NZIER Capacity Rights Proposal - Implementation Issues

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Executive summary

1. A capacity rights approach for the HVDC link has been proposed by submitters to the transmission pricing review. This approach has been outlined in advice from NZIER for RTANZ[1,2]. The Authority has sought to further develop this high level description into a functional method and address where it could design issues inherent within the approach.

2. The HVDC capacity rights proposal provides a market-based approach to the recovery of the costs of the HVDC link. This is achieved by allocating HVDC capacity rights annually out three years based on Transpower's unit cost[3] and enabling the trading of these rights. The owner of the capacity right has a contractual right to a fixed physical amount of HVDC capacity for a defined period.

3. This paper considers the possible operation of capacity rights in more detail and some critical issues that would need to be addressed if a capacity rights approach were to be implemented. These issues are as follows:

Two-solve process

4. The NZIER advice proposes a two-solve process of the scheduling, pricing and dispatch (SPD) model to identify those dispatchable participants requiring capacity rights on the HVDC link. This process would be used to determine the annual allocation of capacity rights[4] as well as the amount of capacity rights needed during the dispatch process. This process requires adjustments to net out the impact of intra-regional transmission losses, transmission constraints and instantaneous reserves requirements from generator output to ensure some consistency between the required capacity rights and the actual flows. Further changes to the market clearing engine (MCE) are needed to ensure feasibility of the 1st ("no HVDC") solve. An effect of addressing the 1st solve ("no HVDC") feasibility is that this could introduce intra-island locational signals where generators closer to loads would require less capacity rights than those further away from loads.

> Issue #1:
>
> The practical implementation of such a process will require modifications to the market clearing engine (MCE[5]). Intra-island locational signals would be introduced where generators closer to loads would be deemed as requiring less HVDC capacity rights than those further away from loads.

[1] Brent Layton, NZIER memo to Ray Deacon, RTANZ, 6 December 2009. Available at http://www.ea.govt.nz/document/4573/download/our-work/consultations/transmission/tpr/submissions/

[2] NZIER Report to Rio Tinto Alcan New Zealand Ltd, 22 March 2010, A Capacity Rights Regime for the HVDC link.

[3] Unit cost is based on the required revenue for the HVDC link and the HVDC link capacity.

[4] Based on historical usage.

[5] Also known as Scheduling, Pricing and Dispatch (SPD). These terms will be used interchangeably in this document.

Capacity rights requirements and allocation

5. The identified beneficiaries of this process are those generators whose output increases between solves of SPD without and with the HVDC link in place. This approach is more aligned with a usage-based beneficiary identification process since those beneficiaries who do not experience an increase in output but do benefit from an increase in price in the two-solve process would not be identified as beneficiaries. To adjust the process to account for financial beneficiaries would require detailed knowledge of operational costs (including marginal water values) and retail hedge positions. Given these information requirements a more practical approach would be to maintain the usage-based beneficiary identification process as proposed in the NZIER advice.

6. The proposed approach is also based on allocating usage and therefore capacity rights requirements to dispatchable participants. In the current final pricing process, wind generators are modelled as negative loads which are non-dispatchable. Furthermore generators less than 10MW in size are not required to provide an offer for dispatch by the System Operator (SO). To address these would require both changes to the market systems (to allow dispatchable wind generation in final pricing) and to the market rules to require generators smaller than 10MW to also submit offers and receive dispatch instructions. There could be significant transaction costs involved with including smaller non-dispatchable generators as part of the scheduling and dispatch process. These need to be traded off against the benefit of sending a consistent signal to all generators that “use” the link.

Issue #2:

- Maintain the usage-based beneficiary identification process as proposed in the NZIER advice.
- Adjust the market systems (including the MCE) to account for dispatching wind generation in the final pricing process.
- Modify the code to ensure generators less than 10MW are dispatchable via the market process (This is likely going to incur large transaction costs. These need to be weighed up against the potential benefits of sending a consistent signal and therefore preventing inefficient construction of smaller non-dispatchable generators).

Dispatch inefficiencies

7. The HVDC capacity market needs to be co-optimised with the energy and instantaneous reserves (IR) market to ensure an efficient dispatch solution. This is consistent with the NZIER advice[6]. This will require changes to the MCE

[6] This is also consistent with the analysis conducted by the Electric Power Optimisation Centre (EPOC) where a balancing market was proposed to ensure efficient re-allocation of HVDC capacity rights with energy and IR co-optimistion.

mathematical model to include additional variables, constraints and adjustments to the objective function to ensure the HVDC rights market surplus is also maximised.

> Issue #3:
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> Co-optimisation of the HVDC capacity rights, energy and IR markets are needed to prevent inefficient dispatch outcomes will require non-trivial modifications to the MCE.

Pricing issues

8. The introduction of HVDC capacity rights within the dispatch process closely links the wholesale energy, IR and HVDC capacity markets with prices in these markets reflecting this linkage.

9. It is also expected that the cost to loads in the sending island would increase during times of constrained HVDC flow. This is because during these times the opportunity cost of the HVDC capacity rights is expected to rise to the difference between the receiving island price and the short-run marginal cost (SRMC) of the marginal sending island generator. Therefore, the marginal sending island generator needs to increase its energy offer prices (above SRMC) to reflect:

   - The additional cost of purchasing the HVDC capacity right at the market determined price (opportunity cost) or;
   - Its indifference to earning the revenue off the energy market or the HVDC capacity rights market if it already owns the capacity rights.

> Issue #4:
>
> It is expected that the cost to sending island loads would increase during times of constrained HVDC transfer with the introduction of HVDC capacity rights. This effect could be particularly significant with the introduction of scarcity pricing.

Cost recovery with the expanded HVDC link

10. The NZIER advice proposes to reduce the HVDC capacity used in the initial allocation based on an average expected usage. The residual HVDC capacity will be offered by Transpower at a premium in the secondary and spot auctions. This is designed to ensure Transpower fully recovers the cost of the expanded HVDC link since it is likely that the available HVDC capacity of the expanded link would exceed the demand (at least initially).

11. This process however exposes the spot energy prices to the estimates of expected HVDC usage. During instances when HVDC flow is in excess of the average expected usage it is expected that the premium levied on the additional HVDC capacity will manifest in the spot energy market since the cost of transmitting across the HVDC (spot HVDC capacity right) has increased.

12. If the average expected HVDC usage exceeds the actual usage then there is still a revenue risk on Transpower.

13. Therefore it is felt that the proposed advice to ensure Transpower is able fully recover the cost of the expanded HVDC link (when supply is likely to exceed demand) still does not guarantee this cost recovery as it dependent on the accuracy of the expected average HVDC usage which could diverge from actual HVDC usage. If it is an overestimate then Transpower would still be exposed to cost recovery risks and if it is an underestimate then the premium levied on the residual HVDC capacity will be borne in the energy market thus leading to an increase in energy prices. To avoid this influence on the energy market it is proposed to utilise the full HVDC capacity in the allocation process. This could result in insufficient revenue to Transpower to cover the full cost of the expanded HVDC link which would be recovered via an adjustment to the interconnection charges.

Issue #5:

Utilise the full HVDC capacity in the initial allocation and subsequent secondary and spot capacity rights auctions. Any HVDC revenue shortfall experienced by Transpower would be recovered via an adjustment to the interconnection charges.

Financial Transmission Rights (FTRs) and HVDC capacity rights

14. FTRs are intended to manage locational energy price risk for participants and facilitate contracting across the transmission network. While not being provided as a means to fund the removal of constraints, they could operate in this way. They are financial rights that are inherently linked to the energy market prices and provide the FTR holder with the rights to loss and constraint rentals between the FTR regions. Currently these regions are the generation centre in the south island (Benmore) and the load centre in the north island (Otahuhu) which is aligned with the nodes used for the energy futures and options contracts market.

15. HVDC capacity rights are physical rights which could also be used to provide additional revenue to the capacity rights holder to manage locational price risk between the HVDC terminal nodes (Benmore and Haywards). Therefore participants wanting to hedge their locational price risk between the generation and load centres would still be exposed under the capacity rights proposal. Therefore it is felt that an FTR product would still be required under the capacity rights proposal to enable participants to hedge the residual locational price risks between the HVDC terminal in the north island (Haywards) and the load centre in the north island (Otahuhu). This would also increase the participation in the energy futures and options contacts market (which trades at Benmore and Otahuhu) thus also improving its liquidity and competitiveness.

Issue #6:

Maintain an FTR to cover the additional locational price risk between the HVDC terminal at Haywards and Otahuhu. This would increase the ability of participants to manage locational price risk between the generation centre in the south island (Benmore) and the load centre in the north island (Otahuhu). Furthermore, this would assist with the liquidity and competitiveness of the energy futures and options contract market currently traded at Benmore and Otahuhu.

HVDC capacity rights and system security

16. The HVDC capacity rights proposal as presented by NZIER is an allocation of physical capacity. Therefore any rights that are not offered into the market would result in a reduction in HVDC capacity available for transfer between the south and north island. This could compromise the security of the system.

17. The security issue could be addressed by enforcing the mandatory offering of all HVDC capacity which would require modifications the Code. This requirement could be enforced during the initial implementation phase until there is greater confidence and experience with the HVDC capacity rights market. This does not prevent participants offering capacity at a very high price which could serve a similar strategic purpose to not offering. To address this, additional modifications to the MCE could be implemented[7] to ensure that the physical HVDC capacity is fully utilised before load or IR reduction is requested.

Issue #7:

To ensure all operational capacity is available to the market will require:

- modifications to the to the market clearing engine (MCE); and
- changes to the Code to ensure all HVDC capacity was offered into the market (at least initially).

Increased liability for Transpower from firm capacity rights

18. Unlike the rest of the grid, generators and load do not have firm rights of access but this is consistent with the regulatory framework encompassing the investment approval process, the contracting and pricing regime that seeks to balance the allocation of risks between the parties and the appropriate cost allocation. The capacity rights approach seeks to integrate an incompatible method by requiring that the owner of the line provide the firm capacity and presumably compensation if the link is out of service for some reason. This additional risk to Transpower would have to be reflected somewhere in its costs, for instance, in a higher WACC or increased insurance costs, greater redundancy etc. Alternatively, a non-firm right may not be considered acceptable or as valuable. This may have implications for revenue recovery.

Conclusion

19. The HVDC capacity rights proposal is a market-based approach to the allocation of HVDC costs with the following advantages:

[7] This could be through the introduction of additional violation variables with associated constraint violation penalties (CVPs).

- Participants can make their own assessment of the value of the HVDC and bid accordingly hence the approach better aligns benefits with costs;
- It may provide a more durable solution to who pays for the link, reducing regulatory uncertainty with its attendant benefits;
- It may provide better investment signals for any upgrades to the link.

20. However, the benefits come with significant implementation requirements and impacts on the energy market. The detailed implementation issues could make such an approach challenging to apply. Furthermore, the impact of this process on the operation of the wholesale energy market is likely to be significant and together with the increased transactional costs needs to be traded off against the potential benefits. There also appears to be some uncertainty around HVDC cost recovery for Transpower.

21. As part of this analysis, a set of design modifications have been proposed which could assist with a practical implementation of the proposed approach. These address issues surrounding details of the two-solve process, allocation of HVDC capacity rights, capacity rights and cost recovery with the expanded HVDC link, maintaining FTRs to better manage locational price risk and mandatory offering of HVDC capacity rights during the initial implementation stage to ensure system security is not compromised.

Contents

1. Introduction and purpose of this report

1.1 Introduction

1.1.1 Some submitters on the transmission pricing review stage 1 and stage 2 consultation papers have suggested the introduction of a capacity rights regime is a possible option for the recovery or partial recovery of the costs of the HVDC link.

1.1.2 RTANZ, as part of its submission on the stage 1 consultation paper, included advice from NZIER[8][9] on the high-level operation of a capacity rights regime.

1.2 Purpose of this report

1.2.1 This report considers the approach detailed in the NZIER advice and considers a number of issues that would need to be considered if a capacity rights proposal were to be developed further.

1.2.2 The report also includes issues clarified following a further discussion between representatives from the Electricity Authority (EA), New Zealand Institute of Economic Research (NZIER) and the Electric Power Optimisation Centre (EPOC).

[8] Brent Layton, NZIER memo to Ray Deacon, RTANZ, 6 December 2009. Available at http://www.ea.govt.nz/document/4573/download/our-work/consultations/transmission/tpr/submissions/

[9] NZIER Report to Rio Tinto Alcan New Zealand Ltd, 22 March 2010, A Capacity Rights Regime for the HVDC link.

2. Background

2.1 An outline of a capacity rights approach

2.1.1 The basic principle of the capacity rights approach is that generators would need to purchase capacity rights in order to use the HVDC link.

2.1.2 The approach, as described at a high-level by NZIER, would involve introducing three new trading processes:

(a) an annual allocation of capacity rights at Transpower's unit cost based on historical usage for the previous five years;

(b) a secondary trading market for capacity rights that would operate up to the start of the half-hour to which a capacity right relates; and

(c) spot trading of capacity rights which would operate in conjunction with the offering of generation for dispatch.

2.1.3 The pricing and dispatch process would then operate as follows:

(a) The system operator would determine which dispatch offers are required to meet both intra-island and inter-island flow requirements by:

(i) determining in the normal manner which generators it would dispatch on the basis of the least cost i.e. as if there were no HVDC capacity rights requirement; and

(ii) determining which generators it would dispatch if there was no capacity available on the HVDC link i.e. a two-island economic dispatch solve; then

(iii) comparing (i) and (ii) to calculate which generators output was increased or decreased given the availability of the HVDC link. This process determines the users of the HVDC link and therefore those that require HVDC capacity rights.

(b) The system operator would then consider the offers for HVDC capacity rights and establish the offer price such that the volumes offered at this price, or less, would just cover the expected inter-island flow.

(c) The system operator would allocate the volume of HVDC capacity rights offered at or below this price to generators whose dispatch offers in the spot electricity market are such that they would be dispatched to meet the inter-island flow, provided they have a bid for HVDC capacity rights at or above the market price for HVDC capacity.

(d) If there are too few generators in the original dispatch stack with sufficiently high bids for HVDC capacity, the system operator would progress up the generator offer stack.

2.2 Issues for consideration

2.2.1 This paper considers the possible operation of capacity rights in more detail and some issues that would need to be considered if a capacity rights approach were to be developed further. These issues considered are as follows:

(a) The two-solve process

(b) Capacity rights requirements and historical allocation of capacity rights.

(c) Dispatch inefficiencies.

(d) Pricing issues.

(e) Cost recovery for the expanded HVDC link.

(f) FTRs and HVDC capacity rights.

(g) HVDC capacity rights and system security.

3. Analysis

3.1 The two-solve process

3.1.1 It is proposed in the NZIER advice that the offers needed for inter-island flow on the HVDC can be determined from a two-solve process.

(a) 1st Solve: Determine which generators to dispatch if there was no capacity available on the HVDC link.

(b) 2nd Solve: Determine in the normal manner which generators it would dispatch as if there were no capacity rights requirements.

3.1.2 From the comparison of these two solutions Transpower would determine which offers are used for inter-island flow across the HVDC link and the volume of the inter-island flow. The proposal is not specific about how these two schedules G^1 and G^2 will be used. It is assumed in this review that those offers in the sending island (South Island (SI) for South to North flow and North Island (NI) for North to South flow) whose output in the 2nd solve (G^2) is greater than in the 1st solve (G^1) would require HVDC capacity rights in proportion to their change in output.

$$\Delta G = G^2 - G^1 \qquad (1)$$

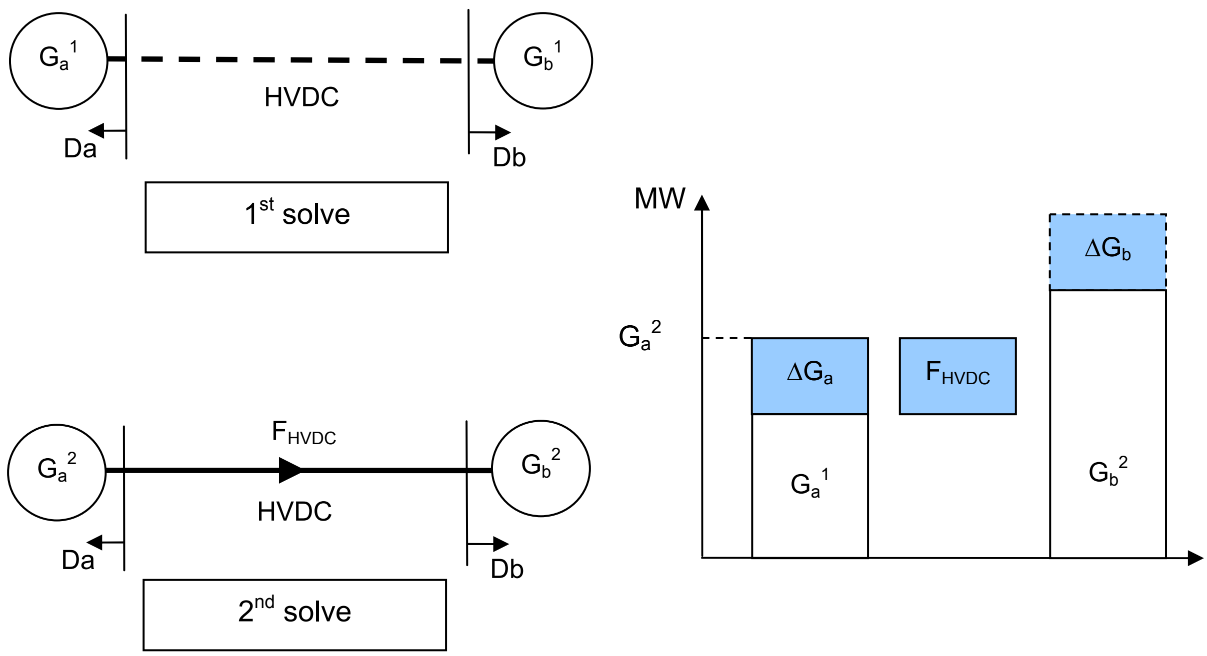

Figure 1: Schematic of proposed two-solve process

3.1.3 In the above schematic, the increased output from the sending island generators in the 2nd solve can be attributed to the inter-island HVDC flow.

3.1.4 In reality, the system representation is more complex and output changes between the two-solves can be attributable to:

(a) intra-regional transmission losses;

(b) transmission constraints and

(c) co-optimised energy and instantaneous reserves requirements (IR).

3.1.5 These issues imply that some of the output changes (between the 1st and 2nd solves) are due to intra-island requirements. If the above output changes are assumed to be for inter-island requirements, the approach could over or underestimate some participants' requirements and hence how much they "use"[10] the HVDC link. These are discussed further below with more detailed examples included in the Appendix.

Intra-regional transmission losses

3.1.6 The output of some generators within the 2nd solve might change due to changing intra-regional transmission losses. The location of these generators relative to the HVDC terminals however could imply that physically the increased output is unlikely to be transferred across the HVDC and more likely to supply the local load and transmission losses[11]. Consideration should be given to adjusting the assumed output changes due to satisfying intra-island transmission losses[12].

Transmission constraints and Intra-island IR requirements

3.1.7 Transmission constraints and intra-island IR requirements could result in more expensive generators being scheduled ahead of cheaper generators in the 1st of the two solves. In the 2nd solve, the transfer across the HVDC alleviates these constraints thus resulting in the more expensive generators being "scheduled down" allowing the cheaper generators in the sending island to increase output. In this case some of the increased output from the cheaper generators in the sending island is used to satisfy the intra-island constraint and IR requirements previously provided by the more expensive generators from the 1st solve. This discounting needs to be considered to ensure that the net increase in sending island generation corresponds to the actual increase in the HVDC flow.

Modelling the two-solve process

3.1.8 To provide some indication of the relationship between the aggregate HVDC capacity right requirements (i.e. net change in output of sending island generation) and the HVDC flow, the Authority has replicated the two-solve process in vSPD[13]. Final pricing cases from July 2009 to May 2010 were

[10] And by extension how much they benefit from the HVDC link

[11] As an example using the flow tracing algorithm, all of COBB's generation rarely exits the upper south island.

[12] These could be average static loss factors or more dynamic factors based on the actual grid configuration.

[13] Vectorised schedule, pricing and dispatch is the Electricity Authority's version of the MCE.

executed. The selected date range provided 12,300 HVDC northward flow half hours and 2000 HVDC southward flow half hours. The results of these are illustrated in Figure 2 and Figure 3.

3.1.9 For a large number of the HVDC northward flow half hours, the net increase in SI generation is a good representation of the increase in HVDC flow (75% of the instances studied are within a 1% deviation[14]). As indicated earlier, loss and constraint effects could result in further deviations. In some instances it was noted that up to 7% of additional SI generation was needed which did not translate into HVDC flow. This additional generation was used to serve the intra-island transmission loss requirements in the 2nd solve.

3.1.10 In some instances however the HVDC flow exceeded the net increase in sending SI generation. This was due to two factors:

(a) In some cases, increases in SI generation sometimes resulted in a reduction in intra-island transmission losses thus enabling additional HVDC transfer.

(b) In others, the 1st solve of the MCE produced spurious results. These spurious results are likely to occur in market model (SPD) as well and are due to the presence of non-physical losses in the intra-island AC network of the 1st solve. Non-physical losses are a mathematical anomaly that arises in the MCE when there is significant zero priced generation with lower loads. This issue arises in the 1st solve (particularly in the SI) when there is significant zero priced generation, combined with must-run frequency keeping generation with only an island load to serve. An option to resolve this would be to ensure that all offers being used in the MCE are greater than $0/MWh. This however implies that the 1st solve reverts to an island-wide loss minimisation problem where generators closer to load centres in the island would be scheduled ahead of those further away from load centres in the 1st solve. In terms of the capacity rights process this would imply that sending island generators closer to load centres would require less HVDC capacity rights than those generators further away from the load centres. This however provides an unintended intra-island locational price signal. The details of this are discussed further in Appendix A.

[14] That is the net increase in sending SI generation is within 1% of the resulting HVDC flow.

(c)

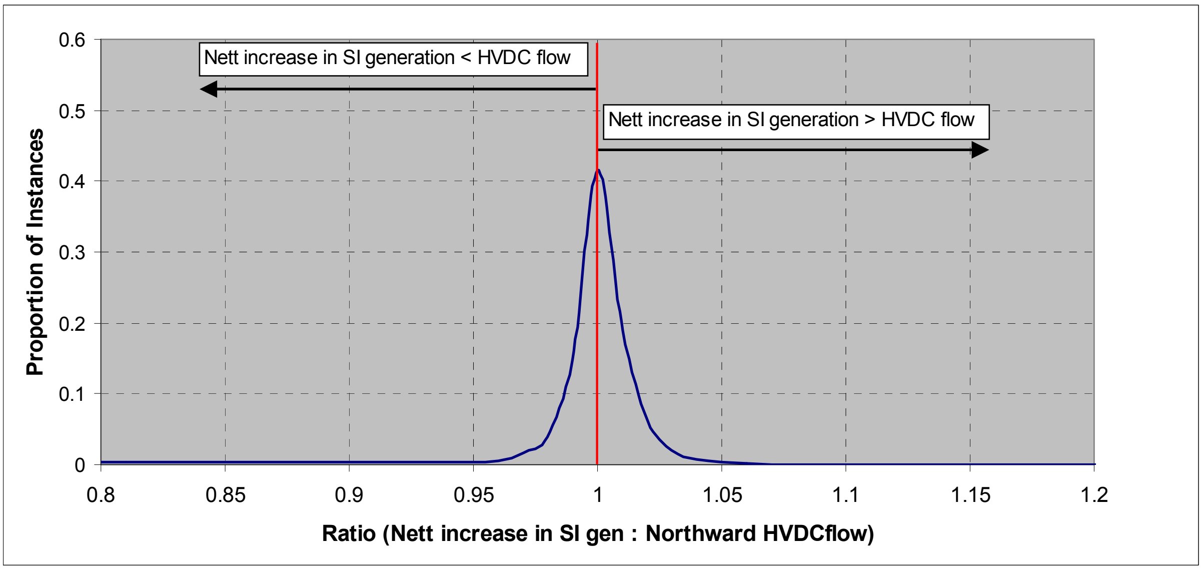

Figure 2: Ratio of net increase in SI generation to northward HVDC flow

3.1.11 For the HVDC southward flow scenarios, there is a high likelihood that the net increase in NI generation would exceed the resulting HVDC flow due to additional intra-island NI transmission losses. The amount of additional intra-island losses is dependent on the system conditions and offers at that time.

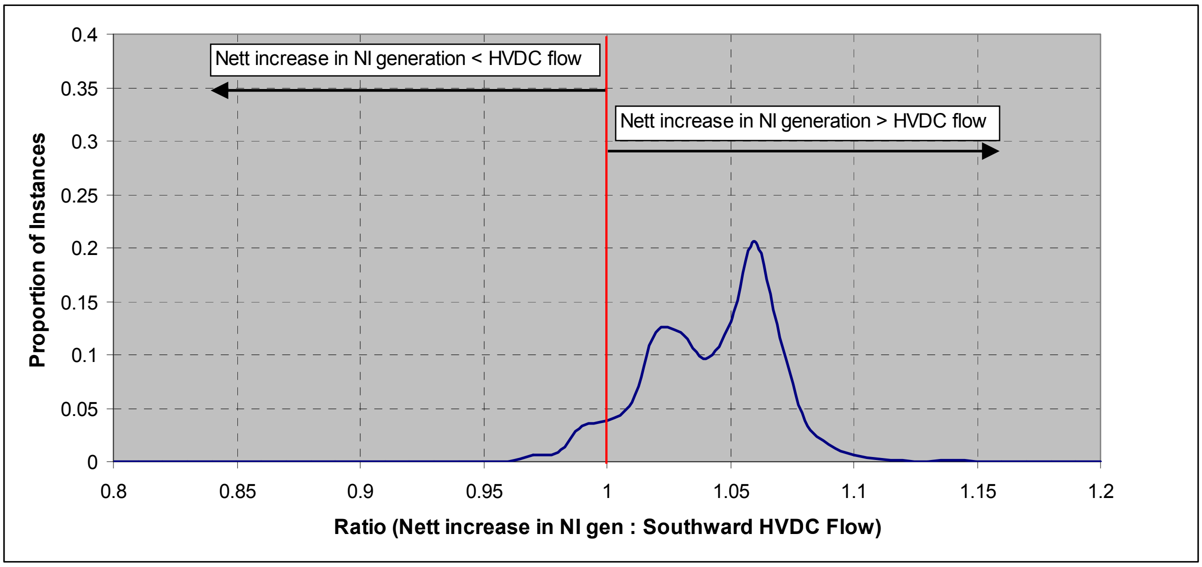

Figure 3: Ratio of net increase in NI generation to southward HVDC flow

Suggestion solution to the over/under estimation of capacity rights requirements

3.1.12 This aggregate analysis of the two solve process illustrates some issues that would need to be considered for the implementation of the HVDC capacity rights approach to ensure there is a consistency between the amount of HVDC capacity rights required in relation to the HVDC flow.

(a) Adjustment for losses: The HVDC capacity required needs to be adjusted by appropriate loss adjustment factors[15] to net out additional generation due intra-regional losses. This however introduces additional levels of complexity and risk[16] for this option.

(b) Net increases in sending island generation: Using the net (adjusting for additional generation due to alleviating intra-regional transmission constraints and IR requirements) rather than gross increases in sending island generation would be more appropriate. If these offsets are not taken into account, then the gross increase in sending island generation could far exceed the resulting increase in HVDC flow thus resulting in a divergence between the amount of capacity rights needed in comparison to HVDC flow.

(c) Integrity of the 1st solve: The structure of the 1st solve with no HVDC transfer introduces some computational complexities within the MCE which if not resolved would compromise the integrity of the process. Currently there is a low likelihood of non-physical losses in the market dispatch and pricing process where the cost of losses is most likely to be greater than zero. However, the 1st solve process increases this likelihood particularly for periods of high storage levels in the south island. To address these issues would require further modifications of the MCE which now introduces an unintended intra-island locational price signal for HVDC capacity rights.

3.2 Capacity rights requirement and historical allocation

3.2.1 The NZIER advice identifies beneficiaries of the HVDC link based on the change in output between the "no HVDC" (1st solve) and the "with HVDC" (2nd solve) scenarios. This beneficiary identification process isolates those participants in the sending island whose output increases with the introduction of the HVDC link in the 2nd solve. It does not identify those beneficiaries whose output does not change but who benefit from an increase in sending island prices with the presence of the HVDC link. This would assist in capturing some financial beneficiaries. The extent of their benefit would also require knowledge of participants' short-run marginal costs (SRMC) and retail hedge positions. Given the extensive information requirements to identify these financial beneficiaries it is probably more practical to utilise the utilisation-based index as proposed in the NZIER advice (i.e. a change in generation output).

3.2.2 There are still some other practical issues that need to be addressed with the implementation of this process. The proposed two-solve approach is based on

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[15] These could be static published factors or more dynamic factors based on the actual system conditions.

[16] To the extent that the purchased HVDC capacity rights are able to accurately estimate the change intra-island transmission losses and not leave the participant short.

[17].

This implies that the capacity rights allocation and requirements are only applicable to dispatchable generators[18]. Therefore any *non-dispatchable* generators would not require an HVDC capacity right under the proposed design[19]. This could influence the sizing of new generation in the system since smaller sized generators would be exempt from incurring an HVDC charge. To address this, the minimum size of dispatchable generators should be decreased in the market rules. This however would also require these generators to implement trading platforms and submit offers and receive dispatch instructions from the System Operator (SO). The increased transaction and implementation costs of this change needs to be weighed up against its possible benefits.

3.2.3 In the current final pricing (FP) process wind generators are represented as negative loads based on their average output in that trade period. This would need to be changed under the proposed capacity rights process where wind generators would need to be represented as dispatchable generators with their capacity limited to their average measured output in that trade period This would require additional changes to the MCE as well as the associated market systems[20].

3.2.4 The NZIER advice favours an allocation of HVDC capacity rights based on some historical usage versus an auction process. This would be used for the first initial allocation covering the current and the next two subsequent years as well as each year for the next year for which no allocation has so far been made[21]. The reasons are due to:

(a) Possible monopolisation of the rights by one or small number of bidders.

(b) An auction process does not guarantee Transpower is able to fully recover the cost of the HVDC link as participants would bid up to the expected value of the link which could be less than Transpower's revenue requirement (especially after the HVDC link is upgraded).

3.2.5 The advice is not clear about the process used to allocate the rights. To ensure consistency with the user identification process, it is felt that a similar two-solve process should also be used for the initial allocation. This however introduces additional practical issues that would need to be addressed.

3.2.6 For the first allocation, historical solves required to determine the historical usage need to be updated to address the non-dispatchable issues raised in 3.2.2 and 3.2.3. This would require some additional information on actual outputs and

[17] Interruptible loads are also dispatched for IR. In the future demand response could also be dispatchable.

[18] This includes peaking generation.

[19] Generators less than 10MW are not required to submit an offer to be dispatched under the current rules.

[20] There would also need to be changes to the market databases that provide and receive information from the MCE.

[21] In the NZIER advice, capacity rights would be allocated 3 years in advance.

short-run marginal costs (SRMC) of previous non-dispatchable generators. Based on this a historical two-solve process could be utilised to identify the HVDC capacity right requirements of the various participants.

3.2.7 An issue identified in the NZIER advice with the proposed allocation process is the potentially adverse impact on new entrant generators. Since the allocation process is based on a measure of historical usage new entrants would inevitably be omitted under the proposed allocation process. A possible way to address is to make some provision for the allocation of HVDC capacity to new entrants based on expectation on availability and expected output. Penalties could also be applied for misleading the market[22].

Suggested solution to capacity rights requirement and allocation problem

3.2.8 The representation of wind generators would need to be changed from negative loads to dispatchable generation within the final pricing process. This would require changes to the market system include the MCE.

3.2.9 The proposed allocation and utilisation process is based on the generators being dispatchable. Under the current market rules, generators less than 10MW are not required to submit an offer to be dispatched. To correct for this the minimum MW threshold for non-dispatchable generators needs to be reduced in the market rules. There are implementation and transaction costs associated with this change that would need to be included as part of the capacity rights evaluation.

3.2.10 To provide capacity to new entrant generation residual link capacity could be made available based on a usage estimate. This would require that not all of the capacity of the HVDC link is allocated.

3.3 Dispatch inefficiencies

3.3.1 To ensure an efficient allocation of system resources during this dispatch process, the MCE, which is used to dispatch the wholesale electricity market, needs to co-optimise the energy, instantaneous reserves (IR) and HVDC capacity rights market.

3.3.2 This co-optimisation is implied in the NZIER advice[23]. Furthermore, analysis[24] by the Electric Power Optimisation Centre (EPOC) indicated a need to introduce a balancing market to enable the reallocation of HVDC capacity rights with energy and IR co-optimisation based on an assumed pre-allocation of HVDC capacity rights. This is equivalent to the co-optimised energy, IR and HVDC capacity rights process as outlined in the NZIER advice and proposed in this analysis.

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[22] This proposed NZIER solution was provided in a subsequent note from NZIER (05 December 2010).

[23] Following advice from the December 2010 Transmission Pricing Technical Group (TPTG) meeting, there was a discussion between the Electricity Authority (EA), NZIER and Electric Power Optimisation Centre (EPOC) to address the possible discrepancies in the interpretation of the proposal.

[24] "Allocating physical capacity rights on an electricity transmission line", Andy Philpott, Le Nguyen Hoang, 4 August 2010.

3.3.3 Co-optimisation of the three markets would require some changes to the System Operator (SO) market systems including the market clearing engine (MCE). The MCE would need to include the HVDC capacity rights bids and offers. Adjustments to the MCE mathematical model would also be necessary. This would include adjusting the objective function to ensure the total welfare of the energy, IR and HVDC capacity rights market is maximised. Additional variables and constraints would also be required in the MCE to ensure a feasible system dispatch. Such changes within the market system would require extensive testing to ensure a robust model design.

Suggested solution to prevent inefficient dispatch

3.3.4 To ensure an efficient system dispatch it is proposed that the energy, IR and HVDC capacity markets are co-optimised. This is consistent with the NZIER advice and analysis from EPOC. This would require non-trivial changes to the mathematical model of the market clearing engine.

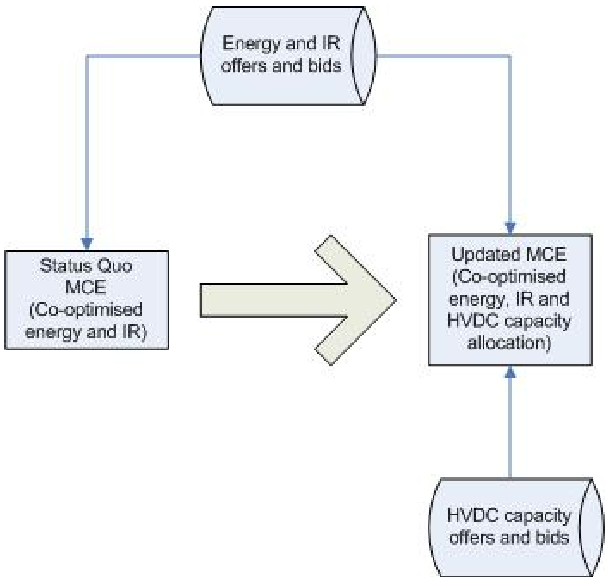

Figure 4: Co-optimised MCE (energy, IR and HVDC capacity)

3.4 Market Prices

3.4.1 In the current pricing process, the nodal energy and island IR market prices are produced from the final pricing solve of the MCE. The energy and IR prices currently reflect the trade-offs between energy and IR resources to satisfy the energy and IR requirements at the respective locations. These provide consistent pricing signals to participants offering in both markets.

3.4.2 The introduction of HVDC capacity rights in the dispatch process would now create a stronger link between the HVDC capacity price and the wholesale energy and IR prices.

3.4.3 On average it is expected that the price paid by sending island loads would increase relative to receiving island loads when the HVDC link is constrained. This is due to the physical nature of the rights offered by the capacity rights proposal. During times of constrained HVDC flow, it is expected that the HVDC capacity price will rise to the difference between the short-run marginal cost (SRMC) of the marginal receiving island generator and the marginal sending island generator. However, under the capacity rights market regime there is a stable market equilibrium where the marginal sending island generator can increase its offer price so that it is indifferent to earning the revenue on the energy market (at the receiving island price) or on the HVDC capacity market. The following example provides a more detailed illustration of this effect.

3.4.4 Scenario 1: Consider two sending island hydro participants (A and B) that have a similar SRMC. Both these participants are long on generation in the sending island and would therefore benefit from an increase in wholesale electricity prices in the sending island. Due to the historical utilisation of the HVDC, participants A and B are allocated 70% and 30% respectively of the available HVDC capacity rights. During periods of surplus storage (with risk of spill), the SRMC of these generators would be zero (or close to it). Due to sufficient water it is expected that the HVDC link would be constrained and the likely receiving island price would rise to $1,000/MWh (due to marginal thermal peaking plant in the receiving island). Consider where both participants A and B would offer in the capacity for the local load at SRMC ($0/MWh) and the additional capacity for which they own HVDC capacity rights at the expected receiving island price ($1,000/MWh).

3.4.5 The profit of participant A is:

Profit A_1 = MWh generation from A x $1,000/MWh

= (70% x sending island demand x $1,000/MWh)

+ (70% x HVDC flow x $1,000/MWh)

Where MWh generation from A comprises of the amount of energy used to satisfy the sending island demand and the amount sent across the HVDC to the receiving island[25].

3.4.6 The profit of participant B is:

Profit B_1 = MWh generation from B x $1,000/MWh

= (30% x sending island demand x $1,000/MWh)

+ (30% x HVDC flow x $1,000/MWh)

3.4.7 For each MWh transfer across the HVDC, participant A's profit increases by $1,000/MWh. Therefore, A would be willing to give up this right at this

[25] The impact of transmission losses have been omitted for the sake of clarity. It does not however change to thrust of this discussion.

opportunity cost. This translates to participant A offering its HVDC capacity right at $1,000/MWh with a corresponding bid for these rights.

3.4.8 Similarly, participant B will value its HVDC capacity rights accordingly and offer into the market at $1,000/MWh (difference between the expected receiving island price and its SRMC) with an appropriate HVDC capacity bid to win this right.

3.4.9 Under this scenario both participant A and B would be dispatched. The sending island price would be equal to the receiving island price ($1,000/MWh) and the price of the HVDC capacity rights would be at the market determined opportunity cost of $1,000/MWh (difference between the SRMC of the marginal receiving island generator and marginal sending island generator).

3.4.10 Scenario 2: Consider the case where participant A attempts to reduce its energy offer price (below B but above its SRMC e.g. $500/MWh) in an attempt to increase profits. Since both participant A and B have the same offer price for the local island load, they will still be scheduled at 70% and 30% respectively to serve the local load in the 1st solve. However for the additional transfer across the HVDC (i.e. the 2nd solve) it is possible that participant A output could increase above its share of the HVDC capacity rights. In order to procure these rights, A needs to bid for the rights of B. Since B is willing to accept $1,000/MWh this implies that for each additional MWh above its 70% allocation of HVDC capacity rights, A would incur an additional $1,000/MWh cost (due to purchasing the HVDC capacity rights at its opportunity cost). The profit of A under this scenario would be:

Profit A_2 = MWh generation from A x $500/MWh

- MWh HVDC capacity rights purchased from B

= (70% x sending island demand x $500/MWh)

+ (70% x HVDC flow x $500/MWh)

+ (30% x HVDC flow x ($500/MWh - $1,000/MWh)

3.4.11 The profit of participant B is:

Profit B_2 = MWh generation from B x $500/MWh

+ MWh HVDC capacity rights sold to A x $1,000/MWh

= (30% x sending island demand x $1,000/MWh)

+ (30% x HVDC flow x $1,000/MWh)

3.4.12 Participant A experiences a loss for each additional MWh of HVDC capacity rights purchased from B if it tries to purchase the HVDC capacity rights at the market determined price and offers in its energy at less than the expected receiving island price. Note participant B is also worse off due to the lower energy price being set by A. In this scenario both participants are worse off than in Scenario 1.

3.4.13 Scenario 3: Consider the case where participant A attempts to increase its energy offer price above the expected NI price (e.g. above $1,000/MWh). In this case participant A would not be scheduled for the additional transfer in the 2nd solve. Participant B with a lower energy offer price (at $1,000/MWh) with a corresponding bid for the HVDC capacity rights at its opportunity cost ($1,000/MWh) will be scheduled together with additional receiving island generation. Note that if B is unable to utilise all of A's HVDC capacity rights due to its generation capacity limits then receiving island generation could be utilised to satisfy the residual NI load at the expected price of $1,000/MWh. In this case the profit of participant A would be:

Profit A_3 = MWh generation from A x $1,000/MWh

+ MWh HVDC capacity rights sold to B

= (70% x sending island demand x $1,000/MWh)

+ min[B residual export capacity, (70% x HVDC flow)] x $1,000/MWh

Where participant B's residual export capacity relates to the amount of capacity that B is able to export to the receiving island in addition to its 30% supply of the local load and its 30% export on the HVDC link given its generation capacity limits.

3.4.14 The profit of participant B is:

Profit B_3 = MWh generation from B x $1,000/MWh

- MWh HVDC capacity rights purchased from A x $1,000/MWh

= (30% x sending island demand x $1,000/MWh)

+ (30% x HVDC flow x $1,000/MWh)

+ (B residual export capacity x ($1,000/MWh - $1,000/MWh))

3.4.15 Participant A experiences a loss of profit in this scenario versus scenario 1 since it increased its price above expected receiving island price. Note participant B does not experience a loss of profit relative to Scenario 1.

3.4.16 Therefore, given the market determined opportunity cost of the HVDC capacity rights rises to the difference between the SRMC of the marginal receiving island and sending island resources, it is likely that the marginal sending island generator would increase its offer price for that portion which it owns HVDC capacity rights to reflect its indifference to earning the revenue on the energy market or on the HVDC capacity rights market. Offering at more or less than this would not be a profit maximising strategy.

3.4.17 It is possible that sending island loads could acquire these rights and hold onto them in an effort to reduce spot energy prices. However the sending island generators would only be willing to give up these rights at its opportunity cost. In this case the resulting spot energy prices would be lower but the increased cost to sending island loads would now be incurred in the secondary HVDC capacity rights market.

3.4.18 These increases in costs to sending island loads during times of constrained HVDC flow could be particularly large with the introduction of scarcity pricing. It is possible that during times of island-wide shortages, the energy prices in that island could reach at least $10,000/MWh. It is also likely that during these times the HVDC flow into the receiving island is constrained and therefore the above situation could arise where the value of the HVDC capacity right could rise to close to the scarcity price in the shortage island.

3.4.19 Under the status quo open transmission access arrangements, both participants A and B with knowledge of a binding HVDC constraint could both offer in capacity at the expected NI price. However the lack of a physical capacity right on the HVDC implies that if either A or B were to reduce its offer price below the expected NI price (and at least its SRMC) they would be able to increase output and increase profit. Thus the status quo open transmission access arrangement provides greater pressure on participants to offer energy at SRMC in the sending island even it times of constrained HVDC flow and thus better preserve locational marginal prices.

3.5 Cost recovery with the expanded HVDC link

3.5.1 The upgrading of the converter stations at Benmore and Haywards increases the capacity of the HVDC link to 1000MW from 2012 and thereafter to 1200MW from 2014. There are future plans to increase the HVDC transfer to 1400MW by adding new undersea cables[26].

3.5.2 This increased transfer capability would reduce the inter-island price differential. There is a concern in the NZIER advice that this increased HVDC capacity would exceed the demand of HVDC capacity rights and therefore result in a price for the HVDC capacity right that does not allow Transpower to fully recover the HVDC costs.

3.5.3 To address this, the advice proposes to reduce the HVDC capacity offered in the initial allocation process based on an expected utilisation of the link over several market development scenarios (MDS) that are produced as part of the Statement of Opportunities (SOO). The expected utilised capacity would be less than the installed capacity and would be used to induce a price to increase the likelihood of Transpower being able to recover the required HVDC revenue (at the unit price) in the initial allocation process. The additional capacity would be made

[26] Information available from www.gridnewzealand.co.nz/f3682,41254891/HVDC_Pole_3_Fact_Sheet2_-26_Nov10.pdf

available by Transpower in the subsequent secondary and spot auctions at a price greater than the initial allocation unit price (e.g. 100% above the unit price).

3.5.4 An issue with this approach is that the market development scenarios are developed using long-term models with different input assumptions (for each scenario) and provide an aggregate usage level. Therefore actual utilisation in a given year could vary quite substantially from the expected utilisation over the different market development scenarios. The impact of this is under the proposed process is that the spot energy prices would now be influenced by the accuracy of this estimated expected HVDC utilisation.

3.5.5 If the actual HVDC flow exceeds these estimated average flows, then the market participants would need to purchase the additional HVDC capacity rights off the secondary and spot markets. If the price of this additional HVDC capacity rights is twice the initial allocation price, then this additional variable cost would need to be accounted for in the sending island offer prices. The impact of this is that the spot energy price would be greater by the amount the HVDC capacity rights price was increased in the secondary and spot markets.

3.5.6 As an example, it is expected that the HVDC revenue requirement in 2012 (after the capacity upgrade) would be $149 million[27] with an average HVDC usage of 364MW[28] this translates to a unit variable cost of ~$46/MWh. If the additional HVDC capacity was offered at 100% of this price by Transpower in the secondary and spot HVDC capacity rights markets, this would imply an HVDC capacity rights price of $92/MWh in these markets. Therefore for a south-to-north flow scenario, of the HVDC transfer was at 364MW, the marginal south island generator wanting to increase its output further to supply the north island load would need to purchase the additional HVDC capacity rights at $92/MWh. In order to absorb this additional variable cost, the south island generator would need to increase its offer price by at least this amount. If the SRMC of the south island generator was close to $0/MWh (due to high hydro levels) and if the marginal south island generator was marginal in the north island (even with the additional cost of the spot HVDC capacity rights at $98/MWh) then this would result in the national energy price being linked to the spot HVDC capacity price (i.e. $92/MWh). If this was a low load period where the national spot price could be set by a marginal south island generator (at zero or close to it) the additional cost then imposed on the energy market would be $92/MWh * 1450MWh[29] ~ $130,000 for a 30 minute trade period.

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[27] This is based on Transpower revenue projections (March 2011).

[28] The vSPD model was executed from 2009 to 2011 using actual market offers and system loads. The average northward flow for this period was 350MW. Assuming a 4% adjustment factor to cater for load growth in the north island being supplied via the HVDC this would translate to an expected average usage of 364MW for northward flow. Note there is a 4% increase in the energy consumption for 2012 compared to the average energy for 2009, 2010 and 2011. Energy forecast information is available from www.ea.govt.nz/industry/modelling/demand-forecasting/.

[29] The national load is likely to be around 2900MW for an off peak period which translates to 1450MWh of energy for a 30 minute interval.

3.5.7 If the spot price of the additional HVDC capacity is not increased relative to the initial allocation price to minimise the distortionary effect on the spot energy prices, then the risk is that participants, in the expectation of excess HVDC capacity would purchase the required amount at the unit cost on the spot market. Since this would typically be less than the HVDC capacity, Transpower would likely experience a shortfall in its revenue requirements to cover the HVDC costs.

3.5.8 Even if the spot price of the additional HVDC capacity is increased (as per the advice) but the average estimated usage of the HVDC (used to derive the unit cost) exceeds the market's expectation then it is possible that Transpower could still experience a revenue shortfall as the allocation of HVDC capacity rights would not be taken up in the initial offering or in the subsequent auctions at the elevated price.

3.5.9 Therefore, the proposed advice does not entirely eliminate the revenue risk to Transpower to cover the full costs of the expanded HVDC link but it also has the added disadvantage of exposing spot energy prices to the accuracy of this estimated average expected usage.

3.5.10 On balance it is proposed that the available HVDC capacity be utilised in the initial allocation. This does increase Transpower's exposure to a risk in recovering the HVDC costs and to address this, it is proposed that these shortfalls be recovered via the interconnection charges. Although there is some benefit from reduced transaction costs from this approach it is believed that the major benefit would be a reduction in the distortion of the wholesale energy market prices.

Suggested solution for the cost recovery of the expanded HVDC link

3.5.11 It is proposed to offer in the full available capacity of the HVDC link in the initial allocation process and recover any shortfall in the HVDC revenue requirements via an interconnection charge. It is felt that this would be less distortionary on the wholesale energy market prices.

3.6 FTRs and HVDC Capacity Rights

3.6.1 NZIER has proposed that a benefit of the HVDC capacity rights approach is that it may assist participants to manage locational price risk and therefore avoid the need to create and trade Financial Transmission Rights (FTRs) relating to inter-island price risk.

3.6.2 The proposed FTR arrangements are designed to manage locational price risk between the generation centre in the south island (Benmore) and the load centre in the north island (Otahuhu). This also aligns with the nodes used for the electricity futures and options contracts traded on the Australian Stock Exchange (ASX).

3.6.3 The HVDC capacity right however only provides capacity rights between the HVDC link terminal nodes (Benmore and Haywards). Therefore participants

3.6.4 Given this it is proposed to maintain an FTR product to allow participants to fully manage their locational price risk between Benmore and Otahuhu. This would improve the ability to hedge between the generation centre in the south island and load centre in the north island. This also aligns with the energy futures markets and therefore would increase the ability of participants to trade in these markets therefore increasing liquidity and competition.

Suggested solution to the locational price risk problem

3.6.5 Maintain an FTR product to allow participants to manage locational price risk between the south island generation centre (Benmore) and the north island load centre (Otahuhu). This would also assist with the competitiveness of the energy futures and options contract markets.

3.7 HVDC capacity rights and system security

3.7.1 Since HVDC capacity rights is an entitlement to the physical capacity on the link, if there is limited HVDC capacity offered into the market there could be a compromise on system security.

3.7.2 While withholding HVDC capacity is unlikely it would be prudent to enforce mandatory offering of all HVDC capacity during any initial implementation of a capacity rights market. The mandatory offer process could be relaxed as the HVDC capacity rights market matures.

3.7.3 In addition to this it is proposed to modify the market clearing engine (MCE) to always enable utilisation of the HVDC up to its available capacity. This is feasible for the HVDC as Transpower will always be fully aware of its operational limits. The adjustment to the MCE would involve including additional violation variables with an associated constraint violation price (CVP). These violation variables would enable capacity in excess of that offered (but not exceeding the available operational capacity) to be included within the market dispatch process. These CVPs would need to be ordered with the other model CVPs. It is proposed to set these CVPs lower than those used for IR reduction. This would ensure that, if needed, the full HVDC capacity would be utilised prior to operating the system with reduced instantaneous reserves or curtailing demand.

Suggested solution to the system security issue

3.7.4 Implement a mandatory offering of all purchased HVDC capacity rights into the market. This could be relaxed once there is greater confidence in the HVDC capacity market matures. It is proposed to implement additional functionality within the MCE to enable full utilisation of the HVDC link (even after any mandatory offer process is relaxed). This would require some changes to the MCE but would ensure that in all cases the full operational HVDC capacity would be utilised prior to any IR reduction or demand curtailment.

4. HVDC capacity rights design modifications

4.1.1 The following section summarises and further considers the high level design modifications for the HVDC capacity rights process that addresses the issues highlighted in the above analysis.

4.1.2 Two-solve process: If the capacity rights allocation process is based on a two-stage solve of the MCE, these allocations would need to be adjusted for intra-island losses, constraints and co-optimised energy and IR effects. Further modifications would also be required to ensure feasibility of the 1st solve in this process. This however would introduce an intra-island locational signal where generators closer to loads would require less HVDC capacity rights than those further away from loads.

4.1.3 Capacity rights requirement and historical allocation: Adjustments to the market systems (including the MCE) and the market rules would be needed to ensure HVDC capacity rights are allocated to (and required from) from current non-dispatchable generators and wind generators. This is due to the design of the current final pricing process and market rules. Some provision for new entrants would also need to be made in the allocation process as they would be disadvantaged under the allocation process.

4.1.4 Dispatch efficiency: To ensure an efficient system dispatch is maintained, it is proposed that the energy, IR and HVDC capacity rights markets are co-optimised within the MCE. This would require some non-trivial changes to the MCE including changes to the mathematical formulation. This approach is consistent with the NZIER advice and analysis from EPOC.

4.1.5 Cost recovery with the expanded HVDC link: To minimise the impact on the wholesale energy market it is proposed that the full available HVDC capacity be utilised in the allocation process. If Transpower is unable to fully recover the cost of the HVDC it is proposed to adjust the interconnection charges to enable full cost recovery.

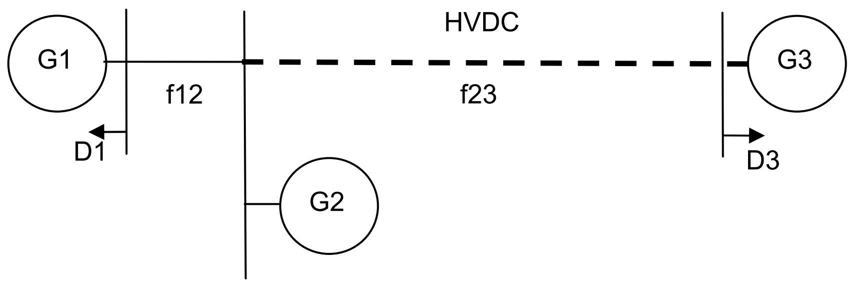
4.1.6 Financial transmission rights: It is proposed to maintain an FTR product to enable participants to fully hedge locational price risk between the generation centre in the south island (Benmore) and the load centre in the north island (Haywards). This also aligns with the energy futures and options contract markets which would increase the ability of participants to offer at these nodes thus improving the energy futures and options contract market liquidity and competition.

4.1.7 HVDC capacity rights and system security: To address any possible security implications due to the full operational capacity not being offered it is proposed to implement a mandatory offer process for HVDC capacity rights. This could be relaxed once the HVDC capacity rights market matures. In addition to this it is proposed to modify the MCE to always enable the dispatch process to utilise the full operational capacity of the HVDC to avoid the need for reduced IR operation or demand curtailment.

Appendix A

Loss example

A.1.1 The following simple example is used to illustrate the impact of losses on change in output between 1st and 2nd solves.



All branch resistance = 0.01per unit

Figure 5: Simple illustrative example to illustrate loss effect

A.1.2 Assume:

(a) D1 = 99MW and D3 = 99MW

(b) G1 offers in 99MW at $15/MWh

(c) G2 offers in 100MW at $10/MWh and a further 50MW at $20/MWh

(d) G3 offers in 150MW at $30/MWh

A.1.3 In the 1st solve (no HVDC) the economic scheduling results in the following:

(a) G2 is scheduled to supply all of D1: $g_2^1 = D1 + Loss_{21}^1 = 99 + (1^2) = 100MW$

(b) G3 supplies D3: $g_3^1 = D3 = 99MW$

(c) G1 is not scheduled: $g_1^1 = 0$

(d) Flow from 2 to 1 is: $f_{21}^1 = 100$ MW and due to branch losses only 99 MW reaches node of generator 1

(e) Since there is no HVDC capacity: $f_{23}^1 = 0$

A.1.4 In Solve 2 (with HVDC) the economic scheduling results in the following:

(a) G1 is scheduled: $g_1^2 = D1 = 99MW$

(b) G2 is scheduled: $g_2^2 = D3 + Loss_{23}^2 = 99 + (1^2) = 100MW$

(c) G3 is not scheduled (due to high offer price): $g_3^2 = 0$

(d) Flow between 1 and 2 is now: $f_{21}^{2} = 0$

(e) Flow from 2 to 3 (HVDC): $f_{23}^{2} = D3 + Loss_{23}^{2} = 100MW$

A.1.5 Comparing these two solves it would be determined that G1 requires HVDC capacity rights since its output increases in the second solve. There is a valid argument (no doubt by G1) that there is no flow on the branch between node 1 and 2 ($branch_{12}$) and with the output from G1 being equal[30] to the local load there is no utilisation of the intra-island branch by G1 and by implication no utilisation of the inter-island link by G1 (i.e. all output from G1 is used to supply the load at the local node L1). Put another way, even if the $branch_{12}$ were taken out of service during this time, the output of G1 and the flow on the HVDC would not be affected therefore none of the output from G1 has no effect on the flow on the HVDC link.

Instantaneous reserve example

A.1.6 The following simple example is created based on an observed instance from implemented two-solve process.

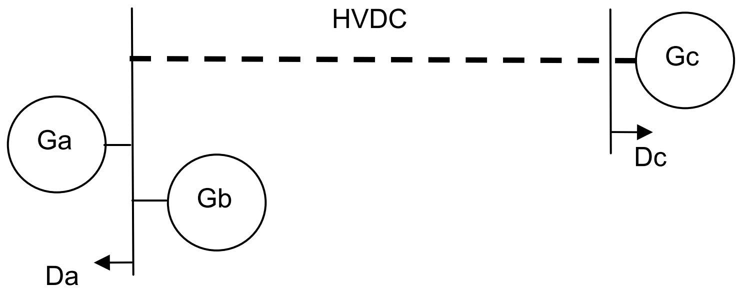


Figure 6: Simple illustrative example to illustrate IR constraint effect

A.1.7 Assume:

(a) Da = 50MW with an IR requirement = 5MW

(b) Dc = 100MW with an IR requirement = 50MW

(c) Ga offers in 100MW at $1/MWh for energy with PLSR[31] = 5%

(d) Gb offers in 100MW at $2/MWh for energy with PLSR = 50%

(e) Gc offers in 100MW at $10/MWh for energy with 50MW at $1/MW for IR

A.1.8 In the 1st solve (no HVDC) the economic scheduling results in the following:

[30] This is consistent with the definition of the power flow problem where net injection at a node is deemed to flow on the connecting branches.

[31] Partially loaded spinning reserve (PLSR): Refers the amount of spinning reserve available as a proportion of scheduled energy.

(a) Ga = 44.44MW for energy and 2.22MW for IR

(b) Gb = 5.56MW for energy and 2.78MW for IR

(c) Gc = 100MW for energy and 50MW for IR

A.1.9 Even though Gb is more expensive that Ga, output from Ga is needed to satisfy the IR requirements for the 1st solve. This is because of the IR constraints on the offers.

A.1.10 In the 2nd solve (with HVDC) the economic scheduling results in the following:

(a) Ga = 100MW for energy and 5MW for IR

(b) Gb = 0MW for energy and 0MW for IR

(c) Gc = 50MW for energy and 50MW for IR

A.1.11 Now the increase in the output from Ga in the 2nd solves alleviates the need to scheduled Gb since the increased energy output from Ga is sufficient to enable the IR requirements in the sending island to be satisfied.

A.1.12 If one were just to look at the increase in sending island generation, the total increase in Ga = 100-44.44 = 55.56MW. Expecting Ga to purchase HVDC capacity rights to cover this increase would be invalid since 5.56MW of its increased output was used to satisfy the local load (since Gb is now scheduled down). Therefore it is more appropriate to consider the net increase in the sending island generation (i.e. Ga scheduled up – Gb scheduled down = 55.56-5.56 = 50MW).

A.1.13 In this simple example, the allocation of this offset is trivial but this could be more challenging when this needs to account for losses and allocated to many generators.

Practicalities of the 1st solve – Non-physical losses

A.1.14 There are practical issues that can arise as part of the 1st solve if there is an excess of generation offered in at zero price.

A.1.15 The first issue is the possibility that the 1st solve could contain non-physical losses[32]. Non-physical losses are a mathematical anomaly that could arise in the market clearing engine (MCE) solution when an increase in transmission losses results in no change or a reduction in system costs.

A.1.16 This anomaly can occur in NZ-wide solutions, but the likelihood of these events increases if each island is solved separately as is the case for the 1st solve in the two-solve process. This is particularly the case for periods of surplus SI generation where large amounts of SI hydro generation are offered in with a zero

[32] Transpower, Scheduling, Pricing and Dispatch Software Model Formulation, 15 February 2008. Available at www.ea.govt.nz/industry/mo-service-providers/system-operator-market-operation-sevice-provider/

price. The problem is worsened by the presence of other must run frequency keeping generators in the island. The cumulative effect is that these zero price generators (with the must run generation) could be sufficient to supply the SI load thus resulting in a market price of zero in the sending island for the 1st solve.

A.1.17 The result of non-physical losses is that the scheduled generation is greater than what it should be since these are providing for load, losses and now non-physical losses.

A.1.18 To illustrate this issue[33], the two solve process was executed[34] for 31 August 2009 TP44. The results are as follows:

A.1.19 Total SI generation: 1st solve = 1789MW, 2nd solve = 2221MW, Change = 432MW

4.1.8 Total HVDC S→N flow (from 2nd solve) = 593MW

A.1.20 The change in total SI generation does not correspond to the change in HVDC flow. The results of this two-solve comparison indicates that a change of 432MW in SI generation results in 593MW of S→N HVDC flow. This is because the 1st solve contains non-physical losses in the intra-island AC SI network thus resulting in the total SI generation from the 1st solve being greater than what it should be. The result of this is that in these cases the change in output cannot be reconciled against the flow on the HVDC from the 2nd solve due to the invalid 1st solve solution.

A.1.21 To correct this issue would require an alteration of the current market clearing engine (MCE) to resolve non-physical losses on all loss branches. In the current MCE non-physical losses are only corrected on the HVDC[35]. Correcting for non-physical losses on all AC branches would increase the computational effort[36] in clearing the market and lead to an increase the solve times to obtain an optimal solution. These increases need to be feasible for the market clearing process times (e.g. for the 5 minute dispatch process).

A.1.22 Even with the correction of non-physical losses, another issue that could arise - that of multiple solutions[37] in the 1st solve solution. If the cost of providing load and losses is zero in the SI for the 1st solve, then there could exist many combinations of generation patterns to serve the SI load and losses (at zero total cost) whilst still satisfying the SI constraints.

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[33] This is also illustrated by the fat tail that exists in the analysis conducted for northward flow scenarios.

[34] Using the EA vectorised schedule, pricing and dispatch (vSPD) model.

[35] As indicated in the SPD formulation document.

[36] Resolving non-physical losses requires the introduction of integer variables for each branch and solving the problem as a mixed-integer linear program. This is generally a much harder problem to solve than a simple linear program thus requiring longer solve times. The impact of this on the dispatch process needs to be evaluated.

[37] The likelihood of multiple solutions in the 1st solve is more likely due to relative size of generation to load in the SI when there is surplus water and significant generation offered at zero price. This same situation would not be the case in the 2nd solve since the total SI generation

A.1.23 The following example is a simplification of the actual zero priced offers and must run constraints from 31 August 2009 TP 44[38]. The metered SI demand was 1552MW.

Participant	Zero Price Offer (MW)	Solution 1	Solution 2
1	1345	1042	1024
2	510 (must run)	510	510
3	18	0	18

Table 1: Multiple solution illustration

A.1.24 If the MCE returns one of the solutions (with many others that exist) then there could be some debate as to why this particular solution was selected over another especially as its selection would now affect the need for HVDC capacity rights when this output is compared to the 2nd solve.

A.1.25 Another approach to resolving this issue together with non-physical losses would be to ensure that all offers are greater than zero, in the scheduling, pricing and dispatch processes. Thus the 1st solve reverts to an island-wide loss minimisation problem where generators closer to load centres would be scheduled in favour of those further away. This however implies that in the 2nd solve, generators further from the load centres would be deemed as requiring more HVDC capacity than those closer to load centres. This provides an unintended intra-island locational signal which could be debatable.

Incentives on generators to increase energy offer prices for HVDC capacity required from the spot market

A.1.26 The following example considers the incentives on generator energy offers when bidding for HVDC capacity from the spot market to support this energy output.

(a) G_1 = MW output of generator in the 1st solve

(b) G_2 = MW output of generator in the 2nd solve

(c) C = energy offer price of generator ($/MWh)

(d) MC = marginal costs of generator ($/MWh)

(e) D(Q') = increased energy offer price of generator for Q' MW

(f) Q = HVDC capacity rights already held by the generator (MW)

(g) Q' = HVDC capacity rights not already held by the generator (MW), $Q' = G_2 - G_1 - Q$

[38] Losses have been omitted for ease of illustration.

(h) λ_S = market determined price for energy at the sending island

(i) P_{HVDC} = market determined price for HVDC capacity

A.1.27 The wholesale electricity market payoff of this generator under the HVDC capacity rights proposal would be:

(a) $PayOff_{HVDCCapacityRights} = (\lambda_S - MC)G_2 + P_{HVDC}(Q) - P_{HVDC}(Q+Q') = (\lambda_S - MC)G_2 - P_{HVDC}(Q') = \lambda_S(G_1+Q) + (\lambda_S - P_{HVDC})Q' - MC(G_1+Q+Q')$

A.1.28 We now explore the incentives on the offers from this generator based on it trying to maximise its market payoff.

A.1.29 <u>Scenario 1: $\lambda s < C$:</u> This implies that the generator is not scheduled and therefore the payoff from the market is zero.

A.1.30 <u>Scenario 2: $\lambda s = C$:</u> The generator is scheduled for G1 and G2.

(a) If G2-G1<=Q then PayOff = $(C-MC)G_2 <= (C-MC)(G_1+Q)$

(b) If G2-G1>Q then PayOff = $(C-MC)G_2 - P_{HVDC}Q' = (C-MC)(G_1+Q) + Q'(C-MC-P_{HVDC})$

A.1.31 If the generator offers in at marginal cost C=MC, then if the HVDC utilisation of the generator exceeds its already purchased HVDC capacity rights (Q) the additional utilisation (Q') reduces the generator payoff (PayOff = $-Q'P_{HVDC}$).

A.1.32 <u>Scenario 3: $\lambda s > C$:</u> The generator is scheduled for G1 and G2.

(a) If G2-G1<=Q then PayOff = $(\lambda_S-MC)G2 <= (\lambda_S-MC)(G_1+Q)$

(b) If G2-G1>Q then PayOff = $(\lambda_S-MC)G2 - P_{HVDC}Q' = (\lambda_S-MC)(G_1+Q) + Q'(\lambda_S - MC-P_{HVDC})$

A.1.33 Again this implies that if the HVDC utilisation of the generator exceeds its purchased HVDC capacity rights (Q) then this additional utilisation (Q') reduces the payoff if the difference between the local nodal energy price and its marginal cost is below the spot HVDC price, i.e. $\lambda_S - MC < P_{HVDC}$.

A.1.34 Therefore, if the generator offered at marginal costs C=MC but ensured that for any amount of generation greater than G_1+Q the offer price was increased by the expected HVDC capacity price ($C = MC+P_{HVDC}$) then the generator would be certain that if it were scheduled greater than G_1+Q, the nodal energy price λ_S would satisfy the requirement $\lambda_S >= MC+P_{HVDC}$ thus yielding a positive payoff from the increased output. That is, the energy price would always be sufficient to pay for the additional cost incurred in purchasing the spot HVDC capacity rights.

A.1.35 Therefore, for a rational generator there is an incentive to increase its energy offer price above marginal costs for that quantity that requires HVDC capacity off the spot market. Furthermore, this increase is the expected HVDC capacity price.