MAJOR ELECTRICITY USERS' GROUP

Guide for customers to be direct market participants

6th June 2014

Some electricity customers might be better off being a direct market participant rather than paying a retail tariff or a having supplier or agency arrangement with either bundled or separate hedges.

There are approximately two thousand customers that use 10,000 MWh per year or more of electricity. They are all possible direct market participants but to date only a handful have elected that option. Reported barriers to becoming a direct market participant include the complexity of Code requirements and uncertainty on implementation costs and ongoing management. This guide de-mystifies the complexity of becoming a direct market participant.

The Code requirements are involved but not difficult with the right advice. There are service providers available to manage routine daily, monthly and other reporting requirements. The three main implementation steps customers need to consider are[1]:

(1) Have you processes to manage spot price exposure?

(2) Have you processes to meet initial and any ongoing calls for prudential requirements?

(3) Have you a direct supply agreement with your local Lines Company?

If a customer can manage the above key functions as effectively as a retailer, then it will be cheaper for the customer to become a direct market participant. Retailers undertaking these functions add a margin. This is likely to be either an administration charge if you are currently on full spot price, plus a spot price risk premium if you are on a fixed price variable volume arrangement. The amount will vary by customer circumstance, but is likely to be significant.

For a 10,000 MWh per year customer some $10,000's per annum of the total energy price[2] is likely to be involved for administration charges.

This guide was prepared with the assistance of Chrissy Burrows of Momentous Consulting Ltd and MEUG and other end customers who have become direct market participants.

MEUG welcomes feedback on this guideline. For detailed advice on becoming a direct market participant we recommend customers seek expert assistance.

Ralph Matthes,
Executive Director

[1] For the few customers at non-conforming nodes there is also an important issue of bids.
[2] In this guide all prices exclude line charges that are invoiced separately. The basis of charging by your local Lines Company and pass-through or bundling of Transpower charges is another matter for consideration.

Level 1, 93 The Terrace, Wellington 6011, New Zealand
PO Box 8085, The Terrace, Wellington 6143, T +64-4 472 0128, info@meug.co.nz , www.meug.co.nz

The big picture

Key decision and implementation steps to become a direct market participant follow:

(1) Do you have a process for managing certified metering?

If you are a grid direct connected customer, then the grid owner provides and manages the metering, and you do not need to be concerned with this requirement.

If you are a local or embedded network connected customer, you will need a process to provide and maintain certified metering installations and could either:

a) contract with a metering equipment provider (MEP), or

b) become a metering equipment provider yourself.

This should not be an issue for most commercial and industrial time-of-use (TOU) customers[3].

(2) Do you have a process for managing spot price risk?

It's not mandatory, but highly advisable, that a customer has strategies to manage financial exposure to spot price volatility and advisedly some physical ability to curtail demand in extreme high spot price trading periods. This is further discussed in the FAQ section.

(3) Do you have processes in place to manage the prudential requirements associated with purchasing directly from the Clearing Manager?

This is mandatory. A customer cannot be approved as a direct market participant unless the Electricity Authority (EA) and their service providers are satisfied you can meet prudential obligations and processes. Customers with a corporate treasury function conversant with say FX futures calls will understand the processes needed and will more easily be able to incorporate this function. Spot electricity markets worldwide are highly volatile and New Zealand is no different and hence prudential requirements can change quickly.

(4) Do you have an arrangement in place with your network company?

It is a requirement under the Code to have such an arrangement. Occasionally customers have found reaching agreement has been so difficult that they have abandoned attempts to become direct market participant. In most cases this has not been an issue; though it can be a prolonged process. Note that:

a) the network company should bill you directly for conveyance charges and you should check that they are not passing on a prudential requirement without agreeing this with you[4], and;

b) the EA has a model agreement on its web site that can be used for information purposes.

(5) Once you know that the above most difficult steps can be completed, then there are a host of mandatory approvals needed prior to commencing to trade as a direct market participant and routine operational requirements once trading. These are summarised in the appendices. These requirements are involved and require time to implement but will not be as costly to implement as the key issues above.

(6) If all of the above steps have been completed or you consider they can be cost effectively completed and expected benefits will exceed costs, then you are able to proceed to implement.

[3] There is a secondary question about the most cost effective ownership of meters. That issue is not considered in this guideline because that decision tends to be on a case by case basis.
[4] cl. 12A.4(2) a use-of-system agreement must provide that the trader can elect to comply with prudential requirements.

FAQ

What are the benefits and costs of becoming a direct market participant?

The main benefit is a saving of retailer margins because the retailer no longer provides a service for managing direct engagement in the wholesale market. If you currently are charged half-hour spot prices, the saving will be in administration charges. On 10,000 MWh per annum some $10,000's per annum is likely involved. If you have a bundled tariff with fixed pricing you will also be paying for the spot price risk of the retailer.

There is an indirect benefit of having greater exposure to spot prices because it focuses management to find savings in use of electricity when spot prices are high.

The main set-up costs to become a direct market participant are making sure appropriate risk management, prudential requirement and distribution conveyance agreements are in place. There are numerous other approvals and process requirements needed prior to and once operating as a direct market participant. Those are involved and can take time to implement but will tend to be low order costs. Details are in the appendices.

Estimating the expected net benefit needs to be made on a case by case basis. As a guide MEUG expects customers using more than 5,000 to 10,000 MWh per year, therefore paying more than approximately half to one million dollars per annum for energy (line charges are separate), are likely to find the medium to longer term benefits of becoming a direct market participant far exceed the costs.

What is a robust risk management strategy when directly exposed to spot prices?

Most large TOU customers will have some experience in managing indirect exposure to spot prices. Smaller TOU customers may not. This is not an impediment to proceeding further, though there are commercial risks with being directly on spot. To give a flavour of the complexity and changes occurring, comments follow on the two levers to manage spot risk exposure.

- The first lever is a physical ability to decrease load when forecast spot prices are high.

  This is not straight forward because forecast prices do not always align with final settlement prices. The EA has work to improve the alignment[5] but there will for the foreseeable future always be some difference between forecast and settlement prices. This makes operating directly in the spot market challenging.

- The second lever is to have hedging strategies to manage financial risk.

  Generators, financial institutions and other customers re-adjusting their hedge cover are all sources of hedges. There are also brokers and advisors specialising in advising clients on hedge portfolios. There are many types of hedge to consider.

  The hedge market is becoming more complex and at the same time risk is being priced more efficiently as liquidity grows in the underlying ASX futures market[6] and FTR market[7]. Both of these markets are expected to grow with new products to be launched by ASX and further FTR nodes added. This will allow better customisation by hedge providers to meet the specific needs of a customer. Nevertheless the electricity hedge market will never be as liquid as other financial derivatives and residual risks will remain such as location risk if the customer is not at a node where ASX futures or FTR are traded.

[5] http://www.ea.govt.nz/development/work-programme/wholesale/alignment-forecast-settlement-prices/
[6] Refer http://www.asx.com.au/products/energy-derivatives/new-zealand-electricity.htm
[7] FTR refers to Financial Transmission Rights. EMS is the FTR Manager, refer https://ftr.co.nz/

How many customers are currently direct market participants?

As at May 2014 there were five end customers registered as direct market participants[8]:

- Cold Storage Nelson Limited;
- New Zealand Aluminium Smelters Limited;
- New Zealand Steel Limited;
- Norske Skog Tasman Limited;
- Winstone Pulp International Limited.

Once a customer decides to become a direct participant, how long to implement?

At least 3 months and probably a month or two longer assuming the customer can meet all requirements and crucially, an agreement with their local Lines Company can be agreed.

Where can I find a list of advisors to consider this option in more detail?

MEUG does not have a list of advisors. Existing direct market participants may be able to assist given their experience.

What policy or possible changes to the Code might affect requirements in the future?

The EA is considering changes to prudential and settlement requirements[9], some of which will reduce volatility in prudential requirements.

The EA are considering better alignment of forecast spot and settlement prices. This will assist direct market participants operate directly in the spot market.

Difficulties by customers obtaining conveyance agreements with Lines Companies are an issue that the EA is considering in the work on more standardisation of use-of-system agreements[10].

Ownership of end customer data and use of that data in terms of the agreement customers must enter into with NZX for access to WITS has been noted by some customers as perhaps requiring a review to ensure no other party has access to that information.

The EA has revised the Electricity Information Exchange Protocols (EIEPs)[11] and these come into effect on 1st November 2014. Apart from those EIEPs regulated, the format and any changes of information in the future between traders and Lines Companies for other EIEPs will, we believe, have a minimal impact on direct market participants.

MEUG believes the spot price risk disclosure statement requirements have little value to the efficient functioning of the market and impose a regulatory burden on end customers wishing to become direct participants. We are hopeful a future review of these requirements will either eliminate or reduce this regulatory requirement.

Can you unwind the process and no longer be a direct participant?

Yes, easily.

[8] Refer EA Participant Register http://www.ea.govt.nz/operations/industry-participants/participant-register/
[9] Refer http://www.ea.govt.nz/our-work/consultations/wholesale/settlement-prudential-security-review-code-amendment/
[10] Refer http://www.ea.govt.nz/development/work-programme/retail/more-standardisation-of-use-of-system-agreements/
[11] Refer http://www.ea.govt.nz/operations/retail/eiep/regulated-electricity-information-exchange-protocols/

Appendices

1	Summary of task list	p6
2	Communication channels	p8
3	Detailed task list	p9
4	Other considerations	p15
5	Helpful information	p16
6	Glossary of abbreviations and terms in this guideline	p18

Appendix 1 Summary of task list

This is for illustrative purposes only. Expert advice should be sought for a case by case consideration[12].

Entity to engage with	Before start trading as a direct participant		Operational requirements once a direct participant		
	Initial requirement	Time ahead of starting	Daily	Monthly	Longer
Mandatory					
Electricity Authority:	Register as a participant[13]	5 days, but give as much notice as practical		Pay EA levies[14] monthly and wash-up annually	
	Obtain a participant identifier[15]	5 days, but give as much notice as practical			
	Obtain certification as a reconciliation participant[16] where connected to a local or embedded network	Certification 3 months after becoming a reconciliation participant, with an initial audit 2 months before certification.			Annual re-certification as a reconciliation participant[17]
	Apply for access to the Registry where connected to a local or embedded network. Where directly connected to the grid, registry access is not required	5 days, Should be done at the same time as application for the participant identifier.		Registry information to be correct for Reconciliation Manager	
• Reconciliation Manager (NZX)	Notice of intention to trade[18] where connected to a local or embedded network	5 days		Provide required monthly information. All information and associated reports by 1600 hrs on day 4 and day 13 for finalising invoices[19]	
• Reconciliation Manager and Clearing Manager (NZX)	Notice of intention to trade where connected directly to the grid. Note that the current reconciliation participant at the grid connection point must also notify the termination date of their trade	5 days, but give as much notice as practical		Grid owner provides information to the reconciliation manager	
• Clearing Manager (NZX)	Prudential requirements in place[20]	In place 1 day prior to trading; though will need at least 1 month to finalise[21]	Calls (or credits) as needed to adjust prudential cover[22]	Pay spot invoice by 1400 hrs on 20th of the month[23] (in cleared funds if you do not have an acceptable credit rating)[24]	As needed must provide information to manage any prudential risk[25]

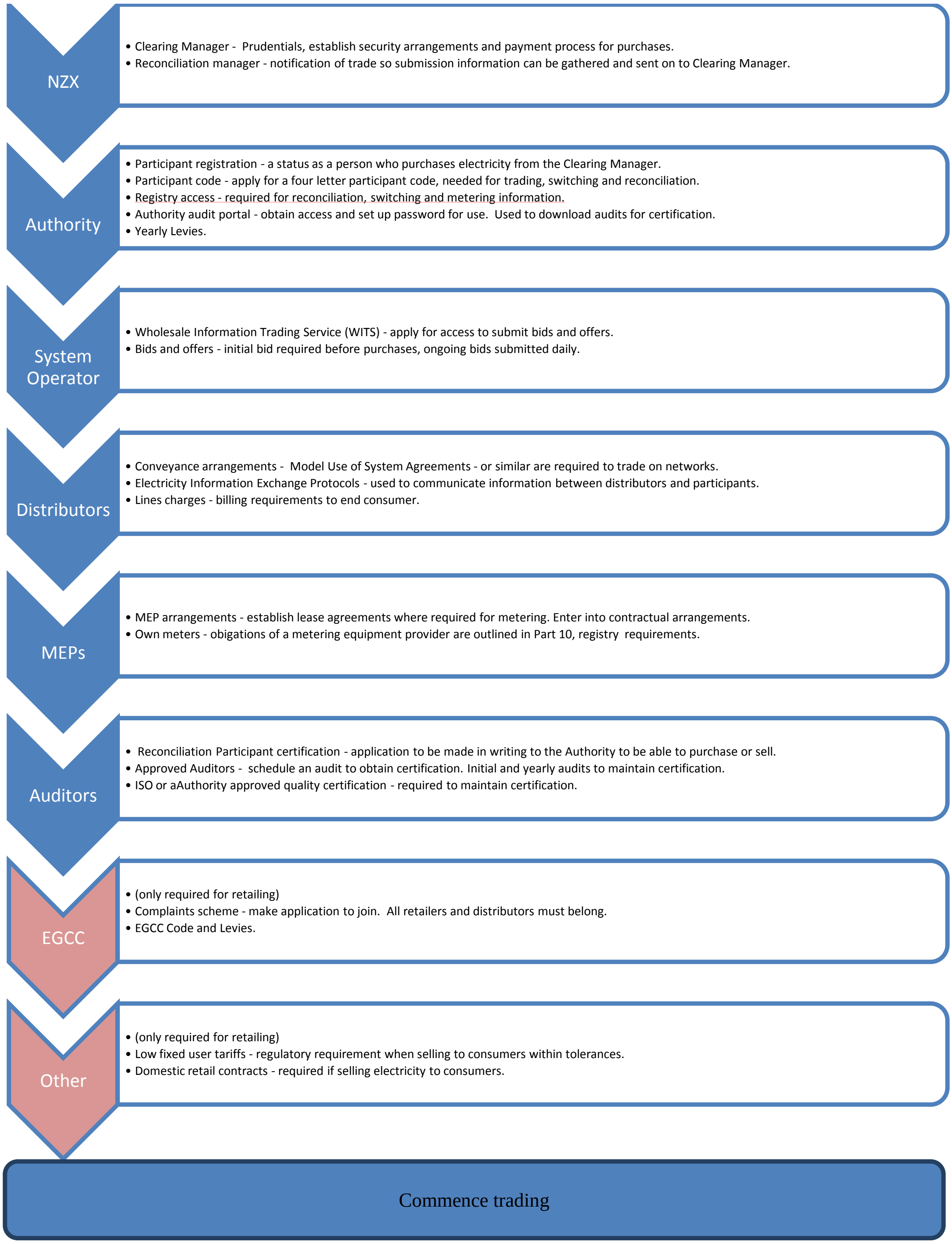
[12] The "Act" refers to the Electricity Industry Act 2010, Refer http://www.legislation.govt.nz/act/public/2010/0116/latest/DLM2634233.html?search=ts_act_electricity_resel&p=1&sr=1. The "Code" refers to The Electricity Industry Participation Code 2010, Refer http://www.ea.govt.nz/code-and-compliance/the-code/
[13] S.7 of the Act defines industry participants and includes s7 (h) "a person who buys electricity from the Clearing Manager."
[14] EA sets levies annually and invoices participants monthly
[15] Code Part 15 Reconciliation, cl.15.39 Participants must use participant identifiers, ie a 4 letter code for that customer
[16] Ibid, Schedule 15.1 Audit and certification processes cl.2 and cl.4. This includes a requirement to meet ISO 9001:2000 or equivalent, cl.5.
[17] Ibid, Schedule 15.1 Audit and certification processes, cl.7
[18] Ibid, cl.15.3 Provision of trading information at point of connection to network
[19] Ibid, Schedule 15.4 – Calculation and provision of submission information to the Reconciliation Manager
[20] Code Part 14 Clearing and settlement, cl.14.3 Payers must satisfy prudential requirements. The Clearing Manager will require either a credit rating or acceptable form of security prior to trading

Entity to engage with	**Before start trading as a direct participant**		**Operational requirements once a direct participant**		
	Initial requirement	Time ahead of starting	Daily	Monthly	Longer
Mandatory continued					
• Information System Manager (NZX)	Access to WITS[26]	5 days, but give as much notice as practical. Note that you will need to agree a use of system agreement			
• System Operator	Initial bid[27]	5 days	Optional to submit daily bids for next day[28]		
• Stress Test Registrar (NZX)					Quarterly spot price risk disclosure statements[29] and annual certification[30]
Metering equipment provider	Appropriate contract with meter provider[31]	5 days, but give as much notice as practical		If contracting an MEP, pay monthly lease invoices	
Local or embedded network	Appropriate conveyance arrangement[32]	The requirement will vary depending on lines company and time to reach agreement.		Provide required information to the lines company and electricity conveyed pay invoices	
Discretionary					
Agent	Contract suitably qualified agents where you do not wish to build the in house capability to fulfil any Code obligations	Determine as soon as practicable	If using an agent to fulfil obligations, pay invoices		
Within own business	Internal processes to reduce demand if high spot prices		Internal processes to reduce demand if high spot prices		
Hedge providers	Appropriate hedges		Appropriate hedges		

[21] Ibid, cl.14.23 Information required from new purchasers
[22] Ibid, cl.14.18 Clearing Manager to assess and call for minimum level of security, ie Clearing manager can make a change to prudential levels and by 1600 hours of 3rd business day the direct market participant must meet the prudential call
[23] Ibid, cl.14.37 Payment of invoices
[24] Ibid, cl.14.6 Acceptable credit rating and security
[25] Ibid, cl. 14.24 Payers must provide information to clearing manager
[26] WITS are the electricity market wholesale information and trading system. Participants must enter into a service agreement with NZX and complete a form for active users' access, refer http://www.ea.govt.nz/operations/wholesale/spot-pricing/wits/
[27] Code Part 13 Trading arrangements, cl.13.7 Purchasers to submit bids, cl.13.7 (2) require 5 days notice before bid for first time
[28] Ibid, cl.13.7 Purchasers to submit bids. This is optional. These provisions relate to conforming GXPs. Most customers are at conforming GXPs
[29] Ibid, Subpart 5A – Spot price risk disclosure, cl. 13.236A for quarterly requirements
[30] Ibid, Subpart 5A – Spot price risk disclosure, cl. 13.236F for annual certification of spot price risk disclosure statements
[31] Code Part 10 Metering. Either the customer can have an appropriate contract with the Metering Equipment Provider or if the customer owns the meters then the customer can apply to be the MEP
[32] Code Part 11 Registry information management, cl.11.16 Parties to ensure arrangements for line function services

Appendix 2 Communication channels

To be able to trade as a participant or trader[33] there is a requirement to notify or make application to several electricity market service providers or participants. The chart below gives a brief account of the communication channels required before trading can commence.



[33] The definitions of participant and trader have slightly different meanings see appendix 5 on helpful information.

Appendix 3 Detailed task list

More detailed list and information on requirements for an end customer to become a direct market participant

There is a subtle difference between being a retailer or a reconciliation participant trading your own Installation Control Point (ICPs). If you intend on billing or trading customers for their own use, as opposed to trading only your own ICPs, you then become a retailer and there are a few additional requirements. These extra requirements, included below, are shaded in orange.

Note: the information below is not intended to be an exhaustive list, not necessarily in the order of process and may change depending on the status of your existing registration or requirements. Some of the tasks below you may already have in place. This is a guide only and you should contact either the Authority or appropriate consultants to advise on your actual requirements.

Ref	Task /Rule	Obligations	Timeframe
1	Registering as a participant Section 7 of the Act	Parties must register if they wish to directly purchase electricity directly through the reconciliation process.	Needs to be done 5 business days before trading commences.
2	Participant identifier Part 15, clause 15.39	Apply for four letter participant identifier in the prescribed form at least 5 business days before the participant identifier is required. The participant identifier is used in all market transactions. If you are directly connected to the grid, your company will already have an asset owner participant identifier. It is preferable (but not necessary) to use a different identifier for clearing manager purchases	The earlier the better, as all service provider system set-ups require the participant identifier. This is also required by the Clearing Manager.
3	Prudential - Clearing Manager (CM) Part 14, clause 14.3	Provide a credit rating that satisfies prudential requirements or acceptable form of security before purchases can be made. The CM requires this before a payer may purchase. So for the first day in the market, Prudential's need to be arranged at a minimum at least the day before. However, discussions will need to be made with the CM well before then, at least a month prior as they need to arrange other transactions in relation to trading e.g. letter of credit, bank communications.	Prudential to be arranged before trading can commence.

Ref	Task /Rule	Obligations	Timeframe
4	WITS (Wholesale Information Trading Service)	Access needs to be applied for and there are two parts: - Enter into a service agreement with NZX - Complete form for active users' access. The application form is available on the EA's web site – http://www.ea.govt.nz/operations/wholesale/spot-pricing/wits/ A user manual is also available from the WITS administrator. cadmin@nzx.com	
5	Initial bids Part 13, clause 13.7 (2)	Purchasers and generators must submit an initial bid.	A purchaser must give at least five days' notice to the system operator before the purchaser makes a bid for the first time.
6	System Operator Conforming GXPs Part 13, clause 13.7 – 13.27	Purchasers and generators must submit and revise bids and offers for electricity each trading day on 1300 hours the day before the trading day for which the bid applies. The bid must be a valid bid for every trading period at every GXP at where there is a requirement to purchase electricity.	Daily
7	System Operator Nonconforming GXPs Part 13, clause 13.7 – 13.27	This only applies to grid connected consumers non conforming GXP Does not apply to consumers connected to local line networks.	
8	Clearing Manager invoices Part 14, clause 14.36 and 14.37	The clearing manager will issue invoices two business days after receiving reconciliation information from the RM. In most cases this will be on business day 9, but in exceptional events may be delayed.	Invoices must be paid in cleared funds into the operating account by 1400 hours on the 20th calendar day of the month following the billing period (or next business day if the 20th falls on a non-business day), or 2 business days after receiving the invoice where the issuing of Clearing Manager invoices is delayed.

Ref	Task /Rule	Obligations	Timeframe
9	Registry Part 11	Application to use registry is only required where connected to a local or embedded network. There is a registry access form which can be downloaded and forwarded as instructed in that form: http://www.ea.govt.nz/operations/retail/the-registry/registry-access/ Use of registry for switching and maintenance can be done through file download or using new web browser access.	Complete at the same time as applying for the participant identifier.
10	Application for certification Clause 2 & 4, schedule 15.1	Where you are connected to a local or embedded network, you will become a reconciliation participant. Reconciliation participants are required to obtain certification from the EA for activities involving reconciliation, registry, and switching.	Application in writing required 2 months prior to intended date of certification.
11	Audit to establish certification Clause 11, schedule 15.1	Reconciliation participants must be certified in accordance with schedule 15.1 no later than 3 calendar months after the date on which that reconciliation participant becomes a reconciliation participant by an EA approved auditor. A schedule of approved auditors is on the EA web site. This will be a desk top audit of processes required under Parts 10, 11, & 15 for switching, registry maintenance and reconciliation.	
12	Authority Portal	Arrange for a login to the Authority Audit Portal (http://audit.ea.govt.nz/) by emailing marketoperations@ea.govt.nz (refer http://www.ea.govt.nz/operations/retail/audits-approvals-and-certification/retail-audit-database-access/) This is to log the audit with the Authority to obtain certification. Free service and once done only requires the input of yearly audit. You can give your auditor permission to do this for you.	

Ref	Task /Rule	Obligations	Timeframe
13	Conveyance Arrangements Part 11, clause 11.16	Where connected to a local or embedded network, arrangements need to be in place with the relevant distributor for conveyance of electricity.	Allow a lot of time for this
14	Electricity Information Exchange Protocols (EIEPs)	EIEP as required by distributor. Revised EIPs come into effect on 1st November 2014, refer http://www.ea.govt.nz/operations/retail/eiep/regulated-electricity-information-exchange-protocols/. Establish what is needed when discussing letter of intent or entering into arrangements with lines company so you can get your systems set up.	Distributors require information on working day 5 by 1600 hours.
15	Reconciliation manager (RM) Part 15 clause 15.3	Notification of intention to trade is required at least five days before commencing trading for the first time.	
16	Quality certification Clause 5, schedule 15.1	ISO 9001:2000 or equivalent. Can't really be done until processes are in place and documented.	
17	Process to enable switching and registry maintenance	Will be required for audit and compliance with ISO standards.	.
18	Metering Part 10	Where you are connected to a local or embedded network, a contractual arrangement is required between the Metering Equipment provider (MEP) and the participant. Your choices are: a) Lease provision of metering from an existing MEP, or b) Own all or part of the metering and contract with an existing MEP, or c) become the MEP and meet all of the Code requirements d) Where you are connected directly to the grid, the grid owner is the MEP and you do not need to do anything	
19	Low fixed user tariffs Clause 5, regulations on low fixed user tariffs.	Where you become a retailer to domestic consumers, you must offer consumers at least one low fixed user tariff for consumers where consumption is less that 8000 or 9000 depending on where the consumer resides.	Will be needed for published prices and website information before commencing trading.

Ref	Task /Rule	Obligations	Timeframe
20	Electricity and Gas Complaints Commission (EGCC)	Where you become a retailer and or a distributor, you must belong to the scheme. Information on website at http://www.egcomplaints.co.nz/. The EGCC have their own Code requirements; these include pricing information (30 days notification of changes) and requirements for advising of the complaints scheme.	Include all required info on web site prior to trading and on customer invoices.
21	Reporting Schedule 15.3	Where you are connected to a local or embedded network, you must provide monthly information to the reconciliation manager. Note that the preparation of this information is complex and you should seek specialist advice. Reports required by the Code are : - Initial information for the previous month by 1600 hours on business day 4 o Submission information. o ICP days o Electricity supplied information - Where information has changed, revised information for the previous months 1, 3, 7 and 14 by 1600 hrs business day 13 o Submission information. o ICP days o Electricity supplied information	
22	Domestic retail contracts	Where you are a retailer, you must have Terms and Conditions (Domestic retail contracts) available for customers. These should be published on a website and all new customers directed to them.	Set up on Web site before trading customers commences.
23	Customer compensation scheme	Where you are a retailer to domestic consumers, and in the event of a national conservation campaign, you will need to pay each domestic consumer an amount specified in Part 9 of the Code.	
24	Invoicing, credit control and receipt of payments	Where you are a retailer you will need to invoice, receive payments, and where necessary carry out credit control. Where you retail to domestic consumers you must follow the EA Protocols set out in http://www.ea.govt.nz/dmsdocument/948. Where you carry out disconnections for credit reasons, you must carry out the quarterly reporting to the Authority noted in this protocol.	
25	Application, website and Call Centre	There are specific requirements that have to be informed to participants e.g. EGCC Medically dependent and vulnerable consumers Alignment with model domestic contract	

Ref	Task /Rule	Obligations	Timeframe
26	Levies The Act and Regulations	Retailers are required to pay a levy. This is based on wholesale market purchases and the number of ICPs owned in the registry. Use the following link to see what the yearly levies are http://www.ea.govt.nz/about-us/what-we-do/how-were-funded/levy-rates/	The levy is invoiced monthly by the EA, and paid monthly and washed up annually
27	Ongoing obligations as requested by the Authority. Subpart 5A of Part 13	Stress test requirement. Participants who consume electricity that is conveyed to them directly from the grid or who buy electricity from the Clearing Manager are required to provide disclosure statements.	Each quarter and an annual certification.
28	Clearing manager electricity purchases	Note that where you are purchasing from the clearing manager for a site connected to a local or embedded network that the reconciliation process adds to the site meter volume, both network losses and Unaccounted for electricity (UFE) to your clearing manager purchase volume. You should allow for this % increase in your cost or pricing calculations. The network loss factor is available from the registry for each ICP, and the UFE for a network area is available from the EA on request.	

Appendix 4 Other considerations

Agents – agents can be used to assist with the gathering of data and submission to the Reconciliation Manager (RM).

Hedges – it is highly recommended that direct market participants consider entering into hedges to supplement purchasing at spot.

Nonconforming GXP – there are special requirements related to a nonconforming GXP. This only applies to grid connected customers.

MEPs – if you own your meters you have responsibilities under part 10 of which you will require additional auditing.

Timeframes – when deciding on becoming a participant allow extra time for letter of credits, bank negotiations and legal requirements to be finalized. It is expected that these will all be done prior to the Code required timeframes.

IT – consider what is required for internal software to produce reporting.

Resources – you may need staff trained to handle reporting and assist at auditing time.

Quality assurance – there is a requirement for processes to be documented.

Appendix 5 Helpful Information

Legislation:

The Electricity Industry Act 2010 (Act) - http://www.legislation.govt.nz/act/public/2010/0116/latest/DLM2634233.html?search=ts_act_electricity_resel&p=1&sr=1

The Electricity Participant Code 2010 – referred to as the Code - http://www.ea.govt.nz/code-and-compliance/the-code/

The Electricity Industry (Enforcement) Regulations 2010 – http://www.legislation.govt.nz/regulation/public/2010/0362/latest/DLM3285301.html

Electricity (Levy of Industry Participants) Regulations 2010 - http://www.legislation.govt.nz/regulation/public/2010/0457/latest/DLM3420901.html

For retailers the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 also apply - http://www.legislation.govt.nz/regulation/public/2004/0272/latest/DLM283614.html

Guidelines:

Model arrangements for distributors were published in September 2012

Electricity information exchange protocols that have been regulated and come into effect 1st November 2014 - http://www.ea.govt.nz/operations/retail/eiep/regulated-electricity-information-exchange-protocols/

For retailers three further guidelines apply[34]:

- Medically dependent consumer guidelines - http://www.ea.govt.nz/dmsdocument/8564
- Vulnerable consumers guidelines - http://www.ea.govt.nz/dmsdocument/8565
- Principles and minimum terms and conditions for domestic contracts for delivered electricity (Interposed), May 2010 found in appendix B, 2011 Alignment review, http://www.ea.govt.nz/development/work-programme/retail/domestic-contracting-arrangements/development/interim-alignment-review-july-2011/

[34] The medically dependent and vulnerable consumer guidelines are found at http://www.ea.govt.nz/operations/retail/retailers/retailer-obligations/medically-dependant-and-vulnerable-customers/

Other:

List of acronyms - http://www.ea.govt.nz/glossary/

Definitions part 1 of the Code - http://www.ea.govt.nz/dmsdocument/17984

The definitions of participant, retailer and trader have slightly different meanings (note bold references noting defined terms are not included in this extraction see Code for full definitions):

Participant (or **industry participant**) is defined under section 5 of the Act "means a person, or a person belonging to a class of persons, identified in section 7as being a participant in the electricity industry." These are:

a) a generator;

b) Transpower;

c) a distributor;

d) a retailer;

e) any person who owns lines;

f) a person who consumes electricity that is conveyed to the person directly from the national grid;

g) a person, other than a generator, who generates electricity that is fed into a network;

h) a person who buys electricity from the clearing manager;

i) any industry service provider identified in subsection (2).

Reconciliation participant means a participant (excluding the Authority (even if the Authority acts as a market operation service provider and the Rulings Panel) who is any of the following:

a) a retailer when purchasing electricity from, or selling electricity to, the clearing manager:

b) a generator:

c) a network owner:

d) a distributor:

e) a person who purchases electricity from or sells electricity to the clearing manager

Retailer is defined under the Act as a business engaged in retailing (retailing means the sale of electricity to a consumer other than for the purpose of resale)

Trader is defined under part 1 of the Code and means a retailer, generator or purchaser who -

a) buys electricity from the clearing manager; or

b) sells electricity to the clearing manager; or

c) enters into an arrangement with another retailer or generator or purchaser to buy or sell contracts (or parts of contracts) for electricity for the purposes of this Code

Appendix 6 Glossary of abbreviations and terms in this guideline

Act	Electricity Industry Act 2010
Authority	Electricity Authority, also abbreviated EA
Board	Electricity Authority Board
CM	Clearing Manager
Code	Electricity Industry Participation Code 2010
EA	Electricity Authority
EGCC	Electricity and Gas Complaints Commission
EIEP	Electricity Information Exchange Protocols
FAQ	Frequently asked questions
FX	Foreign Exchange
GWh	Giga Watt hour
GXP	Grid exit point
ICP	Installation control point
ISO	International Organization for Standardization
IT	Information technology
MEP	Metering equipment provider
MEUG	Major Electricity Users' Group
MWh	Mega Watt hour
NSP	Network supply point
POC	Point of connection
Registry	Electricity registry
RM	Reconciliation Manager
TOU	Time of Use
UFE	Unaccounted for electricity
WITS	Wholesale Information and Trading System