Appendix C Assessment of materiality of problems with HVDC charges under the current TPM

C1. Introduction

C1.1 Purpose of this Appendix

1 This Appendix provides analysis relating to the efficiency of current HVDC charging arrangements. It feeds into the problem definition section in chapter 4 of the issues paper, which discusses the nature and materiality of problems with the current TPM.

2 The Appendix begins by assessing the extent to which HVDC charges are aligned with the private benefits that will be derived from the HVDC link (Sections C2-C4).

3 The current HVDC charge has sometimes been justified on the grounds that South Island generators (who pay the charge) are the beneficiaries of the HVDC link – in other words, that it is consistent with the beneficiaries-pay approach. If this was the case, the suggestion would be that the HVDC charge could be expected to promote more efficient outcomes. However, to date there has been little rigorous analysis to support the assertion that South Island generators are the beneficiaries.

4 The Authority has now estimated the private benefits of the HVDC link using bespoke models. The analysis is divided into two sections; the first estimates the benefits of pole 2 by comparing a *monopole* scenario with a *no-DC* scenario, and the second estimates the incremental benefits of pole 3 by comparing a *monopole* scenario with a *bipole* scenario.

5 It is important to emphasise that this is not a cost-benefit analysis. It compares *private* benefits between various transmission configurations, rather than comparing *public* benefit between a proposed policy and one or more alternatives. The cost-benefit analysis of the Authority's proposal against the counterfactual of the status quo is set out in Appendix F. Appendix F uses a different methodology from the methodology used in this Appendix so the results are only comparable in terms of the likely direction of the costs and benefits rather than the specific values.

6 Note also that, although the bespoke modelling is informative about the consistency of the current HVDC charge with beneficiaries pay, it would not be a suitable method for a new charging regime. A suitable beneficiaries-pay charging regime needs to identify the private benefits obtained by individual participants and adapt to changing circumstances.

7 The Appendix concludes with an assessment of the efficiency of the effects of the current HVDC charge on electricity market investment and operation (Section C5).

8 The assessment considers the effects of the HVDC charge through favouring South Island generation over North Island, discouraging investment in peaking capacity in the South Island, and discouraging South Island generators from offering their full capacity.

9 Again, this efficiency assessment is not a cost-benefit analysis:

a. it does not describe alternatives to the status quo;

b. it does not consider the costs of implementing alternatives; and

c. it does not consider issues such as acceptability or providing certainty to investors.

10 Rather, the efficiency assessment identifies problems that are candidates for resolution through the review and amendment of the TPM.

11 All costs and benefits in this Appendix are expressed on a pre-tax basis. A real discount rate of 6% (pre-tax) is used throughout. In some cases, real discount rates of 4% and 8% are used as sensitivities.

C1.2 Key findings

12 The analysis indicates that the current HVDC charge is not consistent with beneficiaries pay. Some parties that derive a private benefit from the HVDC do not pay the HVDC charge; others do not pay a charge commensurate with their private benefit.

13 Under current HVDC charging arrangements, it is expected that:

a. South Island generators will, in aggregate, derive a private benefit from pole 2 on the order of $540M present value (point estimate), against an estimated HVDC charge related to pole 2 of about $500M PV;

b. South Island generators will, in aggregate, derive a private benefit from pole 3 on the order of $155M PV (point estimate), against an estimated HVDC charge related to pole 3 of about $970M PV;

c. consumers in both islands will, in aggregate, derive a private benefit from pole 2 and pole 3 on the order of $1.8B PV (point estimate), but under current arrangements will pay no HVDC charges; and

d. North Island generators will, in aggregate, face a private cost on the order of $1.3B PV (point estimate) as a result of the HVDC link, but under current arrangements will pay no HVDC charges.

14 These aggregate results will not hold true for all parties in some circumstances. In particular:

a. some individual South Island generators may not derive significant benefit from the HVDC link; and

b. there will be times when some North Island generators do benefit from the availability of the link (i.e. during south flow).

15 The assessment of the efficiency of the HVDC charge identifies that current arrangements are expected to result in a net cost on the order of $30M NPV, made up of:

a. an expected cost on the order of $30M PV (but with considerable uncertainty) through incentivising North Island generation over South Island generation and through discouraging South Island peaking capacity, both of which are (at least in isolation) inefficient;

b. a small expected cost, estimated to be less than $5M PV, through disincentivising South Island generators from operating their generation at full capacity;

c. a small expected benefit, on the order of $5M PV, through deferring further HVDC investment; and

d. unknown, but potentially significant, costs and benefits through affecting the need for further AC investment.

C2. Approach to estimating private benefits stemming from the HVDC link

16 Sections C3 and C4 set out estimates of the private benefits that will be derived by various parties from the availability of poles 2 and 3 of the HVDC link, and compare these benefits with the HVDC charges to be paid.

17 Three scenarios are considered:

a. *no DC* – in which pole 2 was never constructed, pole 1 is soon to be decommissioned, and no pole 3 will ever be constructed (leaving no HVDC link from 2014 onwards);[1]

b. *monopole* – in which pole 2 was constructed, but pole 1 is soon to be decommissioned, and no pole 3 will ever be constructed (leaving a monopole HVDC link from 2014 onwards); and

c. *bipole* – the scenario that actually transpired, in which pole 2 was constructed and pole 1 is soon to be replaced by pole 3 (leaving a bipole HVDC link from 2014 onwards).

18 The private benefit of pole 2 to a particular party (or group of parties) is estimated through the difference in outcomes between the *no-DC* and *monopole* scenarios (Section C3).

19 The private benefit of pole 3 is estimated through the difference between the *monopole* and *bipole* scenarios (Section C4).

20 The pole 2 assessment is based on a single analysis, as opposed to the pole 3 assessment which includes several analyses investigating different aspects of the investment. The reason for the difference in approach is that:

a. upgrading from no HVDC link to a monopole has *major effects through a single function* (i.e. allowing bulk energy transfer between the two islands); but

b. upgrading from a monopole to a bipole link has *moderate effects through several functions* (e.g. increasing bulk energy transfer capacity, allowing South Island generators to contribute to meeting North Island peak, and affecting instantaneous reserve (IR) and frequency keeping markets).

21 The analysis takes into account that the three scenarios would differ in terms of generation operating and investment decisions, and the *no-DC* scenario might also differ from the other two scenarios in terms of generation ownership (because if there was no pole 2, the generator-retailers might have been given different generation portfolios when they were originally formed).[2]

22 Only costs and benefits arising from 2014 onwards are considered. The availability of pole 2 may also have led to some costs and benefits between its commissioning in 1991 and the present day, but these are not covered in this Appendix.

[1] The possibility that pole 1 could be kept in service indefinitely is not considered, as Transpower has indicated this was not a viable option.

[2] The analysis does not, however, take into account the possibility that the market rules might have been different in the *no-DC* scenario.

23 The reader will note that many sources of cost and benefit are considered. Although this complicates the analysis, it is unavoidable because the HVDC link is a key part of the transmission system and affects participants in many different ways.

24 It will also be noticed that the error bounds on the estimates of private benefit are typically very wide. Again this is unavoidable. It is not possible to carry out an experiment to "rerun history" since 1990 with and without the HVDC; all that can be done is to consider how things might have been different if the asset was unavailable. The legitimate uncertainty about how the future might play out means it is difficult to identify exactly how participants might be affected.

25 Where possible, an attempt has been made to identify benefits received by individual participants, but typically this has been infeasible and instead benefits have been estimated for each group of participants (e.g. "all North Island consumers").

26 One consequence is that the analysis is not a suitable method for a new charging regime, because it does not discriminate between generators within an island, nor between consumers within an island. A suitable beneficiaries-pay charging regime needs to identify the private benefits obtained by individual participants. It also needs to adapt to changing circumstances (for example, construction of new loads or new generation, changes in HVDC flows, changes in HVDC capability).

C3. Alignment between private benefits and charges, for HVDC pole 2

27 This section (C3) estimates the private benefits received by various parties from pole 2 and compares them with the portion of HVDC charges relating to pole 2.

28 The analysis focuses on the effects of pole 2 through allowing inter-island energy transfer, and does not take into account:

a. the effect of pole 2 on ancillary service markets *(which is considered to be second order)*; or

b. the effect of pole 2 in terms of promoting retail competition *(on the theory that if pole 2 had never been constructed, the establishment of generator-retailer companies would have been carried out in such a way as to avoid excessive market concentration in either island, and so the extent of retail concentration would have been no less than in reality)*.[3]

C3.1 Key findings

29 As set out in Section C3.2, the estimated private benefits to some key groups of parties are as follows (as pre-tax PV):

a. incumbent South Island generation – benefit of $100-1700M (point estimate $540M benefit);

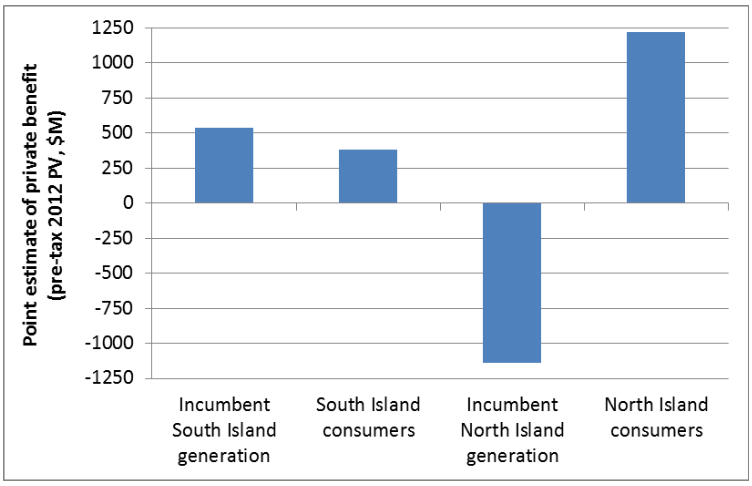
b. South Island consumers – cost of $100M to benefit of $1.2B (point estimate $380M benefit);

c. incumbent North Island generation – cost of $400-3900M (point estimate $1140M cost); and

d. North Island consumers – benefit of $430-4200M (point estimate $1220M benefit).

30 Based on the above point estimates, the *positive* private benefits are broken down as follows: 25% to South Island generators, 18% to South Island consumers, and 57% to North Island consumers (but with considerable uncertainty).

Point estimates of private benefit from HVDC pole 2



31 With regard to individual South Island generators, indicative analysis:

[3] If there *was* excessive market concentration in the South Island under a *no-DC* scenario, then this would likely manifest in terms of poor *wholesale* competition. Without a workably competitive wholesale market, prices might no longer be capped by the costs of new entry (rendering much of the analysis in this section invalid). It seems unlikely that such a situation would be allowed to persist – some form of structural remedy would surely be implemented before long.

a. suggests that Contact and Meridian derive substantial benefit as owners of the Clutha and Manapouri hydro schemes respectively;

b. suggests that Meridian and Genesis may not derive substantial benefit in their capacity as owners of the Waitaki and Tekapo hydro schemes (which are backed by substantial storage and so are better equipped to manage without a HVDC link); and

c. is inconclusive with regard to TrustPower (because the model used is not a good tool for estimating the effect on TrustPower's smaller hydro schemes).

32 Against the private benefits received by the owners of South Island generation from pole 2 availability should be set the level of HVDC charges that they would pay, if only pole 2 (and neither pole 1 nor pole 3) was in service.

a. Under current arrangements, the portion of the HVDC charge relating to the costs of pole 2 is expected to be approximately $55M p.a.[4] (For the next eight pricing years, there will also be a charge of $24M p.a. to make up for historic under-recovery – though some of this charge should be attributed to pole 1 rather than pole 2.)

b. South Island generators also pay Transpower's IR availability costs *(quantified in Section C3.3)*.

c. On the other hand, the costs of the HVDC link are partly offset by HVDC rentals, or FTR residual revenues *(quantified in Section C3.4)*.

33 If all these factors are taken into account, the portion of HVDC charges related to pole 2 is expected to sum to *approximately* $500M PV over the next 20 years.

34 It is therefore expected that, under existing HVDC charging arrangements:

a. the owners of South Island generation will receive a collective private benefit from pole 2 (post 2014) that will probably be on a similar scale to the HVDC charges (relating to pole 2) that they will be collectively required to pay *(though some may benefit more than others – for instance, it is not clear that Genesis Energy will benefit);*

b. South Island consumers will probably receive a collective private benefit *(though summer-peaking loads such as irrigation, and flexible loads able to reduce consumption for weeks or months at reasonable cost, may benefit less than others)* but will pay no HVDC charges;

c. North Island consumers will receive a collective private benefit but will pay no HVDC charges; and

d. the owners of North Island generation will incur a collective private cost *(though some North Island generators may benefit at specific times, i.e. when there is southward inter-island flow).*

[4] Based on the Authority's interpretation of information received from Transpower. This cost includes pole 2 capital cost recovery and depreciation, and a portion of HVDC operation and maintenance costs.

C3.2 Effects of allowing inter-island energy transfer

C3.2.1 Introduction

35 This section estimates the private benefit of pole 2 to various parties (or groups of parties) through allowing inter-island energy transfer.

36 It might be supposed that if pole 2 had never been constructed and the remaining monopole link was removed from service by 2014 and not replaced, then there would be a glut of power and wholesale prices would collapse in the South Island. The implication would be that pole 2 provides great benefit to South Island generators and great cost to South Island consumers.

37 However, as the analysis in this section shows, there would not consistently be a South Island glut (from 2014 onwards) and there is no reason to suppose that *average* South Island prices would collapse in a no-DC scenario.

38 Rather, pole 2 can be expected to produce more moderate benefits – for example:

a. to the owners of existing South Island hydro generation, by reducing spill and allowing them to sell more power than they would be able to if there was no HVDC link;

b. to the owners of existing North Island generation, by allowing them to sell their output at high prices during extended South Island dry sequences, which they would not be able to access if there was no HVDC link;

c. to generation investors, by enabling new generation investment opportunities; and

d. to consumers, by reducing mean energy prices in both islands, relative to what prices would be if there was no HVDC link.

39 This section quantifies these kinds of benefits (and the opposing costs) to the extent possible.

40 The remainder of the section sets out:

a. how parties are divided into groups for the purpose of the analysis (C3.2.2);

b. demand-side assumptions (C3.2.3);

c. for the 2014 year only:

- generation scenarios (C3.2.4);
- impacts of pole 2 on energy quantities generated in each island (C3.2.5);
- impacts of pole 2 on energy prices in each island, and hence on generator profits and consumer costs (C3.2.6);
- sensitivities (C3.2.7);

d. post-2014 impacts (C3.2.8);

e. resulting estimates of private benefit to key groups of parties (C3.2.9 and C3.2.10); and

f. some comments on private benefit to individual parties, as opposed to groups (C3.2.11).

C3.2.2 Groups of parties considered

41 Some attempt is made to estimate the benefits received by individual parties (see C3.2.10), but most of the analysis is expressed in terms of groups of parties.

42 It is useful to introduce a distinction between:

a. *common generation* – which would be operational in 2014 in all scenarios considered;[5]

b. *DC-dependent generation* – which would only be operational in 2014 in scenarios where pole 2 was available;[6] and

c. *sans-DC generation* – which would only be operational in 2014 in scenarios where pole 2 was *not* available.[7]

43 The reason for introducing the distinction is that:

a. *common generation* may receive a (dis)benefit from the HVDC link in terms of the quantity it is able to produce and the price at which it is able to sell that output; but

b. *DC-dependent generation* instead receives an "existence benefit" from pole 2 – by definition, if pole 2 was not available, such generation would not exist in 2014 and would return no profits; and

c. the reverse is true for *sans-DC generation.*

44 C3.2.4 ("Generation assumptions for 2014") sets out how generation might be divided between the three groups (*common, DC-dependent* and *sans-DC*). However, demand-side assumptions are set out first.

C3.2.3 Demand-side assumptions for 2014

45 For the purpose of this work it is assumed that (in both the *no-DC* and *monopole* scenarios):

a. North Island demand in 2014 will be 110% of 2007 demand;[8]

b. South Island demand in 2014 will be 107% of 2007 demand;[9]

c. Tiwai can provide 60 MW of demand response in dry sequences, at $200/MWh;[10] and

d. in more extreme dry sequences, demand can be reduced further through conservation campaigns (100 MW in the South Island at $500-1000/MWh) and rolling outages (at $5000/MWh).

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5 For instance, it is assumed that Otahuhu B will be available in 2014 no matter what happens to the HVDC.

6 For instance, it is assumed that White Hill wind farm would not have been built if there was no pole 2 – see C3.2.4 ("Generation assumptions for 2014").

7 For instance, it is assumed that additional North Island peaking generation would be needed by 2014 if there was no pole 2 – again, see C3.2.4 ("Generation assumptions for 2014").

8 Consistent with the forecasts shown at http://gridnewzealand.co.nz/f4847,60655338/regional-energy-forecasts.xlsx. The planned demand reduction by Norske Skog Tasman is not included, because it was announced after this analysis was carried out.

9 The same reference has 9% growth over the same period, but observations to date suggest that South Island demand growth may be slower than was anticipated. The possibility of demand reductions at the Tiwai smelter is not considered, because it arose after this analysis was carried out.

10 These parameters for Tiwai are broadly consistent with observations during Jun-Oct 2008 and Feb-Mar 2012, though actual quantities vary over time. Of course there is industrial demand response in the North Island as well, but such demand response was not modelled in SDDP as it was not expected to affect South Island hydro outcomes materially in a low HVDC capacity scenario.

C3.2.4 Generation assumptions for 2014

46 The first step is to consider South Island generation development in the *no-DC* scenario.

47 In reality, since the Clyde Dam and HVDC pole 2 were commissioned in the early 1990s:

a. the capability of Manapouri Power Station has been considerably enhanced through the construction of the second tailrace tunnel, midlife refurbishment project and amended discharge project;[11]

b. the efficiency of all three Lower Waitaki power stations has been improved in the course of refurbishments;[12] and

c. White Hill and Mahinerangi 1 wind farms have been constructed.

48 However it is assumed that, in the *no-DC* scenario, none of these generation investments would have gone ahead by 2012.

a. The hydro investments had two functions – increasing peaking capacity and increasing energy production. With a single pole link, there would have been no need for additional peaking capacity in the South Island, and limited use for energy production that was highly correlated with existing hydro plant.[13]

b. The wind investments would also have been of limited use – in wet hydro sequences they would have led to additional South Island spill. From a developer's point of view this would have manifested as a low generation-weighted average price.

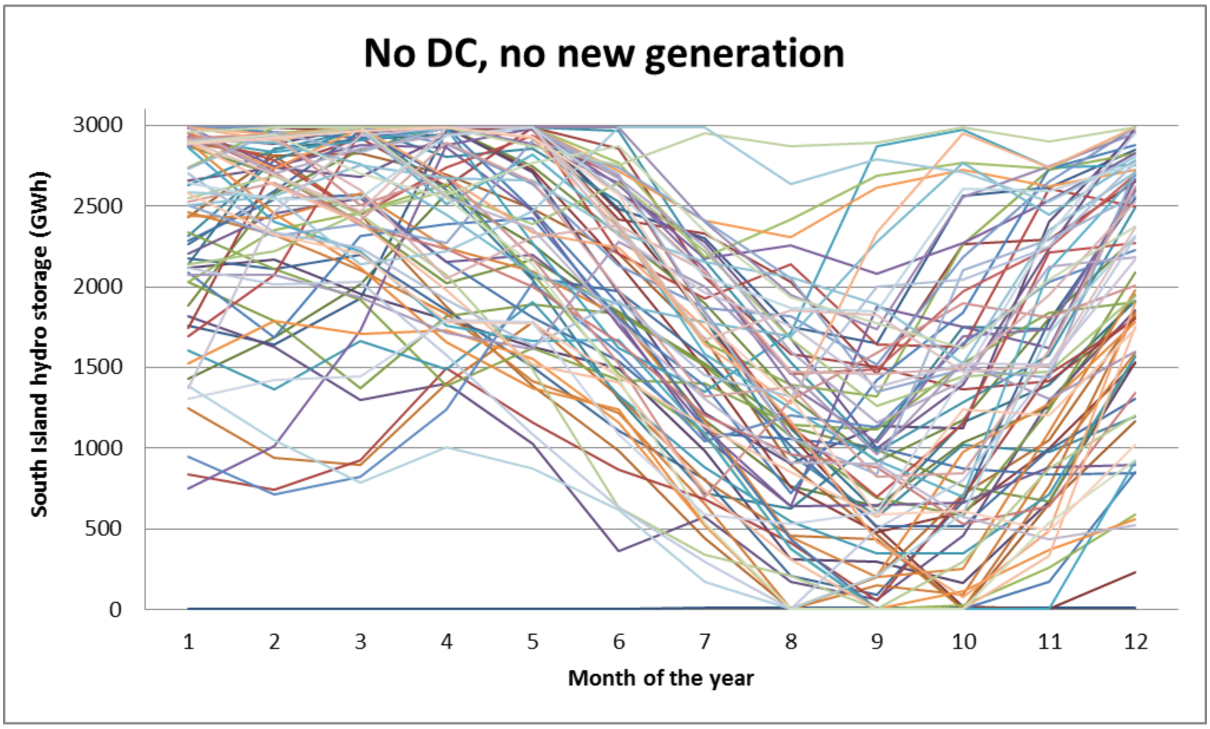
[11] See e.g. http://www.meridianenergy.co.nz/what-we-do/our-power-stations/hydro/manapouri-hydro-station.

[12] See e.g. http://www.odt.co.nz/the-regions/north-otago/29502/benmore-gets-more-with-first-full-rebuild.

[13] Meridian has indicated that the second tailrace tunnel cost roughly $200M to construct (see http://www.meridianenergy.co.nz/assets/PDF/What-we-do/Our-power-stations/0151MEDManapouriwebPDF.pdf). It seems unlikely that this would have been cost-effective with only a monopole HVDC link to export surplus output. Cost figures for Lower Waitaki refurbishments are not readily available but these enhancements add much less production than the works undertaken at Manapouri. At any rate, even if it is the case that all these works *would still have* gone ahead in a no-pole-2 scenario, then the conclusions drawn in this Appendix still broadly hold.

49 The South Island situation would change when pole 1 was removed from normal service and scheduled for decommissioning by 2014, with no replacement.

50 It is useful to consider how the South Island supply-demand balance might look by 2014, with no HVDC link and no South Island generation investment since 1995. SDDP[14] analysis has been used to simulate storage trajectories across 78 inflow sequences.



51 With no HVDC link and no South Island generation investment since 1995, storage levels would be very volatile by 2014. At times there would be a glut of power and considerable spill from major hydro lakes – but at other times there would be a shortage of power and demand curtailment (both voluntary and involuntary) would be required. South Island storage would fall to zero in 20% of the inflow sequences modelled.

52 The conclusion is that:

a. such a level of security would be inefficiently low and would not be allowed to occur. Additional South Island generation would be required before the HVDC link was removed from service; and

b. in a *no-DC* world, prices would not be in a permanent state of collapse. When there was a glut of power, prices would be very low, but when there was a shortage, prices could be very high. There is no reason to suppose that *average* South Island prices would be low – in a workably competitive market they should converge on the entry cost of new generation.

[14] More information on the model can be obtained from the developers of SDDP - http://www.psr-inc.com.br/portal/psr/servicos/modelos_de_apoio_a_decisao/studio_opera/sddp/. Input files will be provided by the Authority on request.

53 The next step is to consider what South Island generation might be added by 2014 in a *no-DC* scenario. Additional hydro would be unhelpful if its inflows were correlated with those of existing hydro (particularly if it was not backed by substantial storage). The most promising options would likely be:

a. wind;

b. coal; and/or

c. oil-fired generation.[15]

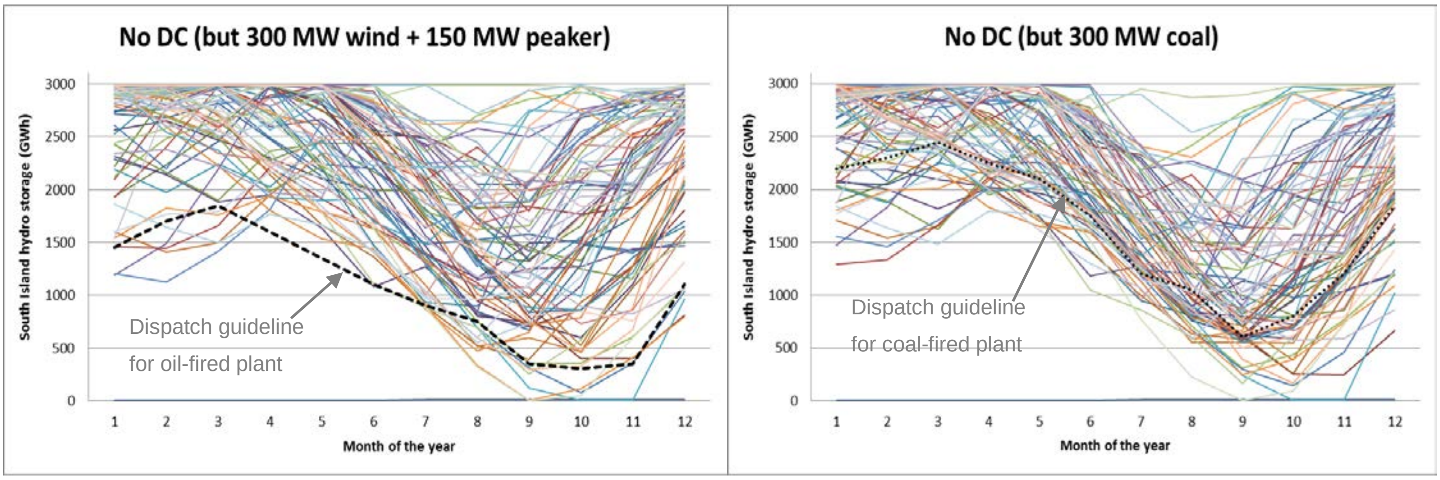
54 SDDP analysis was used to test the economics of various combinations of wind, coal and oil-fired generation. The optimal build decision would depend on various factors including fixed and variable costs and performance. However, over a reasonable range of assumptions, two relatively economic variants of the *no-DC* scenario emerge:[16]

a. *No-DC renewable* – 300 MW wind, 150 MW oil-fired; and

b. *No-DC thermal* – 300 MW coal.

55 In practice, investment decisions would also depend on factors such as consentability, risk appetite and public perception. Construction of coal-fired generation in some parts of the South Island might face hurdles with regard to air quality regulation.

56 Either of these variants would result in a more acceptable level of security:



57 Only in two or three of the 78 inflow sequences modelled would South Island storage fall to zero. Conservation campaigns and rolling outages would still be more common than in recent years, but (given the cost assumptions used) this would be more efficient than adding further generation.

58 On the other hand, the *no-DC renewable* and *no-DC thermal* scenarios would both involve more hydro spill than if there was no generation investment. This would be efficient, because the marginal cost of adding generation (and increasing spill) would roughly equal the marginal value of reducing voluntary and involuntary conservation.

15 Hydro on the West Coast or north of Christchurch might also be economic. However it is not obvious that an admixture of hydro would change the overall conclusion.

16 Information on the range of generation scenarios considered will be provided on request.

59 The next step is to consider South Island generation development in the *monopole* scenario.

60 The *monopole* scenario diverges from reality only in around 2008, when the decision is made not to replace pole 1 when it becomes unavailable. All generation investment decisions made prior to 2008 would therefore be the same as has actually occurred.

61 Probably the only significant change, therefore, is that the Mahinerangi 1 wind farm might not have proceeded if there was not to be a bipole HVDC link. A North Island location would likely have been preferred.

62 The next step is to consider North Island generation development in the *no-DC* scenario.

63 With no HVDC link, there would be much less need for the year-to-year swing provided by the coal-fired units at Huntly Power Station.[17] It is therefore assumed that only two coal-fired units would remain at Huntly by 2014.

64 In such a scenario, the North Island would require additional baseload and/or intermittent generation (probably some combination of geothermal and wind). SDDP analysis indicates that roughly 1700 GWh p.a. of generation would be required to make up for the loss of the HVDC link and the lost Huntly coal-fired units. This could be contributed by (for example) about 200 MW of geothermal generation (in addition to plant that was already operational or committed).

65 Without peak-time injections from the HVDC link, substantial additional North Island peaking capacity would also be required (probably gas- or oil-fired fast-start plant).

66 The next step is to consider North Island generation development in the *monopole* scenario.

67 There is little reason to suppose that North Island generation investment in this scenario would be substantially different from what would happen anyway. By 2014, it is assumed that all current North Island generation would be in place (except for one coal-fired Huntly unit, which would by then have retired) and committed investment including Te Mihi, Ngatamariki, Mill Creek and Todd’s McKee peaker would have proceeded.

68 Some additional peaking generation (probably gas- or oil-fired fast-start plant) would also be required, as a substitute for pole 3’s function of enabling South Island hydro to provide the North Island with peaking capacity.

[17] If the coal-fired units were not required for dry-year backup, then some units could move into near-baseload operation. However, units that were not required as baseload would be “surplus to requirements” – because of their inflexibility (relative to a modern gas turbine) they would not be well suited to staying on in a peaking role.

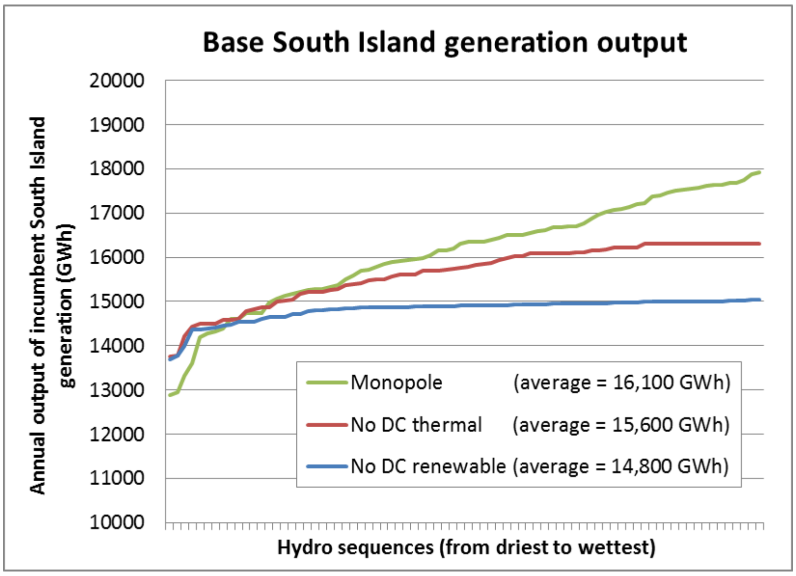
69 The resulting generation scenarios for 2014 are summarised below:

Island	***No DC renewable***	***No DC thermal***	***Monopole***
South	Pre-1995 hydro 300 MW wind 150 MW oil-fired	Pre-1995 hydro 300 MW coal	Pre-1995 hydro Real-world hydro upgrades since 1995 White Hill wind
North	Two coal-fired Huntly units All other existing and committed generation, and some additional peaking capacity 200 MW additional geothermal Even more additional peaking capacity		Two coal-fired Huntly units All other existing and committed generation, and some additional peaking capacity A third coal-fired Huntly unit (for dry year swing)

Common generation is shown in blue, sans-DC generation in red, DC-dependent generation in green.

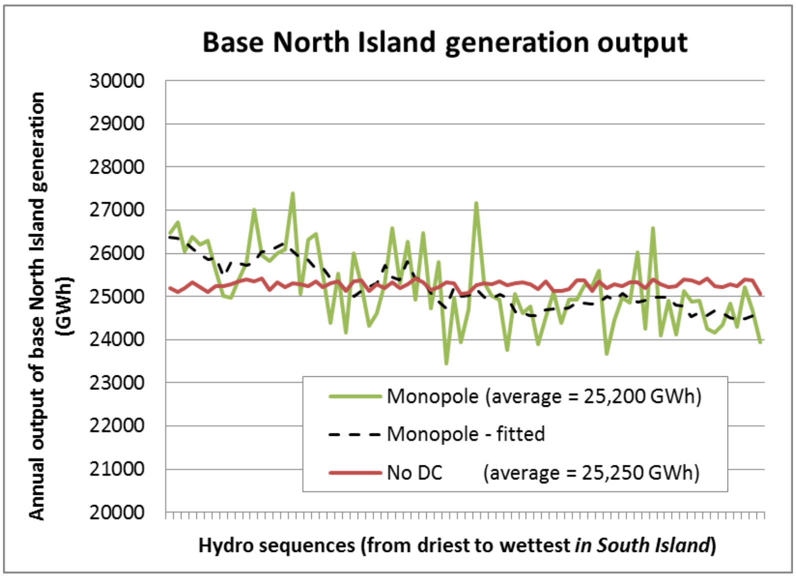
C3.2.5 Quantity impacts in 2014

70 SDDP analysis indicates that, given the demand-side and generation assumptions above, *South Island generation* would be able to produce more output in the *monopole* scenario than in the *no-DC* scenario (in which spill would be much more frequent):



71 On the face of it, this would suggest that the owners of *common South Island generation* are collectively much better off from having an HVDC link – however, as is shown in C3.2.6 , the picture is complicated by the price impacts of the HVDC link.

72 *Common North Island generation* would typically generate somewhat more power in South Island dry sequences under the *monopole* scenario than under the *no-DC* scenario:



The increase in NI production during SI dry sequences (uplift at LH end of graph) *is less than one might expect because the output of the third Huntly coal-fired unit, which is available to generate in dry periods, is not included in the plotted data. This unit is counted as* "DC-dependent generation" *rather than the* "common generation" *plotted here.*

73 This would suggest that the owners of *common North Island generation* are collectively better off from having an HVDC link (because it enables them to ramp up output when South Island prices are high) – however, again, the picture is complicated by the price impacts of the HVDC link.

C3.2.6 Price (and hence profit) impacts in 2014

74 This subsection forms a view on how the price of electricity might differ between the two scenarios (*no DC* and *monopole*), and hence how costs to consumers and profits to *common generation* in each island might differ. Impacts on *DC-dependent* and *sans-DC generation* are not covered here – see instead C3.2.10.

75 The analysis considers spot prices and revenues only – contracting is not included. This is a reasonable approximation, as spot prices and contract prices should converge in expectation over the medium term.

76 The analysis also confines itself to effects on consumers and generators. Costs and benefits received by gentailers *in their capacity as retailers* are not considered.

77 Location factors are ignored – the analysis proceeds as if there was a single price in each island. Ancillary service prices are also ignored.

78 The SDDP modelling described in the previous subsection does yield marginal costs which are sometimes used as a proxy for energy prices. However, for the purposes of this analysis, SDDP marginal costs are not considered to be an adequate proxy for price, because (among other reasons):

a. such ‘prices’ fail to reflect key market dynamics, such as the withholding of capacity to prevent prices from collapsing when there is surplus hydro storage (and spill);

b. SDDP (as used by the Authority) has only five load blocks and does not model prices during periods of capacity shortage adequately; and

c. the mean level of SDDP prices is sensitive to the supply-demand balance in the chosen scenario; if there is an inefficiently high level of investment then mean prices will be depressed and if there is an inefficiently low level of investment then mean prices will be elevated. This makes it a poor tool for comparing prices between two transmission configurations, because the results are driven by the extent of generation overbuild in the two scenarios as much as anything else.

79 Therefore, the analysis in this subsection uses the generation, demand and inter-island transfer quantities produced by SDDP (which are relatively reliable), but develops a new set of *prices* using a bespoke model. These are the quantities and prices that are used to estimate private benefits.

80 The bespoke pricing model seeks to find some firm ground amidst the doubt about what prices might be in a scenario far removed from reality, by coming back to first principles. It is based on the assumptions that mean prices are capped by the cost of new entrant generation and by the cost of keeping aging generation in service; and tend to converge on these caps when new investment is required.

81 One consequence of this principle is that the mean energy price is expected to be equal to the LRMC of new entrant baseload or intermittent generation (at least, in scenarios where new baseload or intermittent generation will be required from time to time).

82 Similarly, the analysis considers other constraints on the price duration curve, driven by the cost structures of other forms of generation (for instance, if there is investment in new oil-fired generation which runs at a mean load factor of 10%, it is reasonable to assume that mean energy prices over the top 10% of the price duration curve will equal the LRMC of such oil-fired plant).

83 The Authority recognises that some participants do not accept the principle that the New Zealand electricity market is a workably competitive market in which mean prices are capped by the cost of new entry. Nonetheless the Authority considers it is reasonable to make this assumption for the purpose at hand.

84 The bespoke pricing model is run separately for each island. For the South Island, it involves the following steps:

a. carrying out a *no-DC* run (South Island only) and a *monopole* run (two connected islands) in SDDP, both for 2014;[18]

b. for each of the two runs:

- obtaining quantity data (i.e. South Island nominal demand and demand response, *common South Island generation* output, and inter-island transfers, if any) from SDDP – by month, hydro sequence and load block;
- sorting quantity data by SDDP marginal cost, to retain the correlation between quantity and price, then dividing it into twenty "bins" and averaging within each bin;
- creating a new South Island price duration curve, representing the full distribution of prices over hydrology, time of year and time of day, which must satisfy various constraints set out on the following pages;
- calculating expected load cost as the sum (over time and hydrology) of South Island demand x South Island price; and
- calculating expected *common generation* revenue as the sum (over time and hydrology) of South Island *common generation* output x South Island price;

c. estimating the expected private benefit to South Island consumers, in 2014, as the difference in expected load cost between the two runs; and

d. estimating the expected private benefit to *common South Island generation*, in 2014, as the difference in expected revenue between the two runs.[19]

85 For the North Island, a similar process is followed, except that:

a. the two runs are *no DC* (North Island only) and *monopole* (two connected islands);

b. the prices and quantities, of course, are for the North Island rather than the South; and

c. since some of the generation is thermal, with substantial running costs, the final estimate of private benefit to *common North Island generation* must take into account the difference in variable costs (based on SDDP quantities) as well as the difference in revenues.

[18] With appropriate burn-in and burn-out periods.

[19] The difference in pre-tax profit is basically equal to the difference in revenue, since renewable generation has negligible variable cost (aside from the value of water, which is factored into the SDDP analysis).

86 The next step is to explain the way in which each price duration curve is constructed.

87 For ease of analysis, each price duration curve is assumed to be a piecewise linear function, determined by a relatively small number of constraints which require prices to:

a. recover (but not exceed) the costs of new generation investment;

b. recover (but, in most cases, not exceed) the costs of keeping existing generation in service; and

c. be consistent with SDDP results *(for example, if SDDP shows a particular generator operating at a 30% load factor in a particular scenario, and an assumption has been made that the SRMC of that generator is $100/MWh, then the 30th percentile of the price duration curve for that scenario is set to $100/MWh. This is not really a "hard" constraint that must apply in a workably competitive environment, more an attempt to match (bespoke) prices to (SDDP) quantities in a reasonably consistent way.)*

88 The table below shows which new entrants (or marginal aging plants) constrain the price duration curves. Critically, installing a DC link exposes the South Island to competition from North Island generation – resulting, for instance, in South Island time-weighted mean prices driven by the LRMC of new North Island generation, rather than the LRMC of new South Island wind (the best local baseload alternative).

Scenario	**Island**	**New entrants, or marginal aging plants, constraining the price duration curve**
No DC renewable	South	New South Island wind and oil-fired
No DC thermal		New South Island wind, and coal-fired
Monopole		New North Island geothermal, marginal Huntly unit, marginal CCGT
Both *no DC* and *monopole*	North	New North Island baseload (probably geothermal), marginal Huntly unit, marginal CCGT, thermal peakers

89 Most of these constraints relate the price duration curve in a particular island to the cost of new investment (or maintaining existing plant) in the same island. The exceptions are some of the constraints on the South Island price duration curve in the *monopole* scenario, which relate to the costs of North Island generation. In order to compare South Island prices to North Island generation entry/exit costs, a South Island / Central North Island price ratio is applied to the South Island price duration curve. This price ratio is modelled as a function of the HVDC transfer level at the time, as reported by SDDP (i.e. for bins in which there is north transfer, South Island prices will be higher than North Island prices, and vice versa).

90 The table overleaf sets out all the constraints that are applied. Although it seems daunting at first glance it is actually reasonably straightforward. There are just a handful of constraints for each scenario and island; in most cases, the table shows a base case assumption about the level of the constraint, and one or more sensitivities. (The sensitivities are quite important because they demonstrate the extent to which the results are affected by the choice of parameters – many of which are set on a quite arbitrary basis.)

91 As an example, the third constraint from the top indicates that in the *no-DC-renewable* scenario, the *"mean price over the top 6% of the [South Island] PDC is equal to the LRMC of new South Island oil-fired plant (assume $645/MWh)"*. This constraint simply requires that prices are high enough to make the new oil-fired generation that appears in the South Island in this scenario is revenue-adequate – but no higher; for if prices were higher at the top of the merit order, then more oil-fired generation would be constructed until prices had fallen to the level of the constraint.

92 See Section C6 (at the end of this Appendix) for the derivation of generation cost assumptions.

Island	Scenario	Constraints	Sensitivities (see C3.2.7)
South Island	*No DC renewable*	Mean SI price is equal to the LRMC of new South Island wind generation (assume $90/MWh)	No – but the key uncertainty relating to the difference between South Island and North Island baseload LRMC is covered, see (*) below
		6th percentile of the PDC is equal to the SRMC of new South Island oil-fired plant (assume $370/MWh) *(Motivated by the SDDP analysis, in which South Island oil-fired plant runs at a 6% load factor)*	
		Mean price over the top 6% of the PDC is equal to the LRMC of new South Island oil-fired plant (assume $645/MWh) *(See above)*	$450, 750/MWh
		15th percentile of the PDC is equal to the cost of demand reductions at the Tiwai smelter (assume $200/MWh) *(Motivated by the SDDP analysis, in which Tiwai demand reductions of up to 60 MW occur up to 15% of the time)*	$150/MWh
	No DC thermal	Mean SI price is equal to the LRMC of new South Island wind generation (assume $90/MWh)	No – but the key uncertainty relating to the difference between South Island and North Island baseload LRMC is covered, see (*) below
		30th percentile of the PDC is equal to the SRMC of new South Island coal-fired plant (assume $100/MWh) *(Motivated by the SDDP analysis, in which South Island oil-fired plant runs at a 30% load factor)*	$75/MWh
		Mean price over the top 30% of the PDC is equal to the LRMC of new South Island coal-fired plant (assume $260/MWh) *(See above)*	$235, 300/MWh
		6th percentile of the PDC is equal to the cost of demand reductions at the Tiwai smelter (assume $200/MWh) *(Motivated by the SDDP analysis, in which Tiwai demand reductions of up to 60 MW occur up to 6% of the time)*	$150/MWh
	Monopole	Using an empirical relationship between HVDC transfer and the South Island / Central North Island (CNI) price ratio:	
		SI PDC must be such that mean CNI price is equal to the LRMC of new North Island geothermal (assume $10/MWh less than the LRMC of South Island wind)	(*) $6, $13/MWh less than SI wind
		SI PDC must be such that mean price over the top 20% of the CNI PDC is high enough to justify the continued operation of the marginal coal-fired Huntly unit (assume $150/MWh)	$135, 175/MWh
		SI PDC must be such that mean price of the top 70% of the CNI PDC is high enough to justify the continued operation of the marginal CCGT (assume $100/MWh)	$90, $110/MWh
		SI has occasional exposure to North Island price spikes – assume SI spot price reaches $2000/MWh in 0.2% of trading periods, corresponding to a central NI price of $2400/MWh. *(It is assumed that SI hydro generation can ramp up to capture the maximum possible volume at this price)*	$1000, $3000/MWh
		2nd percentile of the SI PDC is equal to the cost of demand reductions at the Tiwai smelter (assume $200/MWh) *(Motivated by the SDDP analysis, in which Tiwai demand reductions of up to 60 MW occur up to 2% of the time)*	$150/MWh
North Island	*No DC* (both variants)	Mean NI price is equal to the LRMC of new North Island baseload (assume $83.5/MWh – *this is $3.5 higher than in the monopole scenario, see explanation overleaf*)	(**) $1, $5/MWh higher than in the *monopole* scenario *(again see overleaf)*
		Mean price over the top 50% of the PDC is high enough to justify the continued operation of the 2nd coal-fired Huntly unit (assume $120/MWh)	$110, $140/MWh
		Mean price over the top 70% of the PDC is *(at least)* high enough to justify the continued operation of the marginal CCGT (assume $100/MWh)	$95, $110/MWh
		Mean price over the top 1% of the PDC is high enough for thermal peakers operating at 1% load factor to recover their variable costs and 70% of their fixed costs (assume $1500/MWh)	Recover 50% / 85% of fixed costs
	Monopole	Mean NI price is equal to the LRMC of new North Island baseload (assume $80/MWh)	No – but the key uncertainty relating to the difference between *monopole pole*and *bipole* scenarios is covered, see (**) above
		Mean price over the top 20% of the PDC is high enough to justify the continued operation of the 3rd coal-fired Huntly unit (assume $150/MWh) *(it is assumed that this unit will not be flexible enough to capture the top 0.2% of the PDC)*	$130, 170/MWh
		Mean price over the top 70% of the PDC is *(at least)*high enough to justify the continued operation of the marginal CCGT (assume $100/MWh)	$90, 110/MWh
		Mean price over the top 1% of the PDC is high enough for thermal peakers operating at 1% load factor to recover their variable costs and 50% of their fixed costs (assume $1200/MWh)	Recover 30% / 70% of fixed costs

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93 The use of a North Island geothermal LRMC of $83.5/MWh in the *no-DC* scenario, as opposed to $80/MWh in the *monopole* scenario, requires explanation.

94 As set out in C3.2.4 ("Generation assumptions for 2014"), more North Island baseload or intermittent generation, or both, would be required if there was no HVDC link. It is estimated that generation sufficient to produce 1700 GWh p.a. would be required (to compensate for the lost imports from the South Island, and to replace the output of the marginal coal-fired Huntly unit, which, it is assumed, would not remain in service with no HVDC link to carry its output south). This could constitute about 200 MW of geothermal plant, about 450 MW of wind generation, or some combination of the two.

95 It is further assumed that baseload and intermittent generation is built according to a merit order, with the most cost-effective options constructed first. As generation development proceeds along the merit order, the LRMC of the marginal new entrant increases, and the mean energy price is expected to rise with it.[20]

96 The exact shape of the merit order is not known, and hence it is unclear how rapidly LRMC increases as generation development proceeds. It seems reasonable to suppose that the rate of increase in LRMC is somewhere in the range of $1 to 3/MWh for each 1 TWh of new development.

a. The merit order shown in Figure 17 of the TPAG report[21] increases at about $3/MWh per TWh initially, but (as low-hanging fruit are plucked) soon slows to $1.5 MWh per TWh.

b. As another example, the merit order shown in MED's recent Electricity Demand and Generation Scenarios document[22] begins with a very large tranche of geothermal, over which the slope is about $1.3 MWh/TWh. It may, however, underrate both the slope of the merit order and the extent to which other renewable projects will alternate with geothermal.

97 Because the *no-DC* scenario includes 1700 GWh more North Island baseload and intermittent generation by 2014 than the *monopole* scenario, it is reasonable to consider that the marginal cost of new generation would be on the order of ($2/MWh per TWh) * (1.7 TWh) = $3.5/MWh higher in the *no-DC* scenario than in the *monopole* scenario.

98 Sensitivity cases are considered in which the difference in the marginal cost of new generation is $1/MWh or $5/MWh higher in the *no-DC* scenario.

[20] The increase in prices need not be a one-way street – technological improvements can change the supply curve and act to push prices down over time – but this dynamic is not considered here as it is assumed to affect all scenarios roughly equally.

[21] http://www.ea.govt.nz/our-work/advisory-working-groups/tpag/

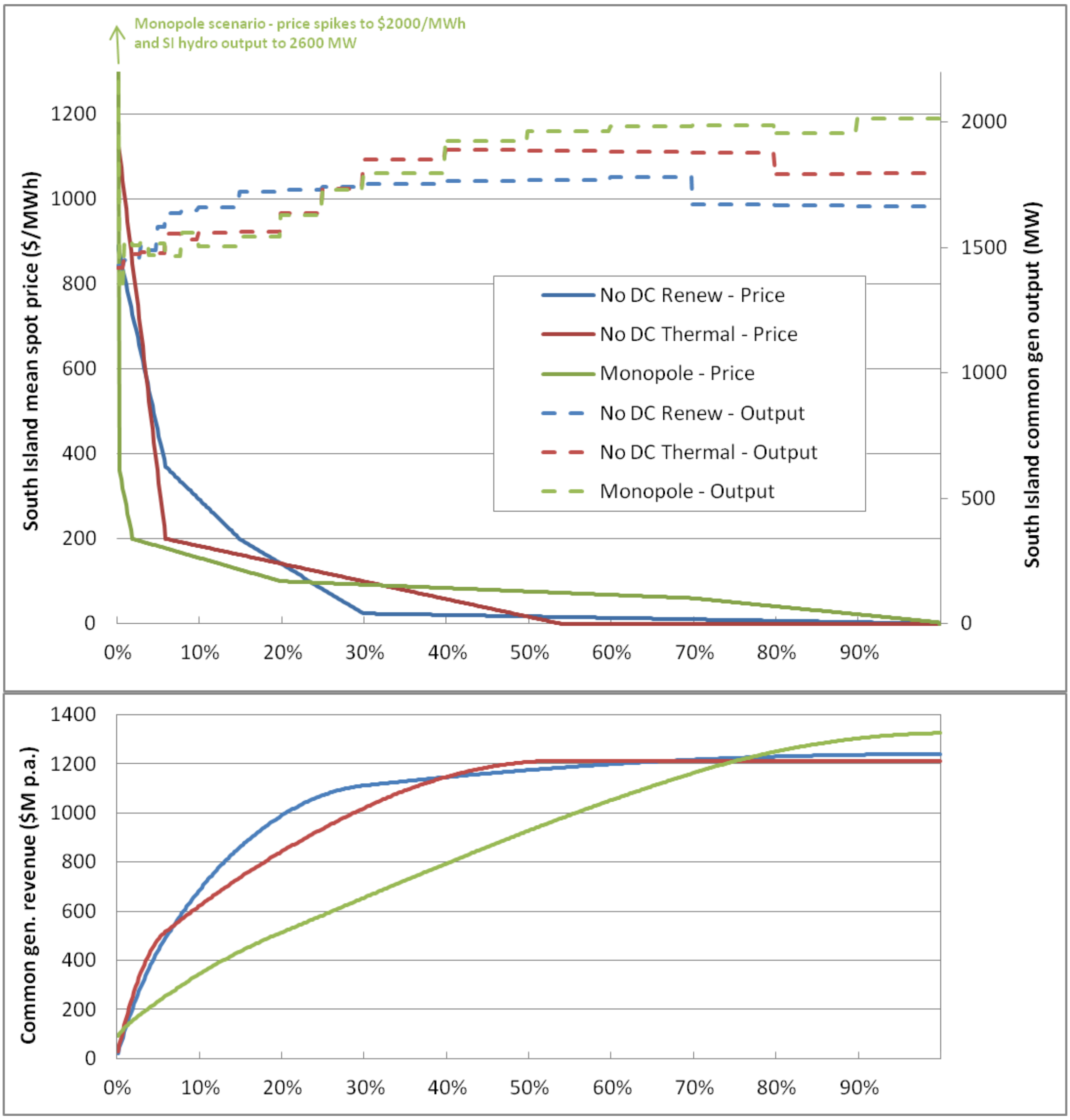
[22] http://www.med.govt.nz/sectors-industries/energy/pdf-docs-library/energy-data-and-modelling/modelling/EDGS/introducing-the-electricity-demand-and-generation-scenarios-discussion-paper.pdf

99 The modelled South Island prices and *common generation* quantities are shown below.

100 Under all scenarios considered, South Island *common generation* (which is hydro) produces the least output when prices are highest (i.e. in dry periods). This is bad for the owners of hydro generation, who end up selling their output at a generation-weighted average price (GWAP) that is well below the time-weighted average price (TWAP) for the island.

101 However, in the *monopole* scenario (solid green line), prices are lower in dry periods and higher in wet periods than in the *no-DC* scenarios (solid red and blue lines). So South Island *common generation* earns more revenue in the *monopole* scenario than in either of the two *no-DC* scenarios – even though average prices are lower in the *monopole* scenario.

102 The bottom plot shows the cumulative revenue earned by *common South Island generation* (i.e. the product of price and quantity) – which is higher in the *monopole* scenario (green line) than in either variant of the *no-DC* scenario (red and blue lines).



Percentage of the time (sorted from highest to lowest SI price)

The monopole *PDC (green) is steepest at the very top end because the HVDC gives South Island generators access to North Island price spikes.*

On the other hand, the no-DC *PDCs (red and blue) are higher over most of the top 20%, due to increased price volatility in dry years with no DC link.*

Prices are low at the bottom end of the PDC in all scenarios, but especially the no-DC *scenarios where, with no ability to export to the North Island, there is extensive spill.*

103 The analysis therefore indicates that (at least in 2014, in this base case) *common South Island generation* collectively gains a private benefit from the availability of pole 2.

104 The above graphs do not show the effect on consumers, but the analysis indicates that (in 2014, in this base case), South Island consumers also collectively gain a private benefit from the availability of pole 2. This is an unsurprising result given the assumption that exposure to competition from North Island baseload drives down South Island mean prices and hence South Island load-weighted average prices (LWAP). The assumption that the HVDC link exposes South Island consumers to occasional price spikes due to shortage of North Island capacity, at times when South Island load is also likely to be high, tends to drive up the South Island LWAP a little relative to TWAP, but not enough to counteract the effects of the reduction in TWAP.

105 For this base case, the private benefits to South Island parties in the 2014 year are shown below.

Scenario	**South Island load cost (mean $M p.a.)**	**South Island *common generation* revenue (mean $M p.a.)**
No DC renewables	1,470	1,260
No DC thermal	1,470	1,240
Monopole	1,420	1,330
	(Collective benefit of $50M p.a.)	***(Collective benefit of $70-90M p.a.)***

106 For interest, some workings are also included:

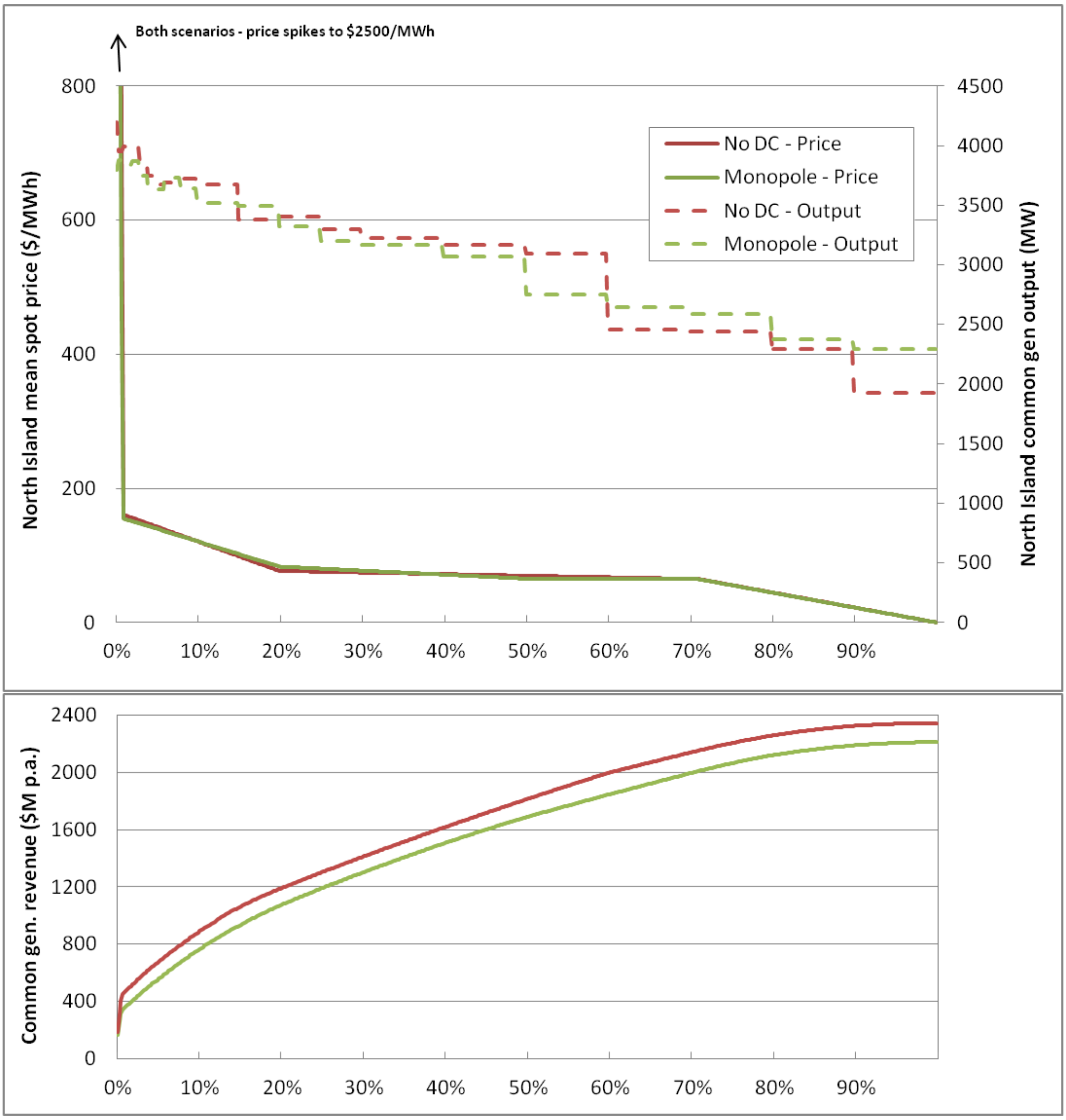
Scenario	**South Island TWAP ($/MWh)**	**South Island LWAP ($/MWh)**	**South Island *common generation* GWAP ($/MWh)**	**South Island *common generation* quantity (TWh)**
No DC renewables	90.0	90.2	84.4	14.9
No DC thermal	90.2	90.4	79.9	15.5
Monopole	85.9	87.0	82.9	16.1

107 Note the gap between TWAP and GWAP is lower for the *monopole* scenario than for the *noDC* scenarios *(because high prices are less coincident with low hydro output)* – which makes up for the lower TWAP *(as a result of North Island competition)*.

108 The modelled North Island prices and *common generation* quantities are shown below.

109 Although the green lines *(monopole)* and red lines *(no DC)* look quite similar, there is a key difference – the left hand end of the price duration curve (where prices are highest) is largely associated with peak periods in the *no-DC* scenario, but is more associated with South Island dry years in the *monopole* scenario. (Recall that periods are ordered according to SDDP "prices" for the North Island – which, naturally, can only be influenced by South Island hydrology if there is an inter-island link.)

110 The bottom plot shows the cumulative revenue earnt by *common North Island generation* (i.e. the product of price and quantity) – which is lower in the *monopole* scenario (green line) than the *no-DC* scenario (red line). The difference between the two scenarios arises from the very left hand end of the price duration curve – i.e. through the amount of revenues earnt when prices are highest – and is maintained throughout the rest of the curve.



Percentage of the time (sorted from highest to lowest SI price)

111 The analysis therefore indicates that (in 2014, in this base case), North Island *common generation* collectively incurs a private cost from the availability of pole 2. The benefit of the HVDC link in allowing North Island generators to earn more profit during South Island dry sequences is not enough to compensate for the reduction in profits at other times.

112 The analysis also shows that (in 2014, in this base case), North Island consumers collectively gain a private benefit from the availability of pole 2. Again this is unsurprising given the assumption that traversing the North Island merit order more slowly drives down North Island mean prices and hence North Island load-weighted average prices (LWAP).

113 For this base case, the private benefits to North Island parties in the 2014 year are shown below.

Scenario	**North Island load cost (mean $M p.a.)**	**North Island *common generation* revenue (mean $M p.a.)**
Monopole	2,430	2,270
No DC	2,600	2,430
	(Collective benefit of $170M p.a.)	***(Collective cost of $150M p.a.,*** *allowing for $10M p.a. decrease in variable costs in monopole scenario)*

114 For interest, some workings are also included:

Scenario	**North Island TWAP ($/MWh)**	**North Island LWAP ($/MWh)**	**North Island *common generation* GWAP ($/MWh)**	**North Island *common generation* quantity (TWh)**
No DC	83.5	101.5	100.9	25.6
Monopole	80.1	90.8	89.6	25.8

115 Not only does the *monopole* scenario have a lower TWAP (as a result of South Island imports), but it also has a much lower LWAP and GWAP (because in the *monopole* scenario, high prices are less coincident with high load and high generation).

C3.2.7 Sensitivities for 2014

116 The analysis is driven by a moderate number of key assumptions, typically relating to generation costs. (See Section C6, at the end of this Appendix, for the derivation of the base case generation assumptions). None of the key assumptions are known with certainty, and it is important to explore their effect on key results.

117 A sensitivity analysis has been carried out, involving changing the various cost assumptions, recalculating the price duration curves and hence revising the estimates of private benefit.[23]

118 As will be shown, key results are relatively insensitive to some assumptions (loosely speaking, 'turning a knob' pushes one part of a price duration curve up, but another part of the curve must therefore fall, with relatively small net effect). Varying other assumptions, however, can have a substantial effect on estimated private benefits.

119 With regard to South Island prices, the following sensitivities were carried out:

a. *Cheaper Tiwai demand-side response* – in which Tiwai can reduce load by up to 60 MW for $150/MWh (c.f. $200/MWh in the base case);

b. *Cheaper thermal generation* – in which the LRMC of South Island oil-fired plant is $450/MWh (c.f. $645/MWh in the base case, the difference perhaps arising as a result of part funding through transmission alternative payments), the SRMC of coal-fired generation is $75/MWh (c.f. $100/MWh in the base case) and the LRMC of South Island coal generation is reduced accordingly, and the revenue requirement for keeping the marginal CCGT and the marginal Huntly unit is 10% lower than in the base case;

c. *More expensive thermal generation* – in which the LRMC of South Island oil-fired plant is $750/MWh (c.f. $645/MWh in the base case), the LRMC of South Island coal-fired generation is $300/MWh (c.f. $260/MWh in the base case), the break-even cost of the marginal CCGT is $15/MWh higher than in the base case and the break-even cost of the marginal Huntly unit is $25/MWh than in the base case;

d. *Cheaper geothermal* – in which the gap between the LRMCs of North Island geothermal and South Island wind is a full $13/MWh, c.f. $10/MWh in the base case;[24]

e. *More expensive geothermal* – in which the gap between the LRMCs of North Island geothermal and South Island wind is just $6/MWh, c.f. $10/MWh in the base case;

f. *Less peaky prices* – in which the occasional price spikes in the *monopole* scenario are $1000/MWh, c.f. $2000/MWh in the base case; and

g. *More peaky prices* – in which the occasional price spikes in the *monopole* scenario are $4000/MWh, c.f. $2000/MWh in the base case.

[23] For the avoidance of doubt, the generation plans were not revised in the various sensitivities, and nor were the SDDP runs redone. Only the price duration curves were adjusted. This approach is approximate, but seems reasonable in the context of the general level of uncertainty.

[24] Note that the gap between NI geothermal and SI wind costs in the Ministry of Economic Development's Electricity Demand and Generation Scenarios is even higher than $13/MWh – see Figure 3 of http://www.med.govt.nz/sectors-industries/energy/pdf-docs-library/energy-data-and-modelling/modelling/EDGS/introducing-the-electricity-demand-and-generation-scenarios-discussion-paper.pdf

120 With regard to North Island prices, the following sensitivities were carried out:

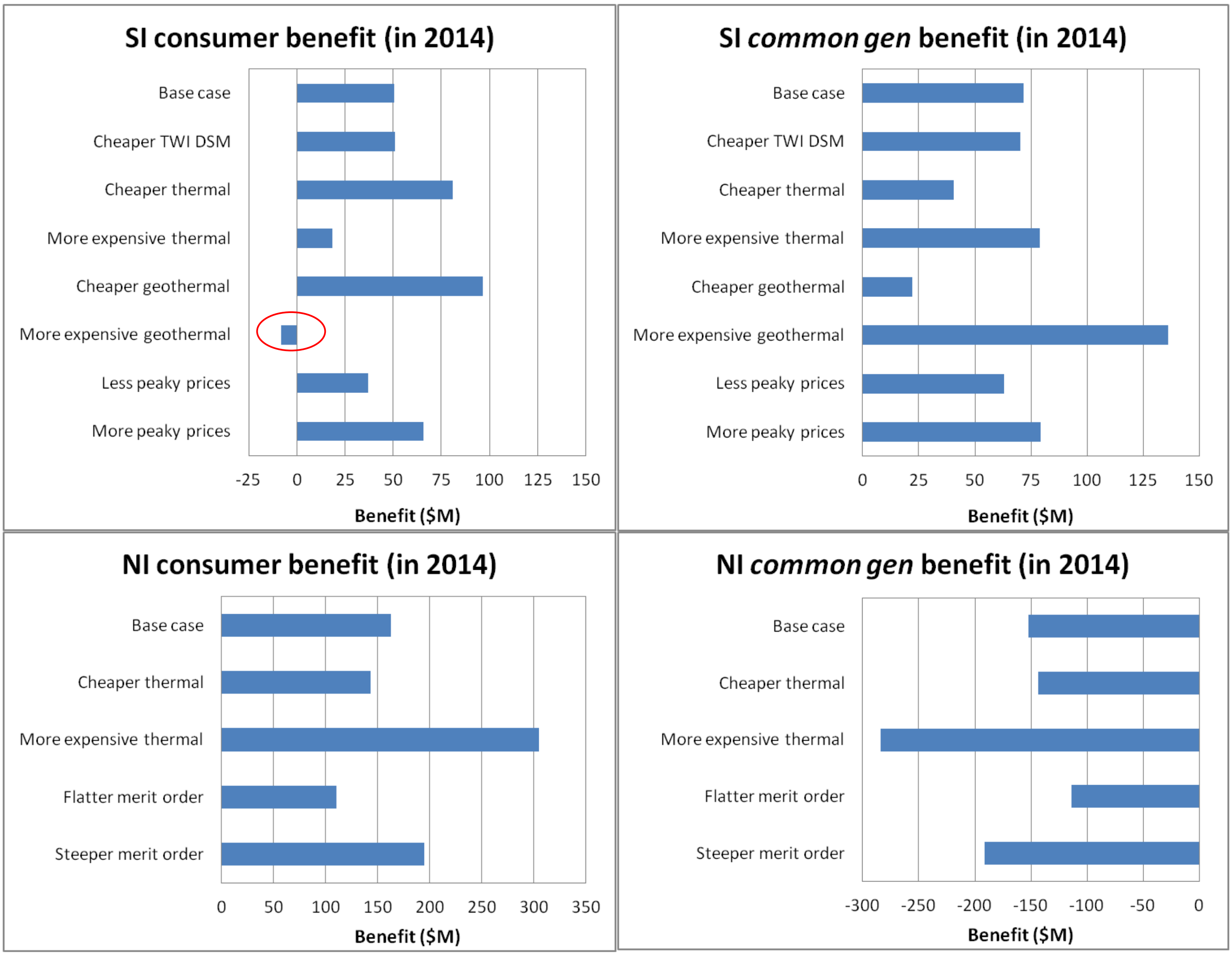
a. *Cheaper thermal generation* – in which the break-even cost of running Huntly is decreased by \$20/MWh, the break-even cost of running the marginal CCGT is decreased by \$10/MWh, and the proportion of peaking generation revenue that must be recovered from prices is reduced by 15 percentage points;

b. *More expensive thermal generation* – in which the break-even cost of running Huntly is increased by \$20/MWh, the break-even cost of running the marginal CCGT is increased by \$10/MWh, and the proportion of peaking generation revenue that must be recovered from prices is reduced by 15 percentage points;

c. *Flatter merit order* – in which the gap in new entrant LRMC between the *no-DC* and *monopole* scenarios is just \$1/MWh; and

d. *Steeper merit order* – in which the gap in new entrant LRMC between the *no-DC* and *monopole* scenarios is a full \$5/MWh.

121 The results (in terms of 2014 private benefits) are shown below. (For South Island, the *monopole* scenario is compared with *no-DC renewables* only – not *no-DC thermal*.)



122 Some sensitivities have relatively little effect. Others have a significant effect on key results, though in only one case does a private benefit actually change sign. (This is the “more expensive geothermal” case, in which there is a cost to South Island consumers in 2014 – because in this sensitivity, North Island geothermal is lower down the merit order than South Island wind, and hence North Island competition does not act to constrain South Island mean prices.)

123 The estimation of private benefits (C3.2.9) uses a wide range of scenarios from among the selection of sensitivities shown here.

C3.2.8 Impacts post 2014

124 All the preceding analysis pertains to the 2014 year. The (dis)benefits of pole 2, however, would continue beyond 2014.

125 There is room for debate as to how long such (dis)benefits would endure. One view would be that they would endure indefinitely (or as long as pole 2 remained in service), because:

a. one might suppose (and SDDP analysis confirms) that, with no HVDC link and ongoing investment in South Island wind/oil-fired generation to keep pace with demand growth, there would still be a surplus of power in the South Island during wet periods and a deficit during dry periods;

b. mean North Island prices should continue to be lower in the *monopole* scenario than in the *no-DC* scenario, because new development would continue to be higher up the merit order;

c. mean South Island prices should continue to be lower in the *monopole* scenario than in the *no-DC* scenario, because the South Island would continue to be exposed to competition from cheaper North Island baseload; and so

d. consumers in both islands and South Island *common generation* would continue to be better off with pole 2, and North Island *common generation* would continue to be worse off.

126 An alternative view would be that the (dis)benefits of pole 2 would erode over time, because:

a. the extent of South Island spill in wet periods could be reduced by:

- organic demand growth (if not countered by additional baseload or intermittent generation);
- an increase in flexible demand, willing to soak up surplus power at low prices;
- countering hydro variability with additional reasonably priced mid-order generation (perhaps coal, biomass and/or coal seam gas); and/or
- new wind generation at sites that were negatively correlated with hydro inflows;

b. South Island incumbent hydro production in dry periods could be increased by allowing more access to emergency storage;

c. the merit order of North Island baseload and intermittent generation might flatten out over time (e.g. through access to large amounts of similarly priced wind and/or geothermal);

d. the cost of South Island baseload might fall relative to the cost of North Island baseload (e.g. through exploitation of good quality hydro and wind resources).

127 Given the legitimate uncertainty, three post-2014 scenarios are considered:

a. *short term* – in which all (dis)benefits decay linearly to zero over 10 years;

b. *long term* – in which all (dis)benefits decay linearly to zero over 20 years; and

c. *permanent* – in which all (dis)benefits remain constant for 20 years and then fall immediately to zero.

C3.2.9 Estimation of private benefits

128 Five sensitivities (or, in some cases, combinations of sensitivities) are considered, which between them cover a reasonable range of uncertainty:

a. cheaper geothermal
b. more expensive geothermal
(a–b: affecting South Island outcomes)
c. base case
d. cheaper thermal and flatter merit order
e. more expensive thermal and steeper merit order.
(d–e: affecting North Island outcomes)

129 Private benefits are as follows (pre-tax 2012 PV with 6% real discount rate, $M):

	Post-2014 scenario		
Sensitivity	**Short term**	**Long term**	**Permanent**
A	SI common gen: 100 SI consumers: 450	SI common gen: 170 SI consumers: 720	SI common gen: 280 SI consumers: 1210
B	SI common gen: 640 SI consumers: –40	SI common gen: 1020 SI consumers: –60	SI common gen: 1700 SI consumers: –100
C	SI common gen: 340 SI consumers: 240 NI common gen: –720 NI consumers: 770	SI common gen: 540 SI consumers: 380 NI common gen: –1140 NI consumers: 1220	SI common gen: 900 SI consumers: 630 NI common gen: –1910 NI consumers: 2040
D	NI common gen: –400 NI consumers: 430	NI common gen: –640 NI consumers: 680	NI common gen: –1070 NI consumers: 1130
E	NI common gen: –1470 NI consumers: 1580	NI common gen: –2350 NI consumers: 2520	NI common gen: –3920 NI consumers: 4200

130 Thus, reasonable ranges of private benefits are:

a. South Island consumers – cost of $100M to benefit of $1.2B (point estimate $380M benefit);
b. South Island *common generation* – benefit of $100-1700M (point estimate $540M benefit);
c. North Island consumers – benefit of $430-4200M (point estimate $1220M benefit); and
d. North Island *common generation* – cost of $400-3900M (point estimate $1140M cost).

131 If a discount rate of 4% (real, pre-tax) is instead used, the above point estimates become:

a. South Island consumers – benefit of $420M;
b. South Island *common generation* – benefit of $600M;
c. North Island consumers – benefit of $1350M; and
d. North Island *common generation* – cost of $1270M.

132 If a discount rate of 8% (real, pre-tax) is instead used, the above point estimates become:

a. South Island consumers – benefit of $350M;

b. South Island *common generation* – benefit of $500M;

c. North Island consumers – benefit of $1130M; and

d. North Island *common generation* – cost of $1050M.

133 For the avoidance of doubt, the alternate discount rates of 4% and 8% are only used in the final PV calculation – effects of the discount rate on (for instance) the LRMC of generation are not considered.

C3.2.10 Benefits to *DC-dependent* and *sans-DC generation*

134 The preceding analysis pertains to *common generation* only. This subsection briefly discusses how the availability of pole 2 might affect other generation – i.e:

a. how much profit would be made by *DC-dependent generation* (such profit being a private benefit to the generation owner from the availability of pole 2); and

b. how much profit would be made by *sans-DC generation* (such profit being a private benefit to the generation owner from the unavailability of pole 2).

135 As set out in C3.2.4, *DC-dependent generation* is assumed to include:

a. real-world hydro upgrades since 1995;

b. White Hill wind farm;[25] and

c. a third coal-fired Huntly unit (for dry-year swing).

136 These upgrades and plants all exist in the real world, but the Authority is not in possession of information about their profitability (nor what their profitability would be in a *monopole* scenario). The economics of the Huntly unit, for instance, are probably driven largely by operations and maintenance costs but these are not public information. At any rate there seems no particular reason to suppose that the availability of pole 2 would allow any of these upgrades or plants to deliver windfall gains.

137 As set out in C3.2.4, *sans-DC generation* is assumed to include:

a. new South Island generation, assumed to be either:

- wind, and oil-fired plant; or
- coal plant; and

b. new North Island geothermal, to include some mixture of:

- geothermal; and
- thermal peaking plant.

138 All this generation is new entrant. Assuming a workably competitive market for generation investment, new entrant generation should only deliver a competitive rate of return.

139 It therefore appears reasonable to suppose that the private (dis)benefits of pole 2 to the generation sector would lie largely in the effect on incumbents.

[25] But not Mahinerangi 1, which (it is assumed) would not have been constructed in *either* the *monopole* or *no-DC* scenario.

C3.2.11 Benefits to individual parties

140 All the preceding analysis pertains to groups of parties. This subsection comments on the private benefits that might be received by individual parties (i.e. the owners of specific generating plant, and major direct-connect consumers).

141 In reading this subsection, it should be remembered that if there was no pole 2, the ownership of specific generating plants might be quite different. It seems unlikely, for instance, that a single party would have been allowed to own the entire Waitaki hydro system *and* Manapouri power station if there was no pole 2 – as this would have resulted in excessive concentration in the South Island electricity market.

142 With regard to consumers, it is not clear that there would be significant variation in private benefit between consumers within each island (except by virtue of the amount of power they consume).

143 The analysis suggests that a South Island consumer might be less averse to the *no-DC* scenario if they:

a. consumed electricity mainly in summer (so that they were relatively unconcerned by high prices and rationing during dry winters); or

b. were flexible, in that they could reduce their load for weeks or months at a time at relatively low cost (so that they could weather extended dry sequences more easily than other consumers).

144 Irrigation loads might fall into the first category. Tiwai may fall into the second category to some extent, since it has demonstrable ability to reduce demand during extended dry sequences. Nonetheless, it is not clear that either irrigators or the smelter would prefer to do without a HVDC link.

145 The analysis suggests that a North Island consumer might have a preference for the *no-DC* scenario if they:

a. were not readily able to interrupt their demand for a period of hours in response to a short-duration price spike; but

b. were well positioned to reduce their demand for weeks or months at a time in an extended dry sequence.

146 However, it is not obvious that there are any North Island consumers who fit this profile.

147 With regard to South Island generators, first principles indicate that the parties deriving the most benefit from pole 2 are the owners of generation that:

a. has inflows that are highly correlated with island storage; and

b. has relatively little local storage.

148 These are the parties who are least able to generate during extended dry sequences, when prices are expected to be higher in the absence of pole 2. They therefore benefit more than others from the presence of pole 2.

149 The price duration curve modelling is valid at an island level but not intended to assess the benefit to individual parties. However, the SDDP runs produced in the course of the work can be used to provide some indication of outcomes for individual generators (though these should be treated with caution, as SDDP is not a market model and has no understanding of market dynamics).

150 SDDP yields generated quantities for each hydro plant, for each year, hydro sequences, month and load block; it also yields marginal costs of demand, which can be interpreted as energy prices. For any given hydro generator in any given SDDP run, these quantities and prices can be used to calculate modelled output, generation-weighted average price, revenue (and hence profit).

151 Based on the results of the *no-DC renewables* and *monopole* SDDP runs, therefore:

a. Manapouri is the hydro scheme whose GWAP increases most from the availability of pole 2; and

b. Clutha is the hydro scheme whose GWAP increases second most.

152 The SDDP analysis indicates that the Tekapo and Waitaki hydro schemes receive relatively little benefit (unsurprising, since although their inflows are highly correlated with island storage, they have substantial local storage and are typically able to generate at reasonably high levels during a dry sequence).

153 The implication, therefore, is that:

a. Meridian derives substantial benefit from the availability of pole 2 (as owner of the Manapouri hydro plant); and

b. Contact derives substantial benefit from the availability of pole 2 (as owner of the Clutha hydro scheme); but

c. Genesis may not derive any benefit from the availability of pole 2 (as owner of the Tekapo hydro scheme).

154 The SDDP analysis is not a suitable tool for the purpose of estimating the benefit received by TrustPower as owner of various small- to medium-sized South Island hydro schemes. (SDDP does not model these schemes well, as currently configured – for instance, available inflow data for most TrustPower schemes are of relatively poor quality.)

155 With regard to North Island generators, the above SDDP approach tends to break down as SDDP struggles to model the top end of the price duration curve (in the presence of potential capacity shortage). It is observed, however, that North Island generators might be less averse to the *no-DC* scenario if they:

a. were able to increase generation for weeks or months at a time in an extended dry sequence; but

b. were not readily able to increase their output for a period of hours in response to a short-duration price spike;

156 Some slow-start thermal generation – perhaps including CCGTs and coal-fired Huntly units – might fit this profile. However, there is not sufficient evidence here to conclude that the owners of such generation would receive a private benefit from the availability of pole 2.

C3.3 Effect of IR availability costs on HVDC charges

157 This section quantifies one of the components of the HVDC charge stemming from pole 2 availability – an increase in Transpower's IR availability costs, which are ultimately paid by South Island generators. It is referenced from Section C3.1, which estimates the portion of HVDC charges relating to pole 2.

158 The costs of IR are recovered from generators with units over 60 MW and from Transpower (as owner of the HVDC link), through the IR availability charge.[26] Under the current HVDC charging regime, South Island generators pay the IR availability charges incurred by Transpower.

159 Based on the scenario framework adopted, the effect of pole 2 availability is to move from a *no-DC* scenario (in which Transpower would pay no IR availability charges) to a *monopole* scenario (in which Transpower would pay a fairly substantial IR availability charge).

160 The amount of IR availability charges that Transpower would pay in a *monopole* scenario is a matter for speculation. Since 2008, Transpower has paid on the order of $10M p.a., with considerable variation from year to year. However, pole 1 has been in limited operation for some of this time – if it had not been available, IR availability charges would presumably have been higher.

161 Transpower has also paid (and passed on to South Island generators) IR event charges and received IR event rebates, but these are much smaller in scale.

162 It is concluded, therefore, that under current HVDC charging arrangements, the portion of HVDC charges relating to pole 2 includes (conservatively) $10M p.a. of IR costs incurred by Transpower.

[26] See Clause 8.59 of the Code.

C3.4 Effect of HVDC rentals, which partly offset HVDC costs

163 This section quantifies an offset to the HVDC charge stemming from pole 2 availability – an increase in HVDC rentals, which are paid to South Island generators. It is referenced from Section C3.1, which estimates the portion of HVDC charges relating to pole 2.

164 Prior to the introduction of FTRs, HVDC charge payers receive HVDC loss and constraint rentals.

165 Once FTRs are implemented, HVDC charge payers will receive FTR residual revenues, which will consist of the allocation to HVDC customers of FTR auction revenue and any unallocated rentals. In theory, these payments could be expected to be similar in scale to the HVDC rentals.[27]

166 Based on the scenario framework adopted, the effect of pole 2 availability is to move from a *no-DC* scenario (in which there would be no link to generate rentals) to a *monopole* scenario (in which HVDC rentals could be quite substantial).

167 Analysis carried out by Energylink[28] estimates HVDC rentals at approximately $30M p.a., in a scenario in which pole 2 is available and pole 1 is in limited service.

168 This is reasonably consistent with recent experience with a pole-and-a-half HVDC link:

Calendar year	Approx. HVDC rentals ($M)
2008	53.3
2009	62.1
2010	19.8
2011	20.1 *(excluding Mar, Nov and Dec, for which figures were not available at time of writing)*

169 It could be expected that rentals would be even higher in a true *monopole* scenario with no pole 1 at all (because inter-island constraints would be more frequent).

170 It is therefore concluded that pole 2 availability results in a private benefit to South Island generators on the order of $30M p.a., which partially offsets the costs of the link.

[27] See: *Information Paper: Allocation of residual loss and constraint excess post introduction of financial transmission rights,* 3 July 2012. Available at: http://www.ea.govt.nz/our-work/programmes/priority-projects/locational-hedges/ftr-development/.

[28] http://www.ea.govt.nz/document/13362/download/our-work/programmes/priority-projects/locational-hedges/ftr-development/

C4. Alignment between private benefits and charges, for HVDC pole 3

171 This section (C4) sets out the estimated private benefits that will be received by various parties from pole 3 availability, and compares them with the portion of HVDC charges that will relate to pole 3.

172 It is based on five separate analyses, which estimate private benefits arising from various functions of the investment. These include:

a. increasing inter-island bulk energy transfer capacity (Section C4.2);

b. increasing the capacity for North transfer at times of North Island capacity scarcity (Section C4.3);

c. potentially reducing the cost of IR (Section C4.4);

d. potentially enabling a national reserve market (Section C4.5); and

e. potentially enabling a national frequency keeping market (Section C4.6).

173 The pole 3 investment approval documentation[29] has been used as a reference in compiling this list of functions.

174 The availability of pole 3 might also affect inter-island price differentials through reducing HVDC losses (for a given level of HVDC transfer), but this effect is considered to be second-order and is not considered further in this Appendix.

C4.1 Key findings

175 The estimated private benefits to some key groups of parties are as follows:

a. for South Island generation:

- a collective benefit on the order of $65M (PV) through spill reduction;
- a cost on the order of $90M through overall lower energy prices;
- a benefit on the order of $180M through the ability to export more power at times when the North Island spot price is high; and
- some second order effects (e.g. through ancillary service markets);

b. for North Island generation:

- a cost on the order of $150M through lower energy prices; and
- some second order effects (e.g. through ancillary service markets); and

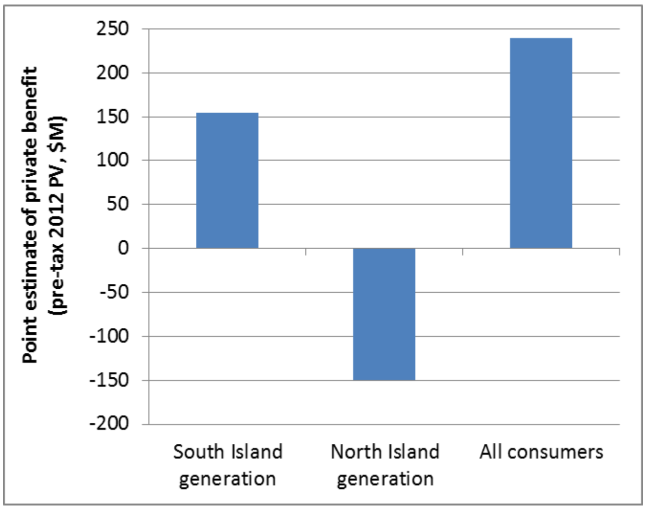
c. for consumers in both islands:

- a benefit on the order of $240M through lower energy prices; and
- some second order effects (e.g. through ancillary service markets).

176 Based on the above point estimates, the *positive* private benefits are broken down as follows: 40% to South Island generators and 60% to consumers (but with considerable uncertainty).

[29] http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/

Point estimates of private benefit from HVDC pole 3



177 Some individual parties will capture more of the benefits than others. For example:

a. spill reduction benefits would largely adhere to the owners of the Manapouri and Clutha hydro schemes;

b. benefits to South Island generators through access to North Island price spikes would mainly go to parties with substantial flexible hydro capacity;

c. parties that were short on IR would benefit through a reduction in IR prices and quantities, whereas parties that were long on IR (such as owners of interruptible load) would be worse off in this regard.

178 Against the private benefits received by the owners of South Island generation from pole 3 availability should be set the net increase in HVDC charges that will result from the construction and operation of pole 3.

a. Under current arrangements, the portion of the HVDC charge relating to the costs of pole 3 is expected to be approximately $70M p.a.[30]

b. Further, the availability of pole 3 will tend to reduce FTR residual revenues, which help to offset the costs of the HVDC link *(quantified in Section C4.7)*;

c. On the other hand, the availability of pole 3 will tend to reduce the amount of IR availability costs passed on by Transpower to South Island generators *(quantified in Section C4.8)*.

179 If all these factors are included, the portion of HVDC charges related to pole 3 is expected to sum to *approximately* $970M PV (over 20 years).

180 It is therefore expected that, under existing HVDC charging arrangements:

a. the owners of South Island grid-connected generation will receive a private benefit, but it will probably be less *(both collectively and for each individual generator)* than the increase in HVDC charges resulting from pole 3 commissioning;

b. consumers in both islands will receive a collective private benefit but will pay no HVDC charges; and

c. the owners of North Island generation will pay no HVDC charges but will still be worse off than if there was no pole 3.

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[30] Based on the Authority's interpretation of information received from Transpower. This cost includes pole 3 capital cost recovery and depreciation, and a portion of HVDC operation and maintenance costs.

C4.2 Effects of increased inter-island bulk energy transfer capacity

181 This section describes one of the ways in which the availability of pole 3 will create private benefits.

C4.2.1 Introduction

182 In terms of bulk energy transfer, the main effect of pole 3 will be to increase the amount of power that can be transferred from the South Island to the North Island, for a given level of North Island IR. This, in turn, will result in:

a. less South Island hydro spill, and hence increased profits for the owners of existing South Island generation;

b. more opportunity for South Island generation development;

c. less need for new baseload and intermittent generation; and hence

d. lower energy prices nationwide, leading to benefits for all consumers and costs for all generators.

183 This section:

a. estimates the likely reduction in South Island hydro spill and hence makes a ballpark estimate of the collective benefit to South Island generation;

b. sets out the argument (also made with regard to pole 2) that reducing the need for additional North Island baseload and intermittent generation is likely to result in lower energy prices, attempts to quantify the likely reduction, and makes ballpark estimates of the resulting benefit to consumers and cost to generators (in both islands); and

c. shows that South Island generators are unlikely to be collectively better off as a result of increased bulk energy transfer capability, as in their case, the above benefits and costs will roughly cancel each other out.

184 The availability of pole 3 may also allow greater southward flow during South Island dry sequences, resulting (at such times) in:

a. increased profit to North Island generators;

b. lower energy prices for South Island consumers; and

c. improved security of supply to South Island consumers (with less likelihood of conservation campaigns or rolling outages).

185 However, the actual increase in south capacity may be quite limited. Even once pole 3 is available, south transfers will still be restricted by Bunnythorpe-Haywards constraints, issues relating to the lower North Island 110 kV network, and the availability of surplus North Island generation.

186 Further, any improvements in security of supply resulting from increased south transfer capacity may be counterbalanced by more aggressive management of South Island hydro storage (i.e. using increased north transfer capacity to draw lakes down to a lower level).

187 Private (dis)benefits stemming from increased south transfer (as a result of pole 3 availability) are therefore assumed to be second order, and are not considered further.

C4.2.2 South Island hydro spill

188 With a single pole HVDC link and the usual 400 MW of North Island sustained instantaneous reserve (SIR), it is possible to transfer about 400 MW of power from the South Island to the North Island (if there is enough supply in the South Island).

189 Once pole 3 becomes available, it will be possible (with the same 400 MW of North Island SIR) to transfer about 950 MW of power from the South Island to the North Island (again assuming there is enough supply in the South Island, which often will not be the case).[31] This will tend to reduce the need for spill at times of ample hydro storage.

190 Two SDDP runs were carried out for the 2014 year:[32]

a. a *monopole* scenario, using the same demand-side and generation assumptions as in the pole 2 analysis, and allowing up to 400 MW of north transfer on the HVDC link; and

b. a *bipole* scenario, allowing up to 950 MW of north transfer.

191 The results indicate that there would be an average of 400 GWh p.a. of South Island spill in the *monopole* scenario, over and above the level of spill in the *bipole* scenario. This result is for 2014 and it could be expected that the difference between scenarios in the amount of spill would diminish thereafter. In the *monopole* scenario, demand growth would gradually act to reduce the amount of spill. In the *bipole* scenario, on the other hand, it could be expected that there would be more South Island generation investment and hence more South Island hydro spill.

192 While 400 GWh p.a. is material, it is nowhere near as much spill as in the *no-DC* scenario described in the pole 2 analysis, and hence less effort is made to value it. Rather, three scenarios are considered, which span the reasonable range of uncertainty about the lost profit to South Island generation:

A. in which the wasted water is worth only $20/MWh (because it occurs at times when there is ample hydro storage and energy prices are typically low), and the difference in spill between *monopole* and *bipole* scenarios drops to nil over 5 years;

B. in which the wasted water is worth $35/MWh and the difference in spill between *monopole* and *bipole* scenarios drops to nil over 10 years; and

C. in which the wasted water is worth $50/MWh and the difference in spill between *monopole* and *bipole* scenarios drops to nil over 10 years.

193 Valuing spill at $20-50/MWh appears reasonable in the light of the monopole price duration curve modelling in the pole 2 analysis – in which South Island spot prices during wet periods are generally less than $50/MWh and sometimes fall to zero.

194 As a point of reference, over 2007-2011, the Benmore price was below $50/MWh 52% of the time and below $20/MWh 19% of the time – driven in large part by hydrology. Note, however, that this was a period of moderate overcapacity.

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[31] This assumes that North transfer is not constrained by other limits such as AC constraints, extended contingent event risk and/or South Island under-frequency management.

[32] Input files will be provided on request.

195 Based on these three scenarios, the benefit to South Island generation is as follows (2012 PV, $M):

	Discount rate (real, pre-tax)		
Scenario	**4%**	**6%**	**8%**
A	23	22	22
B	69	65	62
C	167	151	137

196 On first principles, the South Island generators that would benefit most would be those that had high capacity, inflows that are highly correlated with South Island hydro storage, and relatively little local storage. The obvious candidates (as set out in the pole 2 analysis) are the owners of the Manapouri and Clutha hydro schemes.

C4.2.3 Overall reduction in prices

197 The pole 2 analysis (Section C3) sets out that any reduction in the need for new baseload and intermittent generation can be expected to reduce mean energy prices nationwide.

198 It is assumed that there is a workably competitive market in which the mean energy price is driven by the LRMC of new entrant generation.[33] It is further assumed that baseload and intermittent generation is built according to a merit order, with the most cost-effective options constructed first. As generation development proceeds along the merit order, the LRMC of the marginal new entrant increases, and the mean energy price is expected to rise accordingly.[34]

199 The exact shape of the merit order is not known, and hence it is unclear how rapidly LRMC increases as generation development proceeds. As set out on page 20, it seems reasonable to suppose that the rate of increase in LRMC is somewhere in the range of $1-3/MWh for each 1 TWh of new baseload and intermittent generation development.

200 SDDP analysis indicates that in the *monopole* scenario, incumbent South Island generation would produce on average 400 GWh p.a. less than in the *bipole* scenario. It would therefore be reasonable to suppose that baseload and intermittent generation sufficient to make up the lost 400 GWh p.a. would be constructed in the *monopole* scenario (over and above the amount of new generation in the *bipole* scenario).[35] Such generation could be constructed in either island (or a mixture of both).

201 The implication is that mean wholesale energy prices would be in the range of $0.4-1.2/MWh lower in the *bipole* scenario than in the *monopole* scenario. The gap would likely reduce over time, as the merit order of new generation *flattened* out.[36]

[33] As noted earlier, the Authority acknowledges that some participants do not accept this proposition.

[34] As noted earlier, the supply curve can also fall over time in response to technological improvements. This effect is not considered here as it is assumed to apply equally to both scenarios.

[35] An alternative scenario might be that a coal-fired Huntly unit would be removed from service in the *bipole* scenario but retained in operation in the *monopole* scenario. However this is considered to be a less likely scenario – on the grounds that in the *bipole* scenario, the coal-fired units at Huntly are valuable, since they readily allow 'dry-year swing' (seasonal increases or decreases in load factor in response to hydrology).

[36] In the short term the gap might be substantially higher, if increased imports from the South Island were to create a temporary glut of power in the North Island, delaying the need for new generation and leading to North Island mean prices temporarily dropping below new entrant LRMC.

202 Again three scenarios are considered:

a. in which the gap in mean energy price between the *monopole* and *bipole* scenarios is initially \$0.4/MWh and falls to zero over the following decade;

b. in which the gap is initially \$0.8/MWh and falls to zero over the following 20 years; and

c. in which the gap is initially \$1.2/MWh and falls to zero over the following 20 years.

203 Based on these three scenarios, the cost to the owners of South Island incumbent generation is roughly as follows (pre-tax 2012 PV, \$M):

	Discount rate (real, pre-tax)		
Scenario	**4%**	**6%**	**8%**
A	29	28	27
B	100	90	82
C	150	136	124

204 These costs are very similar in scale to the spill reduction benefits in the previous table. The implication is that the owners of incumbent South Island generation will not collectively be significantly better off as a result of pole 3 (at least in terms of the effects of increased bulk energy transfer capacity), and may even collectively be slightly worse off. (As noted previously, the South Island generators that would likely benefit most would be the owners of Manapouri and of the Clutha hydro scheme.)

205 If new South Island generation was enabled by the bipole, the developers would benefit (though, assuming a workably efficient market for new generation, the benefit would be reasonably small).

206 Based on the three scenarios above, there is also a cost to the owners of incumbent North Island generation (pre-tax 2012 PV, \$M):

	Discount rate (real, pre-tax)		
Scenario	**4%**	**6%**	**8%**
A	49	46	44
B	167	151	137
C	250	226	206

and an equal and opposite benefit to consumers in both islands (pre-tax 2012 PV, \$M):

	Discount rate (real, pre-tax)		
Scenario	**4%**	**6%**	**8%**
A	79	75	71
B	267	241	220
C	400	362	330

C4.3 Effects of increased north transfer capacity at times of North Island scarcity

207 This section describes one of the ways in which the availability of pole 3 will create private benefits.

C4.3.1 Introduction

208 Documentation produced in the course of the HVDC upgrade approval process identifies the main benefit of pole 3 as allowing South Island generation to export power to the North Island at times of capacity scarcity, hence deferring the need for thermal peaking generation.[37]

209 A corollary is that South Island generators can be expected to (collectively) benefit through increased access to occasional high prices in the North Island. Most of this benefit will be captured by those hydro generators that have substantial peaking capacity, backed by storage and available to ramp up in response to high prices.

210 This section proceeds to set out a chain of reasoning in support of this view – first making the case that North Island price spikes will probably be higher and more frequent in the future than they have been in the past, and then estimating the benefit to the owners of South Island generation from increased ability to access such prices.

C4.3.2 Possible incidence of occasional very high prices in the North Island

211 GEM modelling has consistently indicated that there will most likely be a need for new thermal peaking generation in the North Island in the next few years – see, for instance, the 2010 Statement of Opportunities.[38] This result continues to hold in the current version of GEM (v2.0)[39], under reasonable input assumptions.[40]

212 A counter view is that no further peaking generation will be required, and that New Zealand's peaking capacity needs will be addressed through investment in renewables and demand-side response. This is a credible argument and it is addressed with a lower bound case ("sensitivity A").

213 New North Island thermal peaking plants are likely to derive most of their revenue from the possibility of occasional very high prices (typically associated with peak demand, low wind and/or outages of generation or transmission equipment).

214 They will have other sources of revenue – from acting as dry-year reserve, earning transmission alternative payments, operating to reduce RCPD charges and/or running at times of high local prices – but it is reasonable to suppose that such other sources will be secondary.[41]

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37 https://www.ea.govt.nz/document/15958/download/our-work/advisory-working-groups/tpag/tpag-meeting-28-march-2011

38 http://www.ea.govt.nz/industry/ec-archive/soo/2010-soo/

39 http://code.google.com/p/gem/

40 I.e. providing retirement of aging Huntly coal-fired units is modelled, it is assumed that there will be moderate demand growth and that wind and geothermal development will not accelerate markedly, and reasonably conservative assumptions are made about the potential of demand-side response to flatten peaks.

41 Operating in response to RCPD signals may provide a substantial proportion of revenues, though only for flexible, reliable embedded generation.

215 It is reasonable to suppose that, when new thermal peaking generation is needed, either:

a. the top of the North Island price duration curve will rise to a level that is high enough to justify such investment;[42] or

b. while prices will not actually reach such a level, the risk of high prices will be sufficient to allow peaking generation investment to be justified through selling cap style insurance products and/or managing price risk as part of a generation portfolio.

216 For ease of exposition, this section assumes the former scenario (in which peaking investment is funded purely from high spot prices). The latter scenario (in which peaking plant is funded through the *risk* of high spot prices) is probably more realistic – but on first principles the two scenarios should have similar implications in terms of private benefit to South Island generation.

217 Suppose a new North Island thermal peaking plant had a fixed cost of $145/kW p.a.[43] and a variable cost of $400/MWh. Such a plant might be revenue adequate if it was able to make a net profit of $100/kW p.a. from occasional high prices (with the remaining fixed costs being recouped from other sources).

218 This level of revenue could be obtained by operating at full output during:

a. 60 hours per year during which the spot price averaged $2000/MWh; or

b. 20 hours per year during which the spot price averaged $5000/MWh; or

c. 10 hours per year during which the spot price averaged $10000/MWh; or

d. various other combinations of price and quantity.

219 The top of the price duration curve has not been nearly so high in the past. In recent years, the annual revenue that a thermal peaker would have been able to earn from occasional high prices would consistently have been well under half its fixed costs.

220 However, the top end of the North Island price duration curve has been suppressed by the absence of scarcity pricing (so that prices have typically collapsed whenever reserve or energy was scarce). Further, legacy hydro investment has led to an excess of capacity at peak times – and since 2008, there has been an inefficiently high level of investment in generation, probably due to collective failure to anticipate the slowdown in demand.

221 Now that scarcity pricing has been implemented, North Island spot prices may become increasingly volatile – particularly if (and when) capacity margins tighten.

222 Given the uncertainty about the future “spikiness” of North Island energy prices, several scenarios (spanning a reasonable range of possibilities) are considered.

[42] In fact, where investment is “lumpy”, prices are more likely to follow a “saw-tooth” pattern, rising above the level that justifies investment and then falling below it when new plant is commissioned.

[43] This assumption is consistent with the Authority’s recent consultation paper on security standards – http://www.ea.govt.nz/our-work/consultations/sos/winter-energy-capacity-security-supply-standards/. In C4.3.3, the possibility that the fixed costs of a thermal peaker might be substantially lower is explored through a sensitivity case.

C4.3.3 Benefit to South Island generation

223 The availability of pole 3 would enable South Island generators to collectively export more power at times when the North Island spot price was very high.

224 In theory this could provide benefit both in terms of price and quantity. Suppose South Island generators had enough surplus capacity to export 700 MW, and offered it all into the market below the clearing price. With a *bipole* link, the HVDC would not be constrained and the South Island price would be as high as the North Island price, less a loss factor. On the other hand, with a *monopole* link, the HVDC would constrain, less power would be exported, *and* the South Island price would collapse.

225 However, counting both the price and quantity effects would probably overestimate the benefit of pole 3. In the *monopole* scenario described above, it would be more likely that South Island generators would reduce their offers to a level that would prevent the HVDC link from constraining, and South Island prices would remain high. The benefit, then, would be in terms of quantity (at the clearing price) rather than price.

226 For the purpose of this analysis, it is therefore assumed that (at times of high North Island spot prices) South Island generators will act to export as much power as possible without constraining the HVDC, at a price that does not reduce the North Island price significantly.

227 Under this assumption, increasing HVDC capacity increases the quantity that South Island generators can collectively sell, at a price equal to the high North Island price minus a differential resulting from inter-island losses – up to the point where no more South Island generation is available for export.

228 It can be argued that such behaviour will maximise the collective profit of South Island generators (though it may not be to the benefit of every individual South Island generator – most of the benefit will be captured by those with substantial flexible capacity).

229 Sometimes high prices may occur through scarcity pricing, i.e. when the system operator declares a shortage situation.[44] For the purpose at hand, it is assumed that in such cases, there would usually be a national scarcity pricing situation rather than a North Island-only scarcity pricing situation – and hence that South Island generators would still be able to access as high prices as North Island generators (except, again, for a differential driven by losses).

230 As in the previous section, it is assumed that the HVDC will be able to transfer up to:

a. 400 MW (received at Haywards) with a monopole link; [45] or

b. 950 MW (received at Haywards) with a bipole link[46]

during periods of (potential or actual) North Island capacity shortage – providing there is sufficient surplus capacity in the South Island.

[44] Under Part 13 of the Code. Scarcity pricing code amendments will come into effect in June 2013.

[45] These figures assume 400 MW of North Island SIR is dispatched. More power could be transferred if more SIR was dispatched, but with no net improvement in terms of capacity margin (since dispatching each additional MW of SIR would reduce energy dispatch by the same amount).

[46] An implicit assumption is made that HVDC transfers at times of capacity scarcity will not be limited by other factors such as extended contingent event risk, AC constraints or South Island under-frequency risk.

231 It is estimated that, by 2014, the South Island will be able to export an average of about 700 MW (received at HAY) when North Island prices are high – if there is sufficient HVDC capacity. This estimate is calculated as *[anticipated South Island firm generation capacity (derated for planned outages) + expected output of South Island intermittent generation]* minus *[likely South Island demand + South Island IR + South Island frequency keeping – AC losses – DC losses]*.[47]

232 On this basis, the mean amount of power produced by South Island generators during periods of high North Island prices could be expected to be 300 MW higher in the *bipole* scenario than in the *monopole* scenario.

233 There is considerable uncertainty about the estimated mean export of 700 MW. It depends on demand growth, the level of coincidence between North Island high prices and South Island peak demand, and the extent to which South Island hydro generation can ramp up in response to the possible high prices. Given the level of uncertainty, several scenarios (spanning a reasonable range of possibilities) are considered.

234 The amount of power available for export from the South Island will decrease over time as South Island demand grows, but will increase when new South Island generation is added. It would be reasonable to anticipate that South Island export capacity would reduce by about 30 MW p.a. as a result of demand growth.[48] In the absence of new generation, this would reduce average export during high North Island prices to 400 MW in 10 years – at which point the additional capacity provided by the bipole HVDC link would provide little added value.

235 On the other hand, it might be the case that large increments of South Island generation were constructed from time to time (for instance, the North Bank Tunnel project could be completed before 2020, providing over 200 MW of additional firm capacity) – in which case South Island export capacity could be maintained or increased. Again, multiple scenarios are needed to reflect this uncertainty.

236 For each scenario, the collective benefit of pole 3 to South Island generation is estimated as the increase in profit through increased generation volume (at constant price), at times of high North Island price.

237 The increase in profit is calculated as the product of (assumed frequency of high prices) x (assumed increase in mean quantity exported) x (mean South Island energy price at times of high North Island price), suitably discounted.

238 The mean South Island energy price during North Island price spikes is estimated as the product of (assumed mean North Island price x location factor – value of water in the South Island), with a location factor of 80%, based on empirical observations at times of high north transfer, and a nominal water value of $100/MWh.

239 As discussed earlier, the calculation is based on spot revenues only. Contracts are not considered (but the difference in spot revenues can be seen as a proxy for the potential to sell cap style insurance products).

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[47] Specifically: 3200 MW *(firm SI generation capacity)* + 40 MW *(intermittent SI generation output)* – 2200 MW *(SI demand)* – 170 MW *(SI IR + FK)* – 120 MW *(SI AC loss)* – 50 MW *(DC loss)* = 700 MW *(contribution at HAY)*. Of course this is an approximation and actual export capacity will vary over time. However the Authority's "convolution model", recently used to estimate the efficient Winter Capacity Margin standard, takes demand and generation variation into account and yields a similar result – details are available on request.

[48] This assumes demand growth slightly less than 2% p.a.

240 The following three scenarios are considered:

A. in which the quantity difference between *monopole* and *bipole* scenarios starts at 200 MW in 2014 and decreases by 20 MW p.a.,[49] falling to zero by 2024. Further, North Island price spikes are only frequent enough to allow North Island peaking plant to recover $20/kW in 2014, increasing to $50/kW p.a. over 5 years[50] and remaining at that level;

B. in which the quantity difference between *monopole* and *bipole* scenarios starts at 300 MW in 2014 and decreases by 30 MW p.a., but is offset by new hydro plants providing 150 MW of firm capacity in each of 2020, 2025 and 2030. North Island price spikes are sufficient for North Island peaking plant to recover $30/kW in 2014, increasing to $100/kW p.a. over 7 years and remaining at that level; and

C. in which the difference between *monopole* and *bipole* scenarios is 300 MW in 2014 and remains at that level thereafter, with any South Island demand increases being offset by South Island generation increases. North Island price spikes are sufficient for North Island peaking plant to recover $30/kW in 2014, increasing to $120/kW p.a. over 5 years and remaining at that level.

241 On this basis, the benefit to the owners of South Island incumbent generation would be as follows (2012 PV, $M):

	Discount rate (real, pre-tax)		
Scenario	**4%**	**6%**	**8%**
A	30	27	24
B	217	177	147
C	328	271	226

242 Most of the benefit would be captured by those hydro generators that have substantial peaking capacity, backed by storage and available to ramp up in response to high prices – i.e. the owners of the Manapouri, Waitaki, Tekapo and Clutha hydro schemes.

243 Some benefit would also adhere to the owners of mid-size hydro schemes with some ability to ramp up in response to high prices. Cobb, Coleridge, Waipori and Highbank have all demonstrated such ability over recent years.

244 If the benefit is shared between flexible South Island hydro generation, roughly in proportion to capacity, then it is likely to be distributed quite similarly to the HVDC charge.

245 Effects on consumers and incumbent North Island generators will be second order.

246 There will also be an effect on North Island generation developers. Increasing South Island contribution to meeting North Island peak demand will tend to defer the need for North Island peaking generation. This, in turn, will deny the developers of such generation the opportunity to profit. However, assuming a workably efficient market for new generation, the lost benefit should be reasonably small.

[49] Owing to 30 MW p.a. demand growth, partly offset by a gradual increase in South Island embedded generation.

[50] $50/kW is less than half the amount believed necessary to justify investment in peaking plant – perhaps this low level of cost recovery might come about as a result of persistent overbuild of baseload and intermittent generation, or through effective demand response to price. Alternatively, it might be the case that the fixed costs of peaking plant were substantially less than the $145/kW assumed.

C4.4 Effects on IR markets

247 This section describes one of the ways in which the availability of pole 3 will create private benefits.

248 IR is provided by interruptible loads and some generators, who are recompensed through the spot market. The costs of IR are recovered from generators with units over 60 MW and from Transpower (as owner of the HVDC link), through the IR availability charge.[51]

249 All else being equal, the availability of pole 3 will allow a higher level of HVDC transfer for a given level of IR in the receiving island. In the short to medium term, this should result in a reduction in the total amount of IR procured and a reduction in the mean price of IR.

250 The Authority has tested these assumptions through a vSPD experiment. The vSPD model was used to rerun final pricing cases for all trading periods in the 2007, 2008 and 2009 calendar years, for two scenarios:

a. 700 MW single pole HVDC link *(monopole)*; and

b. 1200 MW bipole HVDC link *(bipole)*.[52]

251 All inputs relating directly to HVDC capability were changed, including risk offsets. All other vSPD inputs (including energy and reserve offers) were the same as in the actual final pricing cases.

252 The differences between the two runs, in terms of IR prices and quantities, are summarised below.

		2007		**2008**		**2009**	
		monopole	**bipole**	**monopole**	**bipole**	**monopole**	**bipole**
NI FIR	Quantity (GWh)	2010	1795	2068	1796	2502	1736
	Mean price ($/MWh)	9.9	4.2	5.3	3.1	11.7	0.7
	Total value ($M)	19.9	7.5	11.0	5.6	29.2	1.2
NI SIR	Quantity (GWh)	3394	3199	3348	3024	3634	2982
	Mean price ($/MWh)	17.5	4.0	5.9	5.2	12.2	2.7
	Total value ($M)	59.4	12.6	19.7	15.8	44.4	8.1
SI FIR	Quantity (GWh)	676	575	1413	578	487	458
	Mean price ($/MWh)	2.6	1.0	26.5	0.4	16.2	0.3
	Total value ($M)	1.7	0.6	37.4	0.2	7.9	0.1
SI SIR	Quantity (GWh)	1129	1052	1655	1039	1089	1071
	Mean price ($/MWh)	2.2	1.9	0.9	0.6	0.6	0.2
	Total value ($M)	2.4	2.0	1.5	0.6	0.7	0.2

(For the purpose of this table, IR prices have been capped at $5000/MWh. Mean prices are quantity-weighted.)

[51] See Clause 8.59 of the Code.

[52] As opposed to the real-life HVDC configuration, which over the 2007-09 period was sometimes single-pole, sometimes bipole and sometimes 'pole-and-a-half'.

253 In the vSPD runs, moving from the *monopole* to the *bipole* consistently:

a. reduces the amount of IR dispatched in each island;

b. reduces the mean IR price in each island; and hence

c. reduces IR revenues in each island (quite dramatically, in some years).

254 The vSPD analysis may, however, overstate the likely reduction in IR revenues as a result of moving from a monopole to a bipole HVDC link. The reason is that it uses actual offers, which (for 2008 and 2009) were tailored to a pole-and-a-half link configuration. If a bipole link had been available, then parties that were long on IR might instead have withheld capacity in order to prevent IR price collapse.

255 For comparison, here are actual IR revenues in each island for the last six calendar years:

	Actual IR revenues ($M)					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
NI FIR	10.2	5.2	12.1	34.2	6.0	9.0
NI SIR	21.5	13.0	20.3	29.9	12.9	14.6
SI FIR	1.0	0.7	37.7	0.3	2.0	1.7
SI SIR	0.9	2.1	1.5	0.2	1.1	0.5

256 Actual IR revenues when the HVDC was operating in pole-and-a-half-mode (i.e. from 2008 to 2011) were not substantially higher than when the bipole link was available (i.e. in 2006 and for most of 2007), *except* for:

a. high South Island FIR prices experienced in 2008, which can in large part be attributed to the unavailability of pole 1 for south transfer during a dry sequence; and

b. high North Island IR prices experienced in 2009.

257 The Authority concludes that the exact effect of pole 3 on IR markets is hard to predict (because it depends on system conditions and market behaviour) but that it seems likely that pole 3 availability will tend to:

a. reduce North Island IR revenues by at least $10M p.a. (on average) and possibly substantially more; and

b. restrict South Island IR revenues to a low level, even during extended dry sequences.

258 The availability of pole 3 will also affect the breakdown of IR availability charges. The proportion of IR availability charges that is paid by Transpower is roughly proportional to the 'at risk HVDC transfer'.[53] 'At risk HVDC transfers' will be much lower when pole 3 is available – in fact, Transpower will pay no availability charges for trading periods in which net HVDC flow is less than about 600 MW.

259 The availability of pole 3 will also affect event charges and rebates, but this is second order.

260 The above combination of effects (i.e. an overall reduction in IR prices and quantities, and a change in the allocation of IR availability charges) would affect various participants, in that:

a. IL providers would earn less revenues;

b. generators providing IR would receive less IR revenues;

[53] As defined in Part 1 of the Code.

c. Transpower would pay less IR charges (and see Section C4.8, which discusses how Transpower passes these costs on); and

d. the IR availability charges paid by generators would change, though the net effect is uncertain (in that the total charge to be paid would reduce, but the proportion to be paid by generators would increase).

261 Setting aside the benefit to parties who pay Transpower's IR charges (which is discussed in Section C4.8), the net impacts of these changes might include:

a. a collective private cost in the millions of dollars p.a. to IL providers (notably including Norske Skog, NZ Steel, the Tiwai smelter and Vector);

b. a collective private benefit (probably in excess of $10M p.a.) to generators that are net short on North Island IR (e.g. Contact Energy and Genesis Energy); and

c. a collective private cost (possibly in excess of $10M p.a.) to generators that are net long on North Island IR (e.g. Mighty River Power).

C4.5 Effects of *(potentially)* enabling a national IR market

262 This section describes one of the ways in which the availability of pole 3 could create private benefits.

263 At present, there is a separate IR market in each island, so that:

a. only a relatively small amount of fast instantaneous reserve (FIR) can effectively be transferred over the HVDC link;

b. no compensation is given to the providers of FIR that is transferred over the link; and

c. no SIR can be transferred over the HVDC link.

264 In future a national reserve market (NRM) may be instituted. It is not yet clear how likely it is that a NRM will be created, how exactly it will work, when it will happen or what conditions need to be satisfied first.

265 The availability of pole 3 is probably a precondition for the creation of a NRM. (With pole 2 only, it would frequently be the case that the HVDC itself was setting the binding risk in the North Island. At such times no IR could be transferred from the South Island. This would probably be a deal-breaker.)

266 This section discusses the private benefits of pole 3 in terms of enabling a NRM.

267 An effective NRM:

a. would reduce the total amount of IR procured *(through allowing IR providers to contribute to meeting IR requirements in both islands simultaneously)*;

b. should reduce the mean price of North Island IR *(through increased competition)*; and

c. should affect the mean price of South Island IR – but it is not clear whether the price would rise *(through access to the North Island market, in which IR prices are typically higher)* or fall *(through increased competition)*.

268 Various participants would be affected by these changes. On first principles, the net impacts might include:

a. a substantial collective cost to North Island IL providers (notably including Norske Skog, NZ Steel, the Tiwai smelter and Vector);

b. a substantial collective benefit to generators that are net short on North Island IR (e.g. Contact Energy and Genesis Energy);

c. a substantial collective cost to generators that are net long on North Island IR (e.g. Mighty River Power); and

d. possibly little private benefit to South Island IR providers (it seems unlikely that any increase in price would be sufficient to outweigh the likely decrease in quantity).

269 The Authority has undertaken vSPD analysis to quantify these effects, but is not yet confident that the results can be relied upon as there is considerable uncertainty about:

a. how an NRM might operate; and

b. how market participants might change their offer strategies.

C4.6 Effects of *(potentially)* enabling a national frequency-keeping market

270 This section describes one of the ways in which the availability of pole 3 could create private benefits.

271 At present there is a single frequency keeping market in each island. In future a national frequency keeping market (NFKM) may be instituted. It is not yet clear how likely it is that a NFKM will be created, when it will happen or what conditions need to be satisfied first.

272 The availability of pole 3 is probably not a precondition for the creation of a NFKM (assuming pole 2 can be fitted with the necessary control systems) but may make the creation of a NFKM more economic and hence more likely to occur. With pole 3, the HVDC link would have more 'headroom' and would more readily be able to set aside a capacity band for frequency keeping purposes.

273 This section proceeds to estimate the private benefits of a NFKM – on the basis that if pole 3 increases the extent to which these benefits can be realised or the probability that they occur, then a portion of the benefits should be attributed to pole 3.

274 An effective NFKM should reduce average frequency keeping costs in two ways:

a. by reducing the total quantity of frequency keeping procured *(through allowing each frequency keeper to contribute to keeping frequency in both islands)*, and

b. by reducing the mean price paid *(through increased competition)*.

275 The amount of cost reduction is uncertain. The Electricity Commission published a consultation paper that suggested that implementing a NFKM would save $8-14M p.a.[54] However, the analysis in the paper assumed that allowing multiple frequency keepers in each island would not go ahead until after the NFKM is implemented. In fact it appears that multiple frequency keepers will be implemented first. This initiative can be expected to substantially reduce frequency keeping costs, leaving substantially less benefit to be achieved through a NFKM.

276 Offtake customers pay the cost of frequency keeping services (in proportion to their total offtake)[55] so any cost reduction would result in a benefit to end consumers.

277 The expected benefit to end consumers is estimated as about $1M p.a. (on the basis of pole 3 increasing the chance that a NFKM is instituted in the short- to medium-term by 20 percentage points, multiplied by a $10M p.a. reduction in frequency keeping costs as set out in the consultation paper, reduced by half through implementing multiple frequency keepers first).

278 Over a 20-year period, this is equivalent to aPV of $12M (with 6% discount rate – or $14M with 4% discount rate, $10.5M with 8% discount rate).

279 Such a benefit would be accompanied by a cost to frequency keeping suppliers through lower prices and quantities, partly offset by a reduction in the cost of providing frequency keeping.

280 It is possible that South Island generators might achieve a private benefit by undercutting more expensive North Island frequency keeping suppliers, and increasing the volume of frequency keeping they supplied while maintaining the price they received. However, there is no evidence that this would occur, and it seems more likely that prices would fall as a result of increased competition. If there was such a benefit, it would be insignificant compared to the energy and reserve market benefits discussed in earlier sections.

[54] See Appendix E of the consultation paper at http://www.ea.govt.nz/our-work/consultations/pso-cq/frequency-regulation-market-development-discussion-paper/.

[55] See Clause 8.58 of the Code.

C4.7 Effect of reduced HVDC rentals on HVDC charges

281 This section quantifies a component of the HVDC charge resulting from pole 3 availability – a reduction in HVDC rentals, which are paid to South Island generators. It is referenced from Section C4.1, which estimates the portion of HVDC charges relating to pole 3.

282 Prior to the introduction of FTRs, HVDC charge payers receive HVDC loss and constraint rentals.

283 Once FTRs are implemented, HVDC charge payers will receive FTR residual revenues which will consist of the allocation to HVDC customers of FTR auction revenue and any unallocated rentals. In theory, these payments could be expected to be similar in scale to the HVDC rentals.[56]

284 It could be expected that C rentals (and hence FTR residual revenues) would be lower in a *bipole* scenario than in a *monopole* scenario – because inter-island constraints would be much less frequent (and losses would also be lower, for a given level of transfer).

285 Analysis carried out by Energylink[57] suggests a fall of $20M p.a. in mean rentals, going from a pole-and-a-half to a *bipole* HVDC configuration. It could be expected that the gap between *monopole* and *bipole* would be even more.

286 This is consistent with recent experience:

Calendar year	**Approx. DC rentals ($M)**	**DC configuration**
2006	5.2	Bipole
2007	5.6	Bipole (for most of the year)
2008	53.3	pole and a half
2009	62.1	"
2010	19.8	"
2011	20.1 *(excludes Mar, Nov and Dec – not available at time of writing)*	"

287 It is therefore concluded that pole 3 availability results in a private cost to South Island generators on the order of $20M p.a., in addition to the recoverable costs of the link.

288 Note, however, that the Energylink analysis shows rentals increasing from 2020 onwards in a bipole scenario, as the HVDC link starts to constrain again. The identified cost to South Island generators may therefore reduce over time.

[56] See footnote 27.

[57] http://www.ea.govt.nz/document/13362/download/our-work/programmes/priority-projects/locational-hedges/ftr-development/

C4.8 Effect of IR availability costs on HVDC charges

289 This section quantifies an offset to the HVDC charge resulting from pole 3 availability – a reduction in Transpower's IR availability costs, which are ultimately paid by South Island generators. It is referenced from Section C4.1, which estimates the portion of HVDC charges relating to pole 3.

290 The costs of IR are recovered from generators with units over 60 MW and from Transpower (as owner of the HVDC link), through the IR availability charge.[58] Under the current HVDC charging regime, South Island generators pay the IR availability charges incurred by Transpower.

291 As discussed in Section C3.3, if only pole 2 was available, Transpower's IR availability charges could be expected to be on the order of $10M p.a.

292 The availability of pole 3 is likely to greatly reduce IR availability charges allocated to Transpower through:

   a. reducing the total quantity of IR that is procured;

   b. (probably) reducing the mean price of IR;

   c. (potentially) enabling a NRM that could further reduce IR costs; and

   d. reducing the proportion of IR availability costs that are paid by Transpower, by decreasing 'at risk HVDC transfers' (as defined in Part 1 of the Code).

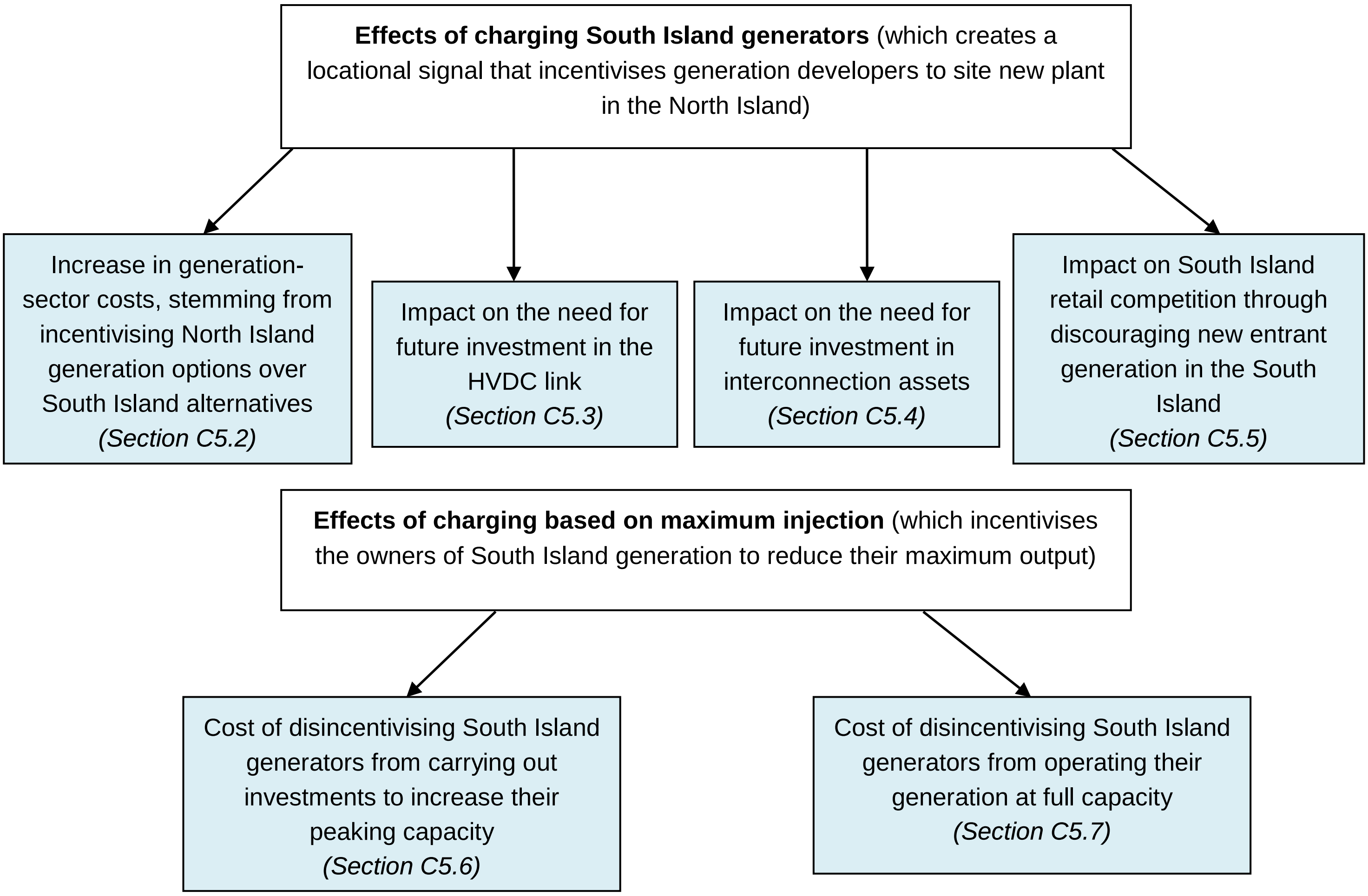
293 In combination, these effects should reduce Transpower's IR charges to a relatively insignificant level. For reference, in 2006 and 2007, with a bipole HVDC link but no NRM, Transpower paid less than $1M p.a. in IR availability charges.

294 The increase in HVDC charges in order to recover the costs of pole 3 will therefore be partly offset by a reduction in IR availability charges, on the order of $10M p.a.

[58] See Clause 8.59 of the Code.

C5. Effects of the HVDC charge on market investment and operation

295 This section assesses the efficiency of the effects of the HVDC charge on market investment and operation. The effects considered are shown in the diagram below.



C5.1 Key findings

296 It is concluded that current HVDC charging arrangements will result in:

a. an expected cost on the order of $30M PV[59] (with considerable uncertainty) through incentivising a pattern of generation investment that is (at least in isolation) inefficient;

b. a small expected cost, estimated to be less than $5M PV, through disincentivising South Island generators from operating their generation at full capacity;

c. a small expected benefit, on the order of $5M NPV, through deferring further HVDC investment; and

d. unknown, but potentially significant, costs and benefits through affecting the need for further AC investment.

[59] About $24M PV from distorting the pattern of generation investment, plus about $8M PV from discouraging investment in South Island peaking capacity.

C5.2 Increase in generation-sector costs

297 The HVDC charge can create a disincentive against investment in South Island generation, relative to North Island generation.

298 The disincentive:

a. does not apply to embedded generation (except where the operation of such generation leads to net injections into the grid at the relevant node);

b. may be reduced or removed for some grid-connected generation under the Prudent Discount Policy; and

c. may affect incumbent generators (particularly Meridian) less than new entrants.

299 Notwithstanding the above exceptions, the HVDC charge will tend to lead to more North Island generation and less South Island generation than would otherwise be the case.

300 Such an impact on generation investment incentives is inefficient (at least when considered in isolation – it may be efficient when the implications for network costs are also considered; see Sections C5.3 and C5.4). The expected outcome is an increase in generation-sector costs.

301 The HAMI allocation of the HVDC charge creates a specific disincentive against investment in South Island peaking capacity – covered in Section C5.6. This section instead addresses the general disincentive against South Island grid-connected generation investment.

302 The TPAG report addresses this issue at length[60], responds to criticisms of the approach, finds that "TPAG has identified a more likely range of $24 ± $9M" for the scale of the inefficiency, and adds that "TPAG has asked the Electricity Authority to update earlier GEM analysis *[on the subject, carried out by the Electricity Commission]*. This analysis is in progress but the results are not yet available. While TPAG recommends that this work is, completed, TPAG does not expect that the update of the GEM analysis will significantly differ from the results of the simplified analysis, but might help to cross check and refine some of the assumptions used."

303 Since the TPAG concluded its work, the Authority has:

a. reviewed the TPAG work using an LRMC-stack model to assess the materiality of the inefficiency;

b. reproduced the TPAG work in the Matlab programming language; and

c. carried out GEM analysis to assess the inefficiency, as recommended by the TPAG.

304 The TPAG's result has been subjected to considerable scrutiny from the industry. The TPAG has answered the criticisms made, apparently satisfactorily, and has shown that the result holds over a wide range of sensitivities, covering all the uncertainties raised by submitters. The result has also been tested through re-implementation in a different software package.

305 Experimentation using the Matlab version of the TPAG model shows that the TPAG finding is not dependent on the effect of the HVDC charge on any one generation plant or small group of related generation plants. (For instance, it does not require that any particular hydro scheme is especially cost-effective or likely to proceed.)

306 The Authority acknowledges the comments made in the Biggar report[61] that the LRMC-stack model has deficiencies (in particular, it ignores the need for peaking capacity) and that using a

[60] Section 5.2 and Appendix A.

[61] www.ea.govt.nz/document/14525/download/search/

model like GEM could provide more information. However, the Authority's GEM study did reach a similar conclusion to the TPAG's work, as did an earlier GEM study published by the Electricity Commission.

307 It is therefore considered that the TPAG's revised results have been demonstrated with an appropriate level of rigour.

C5.3 Impact on the need for future investment in the HVDC link

308 As discussed in the previous section (C5.2), current HVDC charging arrangements are likely to lead to more North Island generation and less South Island generation than would otherwise be the case. In theory this could provide a benefit by deferring future investment in the HVDC link.

309 Transpower is currently in the process of implementing approved investment in the HVDC link. The approved works are divided into two stages. Stage 1 will enable bipole operation up to 1000 MW. Stage 2 will add network reactive support (NRS) at Haywards to enable bipole operation up to 1200 MW. These works are committed and will proceed regardless of generation investment decisions.

310 The next investment would likely be what is referred to as Stage 3 of the HVDC upgrade – consisting mainly of installation of a fourth submarine HVDC cable, enabling bipole operation up to 1400 MW and increasing redundancy in the process. These works have not yet been proposed for regulatory approval as they would not be expected to be required until 2018 at the earliest.[62] The business case for proceeding with them could well be affected by the HVDC charge (through its impact on generation investment decisions).

311 The TPAG report addresses the effect of the HVDC charge on Stage 3 of the HVDC upgrade, raising the prospect that "the optimal timing of investment in a second undersea cable costing $125M [might be] varied 2 years from 2019 to 2021, or 14 years from 2019 to 2032".[63]

312 In order to estimate the potential benefit of the current HVDC charging regime in terms of deferring or avoiding the need for a fourth HVDC cable, advice was sought from Transpower on the business case for the cable.

313 Transpower staff replied that "the most recent information on new South Island generation shows less South Island generation being built than previous, which will defer the need for a fourth cable". Transpower will investigate the issue later this year.

314 Pending its investigation, Transpower is unable to provide much information beyond what was in the original HVDC upgrade approval documentation.[64] However, based on the available information:

a. the cost of a fourth submarine cable is expected to be approximately $150M (real, +/- 20% at least);

b. the need for a fourth cable is expected to be largely driven by the amount of South Island generation capacity available for export at times of North Island capacity shortfall; and

[62] Unless, for example, there is a substantial demand reduction at Tiwai.

[63] Para 5.10.27 (b).

[64] http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/

c. in the original five market development scenarios considered, the fourth cable was only expected to be required before 2030 in two cases – one of which postulated a large, rapid increase in South Island generation capacity such that the cable would be economic by 2018.

315 With Project Hayes cancelled, Contact having decided not to proceed with new Clutha hydro options, less generation than expected being developed in the Upper South Island,[65] and current wind generation development focusing on the North Island, it has become evident that the scenario postulating a rapid rise in South Island generation capacity is no longer plausible. With this scenario removed from contention, only one of the four remaining scenarios involves the fourth cable being built in the next 20 years.

316 Based on the information available, therefore, the chance that a 4th cable might be required before 2030 can be estimated as about 1 in 4.[66] Suppose the HVDC charge leads to a 5-year deferral of the need for the fourth cable in the one remaining pre-2030 build scenario, then the expected deferral benefit is approximately $0.25 * 150 * (1.06^{-10} – 1.06^{-15})$ = \$5M (2012 PV).

317 It is concluded that the expected benefit of the current HVDC charging regime in terms of deferring Stage 3 of the HVDC upgrade is probably only about $5M PV.

318 Further investment beyond Stage 3 appears highly unlikely, at least until pole 2 needs refurbishment or replacement. At this stage, there does not appear to be any reason to believe that the nature, cost or timing of condition-based work on pole 2 is likely to be affected by the current HVDC charging regime.

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[65] http://www.gridnewzealand.co.nz/f4827,71551667/USI_MCP_consultation_document.pdf

[66] It was generally the Electricity Commission's practice to weight market development scenarios equally.

C5.4 Impact on the need for future investment in interconnection assets

319 As discussed in Section C5.2, current HVDC charging arrangements are likely to lead to more North Island generation and less South Island generation than would otherwise be the case. This is likely to have implications for AC transmission investment.

320 The Authority has not investigated the implications in detail and does not have a view on the scale (or even the sign) of the associated inefficiencies.

321 Based on Transpower's Annual Planning Report for 2012,[67] it is suggested that there may be implications in terms of the need for:

a. upgrades to provide additional capacity between Bunnythorpe and Whakamaru, supporting north transfer on the grid backbone (p 59);

b. upgrades to allow additional wind generation to be connected in the Manawatu and/or Wairarapa (e.g. p 62);

c. additional NRS in the upper South Island (p 68); and

d. upgrades to provide additional capacity between Benmore and Twizel, supporting south transfer (p 73),

among other investments.

322 By changing the location of generation investment, the HVDC charge could potentially reduce the need for item a, but could increase the need for items b, c and d. The net effect is unclear.

323 In order to take this issue further, it would be necessary to do a substantial amount of work to investigate the conditions under which each anticipated major AC investment might be justified, determine whether those conditions are made more or less likely by the HVDC charge, and estimate the effect in terms of cost-benefit. Extensive Transpower involvement would be required.

C5.5 Adverse impact on South Island retail competition through discouraging new entrant generation in the South Island

324 The TPAG report discusses the proposition that the HVDC charge is detrimental to competition in the South Island generation investment market. Arguably incumbent generators (particularly Meridian) face a lower marginal transmission charge than new entrant generators.[68]

325 The TPAG commented that if new entrant generation in the South Island was discouraged, then *"it would lead to large incumbent South Island generators increasing their dominance in the South Island with a consequential reduction in competition in generation* ***and retail****, and potential inefficiency."*

326 The Authority acknowledges the view that the HAMI allocation methodology could affect South Island *retail* competition. However, this effect is not considered to be material. A local generation base is a means of dealing with locational price risk – but locational price risk can also be managed through locational hedging arrangements. The industry has made considerable progress with regard to developing tools for managing locational risk.

[67] http://www.transpower.co.nz/annual-planning-report-2012

[68] Paras 5.1, 5.2.2 through 5.2.9, and 5.4.

C5.6 Cost of disincentivising South Island generators from carrying out investments to increase their peaking capacity

327 The Electricity Commission suggested that there could be a substantial cost through disincentivising South Island generators from investing in peaking capacity, since operating such capacity could increase their HAMI and lead to them paying a greater share of HVDC charges.

328 The TPAG report addresses this issue[69] and concludes that, while "there is potential generation investment inefficiency from discouraging new peaking capacity in the South Island... the expected value [of the inefficiency] is likely to be well below the midpoint of this range at $8 ± 8M NPV".

329 The Authority is not aware of any evidence that contradicts the TPAG's analysis.

330 In order to advance this debate, it would be necessary to obtain hard data from generators on the cost-benefit of investments that the HAMI allocation of HVDC charges might prevent them from making, and to independently verify the data provided.

C5.7 Cost of disincentivising South Island generators from operating their generation at full capacity

331 The Electricity Commission suggested that there could be a substantial cost through disincentivising South Island generators from operating their generation at full capacity, since doing so could increase their HAMI and lead to them paying a greater share of HVDC charges.

332 However, the TPAG Report addresses this issue[70] and concludes that "the dispatch inefficiency is more likely to be in the range $0-$5M NPV and probably at the lower end of this range".

333 An earlier report by NERA also concluded this factor was unlikely to be material.[71]

334 The Authority is not aware of any evidence that contradicts the TPAG's analysis. It will be difficult to advance this debate much, other than by waiting to see what actually happens in practice.

[69] Paras 5.3.6 and A.15.8 through A.15.14.

[70] Paras 5.3.2 through 5.3.4 and A.15.5 through A.15.6.

[71] http://www.ea.govt.nz/document/6616/download/our-work/programmes/priority-projects/transmission-pricing-review/stage1/

C6. Generation cost assumptions in the pole 2 analysis

335 For completeness, this section sets out the generation cost assumptions that underlie the price duration curves in the pole 2 analysis (C3.2.6). There is considerable uncertainty about some of these assumptions, but alternative values are considered as sensitivities (C3.2.7).

336 The key assumptions made in the base case are that:

a. the LRMC of new SI wind is $90/MWh;

b. the LRMC of new NI geothermal is $80/MWh;

c. the LRMC of new SI coal-fired plant is $260/MWh at 30% LF;

- which in turn is based on a SRMC of $100/MWh, and fixed costs & capital recovery of $420/kW p.a.;

d. the LRMC of new oil-fired plant is $645/MWh (at 6% LF);

- equivalently, a new oil-fired plant would recover 70% of fixed costs by earning $1,500/MWh for 1% of the time;

- both figures are based on a SRMC of $370/MWh, and fixed costs and capital recovery of $145/kW p.a.[72]

e. the break-even cost of the marginal HLY unit is $150/MWh (at 20% LF) or $120/MWh (at 50% LF);

- both figures are based on a SRMC of $100/MWh, and fixed costs of $90/kW p.a.;

f. the break-even cost of the marginal CCGT is $100/MWh (at 70% LF);

- which in turn is based on a SRMC of $80/MWh, and fixed costs of $120/kW p.a..

337 The next step is to drill down further into these assumptions.

338 With regard to renewables,

a. the LRMC of new SI wind ($90/MWh) is based on a capital cost of $2400/kW including connection, mean load factor of 42%, fixed O&M costs of $50/kW p.a. and variable O&M costs of $3/MWh p.a.; and

b. the LRMC of new NI geothermal ($80/MWh) is based on a capital cost of $4800/kW including connection, mean load factor of 92%, moderate carbon costs, and fixed O&M costs of $105/kW p.a.

339 These assumptions are broadly consistent with MED's[73] "2011 NZ Generation Data Update".

340 With regard to thermal SRMCs,

a. the SRMC of oil-fired plant ($370/MWh) is based on a heat rate of 9.5 GJ/MWh, variable O&M costs of $10/MWh, a carbon price of $25/t, and diesel at $36/GJ excluding carbon. This is consistent with an oil price of US$100/bbl real and a long run 0.66 US$ exchange rate;

[72] This assumption is consistent with the Authority's recent consultation paper on security standards – http://www.ea.govt.nz/our-work/consultations/sos/winter-energy-capacity-security-supply-standards/

[73] Now part of the Ministry of Business, Innovation and Employment

b. the SRMC of coal-fired plant ($100/MWh) is based on a heat rate of 10.5 GJ/MWh, variable O&M costs of $10MWh, a carbon price of $25/t, and coal at $6.25/GJ including variable portion of fuel delivery costs and an allowance for carrying costs, but excluding carbon;

c. the SRMC of the marginal CCGT ($80/MWh) is based on a heat rate of 7.4 GJ/MWh, variable O&M costs of $5/MWh, a carbon price of $25/t, and gas at $8.8/GJ including variable portion of fuel delivery costs, but excluding carbon.

341 The assumed carbon price of $25/t should be taken as a medium- to long-term value – it is too high for the short term.

342 With regard to thermal fixed costs,

a. the fixed costs and capital recovery of new oil-fired plant ($145/kW p.a.) are based on a capital cost of $1155/kW and $15/kW fixed O&M costs;

b. the fixed costs and capital recovery of new SI coal-fired plant ($420/kW p.a.) are based on a capital cost of $2600/kW and $60/kW fixed O&M costs;

c. the fixed cost of the marginal Huntly unit is $90/kW p.a., purely by assumption since this information is not public. This sum is assumed to include capital cost recovery, fixed O&M, and fixed portion of fuel delivery and carrying costs;

d. the fixed cost of the marginal CCGT is $120/kW p.a., purely by assumption since this information is not public. This sum is assumed to include capital cost recovery, fixed O&M, and fixed portion of fuel delivery costs.

--- This concludes Appendix C. Key findings are summarised in Section C1.2. ---