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energy modelling

Analysis of the flow tracing model to calculate deeper connection transmission charges

Report to Transpower

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About us

scientiaconsulting provides specialist modelling and analytical expertise to the energy sector.

This knowledge is based on extensive practical experience spanning operational and regulatory environments of the electricity industry in New Zealand and overseas.

Scientia's key areas of specialisation include electricity market design, analysis, market clearing engine development and testing, transmission pricing, transmission planning, load forecasting and generation expansion modelling.

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Summary

The Electricity Authority (the Authority) has proposed three potential transmission pricing methodology options in its TPM options working paper published on 16th June 2015. A 'deeper connection' charging component, based on a flow tracing approach, features in all of the Authority's proposed options.

Transpower has engaged Scientia Consulting to analyse the flow tracing approach applied by the Authority to calculate the deeper connection charges.[1] In particular, Transpower would like to better understand:

- The details of the flow tracing approach implementation and its application in calculating deeper connection charges
- The potential operational and investment impact the proposed deeper connection charges might have on Transpower and its customers
- The potential stability of the deeper connection charge

A summary of our findings is provided below.

Flow trace approach – how it works

The flow tracing approach proposed by the Authority is based on an assumption of proportional sharing at nodes where each generator and load contributing to the flows are identified by their proportional flow shares.[2] These flow shares are inputs into the deeper connection charge calculation.

We tested the proposed flow tracing model with a number of simplified test cases to better understand its operation and assumptions. Following the tests we conclude[3]:

- The tracing model is consistent with the proportional sharing allocation principle outlined by Bialek using gross flows for the upstream trace (to generators) and net flows for the downstream trace (to loads)
- The use of gross flows for generators will tend to overestimate allocation to generators that are electrically further away from an asset and the use of net flows for loads will tend to underestimate allocation of loads that are electrically further away from an asset
- While we note potential over and underestimation allocation biases in the tracing model approach, we have not attempted to quantify any impact on the overall calculated deeper connection charges or its allocations

[1] As outlined in the Authority's TPM options working paper and modelling files.
[2] The proportional sharing flow tracing approach was proposed by Bialek in his paper, *Tracing the flow of electricity*, IEE Proc.-Generation. Transmission. Distribution., Volume 143, No. 4, Page(s): 313-320, July 1996.
[3] During an initial set of tests, several implementation issues were observed with the tracing model. These issues were sent to the Authority and have subsequently been resolved. We suspect some impact to the calculated deeper connection charges arising from these changes to the tracing model but we have not quantified those.

Design parameters can significantly affect outcomes

As with all models there are a range of assumptions and design parameters choices needed. These assumptions and parameters can affect the magnitude of the deeper connection charge and its allocation amongst transmission customers. In summary these are:

- Implemented flow allocations of substations to generators and loads[4]: We observe that the Authority's implemented approach to calculating the flow shares of substations can result in nodal flow shares greater than a nodes anytime maximum demand (AMD) (for loads) and anytime maximum injection (AMI) (for generators). This indicates a possible overestimation in substation allocation to generators and loads which could increase the likelihood of these loads and generators being allocated the deeper connection charge of a substation
- Herfindahl-Hirschman Index (HHI) and usage thresholds used to calculate the deeper connection charge: Changes in the HHI threshold can have a large impact on transmission customer charges. In particular reductions in the HHI can result in increased charges to generators and reduced charges for mass market loads as assets with lower generation HHI become classified as deeper connection for generators (where previously they were only deeper connection for loads). Increasing the HHI can reduce deeper connection charges as fewer transmission assets are classified as deeper connection (with the higher HHI threshold requirement).
    - The value of the usage threshold (de-minimis) for charge allocation becomes more critical at lower HHI where a reduction in this de-minimus can result in large shifts in deeper connection charges from mass market loads to generators.
- Finally and perhaps most fundamentally is the choice of model approach to use to allocate transmission costs. The proportional share flow tracing approach is one of several potential transmission usage approaches. Other alternative "usage-based" approaches include distribution factors (also called shift factor or marginal methods) or minimum power distance. It is understood these alternate approaches can provide different allocations[5]. We have not evaluated the relative impact of these alternative usage-based allocation approaches to the New Zealand context.

These assumptions and parameters would be key design considerations given the potentially large impact they could have on customers' deeper connection charges.

[4] Flow tracing of substations is not covered by Bialek (1996)

[5] Orfanos G.A., Tziasiou G.T., Georgilakis P.S., Hatziargyriou N.D., "Evaluation of Transmission Pricing Methodologies for Pool Based Electricity Markets", paper accepted for presentation at 2011 IEEE Trondheim PowerTech

The proposed approach would affect participant operational and investment incentives

We consider that some of the proposed design and implementation options of the deeper connection charge can affect participants operational and investment decisions (including Transpower) as there is a close linkage between the operation of the power system (through the flows and consequently the calculated allocations) and the distribution of the deeper connection charges. We consider these effects to include:

- Incentives on some load participants (close to the de-minimus usage threshold) to increase nodal peak demand to reduce their deeper connection charges
- Incentives on other load participants to manage (or reduce) nodal peak demand to limit increases in (or reduce) their deeper connection charge
- Incentives on generator participants allocated according to AMI (anytime maximum injection) to potentially withhold peak generation capacity similar to the current HVDC charge's HAMI effect on South Island generators
- Potential incentives on distributors to reduce the shifting of load between grid exit points to avoid setting new AMD (anytime maximum demand)s. This could have an impact on distribution system reliability.
- Greater incentive on participants to seek to influence Transpower's operational decisions (grid reconfiguration and planned outages) as their allocated deeper connection costs could be impacted
- Incentives on participants to agitate for and against Transpower's investment decisions as their allocated deeper connection costs are affected by altered grid flows
- Potential incentives on some participants to increase demand for transmission energy as this may reduce their deeper connection charges

The proposed charges could be unstable

The Authority has raised some concerns in its companion paper[6] that the proposed deeper connection charge allocation to nodes can be unstable thus increasing the volatility of the charge. A transparent and stable charge is desirable as it can help facilitate effective decision making where participants can understand (at relatively low transaction costs) the impact of their decisions on their transmission costs going forward.

We consider that a regional aggregation of nodes could potentially assist in reducing the nodal volatility observed by the Authority in its analysis whilst still maintaining a locational dimension for charge allocation.

We however also note in this report that some of the interactions created through the proposed deeper connection charge design could lead to counter-intuitive

[6] See Transmission Pricing Methodology Review: TPM options working paper – Companion paper describing the detail of the deeper connection charge, C13-C18 on pages 36 and 37

outcomes and some perverse incentives on participants which could potentially lead to unpredictable and inefficient behaviour. This could exacerbate any unpredictability and instability of the charge observed through historical analysis.

Conclusion

If the tracing approach and deeper connection charge are pursued further, we believe additional consideration should be given to the issues raised in this report.

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1. Introduction

The Electricity Authority has released its TPM options working paper which proposes the use of a flow tracing model to calculate deeper connection charges.

Transpower has engaged Scientia Consulting to analyse the flow tracing approach applied by the Authority to calculate the deeper connection charges.

This report details our approach and analysis of the flow tracing model and its implementation, the key design assumptions and parameters of the model and its application to calculate deeper connection charges and the potential impacts these charges may have on transmission customers and Transpower. Finally we consider the potential impacts on stability of the deeper connection charge.

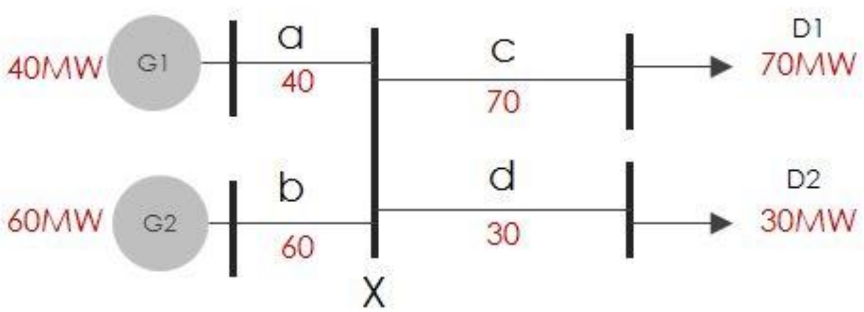
2. Understanding the flow tracing model implementation

The Authority published all modelling files associated with its proposed tracing model. We used these modelling files, associated literature, test cases and discussions with the Authority to gain an understanding of how it had implemented its model.

2.1. An overview of the proposed flow tracing approach

The flow tracing approach proposed by the Authority is based on a model that assumes a principle of proportional sharing, first introduced by Bialek in 1996.[7] The proportional sharing principle assumption is that each electrical bus in the power system is a "perfect mixer" with the incoming flows proportionally distributed among the outgoing flows. Through this, the algorithm proceeds to determine a flow allocation on branches to generators and loads. The simplified example from Bialek (1996) is repeated here for explanation in Figure 1.

Figure 1: Proportional sharing principle



[7] Bialek J, Tracing the flow of electricity, IEE Proc.-Gener. Transm. Distrib., Volume 143, No. 4, Page(s): 313-320, July 1996.

The starting point for the proportional sharing flow tracing algorithm is a solved power flow.[8] In the Figure 1 example, the total flow into bus *X* is 100MW with 40% supplied by line *a* and 60% supplied by line *b*. Using the proportional sharing principle, 40% of the outgoing flow on lines *c* and *d* is supplied by line *a* and 60% of the outgoing flow on each line supplied by line *b*. Hence proportional sharing results in the following allocation:

Flow on *c* from *a* = Fc,a = (40/100) x 70 = 28MW

Flow on *c* from *b* = Fc,b = (60/100) x 70 = 42MW

Flow on *d* from *a* = Fd,a = (40/100) x 30 = 12MW

Flow on *d* from *b* = Fd,b = (60/100) x 30 = 18MW

(more generally Fi,j represents the MW flow on branch *i* due to branch *j*)

Using the proportional sharing principle and inflows at each bus, the branch flows can be "traced" (allocated) to generators and similarly, by considering the proportional sharing of outflows at each bus, branch flows can be "traced" (allocated) to loads. These are more commonly referred to as the upstream and downstream traces respectively. In the example above, the proportional sharing principle results in the following upstream and downstream allocations of flows to generators and loads respectively.

Table 1: Upstream and downstream trace using illustrative example

	Gen or load	Branch a (MW)	Branch b (MW)	Branch c (MW)	Branch d (MW)
Upstream	G1	40	0	70 x (40/100) = 28	30 x (40/100) = 12
	G2	0	60	70 x (60/100) = 42	30 x (60/100) = 18
Downstream	D1	40 x (70/100) = 28	60 x (70/100) = 42	70	0
	D2	40 x (30/100) = 12	60 x (30/100) = 18	0	30

In Bialek's flow tracing model, the network is assumed to be lossless. That is the flows at both ends of the branch are assumed to be the same. Hence adjustments to

[8] In the Authority's proposed implementation the power flow from the solved final pricing solution is used.

branch flows are needed to account for this assumption. Bialek (1996) considered two alternate branch flow adjustments to treat losses for the upstream and downstream traces. These are:

- *Using average flows for both upstream and downstream (option 1):* Branch flows are assumed to be the average of the sending and receiving end flows with half of the branch loss added to the terminal buses of each branch.
- *Using gross flows for upstream and net flows for downstream (option 2):* In this option, for the upstream trace actual generation is used and under the lossless network assumption bus demands are adjusted to account for the additional branch flow (referred to as gross flow in Bialek (1996)) whilst still satisfying Kirchoff's current law.[9] The downstream trace is based on transmission losses being completely removed (referred to as net flows in Bialek (1996)) with generation adjusted down and demand unchanged.

The Authority implemented option 2.

2.2. A simplified test approach to understand the flow trace model implementation

We developed several simple test cases to better understand the workings and results produced by the model. Analysing the model with a simplified set of inputs with a straightforward results verification process assists in understanding the model outcomes to assumptions.

These tests included:

- Multiple upstream: The proportional allocation of flows to multiple upstream generators in a meshed network
- Multiple downstream: The proportional allocation of flows to multiple downstream loads in a meshed network
- Treatment of intermittent generation (negative loads): The proportional allocation of flows to intermittent generators represented as negative loads in the power flow used by the Authority
- Gross and net flows: The treatment of losses and the impact on the upstream and downstream allocation

Appendix A contains details of the test systems and test results using the tracing model.

In summary we conclude that:

- The tracing model is consistent with the proportional sharing allocation principle outlined by Bialek using gross flows for the upstream trace (to generators) and net flows for the downstream trace (to loads)

[9] Kirchoff's current law states that the sum of current entering a node is equal to the sum of current flow out of that node.

- The use of gross flows for generators will tend to overestimate allocation to generators that are electrically further away from an asset
- The use of net flows for loads will tend to underestimate allocation of loads that are electrically further away from an asset
- While we note potential over and underestimation allocation biases, we are uncertain if this will have any impact on the overall results

During the initial set of tests, several model implementation issues were observed. These included:

- An error in developing the upstream distribution matrix resulting in incorrect flow allocations to generators.
- An oversight of omitting generation represented as negative load from the upstream trace[10]
- Incorrect loss adjustments on branches with negative flows[11]

These issues were discussed with the Authority and have subsequently been resolved through updates to the flow trace model. We suspect some impact to the calculated deeper connection charges arising from these changes but we have not quantified those.

2.3. Flow trace modelling and design parameters can impact the deeper connection charges

The primary purpose of the flow tracing model is to calculate the flow shares of transmission customers on assets and identify load and/or generation that are deemed to be "connected by" a transmission asset.

There are several assumptions and design parameters used in the calculation process that could affect the end result (the charge). We discuss these further below.

Substation allocation

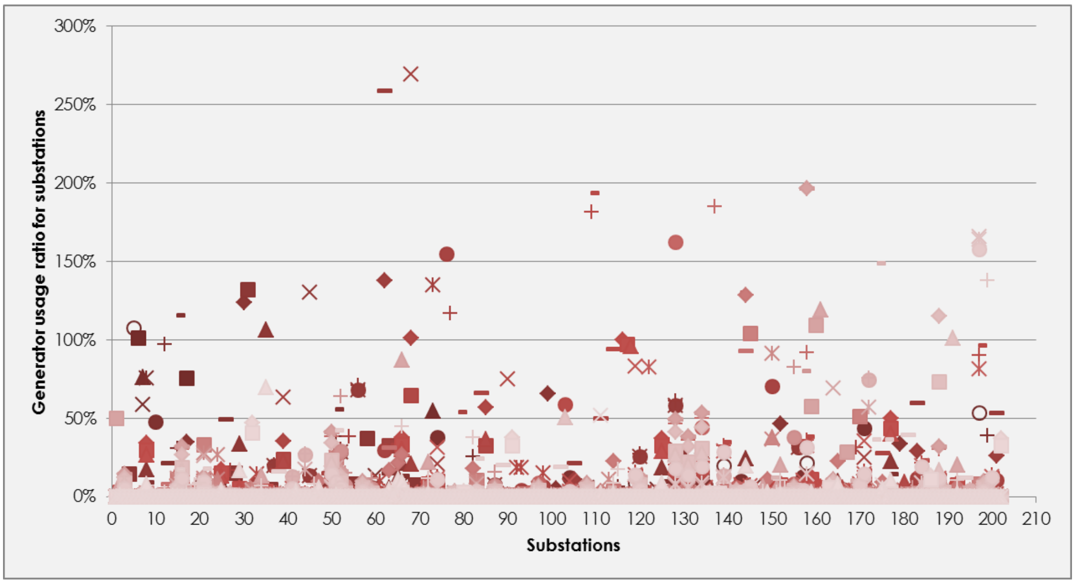
The allocation of substations is not discussed in Bialek (1996). We understand the Authority has implemented an approach that calculates the total flow through all buses and nodes that comprise a substation. Since substations can consist of multiple buses and nodes the effect of aggregation can inflate MW allocations of substations to the generators and loads. If these increased MW allocations are not affecting all "deeply connected" parties equally, there could be an impact on the calculated HHI for the substations which may impact its deeper connection classification and consequently participant deeper connection charges.

[10] Intermittent and some embedded generation with net injection into the grid is represented as negative load in final pricing which were used by the tracing model.

[11] Negative flows refer to flows in the opposite direction to the assumed positive direction. The positive direction is assumed to be from the "from bus" to the "to bus" of a branch hence a negative flow would be from the "to bus" to the "from bus" of a branch.

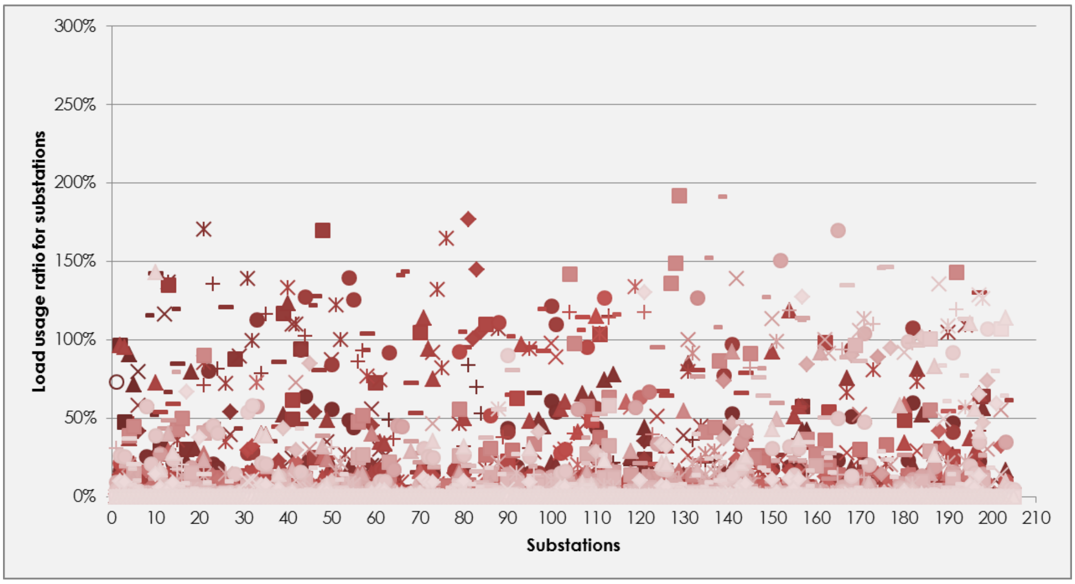
The inflated substation MW allocations would falsely indicate a "heavier" usage and hence the participant more likely to (a) be above the proposed usage threshold of 3%[12] and (b) attract a deeper connection charge if the asset's relevant HHI is greater than 4000[13]. Figure 2 and Figure 3 below illustrate the impact of the increased substation allocation on substation usage ratios for generators and loads respectively.

Figure 2: Generator usage ratio for substations



A usage ratio greater than 100% in Figure 2 indicates a generator usage of a substation greater than its AMI.

Figure 3: Load usage ratio for substations[14]



[12] Currently a usage threshold of 3% is proposed.
[13] See section Appendix B for further details using a sample calculation.
[14] For illustration purposes, the scale has been truncated at 300% however six usage ratios were greater than this.

Similarly, a usage ratio greater than 100% in Figure 3 indicates a load's usage of a substation is greater than its AMD. We don't think usage ratios in excess of 100% should be possible and the presence of such values suggests that the calculated usage ratios are likely being biased upwards which would tend to overestimate allocation of substation charges to some participants through the deeper connection charge.

We believe that if the flow tracing approach is pursued, further consideration should be given to the approach of determining substation allocations[15].

HHI and usage thresholds can affect customer deeper connection charges

The Herfindahl–Hirschman Index (HHI) is calculated for each transmission asset (an HHI for generation and an HHI for load) using the mean of the flow allocations on transmission assets to generators and loads over historic five years. If the calculated HHI for a modelled transmission asset is:

- < 4000, it is not classified as a deeper connection asset
- > 4000 and < 5000, it is a partly deeper connection asset (i.e. a portion of its revenue requirement is recovered through a deeper connection charge)
- > 5000, it is classified as a deeper connection asset.

As noted in the Authority's companion working paper, the choice of the HHI cut-off can affect the assets classified as "deeper connection" and costs allocated through the deeper connection charge.

In the Authority's proposed allocation, after an asset has been classified as part or fully deeper connection, only connected parties with an average allocation at least 3% of their respective anytime maximum injection (AMI) (for generators) and anytime maximum demand (AMD) (for loads) are subject to the deeper connection charges of this asset. It is understood that this 3% "usage threshold" was introduced to exclude the allocation to parties that use assets "lightly".

We considered the potential impact variations in these HHI and usage thresholds could have on transmission customers' deeper connection charges[16]. The following HHI and usage threshold scenarios were considered.

- HHI: Proposed = 4000-5000, higher = 8000-9000 and lower = 1000-2000
- Usage threshold %: Proposed = 3%, higher = 6% and lower = 0%

Figure 4 and Figure 5 below illustrate estimated impact of these different HHI and usage thresholds on the deeper connection charges allocated to an aggregate representation of transmission customers in the North and South Island respectively.

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[15] In the Authority's modelled scenario, approximately 24% of the allocated deeper charge is due to substations however we do not know how many of these substation allocations would be affected by the increased substation allocation calculation.

[16] We assessed customers at an aggregate level (mass market, large industrials and generators). Individual customer impacts could differ (be in the opposite direction) from those of the aggregate change.

Figure 4: Estimated sensitivity of aggregate North Island transmission customers' annual deeper connection charges to HHI and usage thresholds

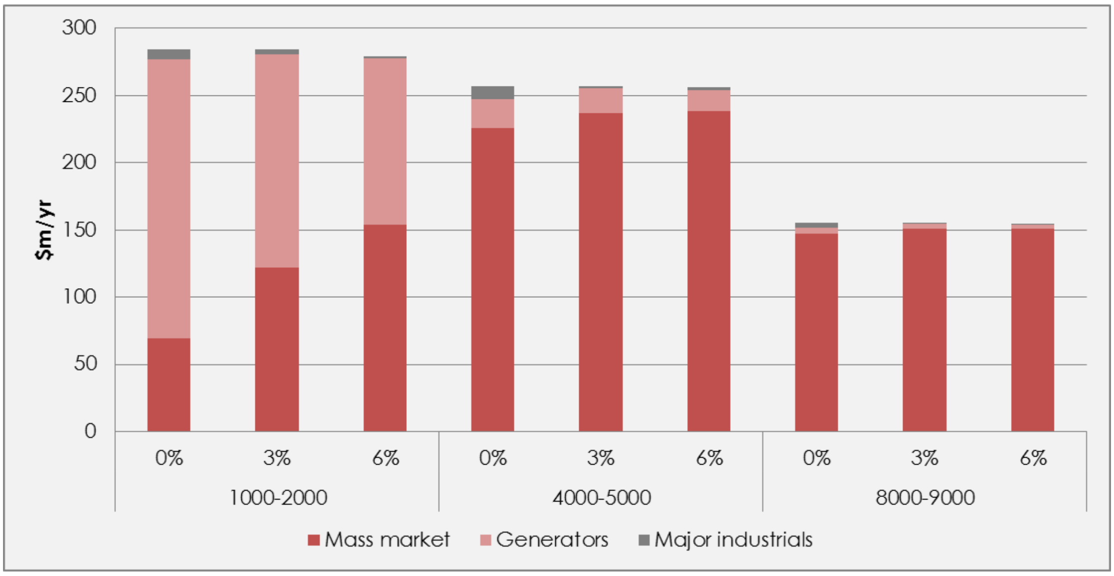
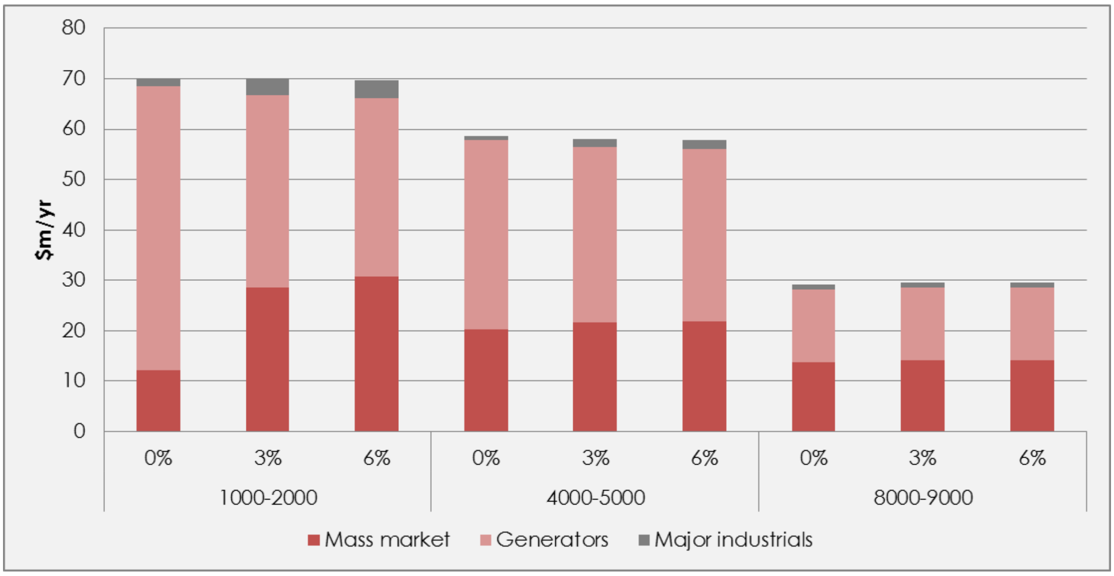


Figure 5: Estimated sensitivity of aggregate South Island transmission customers' annual deeper connection charges to HHI and usage thresholds



With an HHI threshold that is lower than the proposed (4000-5000), there is:

- an increase in the revenue recovered through the deeper connection charge as a greater proportion of the interconnected grid is being "picked up" by the deeper connection charge
- an increase in generator allocation of deeper connection costs as they are allocated a greater share of transmission assets that have a higher load HHI (and previously allocated only to loads)
- a reduction in the deeper connection costs allocated to mass market demand as a consequence of generation being allocated a greater share of the deeper connection costs

For an HHI threshold higher than the proposed (4000-5000), there is:

- a reduction in the revenue recovered through the deeper connection charge as fewer transmission assets exceed the HHI threshold (and consequently classified as deeper connection assets).
- a reduction in deeper connection charges to all the aggregate customer groups[17] as a result of few assets being classified as deeper connection

At the proposed HHI threshold (4000-5000), mass market loads are allocated the majority of the deeper connection charges with the charge distribution between mass market loads, major industrials and generators remaining fairly stable under the different modelled usage threshold scenarios.

We also note that the value of the usage threshold becomes more crucial at a lower HHI threshold. This can be observed (in Figure 4 and Figure 5) by the relatively large shifts in cost allocation between mass market loads an generators as the usage threshold is reduced when the HHI threshold is lower (1000-2000). With a lower HHI a greater proportion of the interconnected grid is classified as deeper connection and there are a greater number of allocated users with varied usage allocations. As the usage threshold is changed a greater number of users are included or excluded from the allocation hence we observe larger shifts in allocation of the deeper connection charge between customers at a lower HHI threshold. At our lower usage threshold scenario (0) any allocation of an asset with an HHI above the threshold would result in the generator (or load) being allocated a proportion of the charge. This could be a very large proportion if the generator (or load) has a large AMI (or AMD) even though their calculated flow share of an asset is comparatively small.

Given the large potential impacts on different transmission customers, we consider that setting the HHI and usage thresholds are likely to be one of the key parameters in the deeper connection charge. We agree with the Authority's observation at 6.5 of its deeper connection working paper that the HHI decision may be controversial and drive inefficient behaviours.

Choice of flow trace model

The flow tracing approach used by the Authority is based on the principle of proportional sharing, as discussed above. We consider this a design decision given the presence in academic literature[18] of other flow allocation approaches which do not use the proportional sharing principle. Some of these alternatives include:

[17] We note that individual customer impacts could vary from the aggregate representation used in our analysis.

[18] Orfanos G.A., Tziasiou G.T., Georgilakis P.S., Hatziargyriou N.D., "Evaluation of Transmission Pricing Methodologies for Pool Based Electricity Markets", paper accepted for presentation at 2011 IEEE Trondheim PowerTech

- *Distribution factors* (or shift (sensitivity[19]) factors). Under this approach the incremental change in flow on a branch, for a given incremental change in generation and load, is used as a measure of allocation.
- *Minimum power distance* method is a further flow allocation approach that is specified in the academic literature. In this approach it is assumed that electricity flows through paths that minimise the total MW-km covered in the power system.

Both these alternate approaches would also have assumptions associated with them and could potentially produce different allocations to those suggested by the proportionate allocation approach.[20] We have not considered the relative merits and impacts of these differing tracing approaches on the asset allocations and deeper connection charges.

3. Potential impacts of the deeper connection charge on participant incentives

The proposed deeper connection charge is linked to the operational decisions made by participants through the calculation of flow shares on assets. Furthermore, the use of the AMD and AMI as allocators is linked to transmission customers operations. With the coupling of the deeper connection cost allocation to the operational decisions of participants we would expect some impact on current and future behaviour as participants seek out their most efficient outcomes given the proposed rules.

3.1. Potential impacts on operational decisions

Charge allocation de-minimis (usage threshold)

We think that the proposed implementation of the de-minimis usage threshold could potentially create perverse incentives. As discussed earlier, connected parties of a deeper connection asset are excluded from being allocated the deeper connection charge if their calculated usage (through the trace) is less than 3% of their AMI (for generators) or AMD (for loads). We refer to this earlier as the usage threshold.

Under the proposed application, a load participant that is "connected" to an asset and seeking to reduce their exposure to allocated costs can either:

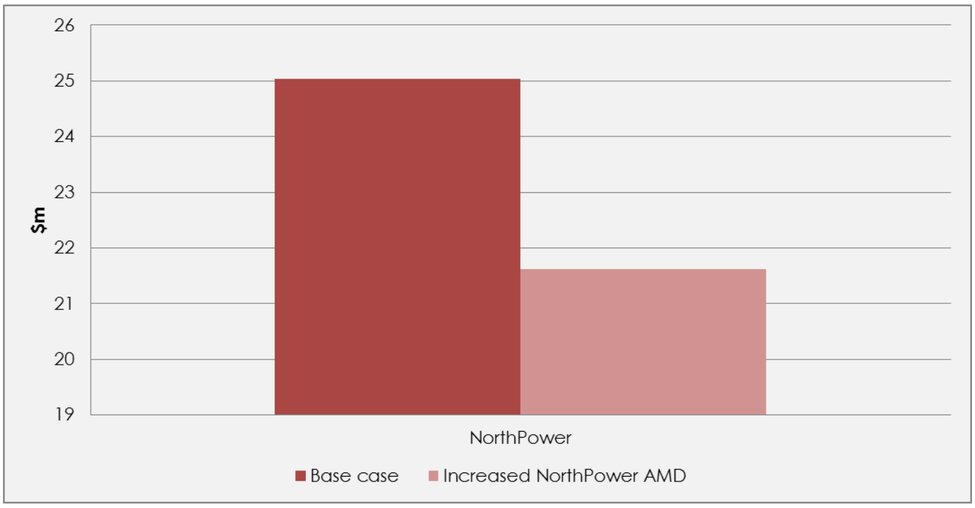
- reduce its allocation or,
- increase its AMD

[19] These are also sometimes referred to as marginal factors since they consider a change in flows for a marginal change in generation and load.
[20] The difference in allocations for a test system is detailed in the following paper: Orfanos G.A., Tziasiou G.T., Georgilakis P.S., Hatziargyriou N.D., "Evaluation of Transmission Pricing Methodologies for Pool Based Electricity Markets", paper accepted for presentation at 2011 IEEE Trondheim PowerTech

An increase in AMD done solely to reduce a customer's deeper connection charge, is very likely inefficient as the action will incur costs (i.e. increase fuel costs for generation/demand-side resources, peaking investment or transmission investment) with smaller commensurate benefit[21].

To test the potential for this, we considered a scenario where we assume NorthPower increased the AMD at each of its grid exit points (GXPs) by 6%[22] (as a strategy of reducing its deeper connection charges). The resulting impact of NorthPower increasing its AMD is a reduction in deeper connection charges as shown in Figure 6. This cost reduction is achieved as the increased AMD results in NorthPower falling below the 3% usage threshold for some transmission assets and excluded from being allocated its deeper connection costs. In the example, the increased costs are allocated to other "connected" participants thus potentially increasing their incentives to follow suit and increase AMD or take other actions to reduce cost exposure. This illustrates the potentially perverse incentives the design of the current usage threshold may create for participants.

Figure 6: Estimated impact of NorthPower increased AMD on deeper connection charges



Anytime Maximum Demand/Injection as an allocator

The Authority proposes to use the AMD and AMI as the allocator for parties whose usage is greater than the 3% usage threshold. We note several potential issues with using nodal AMD and AMI as allocators of the charge.

[21] Note the only reason an increase in demand is engineered is to be assessed below the 3% usage threshold and reduce the deeper connection charge allocation. This increase in demand could be achieved for example through distribution network reconfiguration resulting in load being shifted (swung) between grid exit points or possibly creating a coincident peak with hot water load control. Note the increase in a node's AMD does not have to coincide with another node's increased AMD, furthermore, the increase in nodal AMD only needs to occur for one half-hour trading period in the measurement period.

[22] This corresponds to an ~12MW increase in its cumulative AMD across all nodes. Note the increase in each node's AMD does not have to be co-incident but can occur in any half-hour trading period within historic measurement period.

Peak avoidance signal for demand

Using nodal AMD as an allocator could create a distortionary peak avoidance signal. To understand the potential magnitude of this, we considered the potential impact on Vector's deeper connection costs for a 1% increase in its AMD. This ~22MW increase indicates a potential increase of ~$200k in annual deeper connection costs[23] which would remain (all else being equal) for 5 years[24]. This translates to a peak charge of ~$37k/MW.[25] We consider this effective peak charge could create incentives on Vector (and its customers) to manage their anytime nodal peak demand to avoid increases in deeper connection costs which could be inefficient, considering:

- nodal AMD is more a driver of localised transmission investment and might be less coincident with regional peaks (regional transmission investment driver) or national peaks (generation investment driver) thus reducing its benefit in deferring larger future investments
- large transmission capacity investments have already been made (committed) in many regions

Peak injection cost for generators

The linkage of the deeper connection charge allocation to generator anytime maximum injection (AMI) may have similar effects to those observed currently in the South Island where the HVDC revenue recovery is linked to historical anytime maximum injection (HAMI) of South Island generators.[26]

These generator effects could include (as is the case in the South Island currently) disincentives on increasing generation output above historical levels, disincentives to expand capacity on existing generation and disincentives on investing in grid-connected, low capacity factor generation.

We considered the potential impact of this by estimating the impact on a generator's deeper connection costs if it were considering the impact of some of its peak generation output on its deeper connection cost[27]. For this assessment we consider Contact's Clyde generator and the impact of reducing its AMI from 430MW to 420MW. This 10MW reduction in its AMI results in ~$60k reduction in annual deeper connection costs which translate to an effective peak capacity charge of ~$24k/MW (~$48k/MWh). We note that this is the same order of magnitude of HAMI-based HVDC charges faced by some South Island generators that has led to the inefficient withholding of South Island peak generation capacity to manage their HVDC costs going forward.

[23] Using the Authority's deeper connection charge calculation spreadsheet.
[24] We assume the 5 historical year period proposed by the Authority.
[25] 5 year PV using 7% discount rate
[26] Currently it is estimated that ~177MW of South Island generation capacity is not offered into the market as a result of the HVDC cost recovery being linked to the HAMI of South Island generators.
[27] Such an assessment may be considered before the start of a new 5 year charging period.

Charging on nodal AMD may impact distribution network management

Many distribution companies can shift load between grid exit points (GXPs) through reconfigurations in their distribution network. These reconfigurations can assist in managing planned and unplanned outages, increasing reliability to distribution customers. These periods of load shifts do not represent a normal state and can sometimes result in a new AMD at a GXP which has been allocated a greater share of the distribution load. Using the nodal AMD as an allocator for deeper connection charges could impact the incentives and trade-offs faced by distribution companies during their system management and when there is a risk of setting a new AMD.

Potential impact on Transpower's operation

The deeper connection charging approach creates a strong linkage between individual assets (e.g. branches and substations) and the connected nodes. This linkage can create tensions in the operation of an interconnected grid view where there can be winners and losers for changes on the grid.[28]

Transpower's operation of the interconnected grid could affect a wide variety of parties due to the impacts its decisions may have on branch flows on the interconnected grid which can have flow-on effects onto transmission customers' deeper connection charges. These operational decisions would include maintenance outages and grid reconfigurations. To illustrate this effect, we simulate a modelled day based on 15 August 2012. During this time, the Arapuni bus was split. Historically, the Arapuni bus was solid but was permanently split in September 2011 to release constrained generation out of Arapuni. The grid reconfiguration was shown to have positive net system benefits.[29]

To illustrate the potential impact this reconfiguration may have, we simulated the impact on participant's calculated usage of the Tarukenga interconnecting transformers (TRK_T1 and TRK_T2) under a counterfactual scenario with a solid Arapuni bus. The results, shown in Figure 7 below illustrate the change in calculated usage under the different network configurations[30]. In particular it shows changes in flow allocations (reducing Vector's usage under the split bus configuration[31] from ~6MW to close to zero (0.2MW)) and consequently increasing the HHI as the two remaining users (PowerCo and Unison) are considered more dominant users of the transformers under the split bus (open) versus the solid bus (closed) configuration. In particular it shows PowerCo's and Unison's flow allocations changing from ~52MW and ~40MW under the solid bus configuration to ~18MW and ~35MW respectively

[28] These tensions currently exist, as observed in generator-retailers active monitoring, feedback and suggestions to Transpower on transmission outages and grid reconfigurations. These actions are taken by generator-retailers with a private benefit incentive which, under the spot market arrangements, assist in allocating resources efficiently.

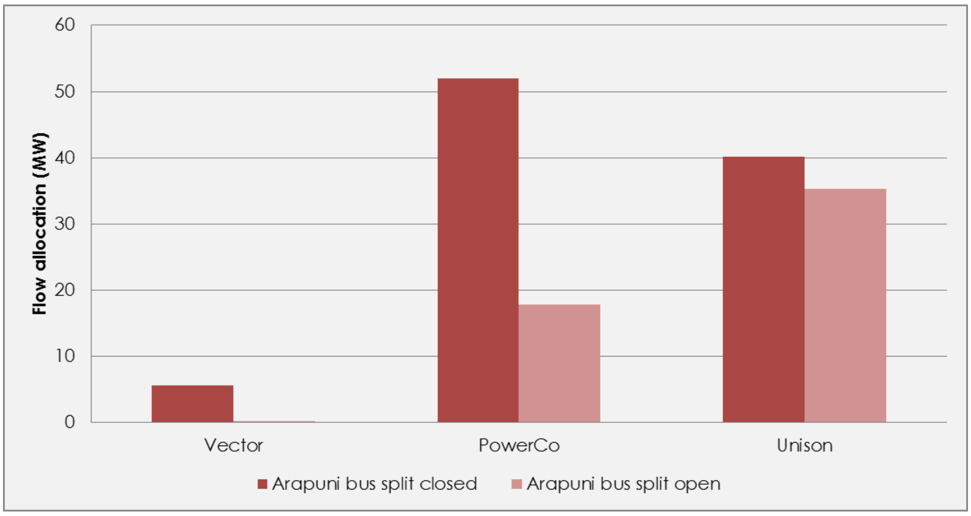
[29] See https://www.transpower.co.nz/news/grid-reconfiguration-arapuni-bus-split-closure

[30] Counties Power, Waipa Power, The Lines Company and WEL have small allocations (less than 0.05MW) under the solid bus configuration and none under the split bus. These have been omitted from the figure for clarity in illustration and do not change the issue being illustrated.

[31] In effect the split Arapuni bus breaks the parallel path through the Tarukenga interconnecting transformers and the 110kV network into the upper North Island hence we observed a reduction in Vector's usage under the split bus configuration.

under the split bus configuration. Note that although PowerCo's and Unison's flow allocation magnitude has reduced under the split bus configuration, their allocation is a greater share of the total (which has also reduced) and so are considered more dominant thus increasing the load HHI on the interconnecting transformers.

Figure 7: Impact of Arapuni bus reconfiguration on TRK_T1 and TRK_T2 allocation to loads



The change in allocations under the different grid configurations were not due to any actions of the load participants (as their modelled loads are the same) but due to external factors (grid reconfiguration), physical laws of power flow and the tracing algorithm. To the extent that these change in allocations affect the calculated HHI at or near the threshold or affect a parties utilisation at or near the usage threshold (de minimis), parties would be incentivised (more than currently) to influence Transpower's maintenance and grid reconfiguration process to increase their private benefits.

3.2. Potential impacts on investment decisions

We consider that the peak signal created by the AMD allocator can create an incentive for nodal peak control, as discussed in section 3.1. Given that the each node's peak demand might not be fully coincident with national or regional peaks there could be muted wider efficiency benefits from such investments in managing the nodal peak demand.

We suspect the "asset-node" linkage implicitly created by the deeper connection charging regime could also have an impact on Transpower's transmission investment process. Transpower's planning process gives consideration to the interconnected national grid and the potential implications of national and regional conditions on the grid.

However, as with the operational impacts, Transpower's investment proposals (probably more so) can create "winners and losers" to the extent that changes in flows on the interconnected grid caused by proposed investments could change the:

- classification of assets as deeper connection (or not) or increase/reduce the likelihood that assets can change state[32]
- eligibility of parties to get allocated a proportion of an assets cost (through the deeper connection charge) or increase/reduce the likelihood of this

The impact on participant private benefits (due to the deeper connection charge design and its allocation) of not only the new but also existing assets, as a result of the change in grid flows resulting from the investment, can influence the transmission planning and investment process as it may both facilitate and potentially inhibit the provision of "best available" information into the planning process[33].

3.3. Interaction of deeper connection charging design components can lead to counter-intuitive outcomes

Under the proposed deeper connection charge design, a transmission asset with:

- load HHI and generation HHI less than a threshold HHI would not be classified as a deeper connection asset
- load HHI greater than a threshold HHI would be classified as a deeper connection asset for "connected" loads
- generation HHI greater than a threshold HHI would be classified as a deeper connection asset for "connected" generators
- load HHI and generation HHI greater than a threshold HHI, would be classified as deeper connection for "connected" loads and generators respectively

In those scenarios where the asset is classified as deeper connection, the "connected" loads and/or generators are allocated a proportion of the asset revenue requirement[34].

However we consider that this "state" change of an asset where it can be classified as deeper connection for loads only, generators only or both can potentially create counter-intuitive outcomes that could affect participant behaviour in unexpected (potentially inefficient) ways and reduce the predictability and stability of the charge.

We will use a simplified example to illustrate this issue (see Figure 8). In this example there is a load (L1) with some local generation (D) and transmission imports into the region provided by generators A to C. Load L1 is allocated the full revenue requirement of the transmission branch x1 as the load HHI (equal to 10000) is greater

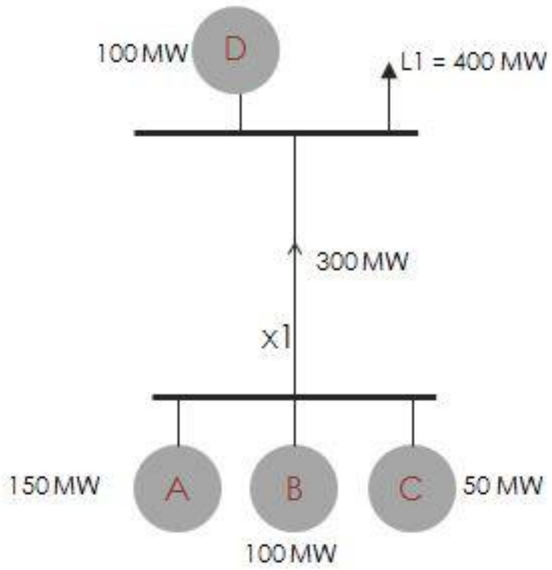
[32] That is increase the likelihood of the asset becoming classified as a deeper connection asset or reducing this likelihood for generators and/or loads
[33] These same incentives exist currently at the boundaries of connection and interconnection assets however by effectively deepening the connection charge a greater proportion of the network could be exposed to this effect.
[34] Provided they are above the proposed usage threshold.

than the threshold and the generator threshold (equal to 3889) is less than the threshold.

We consider a scenario where there is an increase load customer L1's demand for transmission energy through greater imports from the transmission system (as a result of generator D decommissioning) and the additional import into the region (100MW) provided by the marginal generator A.

Under this scenario, the generation HHI for transmission branch x1 increases above the HHI threshold (HHI = 4688) and the connected generators (A, B and C) are now allocated a proportion of the transmission branch (x1) revenue requirement. As a consequence, load customer L1 experiences a reduction in its transmission costs (as it now shares the costs with the generators A, B and C). This reduction in transmission costs for load customer L1 occurs even though its demand for transmission has increased.

Figure 8: Simplified example to illustrate transmission asset "state" change issues



We consider that these types of counter-intuitive outcomes arising from the interaction of the different components of the deeper connection charge could potentially lead to perverse incentives on some participants to increase their demand for transmission energy in an attempt to reduce their deeper connection charges. These perverse incentives can produce inefficient market outcomes and investments. Furthermore, we consider that these counter-intuitive charging outcomes could potentially become even more unpredictable when the loop flow effects on the interconnected grid are considered.

4. Stability of the deeper connection charge

We understand the Authority has made efforts to reduce the volatility of the deeper connection charge. These include using a graduated HHI cut-off and using a five year charging period. However we do also note that the Authority has raised concern that in some of its modelling using two 3-year modelling horizons, the process showed indications that it could lead to significant volatility in deeper connection charges.

We would expect increased volatility when attempting to assign transmission assets at a nodal level. A higher level view of asset allocation (e.g. taking a regional aggregation of nodes) could potentially assist in reducing the nodal volatility observed by the Authority whilst still maintaining a locational dimension for charge allocation.

The proposed deeper connection charging process has many interacting components[35] and there are indications (as noted in the report) that these interactions under the proposed charge design may result in some potentially perverse incentives on some participants. This could result in unexpected market behaviour which could potentially result in increased overall costs and increased unpredictability of the charge going forward.

[35] This is within the deeper connection charge itself. There are also other charging components proposed by the Authority in its options working paper.

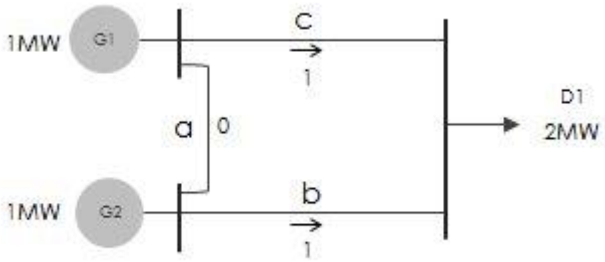
Appendix A – Flow trace testing

We used a set of simplified test systems to understand the outputs produced by the implemented tracing methodology.[36] The model results for each of the tests are tabulated with the expected outcome shown by the corresponding values in parenthesis.

Test 1: Multiple upstream trace

This test was to understand the proportional allocation mechanism with multiple upstream generators in a loop network.

Figure 9: Simplified system for test 1



Under the proportional sharing allocation principle, it is expected that in the upstream trace, flow on branch c would be allocated to generator G1 and flow on branch b allocated to generator G2. In the downstream trace, it is expected that the flow on branch b and c is allocated to D1. The model results correspond to these expected allocations, as shown in Table 2.

Table 2: Test 1 results

	Gen or load	Branch a	Branch b	Branch c
Upstream	G1	0 (0)	0 (0)	1 (1)
	G2	0 (0)	1 (1)	0 (0)
Downstream	D1	0 (0)	1 (1)	1 (1)

[36] All branches are assumed to have equal reactance. Sending and receiving end flows are used where non-zero transmission losses are assumed.

Test 2: Multiple downstream trace

This test was to understand the proportional allocation mechanism with multiple loads in a loop network.

Figure 10: Simplified system for test 2

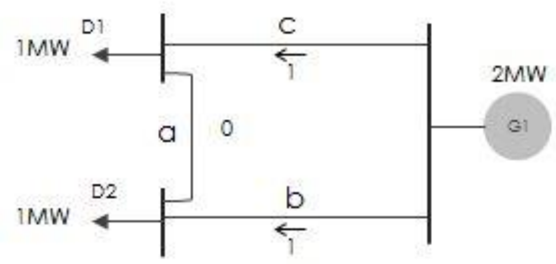


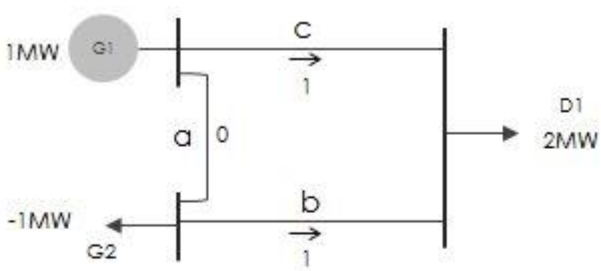
Table 3: Test 2 results

	Gen or load	Branch a	Branch b	Branch c
Downstream	D1	0 (0)	0 (0)	1 (1)
	D2	0 (0)	1 (1)	0 (0)
Upstream	G1	0 (0)	1 (1)	1 (1)

Test 3: Negative load trace

This test was to understand the proportional allocation mechanism with generators represented as negative load (intermittent generators are modelled as negative loads in final pricing).

Figure 11: Simplified system for test 3



The results provided in Table 4 illustrate the correct allocation of both positive and negative generation in the tracing model. These results should be the same as those from test 1.

Table 4: Test 3 results

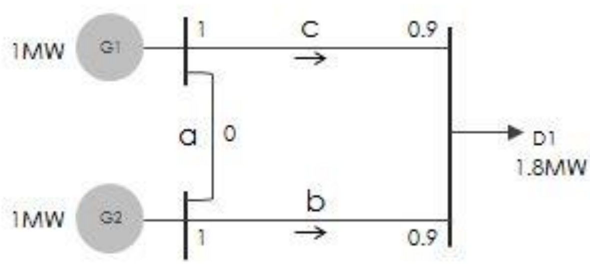
	Gen or load	Branch a	Branch b	Branch c
Upstream	G1	0 (0)	0 (0)	1 (1)
	G2	0 (0)	1 (1)	0 (0)
Downstream	D1	0 (0)	1 (1)	1 (1)

Test 4: Gross and net flow

This test was to understand the proportional allocation mechanism with transmission losses included.

It is understood the Authority implemented a gross upstream trace and a net downstream trace. In the upstream trace actual generation is used and under the lossless network assumption bus demands are adjusted to account for the additional branch flow (gross flow) whilst still satisfying Kirchoff's current law. The downstream trace is based on transmission losses being completely removed (referred to as net flows) with generation adjusted down and demand unchanged.

Figure 12: Simplified system for test 4

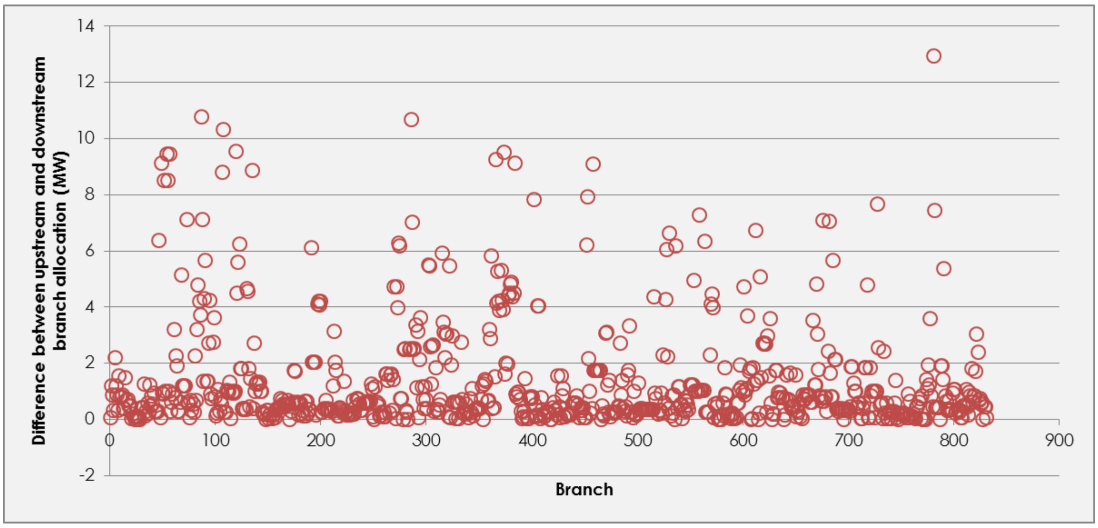


We observe from the results in Table 5 (and expect based on the assumptions of gross and net traces for upstream and downstream allocations) the upstream allocation will tend to incur a greater MW flow than the downstream. This implies the upstream trace will tend to estimate a greater MW utilisation of branches by generators (upstream) than downstream (loads) due to the assumption of gross flows and net flows. This effect is also observed in trace results from the Authority's modelling. Figure 13 illustrates the total upstream allocation less the total downstream allocation for each branch. The positive difference indicates the bias in MW allocation in the upstream trace versus the downstream trace. However, we do not expect this bias to significantly affect the results given the application of the trace to calculate proportionate shares of generation and load allocation separately.

Table 5: Test 4 results

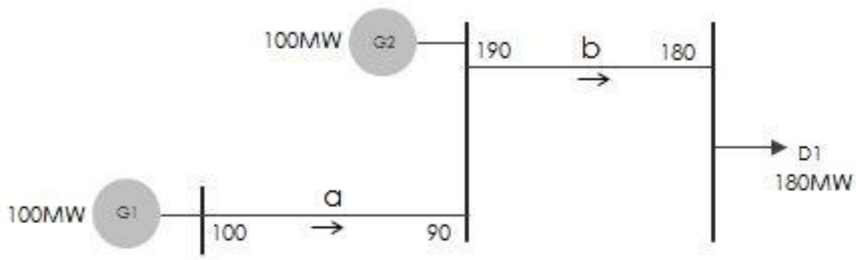
	Gen or load	Branch a	Branch b	Branch c
Upstream	G1	0 (0)	0 (0)	1 (1)
	G2	0 (0)	1 (1)	0 (0)
Downstream	D1	0 (0)	0.9 (0.9)	0.9 (0.9)

Figure 13: Difference in MW allocation from upstream and downstream traces



We do however expect that the gross upstream trace will tend to overestimate the allocations of generators that are electrically further away due to underestimating the effect of losses, as illustrated in the following example.

Figure 14: Simplified system for upstream allocation with losses and remote generator



As observed in Table 6, both generator G1 and G2 are allocated the same proportion of branch b flow under the gross upstream allocation (50% allocation). However using actual flows we conclude that only 90MW of generator G1 can possibly flow on branch b with a maximum proportionate allocation of 47.4% (=90/190). Hence the gross flow assumption will tend to overestimate the allocation of generators that are electrically further away (those that incur greater losses).

Table 6: Upstream trace with remote generator

	Gen	Branch a	Branch b
Upstream	G1	100	100
	G2	0	100

The opposite effect (i.e. allocation underestimation) would also be observed with loads electrically further away due to the net downstream allocation approach.

While we note this bias, we are uncertain of the impact it may have (if any) on deeper connection charges under the proposed application of the flow tracing approach.

Appendix B – Deeper connection example using flow shares

In the Authority's proposal, the flow allocations calculated using its tracing model is used as an input to calculating the deeper connection charges. In summary, the flow allocations calculated by the tracing model is used to calculate an aggregate company flow share on each modelled transmission asset (branches and substations). Thereafter an HHI is calculated for generators and loads based on the upstream and downstream flow allocations respectively. If the HHI is above a specified threshold, the parties connected to that asset, are allocated the revenue requirement of that asset based on an allocator. The proposed allocator is based on AMD and AMI for loads and generators respectively. The process is described in greater detail in the Authority's deeper connection companion paper[37].

Below we describe the mechanics of the deeper connection charge calculation process[38] using the simplified example from Figure 1 and Table 1. In Table 7 we assume an annual revenue requirement for branch c and d of $1m/yr[39] with nodal anytime maximum injections (AMI) for the generator nodes and anytime maximum demands (AMD) for the demand nodes. We also assume three transmission customers (companies) as shown in Table 7. Finally, we assume that the flow allocations calculated in Table 1 are representative of the 5-year average flow allocation.

Table 7: Transmission customer, AMI and AMD for illustrative example

	Company X	Company Y	Company Z	
	G1	G2	D1	D2
AMI (MW)	100	100		
AMD (MW)			100	50

Step 1: For each 30 minute trading period over the last 5 years, calculate upstream and downstream allocations of flow on each modelled[40] transmission asset to individual nodal generator and loads using the proposed flow tracing model.

[37] See "Transmission Pricing Methodology Review: TPM options working paper – Companion paper describing the detail of the deeper connection charge", pg 8.
[38] We discuss some of the implications of the proposed design parameters and assumptions later in section 2 and 3.
[39] In this example we assume branches *a* and *b* are connection assets and hence are not subject to the deeper connection charge.
[40] These are transmission assets (branches and substations) as modelled in the market system and used for final pricing.

Using results from Table 1:

Upstream trace: $f_{g1,c}$ = 28MW, $f_{g1,d}$ = 12MW and $f_{g2,c}$ = 42MW, $f_{g2,d}$ = 18MW

Downstream trace: $f_{d1,c}$ = 70MW, $f_{d1,d}$ = 0MW and $f_{d2,c}$ = 0MW, $f_{d2,d}$ = 30MW

Where $f_{n,j}$ = MW flow on branch j allocated to generator or load n

Step 2: Calculate the average flow allocation over the 5 years. This provides an average allocation of flow on each modelled transmission assets to each nodal generator and load.

Assume results as in step 1.

Step 3: Calculate a company-level flow allocation of each transmission asset by aggregating the average flow allocations (calculated by node) by the companies injecting or consuming at the node. A company flow share is then calculated as its proportion of the total allocated flow on the asset. An upstream and a downstream flow share is calculated for each modelled asset.

$$s_a^i = \frac{f_a^i}{\sum_j f_a^j}$$

where s^i_a is company i's flow share on asset a and f^i_a is the allocated flow of company i on asset a

Upstream

$$s_c^X = \frac{f_c^X}{f_c^X + f_c^Y} = \frac{28}{28 + 42} = 0.4$$

$$s_c^Y = \frac{f_c^Y}{f_c^X + f_c^Y} = \frac{42}{28 + 42} = 0.6$$

$$s_d^X = \frac{f_d^X}{f_d^X + f_d^Y} = \frac{12}{12 + 18} = 0.4$$

$$s_d^Y = \frac{f_d^Y}{f_d^X + f_d^Y} = \frac{18}{12 + 18} = 0.6$$

Downstream

$$s_c^Z = \frac{f_c^Z}{f_c^Z} = 1.0$$

$$s_d^Z = \frac{f_d^Z}{f_d^Z} = 1.0$$

Step 4: An upstream and downstream Herfindahl-Hirschman Index (HHI) is calculated for each transmission asset using the calculated average company-level flow shares from Step 3.

$$HHIa = 10000 \times \sum_i \left(s_a^i\right)^2$$

where HHI_a is the HHI index for asset a.

Upstream

$$HHI_c = 10000 \times [(s_c^X)^2 + (s_c^Y)^2] = 10000 \times [(0.4)^2 + (0.6)^2] = 5200$$

$$HHI_d = 10000 \times \left[\left(s_d^X\right)^2 + \left(s_d^Y\right)^2\right] = 10000 \times [(0.4)^2 + (0.6)^2] = 5200$$

Downstream

$$HHI_c = 10000 \times (s_c^Z)^2 = 10000$$

$$HHI_d = 10000 \times \left(s_d^Z\right)^2 = 10000$$

Step 5: An asset with an HHI exceeding the proposed threshold would be deemed a deeper connection asset and costs allocated to connected parties (identified nodes from Step 2). The Authority proposes a graduated threshold from 4000 to 5000 where charges are scaled linearly from 0 (when HHI = 4000) to 1 (when HHI = 5000 or greater).

Upstream

Branch c is a deeper connection asset for "connected" generators since the upstream HHI_c = 5200 is greater than the 4000 minimum threshold. Since the upstream HHI_c is greater than 5000, the full[1] deeper connection cost allocated to "connected" generators is recoverable from these generators. Note if the upstream HHI_c was only 4500, then only 50% of the deeper connection cost allocated to "connected" generators would be recovered from these generators via the deeper connection charge.

Branch d with an upstream HHI_d = 5200 is also a deeper connection asset for "connected" generators with the full deeper connection allocated cost recoverable from these generators.

Downstream

Branch c and d have a downstream HHI = 10000 and so meet the HHI thresholds for classifying the asset as a deeper connection asset for loads[1]. An HHI > 5000 also implies that the full deeper connection cost allocated to "connected" loads is recoverable from these loads.

Step 6: While the flow trace model is used to calculate flow allocations which are subsequently used to calculate flow shares and asset HHIs, it is not proposed as the allocator. The Authority proposes to use the anytime maximum demand (AMD) and anytime maximum injection (AMI) as the allocator of deeper connection charges for "connected" loads and generators respectively. Furthermore, "light" users of the asset are excluded from allocation of that asset's costs through the deeper connection charge. A "light" user of an asset is defined as a "connected" node whose average MW flow allocation[41] on the asset is less than 3% of their nodal AMD or AMI (for loads and generators respectively).

For connected loads and generators to asset a (that are not "light" users):

$$allocL_a^m = \frac{AMD^m}{\sum_j AMD^j + \sum_k AMI^k} \times reqR_a$$

$$allocG_a^n = \frac{AMI^n}{\sum_j AMD^j + \sum_k AMI^k} \times reqR_a$$

where $allocL^m_a$ and $allocG^n_a$ are the deeper connection cost allocated to load m and generator n respectively for asset a, AMD^m is the anytime maximum demand of load m and AMI_n is the anytime maximum injection of generator n, $reqR_a$ is the required annual revenue for asset a

The recoverable cost for loads and generators respectively are scaled based on the generation and load scaling factors for each asset (as determined in step 5)

$$recovL_a^m = LsF_a \times allocL_a^m$$

$$recovG_a^n = GsF_a \times allocG_a^n$$

Where $recovL^m_a$ and $recovL^m_a$ are the recoverable deeper connection costs from load m and generator n respectively for asset a, LsF_a is the load scaling factor for asset a and GsF_a is the generation scaling factor for asset a.

[41] This is the flow allocation calculated from the tracing model.

Branch c:

Connected generators = G1 and G2 and both have a usage ratio (allocMW/AMI) greater than 3%

Connected loads = D1 with a usage ratio (allocMW/AMD = 70/100) greater than 3%

Total AMI + Total AMD = 300

$$recovL_C^{D1} = 1 \times allocL_C^{D1} = \frac{100}{300} \times 1 = \$0.33m/yr$$

$$recovG_C^{G1} = 1 \times allocG_C^{G1} = \frac{100}{300} \times 1 = \$0.33m/yr$$

$$recovG_C^{G2} = 1 \times allocG_C^{G2} = \frac{100}{300} \times 1 = \$0.33m/yr$$

Branch d:

Connected generators = G1 and G2 and both have a usage ratio (allocMW/AMI) greater than 3%

Connected loads = D2 with a usage ratio (allocMW/AMD = 30/50) greater than 3%

Total AMI + Total AMD = 250

$$recovL_d^{D2} = 1 \times allocL_d^{D2} = \frac{50}{250} \times 1 = \$0.2m/yr$$

$$recovG_d^{G1} = 1 \times allocG_d^{G1} = \frac{100}{250} \times 1 = \$0.4m/yr$$

$$recovG_d^{G2} = 1 \times allocG_d^{G2} = \frac{100}{250} \times 1 = \$0.4m/yr$$

<u>Deeper connection costs summary:</u>

Branch c: Recovered from D1, G1 and G2 equally ($0.33m/yr)

Branch d: Recovered from D2 ($0.2m/yr), G1 and G2 equally ($0.4m/yr)