriate additional component for this particular study. Instead, a rather arbitrary component has been added, inferred from earlier illustrative data. We make no claims with respect to the accuracy or appropriateness of this additional component, and regard it as purely illustrative of the general phenomenon. Although increasing the peak further will imply a somewhat greater proportion of cost recovery in peak periods, it makes little difference to the illustrative discussion below.

Plant Mix to fill NZEM LDC

From the NZEM entry data, we have already determined an optimal PDC, characterised by a critical utilisation factor for each plant type. So, all we have to do now is to locate those utilisation factors on the residual LDC, and slice that LDC into bands to be met by the various available technologies. Figure 7.8 shows the result of applying this approach to the RDC discussed above, using the PDC in the previous section.

We see that a strong emphasis on cost recovery at prices determined by thermal technologies need not imply a strong role for thermal plant in meeting load requirements. In fact, the figure suggests that their role in the optimal plant mix is really quite modest. As discussed above, it will actually be hydro "on the margin" in many of these periods, with the type of thermal generation, or demand response, ultimately displaced only being revealed at a later date.

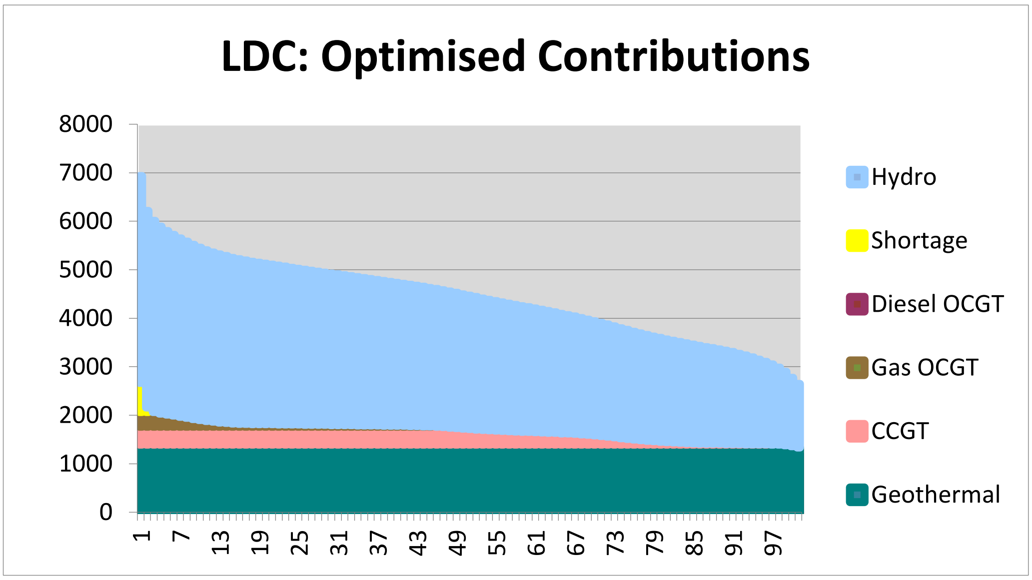

Figure 7.8: LDC Filled by Optimal Plant Mix

[138] The apparent increase in load is obviously not real, but it is offset by matching each effective Residual LDC with thermal capacity that is implicitly assumed to be 100% available, with unavailability accounted for by increasing the effective capacity cost.

Cost Recovery Proportions

We have already discussed estimates of the proportion of their total costs that base-loaded plant might expect to recover in periods when prices spike to shortage cost levels. Other plant will need to recover an even higher proportion of costs during these high-priced periods, though, ranging up to 100% even for gas-fired OCGTs in this example, where Diesel OCGTs do not appear in the optimal plant mix.

If we boldly make the further simplifying assumption that prices are perfectly correlated with load, we can multiply the price in each hour of the PDC by the load in each hour of the LDC, to create a "Revenue Duration Curve" (RDC) for the sector as a whole. From that, we can produce the following pie chart for total industry cost recovery.

While it is obviously very approximate, this analysis suggests that 35% of the revenue required to cover generator costs should be collected in periods when prices are above the SRMC of a gas-fired OCGT peaker, and (approximately) 0% when our base-load (non-storage) renewable option (geothermal in this case) is on the margin.

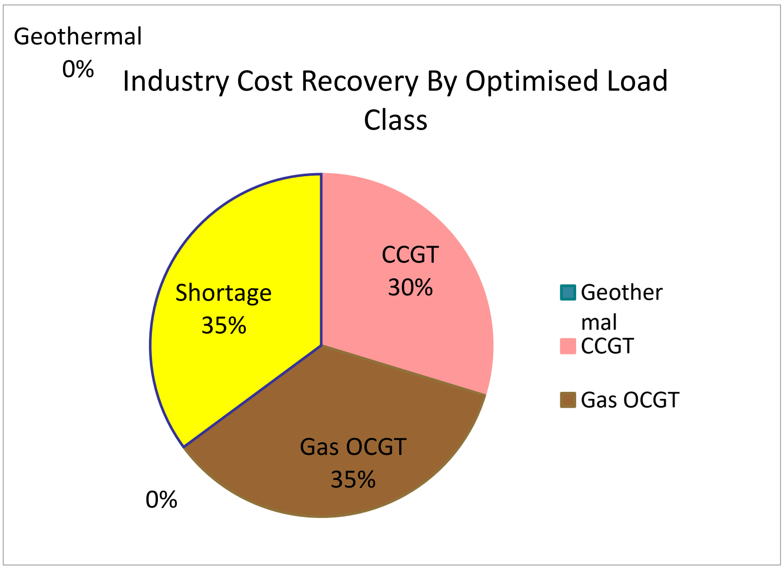

Figure 7.9 Industry Cost Recovery: Risk Neutral Case

These results are definitely subject to some error due to the discretisation of the LDC blocks into 1% classes, though. Nor would we actually want to see shortage occurring in 1% of hours, on average. Section7.4 explores some alternatives involving much fewer shortage hours, but we suggest that none of these variations really makes any difference to the overall cost recovery proportions.

The peaker may recover its costs running at full capacity for 4 hours a year, with VoLL set at $34,692. Or it may recover its costs running at full capacity for 87.6 hours a year (ie1%), with VoLL set at $1,648, as in our spreadsheet analysis. In a more sophisticated analysis, and/or less regulated market environment, it may run at various levels and receive a range of prices set by various levels of demand response. But the per MW total to be recovered is the same, and that same total needs to be recovered by every other MW of capacity operating at that time, in order to provide the cost recovery theoretically guaranteed by an energy only market, with strict SRMC pricing.

We stress again the experimental and illustrative nature of the techniques and results presented here. But the industry cost recovery proportions estimated here, of 25% for base-load plant, and 35% across the whole plant mix (ignoring risk) are quite comparable with other estimates we have made or seen, including the estimates made in Section 7.5. Experimentation with a range of adjustments available within the tool confirms a consistent view that the proportion is likely to be at least 25%, and maybe significantly higher, in an idealised competitive market, with SRMC pricing. So, we believe the results do provide some high-level guidance with respect to the interpretations to be put on results from more detailed analyses.

We also note the implication that, because aggregate pattern of generator output obviously matches the LDC, this same pricing pattern should be considered indicative of the pricing pattern that loads should face, in a hypothetical SRMC-driven market. In reality domestic loads in New Zealand typically face charges in which many fixed costs are "variabilised" into a per kWh price. In theory, though, the cost structure of the industry implies that they should be facing lower energy prices, offset by much higher fixed charges to recover transmission/distribution/ retailing costs. This analysis suggests that, if consumers do not want to face significant spot price variability, a significant insurance premium for dry year backup might logically be included in retail pricing, arguably as a fixed cost item.

Modelling Demand Response

Finally although the above discussion focussed mainly in thermal plant, we are actually moving closer to a 100% renewable system, in which thermal SRMCs become irrelevant, and SRMC revenue should theoretically be zero, if any form of energy is being "spilled".[139] So, theoretically, if thermal generation is eliminated, the proportion of costs recovered during "demand response" periods will eventually have to rise to 100% in a strict SRMC market, because that will be the only way to match demand to supply at other times.

In this preliminary analysis, though, the only one form of "demand response" allowed for is load shedding, at an assumed cost well above the Diesel SRMC. We could better analyse this emerging situation by adding one or more "demand response" blocks, priced at SRMCs both above and below that of a Diesel OCGT. These would represent the range of demand responses that might be expected to occur when market prices are in that range, whether due to opportunity costing of hydro release, or "gaming", or both.

[139] This does not quite happen in these results, because "geothermal" is assumed to have a non-zero SRMC.

We will not do that here, though. partly because (due to the limited number of technologies that the prototype tool can accommodate) we would need to drop a thermal technology for each demand response option added, but also because the assumptions would be rather speculative.

Cost estimates for demand response and shortage are notoriously varied and often difficult to assess. Shortage costs have traditionally been assessed for involuntary "power cuts", with the cost depending significantly on the amount of warning given, e.g by low inflow/lake levels. Values of the order of $5,000/MWh have been suggested when warning is given, rising to $10,000 without warning. These are significantly lower than some of the values calculated in the table above, perhaps implying a greater willingness to tolerate in the NZ market than in some other markets.

Voluntary demand response to high prices is slightly different. MW capacity shortfalls may drive short-term price spikes that do not actually induce much response, unless they are expected. But factors like low inflow levels create energy shortages that drive prices up over a period of time, giving consumers more time to plan and execute response strategies. Broadly, it has been suggested that demand reduction of about 5% might occur at sustained prices between $500-$1,000/MWh, and another 5% at sustained prices between $1,500-$2,5000/MWh.

But we note that demand response is rather like hydro development, in that opportunities are specific and limited. Simplistically, just setting a demand response price allows the analysis to implicitly assume that the system can call on unlimited quantities of that response at that price. Thus, rather than allow a probability of "shortage" it will always recommend reliance on "response" at any assumed SRMC below VoLL, unless that option also has some associated "fixed cost".

Many demand response options will have identifiable fixed costs, including the installation of equipment, the training of staff, and so on. But they will often also be specific to some class of equipment and user, such as supermarket freezers, or whatever. And no matter how attractive it might look, it is unrealistic for a model to recommend "installation" of say, 10MW of capacity from such a source if there is only 5MW available across the nation.

We might think of imposing a physical capacity limit in such a case, but an optimisation will deal with that by assigning a shadow price to the imposed constraint. That shadow price would then represent the net economic value associated with the opportunity of developing that particular form of demand response, once all direct costs have been accounted for. The PDC analysis will only produce a realistic plant/response development mix, then, if we include that opportunity cost in our assessment of fixed costs. In the context of our tool that would involve iterating on the fixed cost to achieve realistic utilisation of each demand response option. While that may provide a more realistic perspective on the future shape of the sector, it would not greatly enhance the conclusions discussed here, and lies beyond our current scope.