ELECTRICITY AUTHORITY
TE MANA HIKO

Report on Completion of Section 42 New Matters in the Electricity Industry Act 2010

31 October 2011

Report of the
Electricity Authority
Te Mana Hiko

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Purpose of this report

This is the Electricity Authority's formal report to the Minister of Energy and Resources in accordance with section 42 of the Electricity Industry Act 2010.

Further information about the Authority and its work is available from: www.ea.govt.nz

Abbreviations Used in this Report

Act	Electricity Industry Act 2010
Authority	Electricity Authority
CCS	Customer Compensation Scheme
Code	Electricity Industry Participation Code
CRE	Competition, reliability and efficiency (components of the Authority’s statutory objective)
DD	Dispatchable demand
DSBF	Demand side bidding and forecasting
FTR	Financial transmission right
IR	Instantaneous reserves
MCA	Ministry of Consumer Affairs
MED	Ministry of Economic Development
MEP	Metering equipment provider
MUoSA	Model use of system agreement (produced by the Authority)
PCC	Public conservation campaign
RAG	Retail Advisory Group
SOI	Statement of Intent
SRC	Security and Reliability Council
TPAG	Transmission Pricing Advisory Group
UoSA	Use of system agreement (produced by each distributor)
UTS	Undesirable trading situation
VoLL	Value of lost load
WAG	Wholesale Advisory Group

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Foreword

The Electricity Authority (Authority) was established as an independent Crown entity on 1 November 2010 by the Electricity Industry Act 2010 (Act). The Authority is responsible for regulating and monitoring the performance of the electricity sector.

The Authority considers its statutory independence provides a strong base to ensure regulatory credibility and durability.

The requirements of section 42 of the Act provided a significant challenge for the Authority in its first year and this report on the completion of those requirements is a major milestone.

The Authority is pleased to report that it considers that the requirements of section 42 have been completed, with solutions that will provide the best results in terms of the Authority's statutory objective.

Completion of the section 42 requirements is one of a number of achievements for the Authority in its first year of operation. Other achievements include:

- The successful establishment of the organisation, including appointing a new management team, setting up new and expanded functions, and setting up Advisory Groups and the Security and Reliability Council.
- Kicking off its consumer switching programme, including the highly successful "What's my number?" campaign, which has resulted in over 400,000 visits to the website and approximately $64 million in potential savings identified on the website calculator. Over 175,000 switches have been completed since the campaign started; a major jump over previous years.
- Completing foundation documents that set out the Authority's approach, and demonstrate its commitment to a transparent, open, inclusive approach with the aim of providing a predictable regulatory environment for industry, and a competitive, reliable and efficient electricity supply for consumers. The foundation documents are the *Charter about Advisory Groups*, the *Consultation Charter*, which includes Code amendment principles, and the *Interpretation of the Authority's statutory objective*.
- Proactively engaging with the sector, including initiating an ongoing programme of visiting consumer and industry sites throughout New Zealand, meeting with key stakeholder groups, and ongoing staff engagement with the sector and consumer groups.
- Building constructive relationships with service providers. These service providers will play a crucial role in implementing section 42 Code amendments made by the Authority.
- Beginning educating interested parties about the electricity sector, including publication of *Electricity in New Zealand*, a range of explanatory papers and plain English summaries to explain key reports, such as the March 26 UTS decision, to non-technical audiences.

The Board considers the work to date has been successful and positively received by stakeholders: in particular the completion of section 42 matters. We are confident that strong foundations are being laid for the achievement of our statutory objective:

> to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The Board's focus is now on ensuring successful implementation of the section 42 matters, monitoring implementation of market initiatives, and developing its strategy and work programme for the next three to five years to deliver on its statutory objective.

Development of this strategy is drawing on input from surveys, strategic stakeholder fora, and lessons learned so far. We will be formally consulting on these matters over the next two months. This consultation will propose a work programme to address some of the strong strategic themes that are emerging, including:

- **Reducing barriers to entry**—to increase competition and efficiency in the retail, hedge, metering, frequency keeping and reserves market.
- **Improving market information and price signals**—to increase efficiency and reliability through greater demand and supply responsiveness to tight supply situations.
- **Operational efficiency**—ongoing focus on reducing transaction and regulatory costs to improve the operational efficiency of the electricity market.
- **Reviewing and monitoring**—review impacts of Code amendments, including undertaking post implementation reviews of section 42 initiatives and review Code provisions and market arrangements for dealing with adverse events.
- **Education**—to inform consumers about the electricity market and build its credibility. Public education on the industry's value proposition, cost-reliability mix, telling the story about things that have been done well (e.g. management of the electricity network in Christchurch following the recent earthquakes) and the provision of easily accessible information for electricity market participants.

Dr Brent Layton
Chair
Electricity Authority

Executive Summary

Section 42 requirements

I. This is a report by the Authority against the requirement in section 42(1) of the Act to:

a) amend the Electricity Industry Participation code (Code) in the manner specified in section 42(2) of the Act; or

b) report to the Minister in accordance with section 42(3) of the Act, explaining why the Authority has not made the specific Code amendments required in section 42(2) of the Act, explain what it is doing instead to address those matters, and explain when those initiatives will be completed.

II. The Act only requires the Authority to report to the Minister in regard to the matters covered by section 42(1)(b). This is the Authority's **statutory report**, and is presented in Part 3 of this document.

III. In addition, the Authority has chosen to provide an **information report** on all of the matters covered by section 42, as section 43 of the Act provides for the Minister to amend the Code on those matters if the Minister considers the Authority's Code amendments are not satisfactory. The information report includes discussion of the implementation of the Code amendments, and is presented in Part 4 of this document.

IV. The Authority is pleased to report that it considers that the requirements of section 42 have been completed with solutions that will provide the best results in terms of the Authority's statutory objective.

V. It is the Authority's view that no further action by the Minister under section 43 is required.

The Authority's approach

VI. The Authority has undertaken a rigorous process of investigation, analysis and consultation to determine the best approach for each of the section 42 matters. Extensive consideration has been given to stakeholder views, international practice (where relevant), and independent and expert advice. In all cases the Authority considers the approach adopted is that most likely to deliver long-term benefits to electricity consumers, as required by section 15 of the Act.

VII. The Authority has provided stakeholders with regular updates on progress with section 42 matters as well as opportunities to provide input.

VIII. The Authority will be continuing to monitor the market to keep abreast of intended and potentially unintended consequences of these market initiatives.

Summary of statutory report

IX. As noted above, section 42(1)(b) of the Act allows the Authority to adopt alternative methods or alternative Code amendments for dealing with a matter listed in section 42(2). The Authority has adopted alternative approaches for two matters:

(a) floors on spot prices during supply emergencies (section 42(2)(b)); and

(b) facilitating, or providing for, an active hedge market (section 42(2)(g)).

X. The Authority has amended the Code to introduce floors on spot prices during supply emergencies (called **scarcity prices**), but only for forced power cuts arising from very short-term capacity shortages (called emergency load shedding), and only if those power cuts are nation-wide or island-wide. The Authority has not introduced price floors for supply emergencies relating to seasonal energy shortages, such as would require public conservation campaigns (PCCs) or rolling outages. It also hasn't introduced price floors to deal with capacity shortages affecting the instantaneous reserves (IR) market.

XI. In regard to the IR market the Authority inherited Code amendments made by the Electricity Commission in early 2010, which adopted a model-based solution and does not set a floor for IR prices. The Authority considered this arrangement was more than satisfactory, subject to introducing some minor refinements to that regime, which the Authority has done.

XII. The Authority was unable to find a model-based solution for PCCs and rolling outages, leaving it with the option of introducing a $500/MWh price floor for the duration of PCCs and a $3,000/MWh price floor for rolling outages. As PCCs could potentially last for several months, and rolling outages could occur over several weeks, the Authority determined that price floors for these events were likely to be counter-productive, and could indeed create perverse opportunities for thermal generators to withhold their plant to bring on those events to earn higher prices.

XIII. After substantial analysis and several rounds of consultation the Authority concluded that a better option was available in the form of Code amendments to require industry participants to undertake 'stress tests' to improve their understanding of the risks associated with PCCs and other supply emergencies, and most importantly, to increase their accountability for their risk management decisions. The Authority is expecting to Gazette these Code amendments on 3 November 2011.

XIV. As noted above, section 42(2)(g) required the Authority to amend the Code to facilitate, or provide for, an active **hedge market**. In this case the Authority has successfully facilitated an active hedge market without Code amendments but has prepared fallback Code amendments in case progress stalls. The Authority considers that significant progress has been made over a short period of time as there are now robust forward price curves and a significantly improved ability for parties to trade volumes at narrow spreads. These conditions will facilitate the development of an active hedge market.

XV. Given the very considerable work the Authority has undertaken on these matters, the Authority believes the Minister should not consider amending the Code, as provided for in section 43(1)(b) of the Act. In the Authority's view it is neither necessary nor desirable for the Minister to make Code on these matters.

Summary of information report

XVI. The table below provides a summary completion report against all section 42 new matters. More detail is provided in the body of the report.

Section 42(2) requirement	Completion summary	Code amendment
(a) provision of compensation by retailers to consumers during PCCs.	**Completed in accordance with s42(1)(a)** Customer compensation scheme included in Code. Code came into effect on 1 April 2011. This scheme requires retailers to pay customers \$10.50 per week when a PCC is called by the system operator based on a predefined trigger.	Code amendments gazetted on 3 March 2011.
(b) imposing a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including PCCs).	**Completed in accordance with s42(1)(a) and (b)** The solution involves two components: 1. Scarcity pricing (a price floor and price cap) for certain emergency load shedding situations; and 2. A 'stress test' regime as described in paragraphs 18 to 45 of the statutory report. The Code comes into effect on 1 June 2013 for scarcity pricing. The Code for the stress test is expected to come into effect on 1 March 2012.	Scarcity pricing Code amendments gazetted on 28 October 2011. Stress test Code amendments expected to be gazetted on 3 November 2011.
(c) mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid.	**Completed in accordance with s42(1)(a)** The Code was amended to provide for the introduction of inter-island financial transmission rights (FTRs), a special type of hedge product to assist parties to manage locational price risks caused by transmission constraints and losses between the North and South Islands, and HVDC reserve risks. The Code came into effect on 1 October 2011.	Code amendments gazetted on 11 August 2011.
(d) mechanisms to allow participants who buy electricity on the wholesale market to benefit from demand reductions.	**Completed in accordance with s42(1)(a)** Two projects completed and Code amendments made: • Demand-side bidding and forecasting (DSBF); and • Dispatchable demand (DD). DSBF improves demand forecasting, scheduled information and price sensitivities due to changes in demand. DD allows demand (at non-conforming nodes, typically large industrial consumers) to be dispatched in a similar fashion to generation. The Code amendments for DSBF come into force on 28 June 2012 and those for DD one year later on 27 June 2013.	DSBF: Code amendment gazetted on 20 October 2011. DD: Code amendment gazetted on 20 October 2011.

Section 42(2) requirement	Completion summary	Code amendment
(e) requirements for distributors that do not send accounts to consumers directly to use more standardised tariff structures; and (f) requirements for all distributors to use more standardised use-of-system agreements, and for those use-of-system agreements to include provisions indemnifying retailers in respect of liability under the Consumer Guarantees Act 1993 for breaches of acceptable quality of supply, where those breaches were caused by faults on a distributor's network.	Completed in accordance with s42(1)(a) Code amendments have been made to provide for more standardisation, e.g. distributor prudential requirements, a requirement that distributors consult before making tariff structure changes, a requirement for distributors to negotiate in good faith or to enter into mediation if parties are unable to agree to terms, standardised data formats used for exchanging tariff rate information, and distributor indemnities. In addition, market facilitation measures are also being developed, e.g. updated distributor Model use of system agreements (MUoSA).	Code amendments gazetted on 28 October 2011.
(g) facilitating, or providing for, an active market for trading financial hedge contracts for electricity.	Completed in accordance with s42(1)(b) An active hedge market has been provided for without amending the Code. See paragraphs 46 to 65 of the statutory report.	No Code amendments made.

Implementation

XVII. Implementation of a number of the Code amendments requires significant software changes to market systems to be carried out by the system operator and other market operation service providers. Although not part of the requirements of section 42, this report includes supplementary information on the current schedules for implementing the system changes.

1. Introduction

1. The Electricity Authority (Authority) was established on 1 November 2010 by the Electricity Industry Act 2010 (the Act).

2. The Act made specific provisions in sections 42 and 43 for addressing key policy issues arising from the 2009 Ministerial Review of Electricity Market Performance.

3. Section 42 of the Act sets out key priorities to be completed by the Authority by 1 November 2011.

> ***42 Specific new matters to be in Code***
>
> (1) Before the date that is 1 year after this section comes into force, the Authority must either—
>
> (a) have amended the Code so that it includes all the matters described in subsection (2) (the **new matters**); or
>
> (b) to the extent that the Code does not include all the new matters, have delivered to the Minister a report described in subsection (3).
>
> (2) The new matters are as follows:
>
> (a) provision of compensation by retailers to consumers during public conservation campaigns:
>
> (b) imposing a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including public conservation campaigns):
>
> (c) mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid:
>
> (d) mechanisms to allow participants who buy electricity on the wholesale market (commonly called the demand side) to benefit from demand reductions:
>
> (e) requirements for distributors that do not send accounts to consumers directly to use more standardised tariff structures:
>
> (f) requirements for all distributors to use more standardised use-of-system agreements, and for those use-of-system agreements to include provisions indemnifying retailers in respect of liability under the Consumer Guarantees Act 1993 for breaches of acceptable quality of supply, where those breaches were caused by faults on a distributor's network:
>
> (g) facilitating, or providing for, an active market for trading financial hedge contracts for electricity.
>
> (3) A report provided under subsection (1)(b) must—
>
> (a) identify which new matters are not included in the Code; and
>
> (b) explain why the Authority has not amended the Code to include those matters; and
>
> (c) suggest alternative methods by which the matters are or may be provided for; and
>
> (d) set out if, when, and how the Authority proposes to provide for the matters.

4. Section 42(1)(b) requires a report to the Minister of Energy and Resources (the Minister) where the Code amendments made do not include all the new matters. **Part 3** of this document provides that report. Called the statutory report, it will be used by the Minister to make decisions in accordance with section 43(1)(b) of the Act (see next page).

5. **Part 4** of this document summarises the Authority's work on all of the section 42 new matters, and outlines the systems implementation of those matters. While not required by the Act, the Authority has provided the additional information to assist the Minister to make decisions in accordance with section 43(1)(a) of the Act.

> ***43 Minister may amend Code to include new matters***
>
> (1) The Minister may amend the Code by including provisions for any of the new matters identified in section 42(2) if—
>
> (a) the Minister considers that the Code's provisions for a new matter are not satisfactory; or
>
> (b) the Minister considers that, in light of the Authority's report given under section 42(1)(b), it is necessary or desirable for the Minister to amend the Code to include provisions for the matter in the Code.
>
> (2) The Minister may amend the Code as if he or she were the Authority, and sections 37 to 40 apply accordingly.
>
> (3) Before amending the Code, the Minister must—
>
> (a) consult with the Authority (in addition to any consultation required under section 39); and
>
> (b) be satisfied that the amendments will achieve the Authority's objective in section 15.
>
> (4) The power given by this section may not be exercised earlier than 1 year after, and not more than 3 years after, the date on which this section comes into force.

6. Section 43(1)(a) provides for the Minister to make Code if the Minister considers that the Authority's Code amendments regarding section 42(2) items are not satisfactory.

7. The Authority considers its Code amendments provide the best solution to the policy issues, and are more than satisfactory. The Authority will also continue to monitor the policy issues covered by section 42 and will further consider Code or other measures if the desired outcomes are not achieved. In some cases the Authority has also identified work that it is undertaking to further progress the desired outcomes.

8. Section 43(1)(b) provides for the Minister to make Code if the Minister considers that it is necessary or desirable to do so to address matters for which the Authority adopted a different approach than specified in section 42(2). Again, the Authority considers the alternative methods and alternative Code amendments it adopted provide the best solution to the policy issues, and it is neither necessary nor desirable for the Minister to make Code in regard to these matters. The Authority will take further action if future developments suggest they are necessary to promote the objective set for the Authority in section 15 of the Act.

9. It should be noted that section 43(2) requires a full and detailed process to be followed should the Minister wish to make Code, including meeting the requirements that the Authority must meet, plus an additional requirement under section 43(3).

2. The Authority Approach

10. The Authority has undertaken a rigorous process of investigation, analysis and consultation to determine the best possible approach for each of the section 42 new matters.

11. Stakeholders expressed widely varying views on the potential options to address the section 42 matters, and in most cases diametrically opposite views were expressed among the range of submitters. The Authority has taken care to understand those views and the reasoning behind them, as well as seeking out independent and expert advice in order to develop effective and durable solutions that promote the Authority's statutory objective. In addition, the approach adopted for each section 42 matter has been developed in relation to the other initiatives, to achieve the best possible overall market arrangements.

12. The Authority will be continuing to monitor the market to keep abreast of intended and unintended consequences of these market initiatives. The Authority will be providing ongoing updates on implementation of the completed section 42 matters, and further work it is carrying out in related areas as outlined in **part 4** of this report.

13. The Authority operates in an open and transparent manner. In particular, the Authority uses its website to ensure that all relevant material that can be made available is published. Published information on the website includes, for example, expert advice commissioned by the Authority, consultation papers, submissions, summaries of submissions, explanatory papers and decision papers. Links to the appropriate page on the Authority website are provided in the sections below explaining each of the section 42 projects.

3. Statutory Report

14. Through the operation of section 42(1)(b) and section 42(3) of the Electricity Industry Act 2010 the Authority is required to deliver a report to the Minister that identifies which of the “new matters” are not included in the Code. The report must also provide an explanation of why the Authority has not amended the Code to include those matters, suggest alternative methods by which those matters are or may be provided for, and set out if, when and how the Authority proposes to provide for the matters.

15. Two of the new matters have been provided for without amending the Code in the manner specified in section 42(2): These are

    (a) Section 42(2)(b). Code amendments have not been made to impose price floors for PCCs and rolling outages. The ‘stress testing’ regime was assessed as being a better alternative for these energy related scarcity situations; and

    (b) Section 42(2)(g). Code amendments are not considered necessary because an active market for trading financial hedge contracts has been provided for without Code amendments.

16. In both cases the Authority considers that the best possible solutions have been identified to address the policy issues, and more specifically the objective sought by the Act. Accordingly, the Authority considers that no further action by the Minister under section 43 of the Act is necessary or desirable.

17. The following sections provide reports on these two matters, addressing the specific requirements of section 42(3) of the Act.

Section 42(3)

A report provided under subsection (1)(b) must—

(a) identify which new matters are not included in the Code; and
(b) explain why the Authority has not amended the Code to include those matters; and
(c) suggest alternative methods by which the matters are or may be provided for; and
(d) set out if, when, and how the Authority proposes to provide for the matters.

Stress testing

18. Section 42(2)(b) requires Code amendments to impose a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including PCCs).

(a) Identify which new matters are not included in the Code

19. The Code amendments did not include a price floor or price floors to cover energy-related supply emergencies, such as for PCCs or rolling outages.

(b) Explain why the Authority has not amended the Code to include those matters

20. The Authority considered, and consulted on in March 2011, a proposal to amend the Code to provide for price floors for PCCs and rolling outages. The Authority also appointed a scarcity pricing forum, comprising representatives of stakeholders from all sectors of the industry, including small and large consumers, and the Ministry of Economic Development (MED). It met several times to discuss scarcity pricing generally, including during energy shortages.

21. Following consideration of submissions and feedback from the forum, the Authority decided against including price floors for PCCs or rolling outages in its scarcity pricing Code amendments for the following reasons:

    (a) Introducing price floors for energy-related scarcity risks creating a perverse incentive for thermal generators to withhold supply in the lead up to PCCs or rolling outages to hasten the triggering of the price floor.

    (b) The imposition of a price floor for PCCs or rolling outages, would risk having a floor in place for an extended period of time that would be very intrusive to market operations if set too high and ineffective if set too low. In contrast, emergency load shedding events arise suddenly and typically have a very short duration, making it less difficult to set a price that reflects expected conditions in such events.

    (c) Price floors during extended energy shortages, which could occur under PCCs or rolling outages, would only be effective (i.e. alter risk management behaviour) if they are perceived to be durable. However, the durability of such an arrangement will be in doubt where participants perceive a risk that a future regulator or Parliament will overturn a price floor (e.g. due to criticism that a price floor is responsible for lost export orders, supplier failures etc). Due to the expected infrequency of PCCs, which should not occur more than once every 10–20 years, it will be difficult to establish policy credibly ahead of time.

    (d) Concerns about energy shortages have already been addressed to a large degree by other measures, notably the adoption of pre-announced trigger points for PCCs, the introduction of the customer compensation scheme applying to electricity retailers, and the physical asset swaps between Meridian Energy and Genesis Energy and the virtual asset swaps involving the same two companies and Mighty River Power.

(e) There is no international precedence for using scarcity pricing for energy scarcity situations, which means that New Zealand would be 'going it alone' in introducing a risky mechanism with potentially high negative impacts without the benefit of observing the effects of such a mechanism in other jurisdictions.

22. In 2010, the Electricity Commission adopted a model-based solution to deal with price collapses when the system operator reduced demand for instantaneous reserves (IR) to free up generation capacity for the energy market. This approach avoided the need to set price floors for the IR market. However, the Authority was unable to develop a workable model-based solution for PCCs or rolling outages. Accordingly, the Authority, cognisant of the serious problems associated with a price floor for extended supply emergencies, developed an alternative approach, called stress testing. The seeds of the idea arose in the scarcity pricing forum of stakeholders.

(c) Suggest alternative methods by which the matters are or may be provided for

23. The Authority has selected an alternative method — the 'stress testing' regime — to address energy-related scarcity situations.

24. Although PCCs and rolling outages are sometimes needed in the short-term to deal with energy shortages, they can undermine long-term commercial incentives for parties to provide last-resort generation plant and demand response capability, as PCCs and rolling outages suppress spot prices just at the time that providers of last-resort plant seek to earn a return on their investments. If spot prices fall below efficient levels then too little last-resort resources will be available to deal with dry year events, and PCCs and rolling outages will occur too often, imposing high costs on electricity consumers.

25. A theoretical benefit from setting price floors for PCCs and rolling outages is that they would stop prices falling below the efficient level when those events occur, provided of course the price floors were set at efficient levels. The prospect of a regulator determining approximately efficient price levels for a period of many weeks or months, across many different locations and circumstances, is not one that the Authority believes is readily achievable.

26. The Authority believes a model-based solution, where demand reductions from PCCs and rolling outages were added back into the final pricing model and market bids and offers were used to determine spot prices, would be more likely to deliver the sought after benefits. Unfortunately the Authority was unable to develop a feasible model-based solution. It was left with the option of setting a $500/MWh floor price for PCCs, and a $3,000/MWh price for rolling outages, which carried the risks and costs discussed in paragraph 21 above.

27. According to MED another primary policy objective of introducing price floors for PCCs was to discourage parties from lobbying in ways that impose high costs on New Zealand. In discussing these issues with the Authority's scarcity pricing forum in early 2011, MED warned that past experience in New Zealand shows that the lobbying often takes forms that tarnish New Zealand's reputation for a reliable and competitively-priced electricity supply, harming investor perceptions of New Zealand. The cost to New Zealand in the form of forgone investment and economic growth was considerable in their view, and worked against the Government's economic growth strategy.

28. Hence, the lobbying itself was considered to inflict considerable cost on New Zealand even if it doesn't alter the frequency of PCCs. MED presented the case to the scarcity pricing forum that a price floor for PCCs would discourage parties from lobbying for PCCs and for other initiatives to suppress prices. Less lobbying would improve international investor perceptions, and it would also give providers of last-resort resources greater confidence the regulatory framework would remain stable and accepting of high spot market prices when supply shortages occur.

29. The forum gave considerable thought to MED's concerns and suggested, among several options, that financial disincentives be imposed on parties lobbying in the lead up to or during PCCs. Authority staff considered this option and decided it would be neither appropriate from a democratic perspective nor feasible from a pragmatic perspective.

30. The forum's suggestion, however, led the Authority to consider why some electricity retailers and business consumers lobby much more vociferously against electricity market outcomes than occurs with other markets, and considered why they choose hedge levels that they later regret because of the impact on their business.

31. Prices in the electricity spot market are many times more volatile than prices for other products such as oil, foreign currencies and dairy products. There can be lengthy periods of relatively modest electricity spot prices (e.g. for two to three years at a time) interspersed with occasional extremely high price spikes (e.g. for two to three months) when conditions become tight.

32. This type of volatility, combined with the fact that electricity is an essential and significant input for many consumers and that the competitive electricity market is a relatively young market borne out of deregulation, provides fertile grounds for parties to believe they can lobby effectively for intervention or some form of relief when spot prices are high.

33. As a result there appears to be an incentive for some parties to purchase their electricity at spot market prices without obtaining sufficient hedge cover to cope with occasional periods of high prices. This choice is more tempting when hedge prices are considerably higher than spot market prices for several years.

34. It is also particularly tempting for large energy intensive businesses that invested in New Zealand in earlier decades when electricity prices were substantially lower than they are now. If they are an unprofitable business at hedge market prices, they have little option but to try to survive by buying from the spot market when it is cheap, and complaining about prices when they are high.

35. The reality is that, when faced with a choice between the survival of their own business or their own job or job prospects, it can be very difficult for parties to accept responsibility for the risks they took, and it is natural for them to look for a scapegoat in the form of 'the spot market is dysfunctional' or 'the spot market is not competitive' type statements.

36. It can also be very difficult for policy makers, especially those not deeply involved in electricity matters, to properly appreciate the risk management choices made by such parties. Also, on arcane topics like electricity hedging it can be very difficult for policy makers to convince the wider electorate that the risk-takers are responsible for the financial hardship their business faces. These difficulties are magnified when employees are stood down, export orders are lost, and New Zealand's reputation for a reliable electricity supply is tarnished.

37. These factors increase the risk of an ad hoc policy intervention during a tight supply situation to provide 'relief' for some parties, even though this undermines prudent hedging decisions made by other participants.

38. The stress testing regime will address these problems by requiring spot market purchasers to calculate their exposure to high spot prices, report their results to their board and to an independent registrar appointed by the Authority. The registrar will compute risk measures and provide them to the Authority in a form in which individual parties could not be identified. The Authority will publish the results on a regular basis and monitor the overall pattern of risk exposure across the market and trends through time.

39. In short, the stress test puts information disclosure mechanisms in place to make it clear to everyone that parties buying from the spot market did so knowing the risks they were taking and knowing that they are accountable for the consequences of their decisions.

40. Poorly hedged parties will find it much more difficult to persuade policy makers and media commentators that high spot market prices, or supposedly uncompetitive hedge prices, are to blame for their predicament as it will be clear that other parties have obtained sufficient hedge cover for their businesses. To reinforce this, the Authority will also be publishing fact sheets comparing long-term hedge prices with the cost of new generation. It also intends publishing a booklet on the stress tests and undertaking educational programs targeted at retail consumers paying tariffs based directly on spot market prices.

41. In essence, the stress testing regime makes it clear accountability for risk-taking lies with the risk-taker, and they will not be 'bailed out' by the Government for poor risk management decisions.

(d) Set out if, when, and how the Authority proposes to provide for the matters

42. The Authority Board has approved the Code amendments for the stress testing regime and it is scheduled to Gazette the Code amendments on 3 November 2011.

(e) Conclusion

43. The Authority considers the stress testing regime is a superior alternative to the imposition of a price floor or floors for public conservation campaigns and rolling outages. As discussed in paragraph 21, the Authority considers the price floor approach carries serious risks that would need to be fully addressed before it would be wise to adopt it.

44. By providing additional ‘belts and braces’ against ad hoc policy interventions occurring, and making it clear to everyone that accountability for risk-taking lies with the risk-takers, the stress test Code amendments will provide investors in last-resort plant with greater confidence about the regulatory environment when high spot prices are needed. The stress test regime is also likely to increase hedging activity by some parties exposed to spot prices, providing more certain revenue streams for investors in last-resort plant.

45. The Authority does not consider further action is required by the Minister under section 43 in relation to this matter.

Hedge market development

46. Section 42(2)(g) requires facilitating, or providing for, an active market for trading financial hedge contracts for electricity.

47. This section provides a specific report under section 42(3). The headings below are the specific requirements of that section.

(a) Identify which new matters are not included in the Code

48. The Authority has not amended the Code to facilitate, or provide for, an active market for trading financial hedge contracts for electricity.

(b) Explain why the Authority has not amended the Code to include those matters

49. The Authority has successfully worked with the Australian Securities Exchange (ASX) and the large generators to get new market-making agreements in place without Code amendments. The new market-making agreements lay the foundations for an active hedge market to develop.

50. The Authority's cost-benefit analysis indicates the long-term interests of electricity consumers are likely to better served by building hedge market activity without resort to Code amendments, provided ongoing progress is reasonable. Adopting Code amendments risks putting a straight-jacket over a nascent futures market that needs flexibility to evolve its trading practices and contracts in ways that best meet the needs of its users.

51. In practice it takes time for participants to build their confidence in new markets, which is the driver for trading activity and liquidity. The experience with futures markets is that the more liquidity they have, the more parties will want to trade on them, which in turn tends to increase liquidity. As it isn't possible to regulate confidence directly, the Authority believes the best approach is to lay the foundations for confidence to build over time as the performance of the market improves.

52. The Authority was prepared to amend the Code to require generators to adopt the new market agreements but that has not proved necessary as the four largest generators have adopted those agreements voluntarily. The Authority considers that significant progress has been made over a short period of time as there are now robust forward price curves and a significantly improved ability for parties to trade volumes at narrow spreads.

53. It is important to appreciate the Act did not require the Authority to achieve an active hedge market by 1 November 2011, but rather to facilitate, or provide for, one to develop. This reflects the reality that building an active market takes time, and the Act did not require the Authority to introduce mandatory hedging arrangements if certain activity levels were not met. The Act is silent on activity levels.

(c) Suggest alternative methods by which the matters are or may be provided for

54. As noted above the Authority has successfully worked with the ASX and the large generators to get new market-making agreements in place to improve the pricing of electricity futures contracts and increase the volumes offered on the NZ electricity futures market. Three generators have signed the new agreements with ASX, and a fourth generator is market-making in accordance with the new approach whilst it is completing internal approvals to sign the new agreement.

55. The revised market-maker agreements provide for a maximum five percent spread between bid-ask prices, and require market-makers to offer 3 MW of futures contracts at each of Otahuhu and Benmore for 3:30 – 4:00pm each business day. They are also required to refresh their offers at least once during the time period by 1 MW.

56. As a result, bid-ask spreads have reduced significantly and trading activity has increased substantially. As at 27 October 2011, unmatched open interest (UOI) had increased to 991 GWh.

57. The Government had set a target for UOI *outside* of the Act, which was set at 3,000 GWh by 1 June 2010. The Authority's view is that the target has effectively been met because Genesis Energy, Meridian Energy and Mighty River Power have indexed their virtual asset swap (VAS) contracts to the ASX NZ electricity futures price.

58. Nevertheless the Authority believes it is also important to achieve greater transparency around the true UOI levels, and to this end it has set new targets for UOI:
    - 1,000 GWh by 1 December 2011;
    - 2,000 GWh by 1 March 2012; and
    - 3,000 GWh by 1 June 2012.

59. The Authority intends obtaining the virtual asset swap contracts from the relevant generators and publishing them if the UOI targets are not met.

60. The Authority also intends to publish a booklet on electricity price risk management and engage an expert to provide presentations on this matter to interested parties.

61. The Authority is encouraging the development of a cap or options contract on the ASX platform, with market-making on those caps or options, reviewing prudential security arrangements for the wholesale electricity market, and reviewing the availability of market-related information, particularly in regard to supply risks. Combined with the scarcity pricing and stress test Code amendments discussed earlier, these initiatives will encourage greater hedge market activity.

62. Despite the very promising progress to-date the Authority has prepared draft Code amendments as a fallback option in the event that generators relinquish the new market-making agreements. It is also continuing with its cost-benefit analysis of market-making criteria to determine whether more generators should be market-makers on the ASX platform and whether Code amendments on that matter would deliver long-term benefits to consumers.

(d) Set out if, when, and how the Authority proposes to provide for the matters

63. The Authority has already successfully achieved the policy objective of s42(2)(g) of the Act, which is to facilitate or provide for an active hedge market. This has been achieved by adopting a market facilitation approach rather than Code amendments.

Conclusion

64. The Authority considers that the requirement of section 42(2)(g) has been met. The Authority has facilitated the development of an active market for trading financial hedge contracts without making Code amendments. It will be undertaking ongoing monitoring of hedge market developments, and is hopeful financial intermediaries and large consumers will enter the NZ electricity futures market, which will further boost activity and liquidity.

65. The Authority does not consider further action is required by the Minister under section 43 in relation to this matter.

4. Information Report

Introduction

66. As noted above, the Authority considers that all of the requirements of section 42 have been completed with solutions that will provide the best results in terms of the policy issues being addressed and in terms of the Authority's statutory objective.

67. While not required by the Act, the Authority has included this part of the report, covering all section 42 new matters, as it considers that this is a useful summary of its work for both the Minister and a broader audience.

68. The seven matters in section 42 have been addressed as follows:

    (a) A customer compensation scheme for section 42(2)(a);

    (b) Scarcity pricing and a stress testing regime for section 42(2)(b);

    (c) A financial transmission rights market for section 42(2)(c);

    (d) Dispatchable demand and demand-side bidding and forecasting for section 42(2)(d);

    (e) A suite of standardisation initiatives for sections 42(2)(e) and (f); and

    (f) New market-making agreements for section 42(2)(g).

69. The rest of this report presents the section 42 requirements, our understanding of the policy issues each was intended to address, the work completed by the Authority, a summary of stakeholder support, and links to the Authority's website where more detailed information can be found. In some cases the Authority has identified further related work leading on from its section 42 work, and this has also been summarised below.

a) Customer compensation

Act requirement

70. Section 42(2)(a) requires provision of compensation by retailers to consumers during PCCs.

Policy context

71. PCCs impose costs on retailer's customers because customers' reduce electricity consumption to lower levels than they would otherwise use. Customers suffer a reduction in economic welfare. In the past, customers have typically not been compensated for their conservation efforts, giving electricity retailers (and large consumers exposed to spot market prices) incentives to call for PCCs earlier than when they are needed or when they are not needed at all.

72. There were three PCCs between 2000 and 2010. Frequently occurring PCCs, combined with a lack of customer compensation, have contributed to increasing levels of dissatisfaction with the performance of the New Zealand electricity market.

Work completed and rationale

73. **Completed as specified in section 42(2)(a):** a customer compensation scheme (CCS) was incorporated into the Code in March 2011. The CCS is a new subpart 4 to Part 9 of the Code.

74. By requiring retailers to pay compensation to customers when a PCC occurs, the CCS encourages electricity retailers to more actively use commercial arrangements to manage dry-year risks, rather than rely on 'free savings' from consumers as appears to have occurred in the past. The stronger focus on commercial arrangements is expected to result in more contracting for demand response, such as demand buybacks and innovative schemes to more closely link compensation payments to electricity savings, greater investment in dry year generation capacity, and greater use of hedge contracts to manage risk. The end result should be better management of dry year risk and reduced frequency of public conservation campaigns.

75. Under the CCS, retailers will pay qualifying customers $10.50 per week during any PCC. Retailers may also take up the option of offering their own compensation schemes potentially linked to individual customers' conservation efforts but consumers have the right to remain on the default scheme if they prefer.

76. The CCS provides certainty as to when a PCC may be called in the future and assigns clear responsibility for triggering and ending a campaign to the system operator. A PCC is triggered by the system operator when hydro storage falls to the point that the risk of shortage is 10 percent or more and is forecast to remain at 10 percent or more for a period of at least one week. The system operator ends a PCC when storage recovers to a shortage risk level of eight percent or less. A PCC may apply to all of New Zealand or to the South Island only, depending on the prevailing hydro storage conditions.

77. If hydro storage falls to low levels close to the trigger point for a PCC, customers would expect to see increased levels of media coverage and public comment, along with direct communication from retailers about their qualification status, the details of the default CCS and any alternative CCS they may have on offer.

78. The value of the compensation payment is initially set at $10.50 a week and will be reviewed after each PCC and at least at three yearly intervals. The initial $10.50 value is based on the estimated savings that qualifying customers in aggregate would achieve during a PCC. The $10.50 payment is intended to remove the benefit gained by retailers when their customers conserve electricity, and provide a reasonable level of compensation for the cost and inconvenience faced by customers in curbing their electricity use.

Stakeholder views

79. The Authority and its predecessor, the Electricity Commission, consulted widely with interested parties on the CCS. Input into the development and design of the CCS was provided through an advisory group comprising industry and consumer representatives. Specialist advice was also obtained from a technical group.

80. There was general, but not unanimous, support expressed by submitters for introducing a CCS. Most acknowledged the need for measures to address the problem but diverged in their views on the extent to which the scheme proposed would deliver the required outcomes.

81. Retailers generally favoured an arrangement under which the Authority would decide whether they could adopt an alternative arrangement to the CCS provisions set out in the Code. The Authority considered it was inappropriate for it to “approve” retailers’ supply offerings and that consumers are the best parties to judge whether an alternative arrangement is more preferable to them than the standard CCS provisions.

Further information

82. Further information is available on the Authority website at: www.ea.govt.nz/consumer/customer-compensation-scheme/

83. A summary of submissions on the scheme proposal is available at: http://www.ea.govt.nz/document/11405/download/our-work/consultations/priority-projects/customer-compensation-scheme/submissions/

Conclusion

84. The Authority considers the section 42(a) requirement has been met with the inclusion of the Customer Compensation Scheme in the Code in March 2011.

b) Scarcity pricing

Act requirement

85. Section 42(2)(b) requires imposing a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including PCCs).

Policy context

86. Section 42(2)(b) seeks to address two related underlying concerns which arise when supply emergencies occur and spot prices are suppressed. Firstly, it addresses the problem that the price suppression that occurs during supply emergencies undermines the business case for investing in last resort generation or demand side measures.

87. On rare occasions, generation capacity can become so scarce that forced power cuts are required. Normally, when a good or service becomes scarce, demand is rationed by higher market prices. However, forced power cuts reduce spot prices for electricity, undermining the financial incentive for wholesale parties to make arrangements with consumers to voluntarily conserve power and for generators to maximise available supply.

88. Future investment decisions may also be affected. Wholesale participants make their decisions based on expected spot prices. If they expect spot prices to be suppressed below a competitive level in a supply emergency, this will reduce their incentive to make decisions to build last-resort generation plant, invest in demand-response capability and/or enter into future supply contracts that can underpin generation investment.

89. In addition, while price suppression is the main concern, when the system is at the limit of its capability there is also a possibility that spot prices will settle well above the level expected in a workably competitive market.

90. Secondly, section 42(2)(b) seeks to address the problem experienced over the last ten years or so, where parties exposed to spot market prices have lobbied successfully for PCCs and for other ad-hoc interventions to suppress spot market prices, when spot prices reach or are expected to reach in the near term high levels for prolonged periods (usually due to low hydro storage levels). Too frequent PCCs damages New Zealand's reputation for a reliable and competitively-priced electricity supply, harming investor perceptions of New Zealand and ultimately economic growth. As discussed in Part 3 (Statutory report), the Authority has addressed this second problem by developing Code amendments that provide for the stress testing regime.

Work completed and rationale

91. **Completed:** Code amendments were gazetted on 28 October 2011 to provide for a price floor and price cap in the event that an electricity supply emergency results in emergency load shedding (forced power cuts) for all of New Zealand or for all of the North or South Island. These amendments collectively implement 'scarcity pricing'. Scarcity pricing comes into force on 1 June 2013.

92. From 1 June 2013 onward, if scarcity pricing is triggered, the generation weighted average spot price (GWAP) will first be calculated for the affected island(s) based on existing pricing processes. If the GWAP is lower than $10,000/MWh, all prices within the affected island(s) will be scaled up so that the GWAP reaches $10,000/MWh. If the GWAP based on existing pricing processes is more than $20,000/MWh, all prices will be scaled downwards so that GWAP is $20,000/MWh.

93. The price floor has been set at the level roughly equivalent to the price required to cover the costs of a last-resort generation station. Setting a price floor at this level should give investors in last-resort resources confidence that emergency load shedding will not undermine the business case for investing in those resources. This promotes reliable supply by the electricity industry.

94. The price cap reflects an upper estimate of the value of forgone consumption during emergency load shedding. It has been adopted to address consumer concerns that imposing a price floor for emergency load shedding situations may embolden providers of last-resort plant to charge prices above what would occur in a workably competitive market.

95. In combination, the floor and cap mechanism during emergency load shedding will give improved revenue certainty for providers of last resort resources (generation and demand response), while also giving more assurance to wholesale purchasers that spot prices in emergency load shedding will not settle well above the level expected in a workably competitive market.

96. Furthermore, scarcity pricing will increase incentives for consumers and net-retailers to enter into hedge arrangements with providers of last resort resources, increasing competition in the provision of these resources. Scarcity pricing will also assist to underpin the development of voluntary demand side alternatives, such as retailers entering into arrangements that reward customers for providing interruptible demand. In this context, it is compatible with the Authority’s dispatchable demand initiative.

97. A stop-loss mechanism will halt the application of scarcity pricing if the average price over any rolling seven day period is greater than $1,000/MWh. Beyond this limit, normal pricing processes would apply.

Stakeholder views

98. Two rounds of consultation were held on scarcity pricing arrangements. More than 20 parties made submissions on both rounds and included a wide range of perspectives, from individual consumers, to lines companies, Transpower, and generators.

99. The great majority of parties supported the application of scarcity pricing to emergency load shedding. Only two parties favoured a broader application of scarcity pricing to PCCs or rolling outages. Most, notably consumers, opposed its application to PCCs and rolling outages.

Further information

100. The Authority temporarily inherited management of arrangements for the Crown-owned Whirinaki power station to be used in the event of a supply shortage. In practice the Whirinaki plant discouraged participants from building last resort generation as they were reluctant to be exposed to competition from a plant that existed essentially for political purposes and not economic ones. The realism of these concerns was demonstrated by the policy decision in 2008 that, in supply shortages, Whirinaki would be offered at prices below the marginal cost of operating the plant. One of the first decisions of the Authority was to replace this policy with a requirement that the plant could not be offered at prices below its operating costs.

101. The Government's planned sale and cessation of operation of Whirinaki will remove its remaining distortionary effects and should, in itself, improve the incentives on market participants to better plan and prepare for potential supply emergencies, which will reduce their frequency of occurrence and effect.

102. Further information is available on the Authority website at: www.ea.govt.nz/our-work/programmes/priority-projects/scarcity-pricing-default-buy-back/

Conclusion

103. The Authority considers the section 42 requirement has been met by the gazettal of Code amendments that provide for scarcity pricing and the imminent gazettal of code amendments that provide for the stress testing regime. .

c) Locational price risk

Act requirement

104. Section 42(2)(c) requires mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid.

Policy context

105. Locational price risk refers to unpredictable movements in the price for electricity at different locations throughout the country. Locational prices are largely driven by transmission constraints that reflect many complex and uncertain aspects of the electricity system. Locational prices are also affected by transmission losses, which are more predictable.

106. Participants in the wholesale electricity market have been limited in how they can manage locational price risk. In general, a purchaser's exposure to locational price risks depended on their volume of hedge contracts and level of self-generation (if any), and on where those contracts and generation units are located relative to the location of their load. Hedge contracts may not provide effective protection against this type of locational price risk.

107. The main source of locational price risk occurs between the two islands—inter-island locational price risk—which accounts for approximately two thirds of all locational price risk. The other third arises within each island, called intra-island locational price risk.

Work completed and rationale

108. **Completed as specified in section 42(2)(c):** Code amendments were gazetted on 11 August 2011, allowing for the introduction of financial transmission rights (FTRs). The Code amendment came into force on 1 October 2011, and the Authority intends for the FTR market to be operating from 1 October 2012.

109. FTRs are essentially hedge contracts allowing parties to cover their price risk between two nodes on the national grid. Effectively, they are a type of insurance that protect wholesale market participants from half-hourly variations in spot market prices in one location versus another.

110. An FTR market, or equivalent, is widely used in other jurisdictions around the world and has been planned in New Zealand for more than a decade. Regulatory intervention has been necessary to enable the surplus funds arising in the spot market to be used to fund FTRs.

111. The FTR rules adopted by the Authority allow a wide range of FTRs to develop, but initially the focus will be on inter-island FTRs. These are FTRs covering price differences between the South Island (at Benmore) and the North Island (at Otahuhu).

112. Inter-island FTRs will be available to retailers and generators, large consumers buying their electricity directly from the spot market, and other institutions such as banks. They will be sold in monthly auctions up to two years in advance of the FTR period.

113. Holding an FTR or multiple FTRs should provide retailers with the confidence to either enter new areas or compete more strongly in areas where they have existing customers. Consumers should therefore see more retail competition and greater competitive pressure on prices.

Stakeholder views

114. Seventeen submissions were received on the draft Code amendment consultation paper. Submitters ranged from demand side participants, supply side participants, Transpower and others, including parties who would potentially be involved in trading financial transmission rights (FTRs).

115. There was broad support from submitters for the proposal (although some of this support was conditional). Four of the submitters were opposed to the proposed FTR scheme. Several submitters commented on the proposed design and operation of financial transmission rights. Some key matters raised in submissions were addressed by the Authority in consideration of the final Code amendment.

Further work—Within-island locational price risk

116. The Authority intends to assess whether a solution for within-island locational price risk is required (noting that inter-island FTRs address locational price risk between the islands). If this assessment is positive, the Authority will follow its normal consultation process, including the development of an issues and options consultation paper in the first instance.

Further information

117. Further information is available on the Authority website at: www.ea.govt.nz/our-work/programmes/priority-projects/locational-hedges/

118. A summary of and response to submissions is available at: http://www.ea.govt.nz/our-work/consultations/priority-projects/lpr-proposed-amendments/submissions/

Conclusion

119. The Authority considers the section 42 requirement has been met and does not consider any other actions are required at this stage, and will be carrying out ongoing monitoring of the regime and its impacts on the outcomes sought.

120. The provision of FTRs fills a major gap in the New Zealand electricity market arrangements that has existed since the wholesale electricity market began in October 1996.

d) Demand side initiatives

Act requirement

121. Section 42(2)(d) requires mechanisms to allow participants who buy electricity on the wholesale market (commonly called the demand side) to benefit from demand reductions.

Policy context

122. The ability of demand-side participants to respond actively to wholesale electricity market conditions is an important component of an efficient wholesale market. While there are existing mechanisms in place to encourage this response, several policy problems were identified with those arrangements.

123. The forecast schedules are not accurate in predicting the final price. This can result in a heightened risk that electricity users will either:

    (a) React unnecessarily to forecast high prices—i.e. curtail load when the final price is insufficient to reward the action; or

    (b) Miss an opportunity to react—i.e. not curtailing when the final price exceeds the value of supply.

124. This uncertainty and risk is almost certainly inhibiting purchasers' responsiveness to forecast prices.

125. Another problem with the current practice is the inter-relationship of interruptible load and electricity usage. A purchaser's interruptible load and electricity usage are treated separately by the scheduling software. This means that a purchaser must make its own decisions about the best option between using electricity and receiving revenue from interruptible load or reducing electricity usage and not receiving revenue from interruptible load

126. The demand-side bidding and forecasting (DSBF) and dispatchable demand (DD) proposals address these problems.

Work completed and rationale

127. **Completed as specified in section 42(2)(d):** Code amendments gazetted DSBF and DD were gazetted on 20 October 2011.

128. The Code amendments for DSBF come into force on 28 June 2012 and those for DD on 27 June 2013.

129. The DSBF initiative improves price forecasts to allow better use of generation and demand response capability. This is achieved by using the demand bids of large consumers (or consumers with standby generation) and the system operator's forecasts for demand for other consumers to calculate a price-responsive schedule (PRS). A non-response schedule (NRS) will also be calculated. Comparing these two

schedules will provide information about how price-responsive bids affect the schedules and assist purchasers and generators in making more efficient demand and generation response decisions.

130. DD provides a mechanism for large electricity purchasers at non-conforming nodes who choose to be dispatched in response to high forecast prices to receive the benefit of that dispatch. In the event that the final prices are different from the forecast prices this benefit will be achieved by the purchaser receiving a “constrained off” payment (when final prices turn out lower than forecast) or “constrained on” payment (when final prices turn out higher than forecast).

131. DD also introduces the co-optimisation by the scheduling software of electricity bids and interruptible load offers. This will benefit not only the purchaser (who will know that its dispatch instructions will be the optimal combination of electricity usage and interruptible load) but also the system operator.

Stakeholder views

132. Of the 11 submissions made on the DSBF consultation paper, five supported the proposal, four remained neutral and two were opposed.

133. Twelve submissions were received on the DD consultation paper. Nine supported the proposal, one was neutral and two were opposed.

Further work—Dispatchable demand

134. Based on experience with the new DD regime for large industrial consumers at non-conforming nodes, an assessment will be undertaken to consider whether DD should be extended to conforming nodes (i.e. for all remaining consumers). If this assessment is positive, the Authority will follow its normal Code development process, including the development of an issues and options consultation paper in the first instance.

Further information

135. Further information is available on the Authority website at:

Demand-side bidding and forecasting (DSBF)—www.ea.govt.nz/our-work/programmes/priority-projects/demand-side-bidding-forecasting/

Dispatchable demand (DD)—www.ea.govt.nz/our-work/programmes/priority-projects/dispatchable-demand/

Conclusion

136. The Authority considers the section 42 requirement has been met.

e) & f) More standardised tariffs and use of system agreements

Act requirement

137. Section 42(2)(e) requires distributors that do not send accounts to consumers directly to use more standardised tariff structures.

138. Section 42(2)(f) requires all distributors to use more standardised use-of-system agreements, and for those use-of-system agreements to include provisions indemnifying retailers in respect of liability under the Consumer Guarantees Act 1993 for breaches of acceptable quality of supply, where those breaches were caused by faults on a distributor's network.

Policy context

139. The diversity of distributors' tariff structures and conditions within distributors' use-of-system agreements (UoSA) creates transaction costs and acts as a barrier to retailers entering into distribution areas and expanding their operations. These factors impede retail competition.

Work completed and rationale

140. **Completed as specified in section 42(2)(e) and (f):** Code amendments were gazetted on 28 October 2011 on the following matters:

    (a) Code amendments to require distributors to consult with retailers[1] if the distributor makes a change to its tariff structure that will materially affect retailers or consumers.

    (b) Code amendments to require distributors and retailers to comply with Electricity Information Exchange Protocol 12 (which is a standard format) when distributors change tariff rate information and send that information to the retailers who trade on their network.

    (c) Code amendments to require the use of standard tariff codes when information relating to tariff codes is exchanged between participants.

    (d) Code amendments to require distributors and retailers to negotiate the terms of their use-of-system agreement in good faith, and to enter into mediation when the parties are unlikely to agree on the terms of the use-of-system agreement.

    (e) Code amendments to provide that if a distributor requires a retailer to comply with prudential requirements, the distributor must offer the retailer the option of meeting these by having either:

[1] The Code provisions use the term "trader" which includes retailers, generators, and direct purchasers who buy electricity from or sell electricity to the clearing manager. However, the 'more standardisation' amendments will overwhelmingly affect the retailer-distributor interface – hence the reference to retailers in this document.

(i) A minimum Standard and Poors BBB- credit rating (or equivalent) and not be subject to a negative credit watch; or

(ii) Providing a cash payment equal to two weeks worth of line charges or third party security or combination of these.

(f) In the case that the retailer elects to provide (ii) above the distributor may determine whether the retailer must provide additional security of the type provided for in the Code, that is, up to two months worth of line charges in total, with additional interest paid by the distributor to the retailer on any amount of additional security required in excess of the 2 week estimate.

(g) Code amendments to provide that, unless agreed otherwise by both parties, each use-of-system agreement between a distributor and a retailer is deemed to include an indemnity in favour of retailers in respect of liability under the Consumer Guarantees Act 1993 for breaches of acceptable quality of supply, where those breaches were caused by event or conditions on the distributor's network. The indemnity does not extend to Transpower.

141. The Code amendments, except as described below will come into force on 1 December 2011:

(a) Clauses relating to exchanging information about changes to distribution tariffs (i.e. EIEP12), using standard tariff codes and negotiating UoSAs (for existing UoSAs) will apply from 1 July 2013.

(b) Clauses relating to prudentials and consultation will apply from 1 May 2012.

142. The Authority considers that these Code amendments meet the requirements of sections 42(2)(e) and 42(2)(f). The Authority did not propose any additional Code amendments because an overly regulated approach to standardise distribution tariff structures risks creating a number of negative effects. Significantly, it could restrict to too great an extent the ability of distributors to tailor and provide for innovative pricing structures, which is likely to become increasingly important as smart meters become more prevalent. The Ministerial Review was very careful to recommend "more standardisation" and not "standardisation" for precisely these reasons.

143. In addition to the Code amendments described above, but not as an alternative, the Authority is reviewing and finalising a set of non-mandatory model use of system agreements (MUoSA) which will provide standard best practice terms and conditions for UoSA. These have been being consulted on and the intent is to introduce them in early 2012.

Stakeholder views

144. Stakeholders generally supported the Authority's finding that the standardisation of distribution tariff structures and UoSAs should be limited. There was very little support for high levels of standardisation provided through the Code, with most parties wary that too much standardisation could impede innovation and the ability of retailers and distributors to tailor conditions to their particular needs and characteristics.

145. There was general support for the Authority's proposal to standardise, through Code amendments, distributors' consultation and negotiation practices and moderate support for standardising tariff rate exchange information. There was much less support, with strong opposition from distributors, to the Authority's proposal to standardise, at a lower level than current practice in some cases, distributors' prudential requirements. Some established retailers were also opposed to the proposed changes to prudential requirements and smaller, new entrant retailers were most supportive of the Authority's approach.

146. There was also concern amongst distributors with the proposal that distributors indemnify retailers for losses up to the acceptable quality standard under the Consumer Guarantees Act where those losses arose out of a fault on the distributor's network. Retailers, however, supported the proposal.

Further work—More standardised tariff structures & use of system agreements

147. The Authority intends to monitor distributors' compliance with the new Code provisions. Authority staff will report to the Board on 1 May 2013 and each year thereafter if the changes made to prudential requirements are causing distributors to cease their non discriminatory practice to retailer access to networks. Report(s) will also be provided to the Board if such a change in practice is brought to the attention of the Authority at any time.

148. The Authority already has in place a set of pricing principles that govern distributors' pricing methodologies. Distributors' alignment with these will be assessed in mid 2012. As a result of this assessment, new Code provisions may be introduced.

149. The Authority will also continue to work through its Standing Data Format Group to progress other technical initiatives to standardise tariff billing process and exchange of tariff information approaches. A consultation paper on these matters is expected to be released before the end of 2012.

150. The Act does not require the Authority to extend the indemnity described in section 42(2)(f) to Transpower. The Authority intends to include within its work programme for 2012 and out-years a project to assess the merits of extending the indemnity to Transpower.

Further information

151. Further information is available on the Authority website at: www.ea.govt.nz/our-work/programmes/market/consumer-rights-policy/model-arrangements/distribution-tariff/

Conclusion

152. The Authority considers the sections 42(2)(e) and (f) requirements have been met.

g) Hedge market development

Act requirement

153. Section 42(2)(g) requires facilitating, or providing for, an active market for trading financial hedge contracts for electricity.

Policy context

154. One of the outcomes of the Ministerial Review in 2010 was that the Minister of Energy and Resources requested the five major generators with over 500 MW of capacity to develop an active market for exchange-traded electricity contracts. The objective was to provide liquidity and improve access to hedge products for new entrant generators, retailers, and consumers.

155. The Minister set the electricity industry a target for satisfactory hedge market liquidity, defined as 3,000 GWh of 'unmatched open interest' (contracts for which the matching offsetting contracts are beneficially held by another independent party), to be achieved by 1 June 2011.

156. The unmatched open interest has been increasing but the industry's 3,000 GWh target was not met by 1 June. The Authority therefore proceeded with work to review and evaluate the progress made in the development of an active market for trading financial hedge contracts for electricity, and assess and introduce changes to address any shortcomings.

Work completed and rationale

157. **Completed: achieved without the need for Code amendment**—see paragraphs 46 to 65 of the statutory report for a discussion of this initiative.

158. Draft Code amendments have been prepared as a fallback option should voluntary measures prove unsuccessful in delivering the desired outcomes.

159. Code amendments have not been made at this stage because the largest generators have adopted new market-making agreements with ASX that will improve confidence in the forward price curve for exchange-traded financial instruments, leading to more generalised improvements in the wider (over the counter) financial hedge market. The three SOE generators have indexed their virtual asset swap (VAS) agreements to the ASX price.

160. The Authority considers very good progress has been made but will continue to monitor industry progress closely.

161. If the Authority decided to pursue the Code amendment option, it would undertake further consultation. Code amendments, if needed, could be implemented within a matter of months, including undertaking the consultation period.

162. As Code amendments have not been made, part 3 of this report contains a statutory report on this matter.

Stakeholder views

163. There were 14 submissions received on the consultation paper. Although some submissions (from small retailers and large users) suggested that the Authority should intervene more directly to encourage active trading, there was a high degree of support from submitters for the Authority's proposed approach.

Further information

164. Further information is available on the Authority website at: www.ea.govt.nz/our-work/programmes/market/hedge-market-development/

Conclusion

165. The Authority considers that the requirement of section 42(2)(g) has been met. The Authority has facilitated the development of an active market for trading financial hedge contracts without having to resort to Code amendments.

Implementation of Section 42 New Matters

166. The previous section shows the Authority has addressed the section 42 requirements in the Act. While the Act does not specifically address implementation, this section has been included to provide an overview of the work that follows to implement the Code amendments in the market systems.

167. Implementation of the section 42 matters involves varying degrees of effort by the Authority, its service providers, and market participants as some projects require complex software changes to systems before the initiative will be live in the market. The Authority is well advanced with this work. There are significant obligations on the system operator and other service providers to carry out work essential for successful implementation of the Code amendments. The Authority is working closely with these service providers and will monitor their progress with the implementation work.

168. The table below provides a summary of the implementation process and timetable, as appropriate.

Section 42(2) sub section and project name	Implementation Date	Implementation comment
(a) Customer compensation scheme	April 2011	The scheme was implemented prior to winter 2011.
(b) Scarcity pricing	March 2012	**Stress test:** the Authority is finalising the stress test specification. Participants will then put in place the processes to provide quarterly stress test results and annual company declarations. The Authority will appoint an independent registrar to consolidate and present the results to the Authority.
	June 2013	**Scarcity pricing:** Implementation requires software changes to be made by the pricing manager and system operator.

Section 42(2) sub section and project name	Implementation Date	Implementation comment
c) Financial transmission rights (FTRs)	The Authority intends for trading to start on 1 October 2012	The Authority is in the process of selecting an FTR manager. A request for proposals for the new service provider role was published on 30 August 2011 and closes on 31 October 2011. Once appointed the FTR manager will prepare detailed design (such as the auction process) in an FTR allocation plan, to be approved by the Authority and implement its systems and processes. Regulations are required to identify the FTR manager as a market operation service provider and to set a liability limit. A Cabinet paper will be prepared in December 2011 following consultation. Software changes will also need to be made by the clearing manager to alter its methodology for calculating the required level of prudential cover, create an FTR account, and set up processes for settlement of FTRs. Declarations to clarify the status of FTRs and authorisations for the clearing manager and FTR manager to trade in FTRs are currently being sought from the Financial Markets Authority. Declarations are currently being sought from Inland Revenue relating to the tax treatment of FTRs.
d) Demand-side bidding and forecasting (DSBF)	The commencement of DSBF is scheduled for June 2012	Implementation requires software changes to be made by the system operator, by NZX to the wholesale information trading system, and by industry participants. To assist participants an implementation forum was held on 12 October 2011.
d) Dispatchable demand (DD)	The commencement of DD is scheduled for June 2013	Implementation requires software changes to be made by the system operator and industry participants, including consumers who wish to participate in dispatchable demand.
e) & f) More standardised tariff structures & use of system agreements	1 December 2011, 1 May 2012, and 1 July 2013	The Code amendments, except as described below, will come into force from 1 December 2011: (a) clauses relating to exchanging information about changes to distribution tariffs (i.e. EIEP12), using standard tariff codes and negotiating UoSAs (for existing UoSAs) will apply from 1 July 2013; and (b) clauses relating to prudentials and consultation will apply from 1 May 2012. Relatively minor implementation work is required in each case.
g) Facilitating hedge market activity	1 November 2011	The Authority has liaised with the large generators to facilitate standardised market-making agreements being put in place. Three are already in place and a fourth is expected to be in place by 1 November 2011.

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