How to be a retailer

Version 9.11

Guidelines

26 January 2021

Market Services

Version control

Version	Date amended	Comments
4.0		
5.0	25 May 2010	Updated to reflect changes in legislation.
6.0	6 December 2010	Updated to reflect changes in legislation and move to the Electricity Authority
7.0	18 November 2013	Updated for Part 10 and stress testing
7.1	20 March 2014	Updated for distributor prudential and regulated Electricity Industry Exchange Protocols
8.1	11 November 2014	Updated to include reference to stress testing and retailer default and disconnections. General additions and corrections.
8.2	4 August 2015	Added retail data provision and operational detail to the switching process.
8.3	5 August 2015	Added section on customer arrangements, outages, and energisation/de-energisation
8.4	6 August 2015	Network pricing, hedging, and risk management sections updated
8.5	17 November 2015	Financial transmission rights updated
8.6	12 January 2016	Updated parts on clearing manager and bids
8.7	20 April 2016	Updated domestic retail contracts
8.8	23 November 2016	Payment arrangements amended
8.9	31 January 2017	Terms and conditions of customer contracts added and paragraphs 5.8 and 5.9 added
8.91	13 April 2017	Time reference in paragraph 5.4 corrected
9	20 April 2017	ERANZ added, also changes to sections 1, 2, 8, and 9
9.1	8 May 2017	Disputes scheme paragraphs commencing 3.29 amended
9.2	5 July 2017	Switching section expanded
9.3	14 September 2017	General update and spot market Authority expectation on retailers added
9.4	13 November 2017	Clarified certification requirements
9.5	6 December 2017	Legal review
9.6	15 March 2018	Added section on Low Fixed Charged exemptions
9.7	20 June 2018	UFE added to pricing section 13.34
9.8	12 July 2018	Amendments to section 9 “Risk management contracts”
9.9	19 July 2018	Clarification to para 13.9

9.10	17 December 2018	Section 10 added, subsequent sections renumbered, and checklist updated
9.11	26 January 2021	Clarification on audit requirements and updates to Part 10.

Disclaimer

This guideline identifies and generally describes the steps required to become an electricity retailer (retailer) under the Electricity Industry Participation Code 2010 (Code) and refers to the relevant statutes, regulations, and Code requirements applicable to retailers.

This information paper does not form part of the Code. It is provided for general information only. It is not as legal advice and does not establish any legal obligation.

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The publishing of this information paper does not place any obligation on the Authority to follow any interpretation contained in it when carrying out any of its functions under the Electricity Industry Act 2010 (Act).

The Code places many obligations on a retailer and should be consulted in full by intending retailers. Some of those obligations are contained in this document, however many obligations may be specific to the type of activity a retailer wishes to trade on. The Authority suggests if you are in doubt that you do ask.

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1 Introduction

The electricity market

1.1 The New Zealand Electricity Market (NZEM) started its operation on 1 October 1996. From that date, any consumer with half hour (HHR) metering was able to purchase electricity from any retailer that agreed to supply it. From 1 April 1999, full retail competition commenced and all consumers in New Zealand that had an installation control point (ICP) identifier had the same choice of retailer.

1.2 The NZEM is a mandatory gross pool market. All generation must be sold to the clearing manager and all consumption must be purchased from the clearing manager. The cost of all clearing manager sales and purchases are settled monthly at the final spot price prevailing at the time, at each individual point of connection to the grid that a consumer is electrically connected to. This is referred to as "wholesale market sales and purchases".

1.3 Lowest cost dispatch is carried out to minimise the total generation cost based on the offers from generators, subject to network and system constraints. The NZEM processes are governed by the Act and the Code. The Code is maintained and enforced by the Authority.

1.4 Unlike other electricity markets, metering is a competitive activity in the NZEM. Metering equipment providers (MEPs) compete on price, service, and functionality to provide metering services.

1.5 The NZEM is complex because there are many interactions between participants, between participants and the electricity market, and between participants and the Authority. The majority of these interactions are set out in:

(a) the legislation listed in paragraph 2.3

(b) functional specifications available from the Authority at http://www.ea.govt.nz/operations/market-operation-service-providers/

(c) Electricity Industry Exchange Protocols available from the Authority at http://www.ea.govt.nz/operations/retail/eiep/

(d) exchanges with MEPs as agreed with each MEP

(e) operational exchanges with other retailers as necessary.

1.6 The non-NZEM components of networks are regulated by the Commerce Commission (www.comcom.govt.nz).

1.7 Electrical safety is regulated by WorkSafe New Zealand (www.worksafe.govt.nz).

The Authority

1.8 The Authority is an independent Crown entity responsible for overseeing and regulating the NZEM.

1.9 We regulate the NZEM by developing and market rules (ie, the Code), enforcing and administering them, and monitoring the market's performance. We place a strong emphasis on voluntary market facilitation measures.

1.10 As an independent Crown entity, we are free to adopt our own work programme provided it promotes competition, reliability, and efficiency for the long-term benefit of consumers in accordance with our statutory objective (section 15 of the Act).

1.11 The Authority is funded through appropriations approved by Parliament each financial year (1 July to 30 June of each year). The Government is reimbursed for the cost of funding the Authority appropriations through a levy on industry participants.

1.12 The levy is collected from generators, purchasers, and distributors (including the grid owner) in accordance with detailed formulae set out in the Electricity Industry (Levy of Industry Participants) Regulations 2010 (Levy Regulations).

2 Retailer general

2.1 The Act provides the following definition of an electricity retailer:

retailer means a business engaged in retailing

retailing means the sale of electricity to a consumer other than for the purpose of resale.

2.2 Clause 1.1(1) of the Code provides the following similar definition of “retailer”:

retailer means as follows:

(a) except as provided in paragraphs (b) and (c), a participant who supplies electricity to another person for any purpose other than for resupply by the other person:

(b) in Parts 1 (except for the definition of specified participant), 8, 10, and 12 to 15, a participant who supplies electricity to a consumer or to another retailer:

(c) in subpart 4 of Part 9, the retailer defined in paragraph (a) who is recorded by the registry manager as being responsible for the ICP described in clause 9.21(1)(b).

2.3 Retailers must comply with the relevant legislative requirements set out in:

(a) the Act

(b) the Code

(c) the Electricity Industry (Enforcement) Regulations 2010 (Enforcement Regulations)

(d) the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC Regulations)

(e) the Levy Regulations

(f) the Fair Trading Act 1986

(g) other statutes applying to contracts generally, eg, the Minors’ Contracts Act 1969.

2.4 Retailers are must comply with relevant legislation as well as the following voluntary guidelines:

(a) *Voluntary good contracting principles and minimum terms and conditions for domestic contracts*, refer to the “Customer terms and conditions” section

(b) *Guidelines for communications about price changes*, refer to the “Price changes” section

(c) *Voluntary Practice Benchmark for Electricity Retailer Credit Management* , refer to the “Credit management” section

2.5 Retailers may purchase their electricity from the wholesale market through the clearing manager or from another retailer.

2.6 Retailers who purchase electricity from the clearing manager must:

(a) use the services of electricity distributors (distributor) to transport electricity to their customers and manage distributor prudential requirements

(b) manage their wholesale market purchases, including prudential requirements

(c) comply with the reporting requirements in the Code.

2.7 The obligations on a retailer depend on how the retailer sources its electricity and who the retailer supplies the electricity to. If you intend to become a retailer, you may also be a purchaser and a certified reconciliation participant under the Code. You should make yourself familiar with the obligations under both the Act and the Code associated with being a participant.

Types of retailers

2.8 There are three different types of retailers:

(a) **Type 1**: Retailers that source electricity from the wholesale electricity market by purchasing through the clearing manager and supply that electricity to consumers.

(b) **Type 2**: Retailers that source electricity from a participant that has ultimately purchased electricity from the clearing manager, and on sell to consumers who have choice of retailers.

Type 2 retailers have limited obligations under the Code. For example, they do not have:

(i) a direct arrangement with the clearing manager

(ii) a participant identifier on the registry (but the participant they purchase from does).

(c) **Type 3**: Retailers who retail to customers that do not have choice of retailers, including:

(i) islanded systems generating, retailing, and distributing electricity solely for consumption by the local community (eg, Chatham Islands)

(ii) customers who are connected to a network (eg, apartment and commercial buildings).

2.9 These three different types of retailers are not necessarily mutually exclusive, and retailers may act in different capacities. However, retailers are expected to understand and comply with the obligations of each type that they undertake.

2.10 Table 1 provides a summary of the obligations of each type of retailer, and the relevant corresponding area in this document.

Table 1 Summary of retailer obligations by retailer type

Paragraph	Retailer requirements	Type 1	Type 2	Type 3
2.11	Register with the Authority as an electricity industry participant for the class of activity you intend to perform	✓	✓	✓
2.16	Notify the Authority of the intention to become a retailer and setup up process for payments under the Levy Regulations	✓	X	X
2.19	Obtain participant identifier	✓	X	X
2.24	Consider membership of the Industry Association for Retailers	X	X	X
3	Customer arrangements (contracts)	✓	✓	X

Paragraph	Retailer requirements	Type 1	Type 2	Type 3
3.4	Provide a copy of terms and conditions (customer arrangements) to the authority to review. You may be required to amend these terms and conditions after the review	✓	✓	**(*)**
3.6	Follow the *Guideline on arrangements to assist low income and vulnerable consumers*	✓	✓	✓
3.15	Provide credit disconnection and MVDC statistics to the Authority quarterly.	✓	✓	**X**
3.17	Have the facilities to deal with network outages if this is required in the use of system agreement with the distributor for each network area	✓	✓	**(*)**
3.19	Have the facilities to deal with electrical connection and electrical disconnection in each network area	✓	**(#)**	**(*)**
3.29	Belong to an approved consumer complaints resolution system	✓	✓	✓
3.34	Retailers must provide consumers, or a consumer's authorised agent, with their electricity consumption data. Note that EIEPs 13A, 13B, and 13C are regulated formats.	✓	✓	✓
3.38	Customer compensation scheme	✓	**X**	**X**
4.1	Agree "Use of Systems agreements" with network owners on the networks you intend to trade over. Note that this includes prudential requirements	✓	✓	**X**
4.8	Set up exchange of information with distributors using the electricity information exchange protocols (EIEPs). Note that EIEPs 1, 2, 3, and 12 are regulated formats	✓	**(#)**	**X**
4.15	Investigate use of registry data hub for EIEP file exchange with distributors, and exchange of information with any other registry user	✓	**X**	**X**
5	Notify the CM of the intention to trade, establish prudential security arrangements with the CM, and set up payment details and process	✓	**(#)**	**X**
5.12	Have the ability to respond in the event of a trader default situation	✓	✓	**X**
6.1	Obtain access to the electricity market's wholesale information and trading system (WITS)	✓	**(#)**	**X**
7.4	On non-conforming nodes, submit notice of initial bid to the electricity market system operator	✓	**(#)**	**X**
7.6	Place initial bids for electricity with electricity market using WITS and set up process for ongoing bids	✓	**(#)**	**X**
8.1	Understand spot price derivation and types	✓	**(#)**	**X**
9.1	Understand hedge markets and mitigate spot market risk in wholesale electricity purchases	✓	✓	**X**
9.20	Understand financial transmission rights (FTR) market	✓	**(#)**	**X**
9.34	Comply with the stress testing requirements	✓	**X**	**X**
9.34(b)	Provide quarterly spot price risk disclosure statements to the stress test manager	✓	✓	**X**

Paragraph	Retailer requirements	Type 1	Type 2	Type 3
9.34(c)	Certify to the Authority each year that the retailer has provided information about stress tests to their customers, and that their Board has considered the contents of the disclosure statements.	✓	✓	X
10	Understand drivers to variation in spot cost, and have appropriate monitoring systems in place	✓	✓	X
11.1	Ensure metering at customer connections is compliant with Part 10 of the Code	✓	(#)	(*)
11.5	Establish lease agreements with metering equipment providers	✓	✓	(*)
12.1	Obtain access to the electricity registry (registry)	✓	(#)	X
12.11	Electrical connection and electrical disconnection of ICPs	✓	✓	✓
12.9	Have processes in place for updating information on the registry (relates to obtaining certification as a reconciliation participant)	✓	(#)	X
12.14 and 12.21	Have the process to enable ICP switching and maintenance of retailer records in the registry	✓	(#)	X
13.2	Processes in place to manage connection and electrical connection of new ICPs	✓	(#)	(*)
13.7	Processes in place to manage electrical disconnection for non-payment	✓	✓	(*)
13.12	Processes in place to manage electrical disconnection for vacant	✓	(#)	(*)
14.2	Obtain certification as a reconciliation participant	✓	(#)	X
14.14	Notify the reconciliation manager (RM) of intention to purchase electricity and obtain access to the RM system	✓	(#)	X
14.18	Supply electricity consumption information to the RM for all customer connections	✓	(#)	X
14.26	Use approved profiles in the reconciliation process	✓	(#)	X
14.31	Report frequency of meter reading	✓	(*)	✓
14.34	Determine retail pricing	✓	✓	(*)
14.37	Comply with the requirements of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (Regulations)	✓	✓	✓
14.38(e)	Provide low fixed charge tariff information to the Authority in accordance with the above Regulations 15 business days before commencing trading	✓	✓	✓
14.45	Spot market expectations on retailers	(*)	(*)	(*)
15	Understand and prepare for network tariff variations	✓	✓	✓

Key:

(✓) mandatory

(X) discretionary

(#) mandatory for a Type 1 retailer

(*) not mandatory, but is recommended practice.

Registration as a participant

2.11 Any party that carries out the activities of an industry participant must register with the Authority. All the types of retailers listed in paragraph 2.8 meet the participant definition in section 7 of the Act.

2.12 The participant is required to provide the information specified in section 27(2) of the Act, including the nature of the business the participant is involved in. There is no cost to register as a participant.

2.13 Information on how to register as a participant is available on the Authority's industry participants webpage. To register as a participant, complete the participant registration form available from this link and follow the directions on the application form to submit it to the Authority.

2.14 The Authority will acknowledge receipt of your application for registration as a participant by email. If you have not received confirmation after five business days, please contact the Authority via the contact details listed on the participant registration webpage (as per the link above).

Exempt participants from requirement to register

2.15 Under section 10 of the Act, the Authority may exempt individual participants from the requirement to register as a participant. An exemption will only be granted if the Authority is satisfied that:

(a) registration is not necessary to achieve the Authority's objective under section 15 of the Act; and

(b) exempting the participant will reduce overall administration and compliance costs.

Electricity levy payments

2.16 Purchasers of electricity from the clearing manager pay a levy in accordance with the Levy Regulations. The amount payable is based on the purchaser's wholesale electricity market purchases to and from the reconciliation manager and on the amount of ICPs they hold in the registry. The Authority invoices the levy monthly, with an annual wash-up after the completion of the financial year.

2.17 For clarity, dispatchable load purchasers pay levy as a purchaser. No additional levy is incurred, further to what would be incurred as a purchaser, when providing a bid or having their dispatch capable load station (DCLS) dispatched.

2.18 Details of the levy and other charges are available on the Authority's levy rates webpage.

Obtain a participant identifier from the Authority

2.19 Participant identifiers are used to track all market transactions, and are only issued by the Authority to active industry participants. You must have a participant identifier to purchase or sell electricity from/to the electricity market.

2.20 The participant identifier is a unique four letter code that identifies each participant, and is used in all electricity market transactions from bids through to clearing manager settlements.

2.21 To obtain a participant identifier, complete the participant identifier application form available from the Authority's participant identifiers webpage and follow the directions on the application form to submit it to the Authority.

Meet your market operator service provider

2.22 Type 1 retailers are encouraged to contact NZX acting in its capacity as the clearing manager, reconciliation manager, and WITS service providers. In the first instance please contact the clearing manager at cmanager@nzx.com.

2.23 NZX will also offer, at least on an annual basis, training on clearing manager, reconciliation manager, pricing manager, and WITS service provider roles and their associated systems.

Electricity Retailers' Association of New Zealand

2.24 Established in 2015, the Electricity Retailers' Association of New Zealand (ERANZ) represents companies that sell electricity to New Zealand customers and businesses.

2.25 ERANZ's role is to promote and enhance a sustainable and competitive retail electricity market that delivers value to New Zealand electricity customers. Find out more about ERANZ at www.eranz.org.nz

2.26 If you wish to contact ERANZ to enquire about membership, please contact admin@eranz.org.nz

3 Customer arrangements

Terms and conditions of customer contracts

3.1 In mid-2009, the Authority proposed a draft set of *Reasonable Consumer Expectations* for domestic electricity consumers, and the extent to which the options identified could assist in meeting those expectations was assessed.

3.2 A retailer must provide terms and conditions for domestic customers, and should provide terms and conditions for all customers.

3.3 Retailers' contracts with domestic consumers should voluntarily follow our contracting principles and minimum terms. Principles for terms and conditions can be found at Terms and conditions.

3.4 The Authority carries out alignment reviews on new entrant retailer terms and conditions to ensure that the appropriate requirements are met to protect consumers.

3.5 The terms and conditions for all customers must provide:[1]

(a) the right for the Authority to assign the rights and obligations of the retailer to another retailer if the retailer commits an event of default (refer to paragraph 5.12)

(b) that the terms of the assigned contract may be amended on such an assignment to—

(i) the standard terms that the recipient trader would normally have offered to the customer immediately before the event of default occurred; or

(ii) such other terms that are more advantageous to the customer than the standard terms, as the recipient trader and the Authority agree; and

(iii) the terms of the assigned contract to be amended on such an assignment to include a minimum term in respect of which the customer must pay an amount for cancelling the contract before the expiry of the minimum term; and

(c) that the retailer must have the customer's consent to

[1] Refer to clause 11.15B (Trader contracts with customers to permit assignment by Authority).

(i) provide information about the customer to the Authority, and for the Authority to provide the customer's information to another trader if required under Schedule 11.5 and

(ii) allow the retailer to assign the rights and obligations of the retailer to another; and

(iii) the terms specified in the terms and conditions must:

A be expressed to be for the benefit of the Authority for the purposes of the Contracts (Privity) Act 1982; and

B not be able to be amended without the consent of the Authority.

(d) Retailers' contracts with domestic consumers should also provide terms for the following:

(i) choice, such as offering a range of pricing plans, products, and services for consumers to consider and make informed decisions

(ii) the connection and disconnection of electricity to the consumer's premises

(iii) contract termination

(iv) the supply of electricity and all related services, such as metering

(v) contractual terms and conditions, such as being fair and reasonable

(vi) costs, for instance unexpected and unfair costs, should not be imposed on consumers

(vii) billing and payment should be timely and accurate

(viii) access to property

(ix) access to remedies in the case of complaints.

Arrangements to assist medically dependent and vulnerable consumers

3.6 Since 2005, a guideline covering electricity retailers' treatment of vulnerable customers who are having difficulty paying their electricity bills has existed.

3.7 Medically dependent consumers are domestic consumers who are dependent on mains electricity for critical medical support, such that loss of electricity may result in loss of life or serious harm. For the avoidance of doubt, medical dependence on electricity could be for use of medical or other electrical equipment needed to support the treatment regime (eg, a microwave to heat fluids for renal dialysis or equipment such as that listed in Appendix B).

3.8 Vulnerable consumers are domestic consumers for whom:

(a) for reasons of age, health, or disability, the disconnection of electricity presents a clear threat to the health or wellbeing of that domestic consumer; and/or

(b) it is genuinely difficult to pay his or her electricity bills because of severe financial insecurity, whether temporary or permanent.

3.9 This guideline was first published in November 2005, substantially reviewed in July 2007, updated in 2008, and further reviewed during 2009. As a result of the 2009 review, the Authority split the arrangements into two guidelines. There are now two guidelines: one to assist vulnerable consumers and one to assist medically dependent consumers.

3.10 Retailers are strongly recommended to discuss with customers, during the acquisition process, if the customer is a "vulnerable" or "medically dependent" consumer. If they are, the retailer should inform them of their rights. Every retailer's back office systems should be capable of recording these customer definitions, providing reporting and management facilities, and store appropriate information securely.

3.11 If the status of a customer changes, the retailer should carry out the process noted above. Retailers should also regularly review the status of medically dependent consumers. ERANZ has produced a guideline on review processes. ERANZ members can obtain this guideline directly from ERANZ.

3.12 Retailers are strongly advised to become familiar with the following guidelines:

(a) *Medically dependent consumer guidelines*

(b) *Vulnerable consumer guidelines*.

3.13 In addition, the Authority has published fact sheets for vulnerable consumers and medically dependent consumers.

3.14 The Authority is responsible for monitoring compliance with guidelines around arrangements to assist medically dependent and vulnerable consumers

3.15 The Authority collects customer, disconnection, and WINZ referral statistics from retailers quarterly, and these are published on the Authority's website. Retailers must provide the disconnection statistics based on the number of disconnections actually completed, and not the number of disconnection initiated, as some customers may elect to pay before disconnection.

3.16 Further information can be found on the Authority's Medically dependant and vulnerable customers webpage.

Network outages

3.17 Network outages occur when the electricity supply to a consumer's installation is interrupted for a period of time. The outage may be planned for maintenance purposes or unplanned in the event of a fault or accident.

3.18 The retailer may be expected to operate an outage notification call centre, and this should be discussed with each network owner at the time of negotiating the use of system agreement. If the network owner requires the retailer to operate an outage call centre, the following may be involved:

(a) **Planned outages** occur when supply to a consumer is interrupted to allow maintenance of the connecting network. The duration of a planned outage will be variable and dependent on the extent of work being carried out, weather conditions, etc. In the event of a planned outage occurring, the distributor will advise the retailer of the ICPs and time period.

Distributors usually communicate planned outages to retailers by sending an EIEP5a[2] file containing all ICP identifiers to each retailer. Retailers must then determine which of the ICP identifiers within the file belong (or will shortly belong) to it.

The retailer will need to:

(i) advise any medically dependent consumers of the impending outage so they can make alternative arrangements for supply of electricity (the retailer may need to assist the consumer in this process, or renegotiate the outage time with the distributor)

[2] Refer to http://www.ea.govt.nz/operations/retail/eiep/non-regulated-electricity-information-exchange-protocols/

(ii) if the distributor does not advise consumers directly (and some do – check the use of system agreement), issue advice to each consumer for each ICP of the planned outage, time, and duration

(iii) if there is a change to the planned outage, re-issue advice

(iv) update consumers who call the retailers call centre on the planned outage.

(b) **Unplanned outages** occur when supply to a consumer is disrupted due to a fault in the connecting network. The duration of the unplanned outage will be variable and dependent on the reason for the outage. In the event of an unplanned outage occurring, the distributor may advise the retailer of the affected ICPs and time period eventually, however, it is likely that the retailer's call centre will receive a large volume of calls.

Distributors usually communicate planned outages to retailers by sending an EIEP5a[3] file containing all ICP identifiers to each retailer. Retailers must then determine which of the ICP identifiers within the file belong (or will shortly belong) to it.

The retailer will need to:

(i) Ensure the distributor is aware of the outage and advise affected ICPs. This will help the distributor determine the extent of the fault.

(ii) Receive advice from the distributor on the outage, cause, and expected duration.

(iii) Pass on any AMI outage information you receive to the distributor.

(iv) If medically dependent consumers are affected, attempt to contact each consumer to ascertain they are safe. If the outage is to be extended, ensure the emergency services are alerted.

(v) Ensure the distributor is aware that a medically dependent consumer is included in the outage area.

(vi) Ideally provide an answerphone update facility as there could be considerable call volumes in the event of an outage.

(vii) Update consumers who call the retailer's call centre on the planned outage.

Electrical connection and electrical disconnection of a consumer

3.19 The terms "electrical connection" and "electrical disconnection" are defined as *"the operation of any isolator, circuit breaker, or switch or the removal of any fuse or link so that no electricity can flow through a point of connection on a network, and electrical disconnection and electrically disconnected have corresponding meaning"*.

3.20 The term "connection" has the common English meaning, and means that permanent wiring (service lines) have been run and may have voltage present. However the Code precludes electrical connection of an electrical installation until the Code-required processes have been completed.

3.21 The term "disconnection" has the common English meaning, and means the permanent wiring (service lines) have been physically disconnected but still may have voltage present.

3.22 The Code deals with two different instances of electrical connection / electrical disconnection. These are set out in the following paragraphs.

[3] Refer to http://www.ea.govt.nz/operations/retail/eiep/non-regulated-electricity-information-exchange-protocols/

3.23 **New connections**. This is where a new ICP and ICP identifier have been created on the distributor's network.

(a) While a distributor may connect the consumer's premises, electrical connection (allowing electricity to flow) may only occur if both the distributor and retailer agree the site is ready for electrical connection.

(b) Nothing precludes a blanket agreement with an agent to arrange new connections and electrical connection, however the agreement should be in writing between the distributor and retailer and agent. The distributor should also receive advice from the agents that the retailer has agreed to allow electrical connections on its behalf.

(c) For clarity, a distributor can connect an ICP but cannot carry out the first time electrical connection of an ICP until the retailer has advised that it intends to switch the ICP identifier in the registry to itself.

(d) Before authorising the electrical connection of a new premise, the retailer must arrange with an MEP to install and certify metering, and the metering must be operational.

(e) If a retailer gives consent for the first time electrical connection of an ICP, the retailer must switch the ICP identifier in the registry from the "Ready" status to either "Active" or "Inactive", as appropriate.

3.24 **Existing connections**. This is when an ICP and ICP identifier already exists on the distributor's network.

(a) A distributor may interrupt or restore supply to a consumer's premises for an outage situation (see above), and must electrically disconnect a consumers premises if a safety situation exists.

(b) In all other cases, only the current retailer in the registry should electrically disconnect or electrically connect a consumer's premise. This means that a retailer may:

(i) Electrically connect an electrically disconnected premises, provided the premise has not been electrically disconnected for a period of six months or more. If this is the case, the premises must have a safety inspection from an appropriately licenced technician.

(ii) Electrically disconnect vacant premises.

(iii) Electrically disconnect premises for credit reasons.

(c) A retailer must not authorise the electrical connection or electrical connection of a consumer's premises if:

(i) the distributor has electrically disconnected the premises for a safety reason

(ii) it does not have an arrangement to be the retailer for the consumer's premises

(iii) the consumer has switched to another retailer leaving debt with the losing retailer.

(d) Before authorising the electrical connection of a premise, the retailer must ensure there is a certified metering installation at the ICP (unless the ICP is solely unmetered load).

(i) If the metering category at the ICP shows "9", the retailer must not authorise the electrical connection and must arrange the installation of metering with the MEP.

(ii) If the ICP has only a category 1 metering installation, the retailer may electrically connect the ICP with an uncertified metering installation, but must arrange with the MEP to have the metering installation certified within five business days.

3.25 Where a consumer switches to another retailer leaving debt with the losing retailer, the losing retailer must rely on the integrity of its terms and conditions contract with the consumer to recover debt. The presence of debt does not prevent a switch from completing. In the case of residual debt, the losing retailer will need to recover payment from the consumer using commercial practices.

3.26 Where an electrical disconnection for credit purposes is to be carried out, the process around a credit electrical disconnection sets out the process that should be followed including communications with a customer.

3.27 Where an electrical disconnection or electrical connection requires:

(a) the use of the distributor's asset, eg, a pole fuse or link box fuse, etc, the retailer must contract with the distributor's "warranted person" set out in the use of system agreement to carry out the activity

(b) the use of contacts within an AMI meter, the retailer must arrange with the MEP to remotely operate the contacts

(c) the use of a fuse or circuit breaker or switch in the customer's premises, the retailer must contract an appropriately licenced technician to carry out the work.

3.28 Where a long term electrical disconnection is to be carried out, the retailer must advise the MEP of the intended electrical connection to allow the MEP to remotely read the meter if necessary. In the case of a long term electrical disconnection, the MEP may elect to recover metering assets. If the MEP removes any metering assets, the metering category at the ICP will revert automatically to "9" and the metering installation will not be in a state that it can be safely electrically connected.

Consumer complaints resolution system

3.29 The consumer complaints resolutions system ensures that consumers, potential consumers, and owners and occupiers of land have access to a free and independent complaints system.

3.30 Every retailer and distributor (including Transpower) must participate in the approved scheme. This means that if complaints are unable to first be resolved by the relevant retailer or distributor, all electricity and gas consumers will be able to refer their complaint to a single, independent, and free disputes resolution service. The approved scheme is Utilities Disputes Limited.

3.31 Utilities Disputes Limited can assist in resolving complex disputes between parties, including indemnity disputes between retailers and distributors. Utilities Disputes Limited also provides staff training opportunities, webinars, and practice statements.

3.32 All retailers and distributors are required to advise consumers of Utilities Disputes Limited, this includes providing Utilities Disputes Limited's details on consumer information including invoices.

3.33 Retailers and distributors should contact Utilities Disputes Limited directly to obtain details for scheme membership and costs.

Requests for consumer consumption information

3.34 Clauses 11.32A to 11.32F of the Code require retailers to give consumers information about their own consumption of electricity upon that consumer's request.

3.35 A "retailer" includes any participant that supplies electricity to any other person for any purpose other than for resupply by the other person. This definition includes retailers that purchase electricity from any other person to on sell to a consumer.

3.36 Any questions about this procedures document should be directed to the Market Operations Team by email to marketoperations@ea.govt.nz

3.37 Further information can be found at Procedures: request for consumer consumption information. This document sets out procedures that apply to retailers when they respond to such requests. The document also contains information that will assist consumers and their agents to make requests for consumption information.

Customer Compensation Scheme

3.38 If customers are asked to conserve electricity during an official public conservation scheme, retailers must pay qualifying customers $10.50 per week.

3.39 In the past, customers have not been compensated for their savings efforts during public conservation campaigns.

3.40 The customer compensation scheme seeks to improve security of supply by removing the incentives retailers had to call for electricity conservation in order to reduce their exposure to high spot market prices.

3.41 An official conservation campaign can only be triggered and ended by Transpower New Zealand (Transpower) in its role as system operator. The summary of the customer compensation scheme also gives more detail as to when an official conservation campaign could be held.

3.42 Each retailer is required to operate a customer compensation scheme. Retailers can also offer their own compensation schemes – these could be linked to individual customers' conservation efforts.

3.43 Details about the customer compensation scheme are contained in subpart 4 of Part 9 of the Code. Further information can also be found at Customer-compensation-scheme.

Providing information about Utilities Disputes and Powerswitch

3.44 Clause 11.30A to 11.30E of the Code requires retailers:

(a) to provide clear and prominent information about Utilities Disputes:

(i) on their website

(ii) when responding to queries from consumers

(iii) in outbound communications directed to consumers about electricity services and bills.

(b) that trade at a residential ICP recorded on the registry to provide clear and prominent information about Powerswitch:

(i) on their website

(ii) in outbound communications to residential consumers about price and service changes

(iii) to residential consumers on an annual basis

(iv) in outbound communications directed to residential consumers about the consumer's bill.

3.45 These requirements will impact customer interactions including billing, call centres and customer notifications. More information on these requirements can be found in the Authority's Guidelines for raising consumer awareness of Utilities Disputes and Powerswitch service.

4 Use of systems agreements

4.1 Where the premises is connected to a local or embedded network, the Code requires a purchaser to have arrangements in place for line function services prior to taking ownership of an ICP in the registry.

4.2 Electricity is conveyed from grid exit points (GXP) to consumers by distributors. Purchasers must have agreements in place with distributors for the use of their distribution systems and must pay the distributors for this service (interposed agreements). In some instances, purchasers may arrange for consumers to directly pay the distributor, or the distributor may require the consumer to pay the distributor directly (conveyance agreements). This will depend on the agreement between the retailer, the customer and the distributor.

4.3 Where the retailer is invoicing network charges on behalf of the distributor to its customers, the distributors may charge the retailer a prudential. This prudential is intended to cover the distributors risk in an event of default. The Code provides alternatives for meeting distributor prudential, and these are:

(a) the retailer maintains an acceptable credit rating of BBB- (Standards and Poors Rating Group) or better

(b) the retailer provides a cash deposit

(c) the retailer arranges of a third party with an acceptable credit rating to provide security in a form acceptable to the distributor

(d) a combination of the above.

4.4 The value of prudential that can be charged must be the distributor's reasonable estimate that the retailer would pay the distributor in a two week period. Where the retailer is increasing in size, the retailer and distributor should agree on how the increase in volume and customer numbers should be reflected in the prudential requirement.

4.5 If a distributor requires additional prudential above the two week period, the maximum amount required must be no more than the distributor's reasonable estimate of the charges that the retailer would pay within a two month period. If this additional prudential is paid in the form of:

(a) cash, then the distributor must pay the retailer the daily bank bill yield rate plus 15 % on the additional security amount paid to the retailer quarterly

(b) third party guarantees, then the distributor must pay the retailer the 3 % per annum on the additional security amount.

4.6 A purchaser must arrange for the conveyance of electricity with the distributor for every customer to which it intends to sell electricity. The network and GXP map on the Electricity Networks Association website may help purchasers.

4.7 The Authority has set default terms to support the adoption of model use of (electricity distribution) system agreements. Further information on the default terms and options to negotiate alternative terms is available on the Authority's more standardisation of use-of-system agreements webpage.

Exchange of information with distributors

4.8 Purchasers that buy electricity from the clearing manager at an ICP will be required under their use of systems agreement with the network owner, to provide and receive information to/from the network owner or distributor. The information required will be set out in the use of system agreement.

4.9 The Authority supports and endorses the use of exchange protocols called the Electricity Information Exchange Protocols (EIEPs). The purpose of the EIEPs is to enable the exchange of low cost, standardised and reliable information between participants. The protocols are agreed between participants and are not mandatory. Further information on the EIEPs can be found in the industry formats section below.

Industry formats

4.10 As previously noted, the Authority supports and endorses the use of exchange protocols called the Electricity Information Exchange Protocols (EIEPs). The purpose of the EIEPs is to enable the exchange of low cost, standardised and reliable information between participants.

4.11 EIEPs 1, 2, 3, and 12 are regulated. The regulatory requirements allow a distributor and retailer to agree a different form but, where they cannot agree, the regulated EIEP must be used.

4.12 EIEPs 13A, 13B, and 13C are also regulated. These particular formats are not negotiable.

4.13 The following EIEPs are available for use:

(a) EIEP1: Consumption info protocols - this protocol provides for detailed consumption information by ICP by meter register-tariff. This can be used for the reporting of both half hour and non half hour data.

(b) EIEP2: Non half hour summary - provides for summary consumption information by price/tariff code by NSP.

(c) EIEP3: Half hour metering information - this protocol provides metered half hour data by ICP. This format can accommodate multiple ICPs in a single file or an individual file per ICP.

(d) EIEP4: Customer information - this protocol is intended to convey a "snap-shot" of the Retailer's customer base at a specific point in time. The purpose is to provide customer information for purposes as agreed between retailers and distributors.

(e) EIEP5: Service interruptions - this protocol is available for use by distributors to provide information to retailers relevant to planned and unplanned service interruptions.

(f) EIEP6: Faults services request - this protocol is available for use between retailers and distributors/retailer service providers for the electronic transfer of service request details to the service provider and vice versa. This protocol has two parts: initiation and status update and closure.

(g) EIEP7: General installation status change - this protocol is available for use by distributors and retailers to provide information on the change in connection status at installations and also provide detail as to the nature of the status change. The file can also be used to provide information to meter owners.

(h) EIEP8: Notification tariff change - this protocol sets out the distributor retailer information exchange protocol for notification of network price category and tariff change. The purpose of this file is for retailers and distributors to notify each other when load group and tariff changes occur in accordance with the agreements they have with each other.

(i) EIEP9: Customer location change notification - this protocol sets out the distributor retailer information exchange protocols for customer location address change notifications. The purpose of this file is for retailers to notify any ICP physical location address changes that may come to the retailer's attention to the distributor so that the registry and distributor's records can be updated if necessary.

(j) EIEP10: Network trust rebate - EIEP 10 is no longer in use.

(k) EIEP11: New connections - this protocol sets out the distributor retailer information exchange protocol for new connections.

(l) EIEP12: Distributor price schedule - this protocol sets out the distributor retailer information exchange protocol for changes to distributors existing pricing and advice of new pricing.

(m) EIEP13A: Detailed electricity consumption information for consumers (half hour and non-half hour) is an electronic file format used by a retailer to respond to a request from a consumer or its authorised agent for the consumer's consumption information.

(n) EIEP13B: Summary consumption information is an electronic file format used by a retailer to respond to a request from a consumer or authorised agent for the consumer's billed consumption information that the retailer has supplied to the consumer.

(o) EIEP13C: Electronic request format for EIEP 13A or EIEP 13B is an electronic file format used to request consumption information from a retailer

(p) EIEP14: Retail tariff rates - this protocol applies when a third party service provider requests a retailer to provide its generally available tariff rates.

4.14 The latest version of EIEPs can be found on the Authority's EIEP webpage.

Registry data hub for EIEP exchange

4.15 The registry supports a secure file transfer protocol (SFTP) data hub where registry participants may exchange encrypted files directly with other registry participants.

4.16 The data hub is a central secure delivery mechanism for any information. Contents are not validated and any medium including zipped files can be exchanged using SFTP encrypted transfer.

4.17 Access is available through the registry online and batch interfaces (SFTP only), and is restricted to approved registry users. Authentication relies upon participants' existing registry access credentials and the naming procedure of the file.

5 Make arrangement for payments with the clearing manager

5.1 The clearing manager invoices industry participants by combining reconciled quantity information, provided by the reconciliation manager, with pricing information, other ancillary costs, financial transmission rights (FTR) settlements, and dispatchable demand settlements to determine the amounts owed to and by each industry participant. The clearing manager also provides buyer created tax invoices where a trader sells electricity to the electricity market.

5.2 Only bona fide business entities may buy and sell from and to the clearing manager.

5.3 New entrant participants must register with the clearing manager prior to switching their first ICP identifier to:

(a) understand the payment requirements and dates: note that all payments for electricity market settlement must be in same day cleared funds, and the invoice must be paid in full and must be no later than 1pm of the day payment is required

(b) establish payment arrangements and bank account numbers

(c) obtain access to the clearing manager's portal in WITS to receive invoices.

5.4 Payments to the clearing manager for electricity purchases are required to be made by 1300 hours on the 20th calendar day of each month (or the following business day, if the 20th calendar day is not a business day) following the billing period for which an invoice had been issued by the clearing manager. The payments must be made in same day cleared funds.

Establish prudential security arrangements

5.5 Before a purchaser may purchase electricity from the wholesale market (and at all times while it purchases electricity), the purchaser must satisfy the prudential requirements as described in Part 14A of the Code. The purchaser is also required to provide the clearing manager with information to enable an estimate of prudential requirements when trading commences.

5.6 Financial settlements associated with the wholesale electricity market are substantial. Accordingly, electricity purchasers, including retailers, are required to establish financial security arrangements with the clearing manager.

5.7 Purchasers also pay for frequency keeping and ancillary services through their wholesale electricity market invoices.

5.8 Prudential security may be provided in a number of ways, and an intending purchaser should contact the clearing manager to determine the most suitable way of meeting this requirement.

5.9 Note that cash deposits require the participant to provide and maintain an acceptable participant's security agreement in respect of the cash deposit. A participant's security agreement must—

(a) be a "security agreement" as defined in section 16(1) of the Personal Property Securities Act 1999

(b) create a first ranking security interest in respect of the cash deposit

(c) secure the participant's payment and performance obligations to the clearing manager under the Code

(d) be in a form approved by the Authority.

5.10 In the event there is a change to a business that could impact prudential arrangements, such as insolvency, sale/purchase, sudden growth or expected decline, the clearing manager must be notified of the change at the earliest possible moment.

5.11 The clearing manager may be contacted via email at cmanager@nzx.com.

Managing an event of trader default

5.12 The Authority has measures in place to manage an event of trader default. An event of default occurs when a trader does not fulfil specific financial obligations, or when a third party has taken control of some of the trader's assets.

5.13 The regulated process for resolving a retailer default is initiated when a retailer does not fulfil financial obligations to the clearing manager, becomes insolvent, or the retailer's use-of-system agreement with a distributor is terminated because of a serious financial breach by the retailer (and certain other conditions are met).

5.14 Retailers should note that if a trader that purchases from the clearing manager defaults, the Authority may assign that defaulting trader's ICPs to other traders. This means that:

(a) if you are a type 1 retailer, you may receive ICPs that you do not want

(b) if you are a type 2 retailer and the trader you purchase electricity from defaults, your ICPs may be transferred to another trader

(c) if you are a defaulting trader, you may lose your ICPs.

5.15 Guidelines on the management of an event of default are available from the Authority's managing trader default webpage.

5.16 The registry functional specifications also provide information on the process the registry will follow in the event of a trader default.

6 Access to the Wholesale Information and Trading System

6.1 The Wholesale Information and Trading System (WITS) is a web based 24/7 platform, that is a central facility for the receipt and publication of information between and on behalf of the various parties involved in the wholesale electricity market. A manual backup system exists for emergency operation should the WITS platform not be available.

6.2 There are two types of access to WITS as follows:

(a) WITS free to air – any person can access to WITS free to air and receive non-confidential electricity market data such as wholesale electricity price, constraints etc.

(b) WITS trader - type 1 retailers (and generators and ancillary service providers) require access in order to manage their wholesale electricity market trading activities. WITS provides services including the placing of bids to purchase electricity and the receiving of wholesale electricity market interim and final charging information. It also makes available confidential electricity market data to participants such as wholesale invoices and supporting files.

6.3 Participants that require WITS trader access to meet Code obligations must complete an application form for WITS Trader access. The application form is available on the Authority's WITS webpage. Follow the directions on the website for submission of the application form.

6.4 New users will be asked to sign an access agreement with NZX. In considering the applications, certain criteria will need to be satisfied before the Authority will grant access.

6.5 A user manual and help is available from the WITS website. Alternately, the WITS administrator can be contacted by telephone on 0800 426 648 or email at admin@nzx.com.

7 Market purchase and bid notifications

General

7.1 A type 1 retailer is required to place bids for the purchase of electricity only at non-conforming nodes from the wholesale market. Further information on conforming and non-conforming nodes can be found on the Authority's conforming and non-conforming GXPs webpage.

7.2 Bids made will not determine whether a retailer may or may not purchase electricity, and a bid does not define the price the retailer will pay for electricity purchased. A bid is an intention to consume electricity at a specific location Bids are for each half hour trading period and must be a reasonable estimate of demand.

7.3 The bid and (generation offer) process is used to schedule the amount of generation that must be available nationally to meet the expected demand. The generators' dispatch and the actual measured consumption are later used to determine the final wholesale price of electricity for each trading period. The final wholesale price at each GXP is the price all retailers pay the clearing manager for electricity purchased at each GXP.

Notice of initial bid

7.4 Where a retailer must provide bids, the retailer must complete a notice of initial bid at least five business days before placing a bid to purchase electricity at any GXP. The notice of initial bid form is available from the wholesale electricity market system operator (Transpower) website.

7.5 Follow the instructions on the system operator's website for submission of the completed notice of initial bid.

Bid to purchase

7.6 A type 1 retailer must have a valid bid submitted to WITS for the next 71 trading periods at every non-conforming node at which they wish to purchase electricity. Note that in the case of embedded networks, the bid must be made at the parent grid-connected GXP.

7.7 Bids to purchase electricity from the wholesale electricity market are described in Part 13 of the Code. Bids must be placed by uploading a file via WITS which has a help section describing how to format and upload bid files.

7.8 A bid will automatically roll over as described in Part 13 if it is not revised or replaced. If a bid is no longer required, it must be removed by submitting a file to WITS with "0" for each trading period and node that the bid is not required for.

7.9 If you have any further questions concerning bids please contact the Market Services helpdesk via the contact details listed on the system operator's website.

8 Wholesale (spot) pricing

Spot price

8.1 The electricity market uses spot electricity prices for each trading period to schedule available generation so that the lowest-cost generation is dispatched first. All sales and purchases to and from the clearing manager are at the spot price.

8.2 The pricing manager is responsible for calculating and publishing the spot prices at which electricity market transactions are settled. Over 12,000 spot prices every day are published via WITS by the pricing manager to market participants.

8.3 Generators make offers to supply electricity at 52 grid injection points (where their generation stations connect to the national grid), and a number of embedded generation ICPs. There are also many embedded generators that are not of sufficient size to be required to provide offers. Demand is modelled by the system operator taking into account grid configuration, to determine likely dispatch, and then using actual GXP metering information to determine final price.

8.4 The changes in demand and supply over the course of a day lead to spot prices being different for each half-hour trading period at each grid exit point (GXP) or grid injection point (GIP).

8.5 Prices also vary by location - this reflects the losses in the transmission grid conveying electricity from generation to each GXP.

8.6 Wholesale prices are derived using models which calculate prices at each node for each trading period based on generator offer prices and quantities, demand, and system conditions.

8.7 Spot electricity prices fall into four categories, that are set out further below:

(a) forecast prices

(b) five minute prices

(c) provisional prices

(d) interim prices

(e) final prices (used by the clearing manager in wholesale electricity market settlement).

8.8 All prices are available to industry participants on WITS.

Forecast prices

8.9 WITS presents forecast prices that have been calculated prior to a trading period using the scheduling, pricing, and dispatch model. This model takes into account:

(a) the expected state of the electricity system

(b) generator offers

(c) purchaser bids (or in some cases a forecast of demand)

(d) dispatchable demand offers.

8.10 Forecast prices:

(a) give industry participants valuable information on when and how best to use electricity

(b) are calculated every two hours for every node (grid injection or grid exit point) across New Zealand for each half hour trading period, up to 36 hours ahead of time.

Five minute prices

8.11 Five-minute indicative prices, often called "real-time prices", are calculated at the end of each five-minute period for every node. They take into account the conditions of the power system at the beginning of the relevant five-minute period.

Provisional prices

8.12 Provisional prices may be published by the pricing manager the day after generated electricity is consumed.

8.13 Provisional prices are only published where there is a provisional price situation. In simple terms this is where the data used to calculate prices is incomplete. For example, there may be a metering situation, which is where actual meter readings are unavailable for one or more GXPs.

8.14 Provisional prices may be missing metering information, such as actual meter readings, but they are the best estimate of what the prices are at the time these prices are published.

Interim prices

8.15 Interim prices are typically published by the pricing manager the day after the generated electricity is consumed, once the data is complete.

8.16 The publication of interim prices may be delayed if a provisional pricing situation must be resolved by the pricing manager. For example, in the case of a metering situation the pricing manager must obtain revised metering from Transpower (the grid owner).

8.17 The publishing of interim pricing enables industry participants to identify if there have been any errors or issues before final prices are published. Participants can claim a pricing error, which will delay the publication of final prices until the error is considered and addressed (if necessary).

How spot prices work - Pricing error claim

8.18 Once interim prices are published on WITS, industry participants have until midday on the next business day to submit a claim for a pricing error via email to the pricing manager.

8.19 A pricing error is:

(a) an incorrect input being used in the calculation of an interim price; or

(b) an incorrect process being followed in calculating an interim price that:

(i) had a material effect on the claimant

(ii) was either not signalled in dispatch prices or forecast prices, or was signalled in dispatch prices or forecast prices but that the claimant was unable to respond to.

8.20 If a valid claim is submitted, the publication of all final prices and final reserve prices for that day would be automatically delayed.

8.21 Further information is available at pricing error

Spot prices - Scarcity pricing

8.22 The scarcity pricing regime is set out in Parts 8 and 13 of the Code. Under the regime, if an electricity supply emergency causes forced power cuts (typically referred to as emergency load shedding) in one or both islands, the system operator notifies the pricing manager, triggering the scarcity pricing regime. The regime is intended to provide increased certainty of spot electricity prices during these emergency situations, as spot prices can be significantly affected by the forced reduction in electricity demand. In a scarcity pricing situation, the scarcity pricing regime sets a $10,000 per megawatt hour (MWh) price floor and a $20,000 per MWh price cap for the island generation weighted average spot price in the trading periods affected by the emergency.

8.23 Further information is available at scarcity pricing

Final prices

8.24 Final prices are calculated by the pricing manager and sent to the clearing manager who uses them to calculate invoices for the settlement of trades between the sellers (for example, generators) and buyers of electricity (for example, retailers and major industrial consumers). The invoices are sent via WITS.

8.25 Final prices:

(a) are currently published at least two business days after real-time; however, if there are pricing issues that need to be resolved, the time scale can be greater than this

(b) determine payments between buyers and sellers for spot market sales and settle electricity risk management contracts, such as futures contracts.

8.26 Pricing trends can be seen in the monthly WITS reports. Historical final prices are also available from the Authority's website at Final_pricing to allow analysis of pricing trends, risks, liabilities, business cases, etc.

High spring washer pricing situation

8.27 A high spring washer is a rare pricing phenomenon where high spot prices occur unexpectedly. These high spot prices flow into financial settlement, so a process exists to ensure that price is correctly calculated, reflects reality, and is not created solely by input data.

8.28 "Spring washer" is a term used to describe the situation where there are large spot price differences between each side of a transmission constraint.

8.29 The prices that result from transmission constraints can be very high and very sensitive to minor variations in input data. For participants to have confidence in final prices, they need to be confident that high spring washer prices reasonably reflect what happened in reality, and are not a result of input data measurement inaccuracies (eg, metering data measurement inaccuracies, transmission impedance data measurement inaccuracies, or security constraint calculation inaccuracies).

8.30 For a full explanation see the high spring washer effect animation - system operator website

8.31 The pricing manager determines whether a high spring washer pricing situation has occurred and may apply a relaxation to the transmission constraint to resolve the situation, reducing the price difference each side of the constraint.

9 Risk management contracts

General

9.1 All electricity bought and sold by the clearing manager in the electricity market is bought and sold at spot rates at each GXP.

9.2 Wholesale markets for electricity are complex, and their structure varies from one country to another. However, they have in common the characteristic that spot prices for electricity are highly volatile. This is a consequence of the inability to store electricity at any significant scale, and the requirement to schedule different priced generation on and off. So GXP prices vary depending on the levels of hydroelectric storage lakes, country demand, available generation, price of generation and reserves, transmission constraints, and generation or transmission outages in delivering electricity to each of the GXPs through the country.

9.3 Hydrological inflows into the country's hydroelectric storage lakes do exhibit seasonal patterns, but they are highly volatile and fundamentally unpredictable except in the very short term (a few days). There is also evidence that the seasonal patterns are changing over time, perhaps partly driven by climate change.

9.4 The financial risk to retailers arises from uncertainties about the purchase spot price (that is variable and fluctuating), volume (that may be either fixed or variable), and the sell price (that may be fixed). A retailer's revenue is at risk if the spot price is very high and there is high consumption from end-users paying a lower-than-spot fixed price on their respective retail contracts. There are many cautionary examples in New Zealand, and around the world where this has occurred.

9.5 It is important for new retailers to understand that the volatility of electricity spot prices in the New Zealand electricity market has changed over time, which means that the spot price risk to which retailers are exposed, has also changed over time. A consequence of this is that historical spot price data does not provide complete information about spot price risks in the future.

9.6 In extreme spot pricing events, retailers can lose all of their equity very quickly, and are faced not only with high wholesale market settlement costs, but also with high prudential cost. An example of this is spot prices that peaked at $1,049.96/MWh on 12 July 2017. A retailer had a contract with consumers that guaranteed a purchase price to the consumers of $100/MWh (10 cents/kWh), and for one trading period the retailer sold 5,000 kWh of electricity, then the following applies:

Wholesale purchase cost

Spot price for one trading period	= $1,049.46/MWh
Electricity volume reconciled	= 5 MWh (5,000 kWh)
Total cost of purchase	= $1049.96 x 5 = **$5,249.80**

Retail sale cost[4]

Fixed retail price for one trading period	= $100/MWh
Electricity volume reconciled	= 5 MWh (5,000 kWh)
Total cost of purchase	= $100 x 5 = **$500.00**

Retail sale margin

Wholesale purchase cost	= $5,249.80
Retail contracted sale cost	= $500.00
Actual **loss** for one trading period	= $4,750.00

9.7 Risk management contracts provide a way for participants to manage the risk associated with the volatility of the spot market and fixed price retail contracts. Risk management is essential in all retail businesses to manage risks, and implement trading strategies within the limits set by these policies.

[4] Ignoring losses in the local distribution network.

9.8 Risk management contracts are also called a “hedge” and are described in more detail below.

Hedge markets

9.9 A hedge is used to manage the price volatility of the spot market for both generators and electricity purchasers. Hedges are referred to in the Code as “risk management contracts”.

9.10 Hedges are either agreed between the parties (known as over-the-counter (OTC)) or purchased as derivatives on the Australian stock exchange (ASX) electricity futures market.

9.11 There is also a separate specialised financial transmission rights (FTR) market to help parties manage the risk they face from large, unpredictable differences in wholesale electricity prices between the North and South Islands, or between GXPs within each island.

9.12 There are several different OTC hedge types such as:

(a) contracts for difference (CFD)

(b) options.

9.13 The different types of OTC hedge are designed to manage different types of risk, as follows:

(a) *Contracts for differences*, also called swaps, are the most common form of hedge contracts. These typically involve the retailer receiving a payment under the “contract for difference” of the difference between the spot price and the fixed contract price, when the spot price is higher than the contract price and paying the difference to the contract seller when the spot price is lower than the contract price. The price difference is then multiplied by the fixed (notional) contract volume. These contracts are agreed via a negotiation between retailer and seller and are tailored to reflect specific requirements in relation to duration and other contract features. CFDs are usually settled monthly, one month at a time throughout the term of the contract, at about the same time of the month as the spot market is settled.

(b) *Options contracts* have a variety of forms but, in essence, the retailer pays an upfront fee to the supplier of the contract for the right to a predefined spot price insurance mechanism. For example, a retailer could enter into an option contract that provides a right for the retailer to receive the difference between the spot price and, for example, 15.0 c/kWh. In this simple example, this option would act as a cap that limits the extent of spot price exposure for the retailer.

9.14 OTC hedges can be settled directly between the parties or lodged with the clearing manager and settled at the same time, and under the same process, as the parties’ electricity market transactions.

9.15 OTC hedges that are lodged with the clearing manager can also be used to reduce a party’s prudential requirement as it can be used to offset their purchases in the wholesale market. Subject to an acceptable agreement (using the form set out in clause 14.4 of the Code), that is lodged with the clearing manager in accordance with clause 14.8 of the Code, a hedge may be lodged with the clearing manager. This lodgement enables the value of the hedge to be offset against spot market prudential security requirements.

9.16 The ASX futures market trades futures and options at two nodes: Otahuhu in the North Island and Benmore in the South Island.

9.17 Futures contracts are a standardised form of contract with buy (bid) and sell (ask) prices quoted on the Australian Securities Exchange (ASX). Similar to contracts for differences, these contracts provide a mechanism to hedge spot p.rice volatility. Futures contracts are a relatively recent addition to the suite of available mechanisms and have been growing in popularity. They require regular attention and a detailed understanding of financial market products and how they trade on exchanges. In particular, futures are settled daily from the day after you buy or sell them, so the cash flow risks associated with futures are more significant and more complex than with CFDs. Financial intermediaries can access futures, deal and use them to underpin offers of simpler derived products to retailers.

9.18 Electricity futures market hedges are always settled directly with the ASX. The ASX also has separate prudential requirements for traders in this market.

9.19 The ASX is continually looking at developing new hedge products to help parties better manage risk. Further information on ASX is available at ASX electricity futures market website

Electricity hedge market disclosure system

9.20 Part 13 of the Code sets out the requirements on industry participants to disclose risk management contract information.

9.21 Participants must disclose this information using the electricity hedge contracts website.

9.22 The disclosure of hedge contract information system allows interested parties to view and compare hedge contract details and produce historic contract curves to better assess the competitiveness of the hedge contract market. Parties in the process of entering into a hedge contract can view details of historic contracts which may assist them when negotiating their own contracts.

9.23 The hedge market disclosure web site can be found at Hedge market disclosure and Energy Link publishes three indices that are based on the disclosed data.

FTR market

9.24 The purpose of FTRs is to manage the price risk associated with congestion on the transmission system. This risk exists where electricity flows are constrained, and prices on the two sides of the constraint decouple. FTRs provide the ability to trade and benefit from changes in the differential between relative energy prices. The outcome from the FTR market can either be treated as standalone trading profits or offset the cost of (hedge against) constraints when they occur.

9.25 FTRs are an important accompaniment to energy markets that have adopted a locational pricing model. FTRs provide all participants in the energy market a tool for managing exposure to the price impact of constraints that are not otherwise countered by hedges with other parties.

9.26 FTRs specify the relative price between two points on a grid for an amount of MWs for a defined period. Settlement is based on the difference between the price of the FTR and the actual differential between prices at the two nodes the FTR is based on.

9.27 The FTR market helps to promote retail competition by encouraging retailers to compete for customers on a nationwide basis, as opposed to focusing primarily on regions close to where they own generation assets. It operates alongside the electricity hedge market.

9.28 The Authority established the FTR market under Parts 13 and 14 of the Code. FTRs are also governed by the Financial Markets Conduct Act 2013 and are regulated by the Financial Markets Authority.

9.29 The FTR market started in June 2013 with two FTR points at Otahuhu and Benmore.

9.30 In November 2014, the FTR market expanded to include new FTR points at Haywards, Invercargill, and Islington and in 2018 Kikiwa (upper South Island), Whakamaru (central North Island) and Redclyffe (Hawkes Bay) were added.

9.31 The FTR manager manages the FTR market under contract to the Authority. The FTR manager publishes the FTR allocation plan containing the auction rules and grid design.

9.32 FTR auctions are held twice monthly. Before and during each auction, the FTR manager also checks with the clearing manager that the amount of security each party holds is sufficient to validate their bids.

9.33 Further information can be found at Financial transmission rights (FTR) market

Spot market risk disclosure (stress testing)

9.34 Spot risk disclosure is described as the “stress testing regime”. This regime requires certain participants in the wholesale electricity market to apply a set of standard stress tests to their market position, and:

(a) report the results to their Board and to an independent registrar appointed by the Authority

(b) provide spot price risk disclosure statements each quarter, no later than five working days before the start of the quarter

(c) certify to the Authority each year that they have provided information about stress tests to their customers, and that their Board has considered the contents of the disclosure statements.

9.35 The objective of the stress testing regime is to help you understand (if you don’t already) the nature and the potential size of the risks that you are exposed to in the wholesale market.

9.36 Participants required to carry out stress testing and provide spot price risk disclosure statements are termed “disclosing participant”, and are participants who:

(a) consume electricity that is conveyed to them directly from the national grid

(b) buy electricity from the clearing manager.

9.37 For clarity, dispatchable load purchasers are participants who buy electricity from the clearing manager.

9.38 The stress tests and associated base case scenarios are set out on the Authority’s Stress tests webpage.

9.39 Spot price risk disclosure forms are available from the registrar’s website.

10 Transmission, generation and gas outage impact on spot price of electricity

10.1 Final pricing can be significantly affected by transmission constraints, generation being removed from service, or the unavailability of gas.

10.2 This type of event occurred in October-November 2018 when a gas outage coincided with the unavailability of hydro generation. The impact on price was significant and forced several retailers to exit the electricity market. The graph below shows final spot prices peaking as high as $941/MWh in some trading periods.

10.3 During this period, the average electricity cost over one month was approximately $350/MWh, while the historical long term average of spot cost is approximately $80/MWh. This significant rise in the spot price will cause a corresponding rise in prudential requirement, as well as monthly electricity invoices from the clearing manager (unless the purchaser has hedges). Because these events can happen unexpectedly, purchasers need to be prepared by ensuring they have sufficient hedge cover, generation cover, or financial reserves.

10.4 The stress test regime is designed to warn purchasers of the potential impact that high spot pricing may have on the cost of electricity purchases.

10.5 Purchasers exposed to spot price should monitor the contributors to high spot price, including:

a) hydro storage levels

b) system operator notifications

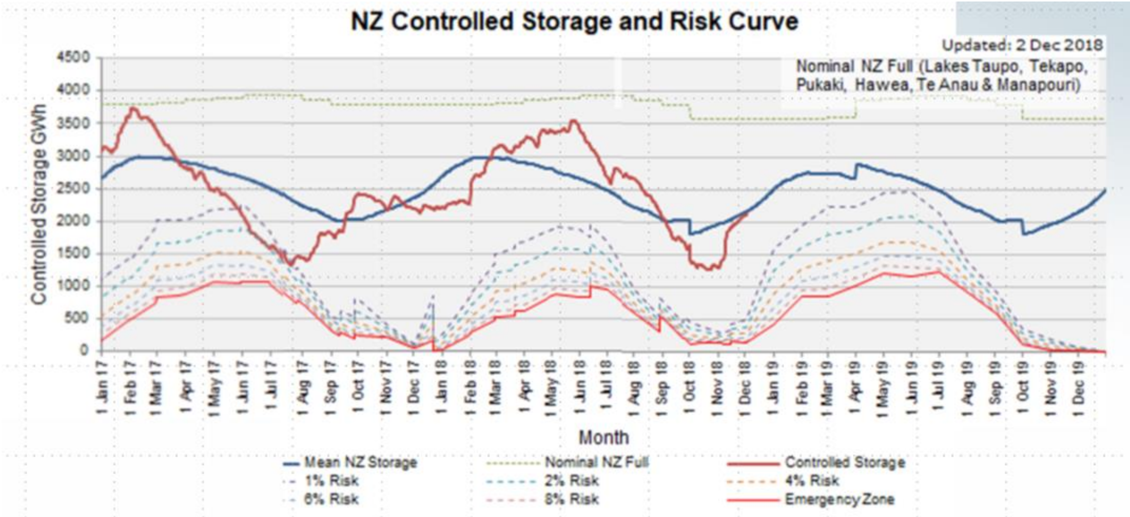
c) generation plant outages and transmission constraints

d) gas outages disclosures are a work in progress, refer to https://www.gasindustry.co.nz/work-programmes/gas-sector-information-disclosure/overview/

Hydro storage levels

10.6 Information on hydro storage information is available on the system operator's web page at https://www.transpower.co.nz/system-operator/security-supply/hydro-storage-information.

10.7 As hydro generation is removed from the electricity market due to low inflows, spot cost may rise. An extended view of hydro storage is shown below:



System operator notifications

10.8 Formal notices are notices that the system operator sends to people who register their email address with the system operator. The notifications inform of events happening on the power system that require parties to take some action. These notifications include:

(a) warning notices (WRN)

(b) grid emergency notices (GEN)

(c) grid emergency reports (GEN RPT)

(d) scarcity pricing situation notice (ISS)

10.9 Any person can register to receive these notifications by following the process set out at https://www.transpower.co.nz/system-operator/operational-information/formal-notices

Customer advice notices

10.10 Customer advice notices (CAN) are notifications that the system operator sends to people that register their email address. The notifications inform of events happening on the power system. The system operator publishes all CANs that are sent out.

10.11 Any person can register to receive these notifications by following the process set out at https://www.transpower.co.nz/system-operator/operational-information/customer-advice-notices.

Gas outage disclosure information

10.12 There is limited gas disclosure information available at this time. Nonetheless, purchasers are advised that they should take note of impending gas outages, maintenance, and breakdowns.

10.13 The Gas Industry Co is expecting to release an options paper for consultation to the industry in early 2019. The paper will layout a set of options for the industry to consider, including whether current information disclosure requirements for the gas sector are sufficient or whether a new set of arrangements are required.

11 Metering installations

11.1 Part 10 of the Code sets out participant obligations in relation to metering standards. Retailers are required to quantify all electricity consumption at their points of connection by a metering installation that complies with Part 10 of the Code.

11.2 MEPs are separate participants in the Code. MEPs may provide all, some, or no components in a metering installation but retain responsibility for compliance of active metering installations. Further information on MEPs is available on the Authority's metering webpage.

11.3 In most instances, the retailer and the MEP may be different parties. However, the retailer is the responsible party under the Code for ensuring that there are metering installations at all of the points of connection before each point of connection is electrically connected.

11.4 Metering is a competitive market in New Zealand. Traders are the participant that decides who the MEP is for a customer with an ICP identifier. Where the existing MEP cannot provide the functionality or services that the trader requires, the trader may contract with an alternate MEP for an ICP. In this case, the trader must notify the registry of a change to that MEP, and have the existing MEP displaced. This is the trader's sole discretion.

11.5 Retailers must have in place a commercial agreement with the MEP for an ICP before they switch an ICP to themselves in the registry.

11.6 Metering installations are certified as compliant by approved test houses (ATHs). It is the MEP's responsibility to ensure ongoing compliance of all metering installations measuring electricity consumed by the retailers' customers.

11.7 A retailer must not cause a metering installation to be altered or modified unless:

(a) it holds an agreement with a customer to be the retailer for an ICP; or

(b) it is the retailer on the register, unless the ICP has a "new" or "ready" status in the registry.

11.8 The Authority also has an advanced metering infrastructure policy and guidelines on its website.

11.9 Information may be exchanged between MEPs using the registry data hub. For more information refer to paragraph 4.16.

Types of meters

11.10 The accuracy of meters and meter readings, and the calculation of electricity conveyed volume information, directly impacts consumer invoices and wholesale market settlement.

11.11 There are two different types of meters used in the electricity market, these are as follows:

11.12 **Non half-hour** (NHH) measures and records electricity conveyed through a meter component. NHH meter readings used in the reconciliation process follow the profiling process described later in this document. This process is complex. NHH meters record electricity either as:

(a) Accumulating meter readings,[5] where the amount of electricity that has been conveyed is determined by the difference between the reading at the end of a certain time period and the reading at the beginning of that time period. As the readings are accumulating, any error in the meter reading is corrected by the next actual reading; or

(b) Absolute meter readings, where the amount of electricity that has been conveyed is measured and recorded directly and does not require any calculation. As such, an error in NHH absolute meter readings is not self-correcting. Consequently, there are stringent requirements on the data capture and handling of electronic meter readings.

11.13 **Half-hour** (HHR) measures and records electricity conveyed through a meter component. HHR meter readings can be used directly in the reconciliation process as the meter readings are usually in trading periods, or are aggregated into trading periods, and are usually in kWh. This process is a lot simpler than the NHH process. HHR meters record electricity either as:

(a) HHR meter reading is where volumes of electricity are measured as absolute values by the meter. An error in a HHR meter reading is not self-correcting. Consequently, there are stringent requirements on the data capture and handling of HHR meter readings.

(b) These types of meters are normally read electronically due to the large amount of information in the meter reading (trading period information) being downloaded. The resolution of information by trading period gives very good information on consumption patterns within a consumer's site, and allows prices to reflect the cost of supply of transmission, lines, and energy if these prices are available.

(c) The accuracy of HHR meter readings and the calculation of monthly consumption volumes directly impacts market settlement.

Types of metering installations

11.14 Metering installations are assemblies of metering components for the calculation process used to quantify the electricity conveyed through a point of connection.

11.15 Metering installations are required to be calibrated, installed by an Authority approved ATH, and are also required to be certified in accordance with Part 10 of the Code. MEPs are regulated in the Code to maintain current certification of the metering installation in accordance with the Code.

11.16 There are three different types of metering installations used in the electricity market, these are as follows:

(a) Unmetered load

(i) Under normal circumstances, the quantity of electricity consumed at an ICP is determined for reconciliation by metering. However, it may be determined without metering in certain circumstances described in the Code. This is then referred to as unmetered load.

(ii) Unmetered load may be the only load at an ICP or may coexist with metered loads at that ICP. Parts 11 and 15 of the Code require each reconciliation participant to submit submission information to the reconciliation manager in relation to certain network supply points (NSP), and points of connection, and in respect of certain consumption periods. The submission information must include any unmetered load.

5 These meter readings record an accumulated value (in a similar manner to the odometer on a motor vehicle).

(iii) The purpose of the Code provisions that relate to the quantification and reconciliation of unmetered load is to ensure that accurate and complete reconciliation information is provided to the reconciliation manager.

(b) **Non half-hour (NHH)**, where the metering installation comprises NHH meters and is certified as a NHH metering installation by an Authority-approved ATH:

(i) only NHH meter reading information may be used in the preparation of submission information for the reconciliation process for electricity market settlement

(ii) any information that the meter can provide may be used in the customer invoicing process.

(c) **Half-hour (HHR)**, where the metering installation comprises HHR meters and is certified as an HHR metering installation by an Authority-approved ATH:

(i) the retailer can choose to use either NHH or HHR information in the reconciliation process for electricity market settlement

(ii) any information that the meter can provide may be used in the customer invoicing process.

12 Management of the registry

Obtain access to the registry

12.1 The registry is a national database that contains information on every ICP identifier on a network from which electricity is supplied. Obtaining access to the registry is only necessary for a trader that buys/sells electricity from/to the clearing manager for an ICP.

12.2 A retailer must establish access to the registry to establish new retail customers, switch retail customers to and from other retailers, and manage its customer connections and reconciliation submissions. Retailers' obligations for the creation and maintenance of information in the registry are described in Part 11 of the Code and the reconciliation manager functional specification.

12.3 The person responsible for providing submission information to the reconciliation manager, for an ICP, is the persons responsible for the trader participant identifier recorded in the registry.

12.4 Only persons approved by the Authority can access the registry, and only on the terms and conditions noted in the Authority's registry access policy.

12.5 To obtain access to the registry, complete the registry access application form and follow the directions on the application form for submitting it to the Authority.

12.6 Under Part 11, retailers must ensure certain information is kept up to date on the registry and is complete and accurate at all times. The purchaser retains responsibility for providing submission information to the reconciliation manager and updating the information until the ICP is switched to another purchaser by the consumer, or the ICP has been decommissioned. Further information on the registry can be found in:

(a) the registry functional specification, which contains valuable information as well as the file formats required when interacting with the registry

(b) the registry user manual.

12.7 Part 11 of the Code provides for:

(a) the management of information held by the registry

(b) a process for switching customers and embedded generators.

12.8 While these obligations reside in Part 11, retailers must be certified as reconciliation participants under clause 15.38 of the Code to perform the obligations that are described in Part 11.

Keep information up to date

12.9 Part 11 requires retailers to ensure certain information is kept up to date on the registry and is accurate at all times. The retailer retains responsibility for updating the information until the ICP is switched to another retailer by the consumer, or the ICP has been decommissioned.

12.10 Retailers are responsible for updating the registry for the fields defined in the Code and registry functional specification, and must monitor the registry to ensure that information is correct.

12.11 Retailers are responsible for the electrical connection and electrical disconnection of an ICP and should have contracts with the appropriate persons warranted by the distributor for work on each distributor's network. Retailers must manage the 'active' and 'inactive' statuses of the ICP. Before an ICP is given the 'active' status there must be:

(a) only one party receiving supply on the ICP

(b) a metering installation or other form of quantification (as approved by the Board) for the electricity consumed on the ICP.

12.12 The term 'active' denotes:

(a) the electrical installation is electrically connected to the electricity supply

(b) submission information is required by the reconciliation manager.

12.13 The term 'inactive' denotes:

(a) electricity cannot flow at the ICP; or

(b) there is no submission information required by the reconciliation manager.

Switching

12.14 Retailers must have a process to enable switching of ICPs. This process can be for either half hour metering or non-half hour metering.

12.15 Non-half hour metering switches are categorised as either one of the following that are described in more detail in the following sections:

(a) a standard or transfer switch (TR switch type); or

(b) a move switch (MI switch type).

12.16 Half hour metering switches (HH switch type) are categorised as:

(a) half hour to half hour (and applicable only to ICPs with the highest metering category of 3 or more)

(b) non-half hour to half hour; or

(c) half hour to non-half hour.

12.17 Specific wait periods are required where a customer is acquired from cold calling. Refer to section 36M of the Fair Trading Act 1986.

12.18 Switches may be withdrawn for a period of up to two months after a switch is completed, but only if both the gaining and losing retailer agree to the switch withdrawal. A list of the advisory code reasons that a switch may be withdrawn for is available on the Authority's transfer of ICPs webpage.

12.19 Non-half hour meter reads at the time of a switch must be aligned between a gaining and losing retailer at all times. However, in the event that a gaining or losing retailer disagrees with the meter read at the time of the switch, the Code sets out a process for the retailers agreeing a change to the switch read. Where a switch read change is not agreed, both retailers must continue to use the original meter read.

12.20 The file formats for ICP switching can be found in the registry functional specification.

Switching process

12.21 The switching process operates as follows:

(a) Switching communications: All participants to a switch carry out comms through the registry. The registry:

(i) validates, stores, and reports all non-compliances

(ii) on sends files between relevant participants, eg, MEPs and networks receive advice of completed ICP switches between retailers.

(b) Arrangement agreed between customer and retailer: The arrangement only becomes binding in the Code when:

(i) the trader considers that all conditions of the arrangement have been met, which includes credit checks, and may include metering, etc

(ii) the cooling off period for cold call sales has expired.

12.22 The losing trader specifies any change of ANZSIC code, or profile code in the switch notice (NT file). On completion of the switch, the registry updates with these parameters automatically, as well as aligning correctly the submission type flags.

12.23 In reality:

(a) Most switches move straight from the initial notification (NT file) to a switch completion file (CS file) within one business day, ie, the switch only involves two files in total.

(b) Approximately 15 % of switches made are subsequently withdrawn.

(c) Most switch event meter readings are estimated despite daily AMI readings being available to losing traders. This is an issue for the Authority if a losing trader trades an ICP as non-half hour, and a gaining trader intends to trade an ICP as half hour.

(d) Approximately 2 % of switch completion files are rejected from the registry due to the losing trader's metering information not matching the information recorded on the registry (eg, incorrect number of meter registers, incorrect length of meter reading, etc).

TR switch type process

12.24 The following switching process applies when a customer at a premise with a metering installation with capacity of 500 amps/phase or less, changes retailer:

(a) The gaining trader issues a switch notice to the registry (NT file) that it is acquiring a customer and may suggest a switch event date (this is the actual effective date of the switch). The gaining trader must provide an NT file to the registry within two business days of an agreement with a customer becoming effective.

(b) The losing trader must initially respond in one of the following ways within three business days:

(i) provide an acceptance notice (AN file) to the registry, which includes a proposed switch event date (determined by the losing retailer); or

(ii) provide a notice of switch withdrawal (NW file) to the registry which includes a valid reason code from RW-010 http://www.ea.govt.nz/operations/retail/the-registry/transfer-of-icps/. The gaining trader does not have to agree to a switch withdrawal from the losing trader. If the gaining trader rejects the switch withdrawal request the switch must still proceed.

(iii) provide a switch completion file (CS file) to the registry, which includes:

a. the actual switch event date (which must be no later than, 10 business days after the receipt of the NT file from the registry)

b. where a channel on a metering component within the ICP being switched has an accumulator type = "C" and settlement indicator = "Y", then the following is required, amongst other data, within the CS file:

a. the serial number of metering components that have an accumulator type = "C" and settlement indicator = "Y"

b. the last actual read date of the metering installation where all channels were read

c. channel number of the channel that have an accumulator type = “C” and settlement indicator = “Y”

d. accumulation meter readings for each channel of the metering components that have an accumulator type = “C” and settlement indicator = “Y”

e. the switch event meter reading which must be either an actual read taken on the switch event date or a permanent estimate for the switch event date.

The registry validates that the required meter readings are provided and the switch completion file is rejected if the metering information does not match the registry. The losing trader must fix its information before the switch can be completed, and only has the unelapsed days left in the switch process to do so.

(iv) If the response described at paragraph (b.i.) or a rejection described at paragraph (b.ii.) is provided, the losing trader must still complete the switch by the provision of a switch completion (CS file). Fifty per cent of switches must be completed within five business days and 100 % within 10 business days.

(v) For two months after the switch event date, either trader may request a switch withdrawal. If both traders agree to the switch withdrawal, the switch transaction is unwound. The registry records the details of the withdrawn switch, but to market settlement it looks like the switch never occurred.

(vi) If the gaining trader disagrees with the meter reading supplied by the losing trader, the process in the following section should be followed.

Switching event meter reading disputes process for TR switch types

12.25 The losing trader and the gaining trader must both use the same non half hour switch event meter reading for the event date as determined by the following procedure:

(a) if the switch event meter reading provided by the losing trader differs by less than 200 kWh from a value established by the gaining trader, the gaining trader must use the losing trader’s switch event meter reading; or

(b) if the switch event meter reading provided by the losing trader differs by 200 kWh or more from a value established by the gaining trader, the gaining trader may dispute the switch event meter reading.

12.26 The Code sets out the switching event meter reading disputes process for TR switch types (RR/AC process noted in the registry function specification). The RR file can only be submitted by the gaining trader to the registry.

(a) For ICPs with AMI metering: If the submission type of an ICP identifier is changing at the time of a switch from NHH “Y” to HHR = “Y”; and a switch event meter reading provided by the losing trader has not been obtained from an interrogation of a certified metering installation with an AMI flag = “Y” in the registry, then:

(i) no later than five business days after receiving the CS file from the registry, the gaining trader may provide the losing trader with a switch event meter reading obtained from an interrogation of a certified metering installation with an AMI flag of Y in the registry; and

(ii) the losing trader must use that switch event meter reading.

(b) For all ICPs: If a gaining trader disputes a switch event meter reading, the gaining trader must, no later than four months after the event date, provide to the losing trader a changed switch event meter reading supported by two validated meter readings, and the losing trader must either,—

(i) if it does not accept the switch event meter reading, advise the gaining trader (giving all relevant details) no later than five business days after receiving the switch event meter reading from the gaining trader; or

(ii) if it notifies its acceptance of the switch event meter reading received from the gaining trader, or does not provide any response, the losing trader must use the switch event meter reading supplied by the gaining trader.

12.27 If a switch event meter reading dispute remains unresolved, the dispute must be resolved in accordance with the disputes procedure in clause 15.29 (with all necessary amendments).

MI switch type process

12.28 The following switching process applies when a customer moves into a premise with a metering installation with capacity of 500 amps/phase or less and changes retailer:

(a) The gaining trader issues a switch notice to the registry (NT file) that it is acquiring a customer and must determine the switch event date (this is the actual effective date of the switch). The gaining trader:

(i) must indicate the required switch event date in the NT file

(ii) must provide an NT file to the registry within two business days of an agreement with a customer becoming effective.

(b) The losing trader must initially respond with one of the following within three business days:

(i) provide an acceptance notice (AN file) to the registry which includes a proposed switch event date (no earlier than, and no later than 10 business days after the gaining traders determined switch event date); or

(ii) provide a notice of switch withdrawal (NW file) to the registry which includes a valid reason code from RW-010 http://www.ea.govt.nz/operations/retail/the-registry/transfer-of-icps/. The gaining trader does not have to agree to a switch withdrawal from the losing trader. If the gaining trader rejects the switch withdrawal request the switch must still proceed.

(iii) provide a switch completion file (CS file) to the registry, which includes:

(A) the actual switch event date (which must be no earlier than, and no later than 10 business days after the gaining traders notified switch event date in the NT file); and

(B) where a channel on a metering component within the ICP being switched has an accumulator type = “C” and settlement indicator = “Y”, then the following is required, amongst other data, within the CS file:

i. the serial number of metering components that have an accumulator type = “C” and settlement indicator = “Y”

ii. the last actual read date of the metering installation where all channels were read

iii. channel number of the channel that have an accumulator type = "C" and settlement indicator = "Y"

iv. accumulation meter readings for each channel of the metering components that have an accumulator type = "C" and settlement indicator = "Y"

v. the switch event meter reading which must be either an actual read taken on the switch event date or a permanent estimate for the switch event date

The registry validates that the required meter readings are provided and the switch completion file is rejected if the metering information does not match the registry. The losing trader must fix its information before the switch can be completed, and only has a few days to do so.

(c) If the response described in paragraph ((B) i.) or a rejection described in paragraph ((B) ii.) is provided, the losing trader must still complete the switch by the provision of a switch completion (CS file). Fifty per cent of switches must be completed within five business days and 100 % within 10 business days.

(d) For two months after the switch event date, either trader may request a switch withdrawal. If both traders agree to the switch withdrawal the switch transaction is unwound. The registry keeps the details but to market settlement it looks like the switch never occurred.

(e) Where the gaining trader disagrees with the meter reading supplied by the losing trader, the Code requires the losing trader to use the gaining traders meter reading if the volume difference is less than 200 kWh/meter register, or use the disputes process noted below.

Switching event meter reading disputes process for "MI" switch types

12.29 The losing trader and the gaining trader must both use the same switch event meter reading for the event date as determined by the following procedure:

(a) if the switch event meter reading provided by the losing trader differs by less than 200 kWh from a value established by the gaining trader, the gaining trader must use the losing trader's switch event meter reading; or

(b) if the switch event meter reading provided by the losing trader differs by 200 kWh or more from a value established by the gaining trader, the gaining trader may dispute the switch event meter reading.

12.30 The Code sets out the switching event meter reading disputes process for MI switch types (RR/AC process noted in the registry function specification). The RR file can only be submitted by the gaining trader to the registry.

(a) For ICPs with AMI metering: If the submission type of an ICP identifier is changing at the time of a switch from NHH "Y" to HHR = "Y"; and a switch event meter reading provided by the losing trader under subclause (1) has not been obtained from an interrogation of a certified metering installation with an AMI flag = "Y" in the registry, then:

(i) no later than 5 business days after receiving the CS file from the registry, the gaining trader may provide the losing trader with a switch event meter reading obtained from an interrogation of a certified metering installation with an AMI flag of Y in the registry; and

(ii) the losing trader must use that switch event meter reading.

(b) For all ICPs: If a gaining trader disputes a switch event meter reading, the gaining trader must, no later than four months after the event date, provide to the losing trader a changed switch event meter reading supported by two validated meter readings, and the losing trader must either,—

(i) if it does not accept the switch event meter reading, advise the gaining trader (giving all relevant details) no later than five business days after receiving the switch event meter reading from the gaining trader; or

(ii) if it notifies its acceptance of the switch event meter reading received from the gaining trader, or does not provide any response, the losing trader must use the switch event meter reading supplied by the gaining trader.

12.31 If a switch event meter reading dispute remains unresolved, the dispute must be resolved in accordance with the disputes procedure in clause 15.29 (with all necessary amendments), provide that the gaining trader notifies that the dispute is lodged within five business days with the reconciliation manager.

HH switch type process

12.32 The HH switch process applies to ICP identifiers if the ICP contains a metering installation of metering category 3 or greater:

(Note: An ICP identifier may contain a category 3 or greater metering installation as well as category 1 and category 2 metering installations. In this case, the HH switch process should still be used and the required accumulation meter readings for the category 1 and category 2 metering installation must be included in the CS file.)

The HH switch process differs from the TR and MI switch process. In the HH switch process it is the gaining trader that completes the switch by issuing the CS files. The following switching process applies

(a) The gaining trader issues a switch notice to the registry (NT file) that it is acquiring a customer and must determine the switch event date (this is the actual effective date of the switch). The gaining trader:

(i) must indicate the required switch event date in the NT file

(ii) must provide an NT file to the registry within three business days of an agreement with a customer becoming effective.

(b) The losing trader must initially respond with one of the following:

i. within two business days with an acceptance notice (AN file) to the registry which includes a proposed switch event date (no earlier than, and no later than, 10 business days after the gaining traders determined switch event date); or

ii. within three business days with a notice of switch withdrawal (NW file) to the registry which includes a valid reason code from RW-010. The gaining trader does not have to agree to a switch withdrawal from the losing trader. If the gaining trader rejects the switch withdrawal request the switch must still proceed.

(c) In this particular switch type, the gaining trader must complete the switch, responding within three business days with a switch completion file (CS file) to the registry, which includes:

i. the actual switch event date, which may be either:

a. a date within the month that the gaining trader advises the registry of the switch; or

b. a date that is no more than 90 days before the date that the gaining trader advises the registry of the switch.

ii. where a channel on a metering component within the ICP being switched has an accumulator type = “C” and settlement indicator = “Y”, then the following is required, amongst other data, within the CS file:

a. the serial number of metering components that have an accumulator type = “C” and settlement indicator = “Y”

b. the last actual read date of the metering installation where all channels were read

c. channel number of the channel that have an accumulator type = “C” and settlement indicator = “Y”

d. accumulation meter readings for each channel of the metering components that have an accumulator type = “C” and settlement indicator = “Y”

e. the switch event meter reading which must be either an actual read taken on the switch event date or a permanent estimate for the switch event date.

The registry validates that the required meter readings are provided and the switch completion file is rejected if the metering information does not match the registry. The losing trader must fix its information before the switch can be completed, and only has a few days to do so.

(d) If the response described in paragraph (b.i.) or a rejection described in paragraph (b.ii.) is provided, the gaining trader must still complete the switch by the provision of a switch completion (CS file).

(e) For two months after the switch event date, either trader may request a switch withdrawal. If both traders agree to the switch withdrawal the switch transaction is unwound. The registry keeps the details but to market settlement it looks like the switch never occurred.

(f) Where the gaining trader disagrees with the meter reading supplied by the losing trader, the Code requires the losing trader to use the gaining traders meter reading if the volume difference is less than 200 kWh/meter register, or use the disputes process noted below.

(g) This process does not include AMI metered ICPs.

(h) This process is used to switch ICPs where the gaining trader also intends to change the metering installation from non-half hour to half hour and vice-versa.

Switching event meter reading disputes process for HH switch types

12.33 The losing trader and the gaining trader must both use the same switch event meter reading for the event date.

12.34 As the gaining trader must determine any accumulation meter readings for category 1 and category 2 metering installations, there is no disputes process.

Customer retention during and after switching (saves and winbacks)

12.35 A ‘save’ is where a retailer entices a customer to stay with them while a switch is in progress. A ‘win-back’ is where a retailer entices a customer to return to them after they have switched away.

12.36 Both of these activities are <u>not</u> permitted.

12.37 All retailers (regardless of if they interact directly with the registry) are not permitted to contact customers that are in the process, or have switched away, including to entice the customer to cancel the switch or switch back to them.

12.38 There are certain exceptions to this prohibition, such as for administrative activities and where there are multi-product offerings that extend beyond electricity.

12.39 Additionally, enticements can be offered if a customer initiates contact seeking an enticement.

12.40 For more information please refer to the saves and win-backs practice note.

13 Electrical connection and electrical disconnection of ICPs

Medically dependant and vulnerable customers

13.1 There are specific recommendations for dealing with customers who fit the definition of medically dependent or vulnerable consumers refer to paragraph 3.6.

Electrical connection of a new ICP

13.2 When a new point of connection is to be electrically connected, the process set out in the distributor's use of system agreement should be followed.

13.3 Retailers should note that a new point of connection cannot be electrically connected unless:

(a) a certified metering installation quantifies electricity conveyed across the customers point of connection

(b) the distributor has accepted that the installation is safe and consented to the electrically connected of the point of connection

(c) the retailer has switched the ICP to themselves within the time periods noted within the Code

(d) the retailer has updated the status of the ICP in the registry to "Active".

Electrical connection of an existing ICP

13.4 When an existing point of connection is electrically disconnected and is to be electrically connected, the process set out in the distributor's use of system agreement should be followed.

13.5 Retailers should note that an existing point of connection cannot be electrically connected unless:

(a) a certified metering installation quantifies electricity conveyed across the customers point of connection

(b) the distributor has not electrically disconnected the premise for safety reasons

(c) the retailer has switched the ICP to themselves within the time periods noted within the Code

(d) the retailer has switched the ICP and updated the status of the ICP in the registry to "Active" within the time periods allowed within the Code.

13.6 If a retailer connects an ICP it is in the process of switching and then reverses or cancels the switch, that connecting retailer is liable for the losing traders' direct costs for the electricity conveyed from the date of the reconnection.[6]

Electrical disconnection for non-payment

13.7 Electricity retailers follow a set of principles and minimum terms and conditions when they set their contracts for consumers. This includes expectations for the process around electrical disconnection for non-payment.

13.8 Electrical disconnection for non-payment should be recorded against an ICP identifier in the registry as an inactive status.

13.9 Even though the terms and conditions are voluntary, most retailers follow them. Simply having them has meant retailers are paying more attention to having clear, easy-to-read contracts that consumers can compare with other retailers in their region.

13.10 Further information can be found on the Authority's retailer obligations webpage.

13.11 The Authority requires retailers to provide quarterly reports on domestic credit disconnections, these reports include the number of consumers disconnected for credit reasons, refer to Electrical disconnection report

Electrical disconnection for vacant premise

13.12 Electricity retailers are responsible for any electricity consumed by a vacant premise, and may not have a customer that they can on-charge the costs of consumed electricity to. Many retailers elect to electrically disconnect premises that are vacant either:

(a) remotely, using the disconnection contacts in an AMI meter; or

(b) locally, by getting power isolated through the removal of a fuse. Link or operation of a switch or similar.

13.13 Electrical disconnection by removing conductors from a meter is discouraged as it can be a safety and metering installation certification issue.

13.14 Electrical disconnection must be recorded in the registry by marking the ICP as "inactive", and using the reason code that indicates where the premise is Electrical disconnected. This allows any gaining retailer to know where supply must be restored from in the case of a switch.

6 10.33(1)(a)(i)(B)(3) and 10.33A(1)(a)(i)(B)(3)

14 Reconciliation

14.1 Part 15 of the Code sets out participant obligations in relation to reconciling submission information in the electricity market. Reconciliation participants are a type of participant that has obligations under Part 15 of the Code to either provide reconciliation information to the reconciliation manager, or generation volume information to the grid owner. This is discussed further below.

Certification as a reconciliation participant

14.2 A purchaser at a network supply point (NSP) connected to the grid:

(a) does not require certification as a reconciliation participant, as the grid owner provides metering information to the reconciliation manager and no interface with the registry is required:

(b) requires certification if the purchaser has the following Code obligations

(i) is a dispatchable load purchaser at or within the NSP

(ii) providing metering information to the pricing manager in accordance with subpart 4 of Part 13 of the Code.

14.3 A purchaser at an ICP is a reconciliation participant and is required to be certified for the following Code obligations:

(a) maintaining registry information and performing customer and embedded generator switching

(b) gathering and storing raw meter data

(c) creating and managing (including validating, estimating, storing, correcting and archiving):

(i) half hour volume information

(ii) dispatchable load information

(d) calculation of ICP days, monthly kWh information of half hour metered ICPs, and electricity supplied

(e) provision of submission information for reconciliation

(f) provision of metering information to the pricing manager in accordance with subpart 4 of Part 13 of the Code.

14.4 Reconciliation participants must obtain and maintain certification to perform these functions in the electricity market. Certification requires a suitable audit from an Authority approved auditor to show to the Authority's approval that the reconciliation participant complies with its Code obligations.

14.5 The performance of any of the functions of a reconciliation participant without holding appropriate certification is a breach of the Code.

14.6 Reconciliation participants can use agents to perform the functions in Part 15 of the Code. However, responsibility for any functions performed by agents under the Code remains with the certified reconciliation participant.

14.7 For further information, please see the information paper on audit and certification requirements for reconciliation participants and distributors.

14.8 For existing certified reconciliation participants seeking recertification, the application form for certification as a reconciliation participant must be submitted to the Authority two months prior to when the reconciliation participant must be certified. The Authority uses the published certification dates on the certified reconciliation participant register as its due date for renewal applications for certification as a reconciliation participant.

Reconciliation participants who need to become certified reconciliation participants must apply to the Authority for certification two months before certification is required.[7]

(a) New entrant reconciliation participants must obtain certification within six months of the date that the purchaser first switched its first ICP identifier. However, the requirement for certification is extended from six months to twelve months if the reconciliation participant:

(i) is responsible for less than100 ICP identifiers in the registry

(ii) trades only ICP identifiers in the registry with category 1 metering installations

(b) In the event that the new entrant that is relying on paragraph (a) above:

(i) gains more than 100 ICP identifiers in the registry in the period between six months and twelve months of the date that the purchaser first switched its first ICP identifier in the registry, the new entrant must immediately gain certification

(ii) gains an ICP identifier in the registry with a category 2 or greater metering installation, the new entrant must immediately gain certification.

14.9 For recertification of an existing reconciliation participant, an application for certification must be made two months prior to certification being required, which means that an audit must be finalised, at the latest, two months prior to certification being required.

14.10 You will need an audit to support your certification at the time you apply.[8]

14.11 Certification can be granted for terms of up to 24 months and this influences the next audit date.

14.12 Due to the 14-month wash-up cycle it is common for participants to have certification and audit periods of no more than 14 months. Periods of between 15 and 24 months are only considered once it can be consistently demonstrated the participant is compliant and compliance is being actively managed to prevent errors from occurring.

14.13 Details about certification can be found on the Authority's retail audit database webpage.

Notification to reconciliation manager of intention to purchase electricity

14.14 This section only applies to grid direct purchasers. It does not apply to purchasers or retailers that trade electricity at ICPs.

14.15 The reconciliation manager receives volume information in the form of submission information, dispatchable load information, or supporting information from all purchasers and generators, and determines the amount of electricity purchased or sold by each purchaser or generator at each grid NSP.

14.16 A purchaser or generator for a premises directly connected to the grid is required to notify the reconciliation manager of its intention to purchase or sell, or cease purchasing electricity or selling on any NSP. It is also required to provide any information that is required by the Code or that is reasonably required by the reconciliation manager. The reconciliation manager must be

7 Clause 2A of Schedule 15.1

8 Clause16A.24 of Part 16A

notified at least five business days prior to the day the purchaser intends to purchase (or to cease purchasing) electricity at any NSP.

14.17 Please provide notification to the reconciliation manager at rm@nzx.com.

Provision of monthly information to the reconciliation manager

14.18 Purchasers and generators (as reconciliation participants) must provide submission information to the reconciliation manager in accordance with the Code and the reconciliation manager functional specification. The reconciliation manager's functional specification can be found on the Authority's website.

14.19 There are specific timeframes that must be met for the provision of this information.

14.20 Note that purchasers at an ICP must also deliver supporting information to the reconciliation manager as follows:

(a) ICP days information for each consumption period

(b) electricity supplied (billing) information

(c) half hourly metered monthly ICP aggregates.

14.21 The reconciliation manager also has useful information on its website.

Access to the reconciliation manager's web portal

14.22 Submission information is uploaded to the reconciliation manager's web portal. Reconciliation results are also published by the reconciliation manager to this website.

14.23 The reconciliation manager also provides a test website for retailers to test the submission of their information. The use of this website is encouraged for new type 1 retailers prior to trading.

14.24 The web portal is also a source of news relevant to reconciliation, such as new embedded networks or reconciliation system outages. The reconciliation manager also manages an email distribution list for the same purpose.

14.25 Please contact the reconciliation manager directly to arrange logon access to both the production and UAT web portals by emailing rm@nzx.com.

Profiles

14.26 A profile is defined in the Code as a "fixed or variable electricity consumption pattern assigned to a particular group of meter registers or unmetered loads". It represents a shape that is used in synthesising electricity volume information into trading period volume information:

(a) apart from the HHR profile code, profiles apply only to submission information derived from non half hour metering installations

(b) a consumption pattern shows the way in which total electricity use for a certain period and group of users would be allocated across half hourly time periods.

14.27 Standard profile shapes are available as follows:

(a) *HHR (half hour):* for all half hour submissions

(b) *RPS (residual profile shapes):* standard non half hour profile shape that can be used for any non-half hour consumption submissions

(c) *UML (unmetered load):* flat load profile that can be used for all unmetered load consumption submissions as an alternative to RPS

(d) *PV1 (photovoltaic):* shaped profile that must only be used for all non-half hour metered photovoltaic generation submissions (this profile has an active period of 9 am to 3 pm)

(e) *EG1 (embedded generation):* flat load generation profile that must be used for all non-half hour generation submissions that are not photovoltaic.

14.28 Any person can create a new profile targeting specific groups using the process set out in Schedule 15.5 of the Code. However, the majority of retailers use a profile based on the shape of all of the electricity conveyed at the local grid exit point, minus the electricity consumed by customers with half hourly meters. This is known as the RPS.

14.29 Schedule 15.5 of the Code details how profiles are administered. An information paper and a list of approved profiles can be found on the Authority's website.

14.30 All non-half hour profiles must follow the process set out in Schedule 15.3 of the Code to calculate and create submission information. Particular attention should be paid to the use of the seasonal adjustment shape, forward and historic estimates in converting non-half hour meter reads into calendar month volumes. A guideline on the application of profiles is available on request to the Authority.

Reporting frequency of meter readings

14.31 Retailers must ensure that meters are read within specified time periods and must provide information to the Authority on the frequency of meter reading.

14.32 Guidelines and a format for submission of frequency meter readings are available on the Authority's website.

14.33 Please send the information to marketoperations@ea.govt.nz

Retail pricing

14.34 Retail pricing, apart for the low fixed charge regulation requirements discussed below, are not currently regulated. There is however guidance on the Authority's website for retailers and consumers, where consumers elect to accept a retail price that is based on wholesale price per trading period.

14.35 A distributor may require a retailer to invoice its network charges to customers on the retailers invoice to consumers, and pay that collected money to it. Where this is the case:

(a) the distributors should make the invoicing arrangements clear in the Use of System Agreement between the distributors and the retailer, and

(b) the registry records who is to bill network charges to consumers on the ICP field labelled "direct billed status". This indicator set as one of "distributor", neither", "both" or "TBA".

14.36 In calculating retail price for a customer, retailers should take into account the following as a minimum:

(a) The GXP for each ICP that is contained in the registry.

(b) The loss factor that applies in adjusting a consumer's losses to the GXP where purchases are made from the clearing manager. The Loss Category Code noted against each ICP in the registry relates to loss factors contained in the registry loss factor table. This table can be downloaded from the registry by registry users, refer to the registry user manual on the registry manager's website.

(c) The UFE that applies within the balancing area that the customer's ICP is within. UFE is an additional loss factor that will be applied to volumes of electricity purchased from the clearing manager and varies between +/-4% depending on the network. Failure to include UFE may make a retailer's pricing unattractive or uneconomic to consumers. UFE is provided to traders at an NSP in the reconciliation files. However, a total summary of UFE from 1 May 2008 by balancing area is available on request to marketoperations@ea.govt.nz

(d) The metering configuration and register content codes that are contained in the registry.

(e) The metering lease costs from the MEP and any associated data provision costs.

(f) The meter reading costs.

(g) Hedging costs.

(h) Where the retailer is to invoice the distributor's network charges, the Price Category Code and any associated installation details and chargeable capacity noted against each ICP in the registry.

(i) The prices for each element of charging necessary within each Price Category Code in the distributor's pricing schedule.

Domestic low fixed charge tariff

14.37 The Ministry of Business, Innovation and Employment (MBIE) is responsible for administering and amending the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (Regulations).The Authority is responsible for enforcing the Regulations. The low fixed charge option is intended to assist low – use consumers and encourage energy conservation for a consumer who uses thresholds of less than 8,000 kWh per annum for homes not in the lower South Island, and 9,000 kWh per annum for homes in the lower South Island.

14.38 The Regulations require

(a) distributors and retailers to make available to residential consumers a pricing option with fixed charges, limited to 15c/day for distributors and 30c/day for retailers, both must be net of discounts and GST. This means that any remaining fixed costs not recovered in the fixed charge must be included in the variable electricity cost in cents/kWh

(b) retailers to offer at least one low fixed charge option for each of their domestic price plans

(c) that the 'average consumer' must not be worse off on the low fixed charge tariff option

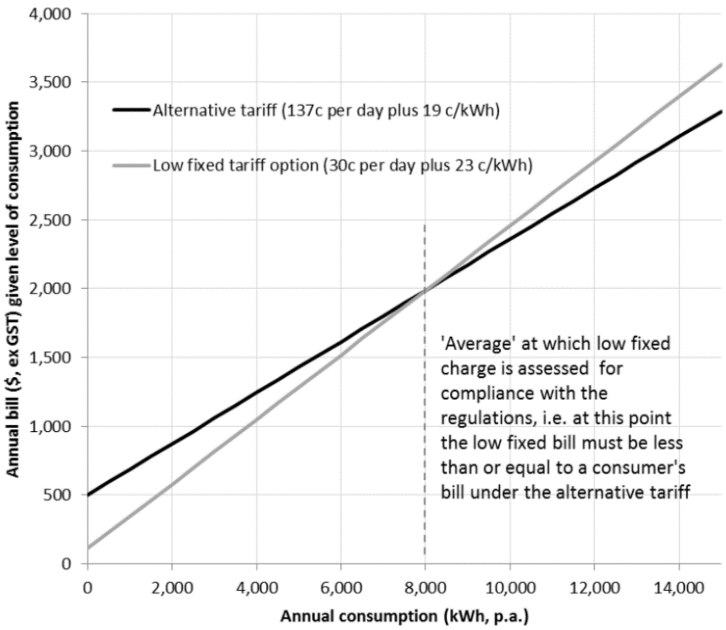
(d) that tiered or stepped variable charges cannot be used in low fixed charge tariff options

(e) retailers to notify the Authority of any changes to tariffs or of the introduction of any new price options, 15 business days before the new price options. Regulation 23 specifies what information must be provided in these notifications. Please send the notifications to compliance@ea.govt.nz.

14.39 The Authority has produced guidelines Variable charges under the low fixed charge Regulations. These Guidelines set out the Authority's view on the requirements of the Regulations with respect to distributors' and retailers' demand and capacity charges. The Authority will enforce the Regulations in line with the views of the Regulations' requirements set out in these Guidelines.

Application of thresholds

14.40 The price for a standard domestic price and a low fixed charge price must not intersect at less than the threshold in para 14.37, as indicated in the graph below. In effect this means that consumers on a low fixed charge price have a low daily fixed charge price, but a higher variable price, than do consumers on a standard domestic price.



14.41 Retailers must advertise and promote LFC tariffs in the same manner as standard tariffs. Every 12 months retailers must promote the low fixed charge tariff to each domestic consumer by identifying how much electricity was purchased in the last year with advice the consumer may be better off being on the standard tariff if they use less electricity than the standard consumer. The Authority interprets the annual aspect of the tariff means that consumers cannot "game" the tariff by changing to the LFC at times of low consumption and then back to the standard option at times of high consumption i.e. only one change per year

Exemption from low fixed charge

14.42 Clauses 26 to 33 of the Regulations allow the Minister to exempt an electricity retailer or electricity distributor, from the requirements of the Regulations, for a particular area or for homes with 3-phase or greater than 15 kVA supply..

14.43 The distributor or the retailer granted the exemption must publish the exemption on its web site.

14.44 An exemption granted to a distributor does not automatically exempt relevant retailers. If a retailer is trading in a network where the distributor has an exemption, the retailer must either

(a) apply to the Minister for an exemption itself. Applications for an exemption on those networks themselves (through MBIE), or

(b) offer LFC despite the distributor having received an exemption. In this case the retailer would be charging LFC prices to a consumer but paying standard network prices to the distributor. In that case the retailer may be exposed to cost they cannot recover.

Spot market expectations on retailers

14.45 The Authority has introduced a market facilitation measure outlining its expectations on retailers offering spot price products to residential consumers (spot retailers).

14.46 The Authority expects all retailers offering spot price products to residential consumers to:

(a) appropriately inform potential customers of the risks, as well as the benefits, of spot price products.

(b) at appropriate intervals, inform their existing customers of the risks and benefits of spot price products.

(c) at appropriate intervals, offer their customers options to manage spot price volatility.

(d) keep data on new customers' accumulated savings to demonstrate the extent its customers have benefited from the spot-priced product over time.

14.47 The Authority will continue to monitor how effectively spot retailers meet the expectations listed above. This means spot retailers can expect requests for information from the Authority's market monitoring team.

14.48 This information will help inform the Authority about the practices being used by spot retailers. In the event of a dry year or during shorter-term price spikes, having access to such information will allow the Authority to respond to any concerns raised by these consumers or by other stakeholders regarding these consumers.

14.49 If the Authority believes insufficient action has been taken by retailers offering spot price products, we may consider Code amendments to introduce mandatory requirements.

14.50 Further information is available at Spot market expectations on retailers

15 Network pricing

General

15.1 Where a retailer supplies a customer connected to a network, the distributor that owns or operates the network will require payment for use of its network.

15.2 There are four types of networks:

(a) Local networks – local networks are connected directly to the national grid and supply consumers who have a choice of retailer

(b) Customer networks – with customer networks the owner of the network purchases all of the electricity conveyed and acts as a retailer to customers connected to the network. Consumers do not have a choice of retailer.

(c) Network extensions - network extensions are owned by someone other than the local network but consumers are treated as if they were connected to the local network. Consumers have a choice of retailer.

(d) Embedded networks – embedded networks are owned and operated by someone other than the local network and are treated as its own network. Consumers have a choice of retailer.

15.3 For more information on networks see the secondary networks guideline.

15.4 The Code, and distributors, require an agreement between a distributor on a network and a retailer prior to the retailer commencing trading activities on the distributor's network. This agreement is call a "Use of System Agreement".

15.5 The use of system agreement agreed with the distributor will set out the arrangements for use of network charging, outage notifications, connections, payments, etc. Retailers need to discuss requirements with each network individually, when negotiating the use of system agreement.

15.6 Distributors may choose, at an ICP level, who invoices use of network charges. This choice is recorded on the registry under the network event in the fields "Direct Billed status" and "Direct billed details". Retailers should check who invoices the use of network charges for each ICP that they switch, prior to invoicing a customer.

15.7 Distributors may choose who invoices the use of network charges to a consumer, and this may be any one of the following:

(a) *Retailer*: distributor requires the retailer to invoice all "use of network charges" to the customer on the networks behalf.

(b) *Distributor*: distributor invoices all "use of network charges" directly to a customer.

(c) *Neither*: no-one invoices "use of network charges" to a customer.

(d) *Both*: both the distributor and the retailer invoice "use of network charges". The details of what is to be invoiced by the retailer should be contained in the "Direct billed details" field.

(e) *TBA*: yet to be determined, refer directly to the distributor.

Network pricing schedules

15.8 Where a retailer is required to invoice the use of network charges to a customer, the use of system agreement and the Code require the distributor to provide a pricing schedule to the retailer. The pricing schedule will sets out the prices that should be charged to the consumer, as well as the eligibility criteria relating to the customer type, characteristic, capacity, and metering configuration.

15.9 Pricing schedules and pricing methodologies are unique to each distributor. Retailers may require specific invoicing setups to invoice use of network charges to customers as setups will vary. When negotiating a use of system agreement retailers should investigate complexity of setup required in their invoicing system to ensure that they can invoice for the customer group that they wish to trade.

15.10 Any change to a network pricing schedule will affect a retailer's agreed charges to its consumers. Part 12A of the Code requires distributors to:

(a) Consult with retailers for any changes as a change may affect:

(i) the eligibility criteria for a tariff rate

(ii) the retailers tariff rates.

(b) Notify retailers of any change to its pricing schedule at least two months before the changes become effective. This allows the retailer sufficient time to recalculate its retail prices if necessary, and provide notification of a price change to its customer.

Loss factors

15.11 When electricity travels through power lines, a proportion of energy is lost as heat due to the resistance in the lines. The greater the distance the electricity travels and the lower the voltages of the line, the higher the losses are.

15.12 Loss factors are determined by distributors so that the reconciliation process and customer invoicing processes can account for the existence of these and other losses.

15.13 Each ICP has a loss category code populated by the distributor in the pricing event. A retailer can determine the loss factor for an ICP by obtaining the loss category code for an ICP from the registry information, and reference that code to the loss factor table in the registry. Average loss factors are in the order of about 5.5 %, so retailers should ensure that loss factors and unaccounted for electricity (UFE) are accounted for in their retail pricing process.

15.14 Loss factors may vary over time. Any change to the loss category code or loss factor at an ICP will affect the retailer's purchases volume from the clearing manager, and consequently may affect the retailer's retail price to customers.

15.15 Where a distributor intends to change either the loss category code or the loss factor at an ICP, the distributor must give two months' notice to a retailer of that change. This allows the retailer sufficient time to recalculate its retail prices if necessary, and provide notification of a price change to its customer.

Network invoices customer directly for use of its network

15.16 In this case, the distributor will invoice the customer and receive payment directly for use of network charges. The retailer normally will not be part of the invoicing or collection of payments processes unless the use of system agreement has specific requirements.

15.17 The distributor may require the retailer to provide information on electricity volumes to enable network charging. The distributor should set out its requirements in the use of system agreement. Any volume information would normally be provided in EIEP1 or EIEP3 format, unless the distributor and retailer agree otherwise.

Retailer invoices customer on behalf of the network for use of network

15.18 Each ICP has a price category code populated by the distributor in the pricing event. A retailer can determine the network tariffs that are applicable to an ICP by obtaining:

(a) the price category code from the registry

(b) the network tariff rates from the network pricing schedule

(c) the register content code and period of availability for each meter register scheduled in the registry where the settlement indicator = "Y", or the retailer can use the HHR data (7304 channel) to time block electricity into the appropriate time period.

15.19 Pricing schedules and pricing methodologies are unique to each distributor. Retailers may require specific invoicing setups to invoice use of network charges to customers. When negotiating a use of system agreement, retailers should investigate the complexity of the set up required in their invoicing system to ensure they can invoice for the customer group that they wish to trade.

15.20 Pricing schedules will contain a key called the price category code. The price category code for each ICP is recorded in the registry under the pricing event. When reviewing an ICP to decide if the retailer wishes to make an arrangement to supply a customer, retailers should review the price category code to ensure that they can invoice the required use of network charges.

15.21 The price category code will contain a list of network tariffs that may be fixed or variable components. Variable network tariffs should be applied to volumes of electricity measured by eligible meter registers within the metering installations at a customer's premises.

15.22 Eligibility criteria for a network tariff can be matched to a meter register by the register content code and period of availability. Each meter register has this information recorded by the MEP in the registry metering records.

15.23 Network tariffs should only be applied to a meter register where the distributors required eligibility criteria, and the register content code and period of availability match. If they do not match, the retailer may need to ask the MEP to modify the metering installation so that the required network tariffs can be charged.

Types of network pricing

15.24 There are several types of network charging arrangements used by distributors in New Zealand. Retailers should discuss and understand the network pricing arrangements for a network area, before they commence retailing or sets its retail pricing. The method of network charging will affect the way in which a retailer calculates its retail prices. These are as set out in the following three sections.

ICP based pricing

15.25 In this instance the distributor provide a rate that applies at each ICP. Network losses and UFE are included within the distributor's rates and do not need to be applied separately. The attributes of ICP based pricing are:

(a) any variable network charges are applied at the meter register level

(b) for network purchases, losses and UFE do not need to be applied to the rate or the metered volume unless the distributor has noted this within their pricing schedule

(c) for electricity market purchases, losses and UFE are added to the meter register volume. Retailer need to provide compensation for these factors in their invoice to a consumer either within their retail price, or as an adjusted invoice volume.

ICP based pricing with scaling

15.26 In this instance the distributor provide a rate that applies at each ICP. Network losses and UFE are included within the distributor's rates and does not need to be applied separately, however the distributor may themselves scale the ICP volumes to match the GXP metered volumes. The attributes of ICP based pricing with scaling are:

(a) Any variable network charges are applied at the meter register level, but scaled to the GXP by the distributor.

(b) For network purchases, losses and UFE need to be applied either to the rate, or the metered volume. Retailers need to provide compensation for these factors in their invoice to a consumer either within their retail price, or as an adjusted invoice volume. Retailers should ascertain the scaling rate (which may vary per month) from the distributor.

(c) For electricity market purchases, losses and UFE are added to the meter register volume. The retailer needs to provide compensation for these factors in their invoice to a consumer either within their retail price, or as an adjusted invoice volume.

GXP based pricing

15.27 In this instance the distributor uses the output from the reconciliation manager's process to calculate invoices for each retailer on their network. Network losses and UFE are allocated by the reconciliation manager and do not need to be applied separately. The attributes of GXP based pricing with scaling is:

(a) Any variable network charges are applied at the meter register level, but scaled to the GXP by the distributor.

(b) For network purchases, losses and UFE are allocated by the reconciliation manager. The network owner charges the retailer for the volume of electricity submitted by the retailer to the reconciliation manager plus network losses and UFE. Retailers need to provide compensation for these factors in their invoice to a consumer either within their retail price, or as an adjusted invoice volume. Retailers should ascertain the UFE (which varies per trading period) from the distributor.

(c) For electricity market purchases, losses, and UFE are added to the meter register volume. The retailer needs to provide compensation for these factors in their invoice to a consumer either within their retail price, or as an adjusted invoice volume.

16 Sources of information

16.1 Summary of sources of information contained in this information paper:

(a) Electricity Industry Act 2010: http://www.legislation.govt.nz/

(b) The Electricity Industry (Enforcement) Regulations 2010

(c) Electricity Industry Participation Code 2010

(d) The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004: http://www.legislation.govt.nz/

(e) Electricity (Levy of Industry Participants) Regulations 2005

(f) Participant registration

(g) Wholesale Information and Trading System

(h) System operator website (for wholesale electricity bids): http://www.systemoperator.co.nz/

(i) Reconciliation information (profile information and frequency meter reading)

(j) Reconciliation participant certification and audit requirements

(k) Reconciliation manager website: https://electricityreconciliation.co.nz/page/home

(l) Domestic retail contracting arrangements

(m) Model arrangements for electricity distribution services: http://www.ea.govt.nz/operations/distribution/distributors/use-of-system-agreements/

(n) Metering equipment provider guideline http://www.ea.govt.nz/dmsdocument/13758

(o) Vulnerable consumers and medically dependent consumers

(p) Consumer complaints resolution system (approval method)

(q) The Electricity and Gas Complaints Authority: http://www.egcomplaints.co.nz/

(r) Advanced metering infrastructure policy and guidelines

(s) EIEPs

(t) NZX markets

(u) How to find out the distributor in your area: http://www.ena.org.nz/

(v) Retail information (general)

(w) Wholesale information (general)

(x) Stress tests.

16.2 The Authority publishes a weekly newsletter called *Market Brief*. This newsletter is designed to provide individuals, businesses, and groups with regular updates and information on a variety of topics in relation to the Authority and its work plan.

16.3 If you require further information, please contact the market services team:

C/o Electricity Authority
PO Box 10041
Wellington

Telephone: 04 460 8860
Fax: 04 460 8879
Email: marketoperations@ea.govt.nz

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ATH	approved test house
Authority	Electricity Authority
Board	Electricity Authority Board
CM	clearing manager
Code	Electricity Industry Participation Code 2010
GPS	Government Policy Statement on Electricity Governance (May 2009)
GXP	grid exit point
ICP	installation control point
MEP	metering equipment provider
NSP	network supply point
Registry	electricity registry
Retailer	electricity retailer
RM	reconciliation manager
WITS	wholesale information and trading system