Market impact of HVDC pole 3 commissioning

Market performance enquiry

24 October 2013

Market Performance

813098-1

Version control

Version	Date amended	Comments
1.0	15 August 2013	Initial draft
1.1	16 September 2013	Including comments from DW
1.2	22 October 2013	Including comments from BS
2.0	24 October 2013	Including comments from legal

Investigation stages

An in-depth investigation will typically be the final step of a sequence of escalating investigation stages. The investigations are targeted at gathering sufficient information to decide whether a Code amendment or market facilitation measure should be considered.

Market Performance Enquiry (Stage I): At the first stage, routine monitoring results in the identification of circumstances that require follow-up. This stage may entail the design of low-cost ad hoc analysis, using existing data and resources, to better characterise and understand what has been observed. The Authority would not usually announce it is carrying out this work.

This stage may result in no further action being taken if the enquiry is unlikely to have any implications for the competitive, reliable and efficient operation of the electricity industry. In this case, the Authority publishes its enquiry only if the matter is likely to be of interest to industry participants.

Market Performance Review (Stage II): A second stage of investigation occurs if there is insufficient information available to understand the issue and it could be significant for the competitive, reliable or efficient operation of the electricity industry. Relatively informal requests for information are made to relevant service providers and industry participants. There is typically a period of iterative information-gathering and analysis. The Authority would usually publish the results of these reviews but would not announce it is undertaking this work unless a high level of stakeholder or media interest was evident.

Market Performance Formal Investigation (Stage III): The Authority may exercise statutory information-gathering powers under section 46 of the Electricity Industry Act 2010 to acquire the information it needs to fully investigate an issue. The Authority would generally announce early in the process that it is undertaking the investigation and indicate when it expects to complete the work. Draft reports will go to the Board of the Authority for publication approval.

The outcome of any of the three stages of investigation can be either a recommendation for a Code amendment, provision of information to a Code amendment process already underway, a brief report provided to industry as a market facilitation measure, or no further action.

From the point of view of participants, repeated information requests are generally concerned with Stage II; trying to understand the issue to such an extent that a decision can be made about materiality.

Executive summary

Transpower carried out commissioning tests on the HVDC pole 3 from February 2013 to May 2013. The tests required different levels of power flow on the new pole. To facilitate this testing and get the desired power flows for each of the different tests, Transpower obtained hedges from market participants. In addition to hedging, Transpower applied constraints on both pole 2 and pole 3 to get the required HVDC flow for each of the tests, and procured additional reserves in the receiving island when the HVDC was considered as a secondary risk.

From March 2013 to July 2013 Mighty River Power also commissioned its Ngatamariki geothermal plant. This resulted in additional reserves being procured in the spot market due to Ngatamariki being considered as a secondary risk during periods of testing.

The constraints and secondary risk requirements were applied in the calculation of final prices and sometimes impacted the final prices. The dry hydrological conditions in early 2013 resulted in increased spot prices which amplified the impact of these constraints on final spot prices when they bound.[1]

The Authority initiated this enquiry in response to observations of these constraints on the final spot electricity prices to better understand the market impact of the HVDC pole 3 commissioning and whether the current arrangements can be improved to incentivise participants to minimise these impacts. While this enquiry was initiated based on the observations of the market impacts of the HVDC pole 3 commissioning, the Authority considered it appropriate to also include in this enquiry the market impact of Ngatamariki, which was also undergoing commissioning tests during this period, rather than initiate a separate enquiry.

The Authority estimates that the constraints and additional reserve requirements applied to the HVDC to support pole 3 commissioning testing resulted in higher average spot prices and a $6.3m wealth transfer in the spot market from loads to generators over the period from 16 February 2013 to 29 May 2013. This additional cost to loads in the wholesale spot market represents 0.5% of the wholesale load costs over the period from 16 February 2013 to 29 May 2013. These wealth transfers are gross of both financial and physical hedges, so the net size of the transfer will be less than these amounts. There was also an estimated $57k (0.7%) increase in reserve costs to generators over this period.

The Authority understands that HVDC testing was accomplished using a range of contracting arrangements. These arrangements are likely to have affected the distribution of costs between participants, reduced the wholesale market impact and affected the offers that were in place in the market at the time. Consequently this analysis measures the incremental impact of commissioning given that these contracts are in place.

The Authority's market impact analysis of the Ngatamariki commissioning estimates that the additional risk imposed by the geothermal station during its commissioning resulted in an increase in spot electricity prices which resulted in a $6.8m wealth transfer from loads to generators in the wholesale spot market over the period from 20 March 2013 to 23 July 2013. This represents 0.6% of the load costs in the wholesale spot market over

[1] See Authority's enquiry into increased electricity wholesale spot and hedge prices – February 2013 to March 2013

this period. Again this amount is gross of hedges. In addition to these increased costs to loads, the market impact analysis indicates an estimated $3.1m (31%) increase in reserve costs to generators.

This market performance report concludes that during these periods of commissioning, the additional cost imposed on loads in the spot market is small (less than 1%) relative to the total load costs in the spot market. However, the report considers that including the additional constraints and reserve requirements for commissioning assets in the calculation of final prices results in the market bearing the additional cost of the commissioning asset, which reduces the incentives on the commissioning party to seek out lower cost options during commissioning.

Therefore the report proposes consideration should be given to removing the constraints and additional reserve requirements, applied during asset commissioning, from the calculation of final energy and reserve prices that would be used for settlement. This would remove the wealth transfers in the spot market but increase the potential for constrained on costs which could then be allocated to the commissioning party or loads, or both. In the analysed instances of the HVDC pole 3 and Ngatamariki commissioning, these additional constrained on costs in both cases were less than 6% of the wealth transfer effects, translating to a lower total cost to loads in the spot market while ensuring that more expensive resources, dispatched as a result of additional requirements during commissioning, are compensated for market costs.

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1 Background

1.1 The HVDC link is an integral part of the New Zealand power system, allowing the load centres of the North Island access to hydro generation in the South Island but also providing dry year security to the South Island loads. The construction of HVDC pole 3 provides additional transfer capability between the islands and also reduces the contingent event risk of a single HVDC pole trip.

1.2 Conducting commissioning tests on such an integral piece of the power system is challenging, and more so when undertaken within a market environment where market participants are trying to co-ordinate their own production and consumption decisions in response to market conditions. This became even more challenging from March 2013 onwards as falling hydro storage meant that hydro generators were trying to conserve water. This resulted in dwindling HVDC transfers between the islands and also elevated spot prices with more thermal generation.

1.3 The unfavourable hydrological conditions in early 2013 threatened the completion of the HVDC commissioning testing with the potential deferment of high power tests to spring (after the winter peak load period).[2] The subsequent improvement in hydro storage levels enabled the full completion of the HVDC commissioning tests and the HVDC bipole link being made available to the market on 29 May 2013 for the winter peak load period.

1.4 Transpower issued Customer Advice Notices (CANs) during the course of testing which informed participants of upcoming tests and updates to tests as conditions changed.[3]

1.5 To facilitate testing of the HVDC pole 3, Transpower contracted with market participants to get the desired HVDC flows. In addition to contracting, constraints were applied on the HVDC link to ensure the correct flows for the specific tests.

1.6 This enquiry explores the market impact of the HVDC pole 3 commissioning from 16 February 2013 to 29 May 2013 and, in particular, how the constraints applied to the HVDC to facilitate testing affected market prices and the associated cost impact on loads in the spot market.

1.7 The report also considers the market impact of the additional reserve requirements imposed by the commissioning of the 82 MW Ngatamariki geothermal station in the central North Island which occurred from 20 March 2013 to 23 July 2013.

2 Market impact of HVDC pole 3 commissioning

2.1 The Authority estimates that the constraints, outages and the additional reserves dispatched to facilitate the testing of the HVDC pole 3 resulted in a $6.3m increase in load costs and a $57k increase in reserve costs over the test period from 16 February 2013 to 29 May 2013. This represents 0.5% of the load costs

[2] See Appendix A for CANs related to these issues.

[3] This was in addition to the updates provided on the Transpower website.

and 0.6% of reserve costs respectively over the period from 16 February 2013 to 29 May 2013.

2.2 To estimate the impact of the constraints, outages and additional reserve requirements applied during the testing of the HVDC pole 3 on final spot energy and reserve prices, the Authority removed these constraints and recalculated prices using its vSPD model. In particular, the following input adjustments were made to the final pricing calculation during HVDC test periods:[4]

(a) outages and constraints restricting the flow on pole 2 were removed

(b) minimum flow constraints on either pole were removed

(c) HVDC as a secondary risk requirement was removed.

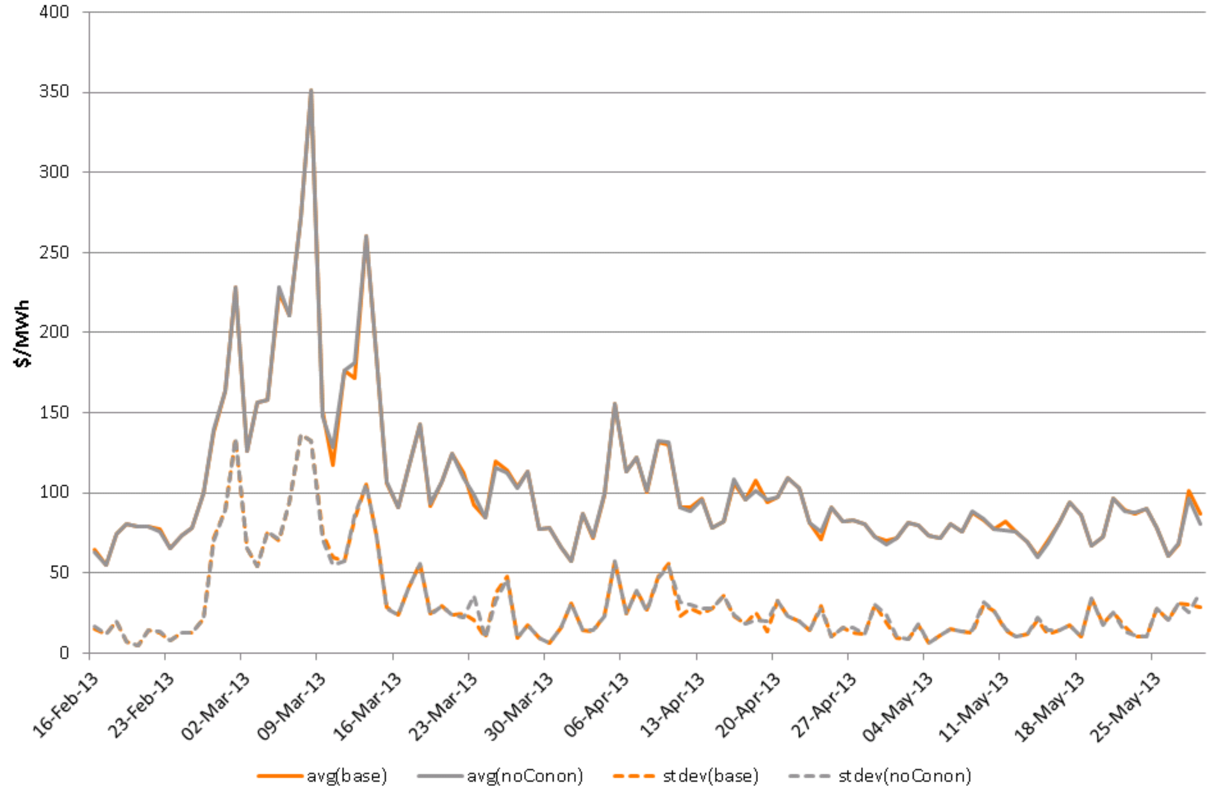
2.3 Maximum constraints applied to HVDC pole 3 were maintained as these would have reflected the tested capability of the asset.

2.4 Figure 1 shows the daily average price and daily standard deviation in spot price at Haywards under the scenarios with the constraints in effect (base) and with the adjusted inputs (noConon). Figure 2 shows the same at Benmore.

2.5 These figures show that there was a greater impact on the South Island prices (Benmore) where the HVDC test constraints and secondary risk (base case) increase both the average and standard deviation of spot prices. This is due to the HVDC test constraints in the base case restricting higher levels of HVDC south flow.

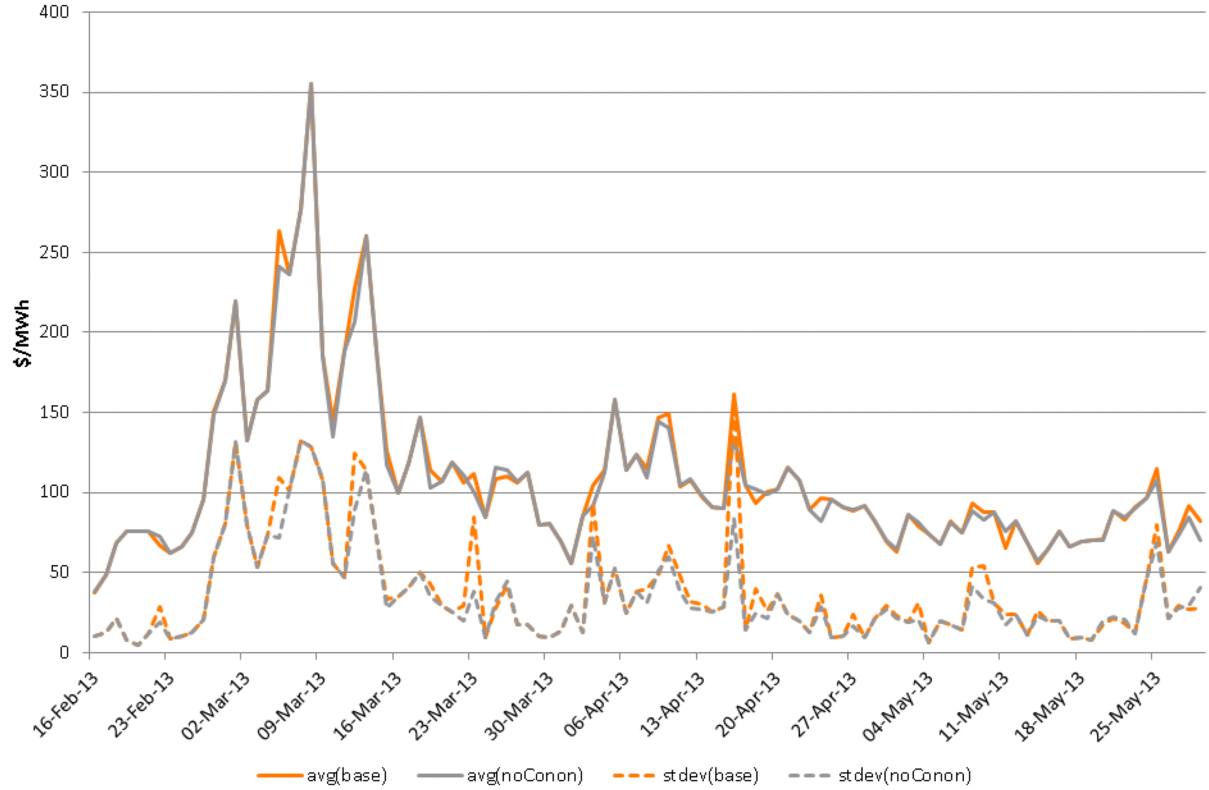
[4] Customer Advice Notices (CANs) issued by Transpower were used to identify the trading periods within which testing was carried out.

Figure 1 Impact on Haywards spot price (16 February 2013 to 29 May 2013)



Source: Electricity Authority

Figure 2 Impact on Benmore spot price (16 February 2013 to 29 May 2013)

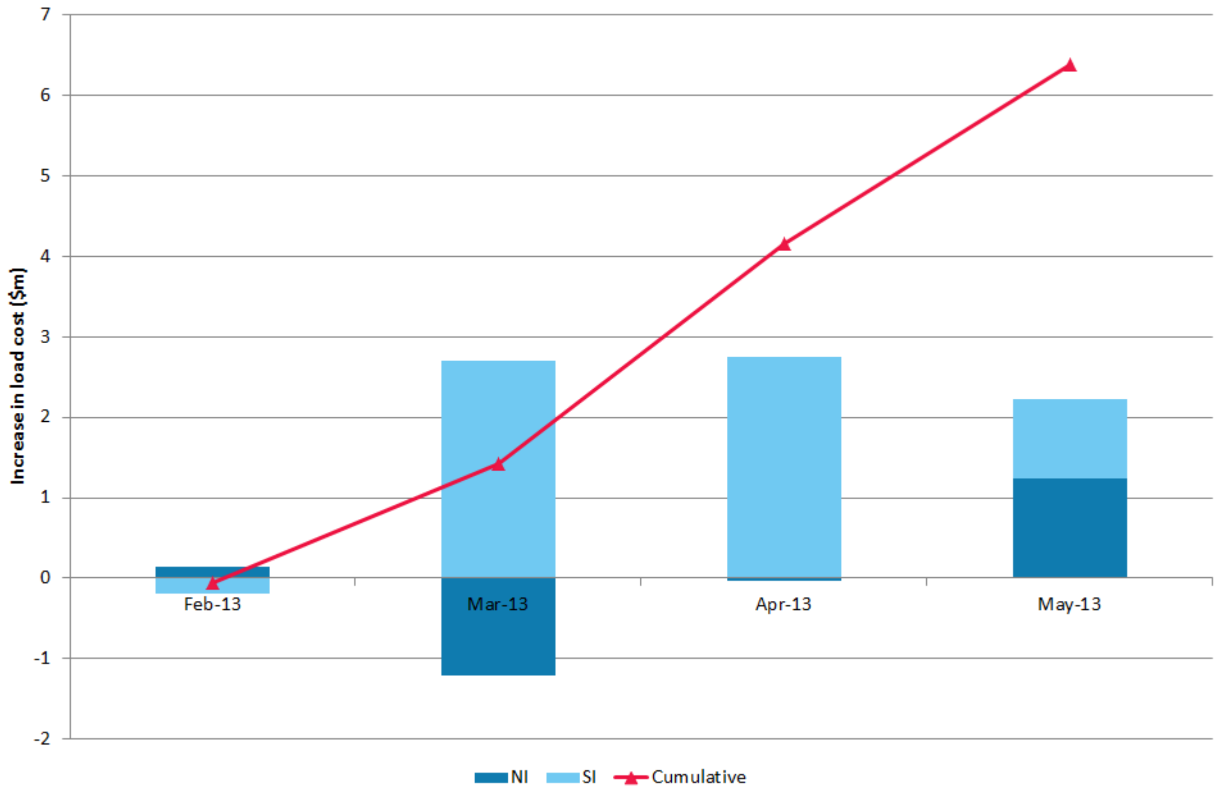


Source: Electricity Authority

2.6 Relative to the scenario where the HVDC test constraints and additional reserve requirements are removed, the increased spot prices in the base case translates to a $6.3m increase in load payments in the spot market over the test trading periods as illustrated in Figure 3. The South Island experienced the majority of the increase in load costs, where the HVDC constraints and its treatment as a secondary risk restricted cheaper North Island generation from being imported during the dry hydrological conditions in March and April 2013. The increase in load cost represents 0.5% of the total load costs in the spot market over the period from 16 February 2013 to 29 May 2013.

2.7 The calculation of these transfers ignores the effect of physical and financial hedges. Hedged load would not pay any more to generators because of the change in spot prices, although the testing could have been built into the hedge price. Likewise the contracting arrangements between participants that were used to accomplish HVDC commissioning similarly affected the incidence of commissioning costs, reduced the wholesale market impact, and affected the offers that were in place in the market at the time. Consequently this analysis is a measure of the incremental impact of commissioning the HVDC given that these contracting arrangements were in place.

Figure 3 Impact of HVDC test constraints on load costs (16 February 2013 to 29 May 2013)



Source: Electricity Authority

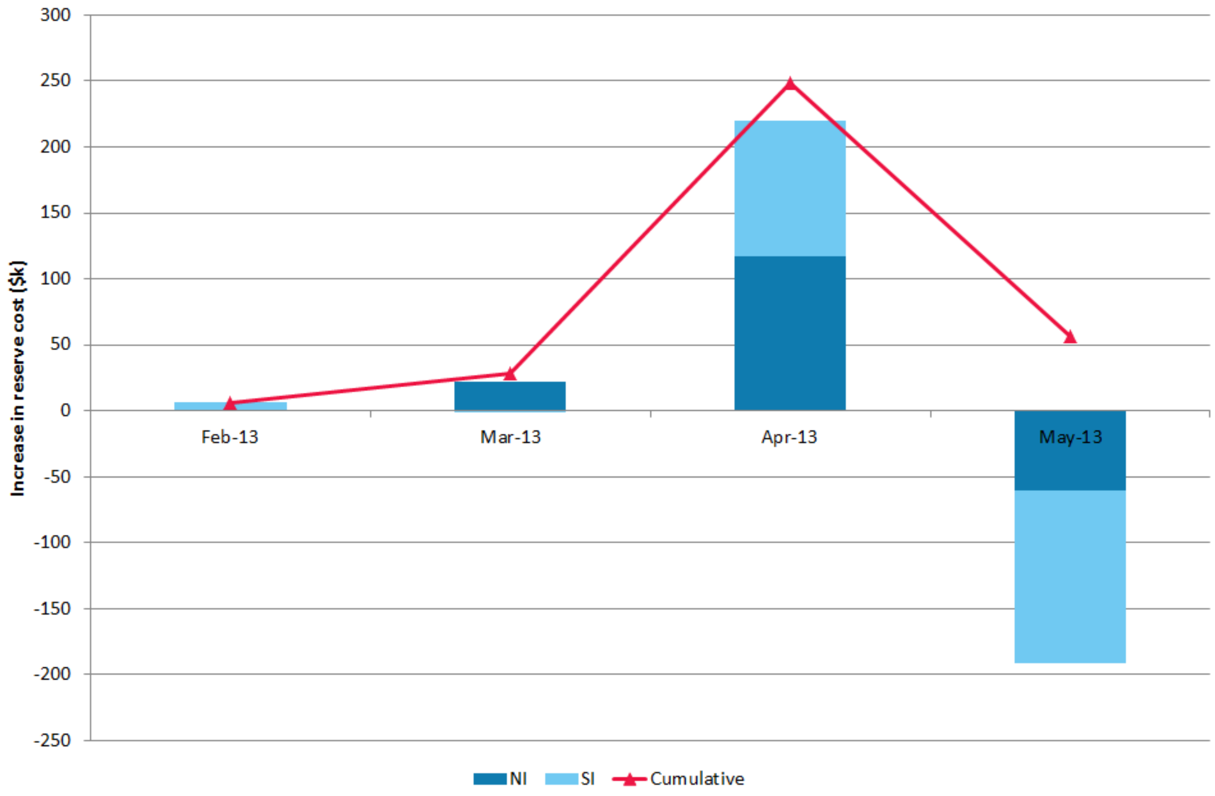
Notes: 1.

2.8 In addition to higher total load payments in the wholesale spot market, there is an increase in reserve costs with the inclusion of the HVDC constraints and secondary risk requirements in the base case. [5] Figure 4 illustrates the calculated impact on reserve costs during the testing periods. For the duration of the test periods, the inclusion of the constraints and HVDC secondary risk results in a $57k increase in reserve costs. This represents 0.7% of the reserve costs over the period from 16 February 2013 to 29 May 2013.

2.9 In May 2013, the inclusion of the HVDC constraints and secondary risk treatment of the HVDC results in a reduction in reserve costs. This seems counter-intuitive but upon further investigation found to be valid. The reduction in reserve costs occurs as the restricted HVDC transfer in the base case reduces the risk, which translates into a reduction in reserves required and reserve price in the receiving island, when the HVDC is the risk setter. By way of example, such a situation arose during the simulation of the 25 May 2013 where the reduced imports into the South Island, with the inclusion of the HVDC constraints, resulted in a reduction in the South Island reserve price with constrained HVDC imports into the South Island. This corresponded to a reduction in reserve costs.

[5] Reserve costs are allocated to generators and the grid owner based on injection above a 60MW. The reserve cost sharing allocation formula is specified in Clause 8.59 of the Code.

Figure 4 Impact of HVDC test constraints on IR costs (16 February 2013 to 29 May 2013)



Source: Electricity Authority

2.10 Removing the constraints and secondary risk of the HVDC from the calculation of final prices but maintaining them for dispatch means that more expensive resources could be dispatched than is reflected in the final spot prices.[6] Therefore, if these constraints and additional risks of the commissioning asset were removed, there would be an increase in constrained on payments. The Authority estimates that over the period from 16 February 2013 to 29 May 2013, the removal of the constraints and HVDC secondary risk would have resulted in a $376k increase in constrained on costs. This reflects the cost of additional energy and instantaneous reserve resources dispatched to meet the constraints applied to facilitate the commissioning of the HVDC pole 3.

3 Market impact of Ngatamariki commissioning

3.1 Mighty River Power's Ngatamariki power station was treated as a secondary risk in the market over the period from 20 March 2013 to 23 July 2013 when it was being commissioned. During the time when it was considered a secondary risk, additional reserves were dispatched by the system operator to cater for the risk

[6] In principle it also means that large industrial consumers use energy when they might otherwise have not done so.

of the commissioning generator tripping following the trip of another generator, or of the HVDC.

3.2 The additional reserves are specified in the market system through the reduction of the net free reserves where the commissioning megawatt (MW) at risk was the amount by which the net free reserves were reduced. This process increases the dispatched reserves above the MW level of the maximum risk setter on the power system to cater for the additional risk of the commissioning generator tripping.[7]

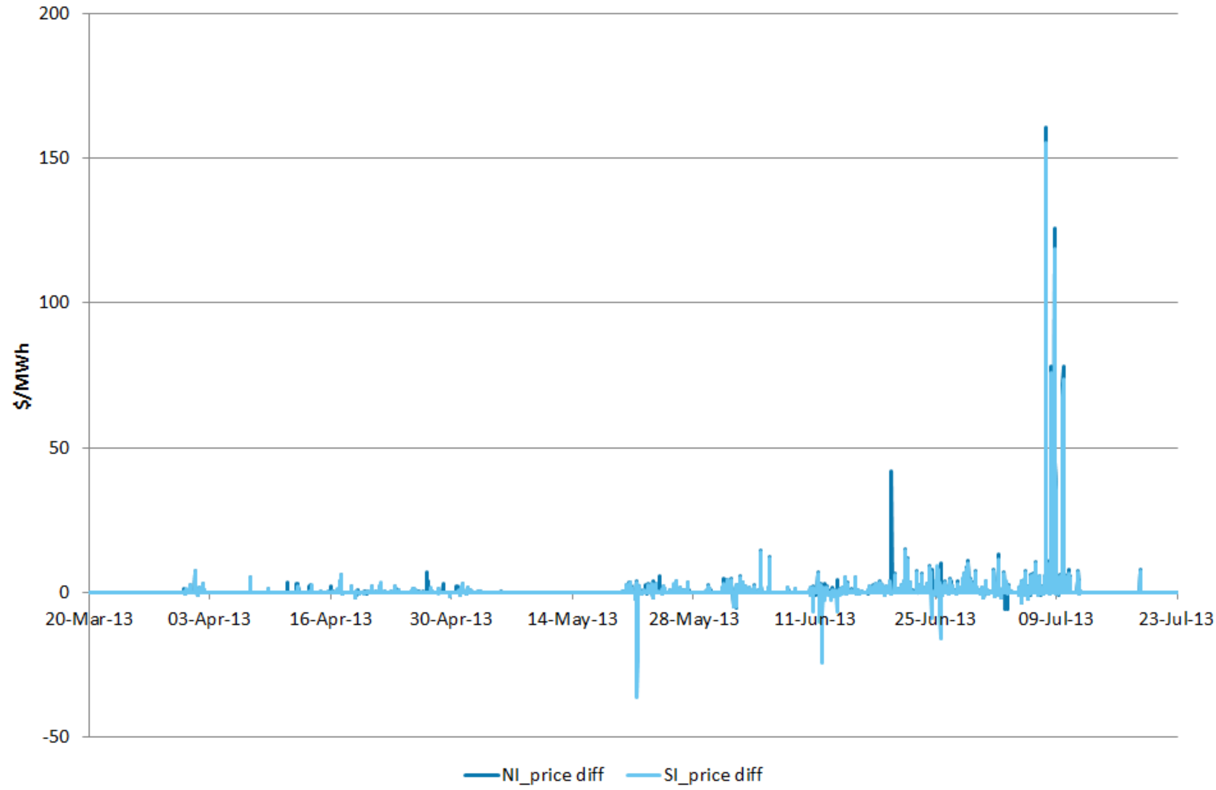
3.3 The Authority estimated the impact of the additional reserves by removing these additional reserves from the net free reserves inputs and recalculating the final market prices over the periods from 20 March 2013 to 23 July 2013.[8] Figure 5 shows the estimated impact on the spot energy price at Haywards and Benmore over this period. The positive values indicate a higher spot price in the base case with the additional reserves included relative to the counterfactual scenario where the additional reserves were removed.[9] Here we see an increased impact of the additional reserves during the higher load periods in June and July 2013.

[7] The negative net free reserve used for the sustained instantaneous reserves was used to estimate the secondary risk adjustment.

[8] From 01 July 2013, there were periods when both Ngatamariki and Kinleith were considered as secondary contingent event risks. During these periods, the Kinleith secondary risk was maintained (35MW).

[9] There are positive differences in price observed in some trading periods. With the reduced reserves required (through increasing the net free reserves) there is always a reduction in system dispatch costs but there could be an increase in spot price. An example being when the increased net free reserve results in increased HVDC flow which in turn increases the price in the sending island as a higher priced marginal generator is dispatched. There is still a net reduction in costs as the output of more expensive generation in the receiving island is reduced.

Figure 5 Price impact of Ngatamariki secondary risk

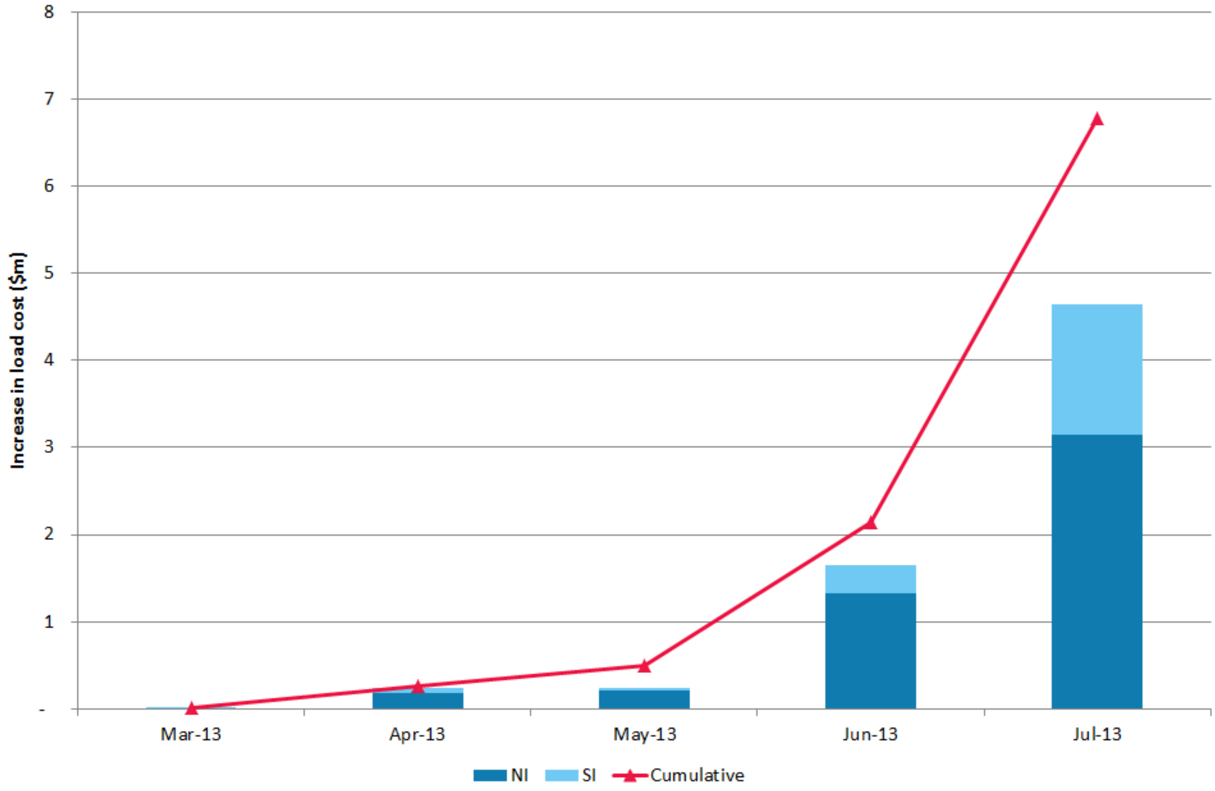


Source: Electricity Authority

Notes: 1. NI and SI represent the HAY2201 and BEN2201 nodes respectively.

3.4 The increase in price with the inclusion of the additional risk results in a $6.8m increase in load payments in the spot market. This represents 0.6% of the load costs in the spot market over the period from 20 March 2013 to 23 July 2013. Figure 6 illustrates that most of the impact is concentrated in the higher demand winter periods (June and July 2013) where the spot price impact of the additional risk was most acute. Again this figure is gross, and any hedges would negate the change in spot prices.

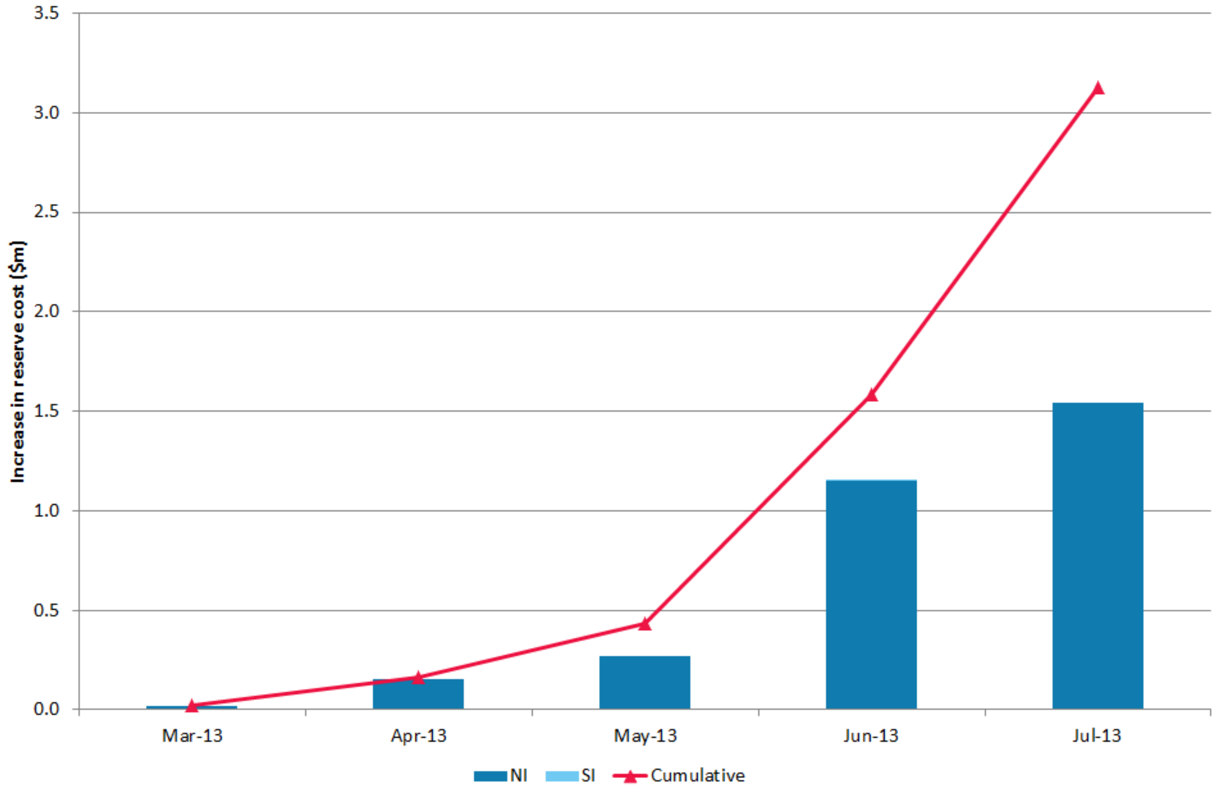
Figure 6 Load cost impact of Ngatamariki secondary risk (20 March 2013 to 23 July 2013)



Source: Electricity Authority

3.5 The impact of scheduling additional reserves during Ngatamariki commissioning on the reserve costs is shown in Figure 7 which, similar to the energy cost impact, also shows an increased impact during the winter months of June and July 2013. The estimated cumulative impact of the additional reserve is $3.1m which represents 31% of the total reserve costs over the period from 20 March 2013 to 23 July 2013.

Figure 7 Reserve cost impact of Ngatamariki secondary risk (20 March 2013 to 23 July 2013)



Source: Electricity Authority

Notes: 1.

3.6 As in the HVDC commissioning market impact assessment, removing the additional reserve requirement for Ngatamariki in the calculation of final prices but maintaining it for dispatch purposes can result in more expensive resources being dispatched than is reflected in the final spot prices. The Authority estimates that, over the period from 20 March 2013 to 23 July 2013, there would have been an additional $125k in energy and instantaneous reserve constrained on costs.

3.7 Procuring additional reserves through the reduction of the net free reserves (as was the case for the Ngatamariki commissioning) does not allow for an economic trade-off between energy and reserves as there is no ability to reduce the output of the additional risk (commissioning generator) if it is imposing excessive costs on the system. This is unlike the secondary risk treatment of the HVDC during its commissioning where the HVDC risk was included as a secondary risk within the SPD formulation. This enabled SPD to reduce the HVDC transfer when it was treated as a secondary risk and imposing large costs on the system. The Authority estimates that had Ngatamariki been treated in a similar fashion to the HVDC secondary risk, the impact of the additional reserves would have reduced to $6.3m (0.6%) for additional load costs and $2.2m (22%) for additional reserve costs.

4 Previous work on cost allocations to commissioning parties

4.1 The Authority released a consultation paper in April 2012 reviewing the cost allocation of any IR procured by the system operator during asset commissioning.

4.2 The key conclusions of the consultation paper were as follows:[10]

(a) *it is appropriate that assets being commissioned should face a causer pays approach for the allocation of UF/ IR costs. Specifically:*

(i) *requiring that any extra IR costs associated with the commissioning of assets be allocated to the commissioning asset owner is likely to deliver material net benefits through incentivising commissioning asset owners to perform commissioning at times when the market is not unduly "tight";*

(ii) *there may be some minor net benefit from requiring that commissioning asset owners pay UF event charges, but almost certainly no net costs which may justify exempting commissioning asset owners from such charges;*

(b) *code amendments and associated market system changes are required to allocate any extra IR costs associated with the commissioning of assets to the asset owner; and*

(c) *no Code or systems changes are required to enable UF event charges to be charged to commissioning asset owners.*

4.3 The conclusion in the consultation paper implied that parties commissioning assets should be liable for the additional reserve costs to cover the additional risk imposed on the system during times of asset commissioning. This required the recalculation of reserve prices and quantities without the additional secondary risk with the commissioning party allocated the additional reserve costs.

4.4 Submissions received on the consultation were varied. Some participants agreed with the causer-pays approach to increase incentives on commissioning parties while other participants were concerned about adverse effects of such an allocation in potentially delaying the availability of commissioned assets and the disclosure of open information during commissioning.

4.5 The Authority has also received an estimate of market system changes to facilitate this allocation and is considering the priorities of implementing this work.

5 Other potential alternatives to commissioning cost allocation

5.1 The above market impact assessment in Section 3 and 4 indicates that including the additional constraints and secondary risk requirements needed for asset

10 See http://www.ea.govt.nz/our-work/consultations/pso-cq/asset-commissioning-testing-issues/ for further details.

commissioning in the calculation of final prices not only results in increased reserve costs but can result in increased spot prices which results in wealth transfers in the energy market from loads to generators. In the above cases of the HVDC pole 3 and Ngatamariki commissioning the estimated gross wealth transfer from loads to generators was $6.3m and $6.8m respectively. There was also a net increase in reserve costs to generators due to the increased reserve costs. These increases are estimated to be $57k and $3.1m for the HVDC and Ngatamariki commissioning scenarios respectively.

5.2 Table 1 below compares the wealth transfer effects of these commissioning constraints and additional secondary risk requirements versus the additional constrained on costs with these constraints removed. Also included is the additional reserve cost component. Here we see that in both instances, the additional constrained on costs is a fraction (less than 6%) of the wealth transfers in the energy and reserve markets.

5.3 While these transfers have no efficiency effect, the price changes that cause them could also cause inefficient behaviour such as switching off load unnecessarily. It is plausible that a commissioning party not facing the full cost of its commissioning could cause higher than necessary price movements and consequent inefficient demand response.

5.4 An efficient outcome would be a commissioning party that minimises both the engineering costs of commissioning plus the market costs of the energy and/or reserves that are required to test the infrastructure. The costs would include costs from generation that would have otherwise not run, opportunity costs for generators that would have otherwise run, and costs for load that either pays more for its energy or switches off due to higher prices.

5.5 Table 1 shows that the transfers are significant, but it is worth remembering that they are small compared to the cost of the assets concerned, and that there is no way to tell in the current system to what extent these costs could have been mitigated if decision makers faced incentives to minimise them. In addition we do not know how much, if any, inefficient action was taken as a result of the price changes that caused the transfers.

5.6 Under the current market arrangements the additional costs imposed during asset commissioning are allocated to market participants through the spot energy and reserve prices. This allocation can reduce the incentive on the commissioning party to adequately consider the costs of the commissioning tests.

5.7 The work undertaken within the Authority to date on asset commissioning and testing issues considers only the allocation of additional reserve costs. The above analysis on the HVDC pole 3 and Ngatamariki commissioning illustrates that the additional reserve costs are only a component of the overall costs imposed on market participants and there can be larger wealth transfers in the spot market from loads to generators. These transfers are gross of any hedges that exist, and are incremental to the contracting arrangements that were in place to support testing.

5.8 An approach to remove the impact of these commissioning constraints on spot prices and their resulting wealth transfer effects on other market participants would be to remove the commissioning constraints and additional secondary risk requirements from the calculation of final prices. These constraints would still be maintained in the dispatch process, and their removal from the calculation of final prices would likely result in final prices not reflecting the marginal cost of supply and consequent inefficient demand response.

5.9 This would require additional constrained on payments to compensate the dispatched resources with offer prices above the final price for their additional costs incurred. However these constrained on payments can be expected to be lower than the wealth transfer effects (had the commissioning constraints been maintained) since they are designed to compensate only for additional costs incurred, which does not include the producer surplus.

5.10 The trade-off in this proposed remedy is between the existing system where the commissioning party may be causing inefficient demand response because it is not facing the full cost of its actions, and the proposal where the final prices wouldn't reflect the marginal cost of generation, again possibly leading to inefficient outcomes.

Table 1 Comparison of additional energy and reserve costs and additional constrained on costs for commissioning scenarios

	Additional energy costs ($k)	Additional reserve cost ($k)	Constrained-on ($k)
HVDC pole 3	6,371	57	376
Ngatamariki	6,786	3,100	125

Source: Electricity Authority

5.11 There are several potential allocations of the additional constrained on costs if the commissioning constraints are removed from the calculation of final prices. These are:

(a) allocate all to the commissioning asset owner

(b) allocate all to offtake

(c) allocate to the commissioning asset owner and offtake in some proportion.

5.12 Allocating all of the additional constrained on costs to the asset owner would be aligned with a "causer pays" approach. Such allocation would make the commissioning asset owner accountable for additional costs imposed on when its asset is being commissioned which would improve the incentives on the commissioning party to minimise the cost impacts during commissioning (such as contracting for additional reserves or conducting commissioning tests during low-priced periods). There is, however, a risk that this allocation can potentially delay the availability of the commissioning asset to the market. In its submission, the system operator had raised a concern that allocating additional costs to the commissioning party could adversely affect the open provision of information during asset commissioning.[11]

5.13 An alternative to allocating the additional constrained on costs to the commissioning party would be to allocate these additional costs to offtake. This allocation is consistent with the current allocation of constrained on costs and a benefit of such an allocation is that it allocates the additional cost across users who would potentially benefit from the asset. Furthermore relative to the status quo, the constrained on costs represent the cost of additional resources used for dispatch and therefore likely to be less than the wealth transfers that currently occur. The disadvantage of this approach is that it does not improve the incentives on the commissioning party to minimise the additional costs due to asset commissioning and, furthermore, it introduces additional cost uncertainty to offtake customers that is unknown at time of consumption since constrained on costs are allocated monthly.

5.14 A sharing of the additional constrained on costs due to commissioning could be an alternate allocation of the additional constrained on costs. This allocation recognises that incentives on the commissioning party are important to reduce these additional costs but also that the wider market can benefit from the availability of the asset.

5.15 The costs and benefits of each of the possible allocations need further consideration before proceeding with a preferred allocation.

[11] Further details can be found at http://www.ea.govt.nz/our-work/consultations/pso-cq/asset-commissioning-testing-issues/submissions/

Appendix A Customer Advice Notices for HVDC commissioning

TRANSPOWER SYSTEM OPERATOR

Customer Advice Notice

To:	CAN NZ Participants	**From:**	The System Operator
Sent:	19-apr-2013 10:42	**Telephone:**	0800 488 500
Ref:	1082726999	**Facsimile:**	07 843 7176

Revision of:

HVDC Pole 3 Commissioning

Further to the CAN issued 16 April 2013, the Grid Owner can now confirm that it will make Pole 3 available in the market upon completion of medium power tests. Full power tests to 700 MW will be deferred to spring due to the continued unfavourable hydrology conditions.

Completion of the medium power tests will allow Pole 3 to be made available with a capacity not less than 350 MW, and possibly up to 450 MW. These tests will be challenging but feasible with the full cooperation of the market. The target date for completing them, assuming the required load flows can be attained, is 10 May. The bipole outage originally scheduled this month will not be required.

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Customer Advice Notice

To:	CAN NZ Participants	**From:**	The System Operator
Sent:	13-may-2013 13:59	**Telephone:**	0800 488 500
Ref:	1102505651	**Facsimile:**	07 843 7176

Revision of:

HVDC Pole 3 Commissioning

This is an update to the CAN issued on 7th May 2013.

HVDC testing proceeded largely to plan last week.

Following a review of recent improvement in lake levels, we confirm that Pole 3 testing will now continue up to full power (700MW).

A 3 day bi-pole outage is required to switch Cable 5 from Pole 2 to Pole 3. This outage is scheduled from Friday 17th to Sunday 19th May.

We anticipate Pole 3 now being available for commercial operation by 30th May 2013.

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Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
Contact	Contact Energy Limited
Genesis	Genesis Power Limited (trading as Genesis Energy)
GWh	Gigawatt hour
GXP	Grid exit point
IMM	Industry and Market Monitoring
Meridian	Meridian Energy Limited
MEUG	Major Electricity Users' Group
MRP	Mighty River Power Limited
MW	Megawatt
MWh	Megawatt hour
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
SPD	Scheduling, Pricing and Dispatch
TP	Trading period
TrustPower	TrustPower Limited
vSPD	Vectorised Scheduling, Pricing and Dispatch

If you wish to delete the Glossary section:

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- tick ‘Glossary’
- and click the ‘OK’ button.

This will ensure the footer page numbering remains correct.