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Review of The Lines Company's Pricing Method

Report to The Lines Company Ltd

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Executive Summary

We have been commissioned by The Lines Company Ltd (TLC) to review the method it uses to price its electricity distribution service.

In recent years TLC has developed and implemented a pricing method based on charging customers for the capacity of their connection to the electricity network (measured in kVA), and the demand they place on the network at peak periods (measured in kW). This pricing method compares with many other electricity distribution businesses (EDBs) in New Zealand that charge predominantly on the amount of energy the customer consumes (measured in kWh).

TLC's pricing method aims to reflect to customers the costs that their usage drives in terms of operating and expanding the TLC electricity network. In broad terms the costs of operating an electricity network:

- Are quite high to provide even a small capacity service to any location, and then costs increase from that point as demand for peak capacity rises.
- Increase with distance, and therefore the average cost per customer is greater in low density and remote areas, versus high density areas.
- Do not change with the level of throughput, within existing capacity.

It is desirable that prices for electricity distribution services reflect the cost structure of providing the service (i.e. that they are cost reflective), as this approach to pricing:

- Ensures customers face the costs that their usage gives rise to, and provides them incentives to moderate their demand at peak times where they have cost effective options to do so.
- Prevents one customer (or type of customer) from imposing costs on others.
- Enables the supplier (TLC) to generate sufficient revenue to cover its short and long term costs to supply the service.

The Electricity Authority has issued Pricing Principles and Information Disclosure Guidelines for the pricing of electricity distribution services. We consider TLC's pricing method is consistent with these Principles. We also consider its pricing disclosures are for the most part consistent with the Guidelines, but that they could be improved, with a view to making them more accessible to customers.

Thus we consider TLC's pricing method is appropriate given the cost structure of providing the service, and that this pricing method is supported by the Electricity Authority Pricing Principles and Guidelines.

The challenge TLC faces is implementing this pricing method well, and that challenge has two aspects to it:

- Determining precisely how demand is to be measured for those customers that have meters (i.e. time of use, or TOU meters) that can record the level of demand used, and its timing. We note that only about 5% of TLC's customers have TOU meters, but TLC plans to roll out TOU meters over the next few years to most of its customers.
- Estimating in some credible and transparent manner the demand of the other 95% of customers who do not have TOU meters.

TOU customers

In relation to TOU customers, there are a range of choices as to how and when their demand is measured for pricing purposes. TLC has opted to measure demand at periods when the network is congested (i.e. when TLC is exercising load control for water heating and other similar appliances), and it takes the highest reading for any three hour period over the busy part of the year.

We support measuring customer demand when the network is congested, as demand in this period drives the need to expand capacity. However, we consider it would be more reasonable to measure demand over a number of periods, and shorten the period over which the measurement is taken. On balance we recommend moving to a 2-hour measurement window, and using an average of the 6 highest readings.

We also recommend TLC attends to a number of housekeeping issues, such as:

- Refine the processes and databases that it uses to generate customer charges, to ensure they are capable of providing traceable evidence for the calculation of demand for each TOU customer.
- Clarify the method for allocating a customer with no controllable load to a particular control period(s).
- Clarify how demand is to be measured in instances where there are no, or insufficient qualifying control periods.
- Develop options for customers above 100kVA that provide them incentives to shift load away from those periods when the network is congested.

Non-TOU customers

The demand of non-TOU customers is estimated using a formula that references the level of the customer's consumption on uncontrolled circuits.

Estimating demand will always be inferior to using measured demand from TOU meters. As TLC plans to deploy TOU meters widely over the next few years, the cost and potential disruption of refining the current estimation formula needs to be weighed against the benefits in the short term, recognising that these refinements will be overtaken once TOU meters are installed. This suggests to us any refinement to the current formula should be limited to those for which existing or emerging data are capable of providing an unambiguous improvement, and that the refinement can be readily justified to the customers involved.

In this context we recommend TLC transitions to a demand formula for each geographic area using all of the ToU data that is available. As TOU meters are rolled out these datasets will increase considerably. This transition will require some judgment as to when there are sufficient data to implement a formula for each geographic area, and which data are used, and we consider such judgments should be documented and published so they are transparent to customers.

We also recommend the estimation formula should incorporate any changes to the way in which demand is measured for TOU customers (as recommended above), to ensure consistency across both groups of customers.

Pricing disclosures

The Electricity Authority Guidelines oblige an EDB to disclose its pricing methodology, the rationale for it, and its prices.

We recommend TLC incorporates all changes agreed to as part of this review into its pricing disclosures, including a description of the impact of the changes on consumer classes and the transition arrangements to implement them, and that it revises its pricing methodology document with a view to making it more accessible from a customer perspective.

We also recommend TLC revise its pricing schedules to incorporate all changes agreed to as part of this review, and with a view to making the pricing schedules more accessible from a customer perspective.

Lastly, the implementation of the above recommendations would require changes to the current per unit prices for demand and capacity, in order for TLC to retain the same level of revenue (as the aggregate measured demand, and possibly capacity values, will change). Price regulation applying to TLC (and other EDBs) places a discipline on such changes, requiring that any such change in prices does not of itself result in an increase in revenue.

Summary of recommendations

1. For the measurement of demand charges for ToU customers we recommend:

- Moving to multiple measurement windows. While the pairing of the length of the measurement window and the number of windows is a matter of judgement, on balance we recommend moving to a 2-hour measurement window, and using 6 measurement windows, and taking an average of these six windows.
- We consider there are good reasons to measure demand in control periods, but this approach raises the following issues we consider warrant further attention:
  - Refining the processes and databases that are used by TLC to generate customer charges, to ensure they are capable of providing traceable evidence for the calculation of demand for each TOU customer.
  - Clarifying the method for allocating a customer with no controllable load to a particular control period.
  - Clarifying how demand is to be measured in instances where there are no, or insufficient qualifying control periods.
  - Developing options for customers above 100kVA to provide them incentives to shift load away from those periods when the network is congested.

2. For the measurement of demand charges for non-ToU customers we recommend:

- Transitioning to a demand formula for each geographic area using all of the ToU data that is available. As TOU meters are rolled out these datasets will increase considerably. This transition will require some judgment as to when there are sufficient data to implement a formula for each geographic area, and which data are used, and we consider such judgments should be documented and published so they are transparent to customers.
- Incorporating any changes to the way in which demand is measured for TOU customers (as recommended above) into these demand formulae, to ensure consistency across both groups of customers.

3. In relation to TLC's pricing disclosures:

- Incorporate all changes agreed to as part of this review into TLC's pricing methodology document, including a description of the impact of the changes on consumer classes and the transition arrangements to implement them, and revise the document with a view to making it more accessible from a customer perspective.
- Revise the pricing schedules to incorporate all changes agreed to as part of this review, and with a view to making these schedules more accessible from a customer perspective.

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1 Introduction

The Lines Company Ltd (TLC) has commissioned us to review the method it uses to price its electricity distribution services. Our report is structured as follows:

- Section 2 provides context in terms of the electricity distribution service being priced, some pricing concepts relevant to this review, and the forms of regulation that apply to TLC.
- Section 3 examines the relative weightings between TLC's current pricing components.
- Section 4 discusses the issues of measuring demand for the purposes of pricing for TOU of customers and recommends way in which these measurements could be improved.
- Section 5 explores the issues of estimating demand for non-TOU customers and recommends ways in which these estimates could be improved.

2 Context

2.1 TLC's electricity distribution service

TLC provides the electricity distribution service in the region bounded by Otorohanga in the north, the Tasman Sea to the west, across to Mangakino and Turangi to the east and covering the area around Ohakune to the south. This service comprises transporting electricity from electricity transmission grid exit points (GXPs) to a wide range of consumers including residences (both permanent and holiday homes), commercial operators, farmers, a large iron sand extraction operator, and so forth. It also comprises transporting electricity from generators embedded within its network footprint to consumers.

TLC's network footprint is challenging in a number of ways. It has one of the most sparse electricity footprints in the country, and a number of the residences and commercial customers operate on a seasonal basis (for instance ski related activity in the ski season only, dairy farmers in the dairy season only, and sheep farmers' requirements peaking at shearing time, and so forth). The network is relatively old and TLC has a large capital expenditure requirement relative to its existing asset base over the next ten years.[1] Many of the areas it serves comprise families and businesses with relatively modest incomes.

2.2 Pricing concepts

The above characteristics highlight the importance of designing a pricing structure that enables TLC as the supplier, and its customers, to function in an as efficient manner as possible, such that:

- Customers face prices that approximate the costs that their usage gives rise to, in order to provide them incentives to moderate their demand at peak times where they have cost effective options to do so, and to ensure that one customer (or type of customer) does not impose costs on others.
- TLC has sufficient revenue to cover its short and long term costs to supply the service, and that its level of revenue is related to how its costs scale.

The costs to supply the electricity distribution service have the following general characteristics:

- The set up costs to provide even a small capacity service to any location are relatively high, and once in place the line assets have little value in another use (that is, they are sunk), but some other assets (e.g. transformers) can be shifted cost effectively to other locations.
- The set up costs increase with distance, and therefore the average cost per customer is greater in low density and remote areas, versus high density areas.
- Costs rise as peak capacity requirements rise. Greater or less throughput within existing capacity has practically no impact on costs.

These cost characteristics, and the desirability for the pricing structure to encourage efficient behaviour on the part of the supplier and customers, suggest a pricing structure with the following features:

- That customers pay in terms of the capacity they require (and particularly at peak periods), rather than the throughput they use; and
- That the greater the average distance to serve a customer (that is, lower density or remoteness) the higher the price for a unit of capacity.

[1] See pages 7 & 8 of *Asset Management Plan*, The Lines Company Ltd

A pricing structure along the lines described above is often referred to as being "cost reflective". However, traditionally in New Zealand (and in many other countries) the price structure for electricity distribution services has been weighted to units of throughput (kWh), not to units of capacity, except in the case of very large users. Reasons for this historical approach to pricing include:

- Historically the price for electricity (the energy component) and the distribution of electricity were bundled by the same supplier, with kWh charges dominating the price structure. Even though the Electricity Industry Reform Act 1998 required the separation of suppliers of the distribution service from that of electricity, many of the legacy price structures for the distribution service retain a heavy weighting on kWh charges; and
- Legacy electricity meters at the majority of installations are capable of reading throughput only. However, the cost of meters capable of also measuring the capacity used (kW), and the time of that use (referred to as time of use, or TOU meters) are now becoming an affordable metering solution.

TLC over recent years has developed a pricing structure that aims to be cost reflective (along the lines described above). This pricing structure has the following four components (although not all components apply to all customers, see page 2 of TLC's Line Charges Methodology of 29 March 2010):

1. A network charge based on usage (or demand) in the previous year.
2. Charges for dedicated assets.
3. A network charge based on contracted capacity.
4. A customer service charge.

From an economic perspective this pricing structure is sound, in that it aims to be cost reflective. In our view it is also a reasonable approach, in that customers face the approximate cost that their usage places on the network, and by so doing this avoids one customer (or one type of customer) imposing costs on others.

There are, however, a number of choices as to how such a price structure is implemented, in terms of:

- The weighting placed on each of the pricing components; and
- The way in which each component is measured for pricing purposes. The most significant measurement issue is that of demand (the first pricing component) in a context where many customers do not have TOU meters.

We discuss each of these issues in the following sections, but prior to doing so we describe the forms of regulation applying to the electricity distribution service.

2.3 Regulatory constraints

2.3.1 Electricity Authority pricing principles and guidelines

The Electricity Authority (EA) inherited a set of pricing principles and information disclosure guidelines for electricity distribution services from its predecessor, the Electricity Commission (EC). These principles and guidelines are the result of work undertaken by the EC in 2009 and 2010 on electricity distribution pricing issues, the result of which is set out in the document "*Distribution Pricing Principles and Information Disclosure Guidelines*", February 2010. The Pricing Principles and the Information Disclosure Guidelines from that document are set out in the two tables below. We have included the Information Disclosure Guidelines as they have relevance to the manner in which an EDB implements its pricing.

We comment on TLC's pricing method in relation to each of the Principles and Guidelines. In general we consider TLC's pricing method complies, with improvements possible in the way in which it is implemented and explained in some cases.

Electricity Authority Pricing Principles	Our comment on TLC pricing method
a) Prices are to signal the economic costs of service provision, by:	
i. being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;	The TLC pricing method is consistent with this.
ii. having regard, to the extent practicable, to the level of available service capacity; and	The demand charge is designed to signal the costs of using capacity at peak times by way of measuring demand in control periods only.
iii. signalling, to the extent practicable, the impact of additional usage on future investment costs.	The demand charge is designed to signal the impact on future investment of usage at peak (controlled) periods.
b) Where prices based on 'efficient' incremental costs would under-cover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.	The capacity charge recovers revenue according to the size of the connection, and the dedicated asset charge recovers revenue according to the size of the connection and the number of other customers using the assets.
c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:	
i. discourage uneconomic bypass;	The TLC pricing method is consistent with this.
ii. allow fair negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and	Choices relating to supply can be discussed with TLC's Customer Service Advisors
iii. where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.	The TLC pricing structure is consistent with this.
d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.	The final prices are transparent but the transparency of the method and data used to determine the demand of customers could be improved.
e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.	TLC's prices are economically equivalent across retailers. The measurement of demand in the absence of TOU meters has some costs attached to it, but these costs will decline as TOU meter penetration improves.

Information Disclosure Guidelines	Our comment on TLC pricing method
a) Prices should be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified clearly and marked.	TLC's pricing methodology is explained in its disclosure and prices based on this methodology are also disclosed. It would be desirable to simplify these disclosures and also make information more accessible as to how the price for any individual customer is calculated.
b) The pricing methodology disclosed should demonstrate:	
i. how the methodology links to the pricing principles and any non-compliance;	This linkage is not made as TLC's methodology was written prior to the principles being issued.
ii. the rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings;	This rationale and method are disclosed.
iii. quantification of key components of costs and revenues;	These are provided.
iv. an explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping;	These explanations and rationale are provided.
v. an explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design; and	These explanations and rationale are provided.
vi. pricing arrangements that will be used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management, where alternatives are practicable and where network economics warrant.	The demand charge achieves this by lowering customers' overall charges to the extent they are able to move demand to off-peak periods.
c) The pricing methodology should:	
i. employ industry standard terminology, where possible; and	In general this appears to be the case, however "industry standards" are not well defined.
ii. where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition arrangements implemented to introduce the new methodology.	Previous pricing changes were made prior to these guidelines. We understand proposed changes and their likely impacts on different customer groups will be communicated to customers.

2.3.2 Commerce Commission default price-quality paths and information disclosure

TLC is subject to a default price-quality path (DPPs) set by the Commerce Commission (CC).[2] The DPP requires TLC to not price above a defined price path, which is determined as an average of all price components weighted by their quantities (the quantities used are from the pricing period two periods prior, for practical reasons). Thus the DPP provides a regulatory check on TLC in terms of its overall level of prices.

The DPP also requires TLC to maintain a minimum level of service quality (but it may supply a superior quality), measured by SAIDI and SAIFI[3] values.

TLC is also subject to information disclosure requirements that include disclosing a range of financial performance and service performance measures, and a ten year asset management plan (AMP). These disclosures complement the DPP. Amongst other things these disclosures require TLC to disclose its profitability each year, expressed as its return on investment (or ROI). This ROI measure is a crude indicator as to whether the overall level of TLC's prices are reasonable. The CC has indicated it will reference an EDB's ROI when deciding every five years whether or not to change the level of an EDB's prices. TLC's ROI for 2009/10 (the most recent disclosed value) was 6%.[4] The CC's most recent estimate of a reasonable ROI for an EDB is 7.22%.[5] Thus on this comparison it appears the overall level of TLC's prices are below a reasonable level. However, we note that a thorough test of overall price levels needs to include an assessment as to whether TLC's cost structure is efficient, and these costs need to be assessed over a multi-year period, but such an assessment is a significant piece of work and falls outside the scope of this review.

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[2] The DPP is set out in *Consolidated Version of Commerce Act (Electricity Distribution Default Price-Quality Path) Determination 2010,* Commerce Commission, 30 November 2010. The DPP applies to all EDBs expect those that are exempted on the basis that they meet certain consumer ownership tests.

[3] System average interruption duration index, and system average interruption frequency index respectively.

[4] See page 23 of *Information for Disclosure for year 1 April 2009 to 31 March 2010*, The Lines Company Ltd

[5] *Input Methodologies (Electricity Distribution & Gas Pipeline Services) Reasons Paper,* Commerce Commission, December 2010, Table 6.6, p 168

One implication of the DPP for this review is that if TLC decides to change the method it uses for measuring demand for pricing purposes, and that change results in a change in aggregate measured demand across all customers, then its revenue will rise or fall accordingly. Such a change is likely to be considered a "restructuring of prices" by the CC and the DPP has specific provisions for restructuring prices, the essence of which is to demonstrate that the restructuring does not of itself increase the EDB's overall revenue (see clause 8.6 and 8.7 of the DPP).

3 Relative weighting of pricing components

As noted above, TLC's price structure has four components:

1. A network charge based on usage (or demand) in the previous year.
2. Charges for dedicated assets.
3. A network charge based on contracted capacity.
4. A customer service charge.

In this section we consider the relative weighing on each of these pricing components, in terms of the percent of revenue collected under each. This is important as different weightings will affect various customers in different ways and have implications for the incentives on customers to modify their consumption patterns.

When considering the relative weightings of the pricing components, components (2) and (4) are relatively straightforward, while components (1) and (3) require a greater degree of judgment.

3.1 Demand and capacity charges

The demand charge makes up 56% of TLC's total revenue, and the capacity charge 17% (together 73%) and thus they are the two dominant charges.[6]

The demand charge is based on the demand the customer in practice places on the system. For the majority of customers (those with a 100kVA or less connection) their demand is measured as the peak demand they use within any load control

[6] *Lines Charges Methodology*, The Lines Company Ltd, 29 March 210, Appendix Two

period lasting 3 hours or more, or if they do not have a TOU meter, their demand is estimated from the uncontrolled KWhs they use (this estimation method is discussed in section 5). The load control period is used for this measurement as this is the time at which the network is congested, and TLC reduces demand at these times by propagating signals in the network to switch off controllable load (e.g. hot water heaters).

For those customers with a connection in excess of 100kVA their demand is measured as their anytime highest 3 hour peak. This different approach is used as it is assumed that the size of these large customers will influence the network requirements, whatever the time their peak occurs.

The demand charge contrasts with the capacity charge. This charge is measured as the size of the connection on the customer's connection application from, or where there is no documentation, the highest use (demand) over system peak periods. Domestic connections are assessed at a minimum of 5kVA.

The capacity charge is best thought of as an option to take supply up to the capacity level, whereas the demand charge reflects the capacity actually taken.

From a customer perspective, with a connection of 100 kVA or below, the main difference between the two charges is that the customer may have ways to moderate their demand peak in control periods by shifting load to other periods (e.g. water heating, freezing or space heating), whereas they do not have the same flexibility to reduce the capacity of their connection.

From the perspective of customers with a connection above 100kVA, there is less of a difference between the two charges as their highest anytime peak defines the demand charge, and also defines their expected capacity requirement (albeit that there may be costs to make physical changes to their connection to lower their capacity charge but not to lower their demand peak).

From the perspective of TLC the capacity charge measure is more stable in that for most customers it does not change from year to year, whereas the demand charge measure may change from year to year.

In our view it is useful in principle to have these two charges as they each present customers with subtly different choices:

- The capacity charge enables customers to make choices on the size of the connection they wish to have, that is the amount of capacity they wish to have an option to use at any time; and
- The demand charge enables them to benefit from shifting load away from control periods, or to bear the costs of not doing so (in the case of those with 100kVA or below connections).

We consider the value of the distinction between the two charges would be enhanced for those with connections in excess of 100kVA (of which there are about twenty) if they had incentives to shift load off network peak periods, similar to those incentives offered to smaller customers with controllable load. From TLC's perspective this would create the possibility that these customers may also contribute to reducing overall network peak demand.

3.1.1 Relative weightings of demand and capacity charges

Given that these two charges are part of the TLC's pricing structure, and that we see no good reason to recommend the removal of one or the other, the question arises as to what their relative weightings should be. At present their weightings are:

- In constrained areas of the network, the revenue from these two charges is approximately 2/3 from the demand charge and 1/3 from the capacity charge.
- In non-constrained areas the revenue from these charges is approximately even (that is, approximately half from each of the demand and capacity charge).

In our view the main consideration as to how to weight these charges lies in the customer incentives the weightings give rise to.

In constrained areas we consider the demand charge signal is more important than the capacity charge, as it more precisely targets the customer behaviour that will relieve network constraints, namely to reduce demand levels in control periods (when the network is at its peak). Having the relative levels set at 2/3 and 1/3 in favour of the demand charge is consistent with this.

In unconstrained areas having the demand charge set higher than the capacity charge is less important, and we consider having these charges set at approximately the same level is reasonable.

The measurement of demand is relatively straightforward for customers with TOU meters as their demand can be measured directly and be charged for accordingly. We discuss demand measurement issues for TOU customers in section 4.

The measurement of demand is more challenging for customers without TOU meters, as in this case demand cannot be measured directly as the meters do not record the relevant variables, and therefore demand needs to be estimated in some way. The majority of TLC's customers have non-TOU meters, that is about 23,000 out of a total of 24,000 customers. We discuss demand measurement issues for non-TOU customers in section 5.

3.2 Charges for dedicated assets and customer service

3.2.1 Charges for dedicated assets

Charges for dedicated assets apply where lines and associated assets are dedicated to the supply of an individual customer, or where transformers and associated assets supply 3 or less customers (see page 2 of TLC's pricing methodology). These charges make up 8% of TLC's total revenue.[7] This approach has the effect of reflecting the long run costs to supply the service to the customers of the service, and thus from an economic perspective is sound.

3.2.2 Charges for customer service

An explicit customer service charge is applied to large industrial customers only. It is set at $1,560 per customer before prompt payment discount and applies to approximately 34 large customers only. In total this charge recovers only a small portion of TLC's revenue.

This charge aims to reflect to large customers the cost to TLC of managing these large accounts, as they tend to require more effort than each mass market account.

4 Measurement of demand for TOU customers

TLC currently measures demand for customers with TOU meters as follows (see page 3 of the Line Charges Methodology):

> *(a) For installations above 100 kVA – by taking the highest consumption over any 3 hour period and dividing that by 3. It is assumed that such installations are large enough that their peak usage influences the local network requirements.*
>
> *(b) For installations 100 kVA and below – by taking the highest consumption over any 3 hour period when we are load controlling the water heating load of the local customers, and dividing that by 3.*

This method of measuring demand for TOU customers takes a particular view on the following dimensions:

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7 *Lines Charges Methodology*, The Lines Company Ltd, 29 March 210, Appendix Two

- Length and number of measurement windows – a single 3 hour window has been chosen.
- Timing of window – for the majority of customers (under 100 kVA) load control periods of 3 hours or more are used.
- Averaging measurement – a simple average is taken.
- Period of application – the resulting measurement is applied for the following pricing year commencing 1 April.

We explore each of these dimensions below and recommend ways in which they could be improved.

4.1 Length and number of control periods and measurement windows

We understand from TLC a 3 hour measurement window has been chosen to reflect that an electricity network is able to withstand a degree of excess loading for short periods, but not generally for more than 3 hours (due to the build up of heat). This engineering issue suggests the window should be no greater than 3 hours, but could be shorter.

From the customer's perspective the longer the window (assuming an average is taken), the more that short-duration spikes within that window will be muted. We note this averaging could also be achieved by taking more measurement windows, potentially with shorter periods. For example, Transpower (for the transmission system) uses either 12 half hour values for more constrained regions or 100 values where the network is not close to constraint.

Another consideration in relation to the length of the measurement window is the length of control periods. For the 2010 year we have found on some TLC network sectors there are no, or very few 3 hour control periods for some control channels, while on others there are in excess of 90. If a greater number of measurement windows are used, it may be desirable to also reduce their length to ensure that a greater number of qualifying periods are obtained.

We discuss below the implications for observed demand peaks of the length of control periods and measurement windows, and the number of control periods and measurement windows.

4.1.1 Length of control period and measurement window

The longer the control period, the greater the probability that a higher demand value will be recorded within the control period. However, as a control period runs for only a number of hours (not days), the external factors and behaviours that give rise to the peak demand are likely to remain relatively constant within that period.

Thus the impact of the maximising calculation will tend to capture slightly higher peak demand from longer control periods. For illustration, a customer may have a spike in demand that is recorded when the control period runs for five hours, but does not feature when the control period is only three hours in duration.

The related aspect of the length of the measurement window (used within the control period) influences the degree of smoothing of short demand spikes. Short measurement windows will result in short demand spikes contributing more to the peak demand measure, while a longer measurement period will lower the average across the longer period of time.

4.1.2 Number of control periods and measurement windows

The more material measurement aspect however is linked to the number of control periods. A customer's demand pattern follows a particular distribution. In a process of selecting the single (or a small number of) highest measurements from control periods, as the number of control periods increase, so does the probability that a higher peak will be recorded.

To illustrate, assume a customer typically uses between 4kW and 8kW during peak periods. In selecting a single peak from a single control period, the value might come from the middle of the range, that is 6kW. Across a larger number of control periods, say 20, the average of the peak demand may still be 6kW but the maximum of the readings is likely to be at the higher end of the customer's normal range.

The related aspect to the number of control periods is the number of measurement windows. With a higher number of measurements, any demand spike in one (or a small number of) window is muted by the averaging over a greater number of windows.

The relevance of this discussion is the number of control periods, and their duration, differ across TLC's geographical regions. These differences in turn are likely to influence the observed customer peaks across geographies. Further, in some areas of the network a shorter measurement window (e.g. 2 hours rather than 3), would pick up morning peaks (driven primarily by commercial customers) that are not included in a 3 hour window.

4.2 Timing of measurement windows

The logic for setting the measurement window at the time load control is being applied is as follows:

- All customers are receiving service off a common set of assets.
- The dimensioning of the common assets is determined by the coincident peak of customer demand.

- Customers willing to offer load for control enable TLC to manage the level of peak demand. These customers thus provide a mechanism for lowering the total costs of providing the electricity distribution service.
- Measuring uncontrolled demand in the load control period rewards customers for offering controlled load, thus providing them with an incentive to do so.
- From the controlled customers' perspective, they can calibrate their demand in the control period by the extent to which they offer controlled load. This is in contrast to if demand were measured on an any-time basis, which could result in the sum of their controlled and uncontrolled load (depending on how TLC operates the control period) driving an individual customer demand peak greater than what would have occurred in the absence of control. Such an approach has the potential to provide a disincentive to customers to offer controllable load.

While the above logic is sound, there are a number of issues that need to be considered when measuring demand in this way:

- This approach to demand measurement requires good quality data on the load control periods and TOU meter data to enable the determination of a demand measure for any particular ICP to be traced. We found it necessary to process the datasets provided to us by TLC in order to correctly match the load control periods to the TOU meter data. This indicated to us that the data held by TLC may not be adequate in its current form to support, in a transparent manner, the demand charging method. A good test for the adequacy of this data is whether TLC could provide any TOU customer with their TOU meter data, matched to load control periods, and thereby demonstrate how the customer's demand had been measured for pricing purposes. As a related exercise to this report we are reviewing the TLC data to check whether this is the case.
- If demand is to be measured in control periods only, the possibility of no qualifying control periods needs to be catered for. For example, TLC informs us that a small number of sub-networks do not currently receive effective ripple signals (but that this issue is being rectified over the next two to three years) and therefore do not have qualifying load control periods. Applying the current demand measurement rules strictly in these circumstances would result in TLC not levying a demand charge. However, we understand in practice TLC in these circumstances levies a demand charge based on demand of the uncontrolled circuit only, measured in the period that control would have applied. In order to enhance the transparency of how demand is measured in practice, and to avoid any perverse incentives on TLC to control load in order to create a qualifying control period even if control is not required, we recommend the demand measurement rules be clarified as to how demand is measured for customers where there is no qualifying load control period.

- There need to be unambiguous and reasonable rules as to how those customers that do not have any controllable load (and who have less than 100kVA capacity) are treated, as any particular network sector may be controlled at different times via differing control channels. We understand at present these customers are allocated to a single control channel (channel 1) as this channel operates in all network areas. However, the choice of control channel could affect the outcome of the customer's demand measure if not all control channels operate over all qualifying control periods. Our review of the load control data indicates that this is indeed the case (that is, not all channels operate over all qualifying control periods). One approach would be to measure their demand in all control periods, in order to identify the maximum they contribute when the network would otherwise be congested. However, this would mean such customers have a considerably higher number of demand measurement periods then customers with controllable load, leading to a higher probability of higher readings. We consider the rationale for the allocation of these customers to control channels or periods needs to be clarified and documented.
- Lastly, the rules around commencement and finishing times for the measurement of control periods must be clear. In our data analysis we used an approach of counting half-hour periods when control operated. An interruption in control signalled that the control period had finished. Therefore, under our approach the starting half-hour period is where load control operates for one-minute or more, and the ending period is where control operates for 30 minutes or less. For illustration, control from 16:25 to 16:35 covers the two half hours 16:00 to 17:00. We have encountered two variations used by TLC or its contractors to the time of measurement that are worthy of mention:
    - A restriction within the analysis that allows only one peak for a customer per day even if there are multiple qualifying control periods on that day; and
    - Rounding that takes the control period start/finish times to the closest half-hour break. That is, quarter-to or quarter-past the hour is moved either forwards or backwards to the hour and similarly for half past the hour. Thus, a control period from 16:16 to 16:44 is of zero duration. Where the finish of one period and the commencement of the next control period round to the same time, the two separate periods are treated as a continuous period. For example, 16:25 to 16:50 and 17:10 to 17:50 would be treated as a single control period of 16:30 to 18:00, excluding the control in the 16:00 to 16:30 period and including the non-controlled period 16:50 to 17:10. However, we note that provided this latter approach is applied consistently across all customers (TOU and non-TOU) it would not materially alter the charges faced by customers (relative to the approach we used in our analysis).

4.3 Average measurement

Currently TLC derives an average demand over a 3 hour period from consumption data. This approach mutes the effect of any one single half-hour demand across the measurement period, which we think is desirable.

If a number of measurement windows are used it is usual to combine the results by way of a simple average. Taking the average of a number of measurement windows would further mute the impact of short-duration spikes within each qualifying period, and also the presence of a single abnormal event.

At this stage we see no merit in devising a weighting regime for either multiple measurements or for the individual half-hour periods that contribute to each peak. Introducing such a system would add significantly to the complexity of the calculation without an identified benefit.

4.4 Summary of demand measurement issues

On the length and number of measurement windows, we explore in section 4.5 the impact of using a 2 or 3 hour windows, and using 1, 2, 3, 4, 5 and 6 measurement windows.

In relation to the timing of measurement windows, we consider there are good reasons to measure in control periods, but this approach raises the following issues we consider warrant further attention:

- Refining the current datasets on load control periods and TOU meter data to provide a robust and traceable basis for measurement of demand for each TOU customers.
- Clarifying the method for allocating a customer with no controllable load to a particular control period(s) or a particular control channel.
- Clarifying how demand is measured in instances where there are no, or insufficient qualifying control periods and ensuring the method used in practice is consistent with that documented.

We agree with the approach of averaging demand within a measurement window and, if more than one window is used, of averaging the results from each measurement window.

4.5 Analysis of data

The core data inputs from TLC that we have used in our analysis are:

- The periods when load control was used during 2010 across the TLC network. This describes the location, channel number and switching times.
- Meter identification meta-data from several files with information listing ICP, meter number and location (note this includes channel data that is specified by default rather than an explicit value).
- Metering information. Half-hourly data for a range of meters including holiday homes and commercial, and including those used in the Longdill demand formula derivation.[8]

In order to run our analysis we needed to match across the three datasets described above. We were able to achieve this match for 411 meters, that is for most of the meters for which we had data (out of a total of 429).

Our analysis takes the control period data and identifies potential measurement windows for each channel across the year. These periods were identified with a 3-hour or 2-hour minimum length respectively. Many control periods appear to be of short duration and therefore are excluded. Further, the start and end periods do not occur at the same defined boundaries for metering so we adopted the following approach:

- The start of a control event is taken to be the beginning of the half hour in which control commences, and the end of a control event is similarly taken to be the end of the ½ hour period in which control ceases.

If we had excluded half-hours with partial load control it would have significantly reduced the number of qualifying periods. Further, the extension of the qualifying control period in this manner introduces a slight upward bias to the peak demand that is measured (see section 4.1 above for the discussion of this point).

We have noted, in identifying 3-hour periods, that not all areas of the TLC network have valid measurement windows. That is, some sub-networks were not controlled for three-plus hours during 2010. This highlights an issue in terms of the demand measurement rules that needs to be addressed, as mentioned above, to clarify what (if any) measure of demand is used in such instances. This is particularly important because the control periods in different regions occur at both different times and at

[8] *Peak Demand Calculation – Winter 2010*, Longdill and Associates, December 2010

different frequencies. This in turn impacts on the potential level of the observed maximum peak demands.

Having identified the qualifying control periods for each channel, these times were overlaid on the meter data. This necessitates good information on the control channel that applies to each customer. The guidance provided by TLC was that by default control is via channel "1". While a default rule is useful for our analysis, in many cases we did not have evidence to link each installation to the corresponding channel (and is another reason for our query of data integrity).

Where a control period lasts longer than the minimum duration, we have taken the single highest 3-hour or 2-hour continuous period for each meter. We also allow for the possibility of more than one qualifying control period on a single day. This allows us to rank the highest peaks for each meter and determine the average of the *N*-highest peaks.

The following graphs show the distribution of the assessed peak demand as we move from a single to two, three, four or six peaks (we also calculated the values for five peaks but have omitted these from the graphs to avoid cluttering). In discussion with TLC we divided the customer data into four groups: holiday homes (Hol Home), the dataset used by Longdill to estimate demand on a kWh basis for non-TOU customers (Longdill), the remaining non-domestic customers (Non Dom), and the total TOU customer base (Total).

The x axis is a percentage derived by dividing the measure from the single highest period (i.e. the measure used currently) by the average from *N*-periods. Where the second, third and subsequent peaks are close to the single maximum, the results remain close to 100%. If the single highest peak is much higher than the averages from multiple peaks, the resulting percentage (on the x axis) is higher. These graphs can be interpreted as the extent of change in demand measurement that would arise from averaging over multiple periods, relative to the current approach of taking the single highest period.

Figure 1: 3 hour measurement windows, total sample

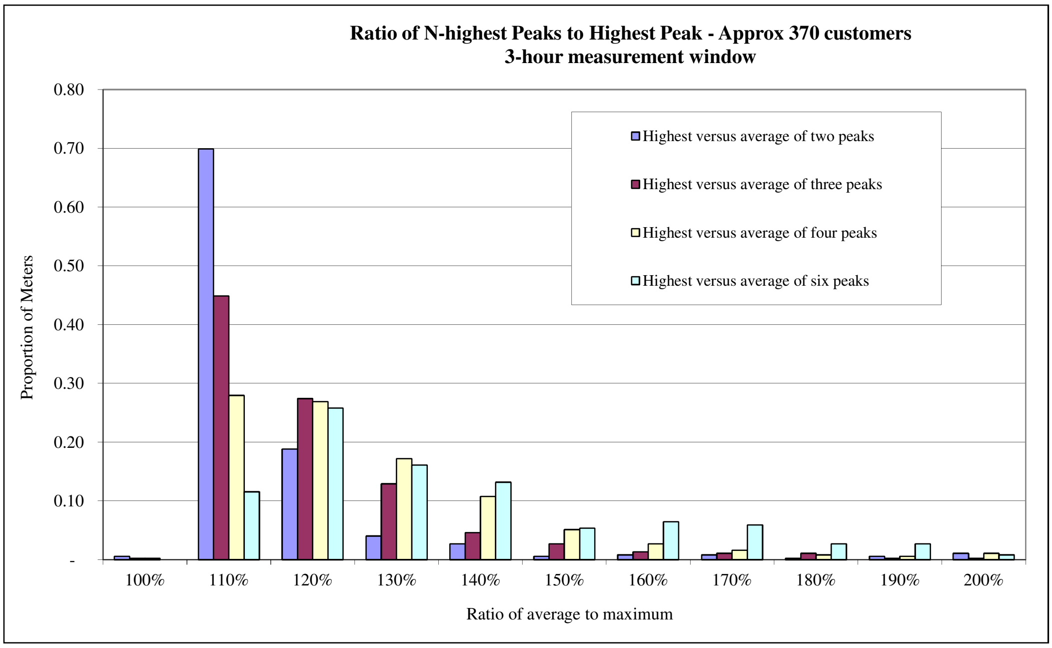


Figure 2: 3 hour measurement windows, non-domestics

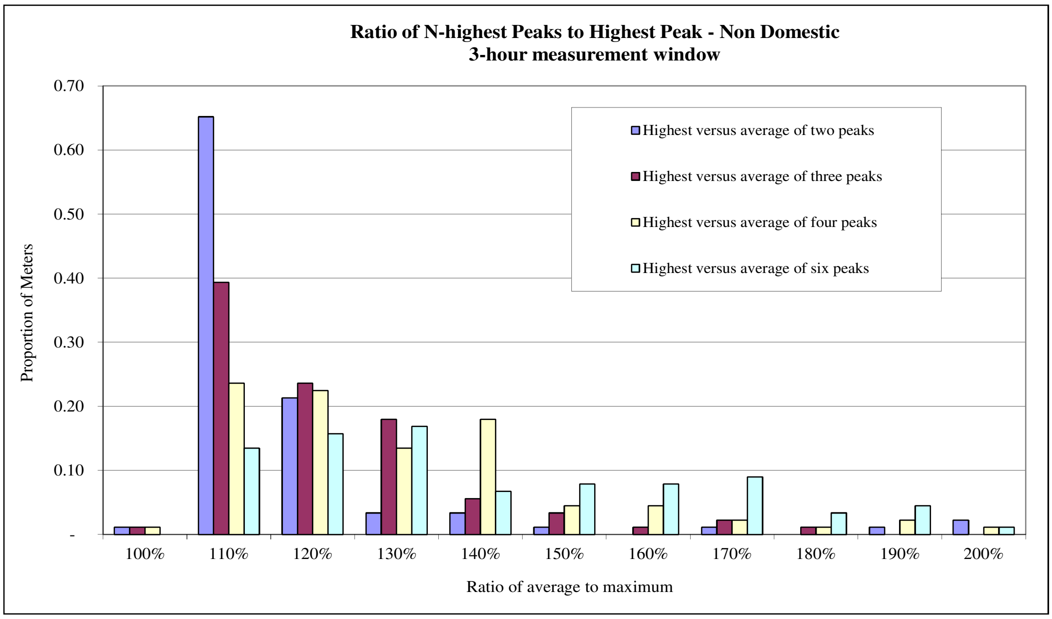


Figure 3: 3 hour measurement windows, Longdill sample

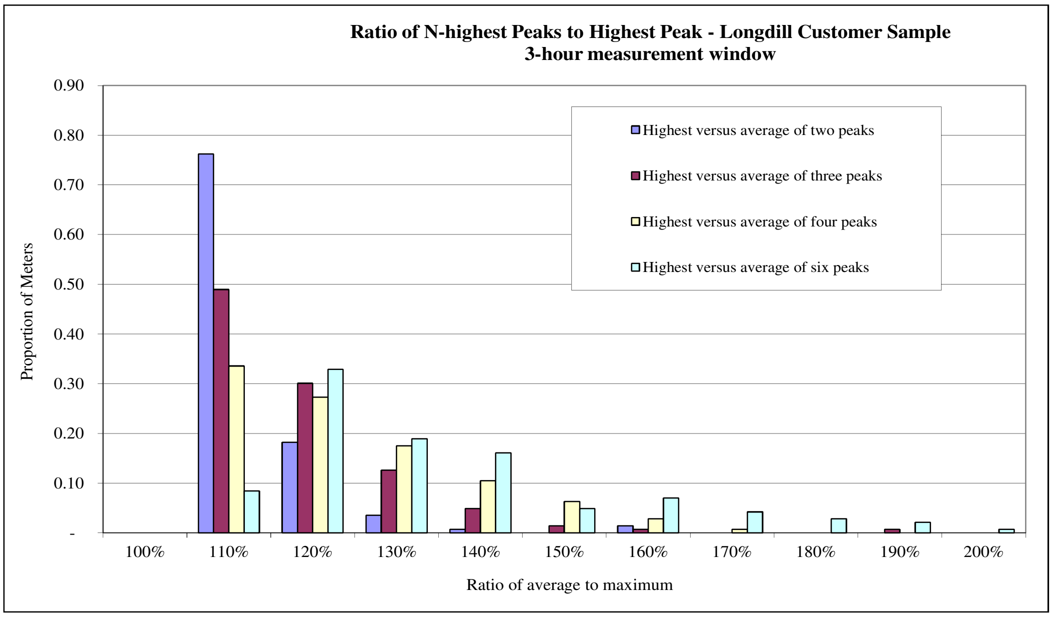
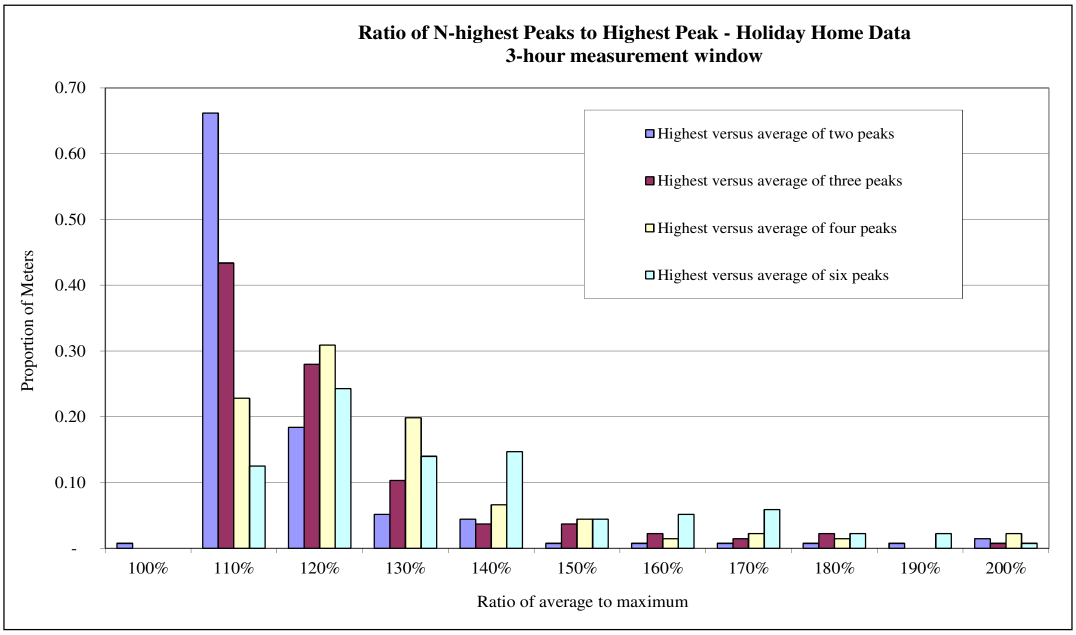


Figure 4: 3 hour measurement windows, holiday homes



The table below summaries the results for each of the customer groups, using 3 hour measurement windows.

Figure 5: 3 hour measurement windows, summary of results

3-hr measurement			Highest versus average of two peaks	Highest versus average of three peaks	Highest versus average of four peaks	Highest versus average of five peaks	Highest versus average of six peaks
Hol_Home	Sum of kW	603.672	553.443	517.784	488.013	463.407	441.356
Hol_Home	Count	169	169	169	169	169	169
Hol_Home	Average	3.572	3.275	3.064	2.888	2.742	2.612
Hol_Home	Ratios		109%	117%	124%	130%	137%
Longdill	Sum of kW	301.581	278.586	262.004	249.088	237.883	228.027
Longdill	Count	144	144	144	144	144	144
Longdill	Average	2.094	1.935	1.819	1.730	1.652	1.584
Longdill	Ratios		108%	115%	121%	127%	132%
Non_Dom	Sum of kW	350.577	328.796	314.583	299.487	286.336	274.506
Non_Dom	Count	97	97	97	97	97	97
Non_Dom	Average	3.614	3.390	3.243	3.087	2.952	2.830
Non_Dom	Ratios		107%	111%	117%	122%	128%
Total	Sum of kW	1,255.83	1,160.82	1,094.37	1,036.59	987.63	943.89
Total	Count	410	410	410	410	410	410
Total	Average	3.063	2.831	2.669	2.528	2.409	2.302
Total	Ratios		108%	115%	121%	127%	133%

The following graphs and summary of results below follow the same format as above, but are for 2-hour measurement windows.

Figure 6: 2 hour measurement windows, total sample

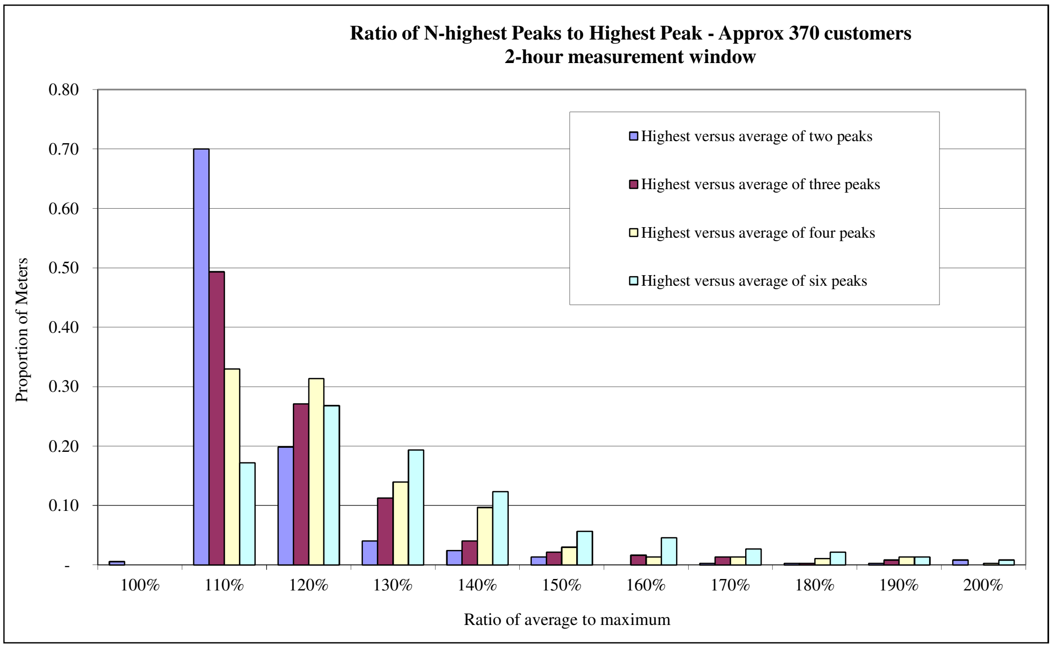


Figure 7: 2 hour measurement windows, non-domestics

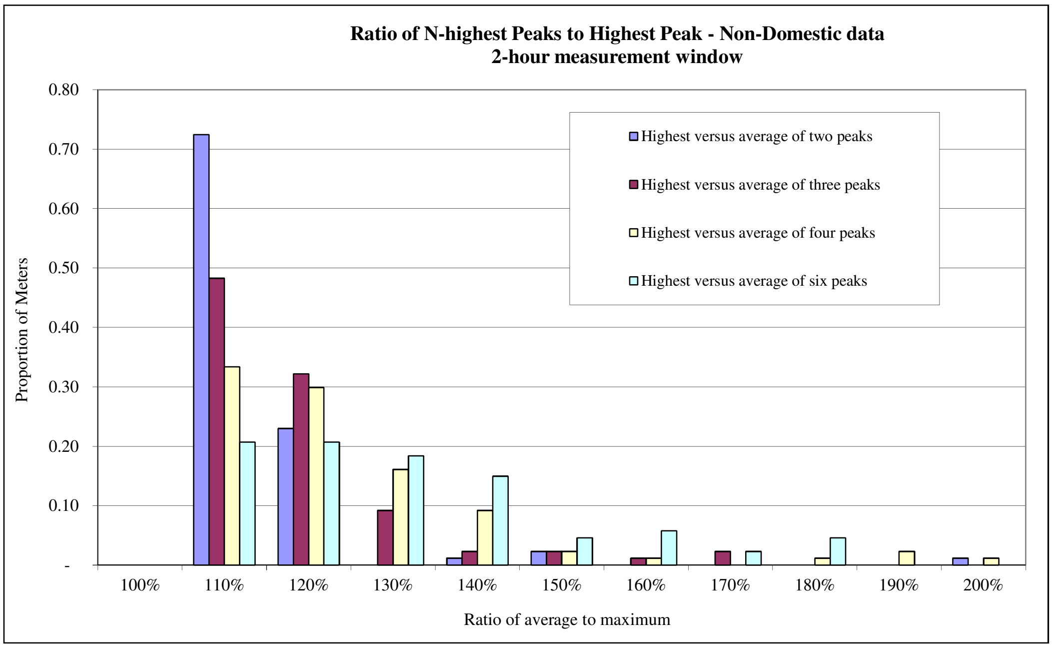


Figure 8: 2 hour measurement windows, Longdill sample

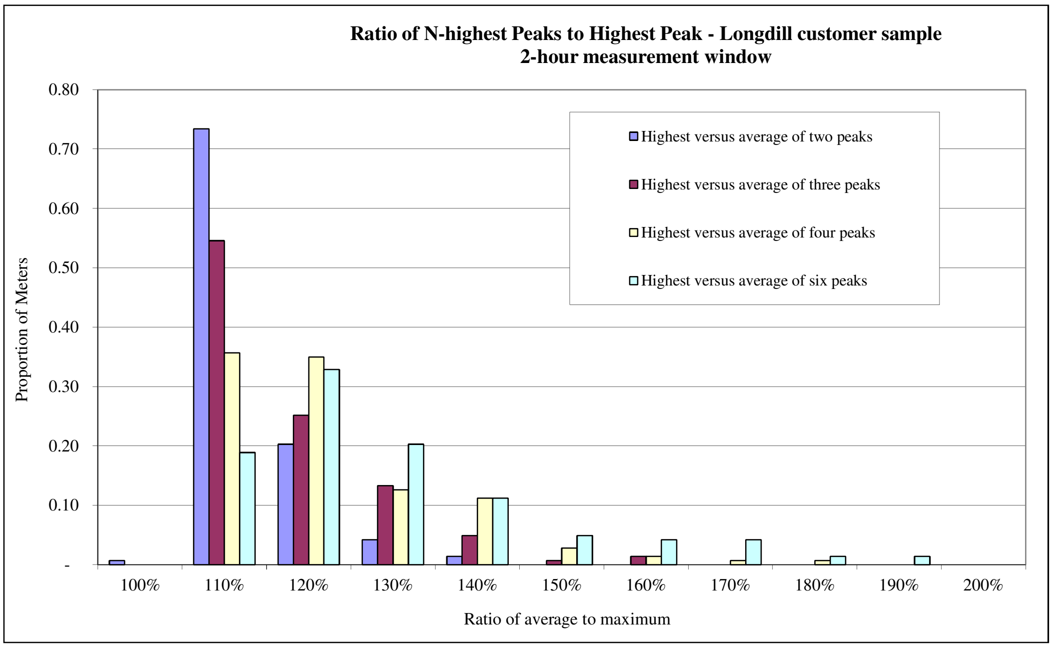


Figure 9: 2 hour measurement windows, holiday homes

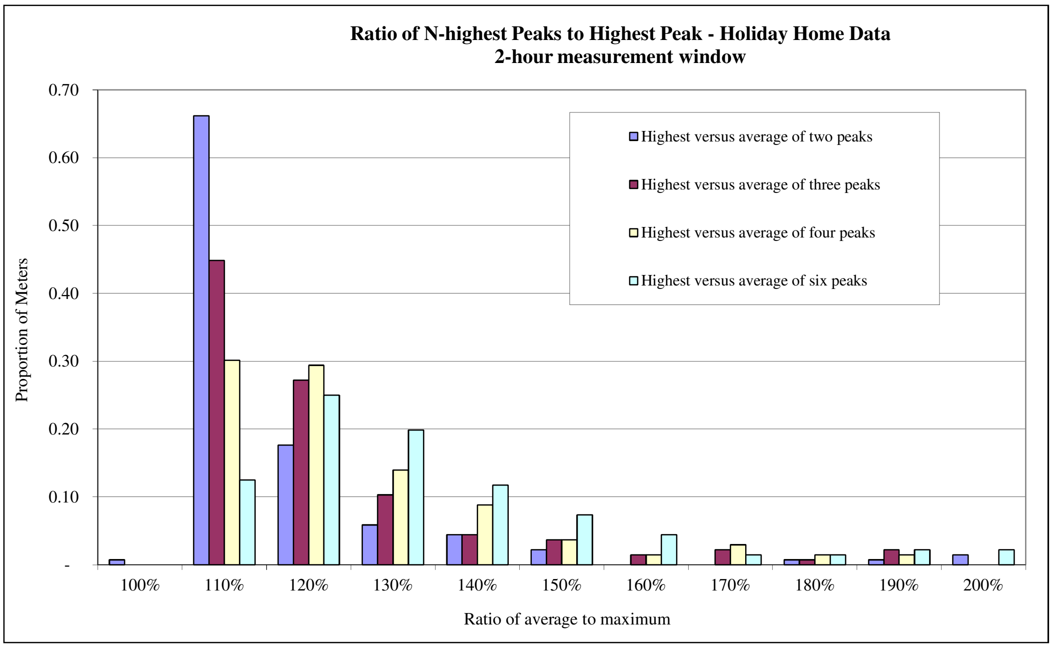


Figure 10: 2 hour measurement windows, summary of results

2-hr measurement			Highest versus average of two peaks	Highest versus average of three peaks	Highest versus average of four peaks	Highest versus average of five peaks	Highest versus average of six peaks
Hol_Home	Sum of kW	693.510	639.811	603.377	573.596	547.610	524.895
Hol_Home	Count	169	169	169	169	169	169
Hol_Home	Average	4.104	3.786	3.570	3.394	3.240	3.106
Hol_Home	Ratios		108%	115%	121%	127%	132%
Longdill	Sum of kW	375.976	351.866	334.268	319.887	308.188	298.258
Longdill	Count	144	144	144	144	144	144
Longdill	Average	2.611	2.444	2.321	2.221	2.140	2.071
Longdill	Ratios		107%	112%	118%	122%	126%
Non_Dom	Sum of kW	398.668	375.072	362.382	351.344	341.217	332.140
Non_Dom	Count	97	97	97	97	97	97
Non_Dom	Average	4.110	3.867	3.736	3.622	3.518	3.424
Non_Dom	Ratios		106%	110%	113%	117%	120%
Total	Sum of kW	1,468.15	1,366.75	1,300.03	1,244.83	1,197.01	1,155.29
Total	Count	410	410	410	410	410	410
Total	Average	3.581	3.334	3.171	3.036	2.920	2.818
Total	Ratios		107%	113%	118%	123%	127%

The choice of the length of the measurement window to use, and the number of windows, involves a degree of judgment. Relevant considerations include:

- The length of the measurement window relative to control periods. Decreasing the measurement window to two hours increases the control periods in which these measurements can be taken, and would include some network peaks otherwise not recorded (e.g. morning peaks driven primarily from commercial customers). It would also result in more qualifying control periods in some areas of the network where otherwise there have been none, or very few.
- Increasing the number of measurement windows mutes the effect of single peaks or other one-off events. However, it is important that this is not taken too far, as too many control periods would weaken incentives on customers to reduce demand.
- The results need to approximate cross checks by TLC of the measured aggregate demand on their networks. TLC informs us that the current average demand results from the Longdill sample (using a single 3 hour measurement

window) are consistent with those cross checks. We note from Figures 5 and 10 above, the combination of a 2 hour measurement window and six windows, using the Longdill sample data, result in a similar average demand value to the current 3 hour single window (2.094kW for a 3 hour single window, relative to 2.071 kW for a 2 hour window times 6 windows).

On balance we recommend implementing a 2 hour measurement window, coupled with 6 measurement windows.

5 Measuring demand for non-TOU customers

For those customers without TOU meters, approximately 95% of all TLC customers, their demand is derived via a formula (developed by Longdill) based on half-hourly data from a sample of customers with TOU meters. This process aims to replicate the approach described above in section 4 for non-TOU customers. The estimate is in the form of a function of demand relative to a customer's uncontrolled energy consumption, that is the demand for a non-TOU customer is estimated using a formula applied to the winter period kWhs they consume that are not subject to load control.

We have identified the following issues which are likely to compromise the extent to which the estimates of demand are representative of the actual demand of non-TOU customers:

- The sample of ToU meters is restricted to domestic installations in one geographic area, but applied to domestic, commercial and industrial customers with a connection capacity of 100 kVA or less, even though some of the customer categories are known to have differing consumption patterns. Some customer segments that are known to have different characteristics are treated separately (such as holiday homes and dairy sheds), but others are not.
- The same installations are used each year in the formula, and do not appear to be drawn randomly from the population.
- The qualifying peak demand periods in the sample area are determined by the operation of load control across a number of channels within that area, and the results are then applied to areas with a significantly different number of control periods, and to customers who may not have controlled load or be assigned to a load control channel. The measurement period and formula are derived from winter usage, but other customer segments are known to have different peaking behaviour (for instance, dairying sheds during spring).

We explore these issues below and recommend ways in which they could be improved. However, we note that estimation of demand will always be inferior to using measured demand from TOU meters, and TLC plans to deploy TOU meters widely over the next few years. Thus the cost and potential disruption of refining the current formula need to weighed against the benefits in the short term, and that these refinements will be overtaken once TOU meters are installed. This suggests to us any refinement to the current formula should be limited to those for which existing or emerging data are capable of providing an unambiguous improvement, and that the refinement can be readily justified to the customers involved.

5.1 Metering sample restricted to domestic use patterns

The charging basis for non-ToU customers is based on a sample of domestic ToU meters. This set of meters is specifically restricted to domestic installations and therefore carries with it the behaviour patterns of residential users.

Domestic usage reflects the occupancy pattern of residents, which typically involves low usage during the night and often during the middle of week days, and higher consumption in the morning and particularly in the evening in association with cooking and heating loads. It is this pattern of behaviour that underpins the demand charging formula that is then applied to a number of other, distinct customer groups that operate according to quite different patterns. Many commercial and industrial enterprises operate during weekday and day-time periods. Commercial and industrial processes may also have much more stable load during their hours of operation and a lower, but also stable level of consumption when not actively operating. Still others cater to specific times of the day or times of the year.

Amongst the significant issues here are the potential differences in the time of theie peak demand. While many of the control periods occur during the evening, a number of control periods also occur during the morning, typically driven by commercial and industrial customers at these times.

The current demand formula does not use ToU data that is available from other users beyond the domestic sample (which is approximately 150 domestic meters). Including the data from other identified customer segments (holiday homes, industrial/commercial, dairying, etc) would provide a wider sample for use in the formula derivation. The inclusion of this additional data should result in a better approximation of the differing customer types and their consumption patterns.

Further, the use of customers with different size characteristics may introduce a degree of segmentation without explicitly needing to model or create demand formulae for the different customer groups. The lower consumption customers would mainly consist of domestic installations and may be described by one part of the formula, while customers with higher consumption may be catered for by the implied relationship at higher consumption values.

5.2 Differences across geographies

Currently all of the domestic meters used to generate the demand formula come from one network area (Hangatiki). The formula is then applied to the other network areas without cognisance of the differences they have compared with the sampling area.

Similar to the issue of customer segmentation raised in section 5.1, the different network areas of the TLC area have differing characteristics in terms of weather patterns, the degree of network constraint, and predominant activities. Other examples of differences include the Ohakune winter demand being heavily influenced by the seasonal snow business, while the Turangi area has concentrations of holiday homes used sporadically throughout the year. These features can result in different load factors and peak demand patterns to those of the Hangatiki-based sample.

5.3 Different load control regimes

The third area of distinction that is not addressed by the demand formula is that each of the different areas operates a different load control regime. The timing, duration and frequency of load control differ from area to area, as does the amount of controllable load. The metering sample is based on the distribution of load control periods around Hangatiki, but the other areas have a very different number of control periods (either greater or less).

As discussed in section 4.2 this difference is likely to result in a measured peak demand and thus implied load factor that is different area to area. The demand formula assumes that the average customer's behaviour overlayed with the different load control regime will make no difference to the implied demand levels and load factor. If the underlying formula was developed for each area, the impact of the number of load control periods in each area would directly influence the observed maximum peak.

5.4 Demand formula - summary

The demand formula is useful as it enables the implementation of charging for peak demand imposed by individual customers on the network, in circumstances where the customer does not have a TOU meter. In Section 4 we discuss how the application of a demand charge for ToU metered customers provide those customers with the incentive to reduce this demand at peak times. For the non-ToU customers, the application of the demand formula falls short of being as effective as for TOU customers, as it does not convey a real time price signal to reduce demand, but it does provide incentives for these customers to shift consumption to controlled circuits (as their demand is estimated using their consumption on uncontrolled circuits).

The issue essentially becomes how to best approximate the demand of a non-TOU customer relative to those customers in the same region that have TOU meters:

- In an area with many more control periods than the domestic sample, the peak measured by a ToU meter is likely to identify a higher peak as it includes the maximum of many readings. Further, the time and distribution of the maximum demands may be on a different basis to those of the domestic sample.
- Areas or customers with no load control would be charged on their uncontrolled load while those with unidentified channel information would still be charged on uncontrolled load but on the default channel basis, even if they have controlled load on a different channel.
- Various customer segments are known to have different characteristics. Holiday homes and dairy sheds, for instance, are treated as exceptions and therefore on a different basis. Other segments, also known to have different characteristics, are currently charged on the formula derived from the demand pattern of Hangatiki-based domestic customers.

These differences provide customers with incentives to either remain with a non-ToU meter or install a demand meter to avoid the demand formula, as they create groups of financial winners and losers. Based on the information available:

- Users with a high proportion of off-peak or base load consumption could install ToU meters to avoid over-paying demand charges.
- Areas with many more demand control periods (Ohakune for example) could stay on the demand formula to avoid proportionately higher peaks.
- High peak load customers (potentially including holiday homes) could stay on the demand formula to avoid proportionately higher peaks.

The combined impact of these pricing incentives is that the original basis for charging under the formula will initially become more unbalanced within each year as customers self-select, until all non-ToU meters are replaced, or the behaviour of the remaining population of customers is reflected in the demand formula.

5.5 Possible Improvements

Any formula based method for estimating demand based utilising energy consumption will have significant weaknesses. In addition, an approach short of charging customers on their measured demand will not in practice provide customers the clear incentives necessary to reduce their uncontrolled demand.

Drawing on the above discussion, some possible refinements are as follows.

- Develop demand formulae for each geographic region to address the primary differences in load control application and secondary differences in environment, end-use and customer behaviour.
- Segment the customer base, as there are several clearly identified customer types. Some have substantially different operating characteristics to the current domestic ToU customer sample. However, for the non-domestic customers, the size of the customer may provide a simple differentiator that can be included in a single demand formula, without a separate formula for each customer group.
- While some customers have self selected ToU meters and may bias results, the spread of ToU data across different areas provides additional information that can be used in formula development. The aim should be that an average customer would not be disadvantaged under either the formula or a ToU meter.
- Analysis of customers and consumption should help identify actual behaviours rather than broad "rule-of-thumb" metrics. For example, the holiday homes data shows average peaks of 3kW+ implying there is little merit in using a 2kW average.
- As the ToU meter roll-out progresses, the averaging result of the formula method will more accurately reflect the population behaviour as a whole (but still not reflect individual customer consumption patterns).

Given the above considerations, we recommend TLC transitions to a demand formula for each geographic area using all of the ToU data that is available. As TOU meters are rolled out these datasets will increase considerably. This transition will require some judgment as to when there are sufficient data to implement a formula for each geographic area, and which data are used. Such judgments should be documented and published so they are transparent to customers.

We also recommend incorporating into these formulae any changes to the way in which demand is measured for TOU customers, as recommended in section 4, to ensure consistency across TOU and non-TOU customers.