

EC Forum on Model Approaches to Distribution Pricing

June 2009



Session

- Explain Aurora UoS Pricing and fit with the Retail Model Approach
- Discuss how we transitioned a Demand tariff structure to Aurora standard structure
- Some interim comments on aspects of the consultation paper.

Opening Comments

- Whilst Aurora pricing is based upon the Retail model, Aurora believes in choice and there should be model approaches
- Aurora not aware of any evidence which says Retail provides better outcomes compared to Wholesale for asset utilisation

Aurora Pricing Objectives

- Obtain sufficient revenue to
 - Meet transmission costs
 - Meet distribution operation & maintenance costs
 - Comply with statutory requirements on public safety, environmental matters & quality of supply
 - Provide an appropriate return on funds

Aurora Pricing Objectives (2)

- Efficiency
 - Promote efficient investment in and operation of network by correctly signaling fixed and variable costs of delivery - improve network utilisation
 - New or increased connections need to be economic based on future income from the new connection plus others need to make contributions towards the use of upstream assets.
- Fairness
 - Recover costs fairly with respect to all users of network

Standard Aurora Pricing Methodology

- Has evolved over the years
 - ESANZ “Guide to Derivation of Line Charges”
 - MED “Electricity Disclosure Guidelines”
 - PAWG work
- Publicly disclosed in Aurora document “Use of System Pricing Methodology” available from Aurora website at www.auroraenergy.co.nz

Pricing Areas

- 3 Pricing areas based upon the markedly different cost drivers using the ratios below
- Distribution - \$ORC/MW of demand
- Transmission - \$/MW of demand
 - Dunedin GXPs – average transmission cost – low distribution cost
 - Frankton GXP – hi transmission cost – medium dist cost
 - Clyde & Cromwell GXPs – average transmission cost – very high distribution cost

Most Network Costs are Asset Specific

- Costs are collected and allocated to the main groups of network assets and by area - Dunedin, Central (Frankton and Cromwell/Clyde)
 - Subtransmission 66 & 33 kV Lines & Cables
 - Zone Substations 33/11 kV or 33/6.6 kV
 - HV Lines & Cables 11 kV or 6.6 kV
 - Distribution Substations
 - LV Lines & Cables

Load Groups

- Network connection points are placed in load capacity groups eg Unmetered 1 kVA, 8-15 kVA, 16-149 kVA, 150-249 kVA, 250 to 499 kVA, 500 to 2499 kVA, 2500+ kVA, Street Lighting.
- Costs are allocated to load groups on basis of use of different assets and on each groups mix of anytime maximum demand and congestion period demand in line with model
eg HV consumers do not pay for LV costs

Distribution Components of Delivery Charges

- Fixed \$
- Capacity \$ / kVA Transformer kVA, Circuit Breaker setting or Fuse size
- kVA - Km Product of Capacity and km from connection to Transpower grid exit point for large connections with capacity > 150 kVA
- Congestion Period Demand kW - \$ / kW
Average kW at peak network loads during dynamic congestion period
- Dedicated asset charge \$ may apply

Transmission Costs

(approx 19% of delivery costs)

- Connection Charges

Recover Transpower costs relating to grid exit point assets – dedicated spur lines

- Interconnection Charges

Recover Transpower core grid costs using top 100 half hour demands

Recover avoided interconnection charges paid to embedded generators

Transmission Components of Delivery Charges

- Capacity \$ / kVA based on transformer kVA, circuit breaker or connection fuse size

- Congestion Period Demand kW - \$ / kW
 based on average kW at peak network loads – same dynamic congestion period as distribution

Standard Structure in both Dunedin & Central Otago

A) **Non Domestic and Non-Standard Domestic**

Applies to all connections except Std Domestic

Five main load groups L1 to L5

6,000 connections

Central Otago

6,700 connections

Dunedin

Charge structure components

- Fixed, Capacity kVA, kVA-km, Congestion Period kW (posted prices with dynamic congestion period) as discussed earlier

A.3 STANDARD CONNECTIONS

Per Annum

	Registry Code	Load Group	Capacity kVA	Fixed \$	Capacity \$/kVA	kVA-km \$/kVA-km	Congestion Period \$/kW
Distribution	SH0	L0	0 - 1	\$102.51			
	SH0A	L0A (note 5)	0 - 2	\$212.82			
	SH1A	L1A (note 6)	0 - 8	\$9.89	\$12.98		\$81.97
	SH1	L1	0 - 15	\$9.89	\$11.53		\$81.97
	SH2	L2 (note 8)	16 - 149	\$19.40	\$16.69		\$73.14
	SH3	L3	150 - 249	\$388.00	\$23.84	\$0.27	\$57.01
	SH3A	L3A	250 - 499	\$388.00	\$22.02	\$0.27	\$57.01
	SH4	L4 (note 9)	500 - 2499	\$970.00	\$12.48	\$0.27	\$44.80
	SH5	L5 (note 9)	2500+	\$970.00	\$7.10	\$0.27	\$28.61
Transmission	SH0	L0	0 - 1	\$53.65			
	SH0A	L0A (note 5)	0 - 2	\$116.05			
	SH1A	L1A (note 6)	0 - 8		\$3.02		\$68.20
	SH1	L1	0 - 15		\$2.18		\$68.20
	SH2	L2	16 - 149		\$1.68		\$68.20
	SH3	L3	150 - 249		\$3.82		\$66.93
	SH3A	L3A	250 - 499		\$3.82		\$66.93
	SH4	L4	500 - 2499		\$3.73		\$66.93
	SH5	L5	2500+		\$4.31		\$66.93

Standard Structure in both Dunedin & Central

B) Standard Domestic

Applies to connection with capacity L1 (8 or 15 kVA)

21,600 connections

Central Otago

46,400 connections

Dunedin

Charge Structure – to met Low Fixed Charge Regs

- Low fixed charge per ICP
- Variable c/kWh charge based on register contents provided by the retailer metering configuration at ICP

A.1 - STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum		
			Distribution	Transmission	
Fixed Annual Charge (15 kVA)		SHSD15	\$54.73		
Fixed Annual Charge (8 kVA) (note 6)		SHSD8	\$15.00		
Uncontrolled Variable Charges		Tariff Code	(¢/kWh)		
General Purpose	All day Summer	010S	4.92	1.10	
General Purpose	All day Winter	010W	5.40	3.62	
Controlled Variable Charges			(¢/kWh)		
General Purpose + 16 hour water heat	All day Summer	017S	2.69	1.33	
General Purpose + 16 hour water heat	All day Winter	017W	3.96	2.07	
Night + 3 hours	11 hour service	024	1.46	0.50	
Night rate	8 hour service	028	0.56	0.00	

Combination of capacity charge and congestion period demand charge structure provides strong incentives

- Size capacity (the size of the electrical pipe) to meet anytime maximum demand
- Meter as much load “off peak” as possible – balance against creating anytime peaks
- Spread consumption over as many hours as possible – this improves the load factor of the installation and connections with a better than average load factor will have lower energy delivery costs on a cents per kWh basis

Connections with capacity greater than 150 kVA

These connections generally large (ie sophisticated) enough for consumer to look after themselves. They make the choice when they wish to be controlled and what load will be controlled rather than be controlled by network.

Dynamic Congestion Period Demand Signal

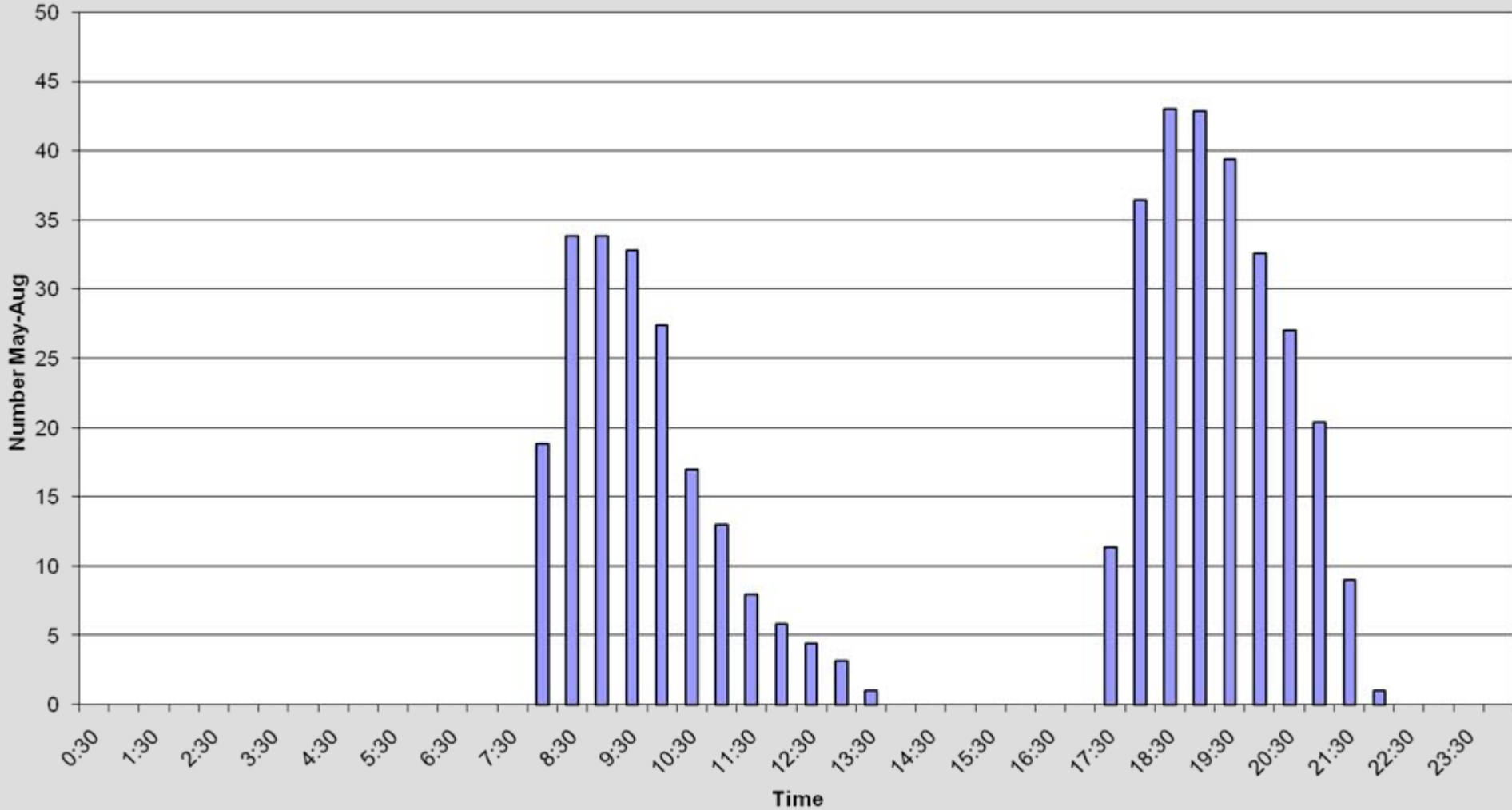
Likely to occur on

- Cold winter days 8am – 12 pm & 5pm to 10.00 pm
- May to September with most activity June & July
- Total hours on 150 to 250 per year

Dynamic Congestion Period Demand Signal

- Signal sent via ripple control - isolated relay contact can be used by consumer to
 - operate a warning device
 - input into a load management system or BMS
 - directly control deferrable load
 - start up a standby generator
 - Email and SMS messages of status sent to consumers – status on website
- See <http://www.auroraenergy.co.nz/content/demandmanagement.php> for more detail on congestion periods

Typical Congestion Period Hours



Under 150 kVA capacity connections

Off peak retailer tariff options currently available for calculation of lower effective CPD kW

- 8 hour service uncontrolled or controlled loads - “kWh discount” = 100%
any night rate metered load
- 11 hour service controlled loads - “kWh discount” = 75%
normally nightstore heating but can be any load
night hours plus 3 hour day boost
- 13 hour service controlled loads - ‘kWh discount’ = 60%
normally under floor heating but can be any load
night hours plus 3 two hour day boosts
- 14 hour service controlled loads ‘kWh discount’ = 100%
“Irrigation control” regime but can be any load
night hours plus ON 11am to 3pm and on at 9pm
- 16 hour service controlled loads - ‘kWh discount’ = 50%
normally water heating but can be any load
target maximum of 8 hours control – normally less than 4 hours

Transition of Price Structure

- Used in transitioning the Central Electric pricing to Aurora standard capacity pricing
- CE Structures
 - HHR metered – Demand tariff
 - Distribution
 - Fixed annual charge (small)
 - Annual Demand charge \$/kW per mth – demand reset monthly
 - Variable c/kWh
 - Transmission
 - Annual Demand charge \$/kW per month – Demand reset annually after winter
 - Profile metered – small fixed charge - variable c/kWh

Why Change

- Inconsistent with Dunedin area pricing – added complexity to our processes
- Existing structure recovered insufficient from some seasonal loads such as irrigators and fruit packing houses, holiday homes, large
- Demand structure over recovered for some connections, frequent requests for dispensations for single high peaks in a month
- Revenue stream was less predictable being so dependent on variable kWh
- Low load factor 50% due to seasonal high loads for skiing and July school holidays

Process Steps Taken

- From 1999 – began process of improving the information base of phases/ fuse size/ transformer size supplying each ICP
- Concentrated on high usage ICPs
- Grandfathered some small kWh usage multiphase ICPs as if they were single phase
- Installed two rate meters on ICPs above 150kVA if not HHR metered to collect congestion period usage during congestion period. (Fewer issues with meter compliance 2000)
- Added congestion period ripple channel to operate when managing load in Central Otago areas

Process Steps Taken

- 2001 – Introduced capacity based pricing structure for new connections in Central Otago
- 2001 and 2002 consulted with retailers re transition process for existing connections, kept improving the information data base
- All agreed that transition should be over 2 or 3 years. Aurora settled on a period of 3 years

Transition Structure

- Standard capacity based pricing modified as follows commenced 2003
 - Full fixed charge and congestion period demand charge
 - $1/3^{\text{rd}}$ of standard capacity charge price
 - $1/3^{\text{rd}}$ of standard kVA-km charge price
 - Balance of revenue requirement via variable c/kWh
- Second year 2004 moved to $2/3^{\text{rds}}$ capacity price and smaller balance requirement c/kWh
- Third year 2005 – standard capacity based prices

EC Model Approach Distribution Pricing – some interim comments

- High level principles generally OK but some devil in the detail
- Insufficient time to analyse fully some of the detail
- When Distributors consider changing pricing structures they significant time to gather data and update information base on which to structure new pricing

EC Model Approach Distribution Pricing – some interim comments

- Aurora does not believe that an ICP that is HHR metered compared to a ICP that is profile metered should be on a different pricing structure – Capacity based load groups provide a better basis. Eg HHR metered connection using the LV network (say 3ph 60 amp) should not be on the same pricing as a HHR 1000kVA connection
- kVA – km distance component is economically rational especially for large loads – overcomes artificial regions based on a set km distance but restrictions around urban / rural cross subsidy for lower loads
- Is the low fixed charge regime achieving its targeted objectives

EC Model Approach Distribution Pricing – some interim comments

- Transmission cost recovery
 - Lower South Island region –
 - Year 0 – Top 100 Demands in Winter
 - Year 1 – Top 100 Demands April & May 08 – no load control
 - Year 2 – Top 100 demands Nov 08 (to date) – no load control
 - Operation of Tiwai smelter (60%) of regional load has huge impact on regional load -
 - Result - difficult to predict when regional loads will peak – EC model pricing approach recommendations for recovery of transmission costs will result in price volatility to the consumer due to the different seasonal movements.