Appendix E Using the SPD method to apply beneficiaries-pay

E1. Introduction

1. This Appendix describes the approach of using the market clearing engine[1] as part of the beneficiary calculation approach for transmission pricing (hereby referred to as the SPD method). Several potential issues with this approach are raised and their impact discussed. Potential solutions are discussed and where practical some of these have been tested.

2. The outlined benefit calculation approach was performed on several upcoming transmission upgrade projects currently being constructed to assess the potential impact on the major generator-retailers from the market beneficiary approach.

E2. Approach

3. The market clearing engine allocates supply resources to satisfy demand at over 250 nodes on the network, given all of the relevant power system constraints. Provided the wholesale market is workably competitive the nodal quantities and prices reflect efficient resource allocation and prices in the market.

4. The Authority's vSPD model is based on the published formulation of the market clearing engine used in New Zealand (more commonly referred to as Scheduling, Pricing and Dispatch - SPD). The vSPD model was configured to solve for each 30-minute trading period using inputs into the final pricing process2 with the resulting nodal prices and quantities (generation and load) from vSPD used to calculate their market benefits.

5. An important design element in the market beneficiary approach is the aggregation of the calculated benefits. While these benefits are calculated by trading period, they can be aggregated across time (daily, monthly or yearly). This aggregation and its affects are discussed further in section E7.

6. The following steps illustrate the market beneficiary approach taken using vSPD for each half hour.

   - Step 1: Solve the final pricing schedule with the transmission asset(s) in place [3] (solve 1).

   - Step 2: Calculate the benefit to injection and off-take participants at each node using the scheduled quantities and prices from solve 1. An illustration of the calculated benefits is provided in Figure 1. In this figure the horizontal axis and Q1 and Q2 represent quantities supplied or consumed (at equilibrium). The vertical axis and P1 and P2 represent prices (at equilibrium).

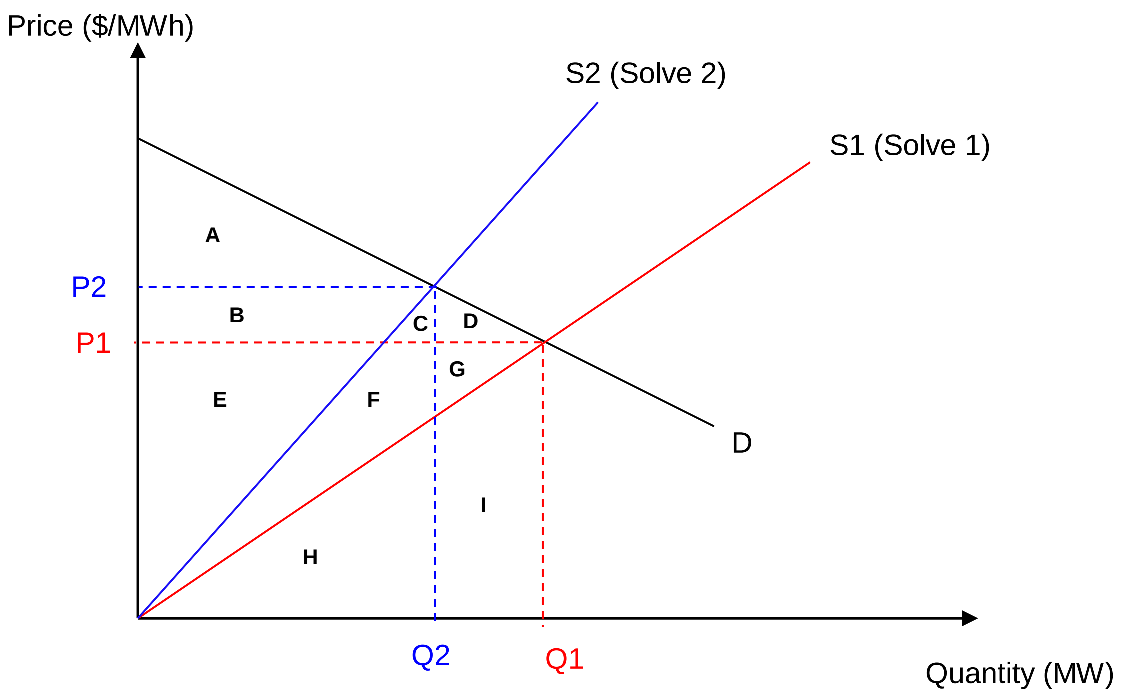
[1] The Authority's vSPD model was used for this analysis.

[2] Final pricing inputs are provided by NZX.

[3] The in-service status for existing transmission assets was retained, i.e. if the asset was out-of-service during the calculation of final prices then this status was retained during solve 1.

- Step 3: Remove the transmission asset(s) and re-solve the final pricing schedule (solve 2).
- Step 4: Re-calculate the benefit to injection and off-take participants at each node using the scheduled quantities and prices from solve 2. (See Figure 1).
- Step 5: Calculate the change in benefit for each participant at each node due to the removal of the transmission asset(s) (from solve 1 to solve 2).
- Step 6: Those participants with a positive change in benefit at a node from Step 5 are classified as market beneficiaries with the calculated change indicating the extent of the benefit.

Figure 1 Illustration of calculated benefits from vSPD solve



	Solve 1	Solve 2	Change
Demand (offtake)	A + B + C + D	A	B + C + D
Supply (injection)	E + F + G	B + E	F + G - B

7. The above figure illustrates the benefits calculated for offtake and injection participants under the market beneficiary approach using the vSPD two-solve process.

E2.1 Implementation issues

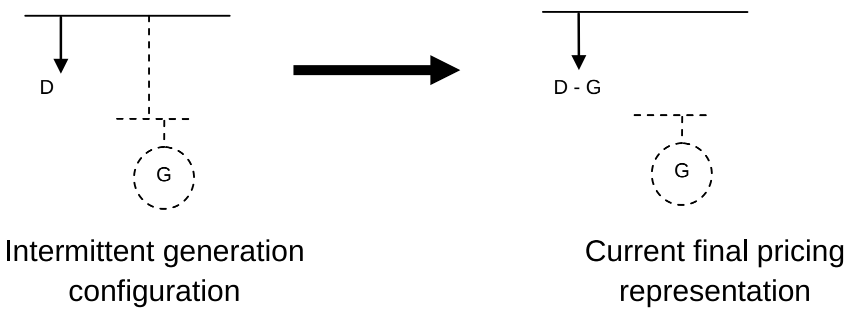
8. A number of issues were noted during the implementation of the SPD method. These are discussed further below.

E2.2 Allocation to intermittent generation

9. Intermittent generation is represented as non-dispatchable negative loads in the final pricing schedule as illustrated in Figure 2. This could affect the benefit allocated to wind generators as their scheduled volume is fixed and any benefit is based purely on changes in market price, which would tend to underestimate the benefit allocated to intermittent generation since no change in volume is considered under the two-solve process. This underestimation however is likely to be minimal due to intermittent generators being offered into the market as price-takers (at $0.01/MWh).

10. To ensure consistent treatment between intermittent and other generators in the beneficiary calculation, wind generation could be represented as dispatchable in the final pricing schedules. The Authority has an existing project to consider changing the treatment of intermittent generation within the final pricing schedule from fixed to dispatchable.

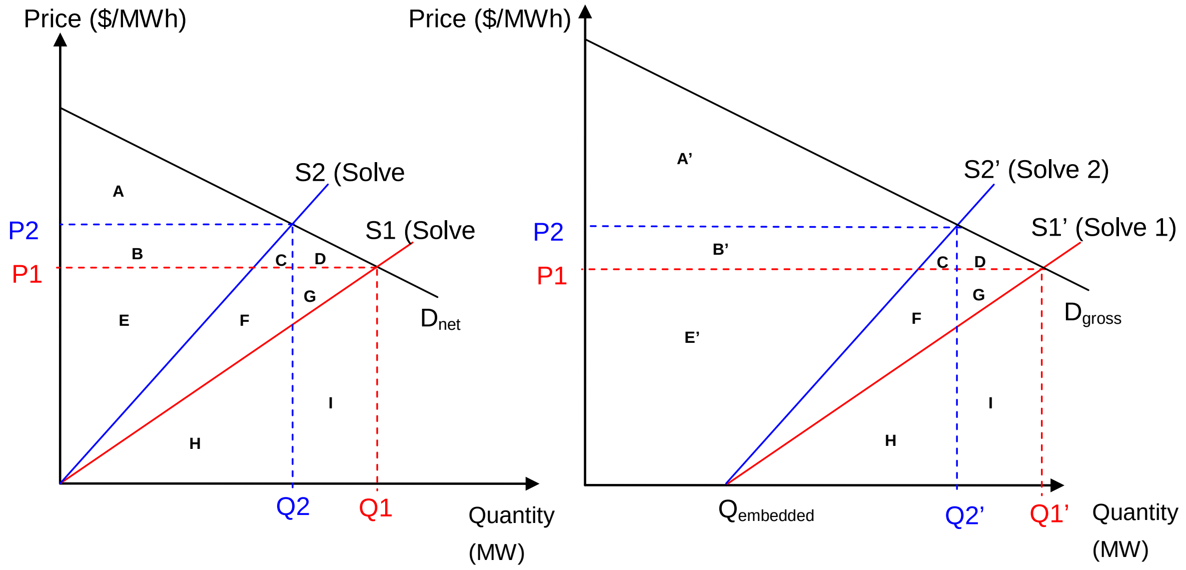
Figure 2 Intermittent generator configuration and representation in final pricing



E2.3. Net demand representation at off-take nodes in final pricing

11. At nodes containing embedded generators, only the net demand is reflected as offtake in the final pricing schedule. Therefore any benefit calculated at the node is based on the net demand representation and therefore can underestimate the calculated benefit using the above approach at the expense of the embedded generator that could be experiencing a reduction in benefit. Figure 3 illustrates this distortion.

Figure 3 Illustration of calculated benefits from vSPD solve



	Solve 1	Solve 2	Change
Net demand	A + B + C + D	A	B + C + D
Gross demand	A' + B' + C + D	A'	B' + C + D

12. In the above illustration the offtake benefit under the net demand representation is underestimated by the amount that the benefit to the embedded injection is reduced.

13. To correct for this distortion, the gross demand needs to be represented to enable a demand curve representation on the total offtake at a node. The embedded generator could be represented as a generator with a fixed output.

14. If net demand is used, the error introduced is relatively modest, since embedded generation is approximately 7% of gross demand.

E2.4 Robust shortage price process

15. The market clearing engine (SPD) has a representation of unserved energy within the model however it is priced at the deficit generation constraint violation penalty (CVP) of $500k/MWh. This elevated price is consistent with its use within the model and ensures all market offers are dispatched before invoking the unserved energy variable.

16. However, if SPD is used within the above two-solve process when existing elements are removed, there are likely to be some infeasibilities introduced into the SPD solve due to the removal of an asset that was actually in place during the market scheduling process.

17. An approach to resolve the infeasibility issue is the introduction of an unserved energy variable within the market clearing engine. In the Authority's tests, the

existing deficit generation infeasibility variable was used with the CVP. The current CVP value of $500k/MWh was reduced to $3k/MWh which represented the cost of a diesel generation alternative in the absence of the transmission asset. A piece-wise constant downward-sloping demand curve could be used to represent the increase in marginal cost for increased reduction in demand. A piecewise constant representation is required to maintain the linear system representation in SPD.

18. For some investments which actually enable the avoidance of non-supply for significant periods or time, the choice of shortage price in the counterfactual will be a significant factor in determining the incidence of transmission charges. It may be desirable to for the shortage price determination to give some credence to the type of generation investment that would have occurred in the absence of the transmission capacity, rather than a singular assumption of diesel peaking in all circumstances.

E2.5 Counterfactual security limits

19. When transmission elements are removed from the network within the two-solve process, the power flow on the transmission network changes, which can result in different sets of transmission security constraints. Since the introduction of SFT (the simultaneous feasibility test is a model to calculate security constrained transmission branch capacities) within the market system, these transmission security constraints are created dynamically based on system conditions. Therefore, the transmission constraints within the historic final pricing cases may not be relevant to the adjusted network configuration when assets are removed from service.

20. To account for this a dynamic constraint creation process (similar to SFT) would also need to be applied within the two-solve process. Therefore, for the solve 2 (without the relevant transmission asset in effect), the SFT-type process would need to be initiated to recreate the set of relevant transmission security constraints given the adjusted network state.

21. This process could either utilise Transpower's existing SFT software, or at modest expense a similar process could be replicated, perhaps of simpler design. Authority staff are already developing an SFT type model to improve the utility of its own vSPD, and does not view this as a significant undertaking.

E2.6 Recalculation of reserve requirements

22. When the HVDC link is removed the system reserve requirements would change. These reserve requirements are calculated during market operation by the Reserve Management Tool (RMT). The updated reserve requirements are passed to the market clearing engine (SPD) via a set of parameters called the net free reserves. This allows SPD to account for the reserve requirements of the system with the given conditions.

23. When the cost of reserves (or the requirements) increases, the reserve price can influence the energy price, thus affecting the calculated benefits using the above approach. If the reserve requirements are not adjusted when the status of the HVDC link is changed the beneficiary calculation, using the above beneficiary

calculation approach, would tend to underestimate the calculated benefits of the HVDC. This is because the HVDC provides some reserve response for a contingent event within an island and, assuming this response is still present without the link, would overestimate the system reserve response.

24. To accurately account for the changes in the system reserve requirements without the HVDC link in service, RMT would need to re-calculate the island reserve requirements.

E2.7 Final pricing schedule quantities versus actual dispatch quantities

25. The benefit calculation outlined above relies on two sets of price quantity pairs with and without the relevant transmission asset. The final pricing schedule is used to calculate the final prices used for settlement in the spot market, however the scheduled quantities in the final pricing solve are the "theoretically" optimal quantities for the trading period given knowledge of all system conditions. In reality, the actual quantities produced by generators can (and generally do) deviate from the final pricing schedule quantities. These deviations are due to differences between the real-time conditions and the average conditions represented for the 30-minute trading period in the final pricing solve.

26. In this analysis the final pricing schedule was used together with the corresponding final price as the optimal price-quantity pair under each solve. There could be trading periods where the actual conditions (and therefore dispatch quantities) differ significantly from the conditions used to calculate final prices, thus resulting in significant differences between the dispatch and scheduled quantities. These differences could lead to anomalies in the calculated benefits. An example is when a generator trips off during a trading period but with its offers still in effect at the start of the trading period and used to calculate final prices for that trading period. The final pricing scheduled quantity would exceed its dispatched quantity (due to it being offline for part of the trading period) and therefore the calculated benefit, using the final pricing schedule quantities could exceed the actual benefit derived during that trading period.

27. One alternative would be to use the two solve process to determine the prices and the change in schedule quantities with and without the transmission asset. The change in the schedule quantities could then be applied to the actual metered quantities to estimate quantity effect in the second solve. This approach will not affect the calculated benefits of generators that are constrained-on (as they would be considered constrained-on in both solve 1 and solve 2 and therefore not affect the calculated benefits as constrained-on payments only serve to recover costs). For generators that are constrained-off, this approach would tend to calculate a lower benefit, than if the schedule quantities were used due to the convexity of the supply curve (i.e. increasing marginal cost of supply).

28. Another alternative would be to use the calculated benefits based on scheduled quantities from final pricing and limit potential impacts on calculated benefits by allocating the costs of the relevant assets on a trading period basis.

E3. Experimental results

29. The feasibility of the above market beneficiary approach was simulated using three major upcoming transmission upgrades with data from 01 July 2010 to 30 June 2012. These transmission projects include:

    a. North Island grid upgrade project (NIGUP);

    b. HVDC pole 3; and

    c. Wairakei ring upgrade.

30. The positive change in market benefits for generators (represented by F + G – B in Figure 1) and loads (represented by B + C + D in Figure 1) were calculated.

31. The following sections describe the results from the simulations for each of the upgrades.

E4. North Island grid upgrade project (NIGUP)

32. The NIGUP project corresponds to the additional transmission circuits constructed from the central North Island to the upper North Island. The NIGUP project would increase the power transfer capacity into Auckland, reduce the loading (and losses) on the existing 220 kV Otahuhu–Whakamaru and Huntly–Otahuhu circuits and reduce the reactive support needed in the upper North Island

33. The calculated market benefits to the major generator-retailer and direct connect consumers based on the two-solve approach using vSPD is shown in Figure 4 and Figure 5 respectively. In total these participants cover 99% of the calculated annualised market benefit. Note these results are not adjusted to present-value.

Figure 4 Annualised NIGUP market beneficiary results over the two year period from July 2010 to June 2012

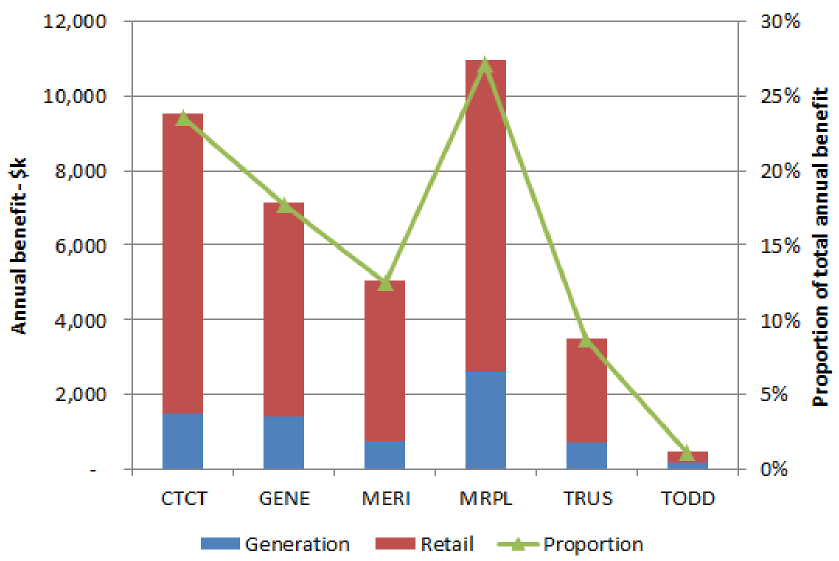
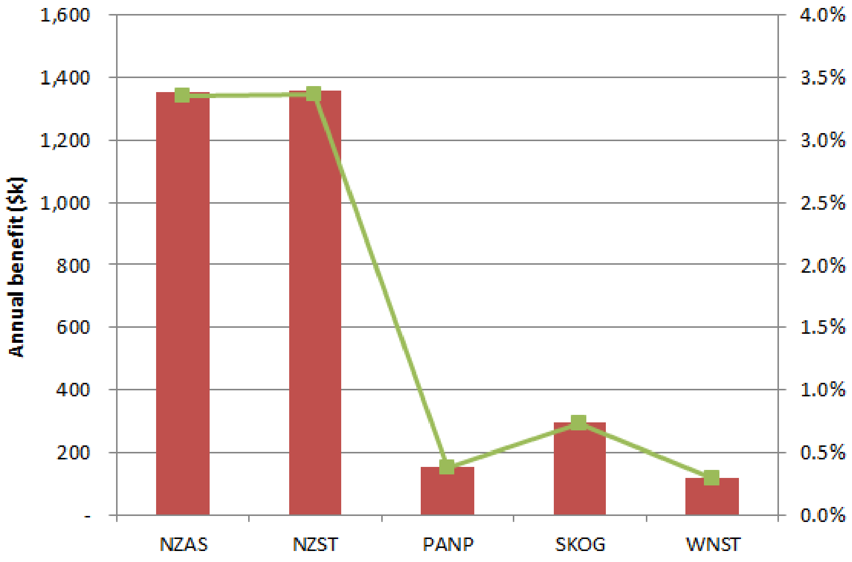


Figure 5 **Annualised direct connect market benefits for NIGUP simulation over the two year period from July 2010 to June 2012**

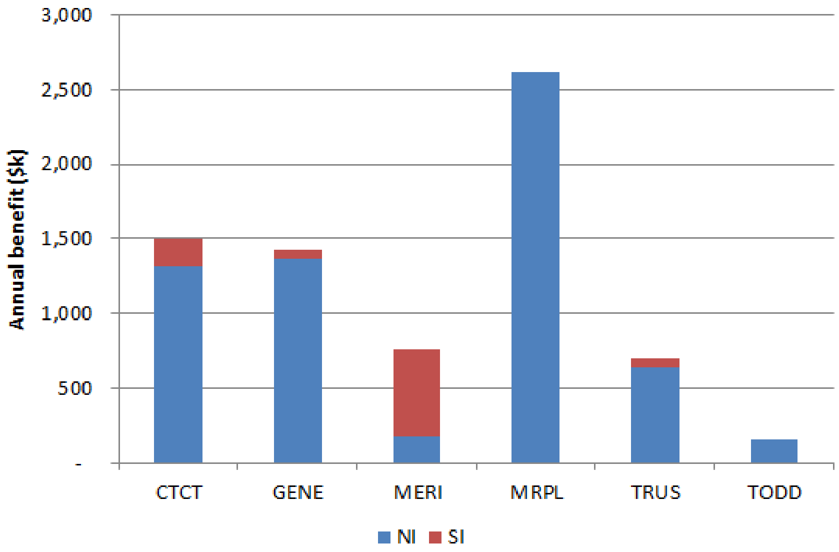


34. The primary market benefit provided by NIGUP in the market simulation (for 2010 to 2012) is a reduction in transmission losses. This reduction in losses translated into primarily positive benefits to the major participants with generation and retail positions in both the North and South Islands and to direct connect consumers in both the North and South Islands.

35. This effect can be explained by considering a simplified example with a sending and receiving end generator, where it is assumed the sending end generator is economically "constrained" due to the additional costs imposed on its imports due to losses (i.e. the marginal loss effect). Under these instances, a reduction in the losses on the transmission system joining these two generators would enable the sending end generator to increase its output resulting in an increase in its local nodal price but still being able to compete with the receiving end generator (due to lower marginal losses). Under this scenario, the sending end generator experiences an increased benefit due to an increase in volume and an increase in price. The generator at the receiving node would experience a reduction in output due to the additional exports from the sending end generator and the lower losses on the interconnecting transmission system. This reduction in output could be at a lower price tranche, reducing prices for the load at the receiving node which translates into a positive benefit for them.

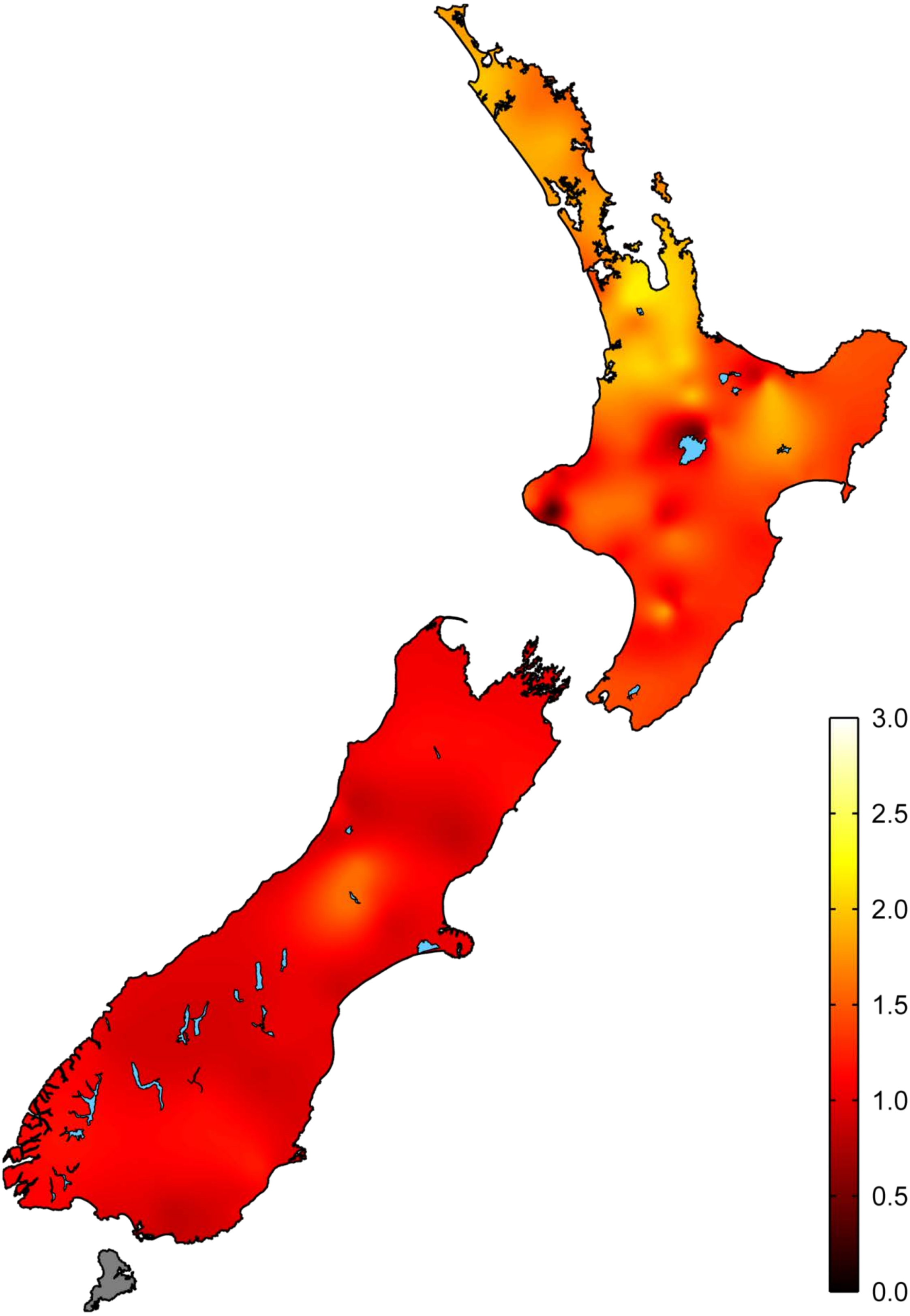
36. Therefore, the generation experiencing increased benefit, are those generators that are in export regions. During periods of sufficient hydro generation, these would include generators in the central and lower North Island who are closer to the transmission upgrade and, to a lesser extent, South Island generators. In periods when hydro generation is being conserved and thermal generation output is increased the exporting generators would be those in the upper North Island. Figure 6 illustrates a breakdown of the annual market benefits to the major generating companies by island. Mighty River Power (MRPL) with the majority of its generation close to NIGUP is calculated as the major generator beneficiary.

Figure 6 Annualised generator benefits by island for NIGUP simulation over the two year period from July 2010 to June 2012



37. Retail in both the North and South Islands are calculated as market beneficiaries of NIGUP due to the reduction in losses and its effect on both the marginal cost of generation and the marginal loss effects. However, given the predominant south-to-north flows on the transmission system, this benefit is largely in the North Island and more specifically in the upper North Island. The geographical distribution of per unit benefit to retail load from the NIGUP simulations is illustrated in Figure 7 below. The areas shaded in yellow indicate areas with large per unit benefits (price reduction) and the areas shaded in red indicate areas of lower per unit benefit (lower or no price reduction) under the SPD method. As expected retail load in the upper North Island who are subject to a larger loss effect, benefit the most on a per unit basis.

Figure 7 NIGUP heat map of normalised benefit ($/MWh)



38. Figure 7 provides an indication of the private benefits on a per unit (MWh) basis. In effect, it shows the regional variation in transmission prices arising from applying the SPD method to NIGUP over the two year historical simulation. The

actual impact will differ in practice as future load and generator offers are likely to change once NIGUP is actually operating.

39. The beneficiaries determined from the SPD method confirm that the primary beneficiaries are retailers in the upper North Island (on a per unit basis). However, the SPD method has identified that these market benefits permeate throughout the power system due to the interconnectedness of the market nodal prices and their quantities.

E5. HVDC pole 3

40. The installation of pole 3 in the HVDC link increases the transmission capability between the islands. This increased capability enables greater access to South Island hydro resources and access to North Island thermal generation during dry periods. Furthermore, the increased capability reduces the constraints between the North and South Islands, increasing the potential for competition in the wholesale electricity market. The increased capability with the introduction of pole 3 also reduces the amount of reserves required to cover an HVDC pole trip due to self-cover provided under bipole operation.

41. The SPD method was used for the new HVDC pole 3. Since it is probable that pole 1 would have been decommissioned even if Pole 3 had not been approved for investment, it seems reasonable to compare SPD solutions including pole 3 and pole 2 against pole 2 only. However historical simulations with pole 1 removed yielded large price separation under instances when HVDC pole 2 was on outage or the system was tightly constrained. This is because the historical offers used for these studies were formed in circumstances where pole 1 was available. The absence of pole 1 resulted in a significant amount of the benefits concentrated around a few instances that would not be a realistic portrayal of how the market would perform under the SPD method. The benefit calculation under the SPD method is consequently distorted by the absence of pole 1, and this is illustrated in Table 1, which indicates a total positive annual benefit of $609m.

Table 1: Pole 3 market beneficiary results with Pole 1 removed from the simulation for the two year period July 2010 to June 2012

Pole 3 (Pole 1 not in Solve 2)	CTCT	GENE	MERI	MRPL	TRUS
Positive Generation Benefit ($k)	41,698	21,448	83,622	11,357	9,011
Positive Retail Benefit ($k)	255,368	224,275	210,627	255,165	106,267
Total Positive Benefit ($k)	297,066	245,723	294,249	266,523	115,277

42. To cater for this distortion in the benefit calculation, the base case (solve 2) was re-solved with pole 1 in service. The introduction of pole 3 in solve 1 then replaced pole 1. The results from this set of simulations are shown in Table 2.

43. Note that Pole 2 was present in all SPD solves, base case and counterfactual, unless it was physically not connected during outages.

Table 2: Pole 3 normalised market beneficiary results for the two year period July 2010 to June 2012

Pole 3	CTCT	GENE	MERI	MRPL	TRUS
Positive Generation Benefit ($k)	26,314	17,750	39,716	11,448	5,624
Positive Retail Benefit ($k)	72,533	57,767	86,439	67,598	30,778
Total Positive Benefit ($k)	98,847	75,517	126,155	79,046	36,402

44. The major market beneficiaries from the introduction of pole 3 is retail which benefits from the lower prices due to the increased transmission capability on the bipole link, and also the reduced price separation between the sending and receiving islands due to both losses and the lower reserve requirements. Conversely, generators in the sending island would be the positive beneficiaries experiencing an increase in generation (which is exported across the expanded link) and a corresponding increase in price. The positive generator beneficiaries would be South Island generators for northward HVDC transfer and North Island generators for Southward HVDC transfer periods. This can be observed with large South Island generators experiencing the majority of the positive benefits from the expanded link. The predominant southward flow in December 2010 and the first half of 2012 would have resulted in benefits to the participants who are predominantly North Island generators.

45. The major retail beneficiaries are those in the North Island, as observed in Figures 8 and 9. This is consistent with the predominant northward HVDC flow over the period and the receiving island loads benefiting from a reduction in prices due to increased HVDC capability under the bipole arrangement.

Figure 8 Pole 3 heat map of normalised benefit ($/MWh) with Pole 1 removed

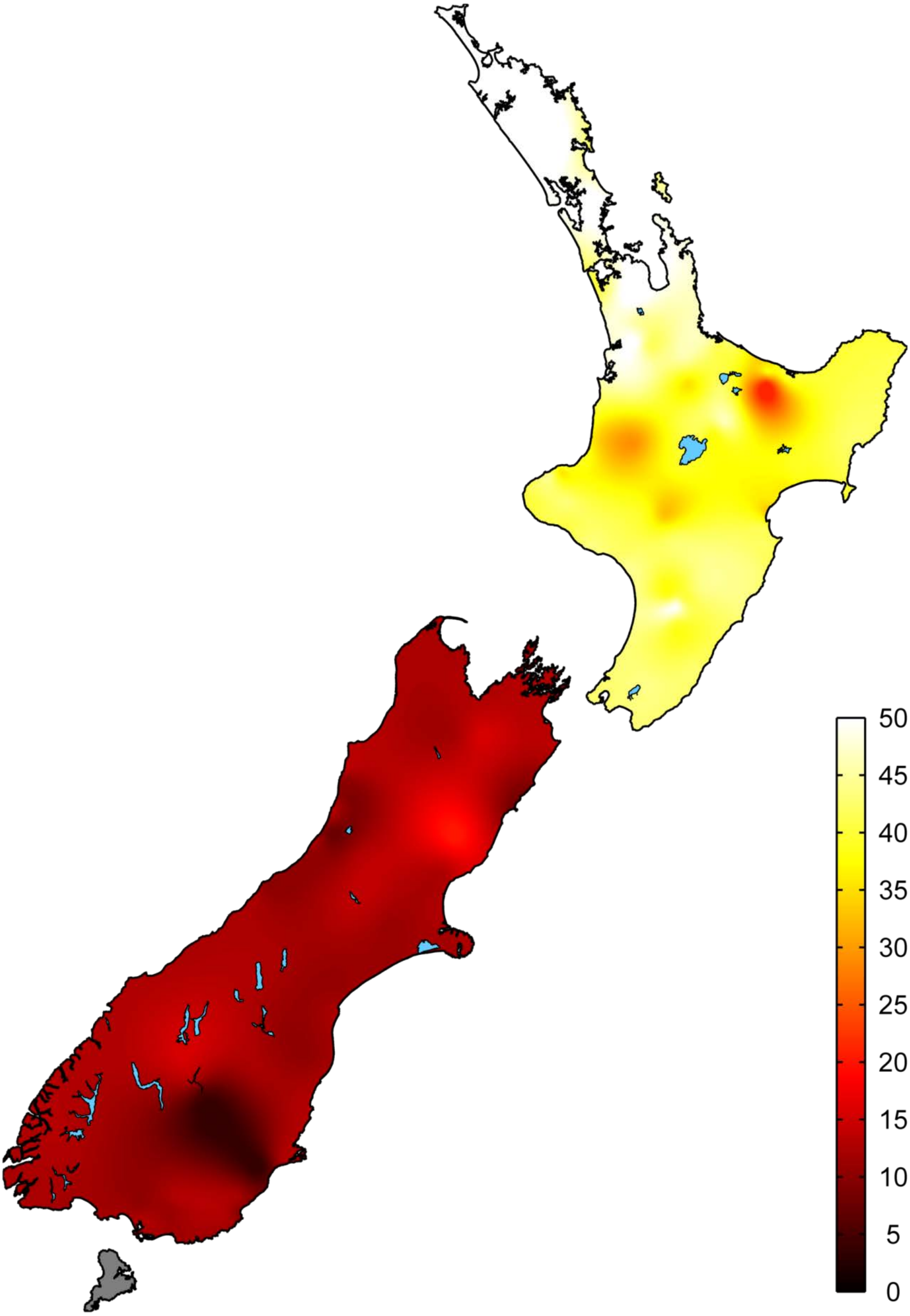
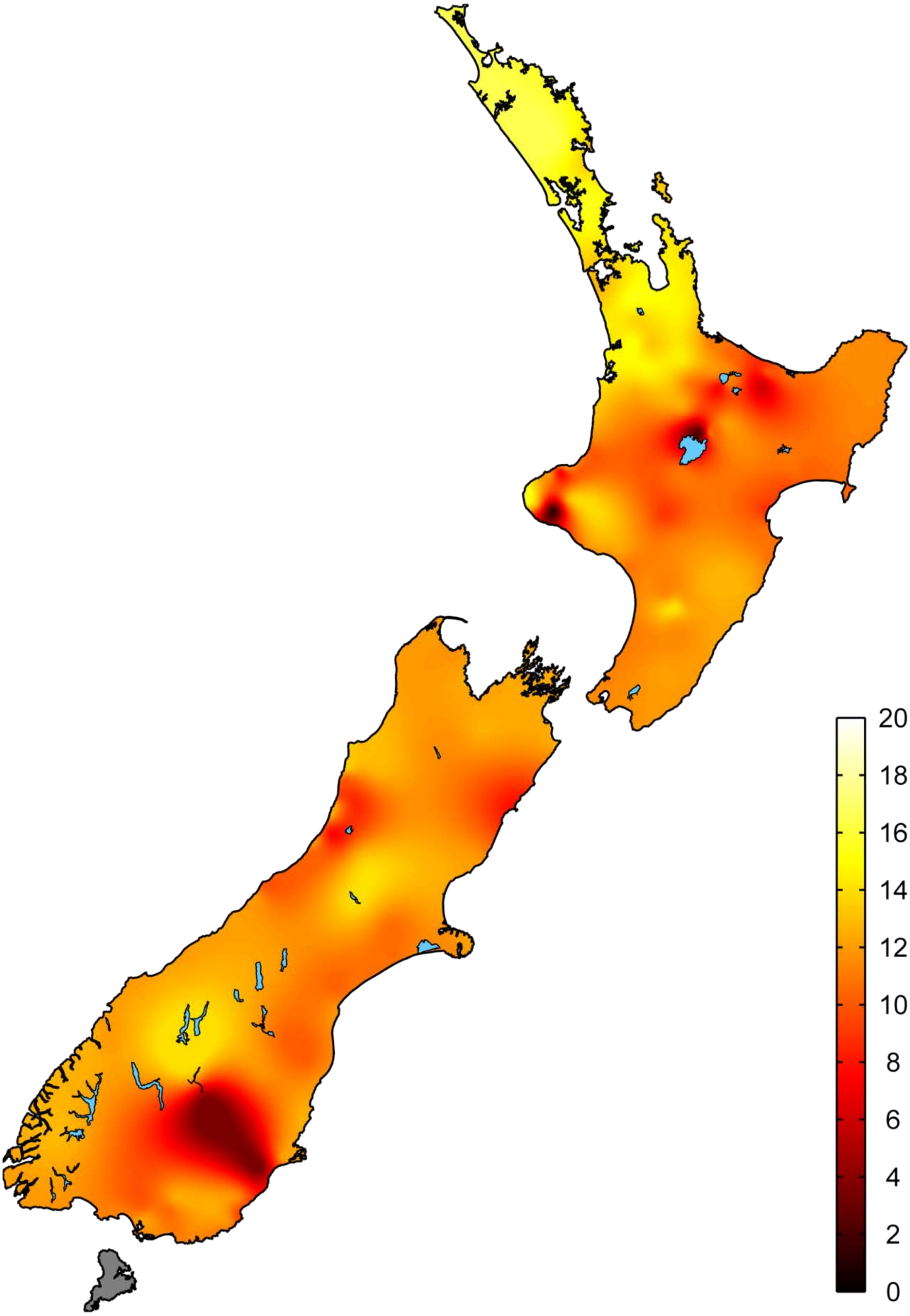


Figure 9 Pole 3 heat map of normalised benefit ($/MWh)



E6. Wairakei Ring upgrade

46. The Wairakei ring upgrade introduces a new double circuit line between Wairakei and Whakamaru. This would replace the existing single circuit line and increase

the contingency transfer into the upper North Island. Furthermore, strengthening the Wairakei risk increases the potential for generation connection in the region.

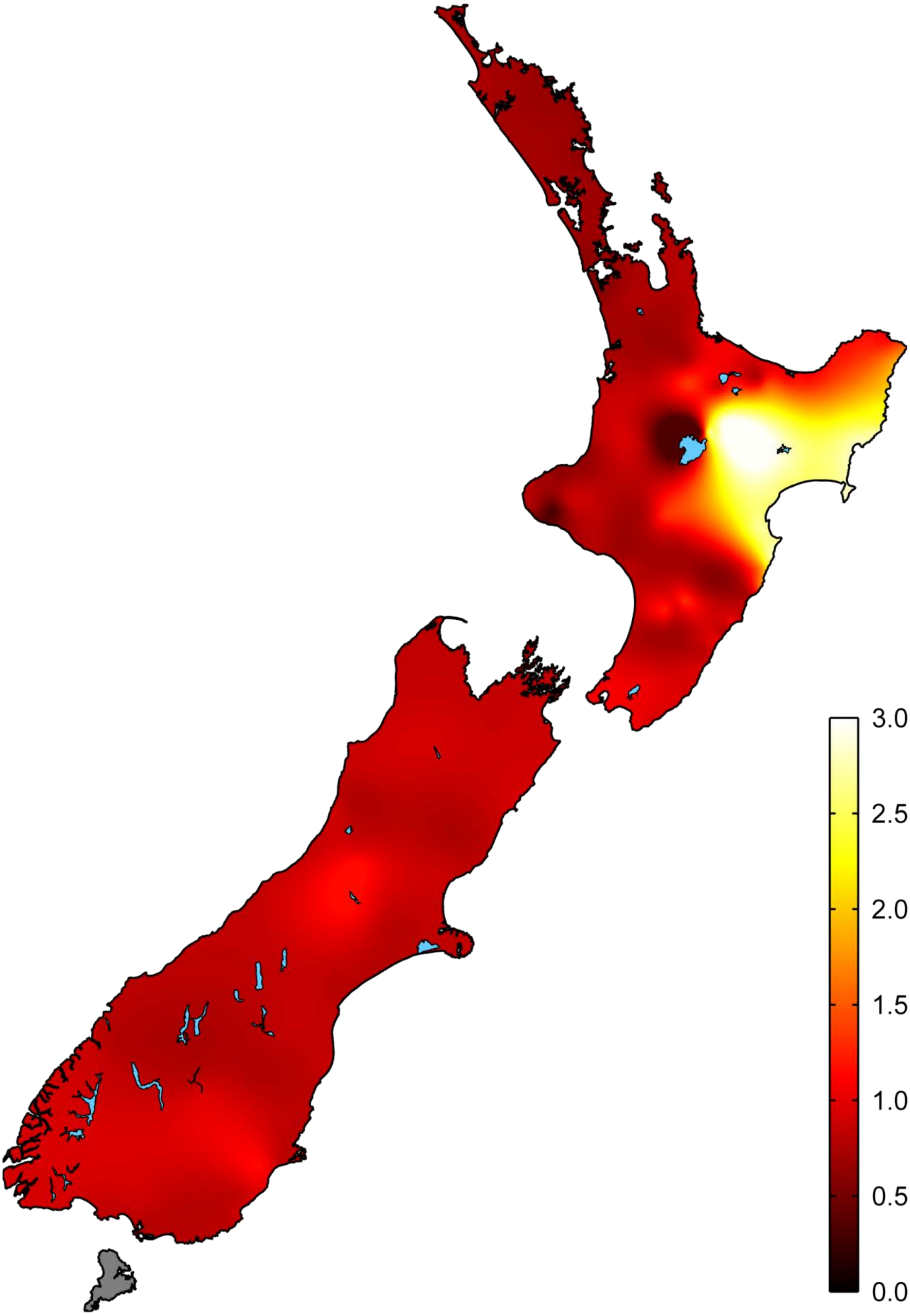
47. The primary benefit of the Wairakei ring upgrade under the market beneficiary approach using vSPD was the reduction in transmission losses. As with the results from the NIGUP simulations the reduction in losses provide benefits to both retail and generation, depending on whether they are importing or exporting energy through the Wairakei ring.

48. As with the NIGUP market effects, the market beneficiaries for the Wairakei ring upgrade include both North Island and South Island retail loads due to the interconnectedness of the nodal prices though the transmission network.

Table 3: Wairakei ring market beneficiary results for the two year period July 2010 to June 2012

Wairakei ring upgrade	CTCT	GENE	MERI	MRPL	TRUS
Positive Generation Benefit ($k)	5,254	3,771	1,742	4,697	794
Positive Retail Benefit ($k)	5,882	4,434	6,461	5,874	2,525
Total Positive Benefit ($k)	11,136	8,205	8,203	10,571	3,319

Figure 10 Wairakei ring heat map of normalised benefit ($/MWh)



49. The above heat maps illustrate the per unit calculated benefit to retail/consumption of three transmission upgrades. It should be noted that these normalised values do not reflect an equivalent increase in retail electricity price,

as the calculated transmission costs would be capped at Transpower's regulated revenue requirement for those assets.

50. The allocation of transmission cost on a regional basis will depend on the determined benefit, and the size of the demand. The following table illustrates the share of benefit to retail in each of three investments. The sums do not make 100% due to the proportion of benefit seen by generation.

Table 4 Proportion of benefit allocated to retail on a regional basis for three investments

TX region	NIGUP	Pole3	WRK Ring
Auckland	29.2%	18.4%	16.1%
Bay of Plenty	2.8%	4.6%	4.3%
Canterbury	3.3%	5.5%	3.6%
Central	2.8%	3.7%	2.8%
Hawkes Bay	1.8%	3.0%	1.9%
Nelson/Marlborough	0.9%	1.6%	1.0%
North Isthmus	15.5%	10.2%	8.7%
Otago/Southland	5.4%	10.2%	6.5%
South Canterbury	0.5%	0.8%	0.5%
Taranaki	1.6%	1.8%	1.3%
Waikato	10.5%	8.4%	8.1%
Wellington	4.9%	6.5%	4.9%
West Coast	0.3%	0.5%	0.3%
Grand Total	**79.5%**	**75.2%**	**60.0%**
Region	**NIGUP**	**Pole3**	**WRK Ring**
UNI	44.7%	28.6%	24.8%
CNI	15.1%	16.0%	14.3%
LNI	9.3%	12.0%	9.0%
USI	4.5%	7.6%	4.9%
LSI	5.9%	11.0%	7.0%
Grand Total	79.5%	75.2%	60.0%

51. Under the SPD method, it is proposed that where the sum of calculated private benefits exceeds the revenue requirement for the asset under consideration, charges to each party benefiting from the asset would be scaled in proportion to their share of the total calculated benefits, such that the scaled sum equals the revenue recovery.

52. This process occurs in each half hour, utilising SPD inputs for the final pricing case, and off-take shares at each grid exit point, as utilised by the clearing manager. The revenue recovery for the transmission asset under consideration is the annual revenue requirement apportioned to a half hour period (i.e. divided by 17560).

53. If the sum of private benefits is less than the half hour revenue requirement, the charge for that half hour is the calculated private benefit.

E7. Impact of allocation using different time periods

54. The allocation of the costs for a transmission asset could vary depending on the time-period used to aggregate the benefits.

55. Allocation by trading period confines any cost allocation to benefits calculated in that trading period and therefore has a higher probability of not recovering the full revenue requirement of the asset as during some trading periods there could be no benefit (such as when the asset is out-of-service). Capping the allocation at the calculated benefit further increases the likelihood of revenue shortfall.

56. Allowing the benefits to be aggregated across several trading periods reduces the likelihood of revenue shortfall however can increase the concentration of the cost allocation to a few participants, particularly if they are deemed to derive a high benefit in a few trading periods due to the avoidance of load shedding at the shortage price. Such an allocation has the potential to introduce greater distortions to participant behaviour as a few trading periods could dictate a large proportion of the transmission costs.

57. The following discussion outlines the potential ways to aggregate the benefit as well as the impact of capping the costs at the calculated benefit:

E7.1 By trading period:

58. This involves proportioning the calculated cost of an asset within each trading period to participants based on their calculated benefit using the two-solve process outlined above.

59. This would involve the following steps:

- Step 1: Determine the cost of transmission asset A to be recovered in trading period t (TC(a,t))

- Step 2: Determine proportion of participant p’s benefit to total benefit in trading period t due to transmission asset A: Proportion(a,p,t) = Benefit(a,p,t)/TOTAL Benefit(a,t)

  Where TOTAL Benefit(a,t) = total calculated benefit of transmission asset a in trading period t. That is:

  TOTAL Benefit(a,t) = sum(p, Benefit(a,p,t))

- Step 3: Determine the cost allocation of transmission asset a to participant p in trading period t:

  Cost allocation (a,p,t) = Proportion(a,p,t) * TC(a,t)

- Step 4: This additional step could be included to limit the allocated cost to the calculated benefit:

  Capped cost allocation(a,p,t) = min(Cost allocation(a,p,t), Benefit(a,p,t))

60. In the above allocation, each determined beneficiary is allocated a proportion of the cost of the transmission asset (up to their derived benefit).

E7.2 By day (month or year):

79. The above allocation could be repeated but rather than the proportionate allocation being done by trading period, the allocation of the daily (or monthly or yearly) cost of the transmission asset could be based on the daily (monthly or yearly) calculated benefit. Additionally, the daily (monthly or yearly) cost allocation could be capped at the calculated daily (monthly or yearly) benefit.

E8. Variability of the charge

80. The calculation of private benefits on a half hourly basis will lead to some variability in charge over time. Private benefit is likely to fluctuate proportionately to wholesale price and volumes, with consequent correlation of transmission charges with seasonality and periods of scarcity pricing.

81. It is possible that the calculated private benefit in some trading period could exceed the participant's surplus in that trading period. For example if there is non-supply in the counterfactual solution, a retail participant will be deemed to have benefited by the avoidance of shortage prices. However in reality, with normal prices, the consumer surplus may be less than the private benefit determined against the counterfactual.

82. The impact of variability in the transmission charge as allocated by private benefit calculation is mitigated by a number of factors.

83. In any half hour, the transmission charge is capped at the revenue requirement for transmission assets in that period.

84. Over time generators will include incremental transmission charges in their offer curves so that revenue shortfalls due to private benefits exceeding producer surplus in some trading periods will be compensated in other trading periods.

85. Similarly, retailers will pass through transmission charges in retail tariffs, as competing retailers in the same region will incur the same incremental transmission charges.

86. Consumers ultimately paying passed-through transmission charges cannot in the end be paying more than the revenue requirement for those assets, which under an assumption of efficient transmission investment, will be less than a local generation alternative. This means the end-consumer surplus will not be exceeded by passed-through transmission charges unless inefficient investment has occurred.

87. In many cases volatility in transmission charges will in fact be correlated with increased producer or consumer surplus.

88. The following figures illustrate the weekly estimation of calculated private benefit for NIGUP, HVDC Pole 3 (with Pole 1 in the base case), and the Wairekei Ring projects. It should be noted that these private benefit estimates have not been

truncated at the estimated transmission revenue requirement, which is certainly exceeded on some occasions.

89. It is evident that sporadic incidents of high price drive a significant portion of the total estimated benefit. This is to be expected for transmission investments, which are typically designed and sized for extreme events.

Figure 11 Weekly estimate of private benefits for NIGUP to generation

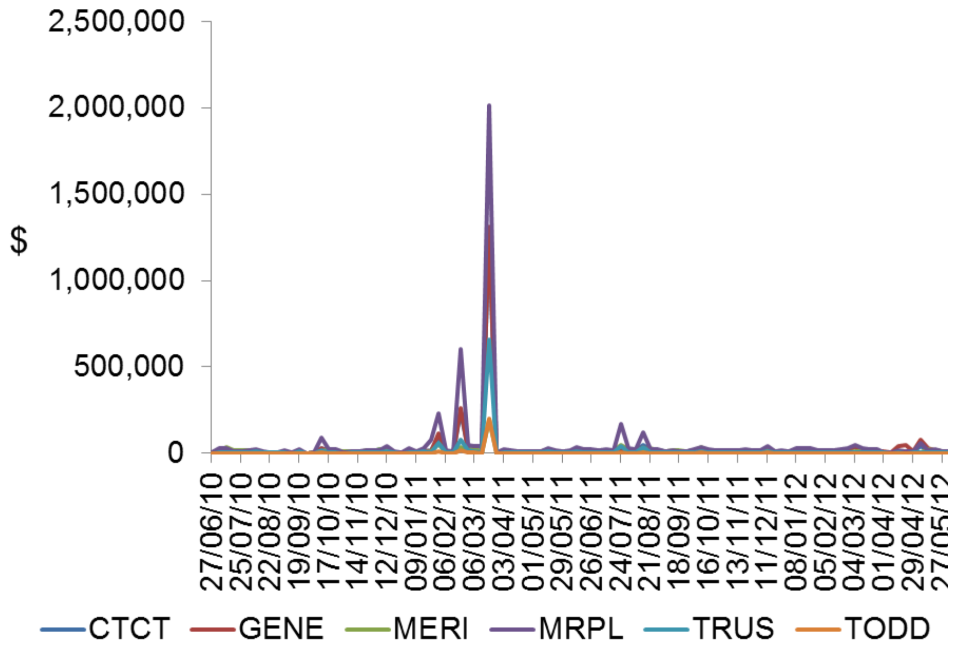


Figure 12 Weekly estimate of private benefit for NIGUP to retail at several load centers

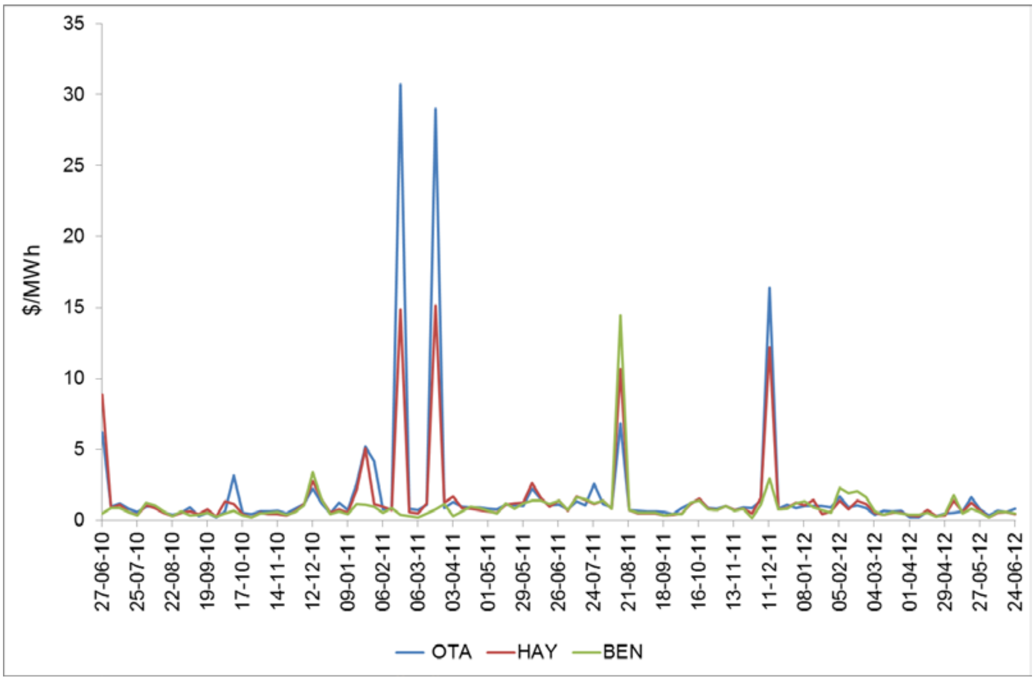


Figure 13 **Weekly estimate of private benefit for Pole 3 (Pole 1 included in bases case) to generation**

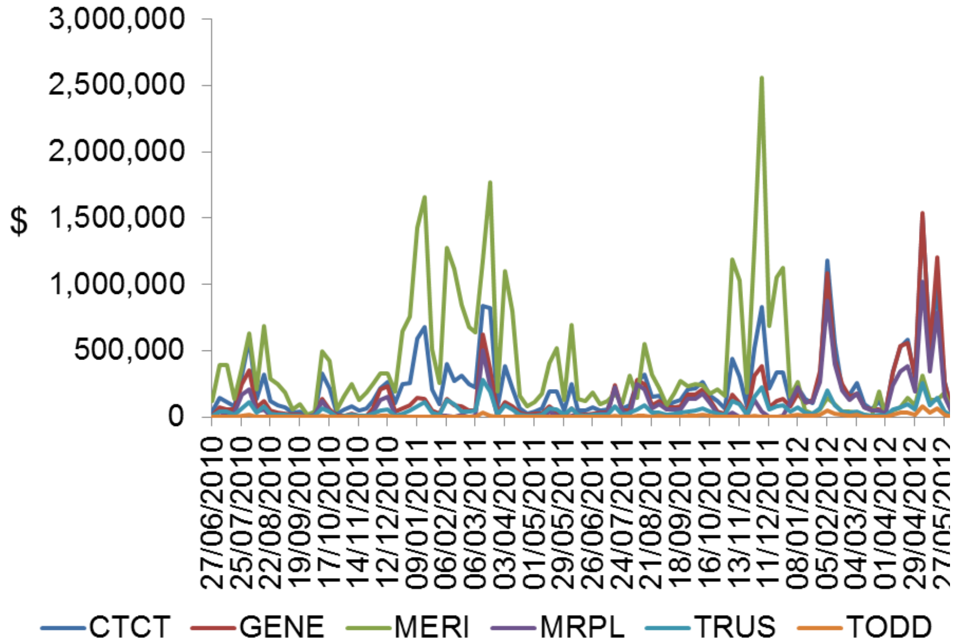
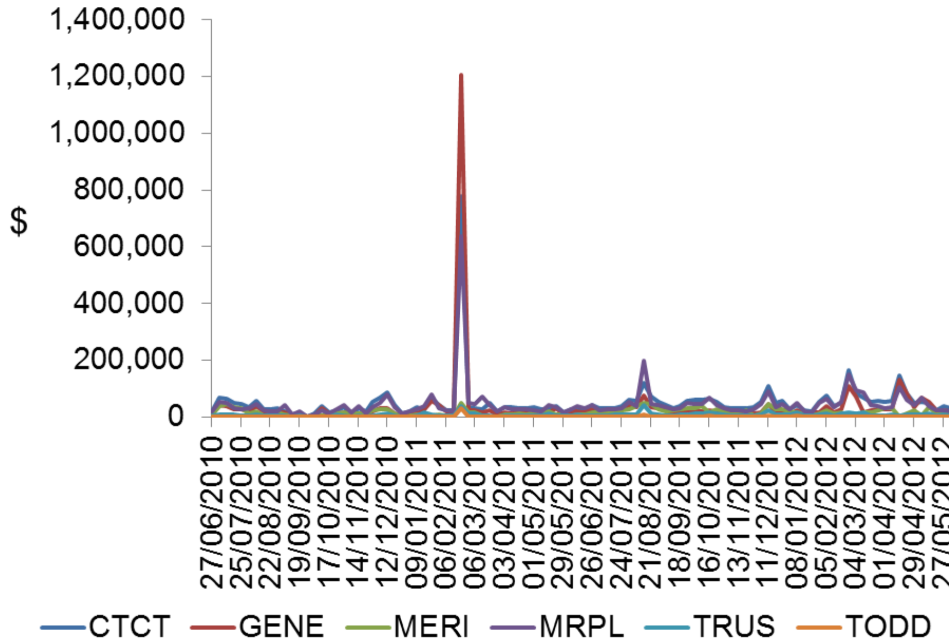


Figure 14 **Weekly estimate of private benefit for Wairekei Ring project to generation**



90. Assets such as the HVDC are subject to variability of benefits as a result of changes in hydrology. This is illustrated in Figure 15, which shows benefits to load are concentrated in the North Island during at wet year such as 2010/11 but the reverse applies in a dry year, such as 2011/12.

Figure 15: Heat maps showing private benefits to load from Pole 3 in $/MWh