Tracing the flow of electricity in New Zealand

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ABSTRACT
Electricity tracing can assess the particular impact of a generator or demand on the power system. For each generator, the technique can determine the demands they supply, and likewise, for each demand, the technique can determine the generators who provide physical supply. In addition, the proportion of the total electricity flow in each individual transmission asset can be attributed to either the generators or demands that use the asset.

A tracing algorithm has been developed and applied to historic market load flow solutions for each half–hour during the ten year time period, 1999–2008. Results are presented illustrating flow patterns from generators to demand and patterns of transmission asset usage. An informed discussion is had on the usefulness of such a tool and its possible applications for resolving some of New Zealand's current electricity market issues. These issues include the further development and implementation of various energy policies such as those described under the current Market Development Program (MDP); specifically, the transmission pricing review investigating changes to Transpower's Transmission Pricing Methodology (TPM), and as a tool for managing locational price risk through a Locational Rental Allocation (LRA).
***Index Terms*—Tracing, Transmission Pricing Methodology (TPM), Locational Rental Allocation (LRA), Market Development Program (MDP)**

I. Introduction

Electricity tracing is not new. New Zealand was perhaps the first in the world to implement an electricity tracing routine when it was used as part of Transpower's Transmission Pricing Methodology (TPM) in 1993 [1]. Several years later, electricity tracing was more formally described by Janusz W. Bialek in his classic 1996 paper *Tracing the flow of electricity* [2] [3]. In more recent years, tracing has been proposed, and used, as a solution to many market related problems around the world. These include; as a method to allocate the merchandise surplus[1] (known in New Zealand as loss and constraint rentals) [4] or to help allocate transmission charges to users of the transmission network [5], including large interconnected networks of multiple countries [6], [7].

In Transpower's 1993 TPM, computational limits meant simplifications were required[2]. This involved use of a modified power flow solution which exhibited unusual behaviour at some locations when applied to a transmission pricing methodology; for example, high year-on-year price volatility at certain locations. As a consequence, some industry participants now have a negative view on tracing based power flow techniques, certainly as far as transmission pricing is concerned[3].

Since 1993 there have been some major developments in both the tracing methodology, and in computer technology, which include:

- A more formulaic representation with sparse matrix inversion that has been fully documented by Bialek [2]; and,
- Increases in computational power that now mean simplifications are no longer required, enabling not only a few operating states to be traced, but every operating state, in this instance, over the previous ten years[4].

In light of these developments, this paper reports on a re-investigation of the tracing method and some of its possible applications in the current electricity market environment. It should be noted that although the method may appear complex, it is conceptually simple and could be used to derive 'rules-of-thumb' or provide simple observations of power system behaviour. Much of this work is ongoing.

A. Transmission network characterisation

Tracing enables assessment of the usage by a particular generator, or load, on the transmission network. It can characterise the transmission network by distinguishing which generators supply, and which transmission assets are used to supply, each individual demand, and *vice versa*. It identifies which elements contribute to providing reliable physical supply to demand. Unlike participation factors based on the marginal effects of a change to demand/generation on the network [8], tracing is able to provide participation factors based on actual usage. This has advantages and disadvantages, depending on what it is intended for.

In the context of the current electricity market, it appears such techniques could have uses for demand-side applications under the premise that most load/demand customers tend not to participate in the marginal nodal market, i.e., they are relatively inelastic to price.

The technique may be useful to aid understanding of how the transmission network is used and therefore help inform decision making, such as the current MDP work underway by the Electricity Commission[5]. Examples of this include; as a tool to address allocation of loss and constraint rentals (Section IV), or to aid understanding of historic grid usage patterns and possibly changes to Transpower's Transmission Pricing Methodology (Section V).

[1]The surplus created by the marginal nodal market due to losses and price separation from constraints on the transmission system.

[2]The method was applied to a *pseudo* operating point that was calculated using a *cluster analysis* on historical power flow solutions [1].

[3]http://www.electricitycommission.govt.nz/submissions/mdp-subs/tpr

[4]For this work, all computations were performed with MATLAB 7.9, on a HP EliteBook 8730w with an Intel Core 2 Duo CPU (T9600 2.80GHz) running Microsoft Windows XP Professional x64 Edition with 8 GBytes of RAM. Even with this computing resource, memory limits were often an issue and many computations took between 1–2 hours per year of simulation.

[5]http://www.electricitycommission.govt.nz/opdev/mdp

II. The technique

The underlying methodology is well documented in the papers by Bialek [2] — [4] and so is not repeated here in detail. The technique rests on a solved power flow solution with known branch/circuit power flows that obey Kirchhoff's current law. It also assumes that electricity is *indistinguishable* and that every node (or substation) is a perfect 'mixer'.

Figure 1 below illustrates the basic proportional sharing principle, as used by Bialek.

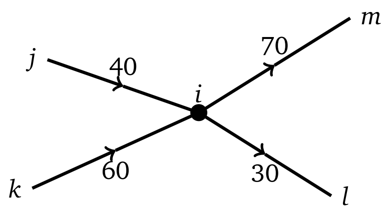

Fig. 1. Proportional sharing principle (as demonstrated by Bialek)

Four lines/circuits are connected to node/substation i, two with inflows and two with outflows. The total power flow through the substation is $P_i = 40 + 60 = 100MW$ of which 40% is supplied by line j–i and 60% is supplied of line k–i. As electricity is indistinguishable, and each of the outflows down the line from node i is dependent only on the voltage gradient and impedance of the line, it may by assumed that each MW leaving the node contains the same proportion of the inflows as the total nodal flow P_i. Hence the 70MW outflowing in line i–m consists of $70\frac{40}{100} = 28MW$ supplied by line j–i, and $70\frac{60}{100} = 42MW$ supplied by line k–i. Similarly the 30 MW outflowing in line i–l consists of $30\frac{40}{100} = 12MW$ supplied by line j–i, and $30\frac{60}{100} = 18MW$ supplied by line k–i.

Repeating this process upstream to generators, or downstream to demand, allows the usage to be derived for particular transmission assets either by generation or demand. This type of trace may be a useful tool for transmission pricing. Likewise, the method can be used to trace from a single demand (Grid Exit Point – GXP), upstream to the generators (Grid Injection Points – GIPs) who supply each demand (GXP→GIPs), or from a single generator (GIP) downstream to the demands (GXPs) that each generator supplies (GIP→GXPs). This type of trace, from generators to demand, may be a useful tool for allocating rentals.

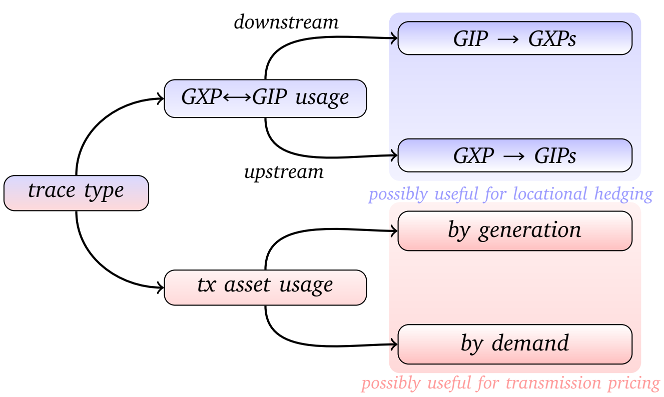

Fig. 2. Different types of trace

III. Application to the NZ power system

In New Zealand the market is scheduled, priced and dispatched with the SPD algorithm by the System Operator [10]. Data of the resulting circuit/branch flows is kept, along with a historic topology description file. These have been used to perform the power trace.

Figure 2 illustrates the different types of trace and the following sections give examples of these.

A. GXP⟷GIP tracing

Two different types of GXP⟷GIP trace can be performed;

GIP → GXPs *Downstream*, from each individual generator to the demands they supply; and,

GXP → GIPs *Upstream*, from each individual demand to the generators which supply them.

For each method, losses are handled by either reducing effective generation, called *net generation*, or, increasing effective demand, called *gross demand*. Tracing from each GIP → GXPs requires actual demand with reduced *net generation* and can be used to quantify actual losses incurred on the network by each generator.

Likewise, tracing from each GXP → GIPs requires actual generation with increased *gross demand* and can be used to quantify the actual losses incurred on the network by each demand.

Figure 3 and 4 illustrate this method for a particular half-hour very early in the morning on the 30th June, 2008.

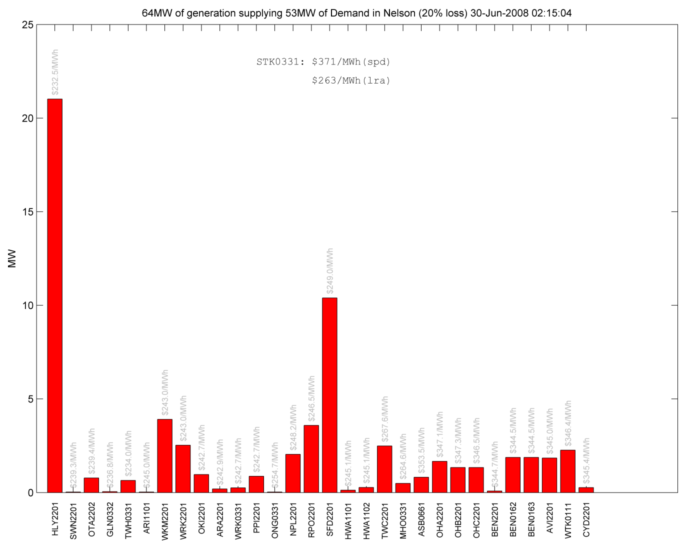

Fig. 3. Generation supplying Nelson very early in the morning on the 30th June, 2008

During this half-hour, the HVDC was running at around 520MW southwards, constrained[6], with many of the North Island generators supplying South Island demands. The sparse matrix output of the trace algorithm is illustrated in Figure 4. Demand/Load buses are on the y-axis with generation buses on the x-axis, both sorted, North to South, by latitude. It can be seen that power from many of the North Island generators supplied South Island demand, from the top of the South Island, to as far south as Oamaru (bus OAM1101).

The pink line in Figure 4 illustrates the generation (where the line intersects the blue dots) that supplied Nelson's main 33kV supply bus at the Stoke substation (STK0331).

[6]Most likely as a result of reserves.

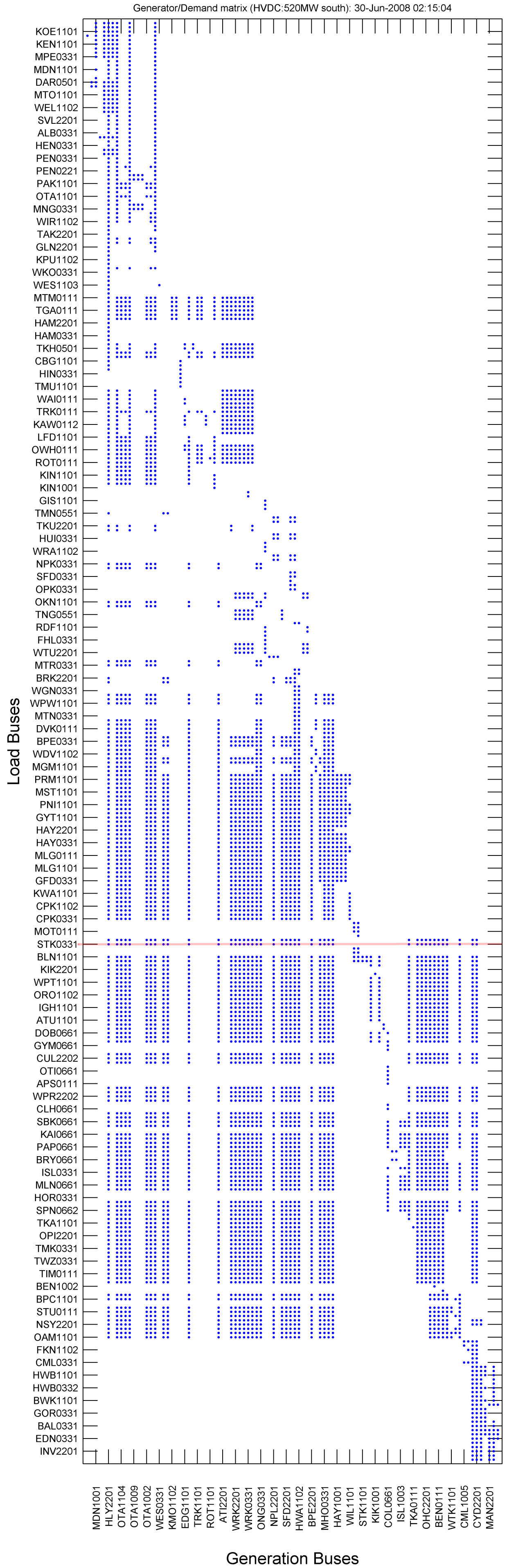

Fig. 4. Sparse matrix illustrating each demands share of generation.

As illustrated in Figure 3, Nelson's 53MW demand was supplied by 64MW of generation[7] across New Zealand from as far north as Huntly, where the majority of the power is coming from, to as far south as Clyde in the lower South Island. This single half-hour is off-peak, during an energy constrained period where it was more economic to supply Nelson, and much of the South Island, from North Island thermal generators. This type of trace may be useful for allocating rentals, (Section IV).

By summing each half-hour over the year, then dividing by the number of half-hours, the average generation that actually supplied Nelson during 2008 is determined. This is illustrated in Figure 5.

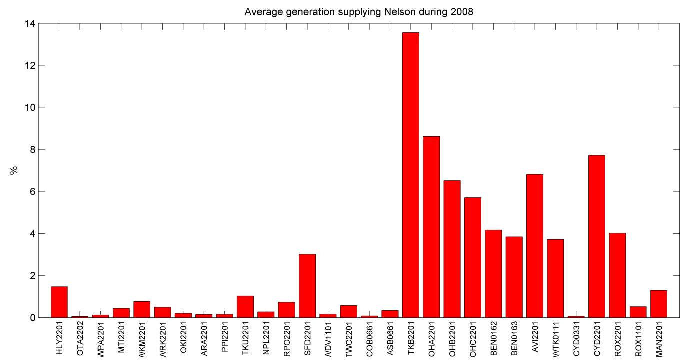

Fig. 5. Average generation supplying Nelson during 2008

Interestingly, power from the Cobb hydro power station which was originally built to power Nelson and the Golden Bay region, rarely makes it out of Golden Bay to Nelson. Of all power stations, Tekapo B supplies the most power to Nelson, followed by the Waitaki Valley chain of stations. These observations also appear true for other years as well.

B. Losses

The average loss attributable to Nelson during 2008 is the difference between the gross demand (i.e., the sum of the generation that supplies Nelson) and the actual average demand. I.e., 76.8MW - 70.5MW = 6.3MW (or 8.9% of actual STK0331 demand).

Figure 6 illustrates the actual average MW losses incurred by each lines company in Transpower's network between 1999 and 2008. The legend provides the average loss incurred on Transpower's network for each year. The variation between years is dependent on a number of factors which include how generators are dispatched, new or decommissioned generation, wet or dry year variation, growth, etc.

Interestingly, the losses in Transpower's grid caused by Vector, the largest lines company in Auckland, have tended to reduce in recent years. This is perhaps due to large new thermal plant being sited close to Auckland, i.e., the Huntly E3P generator. Aside from Wellington Electricity, this appears the case for most North Island demand participants. Wellington Electricity and most South Island distributors appear to have increased their share of Transpower grid losses.

Losses give some indication of grid usage; higher losses tend to indicate more usage, while lower losses tend to indicate less usage. However, the tracing algorithm enables *actual* grid usage to be determined, as described in the following section.

[7] A 20% loss across all generators supplying Nelson.

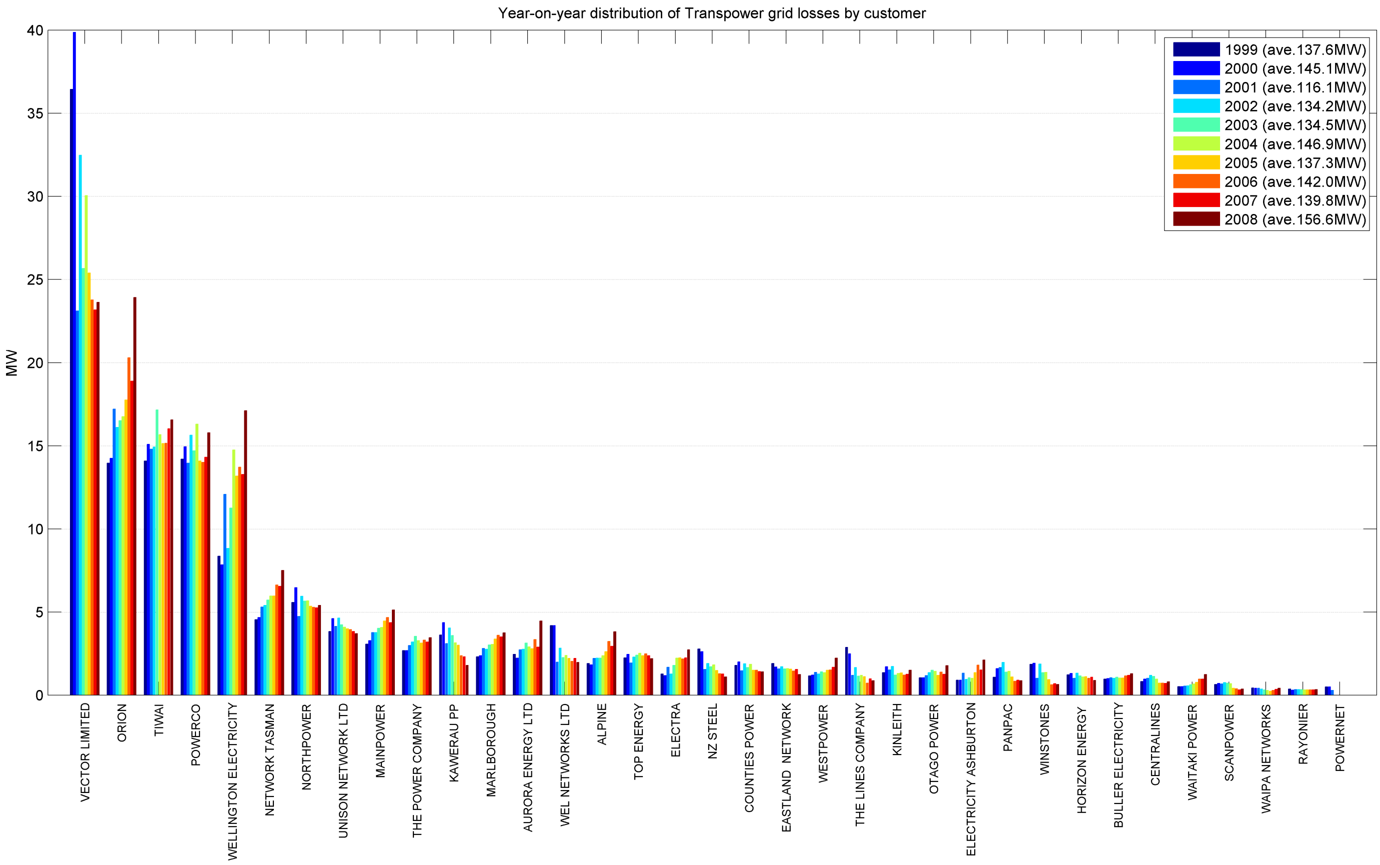

Fig. 6. Year-on-year average losses incurred on Transpower's network from each lines company and large direct connected customers.

C. Transmission asset usage

As previously explained there are two different types of transmission asset tracing; asset usage by demand, and asset usage by generation.

Using the same time as the previous example, 2am on the morning of the 30th June, 2008, Figure 9 illustrates the sparse matrix output of the trace algorithm for asset usage (by demand/GXP) of all transmission circuits, including transformers, in Transpower's transmission network. The horizontal pink line illustrates Pole 2 of the HVDC link. In this instance, with 520MW of southward flow, the South Island GXPs that use the HVDC link are illustrated where the pink line intersects the blue dots. Plotting along this line gives the magnitude of the users traced to the HVDC link, as illustrated in Figure 7.

In relation to the previous example; it can be seen that over 40MW of the electricity flow through the HVDC link supplies Nelson's Stoke substation (STK0331). This flow is from those North Island generators identified in Figure 3.

Figure 7 illustrates a single half-hour in which the HVDC link is in a relatively unusual operating state. By summing each half-hour over the year, then dividing by the number of half-hours, average usage patterns can be determined. In addition to this, load and generator buses can be grouped to provide average participant usage patterns. To illustrate this, Figure 8 shows the annual usage spread among off-take customers for one of the main transmission lines into Auckland from Whakamaru; the Otahuhu-Whakamaru A line.

As illustrated, the three Upper North Island (UNI) lines companies (Vector, Northpower and Top Energy) share the bulk of the usage of this line, however, there are occasional times when electricity flows south resulting in other, perhaps surprising, users. This includes a tiny proportion (perhaps resulting from a single half-hour) when flows through the Otahuhu-Whakamaru A line reached the Tiwai aluminum smelter at the bottom of the South Island. This type of trace could assist with some aspects of transmission pricing (Section V).

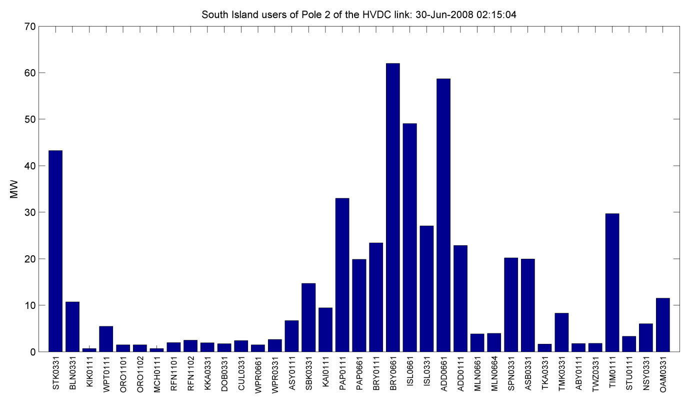

Fig. 7. South Island GXP usage of the HVDC link, early in the morning of the 30th June, 2008

The previous sections (II and III) have described the tracing technique, illustrating its ability to distinguish the physical usage of the grid by participants. The following sections (IV and V) examine how the technique could possibly help solve some of the current market development issues in New Zealand.

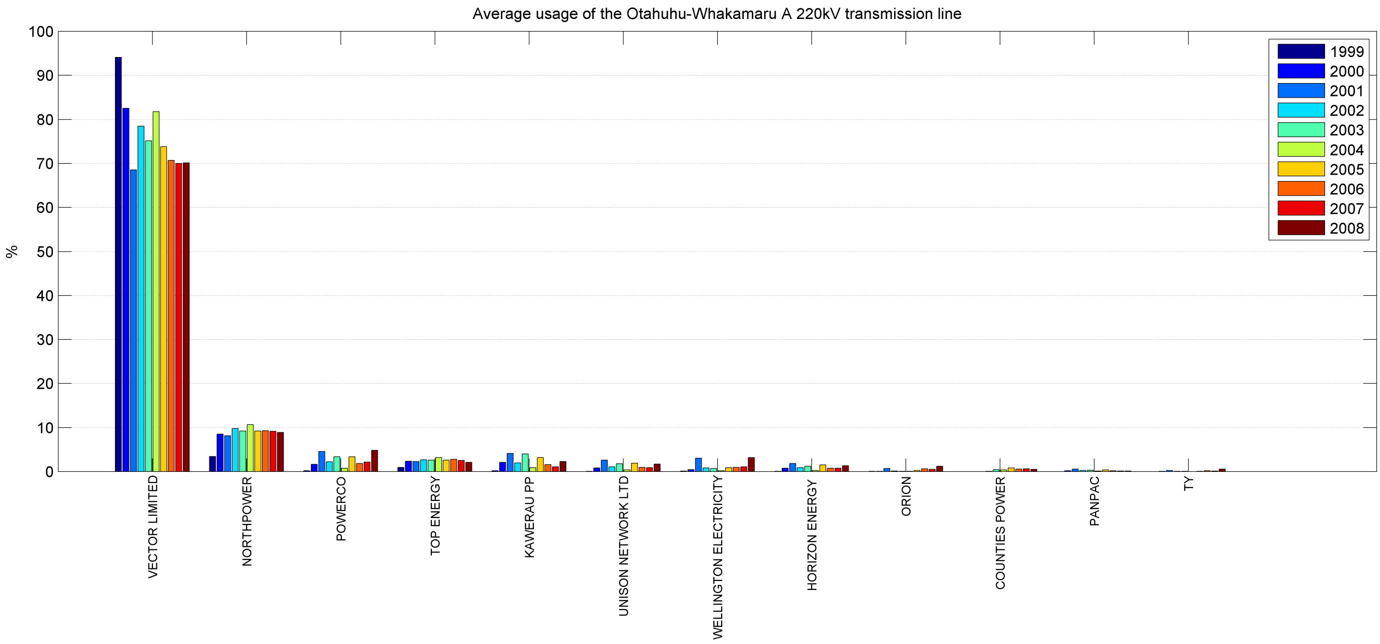

Fig. 8. Average year-on-year usage of the Otahuhu-Whakamaru A line by off-take customers

Fig. 9. Asset usage matrix, early in the morning of the 30th June, 2008

IV. A TRACE BASED LOCATIONAL HEDGING MECHANISM

This section applies the trace to investigate a locational hedging mechanism which could be used for rental allocation in New Zealand. The main problem with any locational hedging solution is how to tailer it to fit the current New Zealand market, especially with the vertical integration of the generator-retailers.

The rental allocation option described here could be considered as a full LRA (in the context of the Electricity Commission's current locational hedging options), or, it could be used in other ways – for example; as part of a hybrid option, or simply as a tool to help inform decision makers.

Though conceptually simple, it is more sophisticated and addresses most of the current issues with simpler LRAs based on weighted average prices. Instead of a national, or island weighted average hub price, the algorithm determines the weighted average of all the generator nodal prices that *physically* supply each GXP. By doing this, a physical hedge is allocated to off-take customers based on their actual usage of the transmission system[8]. The algorithm allocates all rentals all of the time. During transmission constraints, when rentals are high, it allocates rentals precisely to those off-take customers who require them.

Nodal prices for generation remain unaltered, and the main players in the market, i.e., the generators, still face the undisturbed, economically efficient Short Run Marginal Cost (SRMC) prices and should react in a correct way to the incentives and disincentives contained in the pricing signal.

The method could be implemented in real-time using dual nodal prices at each node; the current nodal price for generation, and a weighted average price for off-take[9] (i.e., real-time allocation of rentals). Alternatively, it could be used to collect rentals which are then allocated on a monthly or annual basis[10].

Both forms of LRA could address many of the concerns of industry participants[11].

[8]This may have similarities with allocated, simultaneously feasible Financial Transmission Rights (FTRs) [9].

[9]It could be argued that this weakening of the proper economic signal is acceptable as, for a typical consumer, electricity is usually a relatively minor cost and the sensitivity of response to price is weak.

[10]In New Zealand real-time dual nodal pricing would provide feedback to the generator-retailers which could have disadvantages not only in terms of efficient nodal pricing, but also with the possibility of market power issues over rental collection. This is further discussed in Section IV-A.

[11]http://www.electricitycommission.govt.nz/pdfs/opdev/wholesale/hedge/Summary-Submissions-LPRM.pdf

These include:

1) Conceptually simple and transparent;
2) Allocates rentals on a nodal basis to every GXP;
3) Can allocate in real-time or monthly/annually;
4) Generators still face the full nodal price (for example; promoting peaking generation when prices are high);
5) If allocated monthly or annually, demand still faces the full nodal price;
6) Compensates for the effects of undesirable trading situations and *spring washers* on demand.

However, the method is not without its problems, (see discussion). Whether used in real-time or allocated on a monthly or annual basis, it is worthwhile considering the following example as an illustration of the method for a single trading period. Section IV-B then presents results of the method applied across the New Zealand network.

A. An illustrated example

Figure 10 illustrates a simple two bus power system.
The transmission line is constrained with generator **B** exercising market power. We assume the transmission limit is 110MW and the demand at bus **B** is 160MW. In this instance the market model dispatches the lower cost generator **A** to 210MW @ \$100/MWh while generator **B**, which must be dispatched, is dispatched at 55.4MW @ \$1000/MWh.

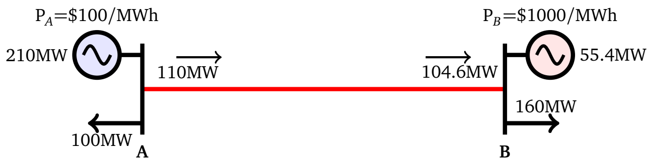

Fig. 10. Example two bus power system, with losses and a constrained transmission line.

The total Demand Payments (DP), Generator Revenue (GR) and rentals/surplus are[12]:

$$
\begin{aligned}
DP &= 100MW \times \$100/MWh + 160MW \times \$1000/MWh \\
&= \$170,000/hour \\
GR &= 210MW \times \$100/MWh + 55.4MW \times \$1000/MWh \\
&= \$76,400/hour \\
rentals &= \$93,600/hour
\end{aligned}
$$

Load **A** causes no transmission loss or constraint, as its demand is fully satisfied locally by generator **A**. Similarly, 55.4MW of demand of load **B** is satisfied locally from generator **B**. However, 104.6MW coming from generator **A** attracts a loss of 5.4MW. Load **B** off-take customers could argue that instead of paying: 160MW × 1000/MWh = \$160,000/hour, as they do currently, they should pay: 55.4MW @ \$1000/MWh + (104.6 + 5.4)MW @ \$100= \$66,400/hour. Generation payments remain unaltered, but the total demand payments and rentals/surplus would become:

$$
\begin{aligned}
DP &= 100MW \times \$100/MWh + 55.4MW \times \$1000/MWh \\
&+ (104.5 + 5.4)MW \times \$100/MWh \\
&= \$76,400/hour \\
rentals &= \$0/hour
\end{aligned}
$$

This eliminates the total surplus/rental across the transmission line and requires that the nodal price for off-take/demand customers at bus **B** becomes: (\$66,400/hour)/160MW = \$415/MWh. Significantly lower than if the demand pays the generator nodal price of \$1000/MWh.
This illustrates the main concept of this LRA methodology which allocates all rentals to those off-take customers who require them, especially under transmission constrained periods.

[12] It is assumed that all energy is traded on the spot market and that there are no bilateral contracts between buyers and sellers.

Discussion

Market power due to vertical integration

Assume that some of the 160MW demand at bus **B** in Figure 10 are customers of generator **B**. In this instance the generator could be incentivised to further increase its nodal price, *collect* the increased rentals (through the lower average price to its retailer at bus **B**), and push up the average price at bus **B** for other retail competitors. The greater generator **B's** retail component at bus **B**, the greater this problem could become. This is an issue if the transmission constraint could be pre-empted, or created, by generator **B**, or during contingent or scarcity events with notional VoLL generators, as described below[a].

Scarcity pricing

Constrained periods can either be transmission related, or, energy/capacity related. Both types of constraints could potentially be handled with the use of notional Value of Lost Load (VoLL) generators that are used to represent demand reduction.
Even a tiny demand reduction, or lost load, at bus **B** in Figure 10 would force the generation nodal price at **B** to VoLL. For this particular case, and assuming a VoLL of \$20,000/MWh, this would correspondingly increase the weighted average demand price at bus **B** to \$6990/MWh[b]. Though VoLL is seen in the nodal price signal, this lower price would be used to allocate rentals over this time period.

A possible solution?

The actual transmission network is interconnected, or meshed, and there are only a few locations on the transmission network that resemble Figure 10 and where market power issues (over rental collection) could become problematic. However, these could increase as generator-retailers alter their behaviour. Possible solutions, aside from splitting retailers from generators, could be to simply allocate rentals on a monthly or annual basis. This helps disable the 'perfect' real-time feedback of the LRA on GXP nodal prices but does not fully solve the issue, and market monitoring by the industry regulator would likely be required.
Further work is required to investigate these options and associated problems, many of which are common to general locational hedging.

[a] This is also a problem for other locational hedging methodologies.
[b] $\frac{104.6MW \times \$100 + 55.4MW \times \$20,000)}{160MW} = \$6990/MWh$.

B. Application to the full New Zealand network

Using the same time period applied in the previous examples, this section illustrates the result of an LRA using a trace at 2am on the 30th of June, 2008. During this time the HVDC was running at around 520MW southwards, it was constrained with many of the North Island generators supplying South Island demands during an energy shortage period.
Figure 3 illustrates all of the generators that were supplying the 53MW at the Stoke substation in Nelson. A total of 64MW was required (a 20% loss) with most power coming from the Huntly and Stratford power stations, transmitted through the HVDC link down to Benmore, then up to Christchurch and the Upper South Island.
There is price separation between islands as indicated by the grey marginal energy prices on top of the bars. The marginal price of electricity in Nelson during this time period was \$371/MWh, whilst the weighted average of the generation supplying Nelson (the LRA price) is considerably lower, at \$263/MWh. This lower nodal price at Nelson could then be used in allocating rentals.

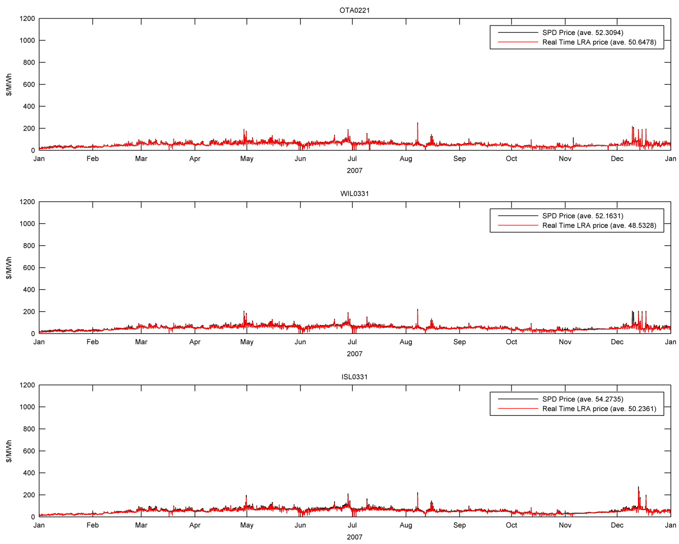

Fig. 11. Nodal Prices for Auckland (OTA0221), Wellington (WIL0331) and Christchurch (ISL0331) for 2007.

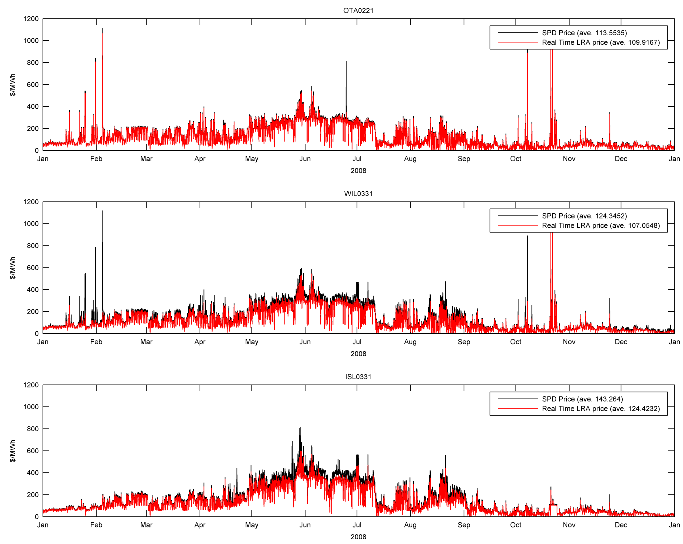

Fig. 12. Nodal Prices for Auckland (OTA0221), Wellington (WIL0331) and Christchurch (ISL0331) for 2008.

C. Comparison of nodal prices

Section IV-B has provided an example of the technique for a single trading period and location. Figure 12 illustrates the difference in nodal prices between three locations; Auckland (OTA0221), Wellington (WIL0331) and Christchurch (ISL0331) after applying the technique over the year 2008[13,14]. The black lines indicate the cleared market SRMC nodal prices while the red lines indicate the LRA prices which could be used to calculate rental allocations[15].

Wellington (WIL0331) can be seen to benefit from the HVDC link during times of constrained northward HVDC flow in late January to early February. The overall benefit or compensation to consumers, at each of the locations, is seen in the reduced average prices (as indicated in the legends). 2008 was a dry year and the HVDC link was constrained for considerable periods, mainly in a southward direction. In contrast, 2007 which was a wet year, is illustrated in Figure 11 with the same y-axis scale for comparison.

D. Undesirable Trading Situations

An undesirable trading situation (UTS) arises when there is a threat to orderly trading on the wholesale market or settlement that cannot otherwise be resolved satisfactorily under the rules. Undesirable trading situations are published on the Commission's website[16].

Participants can make a claim that a UTS occurred, which is then investigated by the Commission and a decision is made regarding the particular event.

Many of the events claimed are the result of *spring washers*, where a transmission constraint, in parallel with a high impedance branch, results in large nodal prices at a particular location. The following example illustrates a historical situation where a UTS was claimed by a market participant, and the decision by the Commission was not to intervene (hence final price data has been recorded).

1) 24th June, 2008: During trading periods 36 to 38 a grid emergency was declared by the System Operator due to a concurrent unplanned outage of the Arapuni – Bombay 1 circuit and an extended planned outage of Huntly – Otahuhu 1 circuit.

[13]Note: this assumes that behaviour of the generator-retailers does not change after implementation of the LRA.

[14]Results for every GXP are available over the ten year period, 1999–2008, but not presented here due to space limitations.

[15]This is achieved by calculating the difference between the two prices for every trading period, multiplied by each retailers GXP off-take, and then summing over all trading periods, either monthly or annually.

[16]http://www.electricitycommission.govt.nz/rulesandregs/uts/

The System Operator advised the Commission that the grid emergency was declared as the loss of the Huntly – Otahuhu 2 circuit would cause the Bombay – Hamilton 2 circuit to exceed its advised rating[17].

The events that gave rise to this grid emergency also caused a high spring washer pricing event. The calculated prices for trading periods 36 to 38 contain high prices (approximately \$3,000/MWh) and low prices (approximately - \$6/MWh)[18] and can be seen in the elevated price for Auckland (OTA0221) in Figure 12. Figure 13 illustrates the actual nodal prices for off-take customers (the SPD model – light blue) and the result of the LRA (pink). The LRA significantly dampens the GXP nodal prices in the Upper North Island (UNI). These lower prices are what could be used to compensate demand customers.

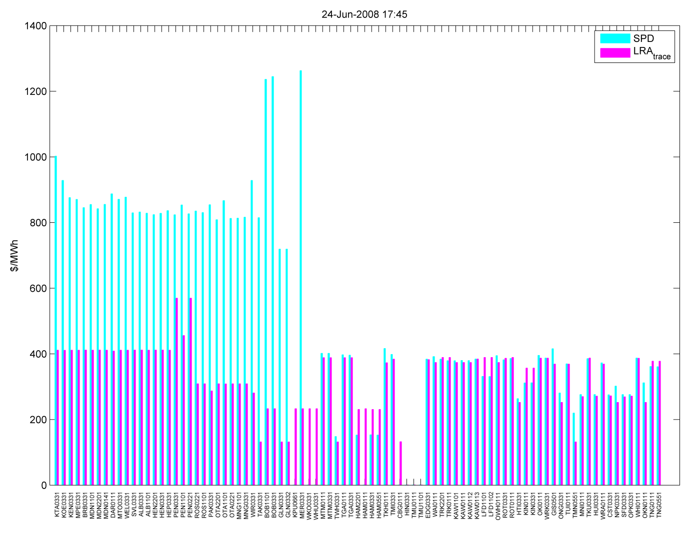

Fig. 13. Nodal Prices (off-take) from Kaitaia to Tangiwai for Trading Period 36 on Tuesday 24 June 2008.

The LRA demonstrated here is likely to improve the risk associated with retailer location. Much of this work is ongoing, and future work could include investigating how rentals might have been allocated to retailers during recent years. The following section looks at applications of the trace for transmission pricing.

[17]I.e., the Upper North Island (UNI) was on N security.

[18]For more information see http://www.electricitycommission.govt.nz/pdfs/rulesandregs/uts/utspdfs/UTS-Decision-Genesis-1Jul08.pdf

V. Transmission Pricing

This section investigates the possible application of a tracing based approach for assisting in future Transmission Pricing Methodologies (TPMs). This work has been done in conjunction with the current transmission pricing review, underway by the Electricity Commission.

In 1993, Transpower used a similar method to determine the usage of the transmission assets. However, for reasons explained in the introduction, it now appears prudent to revisit power flow tracing using modern technology and with the more formal mathematics introduced by Bialek.

A. Connection, Inter-connection and HVDC assets

The current TPM used by Transpower under the transmission pricing guidelines[19] divides transmission assets into connection, interconnection, and HVDC assets. Connection assets are paid by off-take and generation customers on a user-pays basis, while interconnection assets are postage stamped to off-take customers based on their Regional Coincident Peak Demand (RCPD). The HVDC link usage is charged to South Island generators who are postage stamped on their Historic Anytime Maximum Injection (HAMI).

By definition, such differentiation between assets can cause discontinuity and lead to lobbying from those affected by investment decisions made by Transpower. An example includes the current connection/interconnection definition, as outlined in a letter to the Electricity Commission from Transpower in October 2009[20].

Three specific problems described in this letter were all a direct result of the connection/inter-connection asset definition under the existing TPM. Transpower proposed three possible solutions, namely:

Shallower definition of connected assets – where all transmission assets apart from direct connection assets at a GXP/GIP are treated as interconnection assets;

Deeper definition of connected assets – where additional transmission assets are included as connection assets with the potential to create regional connection grids;

Beneficiary/user pays – where some form of beneficiary/user pays approach is used and applied, either across the entire grid, or, just to that part of the grid which is not interconnection.

A tracing based approach could be used to assist in any of these options but would perhaps be more in line with deepening the definition of connection assets, or in a beneficiary/user pays approach over the entire grid.

Tracing demonstrates physical usage, and as such does not determine 'economic utility' to grid users. It therefore may not be desirable to seek to recover all grid revenue using this approach. The following section investigates how deepening connection assets (using a trace) would effectively remove problems currently faced by the current definition of connection and interconnection assets.

*1) **220/66kV capacity into Christchurch**:* Transpower provide a useful example where a new 220/66kV interconnecting transformer is required into Christchurch[21]. By definition, if the transformer is installed at Bromley, it is considered a connection asset, and Orion (the local lines company) pays for the asset. Orion argue that if the asset were to be built at Islington it would be defined as an interconnection asset and they would pay just 10% of the total cost (based on the current RCPD pricing). Transpower, having determined that the greatest economic benefit is to install an interconnecting transformer at Bromley is now subject to lobbying which, if sucessful, may result in uneconomic investment.

Such issues could be resolved using a tracing based methodology. Figure 14 illustrates the usage of an existing Islington 220/66kV interconnecting transformer. As illustrated, Orion is by far the largest user of the existing transformer (over 90% in recent years[22]). Here, if a trace was used to either deepen connection assets or to charge more generally for transmission assets, Orion would be required to pay 100% for a new Bromley transformer (as they use 100% of the Bromley substation assets), or ≈90% for a new Islington transformer (as opposed to 10% under the current TPM). Such a change in the TPM would provide reduced incentive for a lines company to lobby for uneconomic investment.

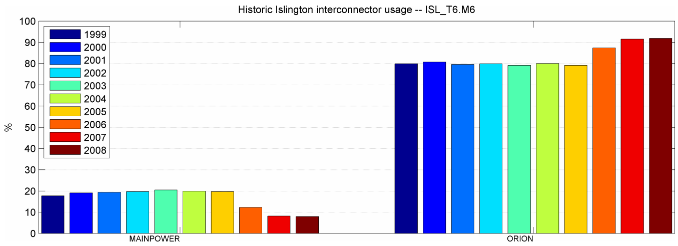

Fig. 14. Usage of Islington 220/66kV interconnecting transformers.

B. A users pays approach?

The tracing algorithm is able to distinguish those assets used by each participant for each historic half-hour. This *ex-post* approach, assuming historic behaviour, can then be used to approximate future use of the transmission system and possibly inform *ex-ante* (future) pricing options (as in the example of the previous section). Such analysis, applied over the grid, would mean that all future projects would be paid for by those who are likely to use them, based on past usage.

User pays and beneficiary pays are not the same thing. Economists argue that any transmission pricing should be based on forward looking *ex-ante* beneficiary pays transmission investment, or total 'economic utility' to grid users, taking into account the future power system as a whole, with its locational dependence on resources, etc. Theoretically this is the perfect outcome for any transmission pricing model.

As the future is unknown, any pricing methodology based on forward looking futures, across multiple scenarios, is at risk of charging assets to the wrong party or charging for assets that are not in fact built. One compromise is to assume that some sort of user pays approach approximates this perfect forward looking view, but with an associated time lag so that historic behaviour, which is known, can then be used to predict future grid usage and hence any pricing methodology. To some extent this is what is done currently under the existing TPM for interconnecting assets, where the grid is characterised by the historic average 12 or 100 peak demand periods. There are multiple ways of doing this, and multiple ways of using the tracing method. At the time of writing, work is still in progress, however, the following section quantitatively illustrates an example of what is achievable using a trace based approach.

Note: This does not reflect any future proposals for a TPM, but is merely provided to demonstrate physical grid usage.

[19] See http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpg/TPM-guidelines-mar06.pdf and http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpm/Appendix2-TPM-final.pdf

[20] See http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpr/TP-ltr-30Oct09.pdf..

[21] This issue is documented on the Commission's website at http://www.electricitycommission.govt.nz/opdev/transmis/tpm/interim-ruling.

[22] In 2006, two new 220/66kV GXPs were installed at Culverden and Waipara for the benefit of Mainpower. The effect is seen in the lower Islington 220/66kV usage by Mainpower, and correspondingly higher usage by Orion.

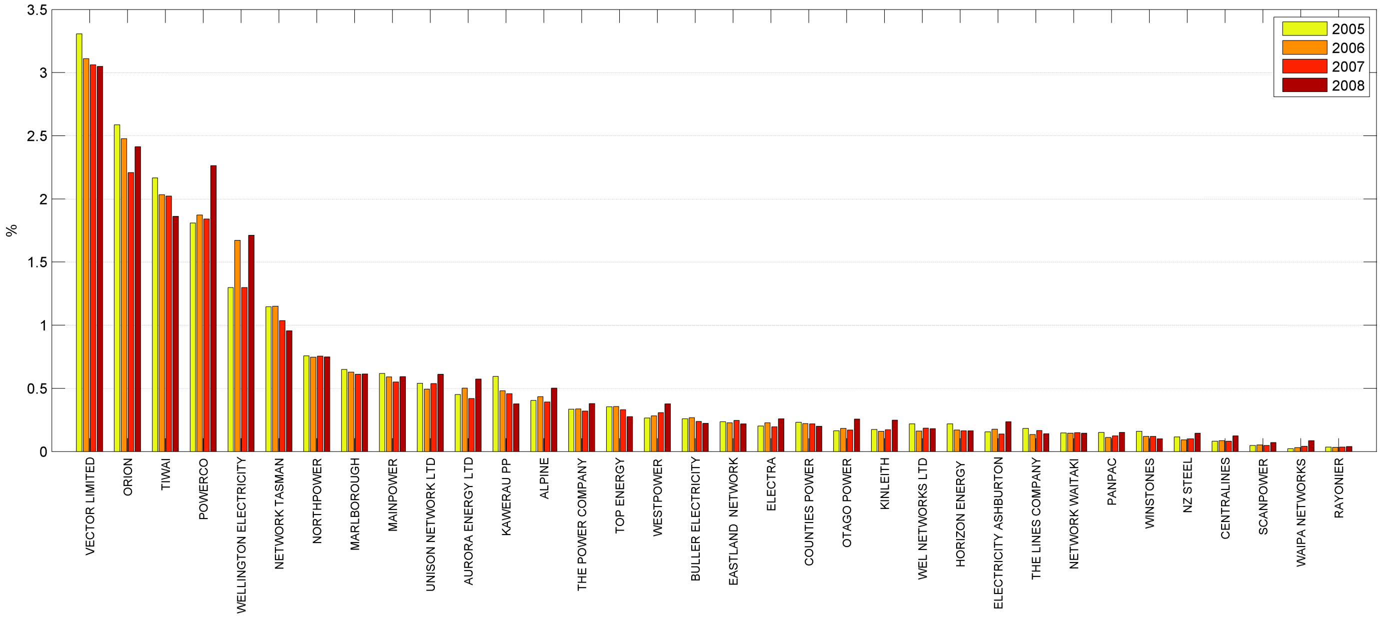

Fig. 15. Average usage of Transpower transmission assets, based on capacity.

*1) **Used grid capacity demonstration**:* 'Usage' can mean either; a percentage of total MW flow on each asset[23], or, a percentage of total asset capacity[24]. If percentage of total MW flow is adopted, then periods with low power flow still allocate full asset costs. If however, percentage of total asset capacity is adopted, then asset costs would only be recovered for the 'used' portion of the transmission asset. As the grid is typically built to handle contingent N–1 events, even at maximum usage, most capacity is unused[25].

One method of 'deepening' the existing connection asset definition could be to assume that *connection* assets become *used* capacity, while *interconnection* assets become *unused* capacity. The tracing algorithm is able to determine both the *used* and *unused* portions for each transmission asset. The *used* portion could then be allocated accordingly, while the *unused* portion could be postage stamped, as done currently, based on peak demand.

If each individual asset's allocated usage is known, then multiplying this usage by asset replacement cost, summing over all assets, and for all participants can reveal interesting results.

Figure 15 demonstrates a preliminary result, showing the average usage of Transpower's assets over all off-take customers between 2005 and 2008[26,27]. The percentages relate to the total *used* asset capacity over the entire grid. As this averages only 20–25% of Transpower's total asset capacity, this is what could be recovered if such a technique were to be used to replace (or redefine) the current connection definition. The remaining 75–80% revenue requirement could then be postage stamped.

If energy retailers were charged for use of the transmission network, this method could compliment the LRA in Section IV as those assets charged for under a *used* asset definition are the same assets used in the redistribution of the rentals, i.e., customers collect rentals off the assets they pay for.

[23]As has been employed to derive the results in Figures 7,8 and 14.

[24]In this case thermal, N, capacity.

[25]The average utilisation of Transpower's transmission assets averages only 20–25% per year.

[26]In this case the HVDC link is not included in the allocated asset base. This could also be performed for generators and split 50/50 with off-take. This would result in the percentages in Figure 15 being halved.

[27]To achieve this, Transpower provided replacement asset cost information on a physical transmission line basis. These costs were then used to cost each electrical circuit of each transmission line using total line length and individual circuit lengths to divide the total line cost among its constituent electrical circuits. Substation costs were divided equally among circuits connecting at each substation. A time stamped pricing matrix was used as changes in network topology such as asset additions, removals, or SPD circuit name changes needed to be handled.

Obviously there are many options and to progress this work further requires quantifying issues that may arise; for example, price volatility and changes in participants transmission charges compared with the current TPM. Further considerations include modelling overall benefits and/or costs for all participants, inclusive of all current market development initiatives; for example, in combination with a locational hedging mechanism such as that described in Section IV.

VI. Summary

This paper has demonstrated, and then applied, a tracing algorithm over the New Zealand power system. It could be useful as a tool to assist in solving some of the current market problems, or be otherwise used to inform participants of transmission network usage.

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