ELECTRICITY AUTHORITY
TE MANA HIKO

23 JUNE 2015

Welcome and introduction

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

DISCLAIMER

This workshop provides general information to help participants understand how the electricity market functions under the Electricity Industry Participation Code 2010 (Code). It reflects the Authority's view.

The information presented at this course is not intended to be definitive and should not be used instead of legal advice.

Requirements of the Code and service provider systems change over time, and participants should ensure that they review the latest copy of the Code and functional specifications.

If there is any inconsistency between information presented and the Code, the Code takes precedence.

ELECTRICITY AUTHORITY
TE MANA HIKO

23 JUNE 2015

CHANGES TO PART 14 AND PRUDENTIAL REQUIREMENTS

RECONCILIATION PARTICIPANTS FORUM

PART 14 OF THE CODE PROVIDES FOR

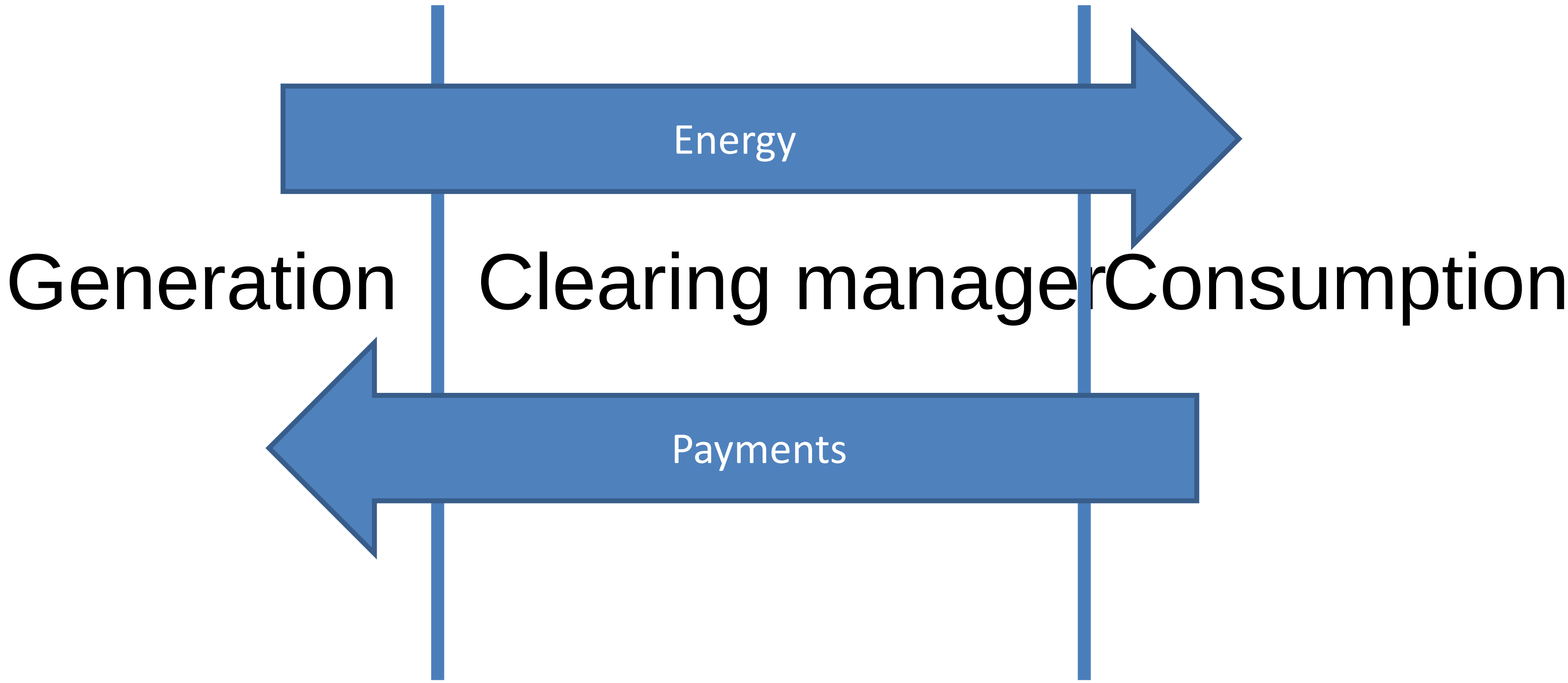
- Sale and purchase of electricity to and from the clearing manager
- How the clearing manager calculates and invoices amounts owing to and by, for
  - Electricity, ancillary services, FTRs, and other payments
  - The settlement of amounts payable
  - Processes and remedies for an event of default
- Requirements for prudential security to be provided by participants, and how they are administered by the clearing manager
- New Part 14 effective 9 March 2015

The spot market and defaults: preventing and managing a default

The clearing manager's role is reducing risk to the market

John Andrews
Senior Energy Analyst
NZX

The clearing manager as the central party



The clearing manager is a service provider:

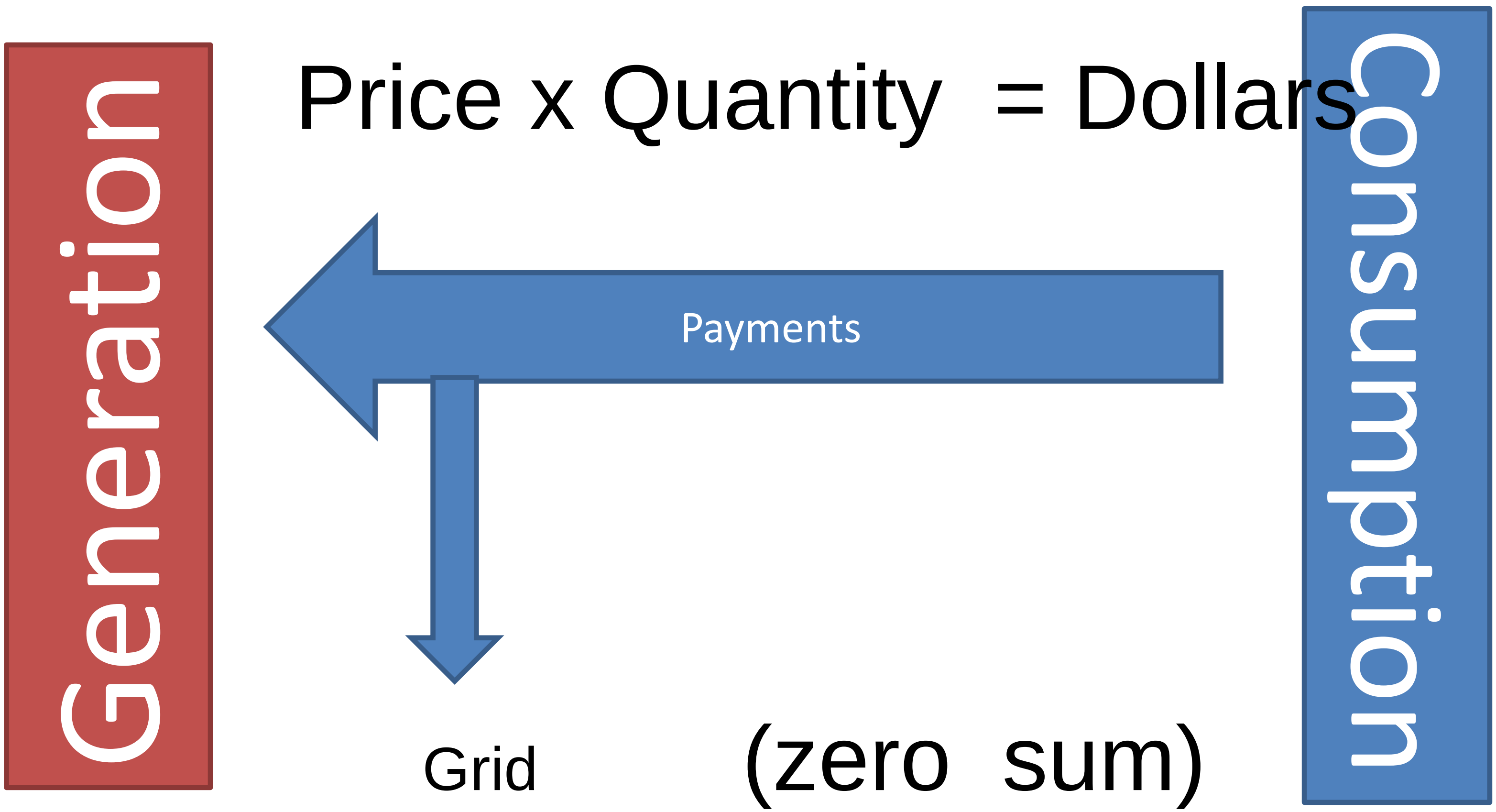
Generation

- System operator
- Pricing manager
- Registry
- Reconciliation manager
- Clearing manager
- WITS
- FTR, ERM

Consumption

Simply using the data provided....

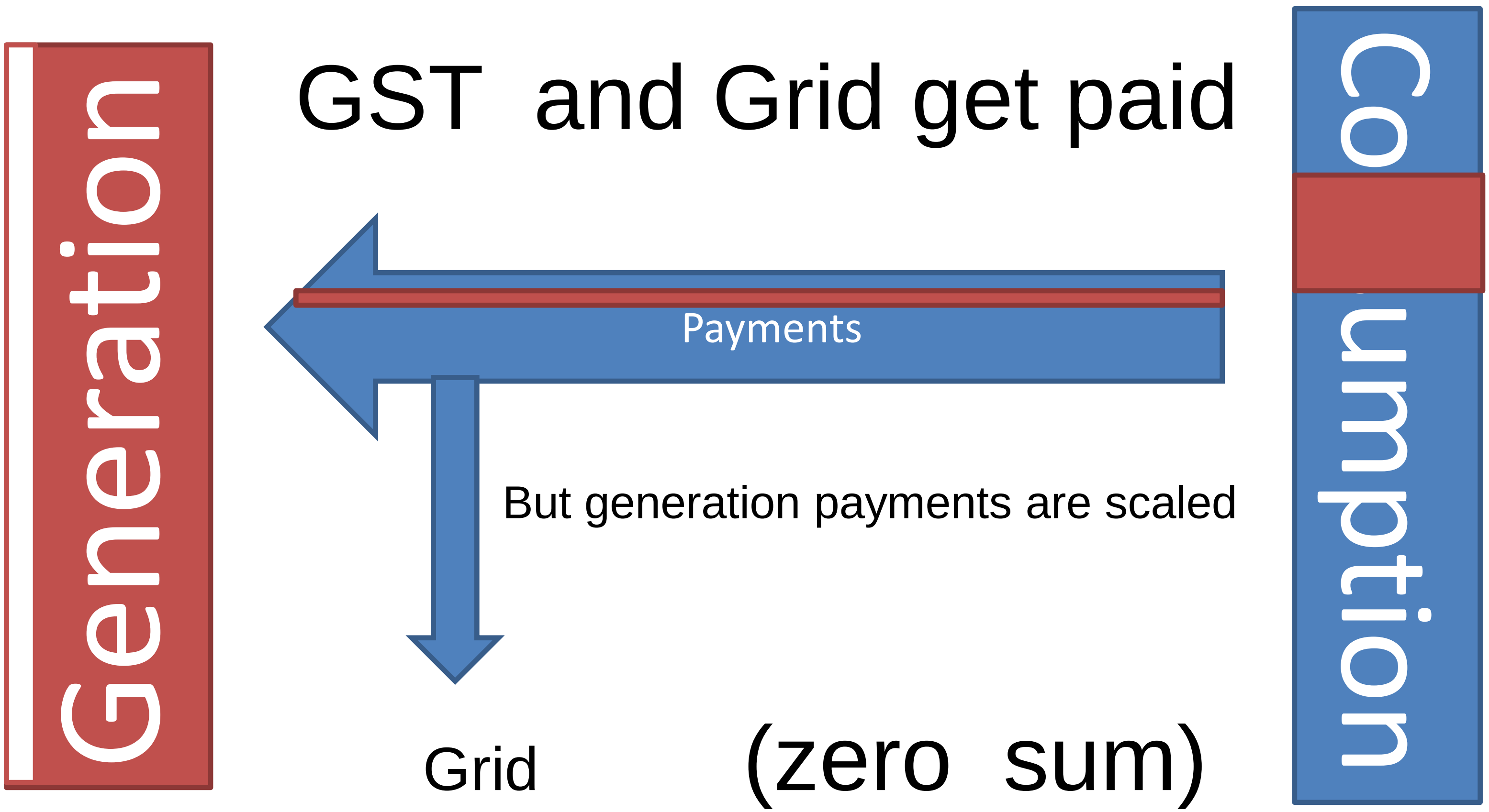
Price x Quantity = Dollars



(zero sum)

(This discussion is only covering the spot market. AS, FTR, and other items are ignored here)

But if someone does not pay....



(This discussion is only covering the spot market. AS, FTR, and other items are ignored here)

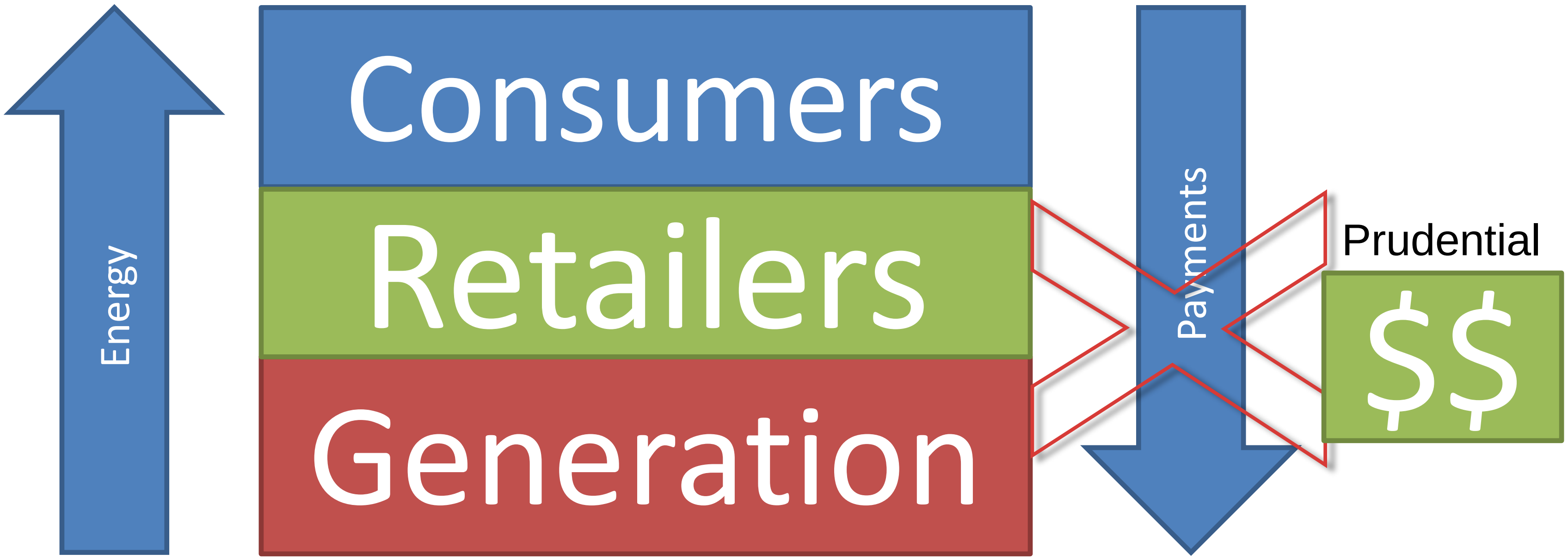
What rights do generators have ?

(This discussion is only covering the spot market. AS, FTR, and other items are ignored here)

What rights do generators have ?

(This discussion is only covering the spot market. AS, FTR, and other items are ignored here)

What rights do generators have ?
They have the clearing manager to protect them!



(This discussion is only covering the spot market. AS, FTR, and other items are ignored here)

Prudential Security- Part 14A

Prudential

$$

Retailers

Generation

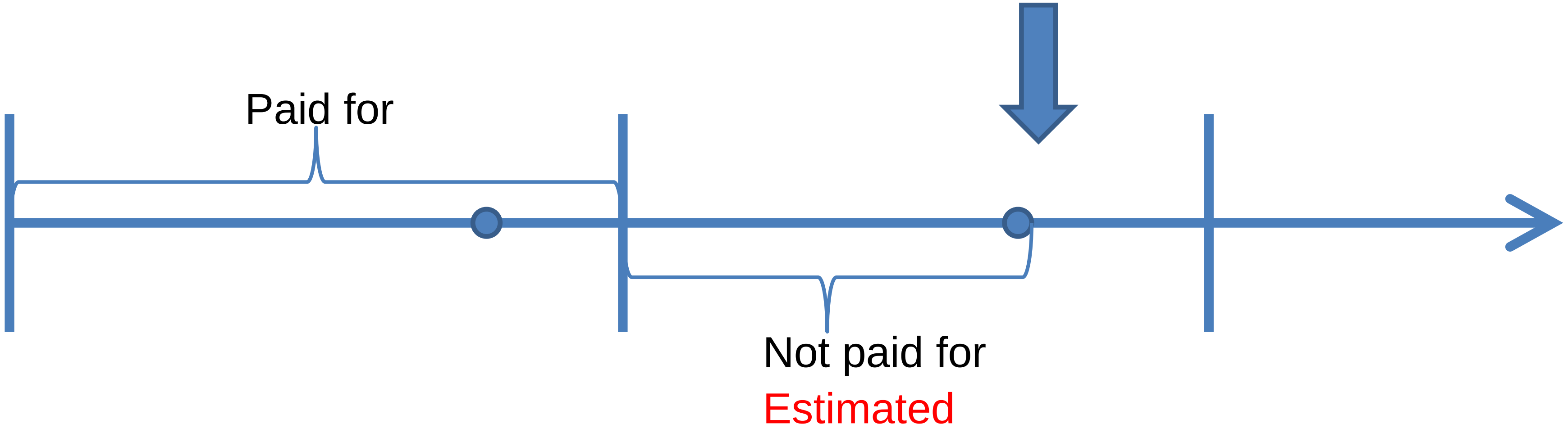
Net risk to the market =
Purchases - sales

For all unpaid amounts

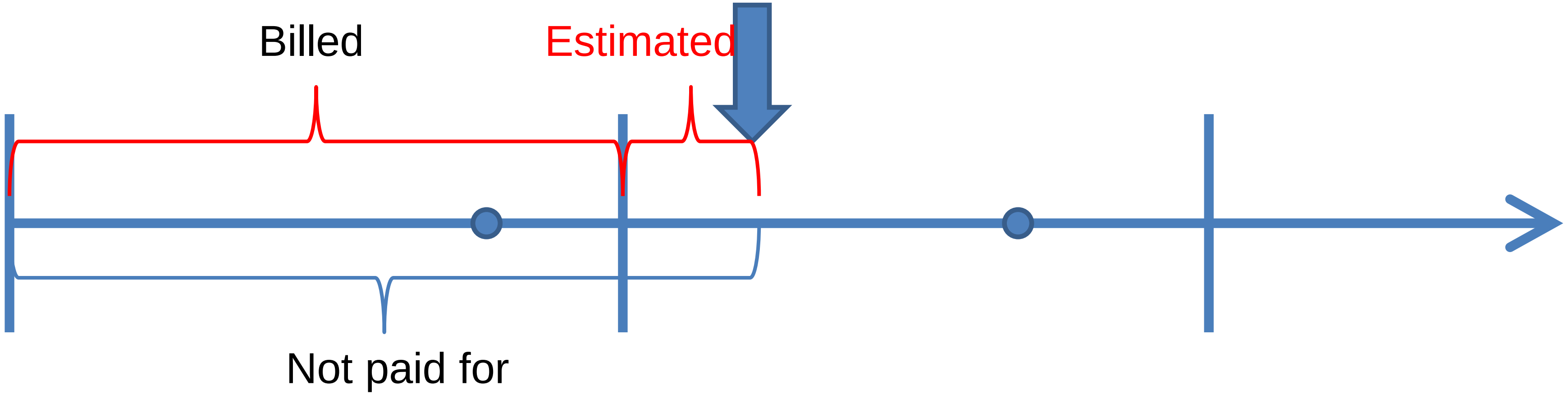
Prudential Security- Part 14A

Net risk to the market =
Purchases - sales

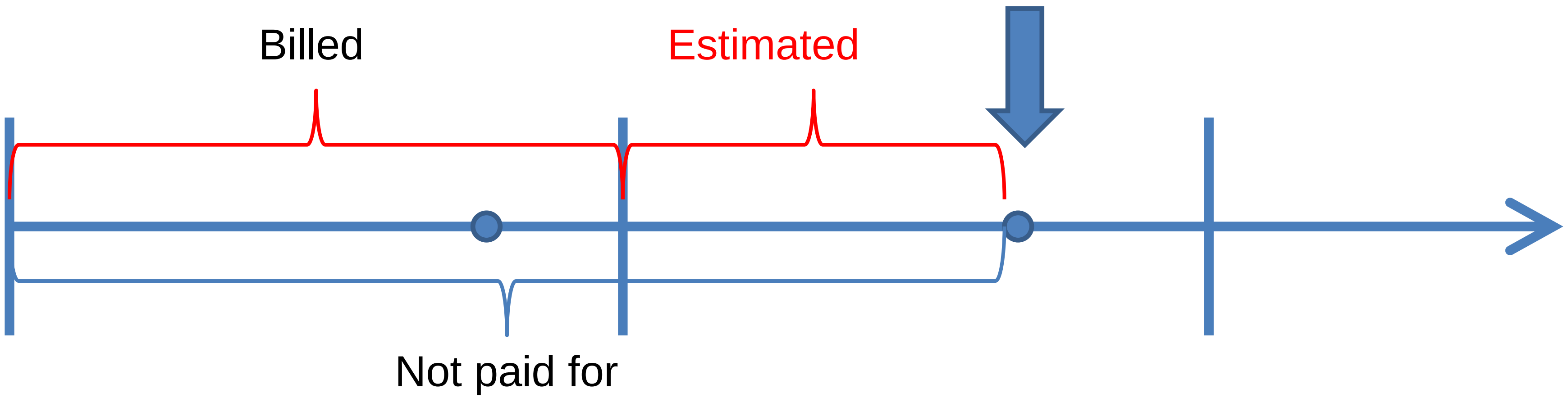
For all unpaid amounts..



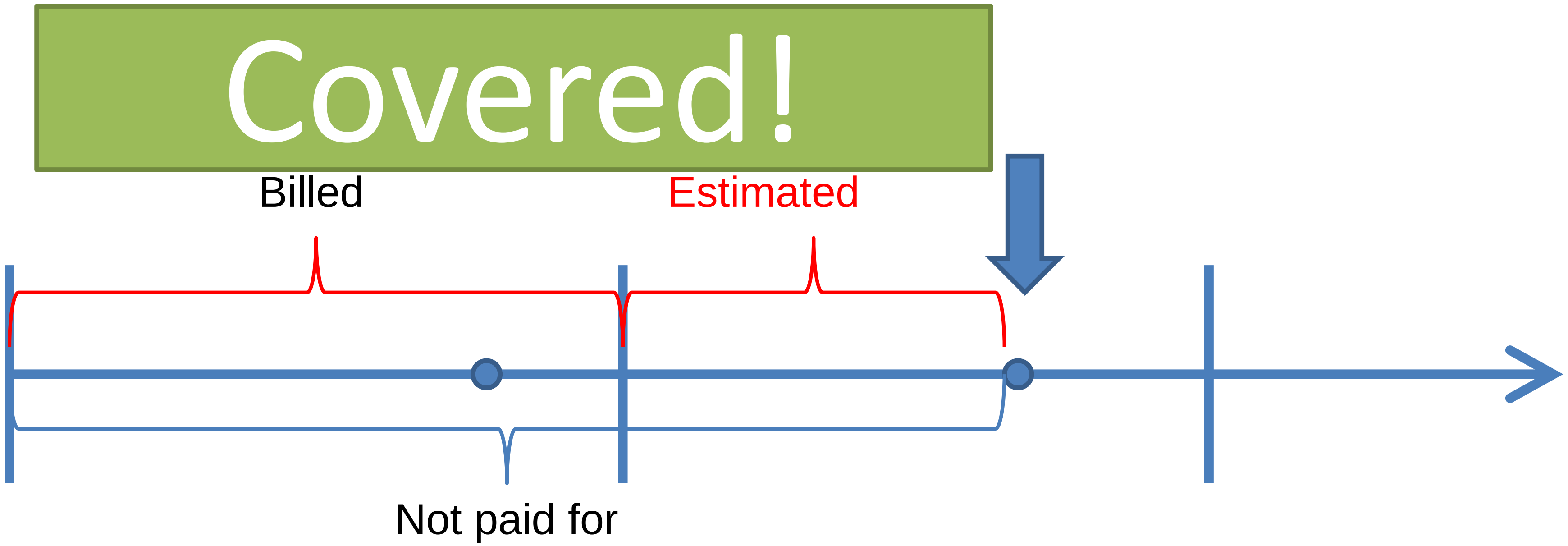
Next month...



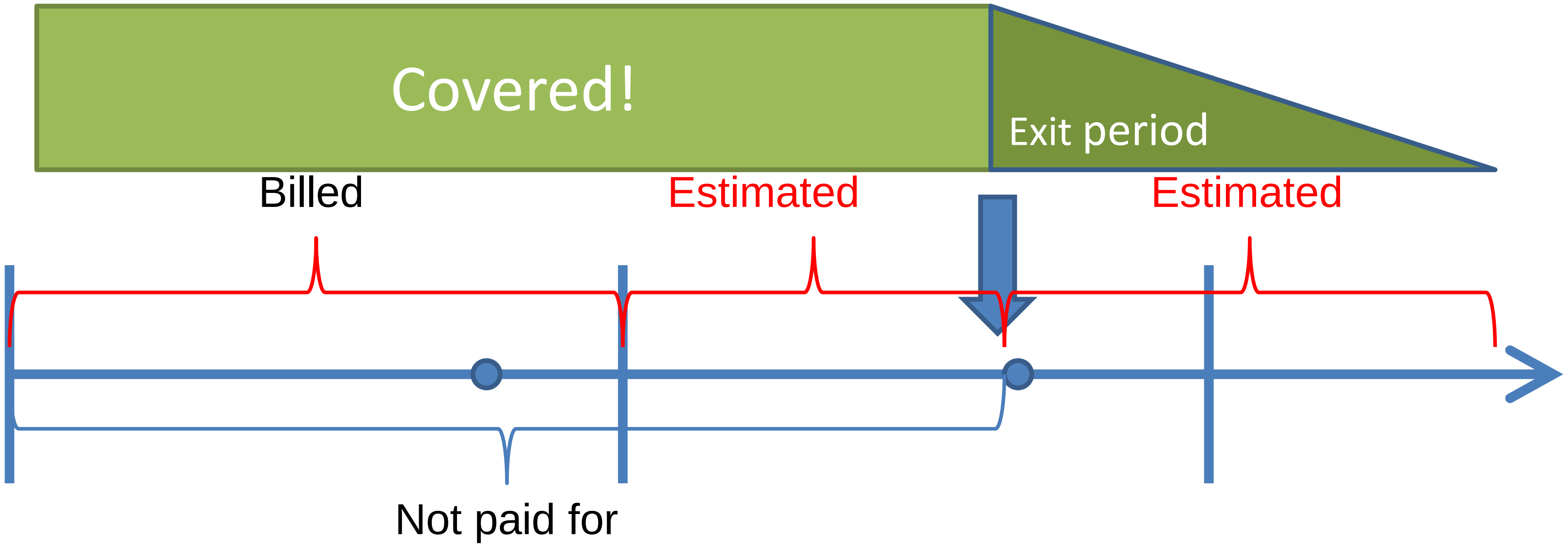
Default on settlement day



Default on settlement day



Exit period prudential:
18 days retailer, 8 days others
@ fixed prices, 21 day avg. volumes



Subpart 7—Events of default

Types of default

14.41 Definition of an event of default

Each of the following events constitutes an event of default:

(a) failure of a participant to provide security for the minimum amount required in accordance with clause 14A.6:

(b) a settlement default:

(c) any action taken for, or with a view to, the declaration of a participant that is required to comply with Part 14A as a corporation at risk under the Corporations (Investigation and Management) Act 1989:

(d) appointment of a statutory manager in respect of participant that is required to comply with Part 14A under the Corporations (Investigation and Management) Act 1989 (or a recommendation or submission is made by a person to the Financial Markets Authority supporting such an appointment):

(e) appointment of a person under section 19 of the Corporations (Investigation and Management) Act 1989 to investigate the affairs or run the business of a participant that is required to comply with Part 14A:

(f) if a participant that is required to comply with Part 14A is (or admits that it is or is deemed under any applicable law to be) unable to pay its debts as they fall due or is otherwise insolvent, or stops or suspends, or threatens to stop or suspend, or a moratorium is declared on, payment of its indebtedness generally, or makes or commences negotiations or takes an other steps with a view to making any assignment or composition with, or for the benefit of

(e) appointment of a person under section 19 of the Corporations (Investigation and Management) Act 1989 to investigate the affairs or run the business of a participant that is required to comply with Part 14A:

(f) if a participant that is required to comply with Part 14A is (or admits that it is or is deemed under any applicable law to be) unable to pay its debts as they fall due or is otherwise insolvent, or stops or suspends, or threatens to stop or suspend, or a moratorium is declared on, payment of its indebtedness generally, or makes or commences negotiations or takes any other steps with a view to making any assignment or composition with, or for the benefit of, its creditors, or any other arrangement for the rescheduling of its indebtedness or otherwise with a view to avoiding, or in expectation of its inability to pay, its debts:

(g) a holder of a security interest or other encumbrancer taking possession of, or a receiver, manager, receiver and manager, liquidator, provisional liquidator, trustee, statutory or official manager or inspector, administrator or similar officer being appointed in respect of the whole or any part of the assets of a participant that is required to comply with Part 14A or if the participant requests that such an appointment be made.

(h) Termination of a retailer's use of system agreement with a distributor because of a serious financial breach if-

(i) the retailer continues to have a customer or customers on the distributors local network ; and

(ii) there is not unrsolved disputes between the retailer and the distributor in relation to the termination; and

(iii) the distributor has not been able to remedy the situation in a reasonable time; and

(iv) the distributor gives notice to the Authority the this clause applies.

What happens at a default?

The clearing manager informs the Authority and the participant

Takes action to obtain cash or other security

Makes payments as possible in event of settlement default

Proceeds with next month’s invoices, statement and settlement

When funds are received, makes payments to the correct billing period

Summary:

The clearing manager bills and collects on behalf of providers

Pays providers as much as possible

Calculates, holds and ensures security of prudential

Applies prudential as required

Works to ensure the market is covered, billed and settled

Thank you

We look forward to working with you

John.andrews@nzx.com

Reconcilation manager
rm@nzx.com
+64 4 498 0044

Pricing manager
managerp@nzx.com
+64 4 498 0028

Clearing manager
cmanager@nzx.com
+64 4 495 2801

www.nzx.com

Level 1, NZX Centre
11 Cable Street
PO Box 2959
Wellington 6140
New Zealand

ELECTRICITY AUTHORITY
TE MANA HIKO

23 JUNE 2015

TRADER DEFAULT ARRANGEMENTS

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

TRADER DEFAULT ARRANGEMENTS

- There is always a risk that a trader may not be able to pay its accounts

- Factors that could cause financial stress to a trader failure are not limited to but include
    - High market price and no hedge (insurance)
    - Hedges not aligned to purchases
    - Failure of hedging counterparty
    - High prudential cost
    - Failure of consumers to pay
    - Errors and omissions

THE COST OF A NON PAYMENT

- Traders responsibilities in the Code are enduring

- If a trader fails to pay its costs to
  - the NZEM, the clearing manager will recover prudentials to pay generators. Scaling of generator payments will occur if prudentials do not cover the debt
  - the distributor, the distributor will recover prudentials to cover debt

- To mitigate the impact of a trader being unable to pay its costs,
  - NZEM requires prudential's under the Code
  - Distributors may require prudential's under its UOSA
  - For clarity, third party providers such as MEPs, ATHs etc do not have default protection under the Code

EVENT OF DEFAULT

- Recovering prudentials is a one off event so a default process is necessary

- In the case of a default, the Authority may, after a Code defined “exit period” decide to take one of three actions. It may
  - Do nothing
  - If the defaulting participant is a trader at an ICP allocate ICPs to non-defaulting traders (exit period = 18 days)
  - If the defaulting participant is a direct purchaser at an ICP or an NSP instruct the network owner to disconnect the direct purchaser (exit period = 7 days max)

ELECTRICITY AUTHORITY
TE MANA HIKO

23 JUNE 2015

EVENTS OF TRADER DEFAULT AT AN ICP

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

MANAGING AN EVENT OF TRADER DEFAULT

In this section we will cover

A. Three phases of an event of default
   1. Day 0 to day 7: focus on defaulting trader
   2. Day 8 to day 14: focus on customers of defaulting trader
   3. Day 15 to day 18: tender, mandatory assignment, switching

B. Day 19 onwards

C. Reconciliation after the event of default

D. Information available to participants

KEY STEPS AND TIMELINE FOR TRADERS

Trader default – key steps and indicative timeline for traders

	Notification & Determination	Day 1	Day 2 to 7	Day 8	Day 9 to 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20 onwards
Event in progress	Receive notification of default	Authority requests customer information from DFTR	Authority receives customer information	Authority determines status of default	Authority performs monitoring	Send first tender to traders	Send second tender to traders	Traders submit exclusion table (TD-020) to the registry	Registry ensures all switches complete	Authority provides customer information to traders	Authority commences review of event of default
Event in progress	Authority determines nature of event	Authority notifies registry of default	Distributor provides customer information (if necessary)	Authority implements marketing campaign	Authority communicates with affected customers	Tendering traders submit bids (TD-040)	Repeat of Day 15 activites	Registry performs allocation of ICPs (TD-070)	Registry performs allocation of ICPs (TD-070)	Authority attempts to advise customers of new trader	
Event in progress	Authority notifies DFTR of its determination	Authority determines communication strategy	Authority determines organisations which require briefing	Authority implements registry controls	Authority determines if tender is required (if not proceed to Day 17)	Traders receive email and Ack file stating success of bid upload	Authority reviews results of second tender	Traders review results (PR-310) and advise of threat to financial viability	Authority reviews allocation	Traders advise customers of new trader and terms	
Event in progress			Authority maintains communication with DFTR	Authority notifies traders of default	Authority prepares for tender	Traders can view report (TD-060)	Authority determines if mandatory assignment is required	Authority may re-assign ICPs	Registry switches the ICPs (TD-080)		
Event in progress				Authority may suspend DFTRs right to trade	Registry prepares for tender process	Authority reviews results of first tender		Registry performs re-assignment of ICPs (TD-090)	Traders receive CS files		
Event resolved				Defaulting trader resolves event prior to day 8				Defaulting trader resolves event prior to end of day 17			

PHASE ONE: DAY 0 TO DAY 7

Notification & Determination	Receive notification of default	Authority determines nature of event	Authority notifies DFTR of its determination	
Day 1	Authority requests customer information from DFTR	Authority notifies registry of default	Authority determines communication strategy	
Day 2 to 7	Authority receives customer information	Distributor provides customer information (if necessary)	Authority determines organisations which require briefing	Authority maintains communication with DFTR

PHASE TWO: DAY 8 TO DAY 14

Day 8	Authority determines status of default	Authority implements marketing campaign	Authority implements registry controls	Authority notifies traders of default	Authority may suspend DFTRs right to trade
Day 9 to 14	Authority performs monitoring	Authority communicates with affected customers	Authority determines if tender is required (if not proceed to Day 17)	Authority prepares for tender	Registry prepares for tender process

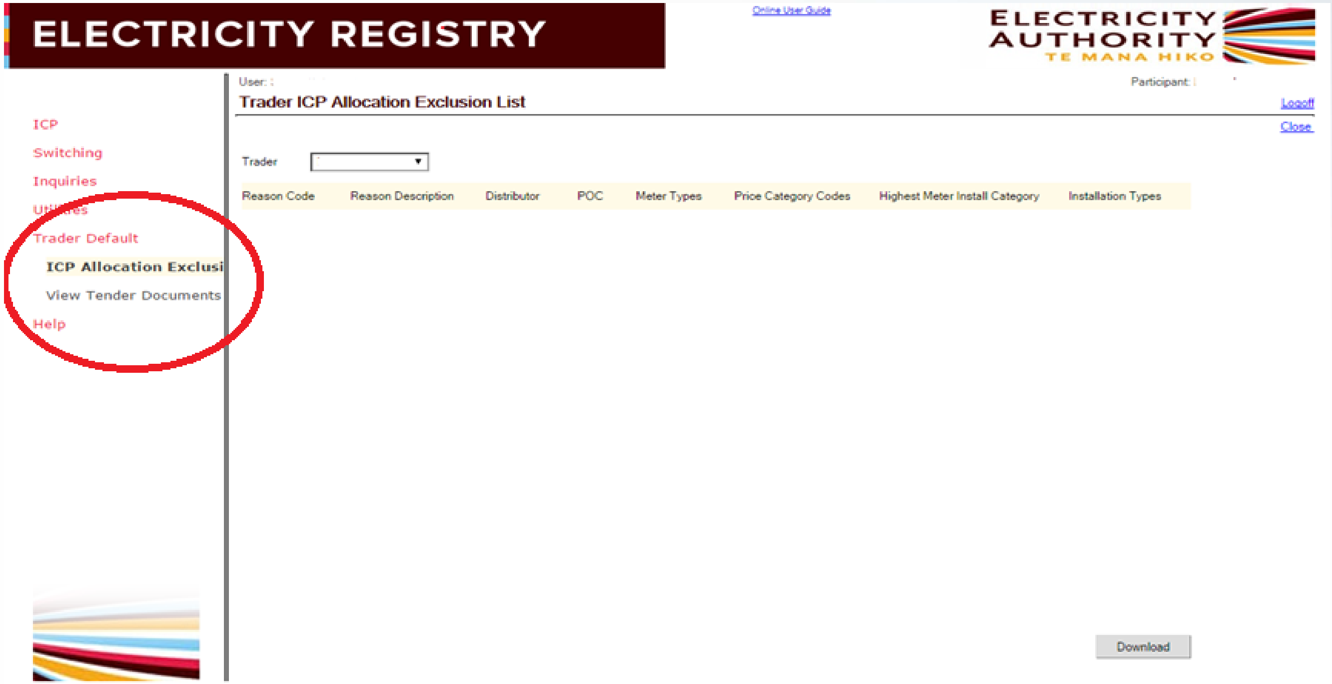
PHASE THREE: DAY 15 TO DAY 18

Day 15	Send first tender to traders	Tendering traders submit bids (TD-040)	Traders receive email and Ack file stating success of bid upload	Traders can view report (TD-060)	Authority reviews results of first tender
Day 16	Send second tender to traders	Repeat of Day 15 activites	Authority reviews results of second tender	Authority determines if mandatory assignment is required	
Day 17	Traders submit exclusion table (TD-020) to the registry	Registry performs allocation of ICPs (TD-070)	Traders review results (PR-310) and advise of threat to financial viability	Authority may re-assign ICPs	Registry performs re-assignment of ICPs (TD-090)
Day 18	Registry ensures all switches complete	Registry performs allocation of ICPs (TD-070)	Authority reviews allocation	Registry switches the ICPs (TD-080)	Traders receive CS files

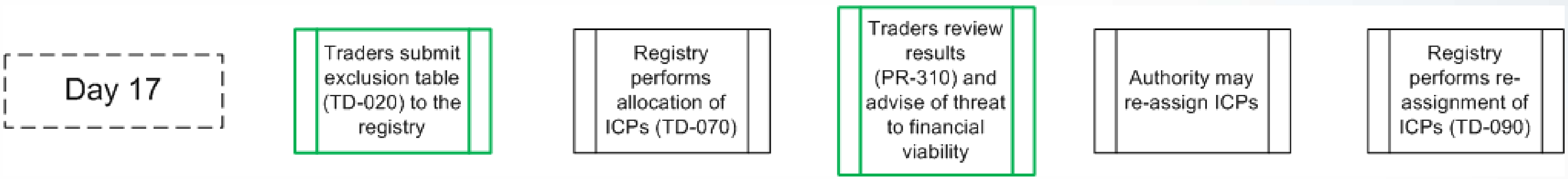
Tender(s): day 15 and 16

Day 15	Send first tender to traders	Tendering traders submit bids (TD-040)	Traders receive email and Ack file stating success of bid upload	Traders can view report (TD-060)	Authority reviews results of first tender
Day 16	Send second tender to traders	Repeat of Day 15 activites	Authority reviews results of second tender	Authority determines if mandatory assignment is required	

Registry: available reporting



Mandatory assignment: day 17

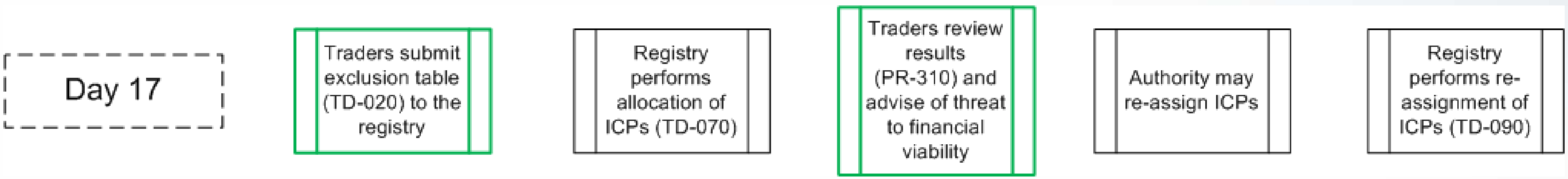


Mandatory assignment: day 17

Traders submit exclusion table (TD-020) to the registry

- Provides information on which ICPs the trader cannot accept
- On event only
- Specified timeframe
- List is not exhaustive
- Effective 28 August 2015

Mandatory assignment: day 17



Switching: day 18 onwards

Day 18

Registry ensures all switches complete

Registry performs allocation of ICPs (TD-070)

Authority reviews allocation

Registry switches the ICPs (TD-080)

Traders receive CS files

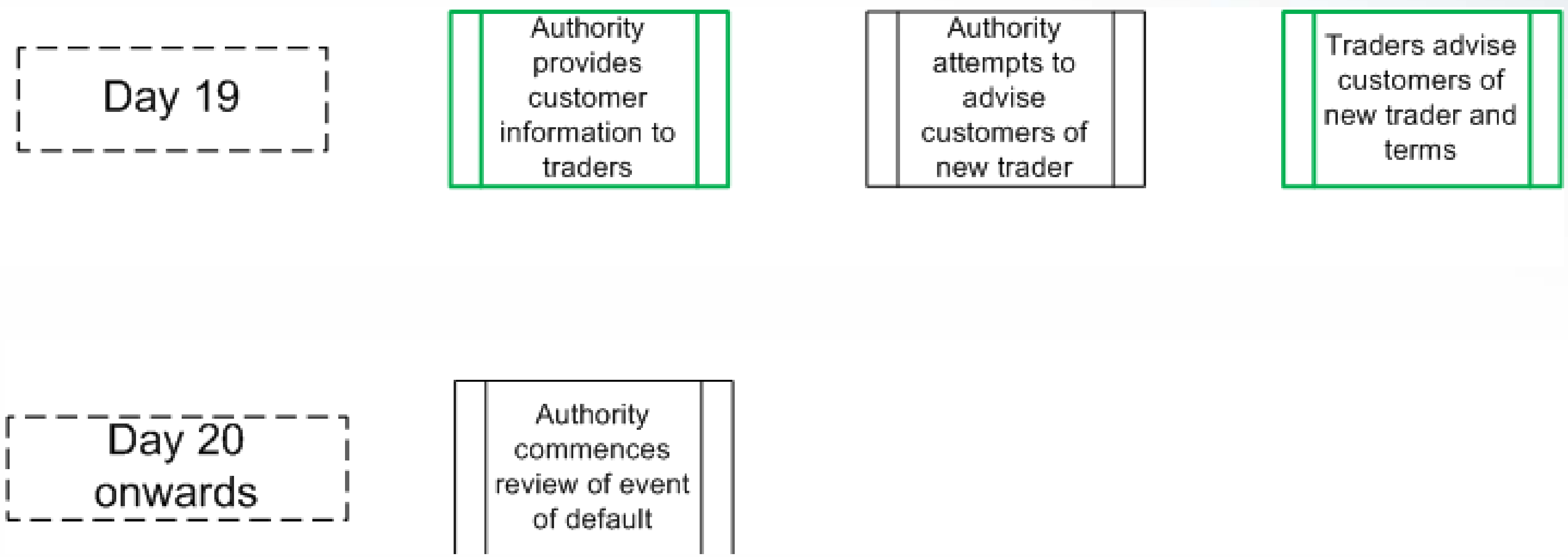
Day 18

Registry switches the ICPs (TD-080)

Day 18

Traders receive CS files

DAY 19 ONWARDS



RECONCILIATION FOR DEFAULTING TRADER

- A defaulting trader must provide submission information to the reconciliation manager until the ICPs have been allocated to a recipient trader
- If the defaulting trader does not provide submission information the reconciliation manager may estimate it (cl 15.25)
- If the reconciliation manager decides submission information is incorrect
  - it should refer the matter to the Authority (cl 15.26(2))
  - the Authority may direct reasonable steps to be taken
- If no or inaccurate submission information, the missing volume will appear as UFE.

RECONCILIATION FOR RECIPIENT TRADERS

- Recipient traders must provide submission information to the RM from the time they acquire the ICP
- Recipient traders may need to estimate a start read for non-half traded ICPs.
  - AMI installations will have actual read obtainable
  - Accuracy of estimate will be improved over time
- Any inaccuracies in reconciliation manager submissions will appear as UFE across all traders

INFORMATION AVAILABLE

- Webpage and guideline
  - updated version due for release
- Registry functional specification
- Market operations team

23 JUNE 2015

EVENTS OF DIRECT PURCHASER DEFAULT

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

DISCONNECTION OF DIRECT PURCHASERS

- Cl 14.49 of Part 14 provides that the Authority may give an instruction that direct purchaser is disconnected

  (3) If an event of default occurs in relation to a direct purchaser and is continuing at the expiry of the direct purchaser's post-default exit period registered under clause 14A.22, the Authority <u>may direct a grid owner or distributor to exercise any contractual right the grid owner or distributor has to disconnect the defaulting direct purchaser</u>.

  (4) <u>A grid owner or distributor that receives a direction under subclause (3) must comply with the direction</u>.

DISCONNECTION OF DIRECT PURCHASERS

- Direct purchasers should be aware of the requirements of cl 14.49(1)

  (1) Each direct purchaser must at all times ensure that the terms of each of its contracts that provide for the connection of the direct purchaser to a network permit the relevant grid owner or distributor to disconnect the direct purchaser on the direction of the Authority if an event of default occurs in relation to the direct purchaser and is continuing at the expiry of its post-default exit period registered under clause 14A.22.

- Distributors should be aware of the requirements of cl 14.49(2)

  (2) Each grid owner or distributor must at all times ensure that the terms of each of its contracts that provide for the connection of a direct purchaser to a network permit the grid owner or distributor to disconnect the direct purchaser on the direction of the Authority if an event of default occurs in relation to the direct purchaser and is continuing at the expiry of its post-default exit period registered under clause 14A.22.

23 JUNE 2015

RETAIL DATA PROJECT

RECONCILIATION PARTICIPANTS FORUM

RATIONALE FOR RETAIL DATA PROJECT

To promote retail competition by:

- Making available consumption information to consumers or their agents in a standard format
- Making relevant retail tariff and connection data accessible to inform consumers and support them to make decisions
- Improving confidence in the electricity market by providing monitoring reports with consistent data

RATIONALE FOR RETAIL DATA PROJECT

This project has been divided into three phases:

- Phase 1: access to consumption data
- Phase 2: access to tariff and connection data
- Phase 3: improving monitoring data

PHASE 1: ACCESS TO CONSUMPTION DATA

- The Authority has amended the Code to require retailers to make consumption data available to consumers (clause 11.32A effective 1 Feb 2016)

- The key elements of the amendment are
  - retailers must provide up to 24 months of consumption data if requested by a consumer or the consumer's agent
  - there must be a process for providing and exchanging consumption data
  - there must be a standard format to exchange consumption data (EIEP13A, 13B and 13C)
  - when making consumers' electricity consumption data available to them, retailers must protect consumers' privacy.

PHASE 1: ACCESS TO CONSUMPTION DATA

- The consumption information that must be provided in EIEP13s is the consumer’s electricity consumption information (X and I), used by the retailer to
  - calculate the amount of electricity consumed or generated by the consumer at each installation control point (ICP) or
  - to provide any service to the consumer

PHASE 1: ACCESS TO CONSUMPTION DATA

- EIEP 13A - specifies the electronic format that must be used when providing detailed consumption information electronically to consumers or their agents. This format also provides for the retailer to respond to the agent if the retailer rejects the request

- EIEP 13B - specifies the formats that must be used when providing summary consumption information either electronically or in printed form to consumers or their agents. This format also provides for the retailer to respond to the agent if the retailer rejects the request

- EIEP13C - is the electronic request file format that an agent may use to request a consumer's consumption information from a retailer

PHASE 1: ACCESS TO CONSUMPTION DATA

Progress to Date

June 2015

- Formats & procedures published
- Test plans published

1 Nov 2015

- Retailers ready to test

1 Feb 2016

- Go live

PHASE 2: ACCESS TO TARIFF AND CONNECTION DATA

Progress to Date

23 June 2015

- Consultation begins

4 Aug 2015

- Consultation ends

End 2015

- Decision made

PHASE 3: IMPROVING MONITORING DATA

This phase requires further analysis. At this stage the aim is to provide the Board with more information by June 2016.

ELECTRICITY AUTHORITY
TE MANA HIKO

23 JUNE 2015

UPDATE ON REVIEW OF PARTICIPANT AUDIT REGIME

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

23 JUNE 2015

CHANGES TO THE SWITCHING PROCESS - 9 OCTOBER 2015

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

CHANGES TO PART 11 EFFECTIVE 9/10/2015

- Decision paper at http://www.ea.govt.nz/dmsdocument/18957
- Changes are
  - "Submission type" auto populated by NT file – already completed
  - Switch event meter reading - there was a conflict between Parts 11 and 15 of the Code as to when final information for a switch should apply
  - Multiple metering types on an ICP - removed uncertainty on how to handle switches when there is a combination of HHR and NHH metering components within an ICP by requiring the switch process to be based on the highest metering category on an ICP
  - Final information - the Code should explicitly state which switch meter readings are required – alignment with current practice

CHANGES TO PART 11 EFFECTIVE 9/10/2015

- Tenure of an ICP - amending the Code requirement for switches where the losing trader's tenure of an ICP that does not have an AMI meter is less than three months including a new definition

__switch event meter reading__, in relation to a __meter__ or __data storage device__ that is located at an __ICP__ that is being switched under Schedule 11.3, means—

(a) a __validated meter reading__, if one is available; or

(b) a reasonable estimate of the __meter reading__ based on the __meter reading__ contained in the final information provided in the switch file that the losing __trader__ received when it gained the __ICP__ if—

(i) a __validated meter reading__ is not available; and

(ii) the losing __trader__ has been recorded in the __registry__ as being responsible for the __ICP__ for a period of less than 3 months; or

(c) in every other case, a __permanent estimate__

CHANGES TO PART 11 EFFECTIVE 9/10/2015

- Metering category – issues identifying non communicating AMI and legacy HHR ICPs - switching by meter category
- Switch event meter reading for AMI ICPs - decided not to proceed with the proposed amendment at this time and has consulted on a reversed option
- Back dated switches - backdating HHR switching to allow the switch event date to be:
  - a date in the same month as the gaining trader advises the registry of the expected event date; or
  - a date in the 90 days before the month in which the gaining trader advises the registry of the expected event date provided that the losing trader and the gaining trader agree.

CHANGES TO PART 11 EFFECTIVE 9/10/2015

- Obtaining final metering installation interrogation options – in the case of a meter change at the time of a switch, the gaining trader must provide an interogation or allow the losing trader, or that losing trader's MEP, the opportunity to interrogate a metering installation prior to any component removal
- Gaining trader provides NHH switch event meter reads options – where a switch type of TR or MI may be completed by the gaining trader. The Authority decided not to proceed with developing a Code amendment or further investigation at this time.
- Rename the half hour switch process – renamed

- The outcome of the consultation on a losing trader providing a revised AMI switch event meter reading will be available shortly.

23 JUNE 2015

TRAINING WEB SITE

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

Resource Centre – Proof of Concept

A potential new way to present Electricity Authority guidelines

whiteboard ENERGY

Proof of concept - aims

A network map of the Authority's operational guidelines that makes intuitive sense to the viewer

- Improve awareness of the wealth of guidelines the Authority has developed
- Improve access to guidelines and improve the learning process
- Develop a multi-level, multimedia approach to providing the industry with operational guidance

Develop a prototype

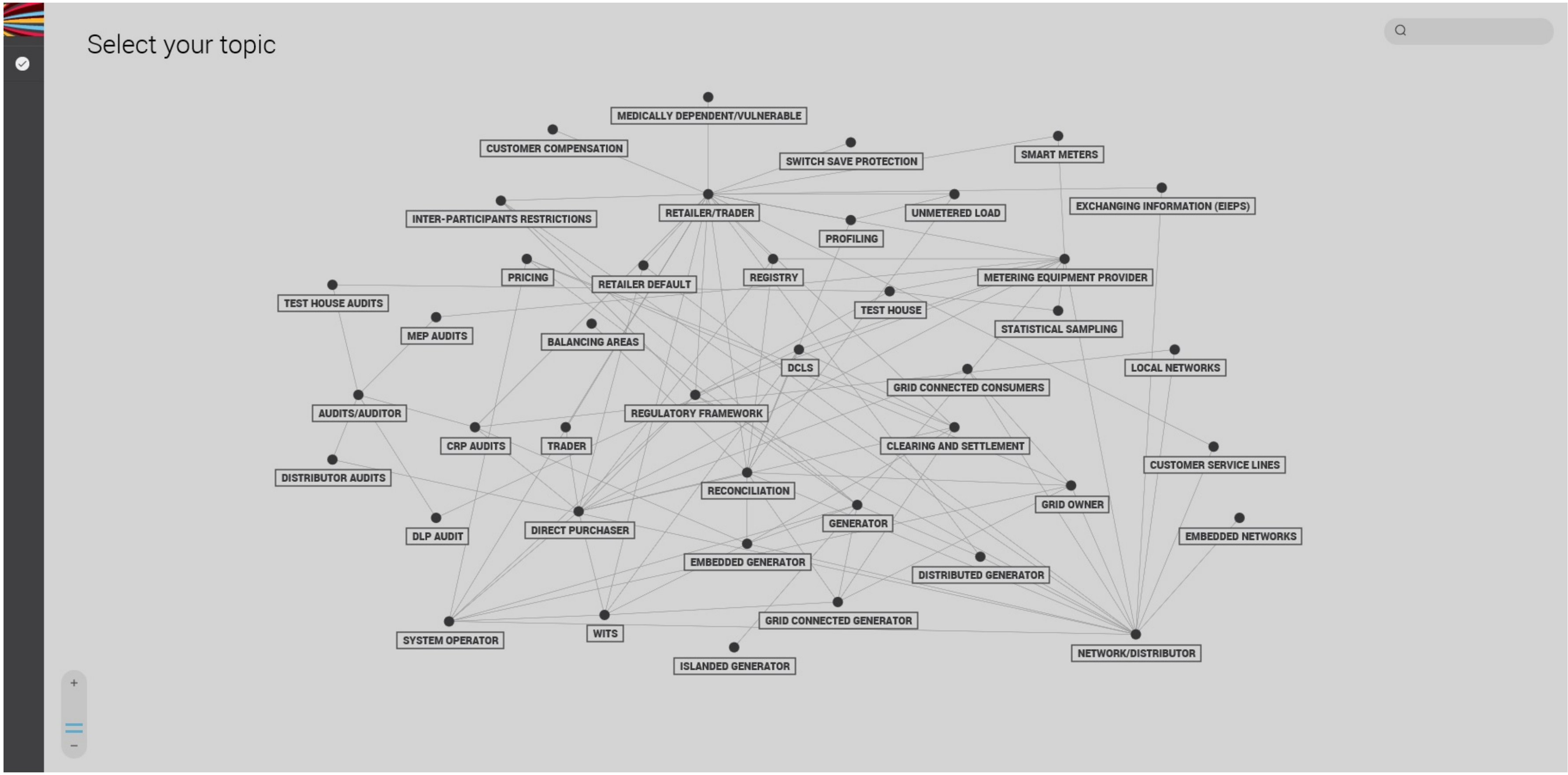
- Test feasibility of the network map approach
- Test the software on the Electricity Authority's webservice

Proof of concept - aims

Get industry feedback

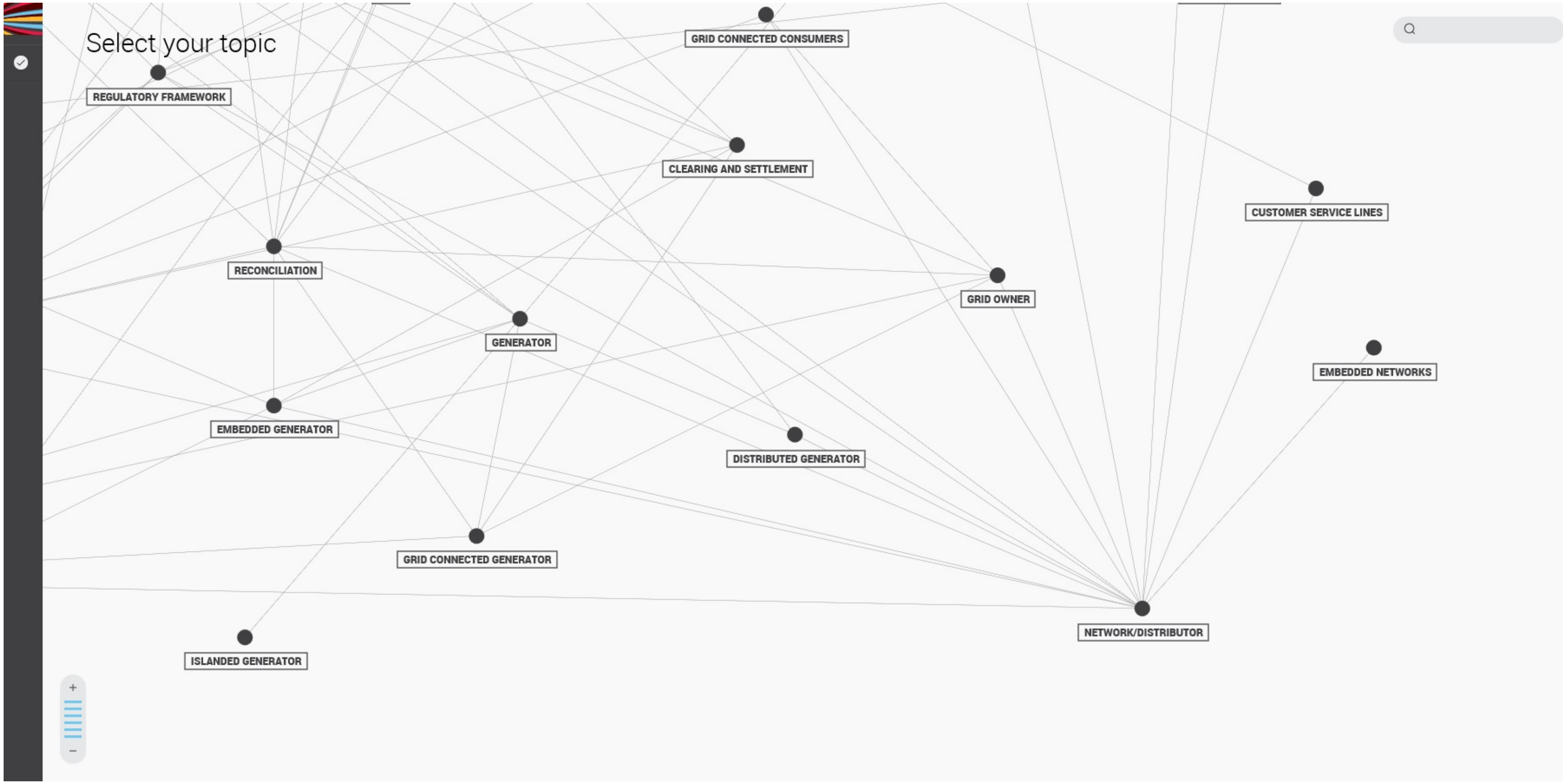
- Does this approach improve access and intuitive guidance?
- Is this something you would use?
- What more could be done?

Network Map - Prototype

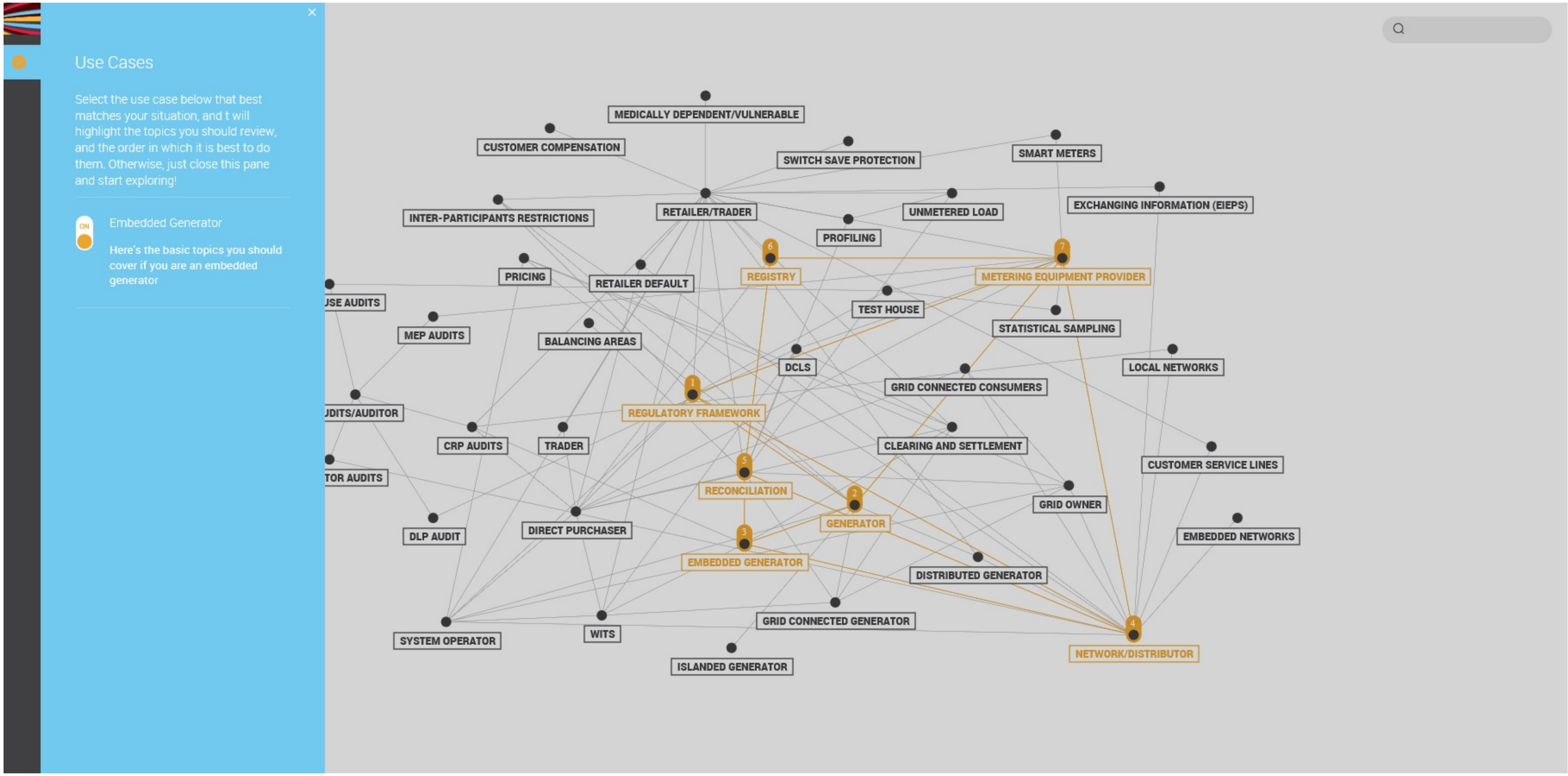


Network map presents all the topics and the relationships between topics

Dynamic zoom and pan

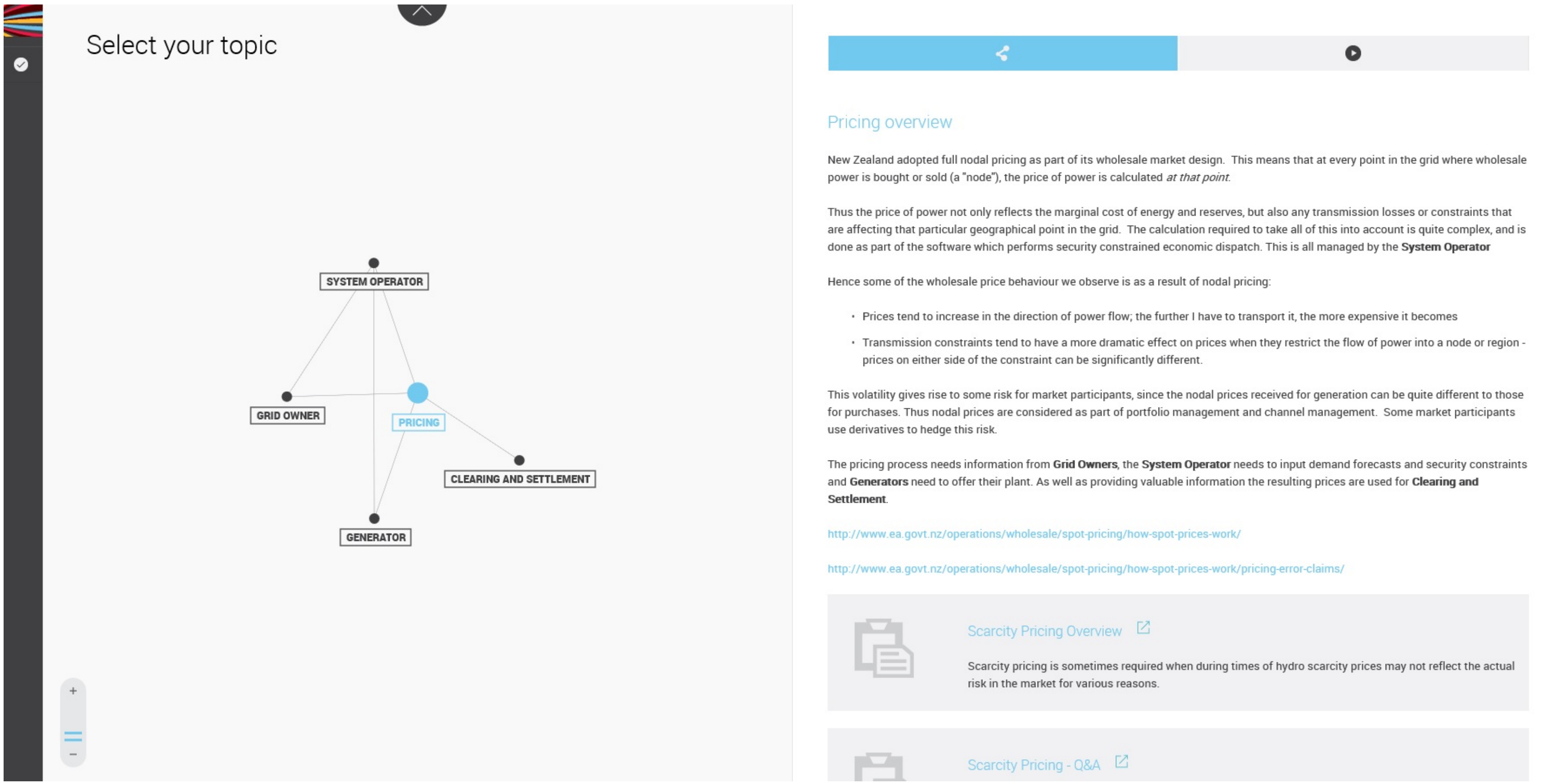


Use cases - example



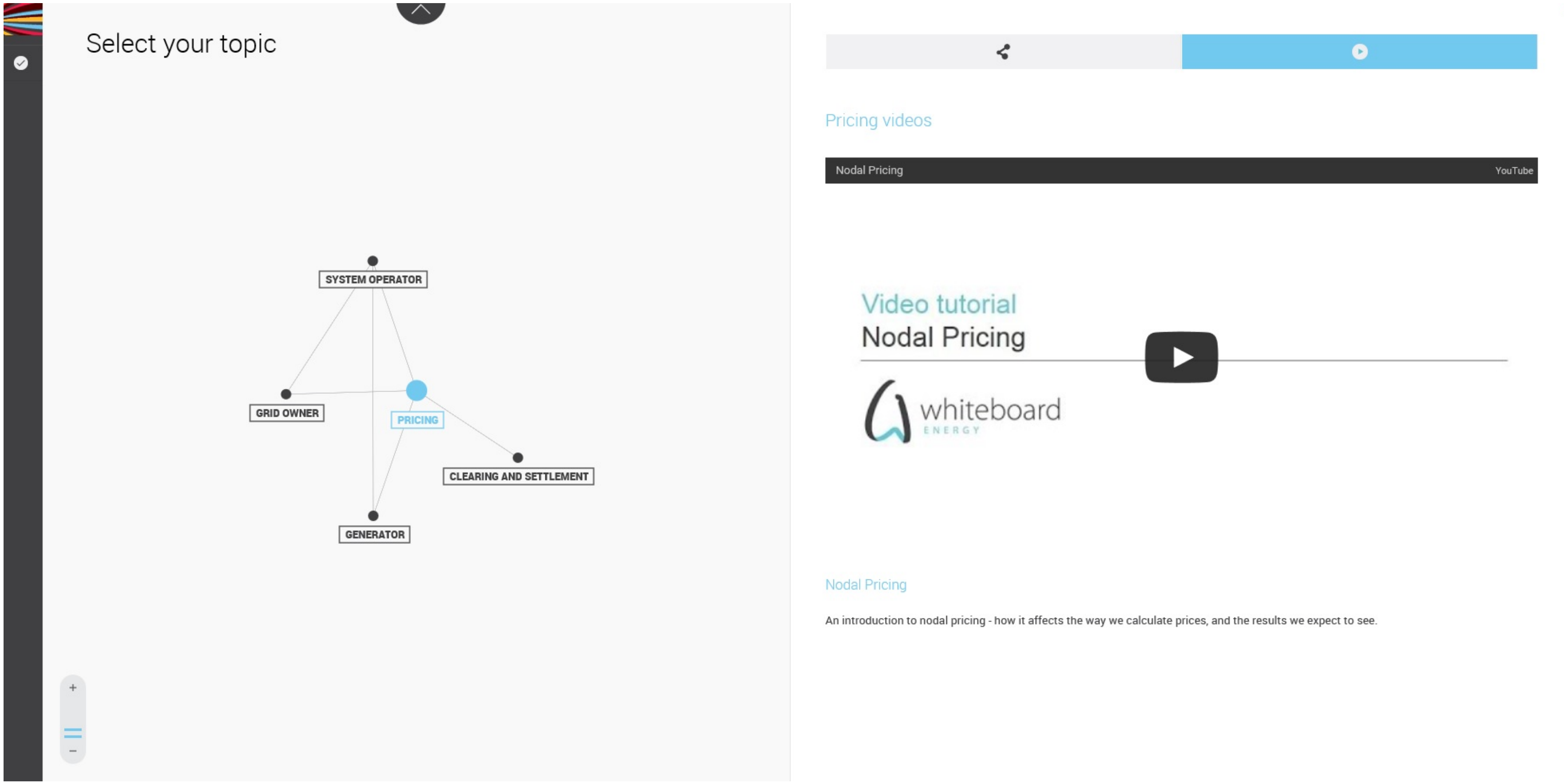
Use cases can show a suggested topic list and order for review

Topic node - example



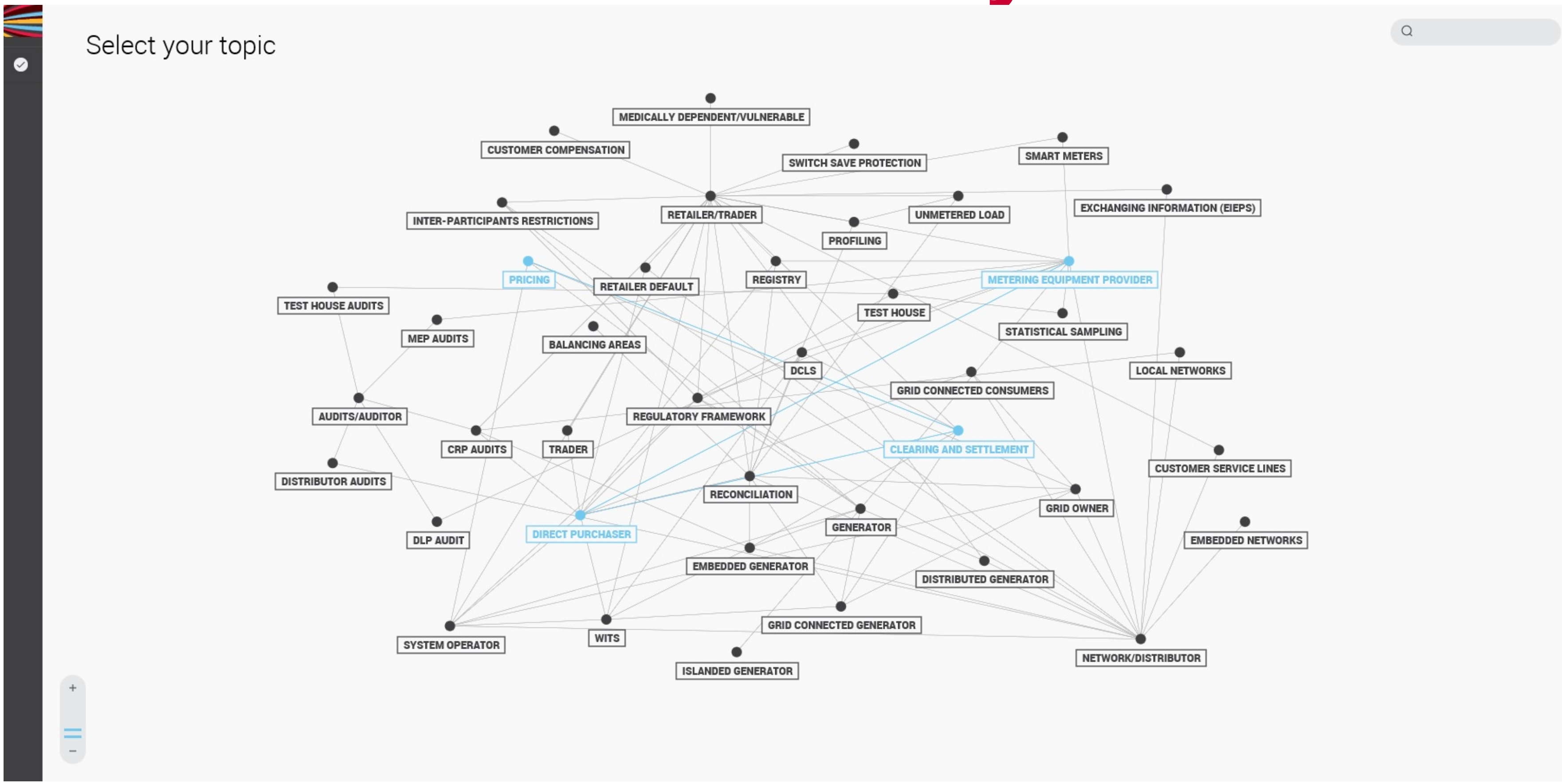
Topic nodes display mini-networks showing the relationships to other nodes.
Nodes can contain short descriptions, weblinks and documents for downloading.

Topic node videos - example



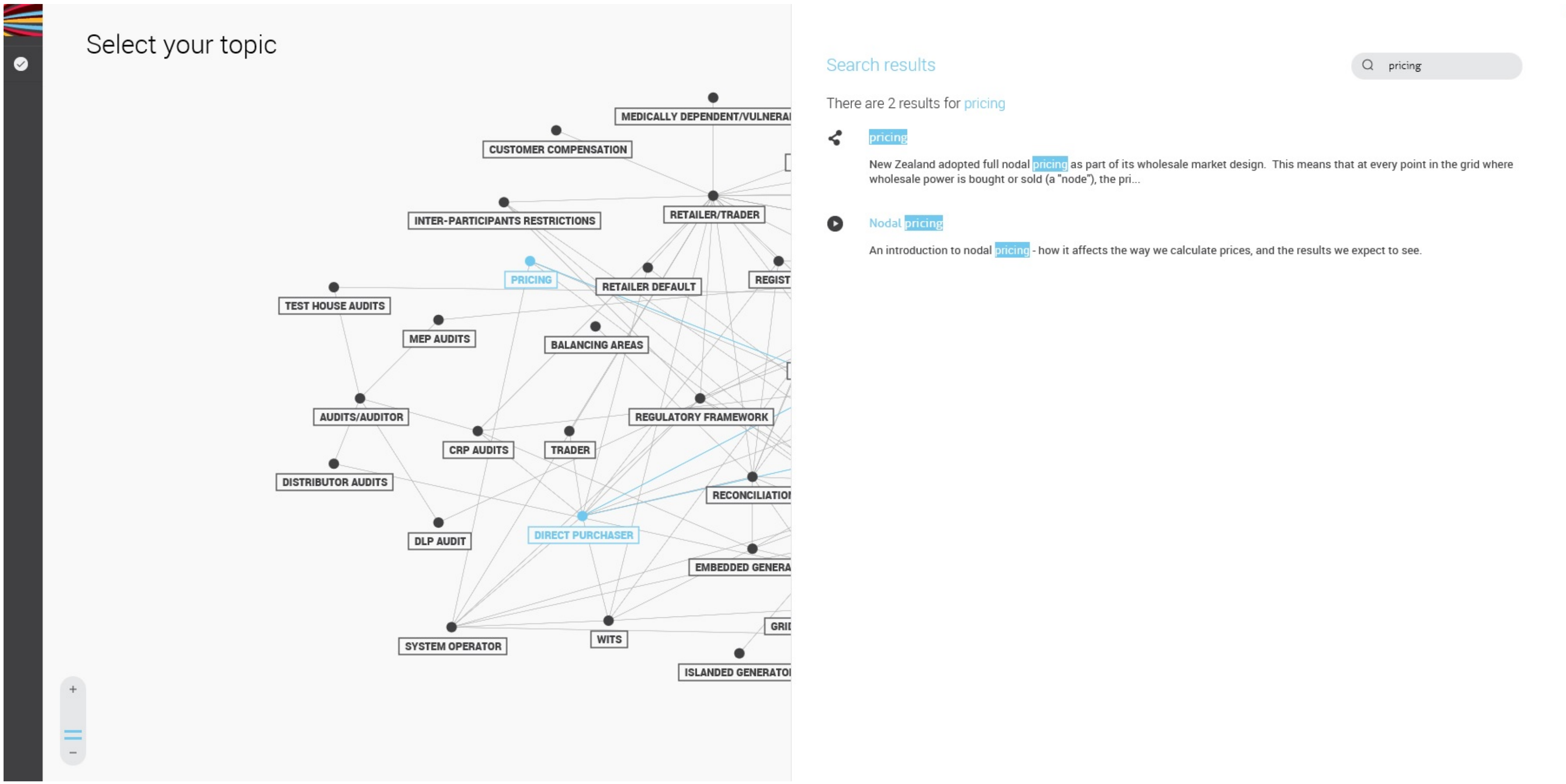
Videos can also be attached to nodes (requires YouTube access)

Session tracks where you’ve been



Colour coding let’s you see what you’ve already done in your session.

Resource centre searchable



Available on most web browsers

Works on IE9+, Chrome, Firefox and Safari

Also works on smartphones and tablets

Doesn’t work properly on Internet Explorer 8 or previous

Standalone prototype is working now with limited sample content

Currently testing the integration with the Authority’s webservers

Next steps

Looking for Industry feedback

Interest in industry workshop

- Review concept
- Review useability and meeting objectives
- Test functionality and approach
  - Network map
  - Topic list and relationships
  - Use cases
  - Content
- Would industry use it?

ELECTRICITY AUTHORITY
TE MANA HIKO

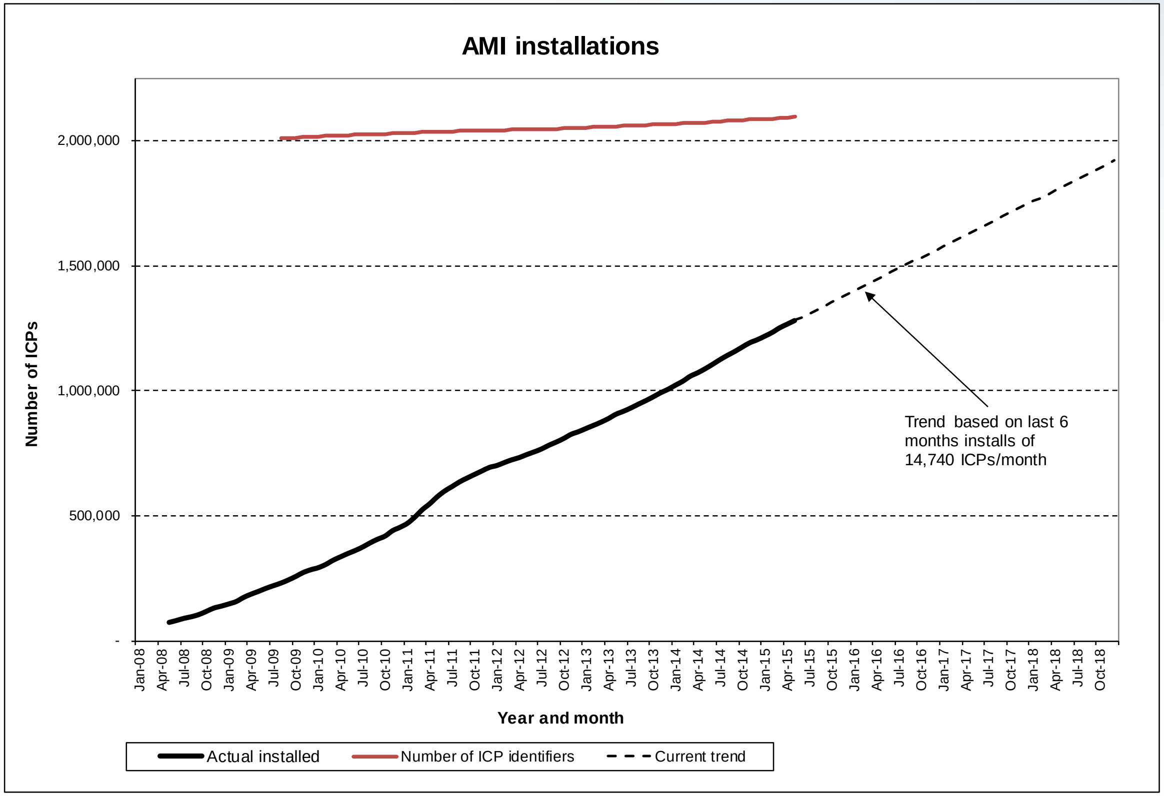
23 JUNE 2015

SOME STATISTICS

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

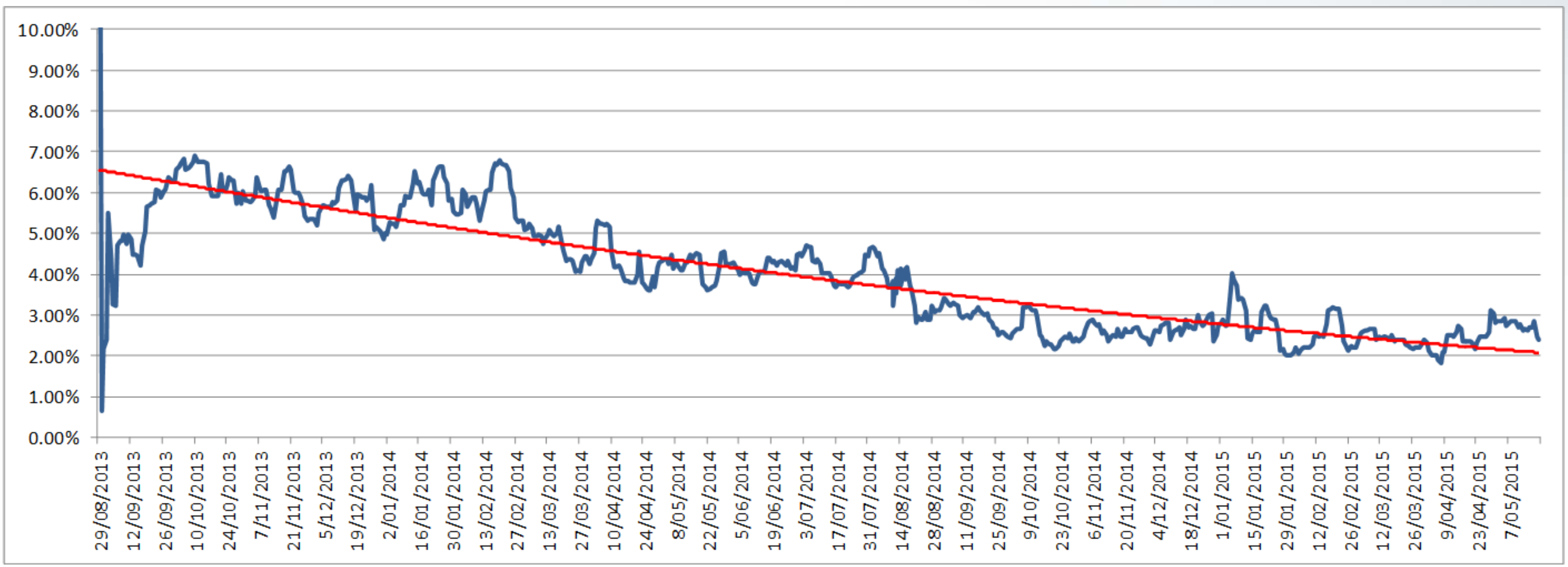
AMI INSTALLATIONS



- As at 31 May 2015, there were approx 1,280,361 ICPs with AMI (communicating)
- 61.15% of active and inactive ICPs

STATS – TOTAL SWITCH REJECTIONS

Total CS failures

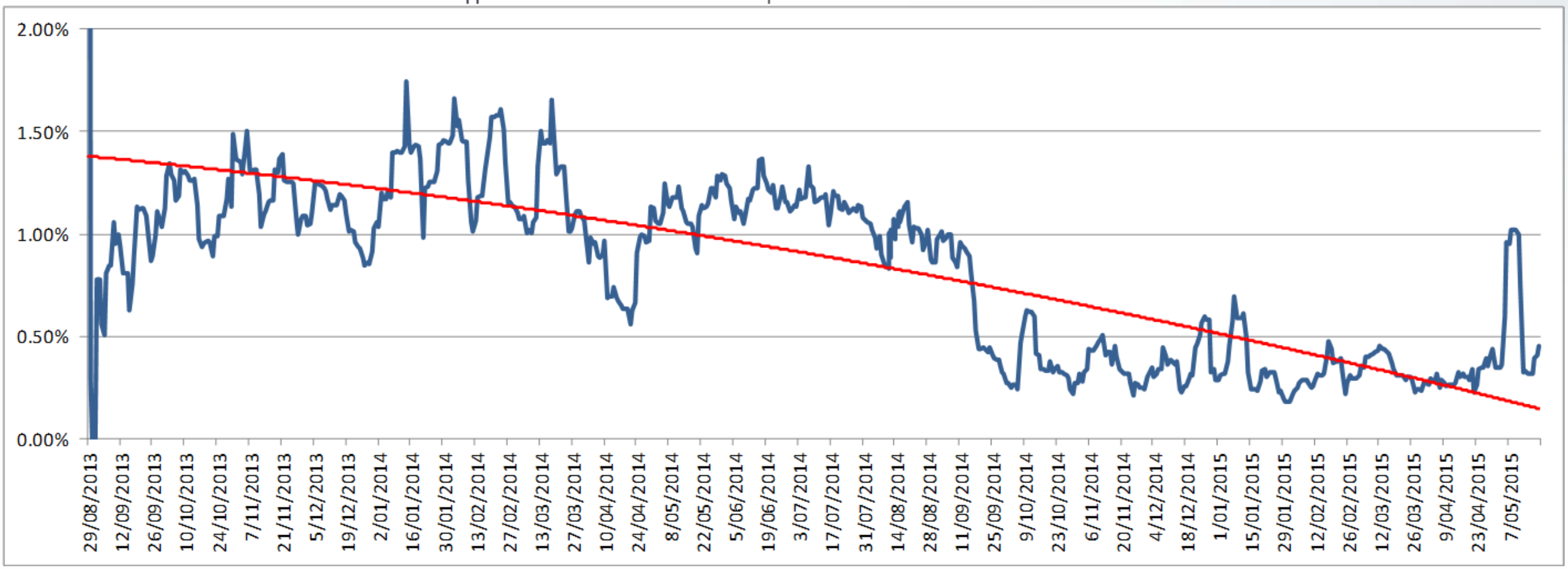


STATS – TOTAL SWITCH REJECTIONS

693 Mismatch on switch read installation

mismatch in the number of installations supplied vs. number required

mismatch on Installation Numbers supplied vs. Installation Numbers required

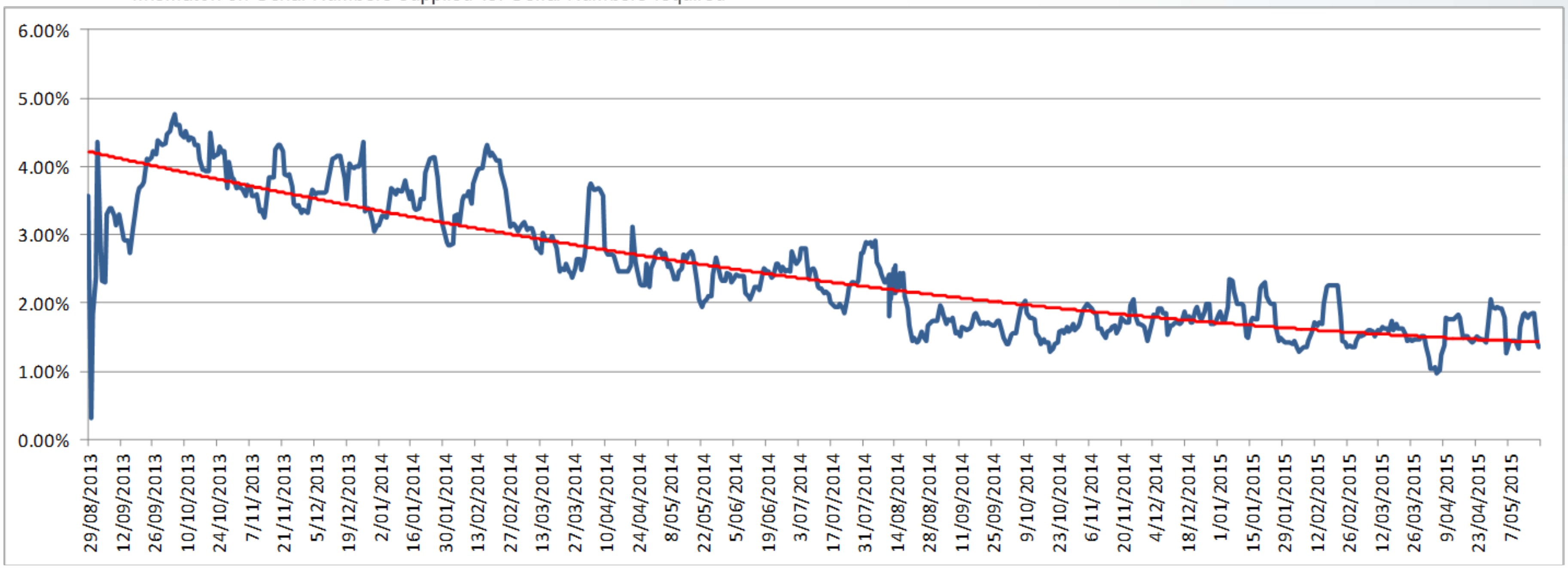


STATS – TOTAL SWITCH REJECTIONS

694 Mismatch on switch read component

mismatch in the number of components supplied vs. number required

mismatch on Serial Numbers supplied vs. Serial Numbers required

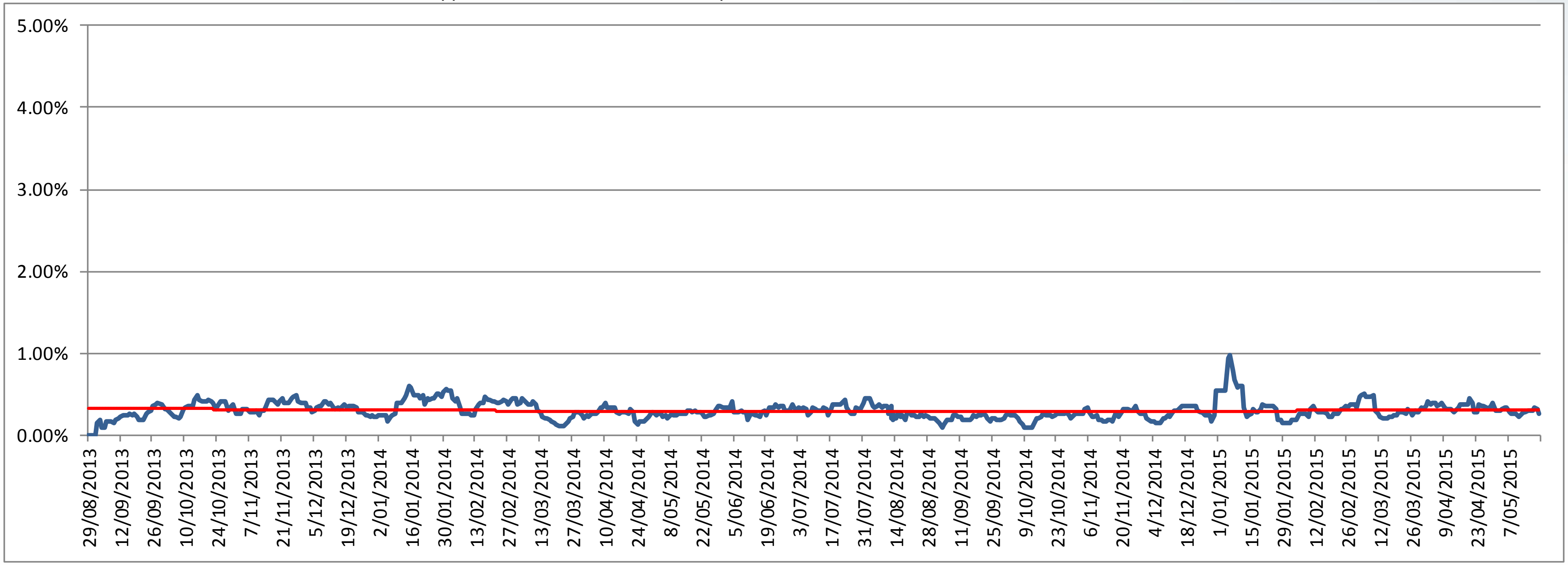


STATS – TOTAL SWITCH REJECTIONS

695 Mismatch on switch read channel

mismatch in the number of channels supplied vs. number required

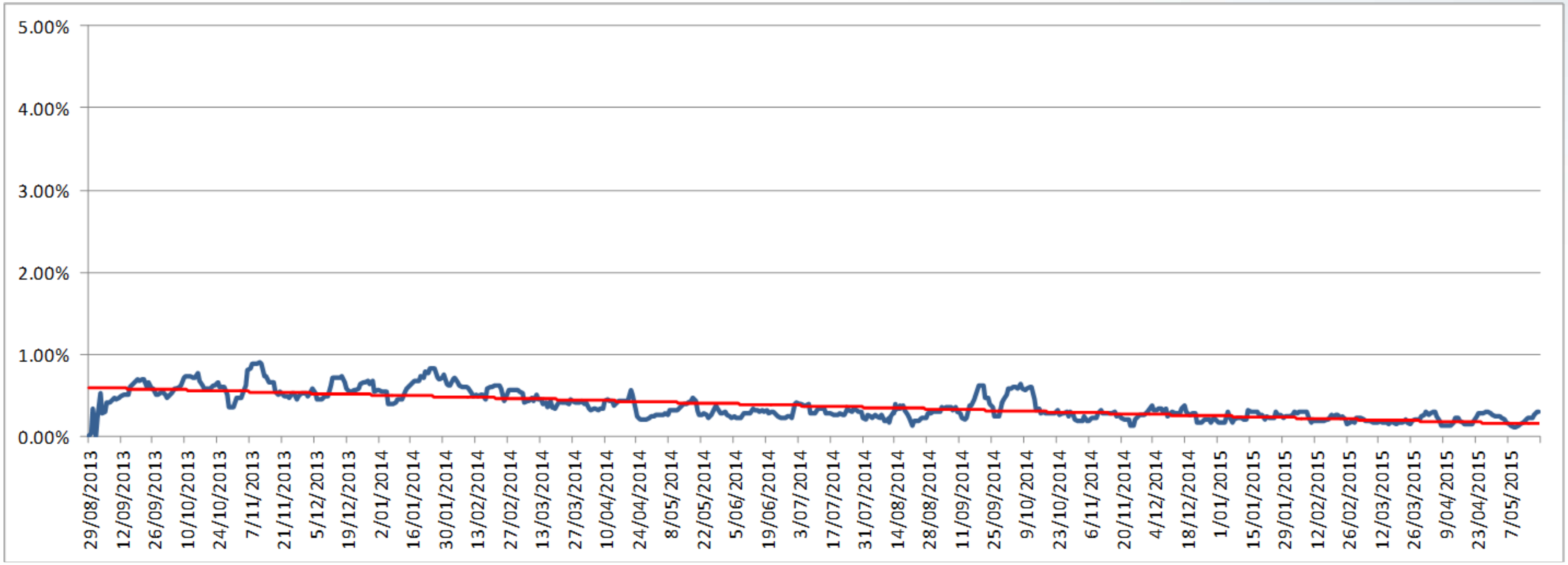
mismatch on Channel Numbers supplied vs. Channel Numbers required



STATS – TOTAL SWITCH REJECTIONS

223 Reg Reading Invalid

supplied Reading length does not match number of dials



23 JUNE 2015

DISCUSSION

RECONCILIATION PARTICIPANTS FORUM

COMPETITION • RELIABILITY • EFFICIENCY

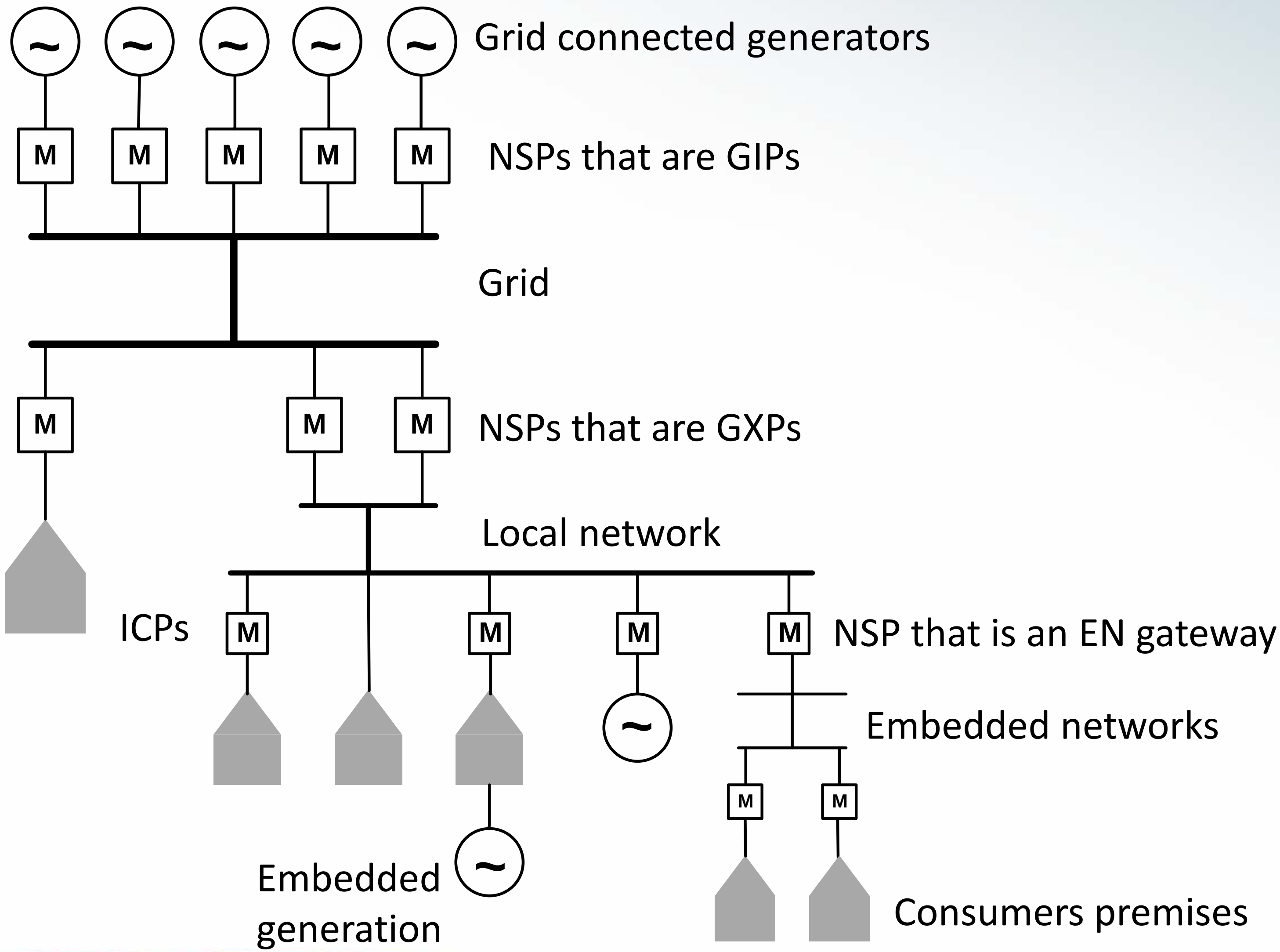
WORKSHOP DISCUSSION

- Metering certification
- ICP days scaling (Andrew Masyek)
- Allocation of residual UFE with advent of ½ hour data available for submissions (Andrew Masyek)
- New connection process
- AMI switching
- Decommissioning secondary networks
- Certification of meters
- Controlled load profiles
- Use of ‘inactive’ status reason code

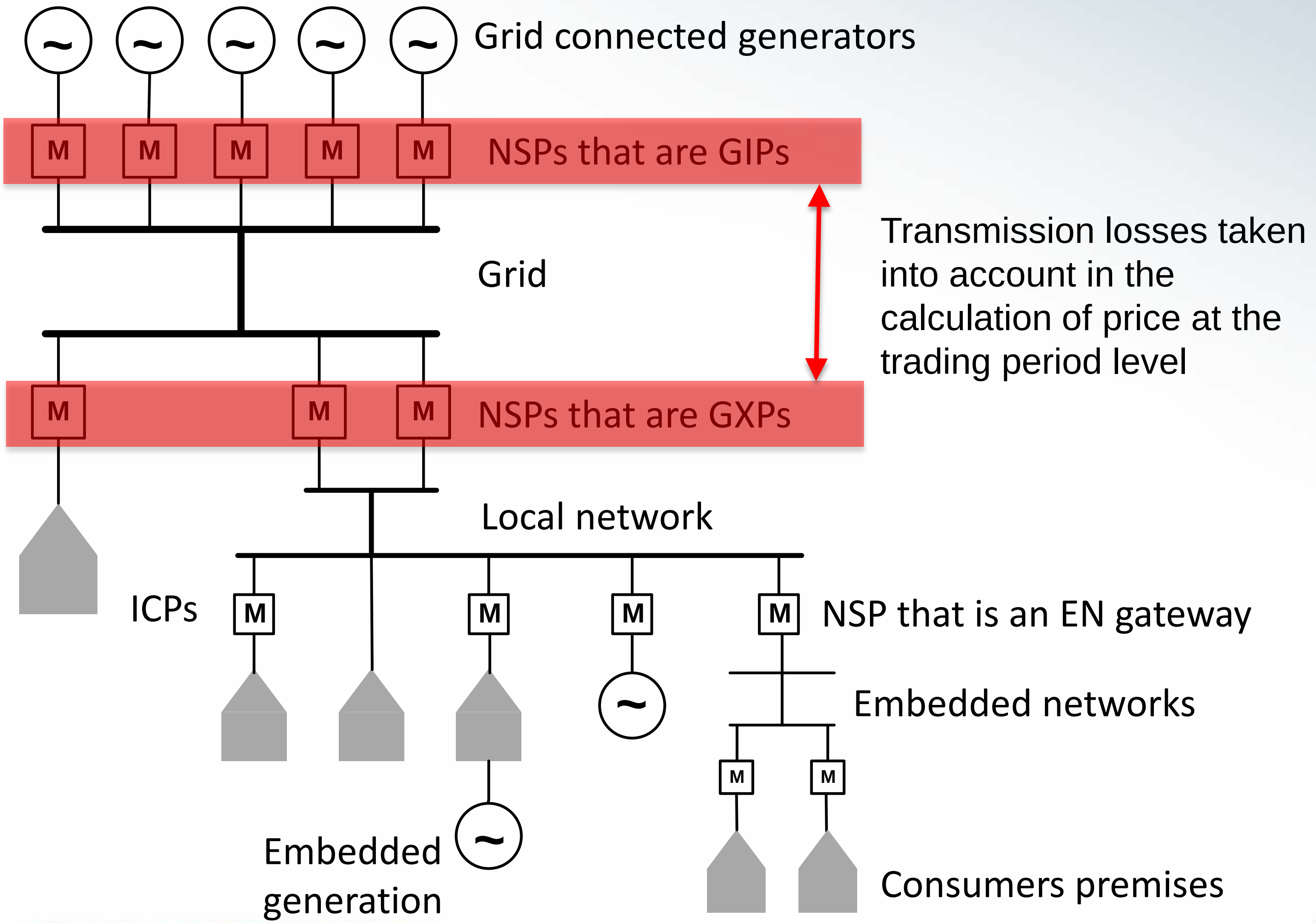
WORKSHOP DISCUSSION

- Time to notify registry of an MEP
- Change of meter at time of a switch
- Unmetered load
- Permanent estimates
- Consequence of errors

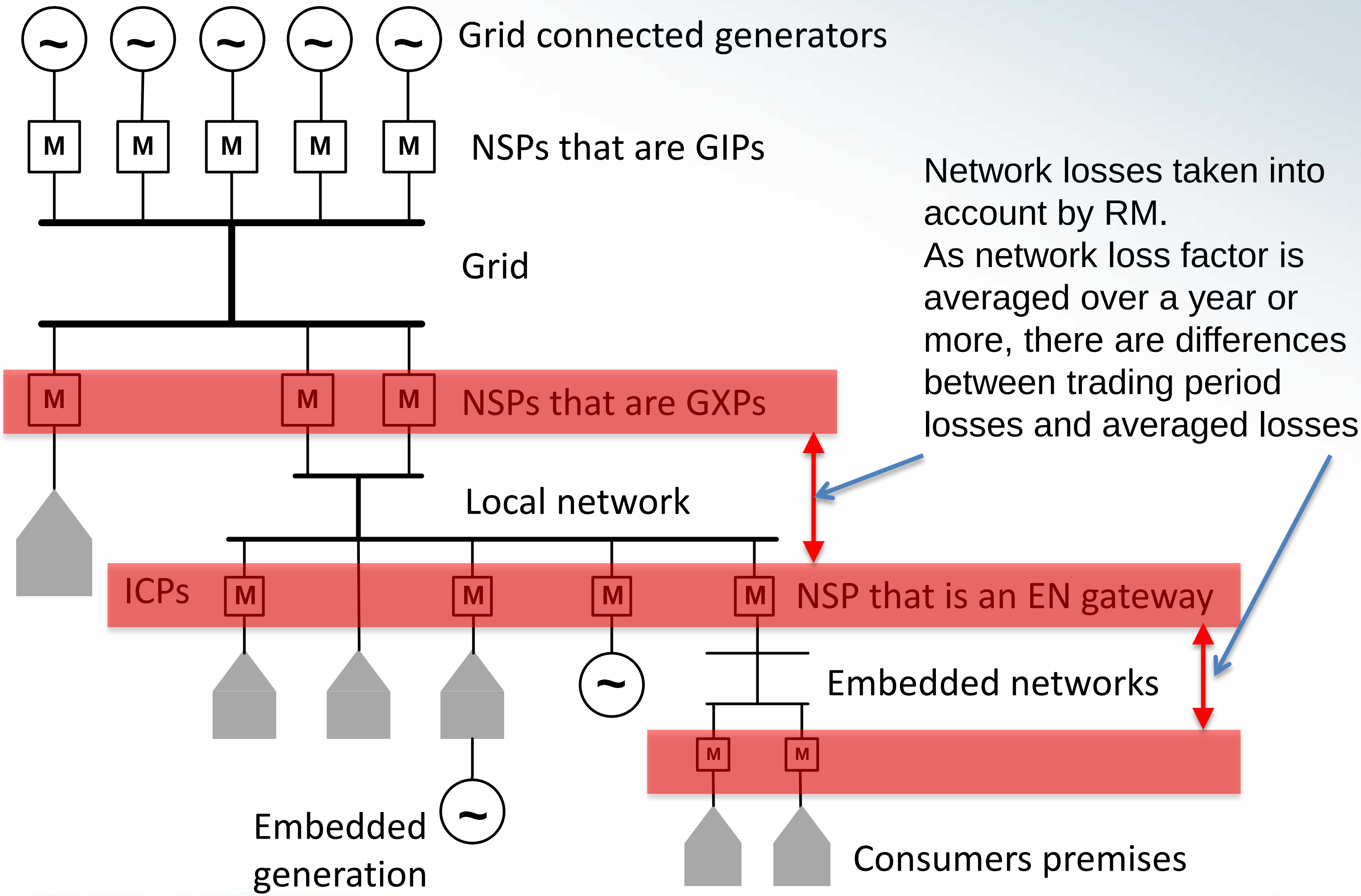
PHYSICAL NETWORK CONNECTIONS



PHYSICAL NETWORK CONNECTIONS

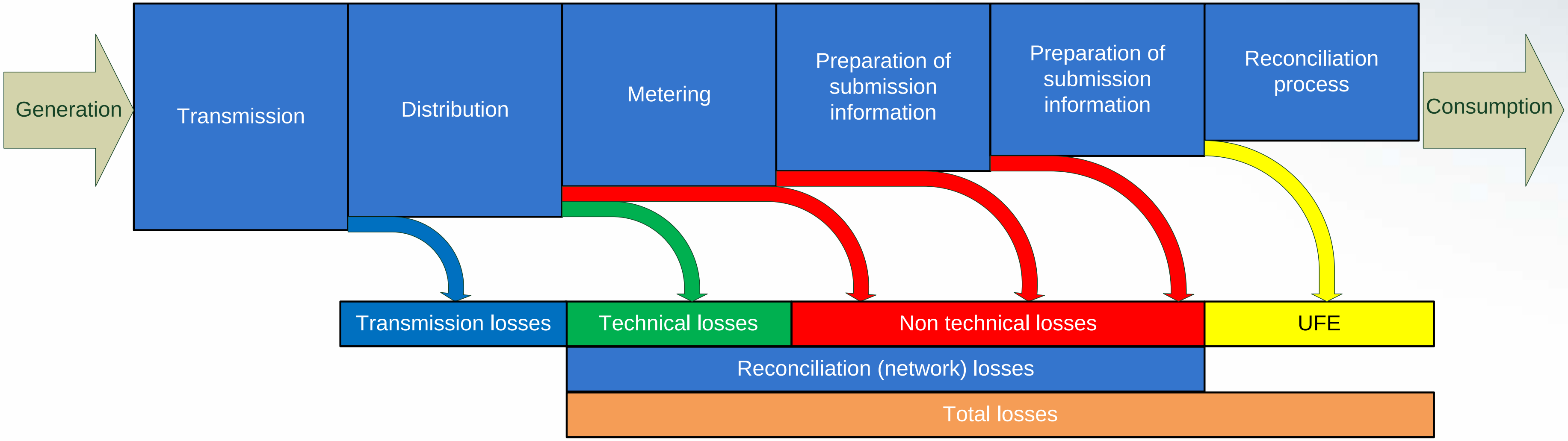


PHYSICAL NETWORK CONNECTIONS

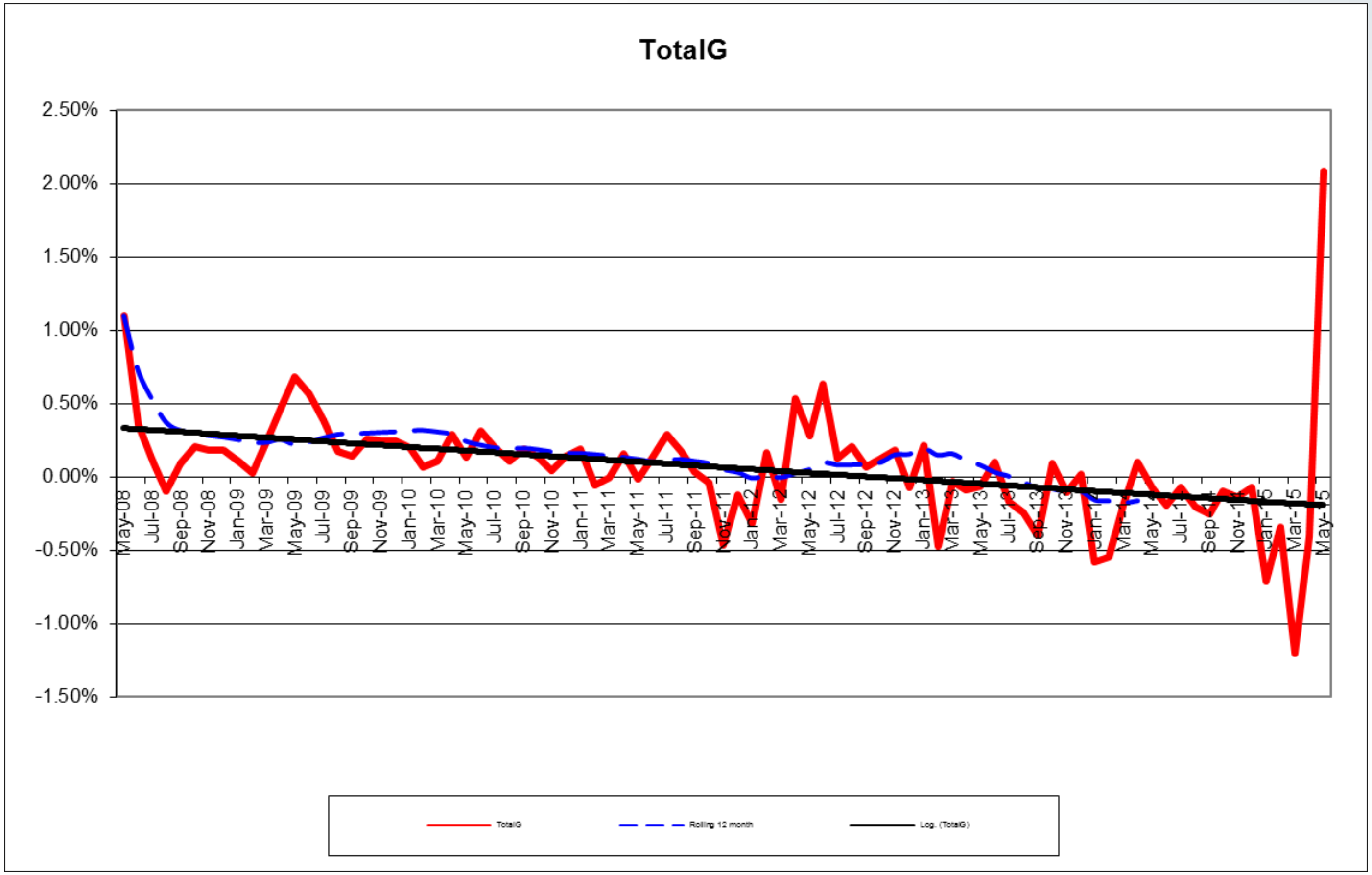


Network losses taken into account by RM.
As network loss factor is averaged over a year or more, there are differences between trading period losses and averaged losses

NETWORK LOSSES



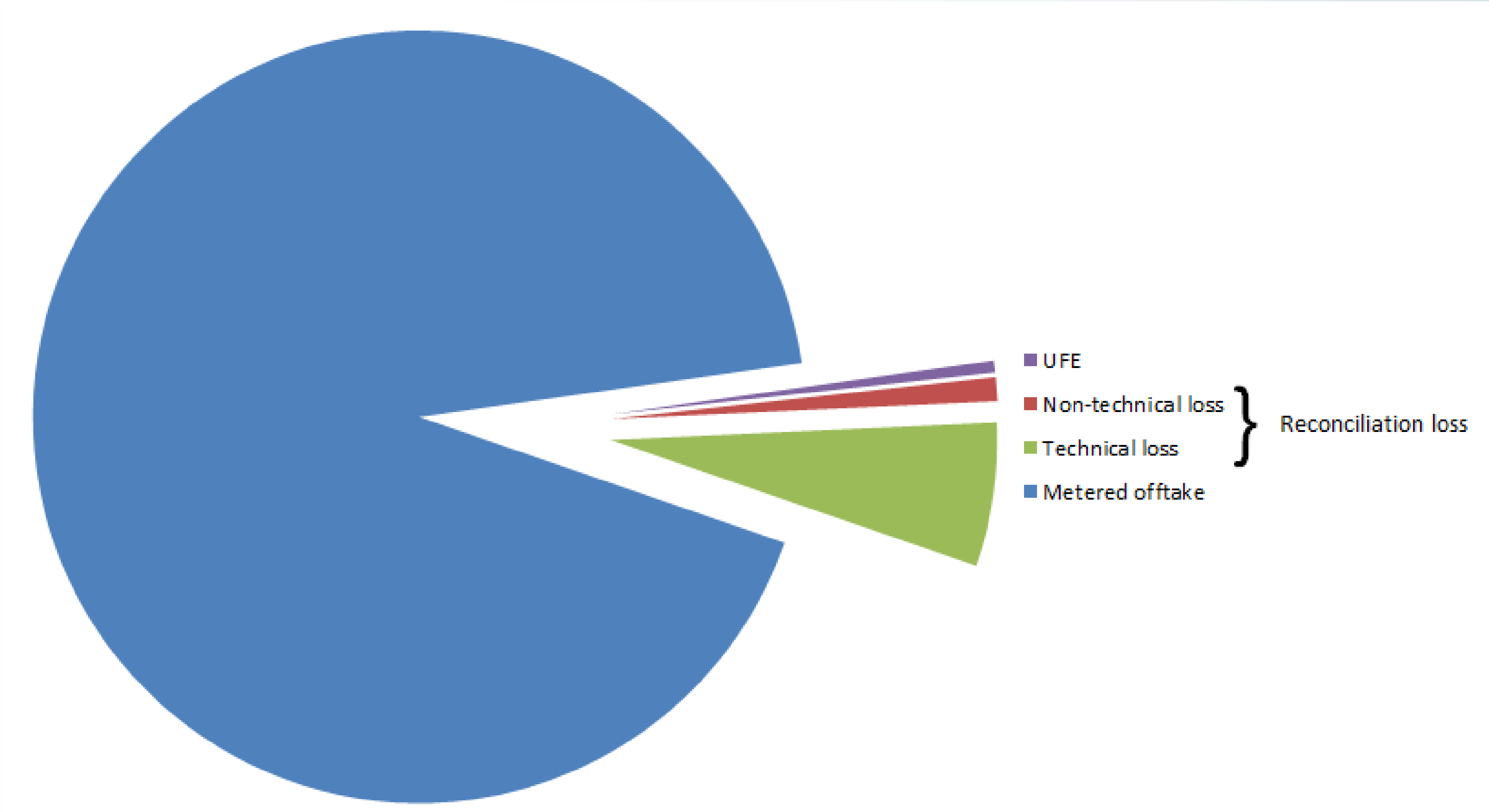
UNACCOUNTED FOR ELECTRICITY



COMPETITION • RELIABILITY • EFFICIENCY

ELECTRICITY AUTHORITY
TE MANA HIKO

NETWORK LOSSES



THERE ARE DIFFERENT TYPES OF NETWORKS

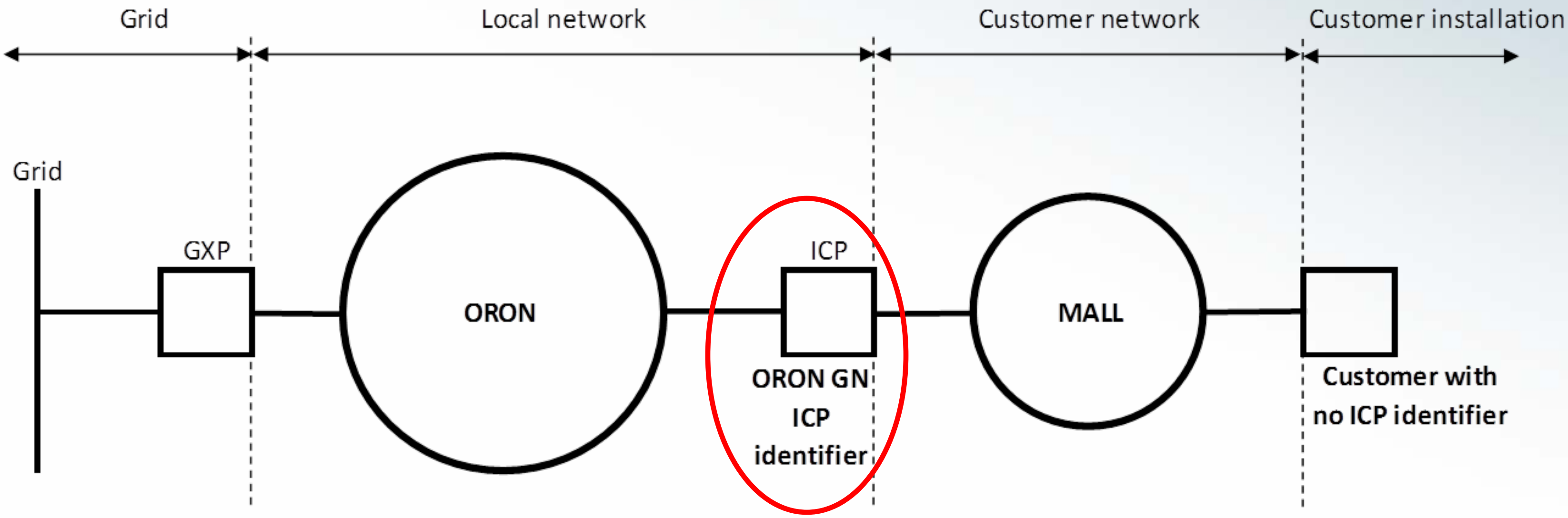
- The grid
- Local networks – networks that are directly connected to the grid
- Secondary networks – networks that are indirectly connected to the grid
  - Customer networks (not mentioned directly in the Code)
  - Network extensions (not mentioned directly in the Code)
  - Embedded networks
- Islanded networks – networks that are not directly or indirectly connected to the grid (not mentioned directly in the Code)
- DO NOT have ICP identifiers for its ICPs at customer POCs
- consumers DO NOT have choice of retailer
- volumes of electricity are not part of electricity market processes

THERE ARE DIFFERENT TYPES OF NETWORKS

- The grid does not have ICP identifiers on its points of connection, it has NSPs
- Local networks will have
  - NSPs where it connects to another network
  - ICP identifiers where it connects to a consumer or generator
- Secondary networks – see next slide
- Islanded networks do not have NSPs or ICP identifiers

SECONDARY NETWORKS

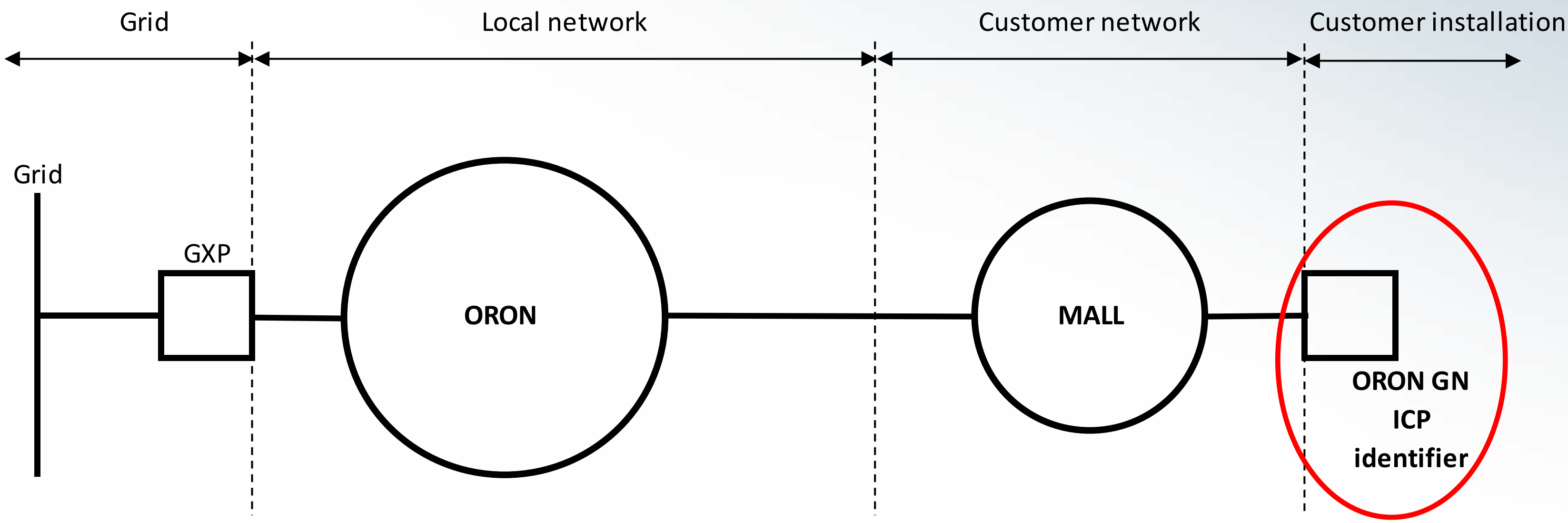
Customer network



- **No ICP identifier within a "privately" owned network**
- ICP identifier issued by local network is at the ICP between parent network and customer network with distributor identifier of ORON and reconciliation type of GN
- No registry distributor records for consumer within consumer records
- Customer network owner purchases electricity at the ICP identifier, and retails electricity to each of their customers, customer does not have choice of retailer
- No transparency to local network owner that they are connecting a customer network
- Unknown how many customer networks exist

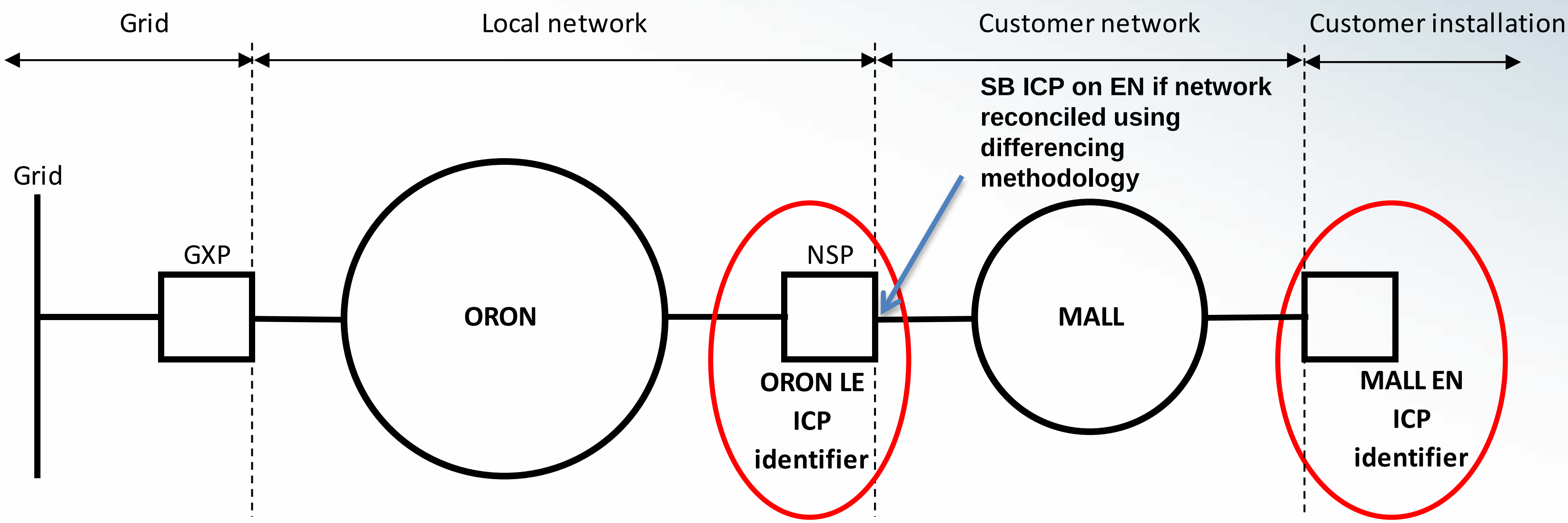
SECONDARY NETWORKS

Network extension



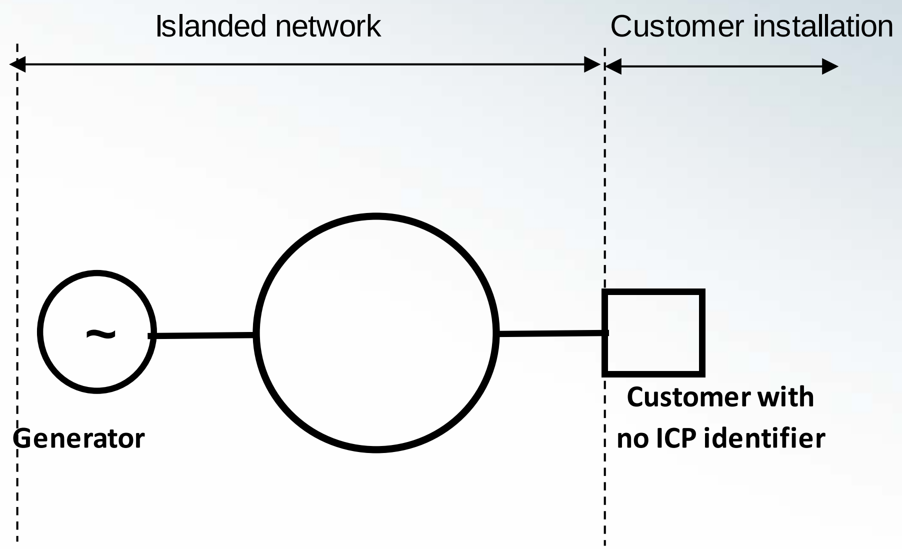
- **ICP identifier within a "privately" owned network**
- ICP identifier at the ICP between customer network and the customer installation, the local network has "extended" its network through the customer network
- Registry records show ICP identifier with distributor identifier of ORON and reconciliation type of GN
- Local network owner must manage registry distributor records
- Customer network owner is passive and does not retail electricity, customers have choice of retailer
- No transparency to local network owner or traders that customer is on a network extension
- Unknown how many network extensions exist

SECONDARY NETWORKS
Embedded network



- **ICP identifier within a “privately” owned network**
- Customer network is now called an embedded network
- ICP identifier at the ICP between embedded network and the customer installation
- Registry records show ICP identifier with distributor identifier of MALL and reconciliation type of EN
- Embedded network owner must manage registry distributor records
- Customers with ICP identifiers have choice of retailer
- Transparency to local network owner and traders that customer is on an embedded network
- SB ICP at NSP if EN reconciled using differencing methodology

ISLANDED NETWORKS



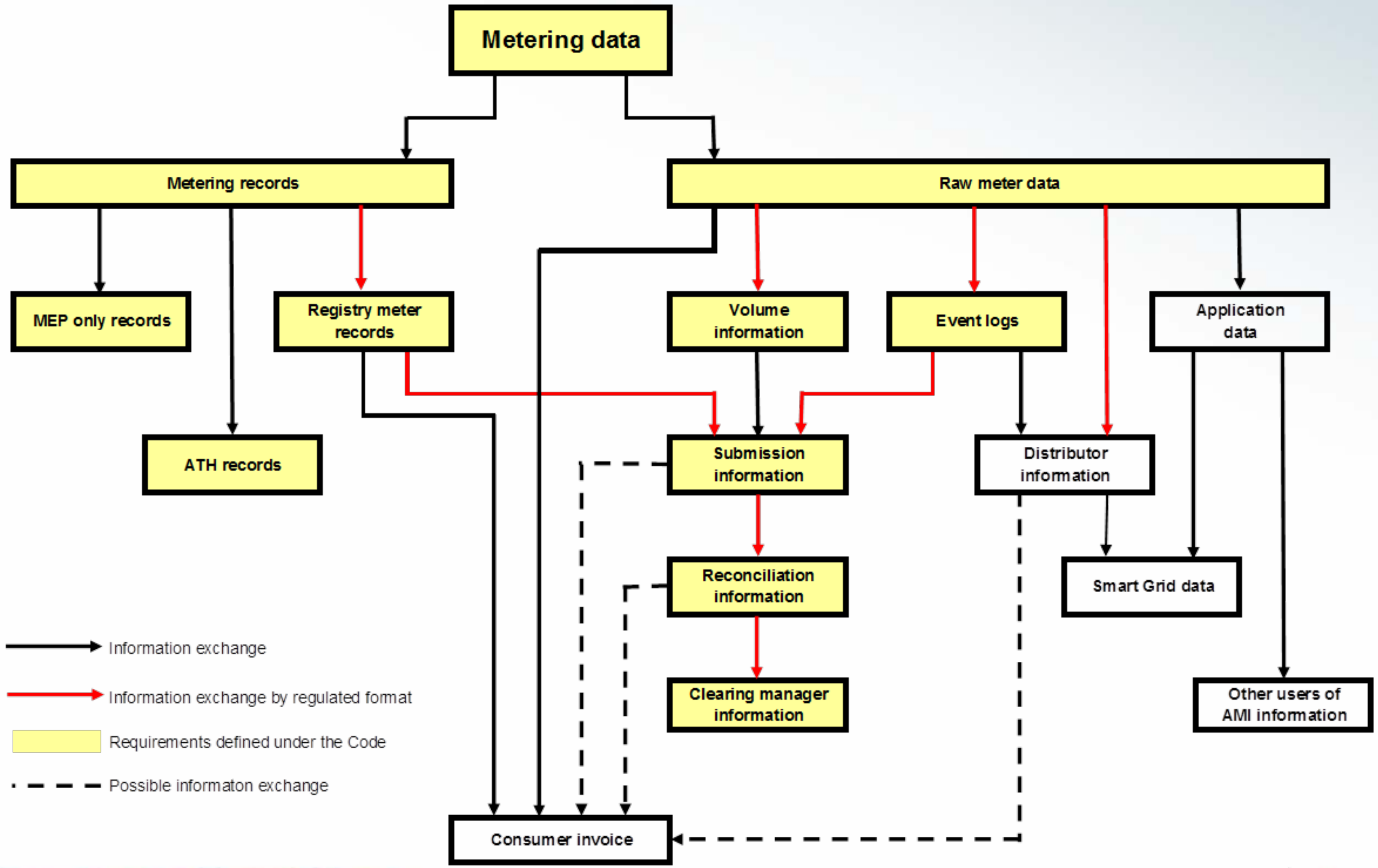
- DO NOT have any NSPs or ICP identifiers for POCs on its network
- Networks are not directly or indirectly connected to the grid (not mentioned directly in the Code)
- Consumers DO NOT have choice of retailer
- Volumes of electricity transacted are not part of electricity market processes

TYPES OF METERING INSTALLATIONS

Table 1: Metering installation characteristics and associated requirements

Defining Characteristics				Associated Requirements of active energy metering							
Metering installation category	Primary voltage (V)	Primary current (I)	Measuring transformers	Metering installation certification type	Accuracy tolerances		Selected component metering installation minimum IEC class (more accurate components may be used)		Metering installation certification and inspection		
					Maximum permitted error	Maximum site uncertainty	Meter	Current Transformer	Maximum metering installation certification validity period	Maximum sample inspection and recertification period	Inspection period
1	V < 1kV	I ≤ 160A	None	NHH or HHR	± 2.5%	0.6%	2	N/A	180 months	84 months	120 months ± 6 months
2	V < 1kV	I ≤ 500A	CT	NHH or HHR	± 2.5%	0.6%	2	1	120 months	N/A	120 months ± 6 months
3	V < 1kV	500A < I ≤ 1200A	CT	HHR only	± 1.25%	0.3%	1	0.5	120 months	N/A	60 months ± 3 months
	1kV ≤ V ≤ 11kV	I ≤ 100A	VT & CT				N/A	N/A			
	11kV < V ≤ 22kV	I ≤ 50A					N/A	N/A			
4	V < 1kV	I > 1200A	CT	HHR only	± 1.25%	0.3%	N/A	N/A	60 months	N/A	30 months ± 3 months
	1kV ≤ V ≤ 6.6kV	100A < I ≤ 400A	VT & CT								
	6.6kV < V ≤ 11kV	100A < I ≤ 200A									
	11kV < V ≤ 22kV	50A < I ≤ 100A									
5	1kV ≤ V ≤ 6.6kV	I > 400A	VT & CT	HHR only	± 0.75%	0.2%	N/A	N/A	36 months	N/A	18 months ± 1 month
	6.6kV < V ≤ 11kV	I>200A									
	V > 11kV	I > 100A									
	V > 22kV	Any current									

METERING DATA



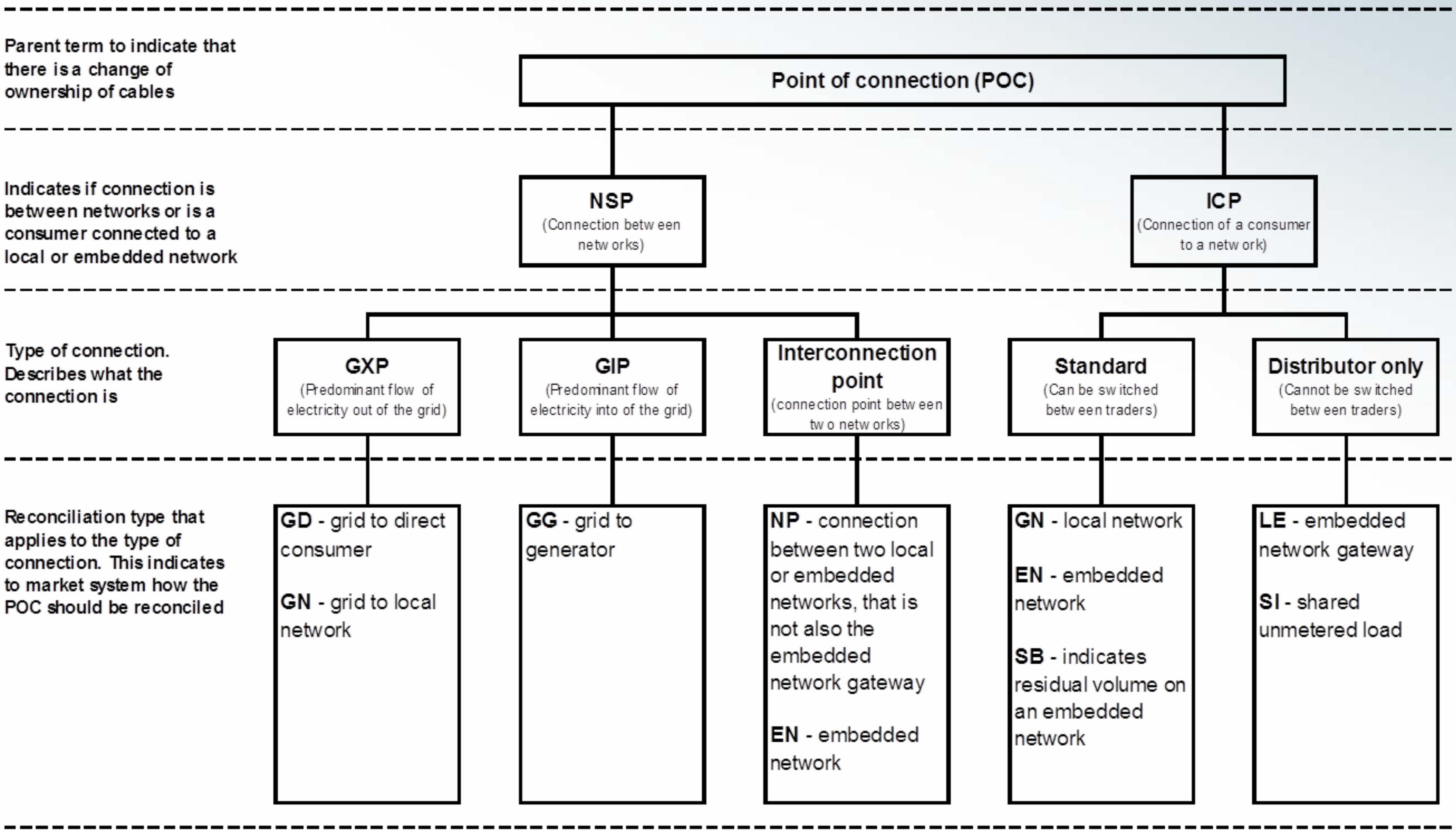
CONNECTIONS AND DISCONNECTIONS

- Distributors
  - authorise “warranted person” that may perform connections to their network on behalf of the distributor
  - cannot energise an ICP without the authorisation of a trader (clause 10.33(4)). This includes Temporary Energisation (for metering certification), although the MEP may give authorisation if they already hold the Trader’s authorisation
  - may de-energise an ICP for safety reasons
  - may decommission an ICP
    - requires advice from the trader to the registry that the ICP is permanently removed from future switching and reconciliation processes (clause 19 + 20 of schedule 11.1)
  - continuance of supply obligations in the Act apply
  - may also be a reconciliation participant for a network interconnection or an MEP, but acts independently for these participant types in the registry
  - must comply with clause 11.2 (accurate registry information)

NEW CONNECTION PROCESSES

- Request/ allocation and commissioning processes are generally proprietary and unique to network operators
- Becomes “standard” when the information is put on the registry
- Required to be done within three business days of the connection being energised.
- Biggest issue is in the dates and times, population of the key dates are required to be the effective date NOT the date the “Paperwork” is received and processed
- Late dates affect Retailer’s energy submissions, ICP Days adjustments, automated claiming (registry rejects a claim that is too early), and consequently the MEP’s ability to lodge metering events with the correct effective dates.

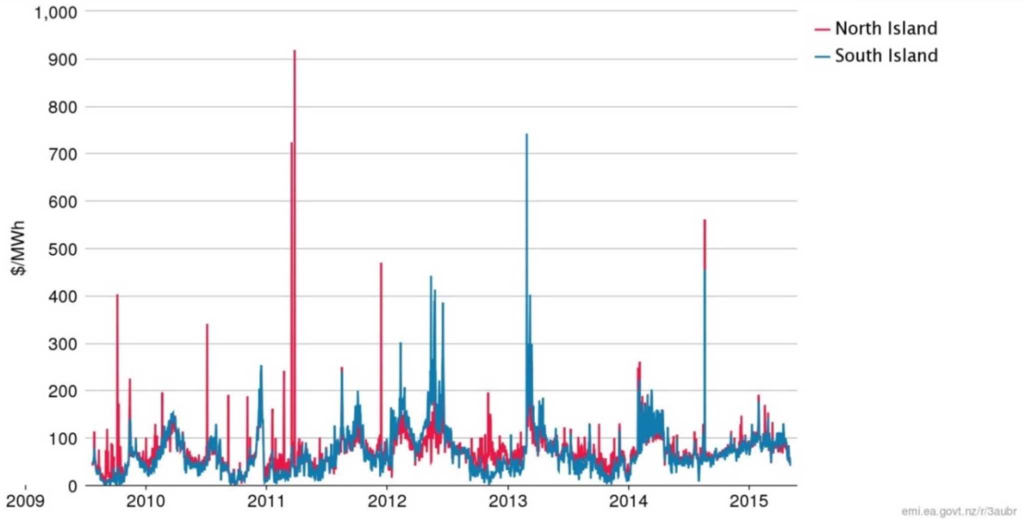
POINT OF CONNECTION (POC)



POINT OF CONNECTION (POC)

- A “point of connection” means a point where electricity may flow into or out of a network
- Where there is a change of ownership of lines, there is a point of connection
- We define points of connection as two types, network supply points (NSPs) or installation control points (ICPs)
- NSPs are points of connection that are either
  - points of connection to the grid, or
  - interconnections between two networks, or
  - embedded network gateways

WHOLESALE PRICE

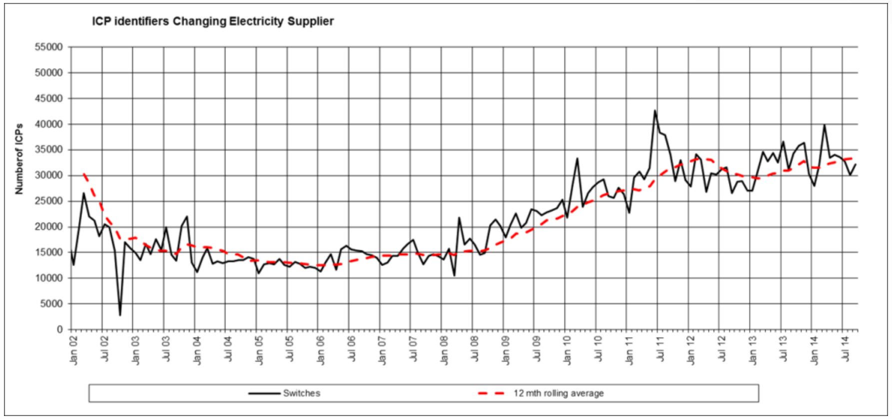


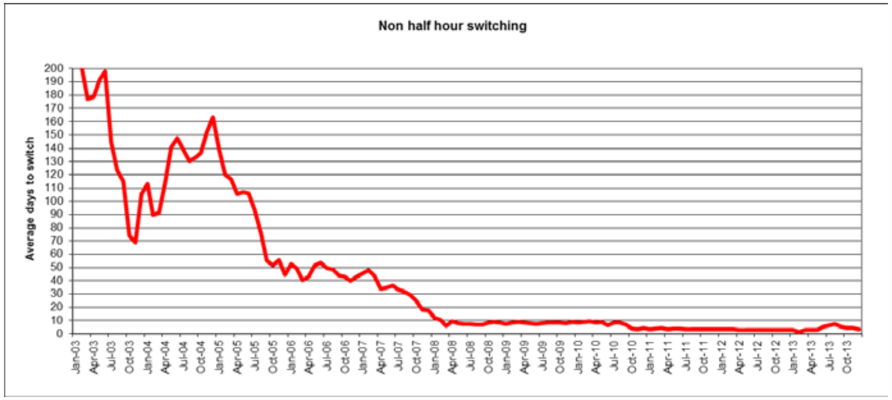
- Wholesale electricity price is determined by a market process
  - Calculated in four stages, forecast, provisional, interim and then final
  - Wholesale price set by highest price generators dispatched to meet demand
  - Prices vary by location, reflecting losses in the grid and grid constraints
  - Demand and supply fluctuations over the course of a day result in price differences in each trading period at each grid connection point
  - Calculated each day for each trading period for 533 nodes but published only 253 nodes. Over 11,000 spot prices are published every day

COMPETITION • RELIABILITY • EFFICIENCY

ELECTRICITY AUTHORITY
TE MANA HIKO

SWITCHING





- Registry manager operates the electricity market database of record
    - Approx 2.08 million ICPs
    - Up to 1500 concurrent users
    - Information contained critical for
    - Consumer invoicing
    - Physical settlement
    - Consumer switching
- Facilitates switch process
    - Consumer switching
    - MEP switching
    - Distributor switching
- Access
    - Web services, web browser, SFTP access
    - File outputs in CSV and XML
- Authority provides an encrypted data hub

INTEROPERABILITY REQUIREMENTS

- Interoperability is essential due to the number of information exchanges that pass between a large number of participants
- Authority provides a data hub for transport of information between participants
- Specified as a mix of regulated, voluntary, and individually negotiated arrangements that include
  - Code
  - MOSP functional specifications
  - Electricity Information Exchange Protocols (EIEPs)
  - Use of system agreements
  - Guidelines

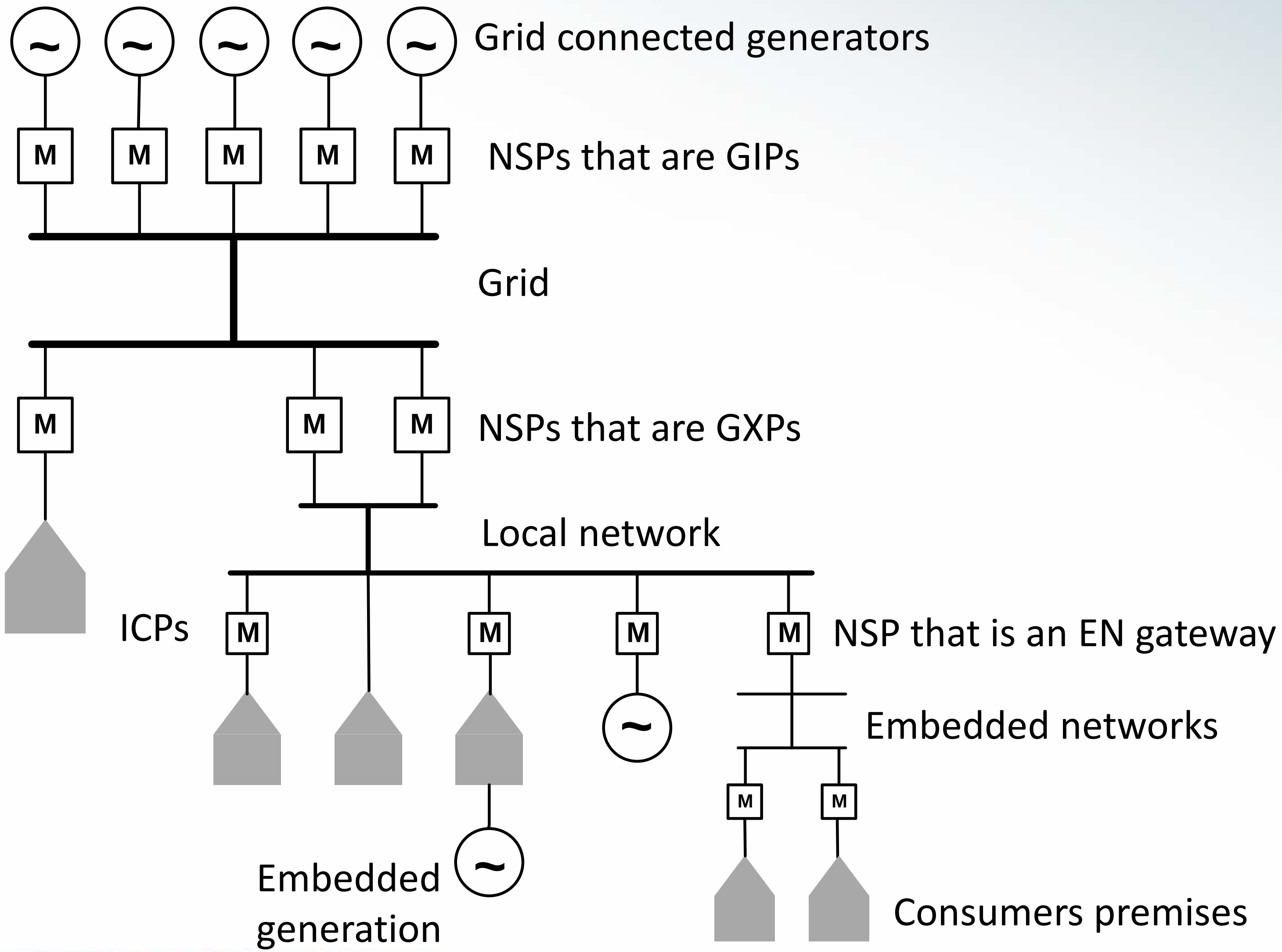
CONNECTIONS AND DISCONNECTIONS

- Distributors
  - authorise "warranted person" that may perform connections to their network on behalf of the distributor
  - cannot energise an ICP without the authorisation of a trader (clause 10.33(4)). This includes Temporary Energisation (for metering certification), although the MEP may give authorisation if they already hold the Trader's authorisation
  - may de-energise an ICP for safety reasons
  - may decommission an ICP
    - requires advice from the trader to the registry that the ICP is permanently removed from future switching and reconciliation processes (clause 19 + 20 of schedule 11.1)
  - continuance of supply obligations in the Act apply
  - may also be a reconciliation participant for a network interconnection or an MEP, but acts independently for these participant types in the registry
  - must comply with clause 11.2 (accurate registry information)

NEW CONNECTION PROCESSES

- Request/ allocation and commissioning processes are generally proprietary and unique to network operators
- Becomes “standard” when the information is put on the registry
- Required to be done within three business days of the connection being energised.
- Biggest issue is in the dates and times, population of the key dates are required to be the effective date NOT the date the “Paperwork” is received and processed
- Late dates affect Retailer’s energy submissions, ICP Days adjustments, automated claiming (registry rejects a claim that is too early), and consequently the MEP’s ability to lodge metering events with the correct effective dates.

PHYSICAL NETWORK CONNECTIONS



POINT OF CONNECTION (POC)