24 JUNE 2015

NETWORKS AND REGULATORY REQUIREMENTS

DISTRIBUTOR WORKSHOP

COMPETITION • RELIABILITY • EFFICIENCY

IN THIS SECTION WE WILL COVER

- Use of systems agreements
- Types of networks
- Measurement
- Points of connection to a network
- Connection/Disconnection process
- Network losses
- Network Pricing
- Embedded generation and Part 6
- Outages

USE OF SYSTEMS AGREEMENTS (UOSAs)

- Use-of-system agreements provide the contractual basis for the relationship between distributors and retailers that trade on the distributors network
- There are two types, conveyance and interposed
- The model UOSA is intended to encourage distributors and retailers to adopt more standardised use-of-system agreements
- Objective is to improve retail competition and efficiency reducing barriers to entry retailers, for the long-term benefit of consumers
- More information is available at http://www.ea.govt.nz/operations/distribution/distributors/use-of-system-agreements/

USE OF SYSTEMS AGREEMENTS

- Part 12A of the Code requires
  - distributors to consult with retailers if it makes a change to its tariff structure that will materially affect traders or consumers
  - distributors and retailers to comply with a standard format for exchanging certain information *(EIEPs 1, 2 , 3 (unless opted out) and 12)*
  - distributors and retailers to negotiate the terms of their use-of-system agreements in good faith, and to enter into mediation when the parties are unlikely to agree to terms
  - unless agreed otherwise by the distributor and retailer UOSA must include an indemnity in favour of retailers in respect of liability under the Consumer Guarantees Act 1993 for breaches of acceptable quality of supply, where those breaches were caused by events or conditions on the distributor's network
  - restrictions on the level of prudential requirements that may be set by a distributor

TRADER DEFAULTS

- There is always a risk that a trader may default
  - Generators are dependent on traders paying for their purchases
  - Distributors may be dependent on traders paying network charges for use of network
- Prudential's are used by networks and the NZEM
- What constitutes a default is set out in cl 14.41 and includes termination of a traders use of system agreement for serious financial breach
- If a default occurs then
  - The clearing manager will recover prudential for NZEM debt
  - The distributor will recover prudential for distributor event

TRADER DEFAULTS

- If a default continues, and if
  - the trader is a retailer, the Authority may, after an 18 day exit period, allocate ICPs to non-defaulting traders
  - The trader is a direct purchaser, the Authority ***<u>may</u>***, after a 7 day exit period, direct the network to disconnect the direct purchaser (cl 14.49(3) and (4))

TRADER DEFAULTS

- Distributors should be aware
  - that by the time that the trader ICP default process is completed, there may be outstanding network charges beyond the prudentials that they hold
  - of the requirements of cl 14.49(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.

THERE ARE DIFFERENT TYPES OF NETWORKS

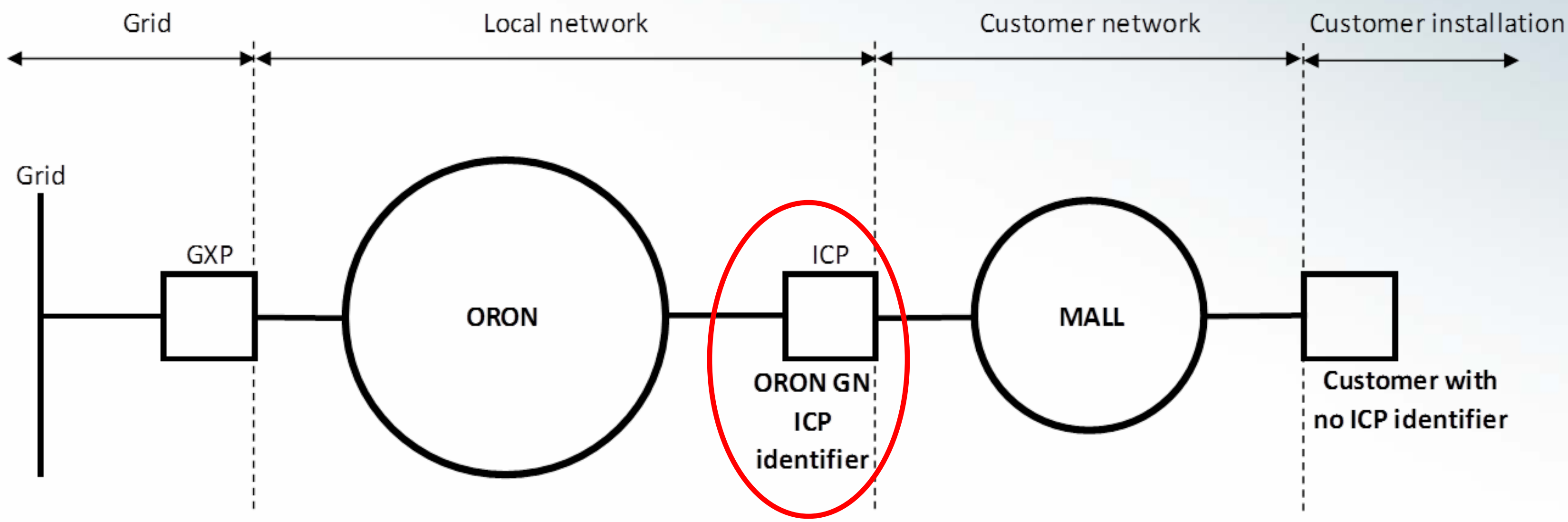
- The grid
- Local networks – networks that are directly connected to the grid
- Secondary networks – networks that are indirectly connected to the grid
  - Customer networks (not mentioned directly in the Code)
  - Network extensions (not mentioned directly in the Code)
  - Embedded networks
- Islanded 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

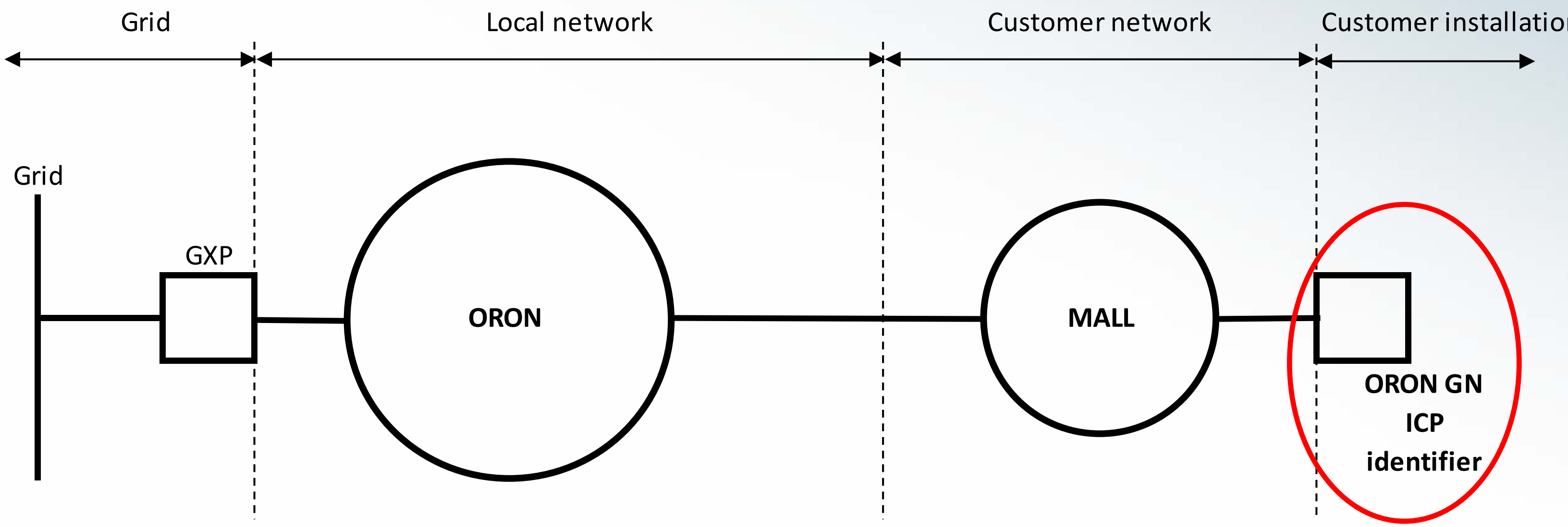
Customer network



- **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

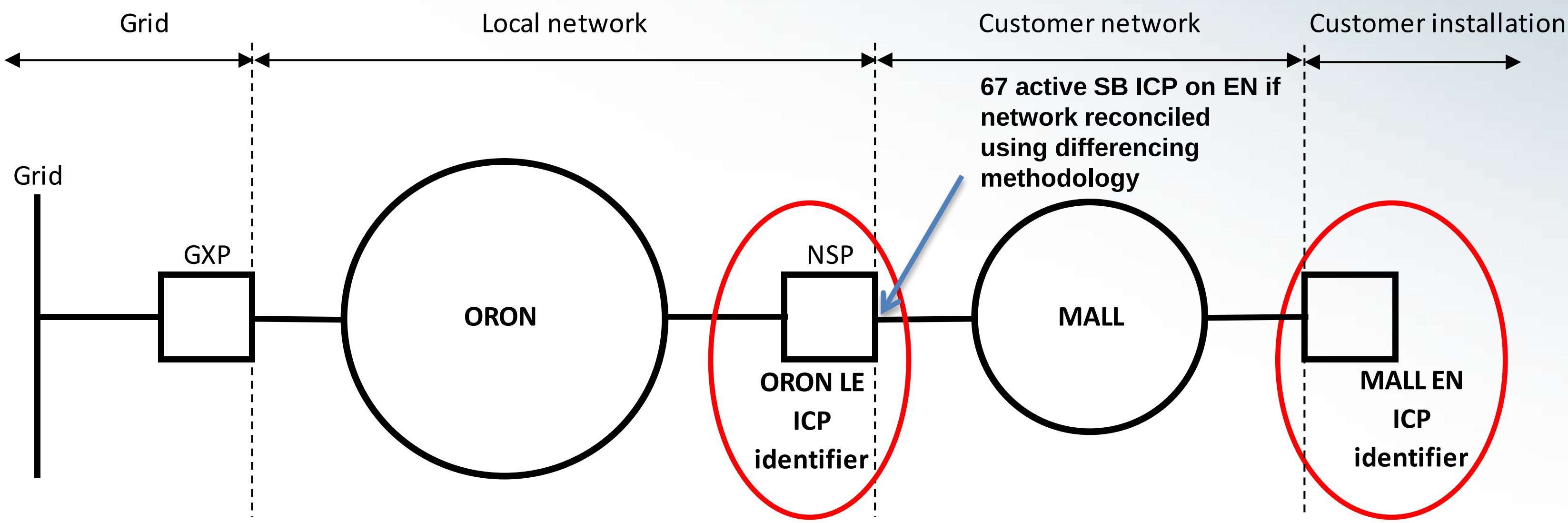
Network extension



- **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

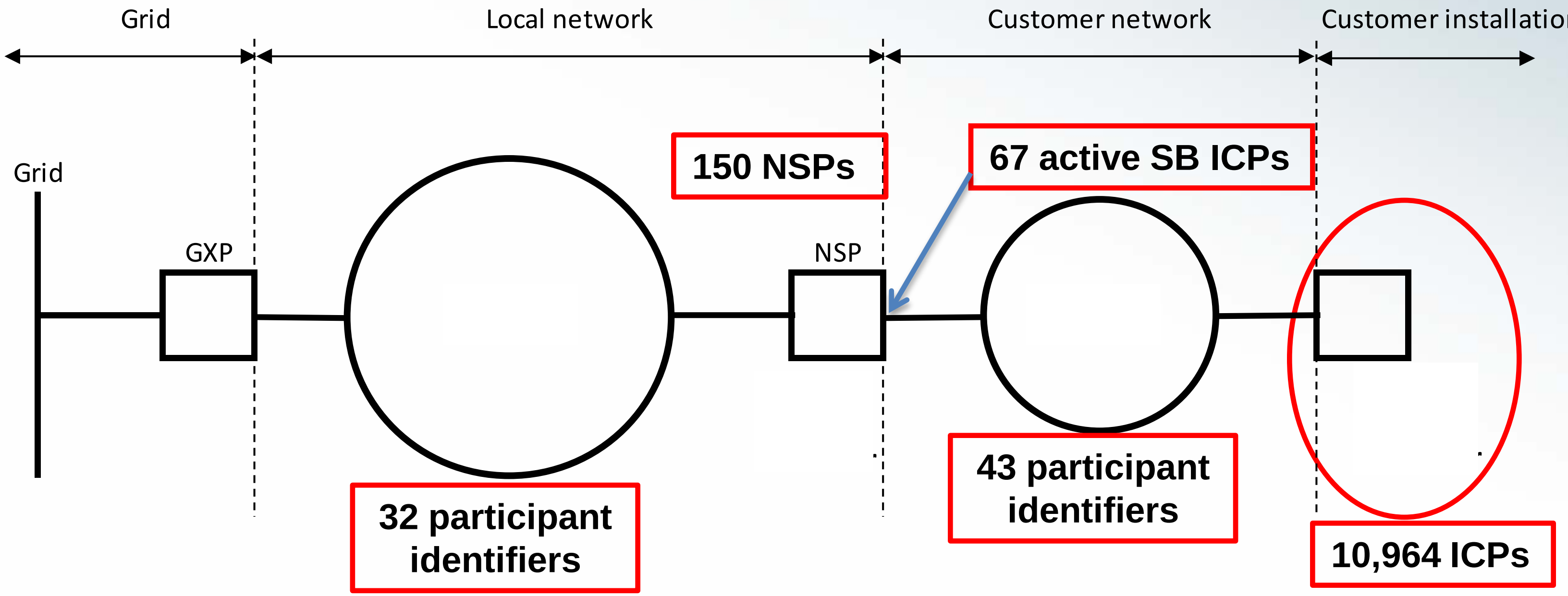
Embedded network



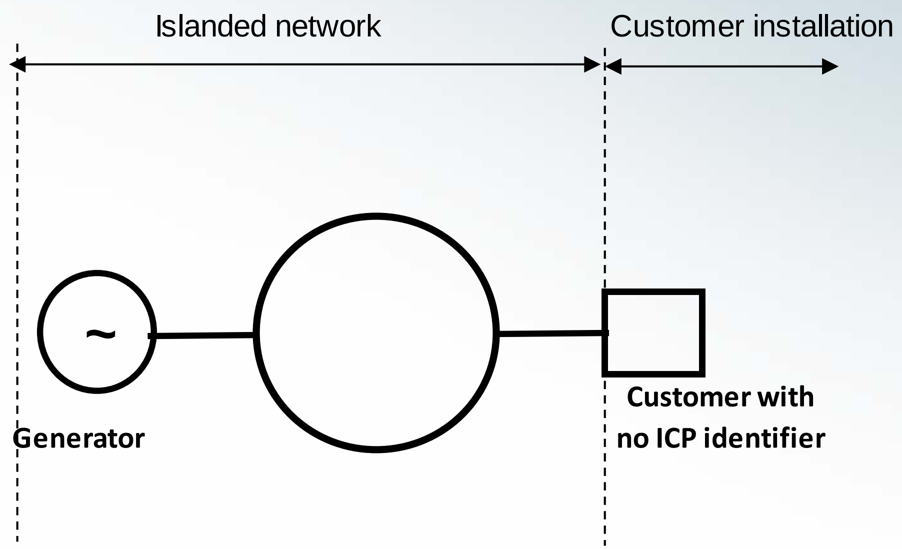
- **ICP identifier within a "privately" owned network**
- Customer network is now called an embedded network
- ICP identifier at the ICP between embedded network and the customer installation
- Registry records show ICP identifier with distributor identifier of MALL and reconciliation type of EN
- Embedded 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

SECONDARY NETWORKS

Embedded network



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

MEASUREMENT AND AUTHORITY OBJECTIVE

EA Statutory objective

- Competition
- Reliability
- Efficiency

EA strategic directions

- Reducing barriers
- Consumer participation
- Efficient price signals
- Flexibility & resilience

MEP

ATH

MEASUREMENT

- Since 1 April 1999 metering has been a workable competitive market
  - metering services are independent of distributor and retailers
  - commercial arrangements required
  - guidelines available at
  - http://www.ea.govt.nz/operations/retail/metering/metering-installation/

- The participant responsible for the electricity flow through a point of connection must ensure there is an MEP
  - trader (retailer) for customer connections to networks
  - grid owner for GXPs
  - generator for GIPs
  - network owners for network interconnection points
  - embedded network owners for gateways NSPs

MEASUREMENT

- Metering equipment providers are a participant that is required to maintain accurate metering installations in accordance with the Code
- NZ has a non-regulated roll out of AMI.
- AMI Guidelines and policy published early 2008, new Part 10 deals with issues of increased functionality and data privacy/security
- Transparency of registry metering records has enabled the Authority to monitor compliance actively

MEASUREMENT

- The Code requires electricity flows to be quantified in accordance with the Code to allow market settlement to occur

- The Code requirements are consumers and the industry's guarantee that information used in invoicing processes is accurate

- The Code places responsibility on
  - traders to ensure that all ICPs they trade have an MEP
  - local network owners that all network interconnection points that they initiate have an MEP
  - embedded network owners that all gateway NSPs and network interconnection points that they initiate have an MEP
  - Grid connected generators that their GIPs to the grid have an MEP
  - Grid owner to ensure that all its GXPs have an MEP

MEASUREMENT

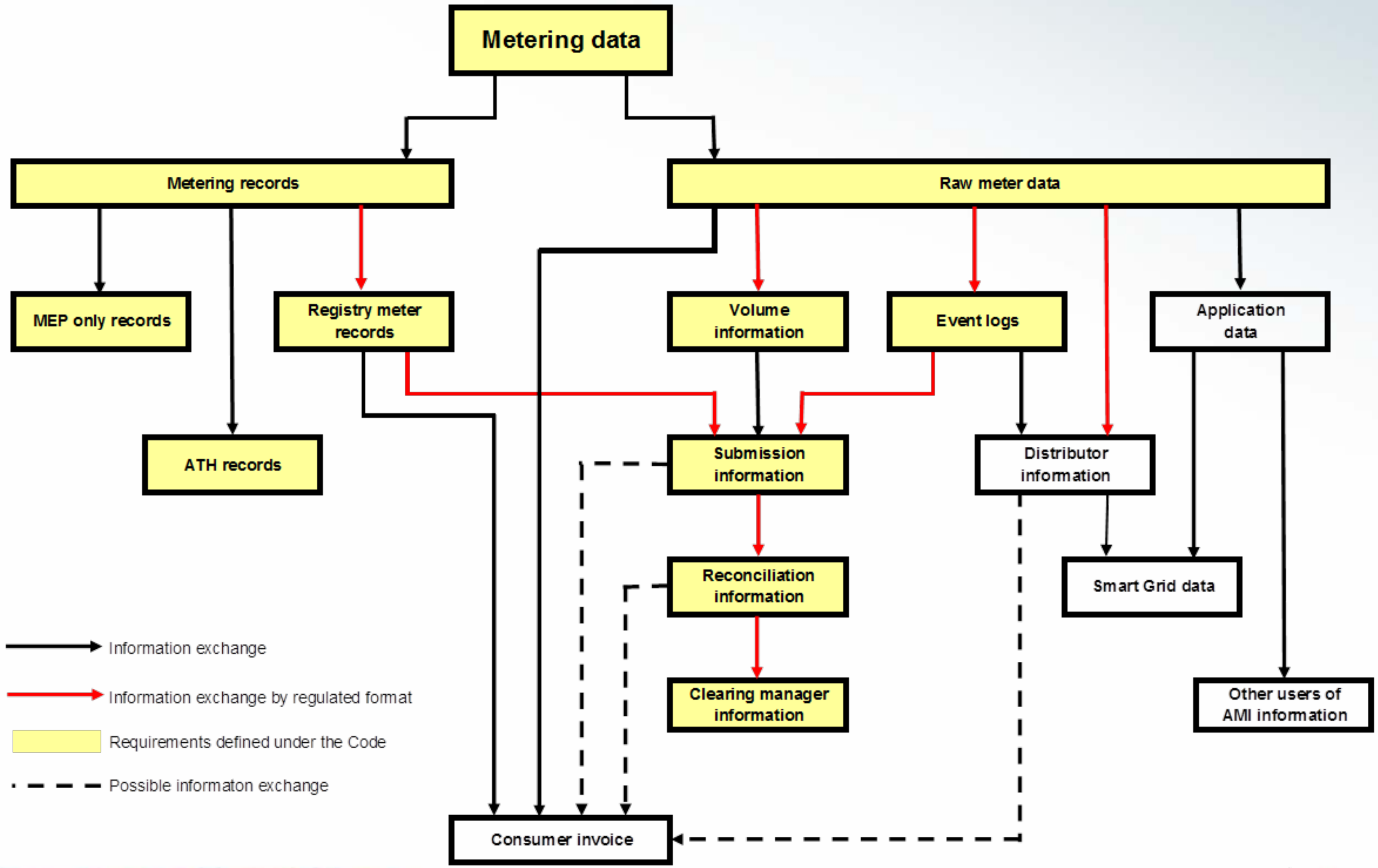
- ATHs are contracted by MEPs to certify metering installations
- MEPs are required to populate registry metering records
- Metering installation may be certified as either non-half hour (NHH) or half hour (HHR)
    - HHR meters may provide both NHH and HHR information into the reconciliation process
    - NHH meters may provide only NHH information into the reconciliation process
- Difference is testing requirements and ability to obtain meter readings
- Testing requirements also vary with the metering category (capacity) of the metering installation

TYPES OF METERING INSTALLATIONS

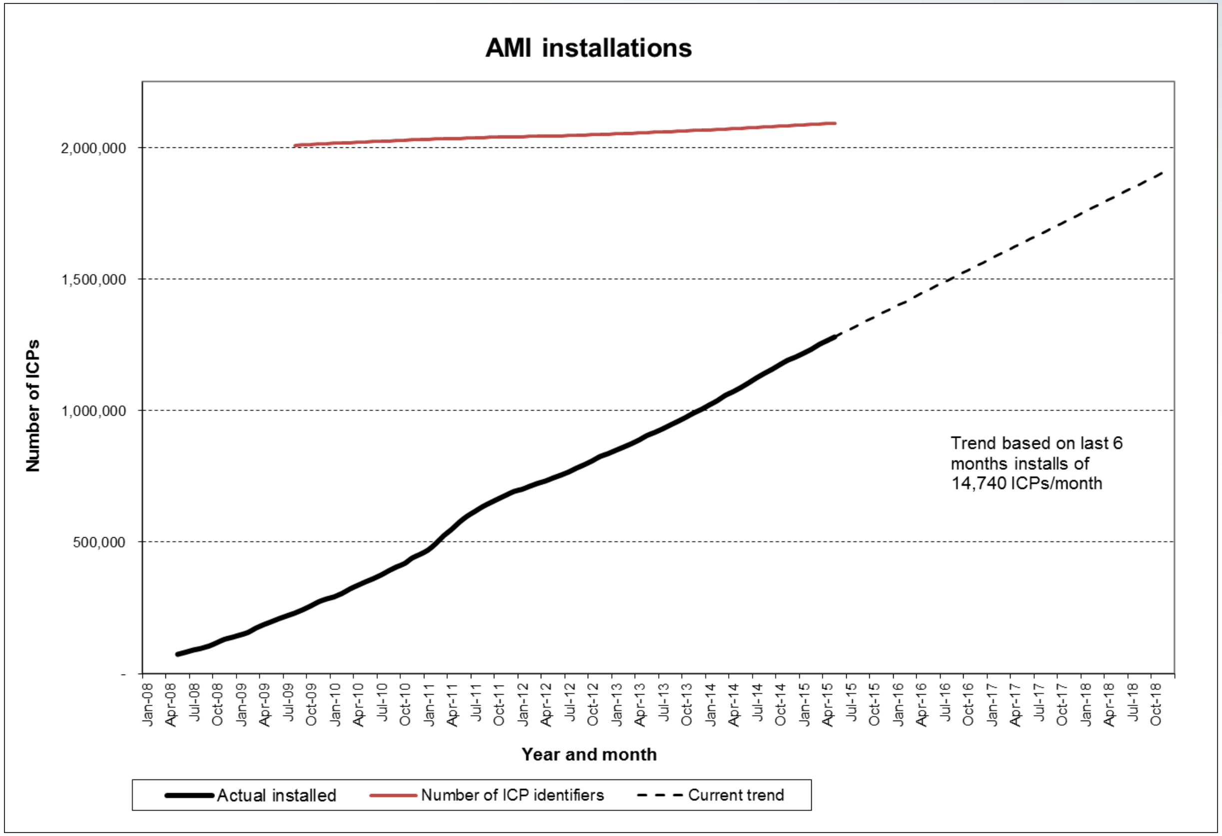
Table 1: Metering installation characteristics and associated requirements

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



AMI ROLL OUT



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

WHAT YOU NEED TO KNOW

- MEPs are enduring until replaced or an ICP is decommissioned
- MEPs are audited to ensure compliance with Code requirements
- MEPs are required to check their designs for metering installations with distributors
- Distributors can be, and some are, MEPs
- The Code does not prevent a distributor from contracting information with MEPs
- Registry metering records are required to be 100% accurate
- Registry metering records should align with EIEPs until such time that traders start time blocking half hour data
- All metering installations are now required to be certified

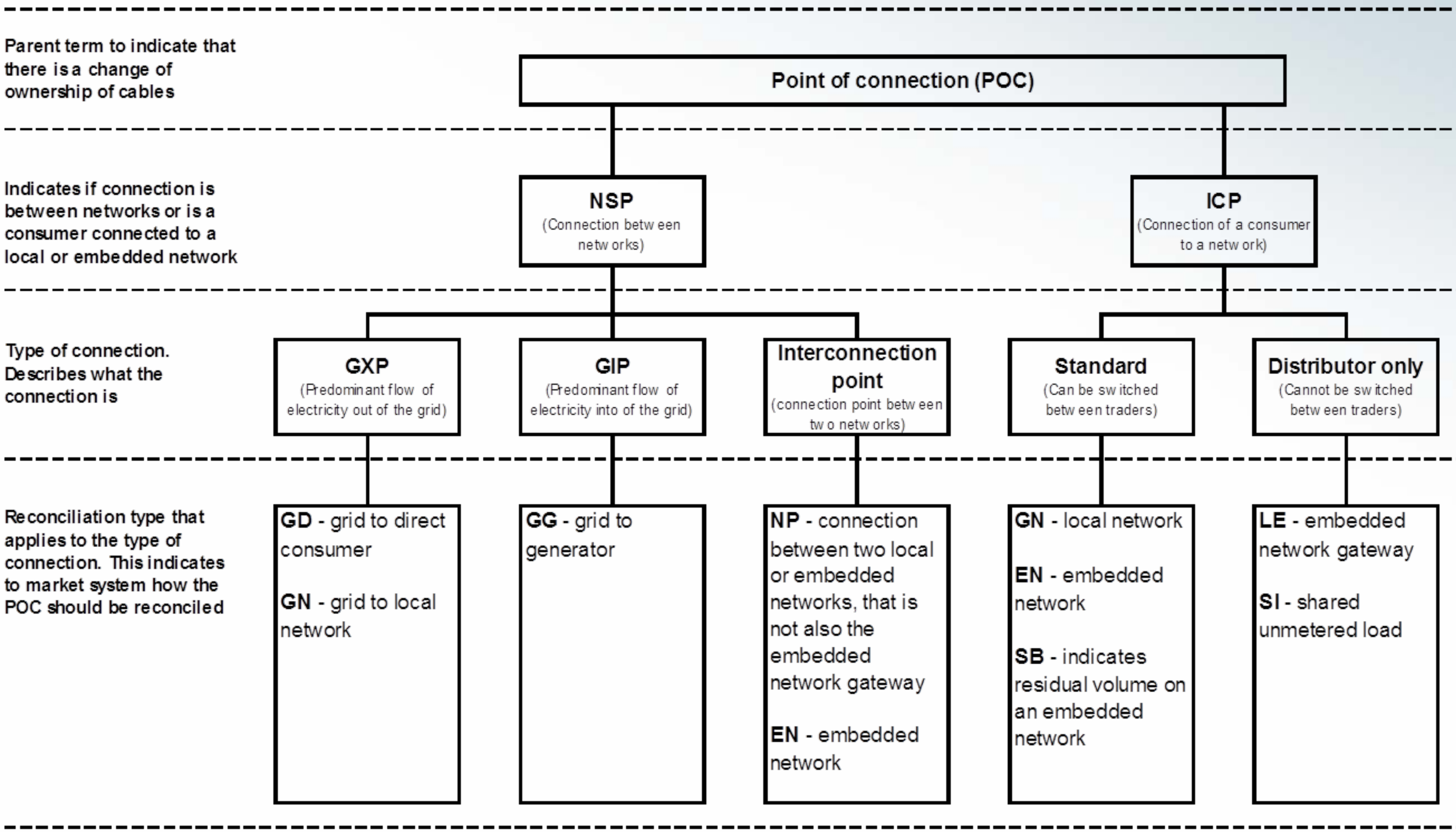
CONNECTIONS AND DISCONNECTIONS

- 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

POINT OF CONNECTION (POC)

- ICPs are points of connection between a local or embedded network and a consumer or a generator
- The Code requires the distributor to create an ICP identifier in the registry for ICP on its network
- An ICP identifier
  - is unique to a point of connection
  - comprises a 10 character number, 2 character identifier unique to the distributor (Authority assigned), and a 3 character checksum
- There are 3 types of ICP identifier
  - standard
  - shared unmetered
  - distributor only

DEDICATED ICPS

- If an ICP is located in a balancing area that has more than 1 NSP located within it, and the ICP will be supplied only from that particular NSP, or the ICP is a point of connection between a network and an embedded network, the ICP must be designated as "dedicated"
- The Reconciliation Manager uses the Dedicated NSP status as a priority order when moving volumes between NSP s to achieve balance
- Unnecessary setting of the dedicated NSP flag to "Y" causes Retailers Pain!

BALANCING AREAS

- Collection of NSPs where load can be supplied from more than one of those Set by the Distributor
- Used by the Reconciliation Manager to mitigate the effects of energy being supplied to ICPs by different NSPs over time.
- Ring feeds, cross connections, emergencies, load shifting – normal day to day network operations.
- Affects seasonal adjustment (shifting of NTOU load between months) and can create unnecessary UFE.
- Review by looking at Volume history for your NSPs (GR050 from RM) or GR120 UFE Factors

NETWORK LOSSES

- A proportion of energy conveyed in networks is lost. Reconciliation loss factors are used to adjust for losses

- Overall loss factor is made up of two components, technical and non technical
  - "**technical loss factor**" – represents fixed component that arises from standing losses in components and arising from the heating effects of the resistance in the delivery conductors
  - "**non-technical loss factor**" - represents losses due to errors in metering measurement, meter reading, theft, and inaccurate data handling

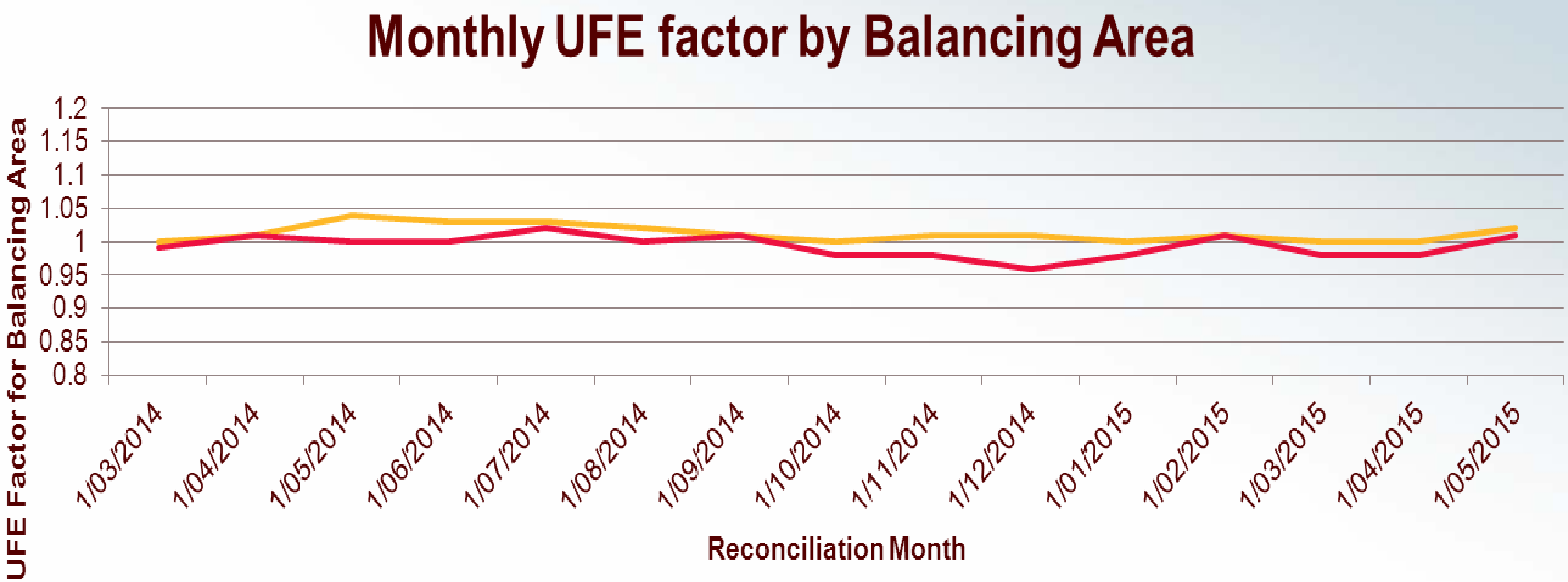
- Any difference between volume supplied from the grid to the Balancing area (NSP) and loss adjusted submissions is UFE

NETWORK LOSSES

- In NZEM, all electricity is bought and sold at GXPs and GIPs, network losses are necessary to adjust volumes to the market clearing point
- Consumers ultimately pay for all network losses. Average was estimated at 5.4% in 2011 but significantly varies between networks
- UFE calculation compensates for losses that are too high or too low at the trading period level
- UFE on some networks is excellent, on other, not so
- Transparency of network losses is necessary so that traders may calculate retail price

NETWORK LOSSES

- UFE is apportioned to all participating retailers on that balancing area pro rata with their loss adjusted submissions.
- May be inequitable (single large customer)
- May affect GXP billing calcs
- Incorrectly set loss factors send wrong signals to retailers who need them to correctly assess energy cost.
- Distributor has an obligation to reassess their loss factors and set appropriate factors
- You can do this by reviewing the GR-120 data file supplied by the RM


Monthly UFE factor by Balancing Area
UFE Factor for Balancing Area
1.2
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
1/03/2014
1/04/2014
1/05/2014
1/06/2014
1/07/2014
1/08/2014
1/09/2014
1/10/2014
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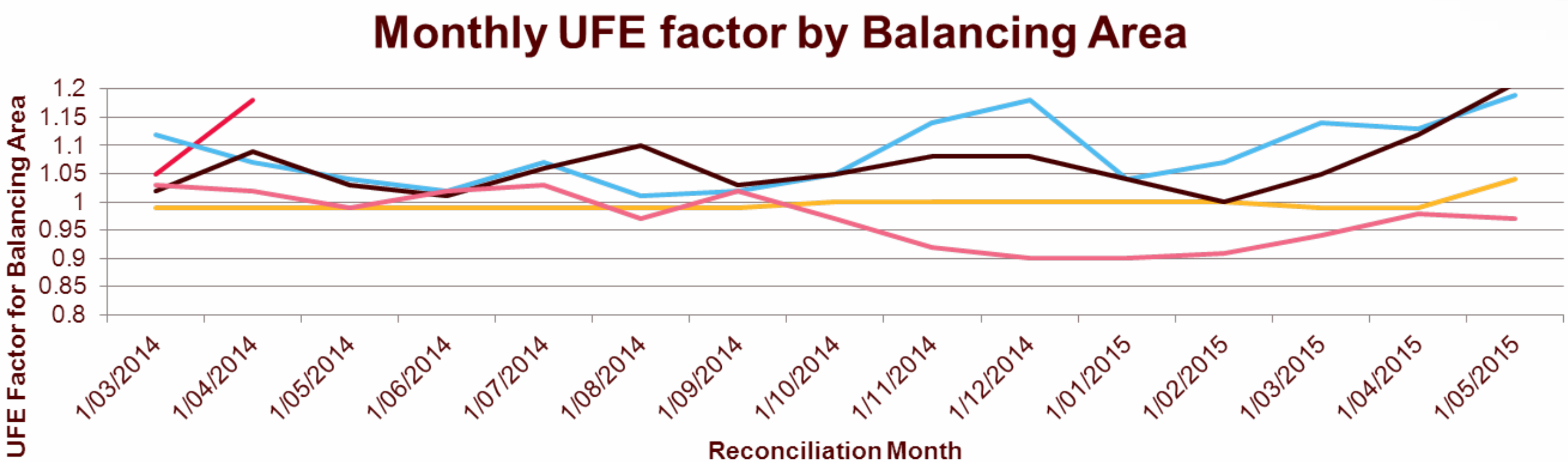
1/05/2015
Reconciliation Month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1/08/2014
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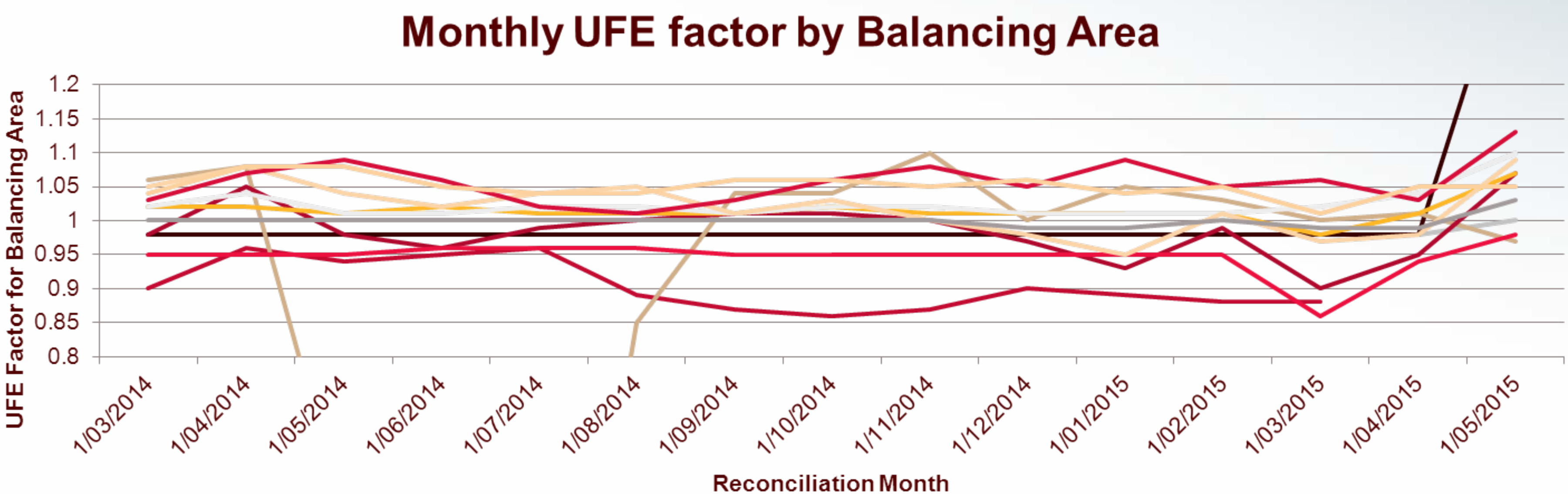
Reconciliation Month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1/06/2014
1/07/2014
1/08/2014
1/09/2014
1/10/2014
1/11/2014
1/12/2014
1/01/2015
1/02/2015
1/03/2015
1/04/2015
1/05/2015
Reconciliation Month

THERE ARE GUIDELINES ON LOSS FACTORS

- The key components of the proposed updated Guidelines are
  - a structure for considering different voltage levels and network segments within a network study area
  - a description of appropriate datasets to use in the calculations
  - a description of the calculation methodology for each network segment
  - generalised assumptions for use in determining the impact on losses of low voltage connections. This is supported by analysis carried out by Hyland McQueen Limited
  - a methodology for determining site-specific loss factors for larger loads and/or embedded generation
  - a description of how to collate results to calculate overall technical loss factors
  - a description of how to take technical loss factors and convert these to reconciliation loss factors
  - an example workbook for collating and reporting results
  - a recommended frequency for review of loss factors within each network area

NETWORK LOSSES

- The Code requires distributors to
  - determine loss factors on their networks
  - populate “loss category codes” on every ICP identifier in the registry
  - assign a unique loss category code to all generators 10MW and greater
  - populate “loss factors” into a registry static data table
- The Code also requires
  - traders to provide submission information to the reconciliation manager which is volume information aggregated by certain criteria including loss category code
  - the reconciliation manager to allocate network losses to trader volumes, which are then used by the clearing manager to calculate invoices for participants

NETWORK LOSSES

- Change of loss factor or loss category code has an impact on
  - traders back office system that assemble submission information
  - traders retail prices that are passed to consumers and generators
  - traders wholesale market settlements
  - calculation of Authority levy
- Consequently
  - Code and the UOSA requires notification to traders two months before a change
  - More in the registry later

NETWORK PRICING

- Distributors set prices for the conveyance of electricity on its network
- Price comprises a number of components, increasing in complexity as the consumer connection increases in capacity
- There are two fundamental pricing methodologies
  - *ICP based pricing where the distributor price is applied at the ICP itself*
    - effectively network losses and UFE is applied to the price and not the volume
    - network owner carries volume related risks
  - *GXP based pricing* where the distributor price is applied to a volumes referenced to the networks GXP
    - effectively network losses and UFE is applied to the volume and not the price
    - trader carries volume related risks
- There are variations

NETWORK PRICING

- We don’t exactly know how many distributor tariffs there are, but work we did suggested in the order of 1500 nationally
- The variety and number of tariffs is challenging to retailers

ELECTRICITY (LOW FIXED CHARGE TARIFF OPTION FOR DOMESTIC CONSUMERS) REGULATIONS 2004

- Introduced in 2004 with the objective of
  - ensuring that retailers offer a low fixed charge (LFC) tariff option (LFC option) or options for delivered electricity to domestic consumers at their principal place of residence that will assist low-use consumers and encourage energy conservation
  - regulate distributors so as to assist retailers to deliver LFC options
- Each LFC option that a retailer makes available must be either
  - bundled LFC option (by which the retailer charges the consumer directly for the electricity supplied to the home); or
  - split charging LFC option (by which the distributor charges the consumer directly for some services to supply the electricity to their home, and the retailer charges the consumer directly for the rest of the electricity supplied to the home)

ELECTRICITY (LOW FIXED CHARGE TARIFF OPTION FOR DOMESTIC CONSUMERS) REGULATIONS 2004

- Regulations require that a LFC option has two components:
  - fixed charge levied for each customer connection cannot exceed 30 cents per day excl GST and prompt payment discount
  - variable charge that varies according to the amount of electricity consumed

- Variable component set so that the average consumer pays no more than on any alternative tariff option

- Trader may only recover charges using a fixed charge, a variable charge(s) and any fees for special services

ELECTRICITY (LOW FIXED CHARGE TARIFF OPTION FOR DOMESTIC CONSUMERS) REGULATIONS 2004

- Two zones for average consumer, 8,000 kWh of electricity per year for any consumer but rising to 9,000 kWh per year if the consumer's home is south of Arthur's Pass

- The electricity retailer must advertise a low fixed charge tariff option at the same time, and in the same manner, as it advertises an alternative tariff option

- If a distributor has a tariff that includes a fixed charge component, it must be capped at no more than 15 cents per day (excluding GST and prompt payment discounts)

ELECTRICITY (LOW FIXED CHARGE TARIFF OPTION FOR DOMESTIC CONSUMERS) REGULATIONS 2004

- Notice must
  - identify the amount of electricity the electricity retailer has sold to the domestic consumer during the previous 12 months
  - explain that, if the domestic premises are the consumer's home, a low fixed charge tariff option is available
  - explain there may be benefits for the consumer in being on a low fixed charge tariff option if the consumer uses less electricity per year than the average consumer uses
  - set out the main features of each of the current low fixed charge tariff options that the electricity retailer makes available to homes in the supply area in which the domestic premises are located

ELECTRICITY (LOW FIXED CHARGE TARIFF OPTION FOR DOMESTIC CONSUMERS) REGULATIONS 2004

- The Regulations also require
  - retailers to promote LFC options to each consumer at least once in every 12 months
  - retailers and distributors to supply the Authority with
    - information regarding a LFC option 15 working days before the date any new LFC option takes effect.
    - schedule of tariff options that the retailer or distributor makes available to homes in its supply area

PRICING SCHEDULES

- Distributors agree under their UOSA to provide pricing schedules to traders
- Would be good if the pricing schedules included register content code and period of availability as eligibility criteria for a tariff
- Part 12A of the Code requires distributors to consult with traders prior to amending a tariff structure
- The distributors UOSA will normally require 2 months of a confirmed price change to allow for
  - Traders to recalculate their retailer rates
  - Give 1 months notice to their consumers of a price change

DISTRIBUTED/EMBEDDED GENERATION

- Distributed generation is generation being connected directly to local networks rather than the national grid (Embedded generation elsewhere in the Code)
- Encompasses a range of technologies and scales from small-scale photovoltaic modules to large wind farms
- Since 1 May 2008, the Code has encompassed switching and reconciliation of embedded generation (no different to trading consumption) (ICPs are bi-directional)
- Part 6 of the Code
  - mandates the application and approval process between the prospective generator and the distributor
  - details default terms of connection
  - details the dispute resolution process pricing principles and information disclosure guidelines (though the parties can contract out of these by mutual agreement)

DISTRIBUTED/EMBEDDED GENERATION

- We monitor the compliance of distributors and generators under Part 6 and, where appropriate, take enforcement action
- In some circumstances we also have a role in dispute resolution between generators and distributors
- The Authority provides 3 relevant documents on its web site
    - Guideline for the connection of small scale distributed generation (equal to or less than 10 kW) to a local network
    - Guideline for a connection of distributed generation (greater than 10 kW) to a local network
    - Information sheet on distributed generation

DG WEB SITE INFORMATION

- Each distributor must provide on its website
  - suitable guidance documentation for connection of distributed generation, including the distributor’s:
    - application forms where applicable6
    - connection and operation standards
    - fees
    - regulated terms for connection and information on how the regulated terms apply if the parties do not enter into a connection contract
    - interruption and curtailment policies
    - contact information

DG WEB SITE INFORMATION

- an up-to-date list of
  - the make and model of every inverter the distributor has previously approved for connection to the network which should identify the specific AS 4777 edition that was used for conformance testing of each approved inverter (e.g. AS 4777-2005)
  - all specific locations on its network that are currently known to be subject to export congestion (or that are reasonably expected to become subject to export congestion within the next 12 months) and, hence, unable to accept additional export of electricity from distributed generation connections at specific times
  - export-congested parts of their networks. This identification should include reference to districts, suburbs, feeders, streets or street addresses (as may be relevant) so as to clearly indicate that a point of connection of distributed generation to the network may be subject to export congestion restrictions