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Modelling of Instantaneous Reserve Sharing via HVDC link in the New Zealand Power System

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Abstract—**New Zealand's current electricity market design co-optimises energy and instantaneous reserve with the limitation that the majority of reserve must be located in the same island as the risk itself. The current market design allows the HVDC link to share only a small amount of reserve between islands. Future upgrade plans for the link may allow for greater levels of reserve sharing during contingent events such as a generator tripping. The ability of a future bipole link to share instantaneous reserve has the potential to reduce costs by reducing the level of reserve procured by the market. Testing this intuitive assumption of cost reduction may be achieved through long term economic modelling and simulation of the proposed new market design. This paper describes the current market and modelling design and outlines the additional constraints and economic modelling of an instantaneous reserve sharing market design. The value of reserve sharing is tested via a small case study using Plexos^{TM}[1] software.**

Keywords: Power system modelling, Power system economics, Reserve sharing, Cooptimisation, HVDC

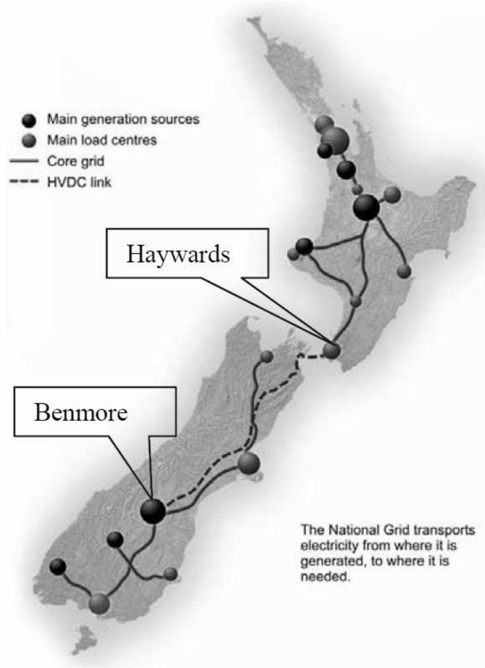

Figure 1: New Zealand Map and HVDC Link [2]

1 Introduction

The New Zealand power system is characterised by a long, stringy transmission grid running the length of the North and South Islands. The AC grid infrastructure in each island is connected via an HVDC link running between Benmore in the South Island and Haywards in the North Island shown in Figure 1. The current configuration of the HVDC link consists of two paralleled, mercury arc valve poles, Pole 1, running in parallel with a newer thyristor based pole, Pole 2. The mercury arc valve poles are currently in limited operation and are being decommissioned and replaced via a staged program with a new thyristor pole [3]. The new pole, Pole 3, will operate in parallel with the existing thyristor pole, Pole 2, resulting in a symmetric thyristor bipole configuration at project completion. The development of the technical specification for the new HVDC pole has highlighted how the new bipole configuration could provide additional functionality to the New Zealand market particulary in the areas of frequency regulation and reserve sharing between islands.

The current market design co-optimises energy and instantaneous reserve with energy transfer between islands restricted by HVDC capacity. Reserve sharing between islands is ultimately limited by HVDC capacity but is more constrained by operational restrictions of the HVDC and generator governor settings. Instantaneous reserve is dispatched to cover a reserve risk in the North Island and a reserve risk in the South Island. Intra-island constraints are not considered when allocating reserve provision. The North Island reserve risk is defined as the larger of, the loss of the largest North Island CCGT unit or the tripping of a single HVDC pole when in northward transfer. The South Island reserve risk is defined as the larger of, the loss of the largest generating unit[1] or the loss of a single HVDC pole in southward transfer.

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[1]The South Island has no large CCGT units as the majority of generation is hydro.

The HVDC can currently share a small level of fast reserve between islands, around 25MW in summer and 50MW in winter. This reserve sharing occurs through the frequency modulation functionality of the HVDC. A drop in frequency in one island is compensated for by a combination of spinning reserve provision and the HVDC ramping power transfer up or down (depending on direction of flow) in the opposite island. The level of reserve sharing that occurs is a result of both increased power transfer from increased generation, via governor control in the exporting island, and a small reduction in exporting island frequency.

The new thyristor bipole configuration and upgraded control systems of Pole 2 and Pole 3 may have extended capability to allow greater levels of sustained instantaneous reserve sharing between islands. Quantifying the cost benefits that reserve sharing could provide is an initial step in identifying if reserve sharing via the HVDC link would be a valuable enhancement to the New Zealand market design.

While reserve sharing between regions is not novel[4][5] the New Zealand system presents unique challenges. The system is small with a peak winter demand of slightly less than 7000MW[6] and is not interconnected with any other power system. The combination of these two factors mean that even small disturbances in generation output can have large impacts on system frequency.

Modeling how reserve sharing via the HVDC link may be implemented is the subject of this paper. The software Plexos is used to simulate the hourly short term operation of a nodal market that allows reserve sharing across the upgraded HVDC link. The remainder of this paper details calculation of reserve risk in the New Zealand electricity market, development and implementation of constraints that facilitate reserve sharing, a case study of the new market design and discussion of results.

2 Contingent Events, Reserve Dispatch and Modelling Implications

2.1 Contingent Events

Two types of contingent event are considered in the calculation of instantaneous reserve risk in the New Zealand market; a generator tripping, or a single pole tripping of the HVDC link[2]. The HVDC link operates bidirectionally and is therefore considered as a reserve risk in the receiving island. Currently the HVDC has no self cover ability due to the limited operation of the mercury arc valve pole, Pole 1. After the project to commission Pole 3 the HVDC bipole will be able to provide some self cover ability for a single pole tripping. The resulting level of reserve risk the HVDC poses will be less than the total power transfer of the link. Equations 1 and 2 show how the HVDC reserve risk is calculated and illustrate how spare capacity on the remaining in service pole can be used to cover power transfer on the tripped pole.

$$HVDC_{risk} \geq flow_A - (cap_B - flw_B) \quad (1)$$
$$HVDC_{risk} \geq flow_B - (cap_A - flw_A) \quad (2)$$

Where:
A, B = Pole A or B respectively
cap_A = Capacity of HVDC pole A
$flow_A$ = HVDC power transfer on pole A
$HVDC_{risk}$ = Reserve risk posed by HVDC

The larger of the two possible contingencies, generator or HVDC single pole tripping, sets the reserve risk for an island with a reserve risk being defined in both islands in all trading periods.

2.2 Reserve Dispatch

Operationally instantaneous reserve provision is split into two categories, Fast Instantaneous Reserve (FIR) and Sustained Instantaneous Reserve (SIR). FIR is designed to arrest the fall of frequency in an island in the 6 seconds following a contingent event. Providers are dispatched with the intention of keeping frequency above 48Hz during the excursion. SIR is dispatched to allow the island frequency to recover to at least 49.25 Hz within 60 seconds and must be available for at least 15 minutes after the event[11].

The characteristics of the New Zealand power system are such that reserve sharing is most likely to occur from the South Island to the North Island. The South Island has large amounts of hydro generation with low load whereas the North Island has a mixed generation profile of hydro, thermal, geothermal and wind with comparatively larger load centres. The speed at which hydro governors in the South Island can increase generation output in order to provide reserve for a North Island event is too slow to provide significant levels of FIR cover. Any potential for reserve sharing from the South Island to the North Island is modelled as being restricted to SIR only.

Long term economic modelling of power systems studies the costs of operating the power system over extended periods of time, usually greater than 20 years. The available computing resources restrict the level of detail at which the system can be studied. While the New Zealand power system can be re-dispatched as often as every 5 minutes (or less) if required, the long term economic models do not attempt to recreate this level of detail. A tradeoff of modelling accuracy versus efficiency of solution is necessary. The resulting long term economic models concentrate on modelling SIR rather than FIR. SIR dispatch is

[2] A bipole contingent event is considered an "extended contingent event" and is covered by various reserve providers and services such as AUFLS (Automatic Under Frequency Load Shedding) schemes

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approximated via optimisation models as half hourly or hourly modelling is possible for short periods of time, e.g. single year studies.

2.3 Modelling

The modelling described here represents the long term economic modelling approximation of a SIR sharing market across the HVDC link. The modelling assumes the commissioning of Pole 3 has occurred and that a symmetric bipole HVDC link is in operation. To model a SIR sharing market the current energy and reserve co-optimisation problem must be altered to allow South Island reserve to provide cover for North Island risks and vice versa. This is achieved by providing additional linear constraints to the model that focus on the reserve sharing limits dictated by HVDC capacity.

3 Modeling and Constraints

The constraints developed for a SIR sharing market are based around the need to identify the restrictions on the level of reserve sharing that is available. This is influenced by the available capacity, utilisation and control systems of the HVDC link. Currently the frequency modulation and reserve sharing functions of the HVDC can ramp HVDC power transfer up to a ±250MW hard limit though this level of transfer is not usual. This limit helps ensure stable HVDC operation. It is currently unknown if the new Pole 3 upgrade will continue to operate this hard limit and therefore has not been modelled in this research. If the limit is imposed the potential cost savings from reserve sharing would be reduced.

Existing market design requires the sum of instantaneous reserve provision to be greater than or equal to the reserve risk in each island. In the new market design this definition alters to incorporate the potential reserve sharing into an island. Equations 3 and 4 detail this constraint change.

$$NI_{res} + NI_{imp} \geq NI_{risk} \quad (3)$$
$$SI_{res} + SI_{imp} \geq SI_{risk} \quad (4)$$
$$NI_{imp} \leq SI_{res} \quad (5)$$
$$SI_{imp} \leq NI_{res} \quad (6)$$

Where:
NI_{risk} = max (largest generator in NI, IF northward HVDC flow THEN single pole HVDC event ELSE 0)
SI_{risk} = max (largest generator in SI, IF southward HVDC flow THEN single pole HVDC event ELSE 0)
NI_{res} = reserve provision by providers located in the NI
SI_{res} = reserve provision by providers located in the SI
NI_{imp} = reserve that is imported across the HVDC link into the NI
SI_{imp} = reserve that is imported across the HVDC link into the SI

3.1 Restrictions on Reserve Sharing

The restrictions on reserve sharing between islands are related to the level and direction of power transfer and the available spare capacity on the HVDC. The first set of constraints restrict reserve sharing to be less than or equal to the spare capacity available on the HVDC link and imply that reserve is transferred in the same direction as power transfer.

$$NI_{imp} \leq (cap_A + cap_B) - (flwnth_A + flwnth_B) \quad (7)$$
$$SI_{imp} \leq (cap_A + cap_B) - (flwsth_A + flwsth_B) \quad (8)$$

This constraint set does not consider how the location of reserve provision must account for a potential HVDC pole trip. In the event of an HVDC pole trip, the island importing power must have sufficient instantaneous reserve dispatched to cover the loss of imported power regardless of whether the HVDC is setting the reserve risk. The second constraint set in Equations 10-12 ensures that the importing island dispatches sufficient reserve to cover a single pole contingent event.

$$NI_{imp} \leq max[0, ((cap_A) - (flwnth_A + flwnth_B))] \quad (9)$$
$$NI_{imp} \leq max[0, ((cap_B) - (flwnth_A + flwnth_B))] \quad (10)$$
$$SI_{imp} \leq max[0, ((cap_A) - (flwsth_A + flwsth_B))] \quad (11)$$
$$SI_{imp} \leq max[0, ((cap_B) - (flwsth_A + flwsth_B))] \quad (12)$$

Each constraint is written with respect to the limitations of reserve sharing into the importing island but, due to the self cover ability of the HVDC and symmetric operation, reserve sharing is unlikely to occur during an HVDC contingent event. These constraints are designed, in conjunction with the constraints in Equations 3 and 4 to force the importing island to provide sufficient instantaneous reserve cover for an HVDC contingency.

The constraints in Equations 9-12 will always be more constraining than those in Equations 7 and 8 because a the single HVDC pole capacity will always be lower than the bipole capacity, making Equations 7 and 8 redundant.

The constraints above describe reserve sharing from the island exporting power across the link to a reserve risk in the island that is importing power. A third set of constraints are developed to allow the importing island to provide reserve cover to the exporting island, against the direction of power transfer. Should a contingent event occur in the exporting island, the level of exported HVDC power will be reduced to provide reserve cover for the tripped plant. Due to the reduction in power transfer the importing island must have sufficient instantaneous reserve dispatched to manage the sudden drop in imported power.

$$NI_{imp} \leq (flwsth_A + flwsth_B) \quad (13)$$
$$SI_{imp} \leq (flwnth_A + flwnth_B) \quad (14)$$

Equations 13 and 14 describe the restrictions on imported reserve against the direction of HVDC transfer.

3.2 Swamping Terms

Each of the new constraints that describe reserve sharing have components regarding direction of HVDC power transfer. In order to apply all new constraints to the model simultaneously it is necessary to introduce swamping terms that effectively switch constraints on and off depending on direction of power transfer.

The following group of constraints illustrates swamping terms for reserve sharing and dispatch in the North Island.

$$NI_{imp} \leq (cap_A + cap_B) - (flwnth_A + flwnth_B) + 10000 * (flwsth_A + flwsth_B) \tag{15}$$

$$NI_{imp} \leq max[0, ((cap_A) - (flwnth_A + flwnth_B))] + 10000 * (flwsth_A + flwsth_B) \tag{16}$$

$$NI_{imp} \leq max[0, ((cap_B) - (flwnth_A + flwnth_B))] + 10000 * (flwsth_A + flwsth_B) \tag{17}$$

$$NI_{imp} \leq (flwsth_A + flwsth_B) + 10000 * (flwnth_A) \tag{18}$$

The swamping terms make constraints 15, 16 and 17 most constraining when power is transferred north as $flwsth_A$ and $flwsth_B$ will equal 0. When power transfer is southward, constraint 18 is most constraining as $flwnth$ equals 0. The constraints and swamping terms of Equations 15-18 can be mirrored for the South Island.

4 Case Study

A case study of the New Zealand power system with a reserve sharing market design has been undertaken using the modeling and optimisation software Plexos^{TM}. The objective is to identify if operational cost savings are possible if a reserve sharing market is implemented after Pole 3 commissioning is completed. Plexos performs a mixed integer optimisation to co-optimise energy and SIR dispatch for the New Zealand nodal network model. The model optimises hydro storage and release over the time period of the optimisation to minimise thermal fuel use. The optimal tradeoff of hydro and thermal generation is particularly important as the New Zealand system is hydro dominated, particularly in the South Island.

4.1 Scenarios

Scenario analysis is used to consider system operating costs under different future system states. These scenarios have been developed by the Electricity Commission and are published in the Statement of Opportunities[10]. Five scenarios are used that reflect different generation investment paths, demand forecasts and industrial expansion in future years. A brief description of each scenario follows:

Scenario 1: Sustainable Path - Large amounts of renewable generation investment backed by thermal generation. Significant electric car uptake after 2020

Scenario 2: South Island Surplus - Moderate amount of renewable generation investment with gas units remaining in service. Significant wind and hydro investment in the lower South Island.

Scenario 3: Medium Renewables - Renewable generation developed in both islands with emphasis on geothermal in the north. Tiwai aluminium smelter in the lower South Island assumed to decommission in mid 2020's.

Scenario 4: Demand Side Participation - Electric vehicle uptake is high as is vehicle to grid technology. Major generation developed is geothermal, coal and lignite.

Scenario 5: High Gas Discovery - Major gas discovery keeps gas prices low stimulating gas fired generation plant investment. The demand side remains relatively uninvolved.

A generation expansion plan is found for each scenario using an unconstrained New Zealand transmission network via the Electricity Commission's GEM software[9]. Each generation expansion scenario, demand forecast and varying fuel costs are modelled in Plexos alongside the existing network model and the upgraded HVDC assets.

4.2 Optimisation

To identify the benefit of the reserve sharing market design a base case is modeled for each scenario as a comparison. The base case represents the current power system state and market, as modelled in long term economic studies. The base case is this analysis models an approximation of the New Zealand power system and market design where each island has a single reserve risk, either a single HVDC pole or a generating unit, whichever is larger. No SIR sharing is modelled in the base case as the current levels of reserve sharing are very low. The new reserve sharing market design is then modelled for each scenario. The constraints described in Section 3 are added to the optimisation problem.

The objective of the optimisation is to minimise the operating cost of the power system, i.e. energy and reserve dispatch. The optimisation is solved for each scenario for both the base case and reserve sharing models with the operational costs averaged across all scenarios.

4.3 Results

The optimal system operation cost is comprised of the fixed and variable operating and maintenance costs, fuel costs and reserve costs. The optimisation runs in hourly

Table 1: Base Case Operational Costs

Scenario →	1	2	3	4	5
Fixed Costs ($000)	222,786	219,334	214,358	193,021	227,666
Variable Costs ($000)	84,837	124,959	70,075	83,120	101,265
Fuel Costs ($000)	505,585	632,188	455,218	528,710	832,187
Reserve Costs ($000)	1,309	148,822	103,900	41,562	102,303
Total ($000)	814,518	1,125,303	843,551	846,413	1,263,421
Avg ($mill)	978.6				

Table 2: Reserve Sharing Operational Costs

Scenario →	1	2	3	4	5
Fixed Costs ($000)	222,843	222,710	214,372	193,055	227,716
Variable Costs ($000)	84,822	127,155	70,363	83,034	100,977
Fuel Costs ($000)	505,873	643,045	458,193	529,827	830,107
Reserve Costs ($000)	52	104,961	60,999	11,406	55,914
Total ($000)	813,590	1,097,871	803,927	817,322	1,214,714
Avg ($mill)	949.4				

time steps over a single snapshot year, 2018 using an average hydro inflow sequence.

The base case system costs are shown in Table 1 and the reserve sharing case in Table 4.3. The market benefit of implementing a reserve sharing market design is given by the difference between the average base case and average reserve sharing case results. This difference for 2018 is $29*mill*. Using a discount rate of 7% the market benefit from reserve sharing over 20 years [3] is equal to $309*mill*.

While the input assumptions such as demand and hydro inflows are average values the market benefit value of $309*mill* should be treated as an upper bound on the savings that increased reserve sharing could deliver. No FIR dispatch is modelled and the time frame of optimisation is longer than typical reserve cover requirements. No hard limit on HVDC sharing has been modelled. If one were to be imposed, the level of reserve sharing possible would be reduced leading to reduction in cost savings.

5 Discussion

The modelling undertaken in the case study considers a narrow range of input assumptions. A single, mid-range demand forecast is assumed and a single averaged valued hydro inflow sequence is analysed. The sensitivity of the results to changes in input assumptions has not been tested and would provide greater insight into how the results would be affected by changes in demand forecasts, generation investment paths and hydro inflow levels.

[3] A 20 year net benefit calculation is undertaken as this is the time horizon specified for economic analysis in the Grid Investment Test (GIT)[8] in NZ.

Higher than average demand growth will reduce capacity available for generation and reserve particularly in the North Island, where the largest load centres are located. The ability to share reserve from the south to the north will reduce the cost of system operation and investment as the North Island load grows because less NI capacity will need to be allocated for reserve dispatch.

Hydro inflows have large impacts on the NZ system, particularly in dry years. Lower inflows often result in higher southward HVDC flows as energy is exported from the North Island to conserve South Island lake storage levels. Southward transfer can be restricted due to insufficient levels of reserve being available in the South Island to cover an HVDC single pole tripping. This often results in high nodal prices and operating costs. If reserve sharing from north to south is available, the costs of low hydro inflow years will be reduced as more power can be transferred south due to the additional reserve cover available from the NI.

Each scenario modelled has assumed the same generation investment path based on an unconstrained transmission network. Reserve sharing functionality is likely to alter generation investment types, sizes and timing as different levels and locations of instantaneous reserve provision are available. The cost of system investment is likely to drop with reserve sharing due to less reserve capacity being required in the North Island. If lesser amounts of reserve capable generation are required, due to reserve sharing, greater levels of intermittent generation, such as wind, may be able to connect to the grid.

This research has considered only SIR provision and

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therefore cannot be considered a precise indication of the cost of reserve in the New Zealand market. The entire market is often re-dispatched within two or three minutes after a contingent event leading to reserve re-dispatch. Plexos does not model system operation on such a small time step so any reserve costs calculated will be an upper limit on actual costs. If a hard limit on reserve sharing is imposed to ensure stable HVDC operation, the level of reserve sharing will drop. The reduction in cost savings due to a hard sharing limit also suggests the reserve costs modelled in Plexos are an upper bound.

None of the modelling in this research has considered if the technical changes to both physical plant and/or control systems could be implemented to increase reserve sharing with the new HVDC Pole 3 upgrade. If increased reserve sharing is possible other ancillary services such as frequency keeping and HVDC short term overload are also possible. These additional services vying for HVDC capacity have not been considered but would potentially reduce the level of reserve sharing available if HVDC power transfer is high. Should a range of ancillary services be provided via the HVDC this may be seen as a capacity derating by market participants therefore negatively affecting investment incentives, particularly for renewable generation in the South Island.

6 Conclusion

The modelling and constraints shown in this paper illustrate how to implement a SIR sharing market design for long term economic modelling in the New Zealand power system. The modelling has assumed the completion of commissioning of the new Pole 3, resulting in symmetric bipole operation of the HVDC link. The case study undertaken shows that there is value in a reserve sharing market design. The estimated upper bound of benefits of reserve sharing over 20 years is \$309$mill$. This value is an upper bound because; the modelling does not represent FIR dispatch, it is restricted to a time frame of hourly dispatch rather than a finer time step required for accurate reserve dispatch, and it is likely that a limit may be imposed on reserve sharing to ensure stability of HVDC operation.

Future work on this topic should include consideration of the impact that a stability limit would have on reserve sharing and cost savings. Sensitivity analysis is also necessary to identify how the results presented are influenced by the demand forecast, generation expansion path and hydro inflows. Whether the new HVDC investment and upgrade program can deliver the required capability and the market can be successfully restructured while providing a cost saving to New Zealand is unknown but worthy of further investigation.

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