Market Development Programme (MDP) Overview Paper

Prepared by the Electricity Commission

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Executive summary

1. Two key problems areas have been identified with the performance of current electricity market arrangements:

   - **Lack of confidence in supply security** - there is a widespread impression that the New Zealand power system is unreliable and on the brink of insecurity. Electricity users have been called upon to make ‘voluntary’ savings three times since 2001. The frequency of such calls reinforces a perception of insecurity. There is also doubt about whether current arrangements provide sufficient reward for investment/retention of resources (generation and/or demand-side response) which are required very infrequently; and

   - **Concern about electricity prices** - there is a perception among some parties that retail electricity prices are too high. Prices have increased for all customer groups, but have risen especially sharply for residential users. There is uncertainty over whether the increases reflect rising costs, poor efficiency or the exercise of market power.

2. The Commission has developed a suite of measures to address these concerns, referred to as the Market Development Programme (MDP). The MDP recognises the complex and interlinked nature of the electricity supply chain, and has therefore been designed as integrated package.

3. The MDP seeks to address the root causes of the problems with existing arrangements. In the security of supply area, it focuses on the incentives which lead to over-reliance on ‘voluntary’ conservation campaigns, and the factors which undermine the rewards for retaining or investing in plant and for demand response capability that is required for security.

4. In relation to concerns about end-user prices, the MDP seeks to sharpen up competitive pressures and make it easier for consumers to shop around. It also aims to widen the scope for electricity users to more actively manage their own demand, to provide a greater counterweight to suppliers’ market power.

5. This paper outlines the measures in the MDP, explains how they fit together, and sets out the next steps that the Commission proposes to take.

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1. Introduction

1.1 Background

1.1.1. The Electricity Commission (Commission) has been examining the performance of current electricity market arrangements, drawing on the Market Design Review[1] and the 2008 Winter Review[2], and associated submissions from stakeholders.

1.1.2. The Commission has also given careful consideration to the electricity sector Investigation Report and related materials published by the Commerce Commission in May 2009[3].

1.1.3. As well as examining historic performance, the Commission has considered how market arrangements might need to change to reflect underlying trends in the sector. These include:

- higher costs for thermal fuels – for example, real gas prices have increased from around $3.50/GJ to around $7.00/GJ;
- the expected introduction of carbon pricing – which could add around $190 million[4] to annual generation costs;
- a changing generation mix, with a rising contribution from inflexible and intermittent plant, as renewables become increasingly important;
- the fact that the electricity system is becoming more constrained by the shortage of peak generation;
- the need for sizeable investments to reflect these changes – around $500 million per year in new generation, and approved grid investments of $2.7 billion, with more expected in future; and
- technology shifts – such as the widespread adoption of ‘smart meters’ and new grid technology options.

1.2. Problem definition

1.2.1. Work undertaken in the Market Design Review and the Winter 2008 Review has identified two key problem areas:

- **Supply security** - there is a widespread impression that the New Zealand power system is unreliable and on the brink of insecurity. Electricity users have been called upon to make ‘voluntary’ savings three times since 2001. The frequency of such calls reinforces a perception of insecurity. There is also doubt about whether current arrangements provide sufficient reward for investment/retention of resources (generation and/or demand-side response) which are required very infrequently; and
- **Electricity prices** - there is a perception among some parties that retail electricity prices are too high. Prices have increased for all customer groups,

1 See http://www.electricitycommission.govt.nz/consultation/mktdesignreview
2 See http://www.electricitycommission.govt.nz/opdev/secsupply/winter08/index.html
3 See “Investigation Report – Commerce Act 1986 s27, s30 and s36 Electricity Investigation”, *Commerce Commission*, 21 May 2009.
4 Based on 2007-08 average generation and around $25/tonne for carbon.

but have risen especially sharply for residential users. There is uncertainty over whether the increases reflect rising costs, poor efficiency or the exercise of market power.

1.2.2. The Commission has developed a suite of measures to address these concerns, referred to as the Market Development Programme (MDP). The MDP recognises the complex and interlinked nature of the electricity supply chain, and has therefore been designed as integrated package.

1.2.3. The balance of this paper describes the problem areas, and sets out the Commission's proposed solutions.

2. Improving security of supply and efficient investment signals

2.1. Overview

2.1.1. There are three key areas of concern with security of supply[5] under existing arrangements:

- whether there is sufficient incentive to retain and invest in peaking or hydro firming[6] plant;
- the level of demand side participation; and
- management of dry year risk.

2.2. Incentives to retain and invest in peaking/hydro firming plant

2.2.1. All electricity systems require some plant that will be needed very infrequently, for example to provide energy during extreme dry periods, meet peak demand, or to compensate for short windless periods. Under New Zealand's current energy-only[7] market design, such generation must be able to recover its variable and fixed costs from spot prices or hedges with counterparties who wish to cover their risk from high prices – as there is no formal payment for capacity or availability.

2.2.2. This means that spot prices[8] must reach (or be expected to reach) very high levels during the period that this infrequently used plant is operating. For example, a plant with average utilisation of 0.5%[9] might require spot prices to be $3,000/MWh or more during its brief operating periods to cover its fixed and fuel costs.

2.2.3. If spot prices cannot reach sufficient levels, plants with low expected utilisation (capacity factors) won't be economic, leading to insecure supply. There are signs that this problem may be emerging in New Zealand:

- Genesis has signalled that it is becoming difficult to justify the continued retention of four units at Huntly. It has stated that "with the introduction of thermal generators into the NZETS from 1 January 2010 (less than 10 months from the time of writing) Genesis Energy must soon decide the future role of the coal-fired units at Huntly. The high level of fixed costs, and the continuing capital investment and ongoing contracting for fuel supplies required to maintain availability of the coal-fired units, represent a significant commitment for the company and its shareholders. There may come a point where the most

5 This paper considers security of supply at the wholesale market level. The performance of downstream transmission and distribution networks is also important to security outcomes for end-users, but this issue lies outside the scope of this paper.

6 Hydro firming plant are stations that increase production to offset lower hydro generation during extended dry periods.

7 This refers to the fact that plant is paid based on energy *production*, with no explicit payment for *capacity* or *availability*. See Market Design Review – Options Paper for more detail.

8 The plant may recover its revenue directly from the spot market, or from contracts which insure buyers against high spot prices. In both cases, unless spot prices can reach necessary levels, the plant will be uneconomic.

9 Equivalent to around 2 days a year, or 20 days every ten years.

commercially attractive option for Genesis Energy is to decommission some of the 250 MW units. In the absence of compensation, with the onset of carbon obligations next year and displacement by renewables, Genesis Energy could be carrying a cost with no offsetting revenue. In such a scenario, at some point it will become non-commercial to maintain all of the four 250MW units"[10]; and

- the revenue available from the 'top of the spot price curve' is insufficient to support investment in peaking plant. But more of this type of fast-start plant is likely to be required to balance the rising proportion of renewable generation, which is generally intermittent (e.g. wind) or inflexible (e.g. geothermal).

2.3. Limited demand-side participation

2.3.1. Some electricity users are prepared to reduce their demand at times of system stress, such as dry years, peak demand periods or when a large generator or transmission circuit is lost unexpectedly. Users receive compensation for providing demand response in the form of a specific payment, or via a reduction in their electricity purchase charges. Participation from the demand-side is very important at the wholesale level, because it increases the resilience of the system. It also provides a natural counterweight to supplier market power.

2.3.2. At present, there is limited participation from the demand-side. Some major industrial users have shown significant response during dry periods, but response has been less active over shorter timeframes. Demand response from commercial and residential users has been even more limited (while including 'voluntary' response to campaigns noted below). There has been some response from distributors and retailers utilising ripple control of hot water heating, but this tends to be used to manage a network peak, rather than to manage a sustained high energy price peak as a result of a dry year.

2.3.3. One reason for limited participation is that many demand response providers have characteristics similar to peaking/hydro firming plant, because they need high spot prices to cover their fixed set-up costs and the opportunity value of electricity.

2.3.4. This was evident in the winter of 2008 when a number of industrial users made plans to reduce grid demand by rearranging their production schedules or relying on standby diesels. However, spot prices never reached the levels of $500/MWh or more required to make these options economic. This was despite the Commission being obliged to consider the possibility of supplementary reserve energy procurement, which might have had even higher costs.

2.4. Management of dry year risk

2.4.1. Experience in 2008 (and earlier years) shows that when conditions become dry, parties exposed to high spot prices have an incentive to shift this cost on to others. These parties can be electricity users who don't have sufficient hedge cover for their expected demand ("under-hedged buyers"), or generators that have sold more electricity on fixed price contracts than they can produce ("over sold generators"). These parties have an incentive to call for 'voluntary' conservation campaigns to reduce demand and ease spot prices. However, such campaigns have a cost to the general public and businesses who suffer inconvenience or disruption. The campaigns undermine confidence in market arrangements by the public and policy

[10] Genesis submission on the Emissions Trading Scheme, February 2009

makers. They can also reduce general investment confidence, by feeding a perception of supply insecurity.

2.4.2. The operation of the reserve energy scheme can have a similar cost-shifting effect, because some costs are recovered from all wholesale purchasers, whereas the benefit of operation is felt by parties exposed to spot prices[11].

2.4.3. Cost shifting could also occur if forced power cuts were ever required[12] (they haven't been to date). In that situation, under hedged buyers and over sold generators exposed to high spot prices would benefit, but the costs would be borne by the electricity users who are forcibly turned off. In effect, parties benefiting from lower spot prices would obtain this 'demand response' for free.

2.4.4. These factors increase the incentive on parties to 'gamble' with security (by under hedging their usage or overselling their generation), because they can capture the rewards of their decisions, but 'socialise' some of the costs and risks.

2.5. Underlying problems

2.5.1. At the heart of these problems is the issue of incentives. The current framework is predicated on wholesale market participants reaping the rewards and risks of their own actions. However, as noted above, in a number of areas, participants can pass costs and risks onto others.

2.5.2. This ability to shift costs saps the revenue base for potential 'security providers' because participants are less concerned about having unhedged demand or insufficient generation (or buyback options) to meet their contracted sales. The reduced revenue base for peaking/hydro firming plant and providers of demand side response means that overall security is degraded.

2.5.3. Under the current framework, the key tool to address this problem is the reserve energy scheme. This obliges the Commission to act if projected security falls below a pre-defined threshold, by procuring additional generation or demand response to 'top-up' overall security.

2.5.4. However, this mechanism can itself have an unintended effect of reducing the potential revenue base for market-based alternatives. This arises because unlike the market-based alternatives, reserve energy resources are not dependent on the spot and contracts markets for all their revenues. This undercuts the revenue base for the market-based provision of peaking/firming plant and demand response resources. This can further increase the need for reserve energy procurement, and so forth.

2.5.5. Ultimately, there is a risk that the reserve energy scheme becomes the primary means of paying for all new supply and infrequently used plant. At that point, the scheme is unlikely to be sustainable because it is no longer a 'back stop' as originally intended.

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11 It could be argued that *all* electricity buyers benefit because the *existence* of the Whirinaki plant lowers expected spot prices. However, this benefit would only occur if the reserve energy scheme results in more plant being on the system than would otherwise be the case. It is likely that investors in 'market' plant take the reserve scheme into account, and adjust their investment plans, resulting in no overall change to security.

12 That is, if the Commission were to direct mandatory outages under Clause 10 of the Electricity Governance (Security of Supply) Regulations 2008.

2.6. Possible solutions

2.6.1. There are two broad choices to move forward:

- 'scarcity pricing/compensation' – this would retain an energy-only spot market, but seek to address the opportunities for cost shifting, so generators don't have an incentive to sell more than they can reliably produce (or buy back) and users no longer have an incentive to under hedge. Put another way, costs should lie with the parties best able to manage the consequences of their actions. In this context, it would be important to ensure that spot prices reflect the true value of electricity (and hence security) when supply is scarce (e.g. when an official demand conservation campaign is triggered, or if forced power cuts are ever required). This could be done by applying default spot prices[13] in these types of situations. Another related approach to limit cost shifting would be to require suppliers to compensate tariff-based consumers for any demand conservation measures[14]. In effect, this would be a form of default buyback, and would reduce the undue incentive to rely on public conservation campaigns as a risk management tool. The reserve energy scheme would also need to be reviewed to remove or reduce opportunities for cost shifting (see section 2.7); or

- 'compulsory contracting mechanisms[15]' – this would seek to remove the opportunity for participants to under hedge or over sell by directly constraining their actions. This could take the form of a mandatory requirement on wholesale purchasers (retailers and major users) to be hedged, or the centralised procurement of hedges on behalf of all purchasers. Under either option, the intention is to ensure that all demand is covered by firm generation or contracted demand response. The requirement might extend a number of years ahead to ensure adequate investment signals. The entitlements could be in the form of supply contracts with generators, own generation resources, or firm demand-response arrangements. An auditing regime would be required, with stiff penalties for non-compliance. In effect, this option would be a form of compulsory energy insurance.

2.6.2. Both approaches have been adopted internationally and each has its merits.

2.6.3. In brief, the scarcity pricing/compensation approach would be less complex and provide participants with greater choice, allowing more scope for innovation and competition between various generation and demand side solutions over time. However, it relies on sharper price signals, with spot prices possibly reaching very high levels at times – for example up to A$10,000/MWh in Australia.

2.6.4. Participants would need to be able to mitigate their exposure to sharper price signals. It would also be important to ensure that any scarcity pricing regime did not give rise to unmanageable price risk. This would require careful design. The other key concern with this option is the potential for generators to exercise market power, by creating 'artificial' scarcity. In other markets, this has required various

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13 This might be in the form of a default price level, or by applying an 'adder' to spot prices.

14 The *primary* objective of such a mechanism would be to reduce the incentive on retailers to call for public conservation measures as a means of reducing their spot market exposure. A secondary objective could be to encourage conservation by mass market consumers.

15 This would be mandatory contracting regime to ensure capacity or energy adequacy. It is also sometime referred to as a 'capacity mechanism', as this is the predominant form of this instrument in overseas markets. Such mechanisms create an explicit payment for capacity/adequacy that is separate from an energy-only payment based on energy production.

safeguards to be put in place to address the issue, such as limitations on the application of scarcity pricing, and/or 'event reports' whenever it is triggered.

2.6.5. The compulsory contracting mechanism approach is less susceptible to the exercise of market power if forward contracting occurs over years, allowing new entrants to compete. Furthermore, because generators would be highly contracted, they would have little incentive to exercise market power in the spot market. However, it would not address any market power in the contracts market.

2.6.6. The key drawbacks of compulsory contracting mechanisms are their constraining effect on participant choices (some parties perceive them as 'anti-market') and their relative complexity. In New Zealand, this would be more complex than where it has been used in other predominantly thermal, peak constrained systems. This arises because it would need to address the dual adequacy requirements of capacity and energy supply. For example, there would be a need to define the available firm supply of capacity and energy for each generation plant, to ensure that its owner did not 'oversell'. This would be especially challenging for hydro plant as the available capacity would be a function of storage and inflows, which vary over the year. Rules would also need to account for some locational effects, given that firm supply in the North Island would not necessarily be able to meet demand in the South Island. Once again, there would be important transition issues to consider.

2.6.7. Both options would have significant consequences for generators, retailers and other wholesale buyers. Each would represent a substantial change from current arrangements, and should not be considered lightly.

2.6.8. The Commission sees merits and drawbacks in both of the proposed new options. Accordingly, the Commission intends to evaluate each of them in more detail, with the intention of selecting a preferred option to compare against current arrangements.

2.7. Future of Whirinaki and Reserve Energy scheme

2.7.1. As noted above, the Reserve Energy scheme (and the Whirinaki plant within it) is intended to provide a backstop in the event that market arrangements don't provide sufficient security. However, experience in the winter of 2008 shows this has been problematic. Participants are likely to factor the scheme into their plans, meaning that it is doubtful whether it lifts overall security, as compared to the status quo.

2.7.2. Furthermore, the scheme can have the unintended effect of reducing the incentive on parties to prudently manage their risks. This arises because a wholesale purchaser with an unhedged position gets more benefit from Whirinaki's operation than one which is fully hedged[16], yet both pay the same contribution to the plant's costs through the levy. At the margin, this reduces parties' incentive to hedge, build plant or enter into firm demand response arrangements.

2.7.3. The scheme also fits awkwardly with the Commission's role as a regulatory body.

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16 In this example, the hedged party is indifferent to whether Whirinaki runs (because it is fully hedged) whereas the unhedged party would benefit to the extent that spot prices are lower as a result of running Whirinaki. It might be argued that the hedged party also benefits from the presence of Whirinaki at the time of negotiating its hedge contract. This is correct provided the presence of Whirinaki does not alter the investment or operating decisions of other parties. However, this appears unlikely to be the case, as market participants are likely to make some adjustments, relative to a situation where the system had no Whirinaki station.

2.7.4. The Commission does not have the legal power to significantly modify the Reserve Energy scheme as it would require changes to existing legislation. However, the effects of the scheme have been noted in the Ministerial Review of Electricity Market Performance , and the Government has signalled a willingness to consider changes to the scheme.

2.7.5. For these reasons, the Commission believes it is likely that the Reserve Energy scheme will be modified with the aim of transitioning to more market-based arrangements.

2.7.6. In the meantime, the Commission is looking at options to improve the effectiveness of the Reserve Energy scheme

2.8. Transmission and distribution pricing

2.8.1. Both the underlying trends in the electricity sector and the proposed changes to the market arrangements that are laid out in this paper could result in changes to the use of existing transmission assets and to investment in new transmission assets or transmission alternatives.

2.8.2. In light of these changes in the transmission environment, it is important that the allocation of transmission costs continues to promote efficient outcomes for use of, and investment in, the transmission network and in alternatives.

2.8.3. For example, the proposed changes to the market arrangements will influence the investment signals for generation – particularly peaking generation.

2.8.4. The Commission recognises that, for investment in transmission and generation to be efficient, there needs to be appropriate cost allocation and investment signals throughout the electricity value chain. Factors that are particularly relevant to the efficient investment in transmission and generation are the location of generation, peak power flows and Transpower's incentives to efficiently maintain equipment.

2.8.5. The Commission is undertaking a comprehensive review of transmission pricing. This review will need to take into account the proposed market developments outlined here in order to ensure consistent signals. Whilst the review is considering a breadth of issues and will consider a range of options, the aims are to contribute to the following efficiency benefits:

- efficient network investment – better downstream management of load and distributed generation can defer transmission (and distribution) investment;
- efficient facilitation of entry and location decisions by generation – by transmission cost signalling; and
- recovery of sunk costs in a manner that minimises distortions to production/consumption and investment decisions by grid users and consumers.

2.8.6. The Commission is also developing guiding principles and a model approach to distribution pricing. Distribution pricing has important potential consequences for investment and efficient use of resources, particularly in relation to demand side decisions, demand side market participation, and retail competition.

2.9. Proposed actions to improve security and investment signals

2.9.1. In summary, the Commission intends to take the following steps to improve security of supply and investment signals:

- investigate scarcity pricing and compulsory contracting mechanisms in more detail, with the intention of implementing the option with the greatest net benefit;
- review transmission and distribution pricing methodologies to identify any changes that are required in light of industry trends and revisions to other market arrangements; and,
- review the future of the Whirinaki station and of the Reserve Energy scheme.

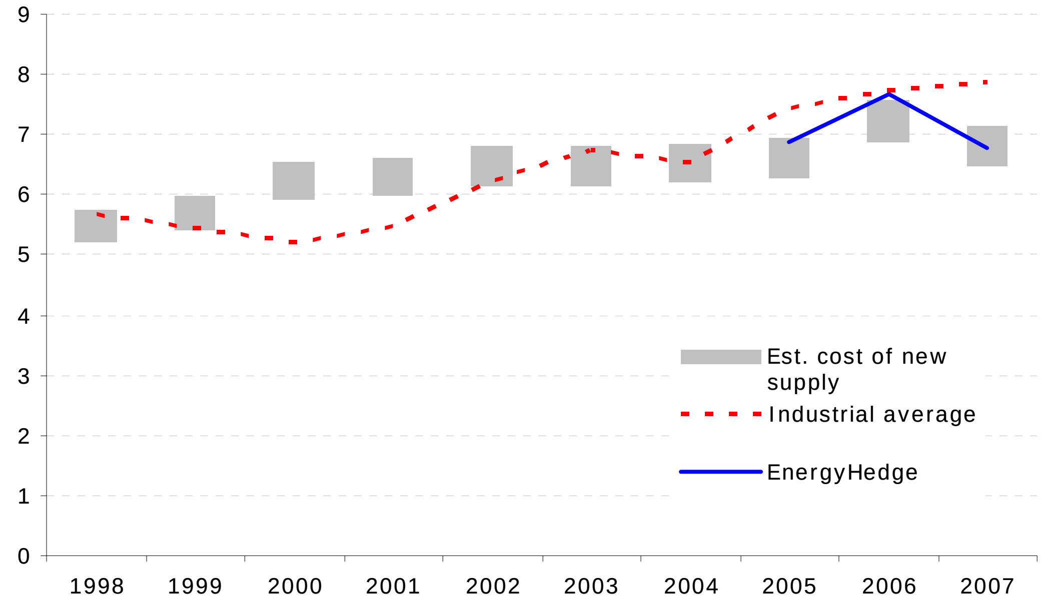
3. Strengthening wholesale competition

3.1. Overview

3.1.1. There has been a significant upward trend in the wholesale price of electricity in recent years. The Commission undertook analysis to compare wholesale price indicators with the estimated cost of new supply. Figure 1[17] depicts two wholesale price indicators – the track of average electricity purchase costs (excluding network costs) for all industrial users, and contract prices quoted on EnergyHedge.

3.1.2. These are compared with the estimated cost of new supply based on a combined cycle gas-fired plant. Given the uncertainty about some cost elements, this is shown in the form of a range estimate indicated by shaded bars.

Figure 1 – Wholesale price indicators and estimated new supply cost (c/kWh - 2008 real terms)



3.1.3. Based on its analysis, the Commission concluded that there was no evidence of persistent overshooting of contract prices above the cost of new supply. Having said that, the Commission noted that data on contract prices is limited, and that there was some uncertainty in estimating new supply costs. It also recognised that the wholesale charge constitutes a large proportion of all customers' final bills.

3.1.4. For these reasons, the Commission will continue to pursue measures to strengthen competition in the wholesale market. It has focussed on the tools currently provided in the Electricity Act, and has not considered measures of a structural nature.

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17 Industrial prices have been chosen because this category of customer is the most reflective of wholesale contract price movements. Significant adjustments would be required to prices paid by other customer categories to take account of factors such as load shape, distribution losses and retail operating costs. Note that a 3% increase has been applied to the 'raw' cost of new supply estimates to reflect average transmission losses, which could be expected to be reflected in industrial prices.

3.1.5. As a first step, the Commission intends to increase the formal monitoring of prices and competition in the wholesale market. The recently introduced hedge price disclosure regime will assist in this respect.

3.1.6. The Commission has also examined charges for ancillary services, given the upward trend in procurement costs. In part, this movement is driven by the rising level of wholesale energy cost. However, ancillary services are a distinct category of service and the Commission believes there are opportunities to increase competition in their provision.

3.1.7. Another area of concentration will be effort to improve the level of demand side participation in the wholesale market. In particular, the Commission is exploring options to allow wholesale purchasers and intermediaries such as demand aggregators to participate more actively in spot price formation.

3.1.8. One possible approach is to allow qualifying users to opt-in to the dispatch process, in an analogous manner to generators. This mechanism would provide users with certainty that they will not be required to shed load unless spot prices reach their pre-defined threshold, and vice versa. If viable, this could address a concern expressed by some parties that they can get 'caught out' at times[18].

3.1.9. Under a demand dispatch mechanism, demand-side bids would be able to set the spot price. This is important because small cuts in demand at times of peak can lead to sizeable reductions in spot prices, providing an important counterweight to generator market power. Improved demand-side participation would also be a desirable feature of a scarcity pricing option in order to mitigate potential supply side market power.

3.1.10. The Commission will also examine the ownership of load management rights, to ensure arrangements are clear and allow efficient trading of rights. This is a prerequisite to effective demand side participation by mass market consumers, either directly or via intermediaries such as retailers or demand aggregators.

3.2. Proposed actions to strengthen wholesale competition

3.2.1. In summary, the Commission intends to take the following steps to strengthen wholesale competition:

- undertake regular monitoring of competition and pricing in the wholesale market;
- pursue measures to increase competition in the provision of ancillary services, such as the possible introduction of multiple frequency keepers, and addressing performance standards that may restrict the provision of interruptible load from demand-side providers;
- facilitate more active participation from the demand side in the wholesale market, by measures such as an option to allow users to be dispatched in a manner analogous to generation, with their offers directly affecting spot price formation. This would assist in redressing the balance of bargaining power between wholesale buyers and sellers during times of market stress; and
- ensure load management rights are clear and can be efficiently traded.

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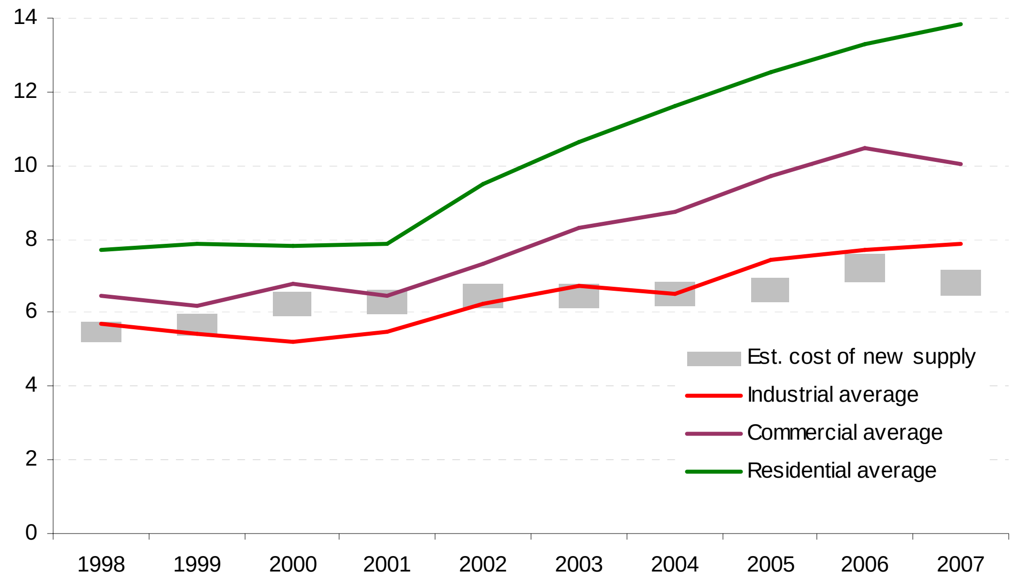
18 In other words, they react to forecast high spot prices by cutting load, but find that this action is not worthwhile in light of final spot prices, or vice versa.

4. Strengthening retail competition

4.1. Overview

4.1.1. Analysis undertaken by the Commission in 2007 and 2008 highlighted the increase in electricity prices for residential and commercial users. Unlike the price trend for industrial consumers (discussed above), movements in residential prices up to 2008 were not readily explained by the rising cost of new supply at the wholesale level, as illustrated by Figure 2.

Figure 2 – Electricity prices (c/kWh - 2008 real terms)



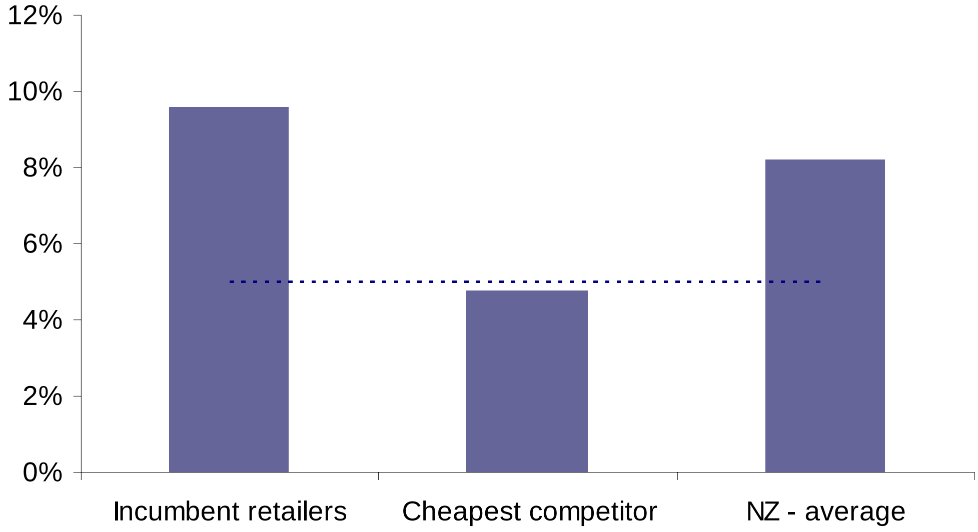
4.1.2. In light of these trends, residential price information for 2007/08 was analysed in more detail to estimate the level of profit margin on sales[19]. The results of this historical analysis are summarised in Figure 3

4.1.3. For households with the local incumbent (main) retailer, the margin averaged almost 10% across New Zealand. The national average based on the cheapest retailers in each area was almost 5%. The weighted average over all residential customers was estimated at approximately 8%[20].

4.1.4. Australian regulatory bodies have generally regarded a margin of around 5% on the total bill as reasonable in setting regulated tariffs, and this is shown on the chart as a dotted line. While retail markets in the Eastern Australian states have similar features to the retail market in New Zealand, there are some important differences. For example, customer switching rates in Australia are generally higher than New Zealand, suggesting a higher margin may be required in Australia. On the other hand, New Zealand's use of full nodal pricing may make energy procurement more risky here, suggesting a greater margin is required in New Zealand. Given these various factors, the 5% figure should be treated as an indicative guide only.

[19] See Market Design Review Options Paper for more detail.
[20] Assuming that the 30% who have switched chose the cheapest retailer in their area.

Figure 3 – Retail profit margin (% of total bill – mix of low user and standard tariffs)

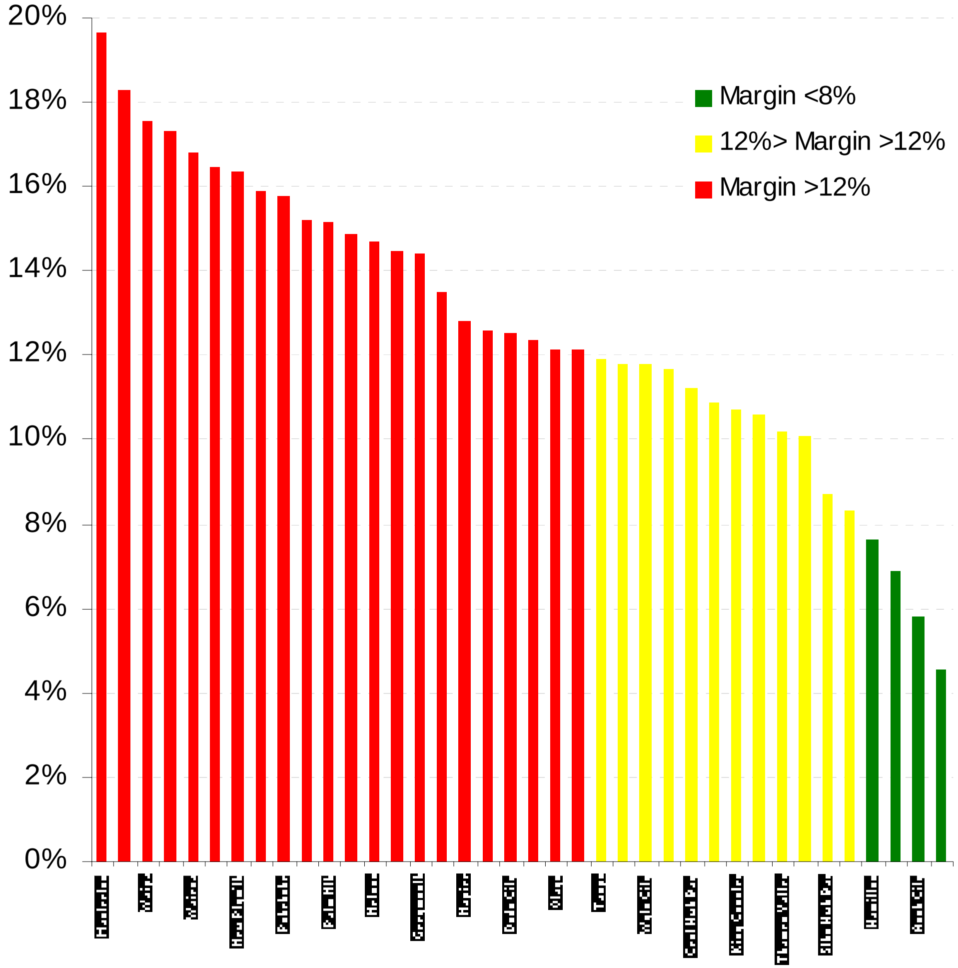


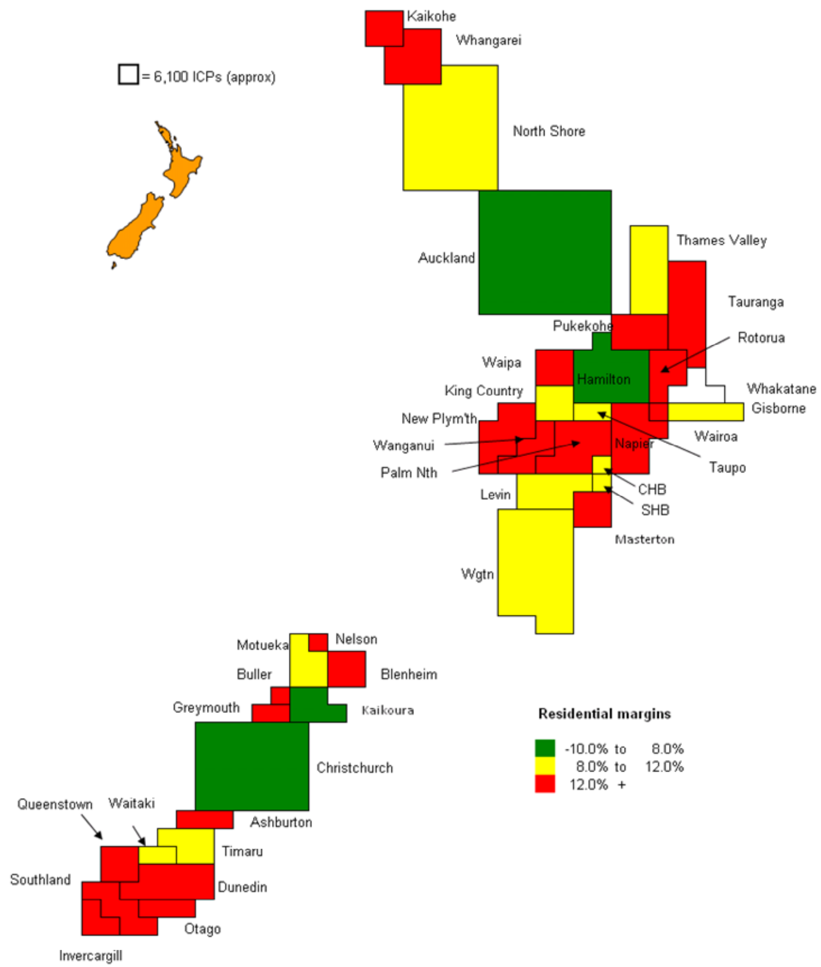
4.1.5. While the data are subject to some estimation uncertainty[21], the results suggest that average margin for residential customers served by the incumbent retailer was somewhat higher than 5%. In contrast, the average margin was slightly below 5% for customers served by the cheapest retailer in each network area.

4.1.6. The picture was fairly mixed at the regional level, with wide variation evident across different network areas, as shown in Figure 4. Estimated margins in many areas were above the 5% level, reaching 15% or more in certain areas. These equated to profit margins of $300-400/year on a total bill of around $2,000. Even after allowing for some estimation uncertainty, margins at these levels would be a cause for concern if sustained over time.

[21] See the "Issues Paper" and "Options Paper" of the Market Design Review for more detail.

Figure 4 – Incumbent supplier – estimated profit margin by network area (9,000 kWh user)





Medium residential (9,000 kWh/annum) incumbent retailer net margins ($170 cost-to-serve)

4.1.7. The chart also shows the margin information in stylised map form, with each network area sized according to the number of connections, and colour coded based on whether margins are below 8% (green), between 8-12% (yellow) or higher (red).

4.1.8. The analysis indicated that many customers could have saved $150/year or more by switching to another supplier. This raised questions about why more customers did not switch and why competitors were not more aggressive in marketing their offers.

4.1.9. It is important to emphasise that these estimates were compiled using 2007/08 data. A number of changes have occurred since then, including movements in wholesale energy costs and retail prices. Furthermore, as noted earlier, margin estimates are inherently subject to significant measurement uncertainty. For these reasons, the Commission would be cautious about drawing firm conclusions based on a 'snapshot' at one point in time.

4.2. Importance of effective retail competition

4.2.1. The Commission believes that effective retail competition has a vital role to play in maintaining downward pressure on prices. Effective competition also contributes to ensuring energy affordability, reinforcing the measures taken outside the electricity market in the income support and energy efficiency arenas.

4.2.2. The Commission believes that effective competition at the retail level would be characterised by:

- rivalrous conduct between retailers (and/or the threat of entry by new retailers) to offer the products, services, prices, and other conditions of supply which are most attractive to consumers;
- informed and active consumers seeking to obtain energy products, prices and other terms and conditions of supply which best meet their needs; and
- low barriers to entry - freedom of movement for resources into and out of the market in pursuit of profit opportunities, thereby eroding any excess profits over time.

4.2.3. Looking forward, the Commission intends to monitor the retail market across these three areas to assess the level of retail competition.

4.2.4. In the meantime, the Commission has identified a number of factors that appear to inhibit retail competition:

- the limited liquidity of the hedge market – which can impede the ability of existing retailers to expand coverage, and for new retailers to enter the market;
- the difficulty that retailers have in managing exposure to nodal spot price risk. In essence, vertically integrated participants tend to focus their retail efforts near to their generation bases. As a result, regions with fewer generators also generally have fewer active retailers;

- the wide variation in distribution network pricing structures and terms, which may retard the expansion of retailers' service areas, particularly on to networks with fewer customers;
- a large number of small distributors with unique distribution network prices, terms and conditions; and
- difficulties that customers have in obtaining and comparing up to date pricing information.

4.3. Proposed actions to strengthen retail competition

4.3.1. In considering measures to improve retail sector performance, the Commission has focussed on the tools currently provided in the Electricity Act, and has not considered measures of a structural nature. The Commission intends to take the following steps to strengthen retail competition:

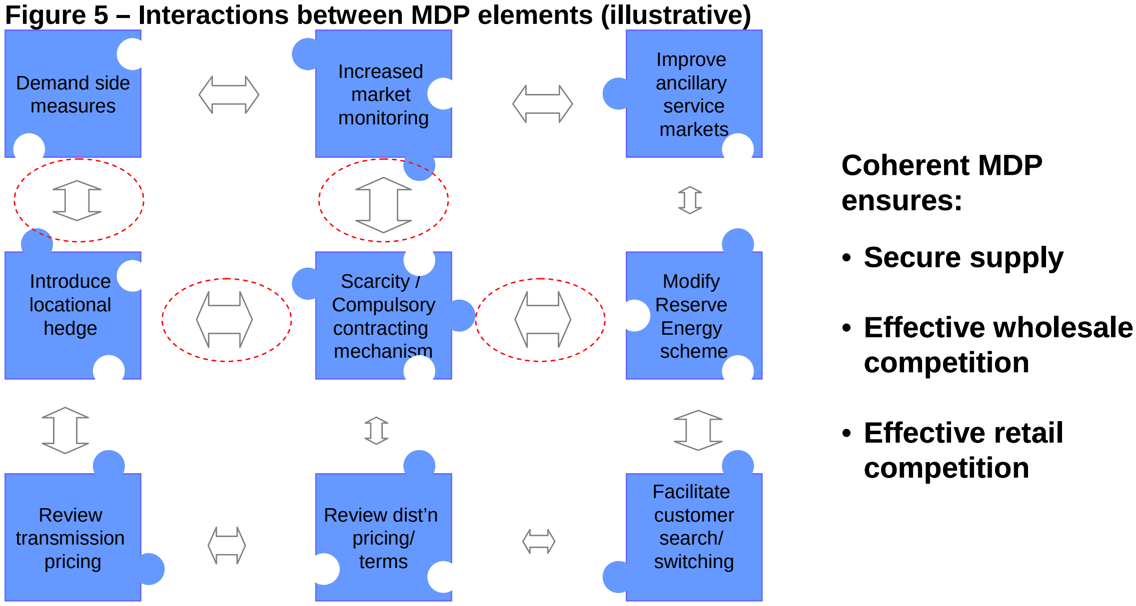
- examine the introduction of locational (transmission) hedges to improve retailers' ability to manage nodal price risk, and to increase the depth of the energy hedge market;
- continue to consider transmission investment proposals in a timely manner;
- investigate introducing measures to achieve greater standardisation of distribution network prices, terms and conditions;
- work with Consumer New Zealand and the Ministry of Consumer Affairs to further enhance Powerswitch, to reduce consumer search costs and make it easier to compare retailer offers;
- ensure that the roll-out of advanced metering infrastructure ('smart meters') facilitates retail competition and helps to underpin greater demand-side participation; and
- extend the monitoring of the retail market performance to determine if:
    - regions of higher than average prices are justified by market conditions or indicate localised retail barriers to competition;
    - regions where the main retailer prices are substantially higher than its competitors are justified by superior product offerings, or indicate retail competition barriers (including customer information problems);
    - residential prices appear reasonable compared to other customer classes (e.g. commercials), and where differences arise determine whether they reflect differences in underlying cost or competitive barriers; and
    - product offerings appear reasonable, especially as they relate to the potential for demand side participation and uptake of advanced metering infrastructure.

5. Interactions between MDP elements

5.1.1. The preceding sections discussed the major elements of the MDP in the separate contexts of security of supply, wholesale competition and retail competition.

5.1.2. In practice, the seamless nature of the physical electricity supply chain means that all MDP elements need to be considered as an integrated whole because of their potential interactions. These linkages can be direct or subtle in nature.

Figure 5 – Interactions between MDP elements (illustrative)



5.1.3. Some of the more important interactions are illustrated by the dotted circles in Figure 5:

- Scarcity pricing or compulsory contracting mechanisms could introduce greater scope for the exercise of market power in the wholesale market – this could be mitigated in part by increased market monitoring;

- Introduction of locational hedge products should improve the functioning of the hedge and energy contracts markets – this would be of benefit to wholesale market buyers if scarcity pricing were introduced;

- The requirement for the Reserve Energy scheme would be affected by the effectiveness of other measures to ensure security of supply – for example the presence of scarcity pricing/compensation or compulsory contracting mechanisms; and

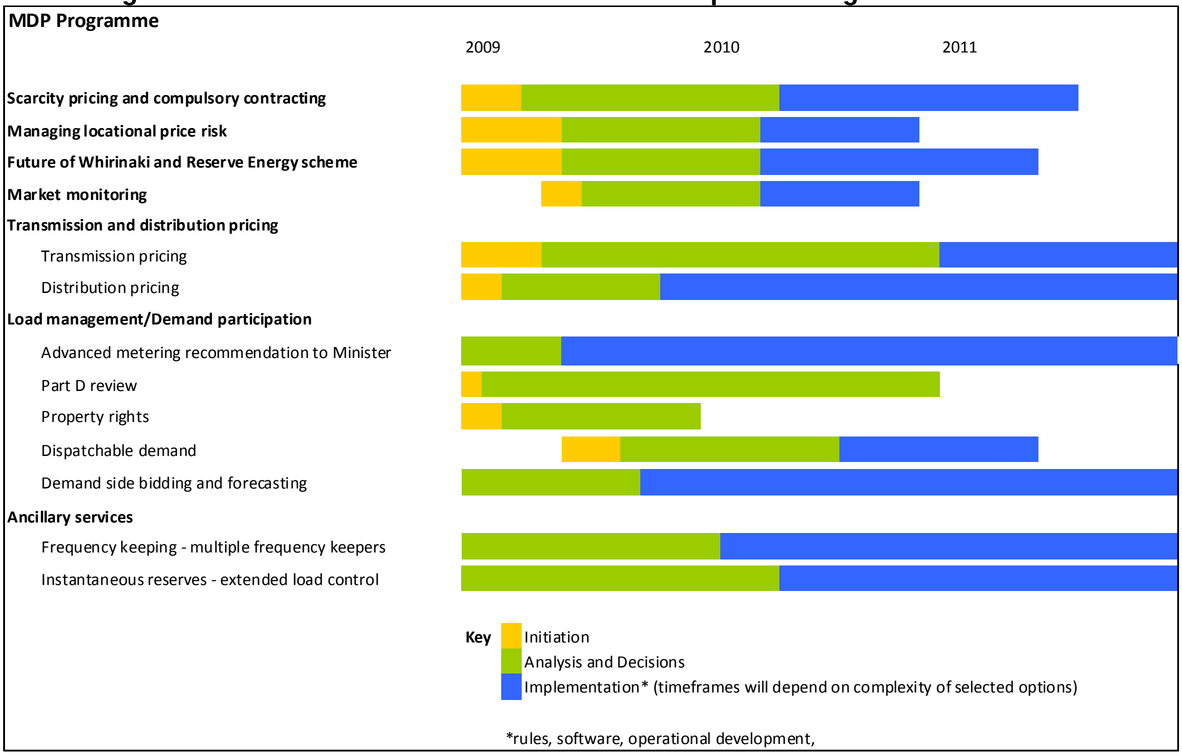
- The design of a locational hedge arrangement could affect the incentives and ability to undertake demand side response during periods of market stress.

5.1.4. The Commission is very aware of these types of issues, and will take them into account as it moves forward with the MDP. It is also conscious that other aspects of its overall work programme (see Appendix) need to be progressed in a manner that is consistent with the MDP goals and underlying design principles.

6. Next steps

6.1.1. The next action will be the release of consultation papers on major elements of the MDP. This will occur progressively over coming months, and the indicative timeline[22] is set out in Figure 6.

Figure 6 – Indicative timetable for Market Development Programme



6.1.2. The MDP represents the Commission's current thinking on the weaknesses with current market arrangements, and the best options to address them. It is important to stress that the Commission has not made final decisions in respect of any specific MDP issues. Decisions about preferred options for specific projects will only be made once the required analysis is completed, and the Commission has had an opportunity to consider the views of interested parties.

6.1.3. The Commission plans to release consultation papers on the individual measures within the MDP progressively and will encourage strong input from interested parties. There will be opportunities to contribute to both the high-level considerations of options and the more detailed design phases where appropriate. In addition, the Commission will involve the new advisory groups in the process and in some cases it may be necessary to form technical groups from a range of interested parties.

6.1.4. The Commission looks forward to engaging with stakeholders as the MDP progresses.

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[22] A more detailed workplan calendar is provided on the Commission's website at: http://www.electricitycommission.govt.nz/opdev/workcal/?searchterm=calendar

Appendix – List of current initiatives related to MDP

- Amend the processes for new grid connections
- Electricity hedge market development
- Investigation of the value of unserved energy
- Review retailer insolvency arrangements
- Offer and dispatch development – wind integration
- Optimise emergency management arrangements
- Pricing process improvements
- Transmission to enable renewables – phase 2