Post implementation review of national market for instantaneous reserves

Market performance review

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Executive summary

The national market for instantaneous reserve (NMIR), which was introduced at the end of 2016, was successful in increasing the efficiency of the reserve market without sacrificing security. The total amount of reserve dispatched dropped, and more reserve was dispatched from the South Island, which is cheaper on average. Instantaneous reserve is one of a few security products that the electricity market procures in order to make sure the lights stay on. Instantaneous reserve provides backup generation and interruptible load which are able to respond in the event of a failure in the system, such as a generator tripping off or an interruption of the HVDC.

The Scheduling, Pricing and Dispatch model (SPD) co-optimises the dispatch of energy and instantaneous reserve. This means that the reserve market can impact the dispatch and price of the energy market (and vice versa). Until the end of 2016, the SPD dispatched reserve for the North Island and the South Island separately, ensuring that each island had enough reserve to cover the largest failure in that island. In 2013 pole 3 came into commission returning the HVDC into bi-pole mode. This increased the energy transfer capacity between the North and South Island and also allowed the sharing of security products, such as instantaneous reserve, across the HVDC. This meant that reserve procured in one island could be used to help cover a failure in the other island, decreasing the total amount of reserve needed.

The cost benefit analysis predicted there would be $1.5 million in savings per annum from lower economic costs. This prediction was sound, as the national market provided the benefits of using less reserve and providing it from the cheapest source possible. As the reserve market is co-optimised with the energy market, this meant more generation capacity was available to the energy market likely resulting in lower energy costs. This resulted in more efficient dispatch, especially when the HVDC was constrained, and may have had the benefit of deferring investment in peaking generation.

However, the CBA assumed the cost of procuring reserve would also decrease by $1.5 million. This was based on the assumption that offers in the reserve market would not change as a result of the national market. Instead, the analysis found that offers in the North Island did change when the market was nationalised. The offer changes indicate that generators have some market power in the reserves market. Three generators based in the North Island, Contact, Mercury and Trustpower, all showed signs of changing their offer behaviour. Contact had the biggest change to their North Island offers, likely to increase South Island reserve prices where more of their reserve was now being dispatched. Mercury’s strategy seems to attempt to maintain competitiveness with South Island reserve providers by keeping most of its reserve at a low offer price, but increasing the price of their last few tranches significantly. Trustpower made small changes to their offers which seemed to balance the need to stay competitive to be dispatched with a desire for higher prices. Genesis and South Island generators did not make significant changes to their offers due to NMIR. We will continue to monitor ancillary offers for any signs of u market power and consider enhancements to improve the competitiveness of the reserve market.

The analysis also found that if average demand and peak demand increase in future then the benefits of NMIR would increase. There is also a chance that in future higher reserve prices in the South Island could entice more participants into the reserve market, such as IL providers, which would further increase competition in the market.

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1 Post-implementation reviews assess the effectiveness of regulatory change

1.1 This paper presents the Authority's post-implementation review of the changes to the Instantaneous Reserve Market made in November 2016. The purpose of a post-implementation review is to evaluate an initiative against its expected outcomes. From the Authority's perspective, this enables learning about how regulatory decisions-or decision not to regulate-are affecting the sector and whether further policy action is required.

2 Background

2.1 The nature of electricity means that electricity generation and power use (load) must be in balance from one moment to the next. In New Zealand, when load and generation are in balance the frequency of the power system measures 50 Hz (50 cycles a second). Frequency drops below 50 Hz when generation is lower than load.

2.2 The frequency of the power system must not fall too far below 50Hz. Generators are designed to work in a limited range around 50Hz. If the frequency drops below the equipment's lower bound then it will trip off to prevent damage. If a generator tripped off then the frequency would drop further, causing more generators to trip off. This is known as a cascade failure, where each trip causes more trips, and if not halted may result in a complete power blackout.

2.3 To help prevent a cascade failure the system operator procures instantaneous reserve (reserve). This is spare capacity in the system which can quickly respond to a large drop in frequency by either increasing generation or dropping load. The system operator must ensure there is enough reserve in each trading period to cover the largest possible failure in the system, known as the contingent event (CE).

2.4 There are other ancillary products which also keep frequency close to 50Hz. Frequency Keeping is the main product which is procured from one or more generators who can make small changes to generation output in order to keep frequency within a band of 49.8 to 50.2 Hz. Over-frequency reserve is procured from generators who can quickly drop generation in response to a large increase in frequency. These products are not discussed in this report.

2.5 Instantaneous reserve can be provided by:

(a) generators, who have spare capacity to increase generation output quickly. There are two types of spare capacity available.

(i) Partially Loaded, generators who are generating at less than full capacity and can quickly increase generation when needed.

(ii) Tail water depressed, hydro generators can spin the turbines but with no water flowing through. When more generation is needed they can release water into the turbines, making them suitable providers of reserve.

(b) large commercial power users who are willing to be disconnected from the grid for a short period of time, known as interruptible load.[1]

2.6 Instantaneous reserve are split into two products:

(a) Fast instantaneous reserve (FIR), which must be able to respond within 6 seconds of a CE.[2] FIR is procured in sufficient quantity to ensure frequency does not fall below 48Hz.

(b) Sustained instantaneous reserve (SIR) is procured to ensure the frequency is returned to 49.25Hz. It must respond within 60 seconds of a CE and remain available for up to 15 minutes after the event. This ensures the power system is kept stable long enough for the system operator to dispatch generation to return the system to a secure state.

2.7 The amount of FIR and SIR a generator can provide in a given trading period depends on how much energy they are generating, how quickly they can increase generation, and how long they can sustain that increase.

2.8 Likewise, commercial power users and distributors can only offer interruptible load equal to their current load (or a set part of their load, depending on their operational set-up).

[1] Some IL is also provided by distributors who are able to use ripple control to reduce demand (in the short term) from consumers (mostly from domestic hot water cylinders).

[2] Interruptible Load is expected to respond with 1 second of the frequency falling to 49.2 Hz.

2.9 The system operator co-optimises the reserve market with the energy market using the scheduling, pricing and dispatch model (SPD) to meet demand and security constraints at the lowest cost possible. For example, when reserve costs are high than reducing the generation output of the largest generator, and dispatching a higher cost generator instead, would reduce required reserve and could reduce overall costs.

2.10 The HVDC is the link between the transmission grid in the North Island (at Haywards) and the South Island (at Benmore). It usually flows north so generation from the large hydro lakes in the South Island can cover demand in the North Island.

2.11 Prior to 2007 the HVDC had two poles, known as a bi-pole, which allowed higher energy flows between the islands, and reduced the risk of separation of the two Islands. Pole 1 decommissioned in 2007 for safety concerns, and there was only one pole until pole 3 was ready for operation in 2013.

2.12 The new control system for the HVDC which was implemented in 2014 after Pole 3 became operational also made it possible to introduce a national market for instantaneous reserve.

Terminology

Term	Acronym	Definition
Instantaneous reserve	IR	Generating capacity, or interruptible load, available in the event of a sudden failure of a large generating plant or the HVDC link.
Contingent Event	CE	The loss of a single block of generation in service, or the loss of one HVDC pole.
High voltage direct current	HVDC	The link between the transmission grid in the North Island and South Island, connecting Haywards to Benmore.
Scheduling Pricing and Dispatch model	SPD	This model takes generation and reserve offers, and dispatches them to meet demand at the lowest total cost of generation and reserve, while satisfying the many constraints on the system
National Market for Instantaneous Reserve	NMIR	A market for reserve which allows reserve procured nationally, letting reserve in one island cover risks in the other island, allowing for HVDC constraints.
Fast instantaneous reserve	FIR	Reserve which can respond within 6 seconds. FIR is procured in sufficient quantity to ensure frequency does not fall below 48Hz.

Sustained instantaneous reserve	SIR	Reserve which can respond within 60 seconds and remain on for 15 minutes. SIR is procured in sufficient quantity to ensure the frequency is returned to 49.25Hz within 60 seconds of a contingent event. This ensures the power system is kept stable long enough for the system operator to dispatch generation to return the system to a secure state.
Bi-pole mode		When two poles are in operation on the HVDC, allowing increased flows, as well as flows in both direction (round power), and a degree of redundancy should one pole fail.
Interruptible Load	IL	Load of large power users which they are willing to interrupt for a short period.[3]
Risk setter		For each island the risk setter is either the generator or the HVDC, that constitutes the larger net risk in that island.[4]
North Island/South Island	NI/SI	The price of reserve is calculated by island both before and after NMIR. Energy prices used to compare to reserve prices have been taken from the Haywards node and the Benmore node.

[3] Some IL is also provided by distributors who are able to use ripple control to reduce demand (in the short term) from consumers (mostly from domestic hot water cylinders).

[4] The HVDC CE risk takes into account the redundancy provided by the remaining pole

3 The changes that were implemented

3.1 Previously instantaneous reserve was procured separately in each island according to the biggest risk in each island (commonly the loss of a large generating unit or the net reduction in flow following the loss of one Pole of the HVDC). However, once the full bi-pole control mode was available for the HVDC it became possible to share reserve between the islands (ie, in both directions) in most trading periods.

3.2 The objective of introducing NMIR was “increasing the competition to supply reserve and improving operational efficiency by reducing overall reserve requirement.[5]

3.3 Initial changes were made to allow a limited degree of FIR and SIR sharing across the HVDC before introducing a national market, with the national reserve market fully implemented at the end of 2016.

3.4 Changes were made to the SPD to allow the system operator to procure reserve from either island to cover the single greatest contingent event risk in either Island subject to the physical limitations of the HVDC configuration. These changes were the main cost of introducing the NMIR at an estimated $3.0 million to $4.8 million.

3.5 FIR needs to be able to respond quickly, in 6 seconds or less; therefore, it is less effective to acquire FIR from across the HVDC due to time lags in the control system, eg, if 80MW of FIR is needed in the North Island than the SPD requires at least 100MW of FIR from the South Island to ensure at least 80MW reaches the North Island within 6 seconds.

3.6 Changes were not required to participant systems. Reserve prices continue to be determined and published for each island. Participants enter offers in the same format as previously, and settlement is worked out the same way as it had been prior to the NMIR.

[5] Wholesale Advisory Group, *National Instantaneous Reserve Market recommendations paper*, July 2013

Timeline

3.7 HVDC pole 3 came into operation on 29 May 2013 allowing the HVDC to operate in bi-pole mode. This allowed power to flow in opposite directions in each pole (round power mode) and enabled the system to share reserve between the islands.

3.8 A report prepared in July 2013 for the Wholesale Advisory Group (WAG) concluded that implementing a NMIR would result in a substantial net economic benefit and recommended prioritising the implementation of the NMIR.

3.9 A proposal paper was released in November/December 2014 on "Enabling a national market for instantaneous reserve". It proposed changing the SPD to allow the NMIR to start in mid-2017. All feedback received from the consultation supported establishing the NMIR and the only concerns raised were in relation to some of the technical aspects of the changes.

3.10 There were already processes in place to allow 50MW of FIR to be shared between the islands, but in December 2014 the SPD was changed to increase the amount of FIR sharing to 60MW.

3.11 In September 2015 the SPD was changed to also allow up to 60MW of SIR to be shared between the islands. This was considered an interim change to be made in advance of the introduction of NMIR.

3.12 The NMIR was introduced on 20th October 2016. The NMIR allowed reserve to be procured nationally, using the cheapest combination of reserve between the two islands to cover the risks in both islands. Initially the amount of reserve that could be procured in one island to cover was capped at 60MW per trading period. This capacity was then increased to 120MW on 3rd November and then to 220MW on 17th November 2016.

3.13 The NMIR has been fully functional since then, excluding a brief period of planned HVDC outages. There are trading periods where reserve sharing is limited by either constraints of the HVDC or because the HVDC is a risk setter in one island, at which point the market may behave more like two separate markets. As this is a feature of having a NMIR it is taken into account in the analysis.

4 The costs and benefits identified in WAG report and proposal paper

4.1 Both the WAG report and the proposal paper included expected benefits from cost benefit analysis. This analysis included both the impact of the bi-pole and the NMIR.

4.2 The proposal paper[6] reported a one off cost of the NMIR to the system operator of between $3.0 million to $4.8 million. This estimate covered the cost of changing the SPD and associated business costs, such as retraining staff who used the SPD.

4.3 The analysis identified that the changes would reduce the total amount of reserve procured as reserves procured in one island could cover a contingent event in the other island, provided the HVDC was not the risk setter.

4.4 The cost benefit analysis (CBA) also identified cost savings of around $1.5M per year through reduced reserve provision costs and reduced generation costs.

(a) “The WAG estimates that a NMIR would conservatively deliver economic benefit of approximately $1.5M per year…through reduced reserve provision costs and reduced generation costs”.[7]

(b) “A national market is…expected to reduce costs in the wholesale market. A provisional analysis using vSPD indicates that these could be of the order of $1.75 million per year…”[6]

4.5 The proposal anticipated that introducing the NMIR would reduce reserve provision costs as reserve could be procured from the cheapest source. Hydro generators are usually able to provide reserve at a low cost even when they are not running (tail water depressed reserve). However, most thermal generators take time to ramp up generation from zero, with significant start-up costs, meaning that forecast energy and reserve prices must be high enough to justify starting up the thermal generator.

4.6 As the South Island has more hydro generation, the NMIR could give the North Island access to cheaper reserves from the South Island.

[6] Electricity Authority, *Enabling a national market for instantaneous reserve: proposal to make changes to SPD*, November 2014

[7] Wholesale Advisory Group, *National Instantaneous Reserve Market recommendations paper*, July 2013

4.7 There may also be some benefit from NMIR deferring the need for investment in peaking capacity due to less reserve being procured during peak load.

(a) "It has been suggested that a NMIR might also deliver additional economic benefits of at least $7M per year… by deferring the need for investment in peaking capacity." [7]

4.8 Higher reserve prices in the South Island could also encourage increased participation in the reserve market in the South Island. [8]

(a) "There may also be dynamic efficiency benefits as a result of new reserve providers entering the market in the South Island."[9]

[8] For example, more users or distributors could offer interruptible load in the South Island

[9] Wholesale Advisory Group, National Instantaneous Reserve Market recommendations paper, July 2013

5 Understanding the effects of the scheme compared to the CBA

5.1 We initially used the framework from the CBA to assess the actual impact of the NMIR. We found that the physical impacts assumed by the CBA were correct. Reserve sharing between the islands reduced the overall quantity of reserve needed and the national market increased the amount of reserve procured from the South Island.

5.2 However, we did not find evidence that reserve provision costs were reduced, or at least not to the degree expected as a result of increased competition in the reserve market. There was some evidence that reserve offers may have been increased to stop North Island reserve prices from dropping, and South Island reserve prices increased as expected, meaning overall prices increased.

5.3 But the underlying assumptions that economic costs would reduce were still sound, less reserve was used and more came from cheaper sources, and generation costs were most likely cheaper than they would have been otherwise, especially during peak load. However, offer changes, and the resulting wealth transfers, make it difficult to model the value of the economic benefit beyond what was already modelled in the CBA.

5.4 There has not yet been evidence that NMIR has delayed peak load investment or encouraged increased participation in the reserve market[8] in the South Island, but these benefits could still be realised in the future.

Four key changes to the market

5.5 Four events are marked on the graphs in this section to indicate changes in the market, they are explained as follows:

(a) **Bi-pole:** HVDC pole 3 comes into operation allowing the HVDC to operate as a bi-pole from 29 May 2013. This increases capacity of the HVDC and enables the system to share reserve between the islands, starting with 50MW of FIR.

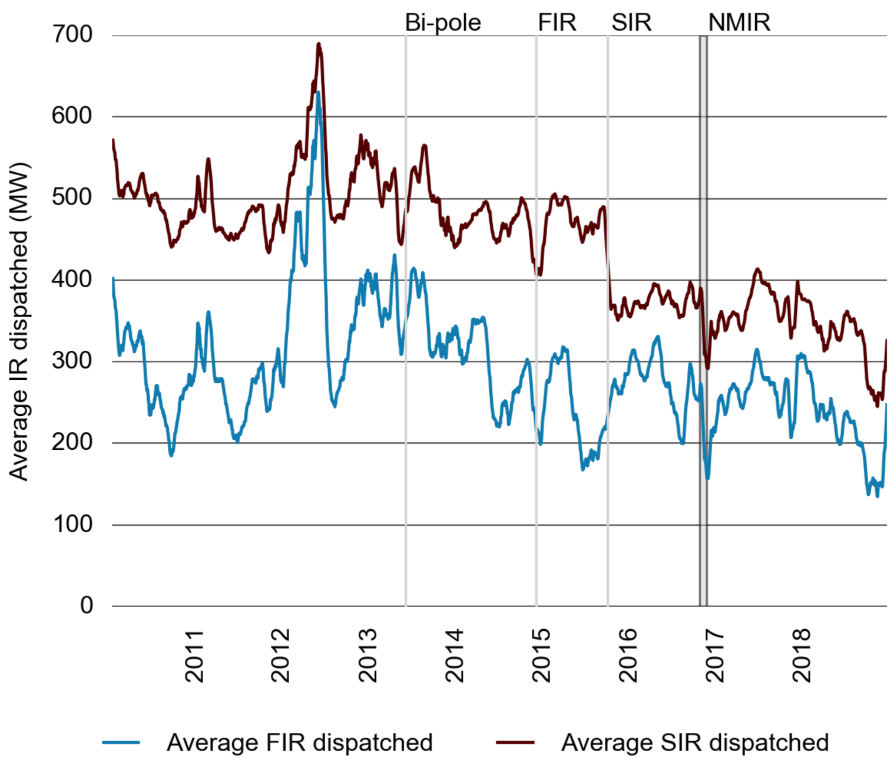
(b) **FIR:** The SPD is changed to allow up to 60MW of FIR to be shared between the Islands in December 2014.

(c) **SIR:** The SPD is changed to allow up to 60MW of SIR to be shared between the Islands in September 2015.

(d) **NMIR:** The national market for instantaneous reserve was introduced on the 20th October 2016, with capacity limited at 60MW. This capacity in increased to 120MW on 3rd November and then to 220MW on 17th November.

Sharing reserve decreased the quantity of dispatched reserve

Figure 1: Quantity of FIR and SIR dispatched nationally (28-day moving average)



5.6 The cost benefit analysis predicted that the introduction of the bi-pole and the NMIR would reduce the overall quantity of reserve dispatched.

5.7 Prior to the bi-pole coming into operation, the quantity of FIR dispatched fluctuated between 200 to 400MW, with a brief high period in 2012 when high flows on the HVDC southwards required higher amount of reserve.

5.8 When the bi-pole operation started FIR sharing started at 50MW which than increased to 60MW at the end of 2014. This had the combined effect of reducing FIR dispatched to below 350MW. Since FIR was introduced it has rarely been over 300MW.

5.9 The quantity of SIR fluctuated around 500 MW until the introduction of the bi-pole. The change in September 2015 to allow up to 60MW of SIR to be shared between the islands in either direction, reduced dispatched SIR by about 120MW to less than 400 MW, and since NMIR was introduced it has fluctuated between 250 and 400MW.

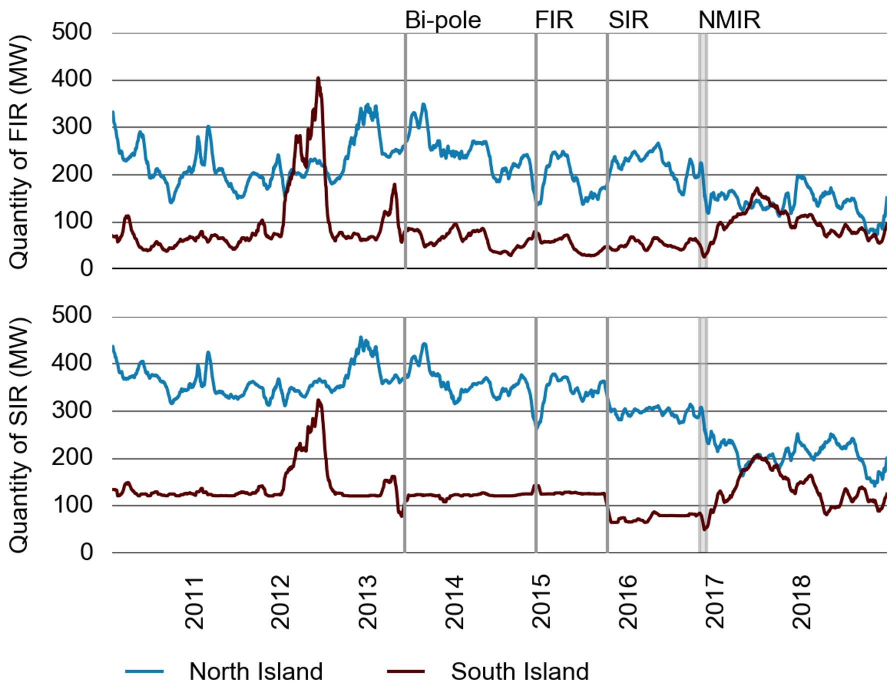
5.10 The changes had a bigger impact on the quantity of SIR dispatched because sharing FIR over HVDC is less efficient due to time lags.[10]

The NMIR increased the quantity of reserve dispatched from the South Island

5.11 The cost benefit analysis predicted that the NMIR would result in a decrease in the quantity of reserve dispatched from the North Island and an increase from the South Island.

5.12 In the North Island the quantity of both FIR and SIR was highest prior to the introduction of the bi-pole. Both reserve sharing and the national market reduced the quantity of reserve dispatched in the North Island, especially for SIR which almost halved from around 400MW to 200MW.

Figure 2: Quantity of FIR and SIR dispatched by island (28-day moving average)



[10] See paragraph 3.5, on page 12

5.13 In the South Island prior to NMIR the quantity dispatched was usually steady at 120 MW for SIR and under 100 MW for FIR in most periods, indicating the amount of reserve needed to cover the biggest generators in the South Island. It increased dramatically in 2012 when high flows south increased the amount of reserve needed to cover the HVDC.

5.14 The introduction of the NMIR saw the South Island quantity of FIR and SIR increase and become more variable, as it began to be used to cover North Island generation as well as South Island.

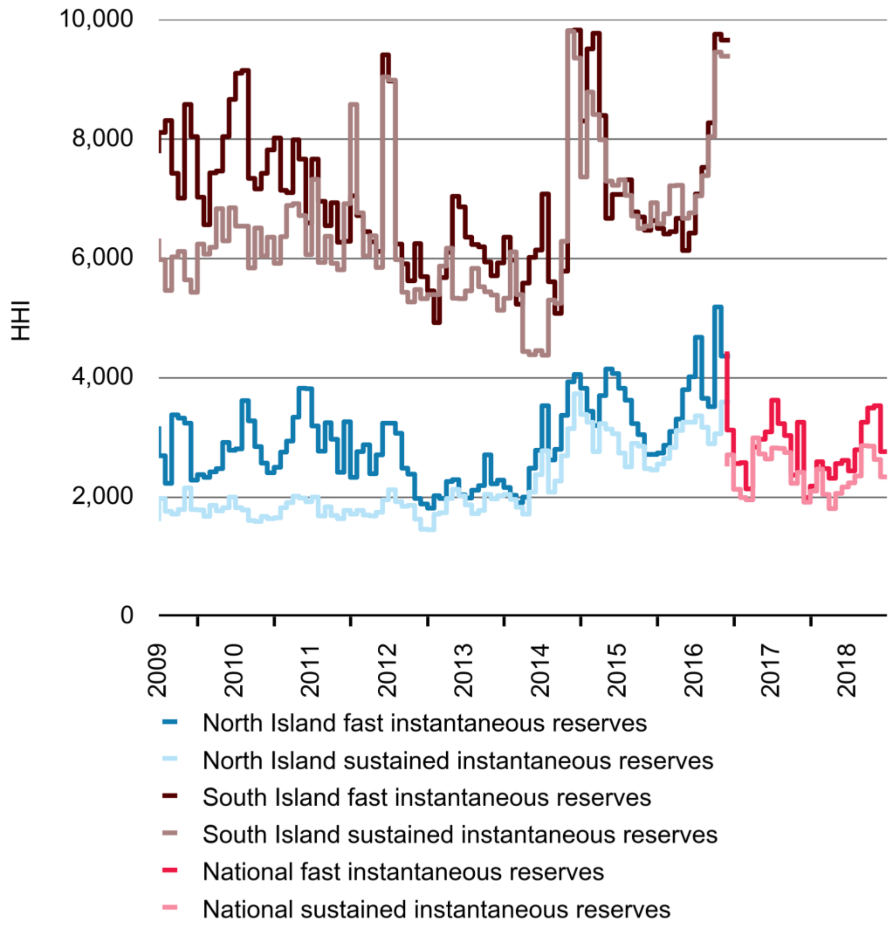
5.15 The changes are more distinctive for SIR than for FIR, especially in terms of the amount of reserve needed in the North Island. Again, this may be due to the inefficiencies from sharing FIR across the HVDC.

5.16 The quantity of reserve dispatched in the North Island did not trend towards zero though. There is a limit to the amount of reserve which can be shared over the HVDC and also in every trading period there needed to be enough reserve in the North Island to cover an HVDC contingent event. The North Island providers do not have to compete with South Island providers for that particular amount of reserve.

NMIR brought overall competition in line with North Island competition

5.17 The cost benefit analysis predicted that the NMIR would increase competition in the reserve market. The HHI (Herfindahl–Hirschman Index) is a measure of competition in a market, where a score of 10,000 indicates a monopoly and lower scores indicate less concentrated market structures.

Figure 3: HHI for the instantaneous reserve market

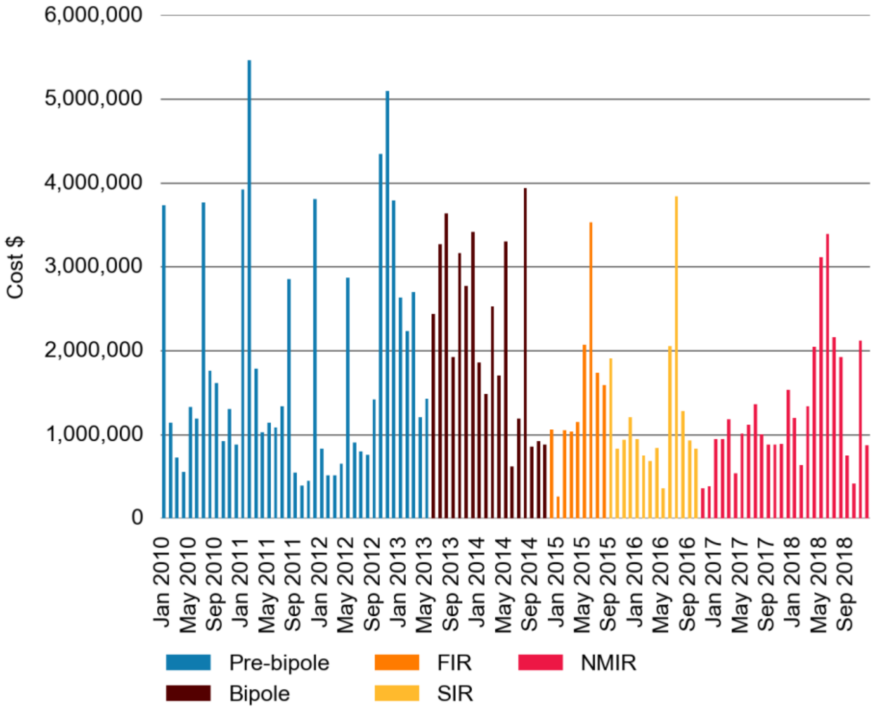


Source: System operator

5.18 The HHI was higher in the South Island than the North Island due to the presence of more diverse ownership of generation plants in the North Island and other reserve providers. The HHI brought the South Island into competition with the North Island and the result was an HHI that was lower than previously seen in the South Island but not significantly different to the HHI already seen in the North Island.

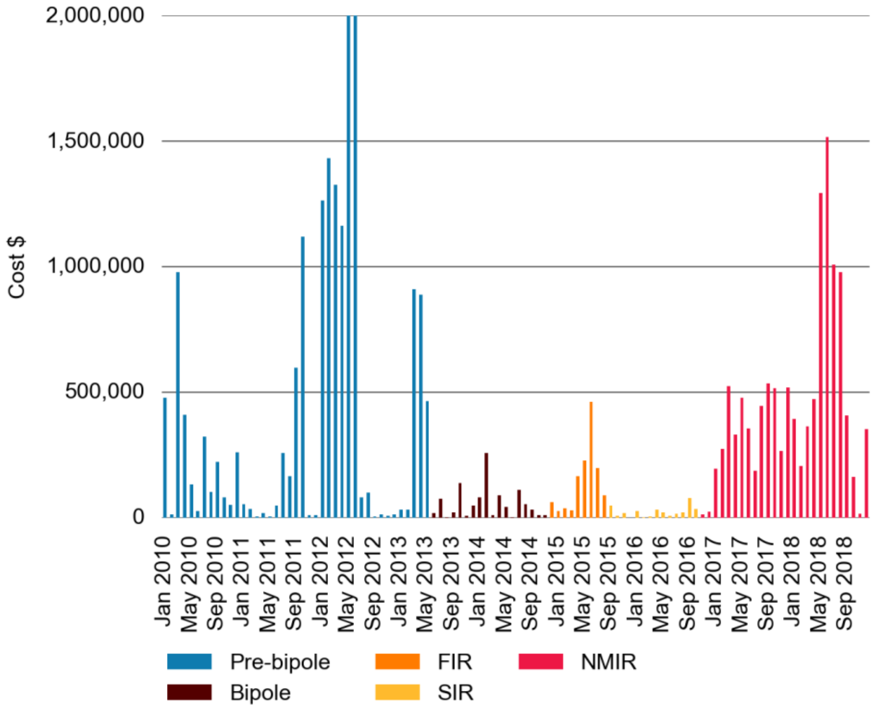
NMIR increased monthly payments for South Island reserve

Figure 4: Total monthly payments on instantaneous reserve for the North Island



5.19 Monthly payments for reserve in the North Island are volatile, ranging from less than $1 million to $5 million per month. It is hard to find a clear pattern of changes due to NMIR. While there were no payments higher than $2 million in the first year of NMIR, there were several months higher than $2 million in the second year.

Figure 5: Total monthly payments on instantaneous reserve for the South Island

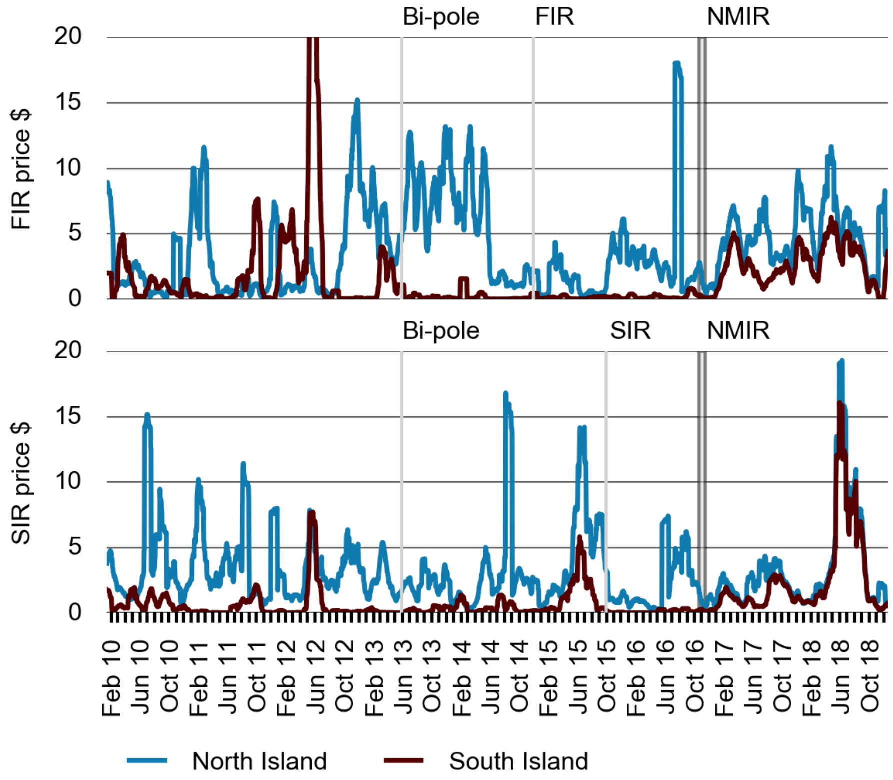


5.20 Note for Figure 5, the payment in May 2012 was $11m and in June 2012 was $7m during which time there was low storage in the South Island.

5.21 Prior to NMIR the monthly payments for the South Island were quite low, only rarely above $500,000 and often much lower. Payments were especially low after the bi-pole was introduced; averaging about $65,000 a month. Since the national market started, payments made to the South Island averaged about $500,000 a month. Excluding the outlier months in 2012, it is clear that the national market increased reserve payments to the South Island.

NMIR increased South Island prices to be in line with North Island prices

Figure 6: Price of FIR and SIR by Island (28 day moving average)



5.22 Prior to the introduction of NMIR the average price for reserve in the South Island was usually much lower than in the North Island, except around 2012 when the South Island prices were very high. There was also no clear relationship between the South Island and North Island price of reserve.

5.23 Since NMIR started the price in the South Island closely followed the price in the North Island most of the time, as expected from introducing a national market.

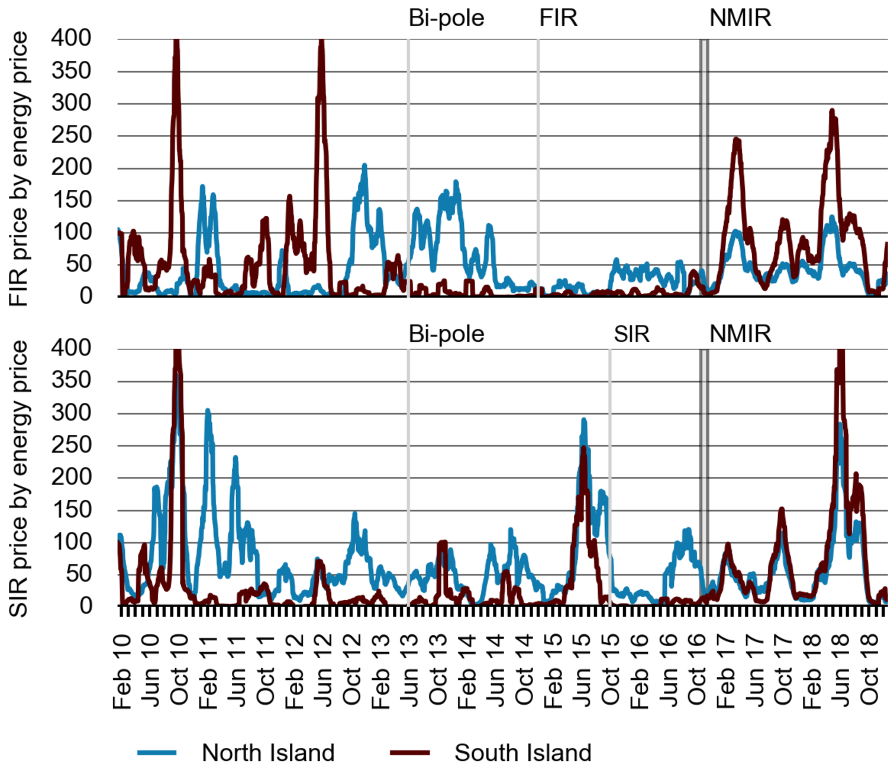
5.24 Price separation did still occur after NMIR was introduced, driven by constraints of the HVDC. This was more common for FIR where reserve sharing was less efficient due to the need of a quick response.[11]

5.25 This led to an overall increase in the price for the South Island, as expected, but with no clear indication of a decrease in North Island prices. It was expected that the

[11] Price separation in November 2018 was due to a planned HVDC outage from the 22nd to 25th of November, which prevented reserve sharing

increased competition would bring North Island prices down. It is possible that this just reflects energy prices, so we compared the reserve price to the energy price.

Figure 7: Index of reserve prices by energy prices in North Island (28-day moving average)



5.26 The price of FIR relative to energy price was initially quite volatile. When the bi-pole came in there was a drop in the price of FIR relative to energy price. Since NMIR started the price of reserve by energy price has been relatively high for an extended period for both FIR and SIR.

5.27 The price of SIR relative to energy price has not followed any noticeable pattern through the transition period. There was a period of relatively high prices for SIR in 2010 and recently in 2018 for both FIR and SIR.

5.28 Therefore the reserve prices after the national market started cannot be explained solely based on changes to the energy price.

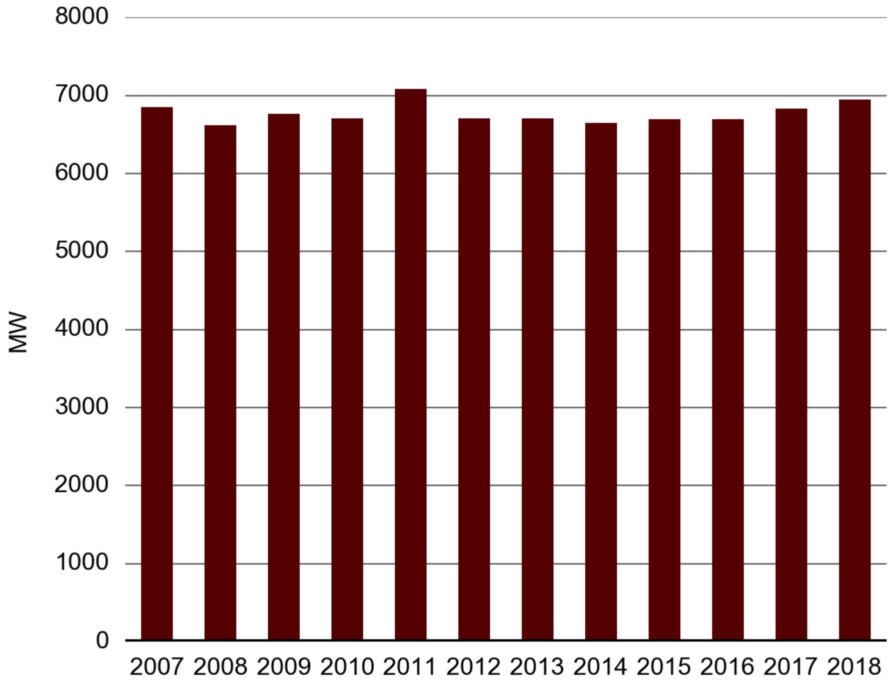
NMIR could defer the need for investment in peak generation

5.29 The CBA also claimed a benefit of $7 million per year from 2018 onwards as a result of delayed investment into peak generation, due to less reserve being procured during peak load.

5.30 The ability to share reserve between the two islands did reduce the amount of reserve procured in the North Island during the peak demand trading periods in 2017 and 2018. During the trading period with peak demand in 2017, an additional 206 MW of SIR would have been needed in the North Island and in 2018, an additional 176 MW of SIR needed in the North Island if South Island reserve had not been used to cover some of the North Island's reserve need.

5.31 While the 2017 and 2018 demand peaks were higher than the previous five years, they were still lower than the peak in 2011. The flat growth in peak load means that there has not yet been a need to invest in peak generation. The additional 150–200 MW provided by NMIR likely delay investment in peak generation when demand growth starts to pick up again, and it certainly helped to keep the cost and security risks down during these peak load periods.

Figure 8: Peak Demand 2007–2018



NMIR kept the cost of energy down

5.32 Related to delaying investment in peak generation, the NMIR probably reduced cost of energy, especially during periods of peak generation, by freeing up generation capacity that would have otherwise been used for reserve.

5.33 It is difficult to find out the amount by which NMIR reduced energy costs due to the high variability in the market and the indication that reserve offers were changed.

No new entrants to the South Island reserve market yet

5.34 The CBA stated that there could be additional benefits from new reserve providers entering the South Island market, without explicitly valuing this benefit. So far there have not been any new entrants into the reserve market.

Attempts to estimate changes to the economic cost of NMIR indicated potential changes in offer behaviour

5.35 The cost benefit analysis estimated that one benefit of introducing NMIR would be that the economic cost of providing reserves would reduce by $1.5m per annum.

5.36 The NMIR was assumed to reduce economic costs, by:

(a) reducing the total amount of reserve dispatched; and

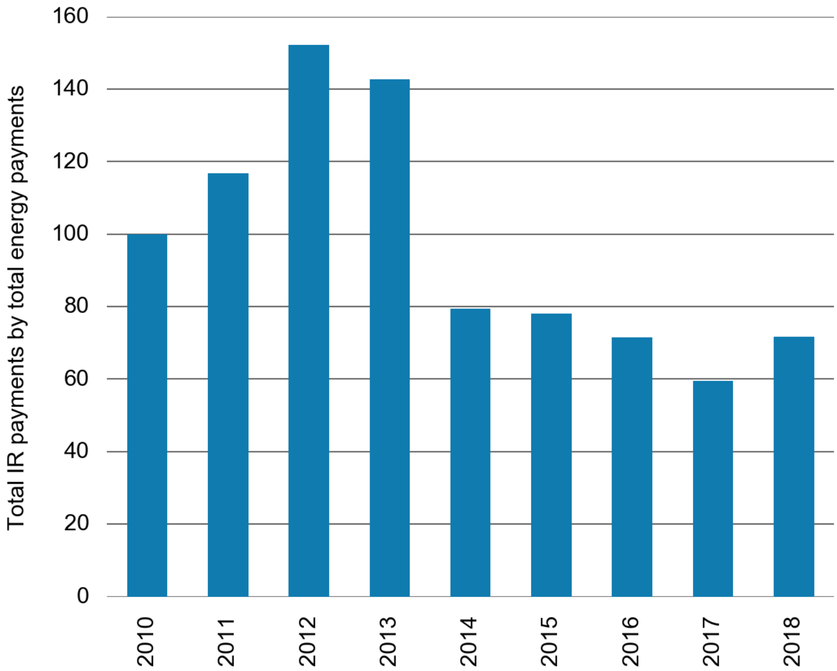
(b) allowing reserve in one island to substitute for (more expensive) reserve in the other island.

5.37 We can see that these have happened, Figure 1 shows that the total amount of reserves dispatched has dropped compared to before the bi-pole. Likewise, since NMIR started, more reserve has been dispatched from the South Island and less from the North Island (see Figure 2), which on average is more expensive.

5.38 We could estimate economic costs by looking at changes to payments to reserve providers. The payments for reserve did drop when Pole 3 became available, but have risen again since the NMIR started. While the annual payment in 2017 was one of the lowest since 2010, 2018 was one of the highest. However, given the variation seen between 2010 and 2013, before any changes to the market, we need to take into account other factors that could impact payments for reserve.

5.39 To note, a change in the payments for reserve do not represent a change in economic costs if underlying costs of providing reserve have not changed. Instead they represent a wealth transfer. Reserve payments are paid for by generators operating units above 60MW and Transpower (for the HVDC link)[12]. An increase in reserve payments without underlying cost changes would be a wealth transfer from these generators and Transpower to the generators who provide reserve and interruptible load providers.

Figure 9: Index of annual payments for reserve by energy payments



5.40 The main factor which impacts the cost of reserve is the cost of energy. Figure 9 shows the index of reserve payments by energy payments for 2010 to 2018. We see that there has been a drop between 2013 and 2014, which coincides with when the bi-pole returned into operation, and since then the index value has remained about the same.

5.41 This change captures the savings that were found from reducing the amount of reserve needed, but it does not show any savings in economic cost from substituting

[12] Additionally, generators who cause contingent events are charged $1,250 per MW of lost injection. This payment is rebated to generators and Transpower who paid for the reserve. This provides incentives to generators to not cause a contingent event.

North Island reserve with cheaper South Island reserve, even though we know this happened. However, this only represents what was paid for reserve and not the actual economic cost of reserve. As noted above, it may only represent a wealth transfer from larger generators to reserve providers.

5.42 Another way to estimate the change in the economic cost would be to look at the reserve offer stacks. In fact, the methods used in the CBA assumed that the offer stacks were equal to the marginal cost of providing reserve and would not change in response to the NMIR. One method looked solely at the offer stacks to estimate the economic cost using the reserve stack models.

5.43 The model assumed the offer stack would not change and estimated the change in economic cost as the difference between the:

(a) simulated reserve provision cost without a NMIR, calculated as the sum (over cleared reserve offers) of the actual cleared quantity multiplied by the actual offer price; and

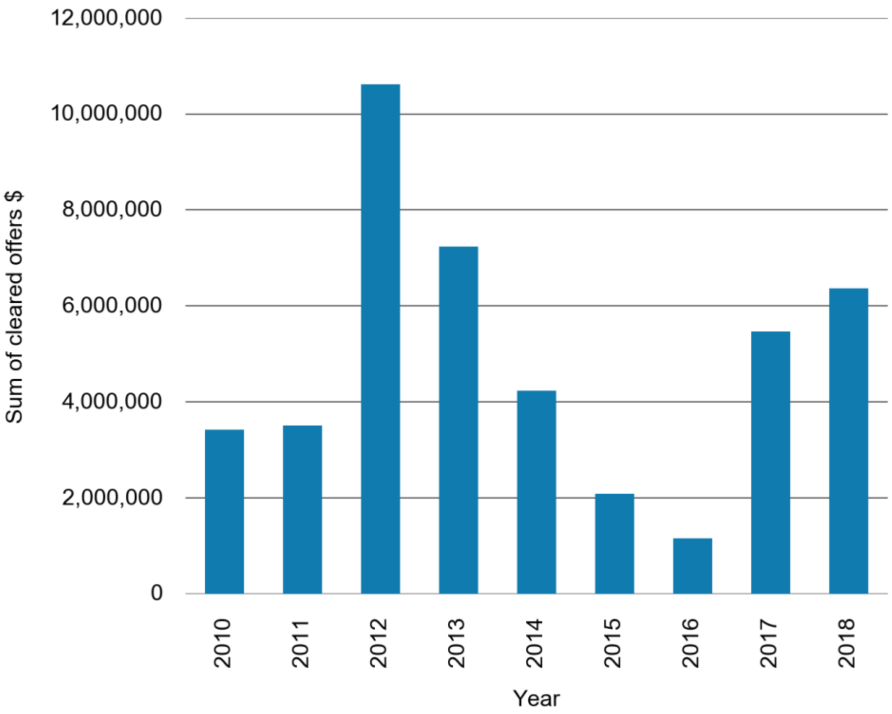
(b) simulated reserve provision cost under a NMIR, calculated as the sum (over reserve offers cleared in the simulation) of the simulated cleared quantity multiplied by the actual offer price.

5.44 When using the offer stacks to estimate changes in economic cost we would need to assume that the offer stacks accurately reflected marginal costs and that the NMIR did not have a major impact on marginal costs.

5.45 The cost analysis noted the limitations of this assumption. It should be reasonable when focussing on marginal suppliers, because those parties will presumably not offer their resources if the revenue does not cover costs. Furthermore, if the offer price is persistently above the full cost of supply, this is likely to attract alternative providers (absent barriers to entry).

5.46 However, this logic does not necessarily hold for offers by non-marginal suppliers. Providers with resources that have a high commitment cost or lead time may prefer to offer their resource at below full production cost to ensure commitment, and rely on an expectation that the clearing price will be acceptable. This means that offer prices for non-marginal reserve may not be a good indicator of economic cost.

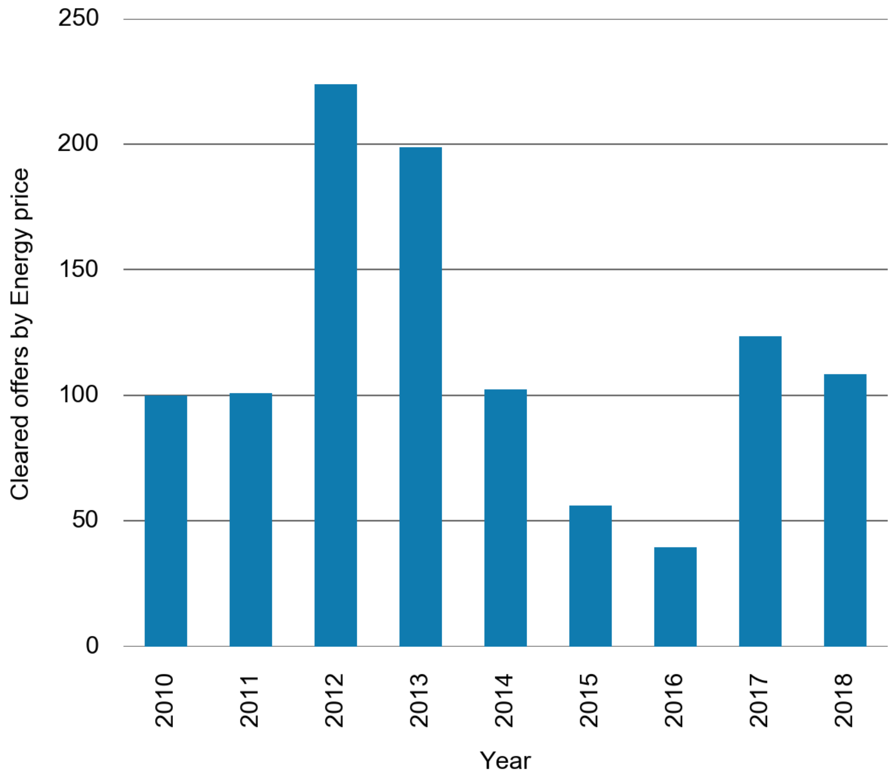
Figure 10: Sum of cleared quantity of reserve multiplied by the offer price, 2010–2018



5.47 If we assume that the offer price did equal the marginal cost in every year, then the economic cost of reserve decreased significantly in 2015 and 2016. This coincides with when the quantity of reserve dispatched decreased as sharing over pole 3 increased, and supports the assumptions made in the CBA.

5.48 However, holding to this assumption also suggests that the cost of reserve then increased significantly when NMIR started at the end of 2017. This is not what was expected, as there was a shift from reserve dispatched in the North Island to the South Island, which was historically cheaper, so we expect to see costs reduce even further, all other things being equal.

Figure 11: Index of cleared offer price by energy price, 2010–2018



5.49 Figure 11 is the same data as in Figure 10, but controlled for the energy price, to create an index. Again we find the same changes as in Figure 10, but to a lesser extreme. When energy prices are held constant, we find that the value of the offer stacks in 2017 and 2018 are higher than in 2010 and 2011.

5.50 It seems logical, therefore, that the offer prices in the stack do not always reflect the marginal price and they were changed to try to increase revenue from reserve. This is supported by our findings, which are elaborated on in section 6.

6 Impact the National Market had on reserve offers

6.1 The following section looks at the offers of reserve providers to assess whether or not there have been changes to offer behaviour as a result of introducing NMIR. If reserve providers were placing offers at their marginal cost we would not expect any noticeable changes in offers after taking into account other impacts on the marginal cost.

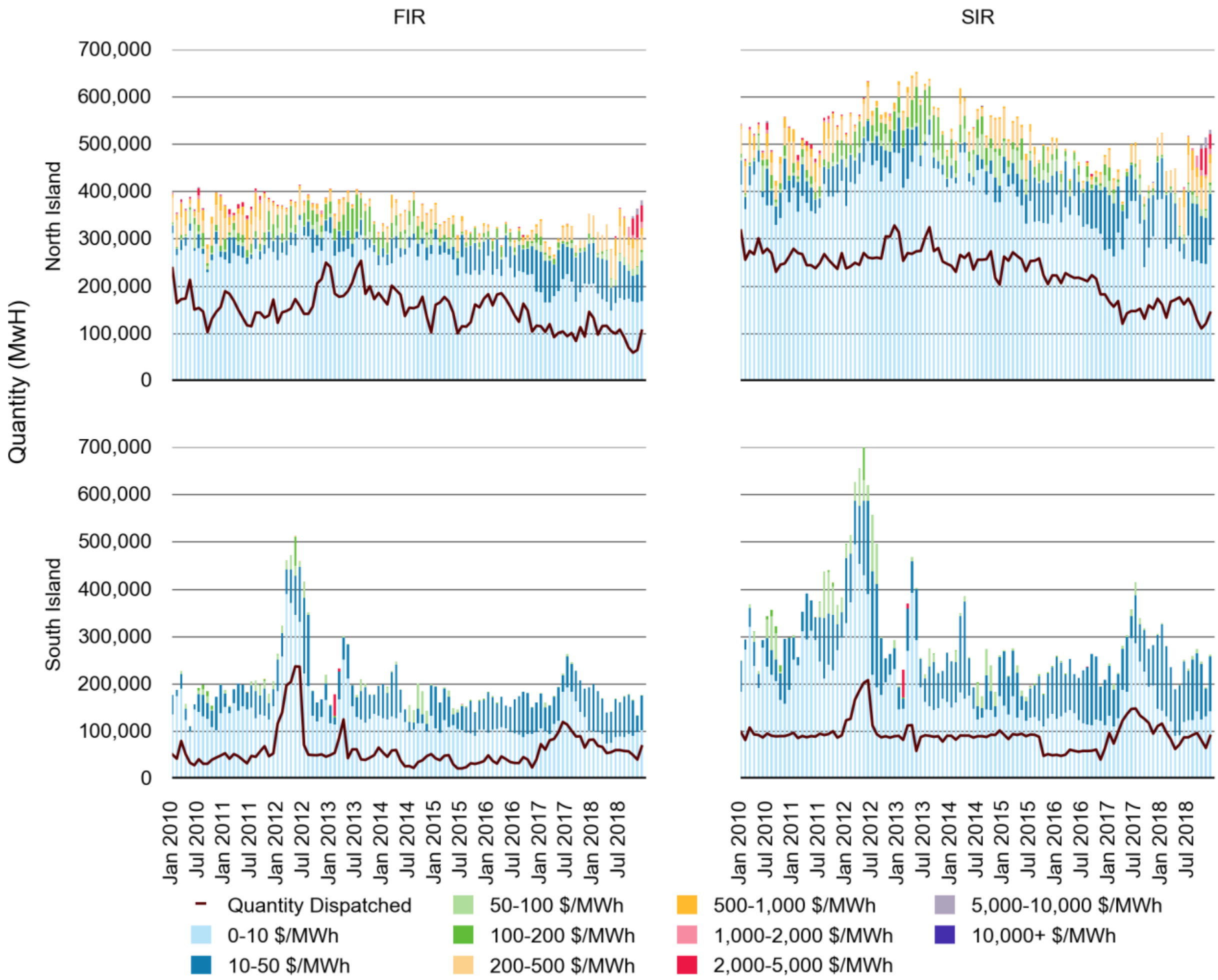
6.2 We found evidence of changes in offer behaviour in the North Island that was not fully explained by other changes such as the price of energy. We was also found that North Island reserve prices did not significantly change as a result of NMIR, suggesting that the changes to offers in the North Island stopped North Island prices from dropping.

6.3 Figure 12 shows the quantity of reserve offers in the market each month for each price band. The brown line shows the total quantity of reserve that was dispatched each month, which indicates on average how much excess capacity there was in the market, though this could vary by individual trading periods.

6.4 In the North Island there has been a decreasing trend in quantity offered at the $0–$10/MWh. There has also been an increase in the quantity offered at the $10–50/MWh price band, which is most noticeable for the North Island FIR offers.

6.5 In the North Island there has been an increase in offers in the higher price bands, especially in 2018 where some offers $1000/MWh. These high reserve offer prices could be due to the gas shortage and outages seen at the end of 2018.

Figure 12: Quantity of FIR and SIR offered and dispatched[13]



Regression Analysis

6.6 In order to check that the changes seen to offers are a result of the bi-pole and the national market and were not caused by other factors we developed a linear regression model of the average load weighted offer price of offers and the final reserve price, including the main factors that would influence reserve price, such as the energy price.

6.7 In any given trading period a generator may make several offers for a set load and price, which creates their offer stack. The load weighted offer price is the average of these offer prices weighted by the load offered in at each price point. An increase in

[13] Offer stacks excludes interruptible load

load weighted offer price may be due to an increase in the prices, a decrease in the load offered at low prices or an increase in the load offered at high prices.

6.8 In this section this is averaged over all generators (but excludes interruptible load). A look at individual generators offers and interruptible load offers is in section 7.

6.9 The model had several variables for factors we expected would have an impact on load weighted offer price, such as the energy price, and also two dummy variables for the two events, introduction of the HVDC bi-pole and the introduction of NMIR, to see if these events had significant impacts on the load weighted offer prices. As we are only interested in the impact of these two events only these results are shown.

6.10 The P value provides the probability that the null hypothesis is true. If there were no changes to offer behaviour after NMIR started we would expect the P value to be large. However, if the P-value is very small we can reject the null hypothesis which gives us evidence that there were changes to offer behaviour as a result of NMIR.

Table 1: Impact of bi-pole and NMIR on load weighted offer of FIR

Island	Change	Mean	Confidence Interval	Standard Error	P value
North Island	Bi-pole	-$81.47	(-$104,-$59)	$11.29	<0.001
	NMIR	$62.90	($41, $85)	$11.24	<0.001
South Island	Bi-pole	$8.34	($4, $12)	$1.85	<0.001
	NMIR	-$7.34	(-$11, -$3)	$1.85	<0.001

6.11 The results for FIR in the North Island estimate that when the bi-pole was introduced the load weighted offer price decreased by about $81. The introduction of NMIR increased the average load weighted offer price by almost $63.

6.12 The results for FIR in the South Island estimate that when the bi-pole was introduced the average load weighted offer price increased by about $8. The introduction of NMIR decreased the average load weighted offer price by around $7.

Table 2: Impact of bi-pole and NMIR on load weighted offer of SIR

Island	Change	Mean	Confidence Interval	Standard Error	P value
North Island	Bi-pole	-$15.46	(-$35, $4)	$9.91	0.119
	NMIR	$20.06	($1, $40)	$9.94	0.043
South Island	Bi-pole	-$0.61	(-$3, $2)	$0.95	0.520
	NMIR	$0.25	(-$2, $2)	$0.95	0.795

6.13 The results for SIR in the North Island estimate that when the bi-pole was introduced the average load weighted offer decreased by about $15 and the introduction of NMIR increased the average load weighted offer price by about $20.

6.14 The results for SIR in the South Island estimate a more than 50% chance that the load weighted offer price of offers did not change due to either the bi-pole or NMIR. The results for the South Island SIR are the only one consistent with the assumption that reserve offers would not change.

6.15 Note, an increase in the load weighted offer price might not always indicate an increase in the average price (or vice versa) as it is the marginal offer which determines the price.

Table 3: Impact of bi-pole and NMIR on price of FIR

Island	Change	Mean	Confidence Interval	Standard Error	P value
North Island	Bi-pole	$0.53	(-$13, $14)	$6.78	0.938
	NMIR	-$2.49	(-$16, $11)	$6.77	0.713
South Island	Bi-pole	-$1.41	(-$5, $2)	$1.63	0.395
	NMIR	$4.47	($1, $8)	$1.66	0.006

Table 4: Impact of bi-pole and NMIR on price of SIR

Island	Change	Mean	Confidence Interval	Standard Error	P value
North Island	Bi-pole	$2.49	(-$2, $7)	$2.08	0.233
	NMIR	$1.61	(-$3, $6)	$2.30	0.484
South Island	Bi-pole	-$2.95	(-$5, -$1)	$0.63	<0.001
	NMIR	$1.80	($0, $3)	$0.63	0.004

6.16 Table 3 and table 4 show the impact of NMIR and the bi-pole on final prices of reserve.

6.17 Only the prices in the South Island for NMIR reject the null-hypothesis. This is consistent with our earlier analysis which showed that South Island prices increased to be in line with North Island prices after the NMIR started. The null hypothesis is also rejected for the price of SIR in the South Island for the bi-pole.

6.18 The analysis found that the NMIR caused load weighted offer prices in the North Island to change but did not have an impact on the final offer prices, suggesting that changes to the offers were done in order to keep the North Island prices from dropping.

6.19 On the counter side, the fact that South Island prices increased even when there was no evidence of changes to offers indicates that those offering reserve in the South Island had little incentive to change their offers as they received higher prices anyway.

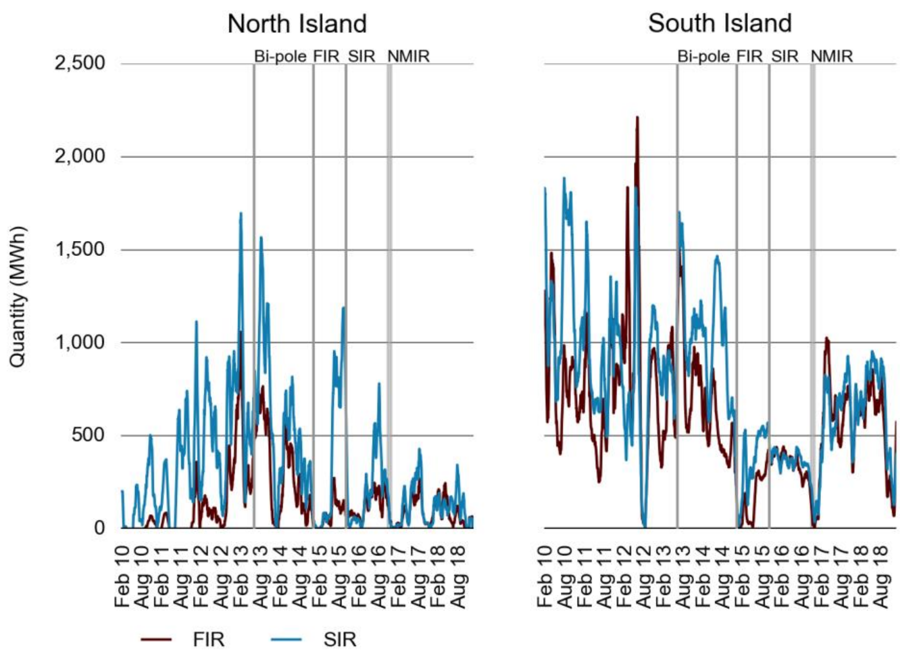
7 Individual generators' offer reactions to NMIR

7.1 The following section looks at generators where there is evidence that the introduction of NMIR had an impact on their offers. All of these generators trade in the North Island, which is consistent with the findings in the last section that there was no major impact on the offers in the South Island.

Contact

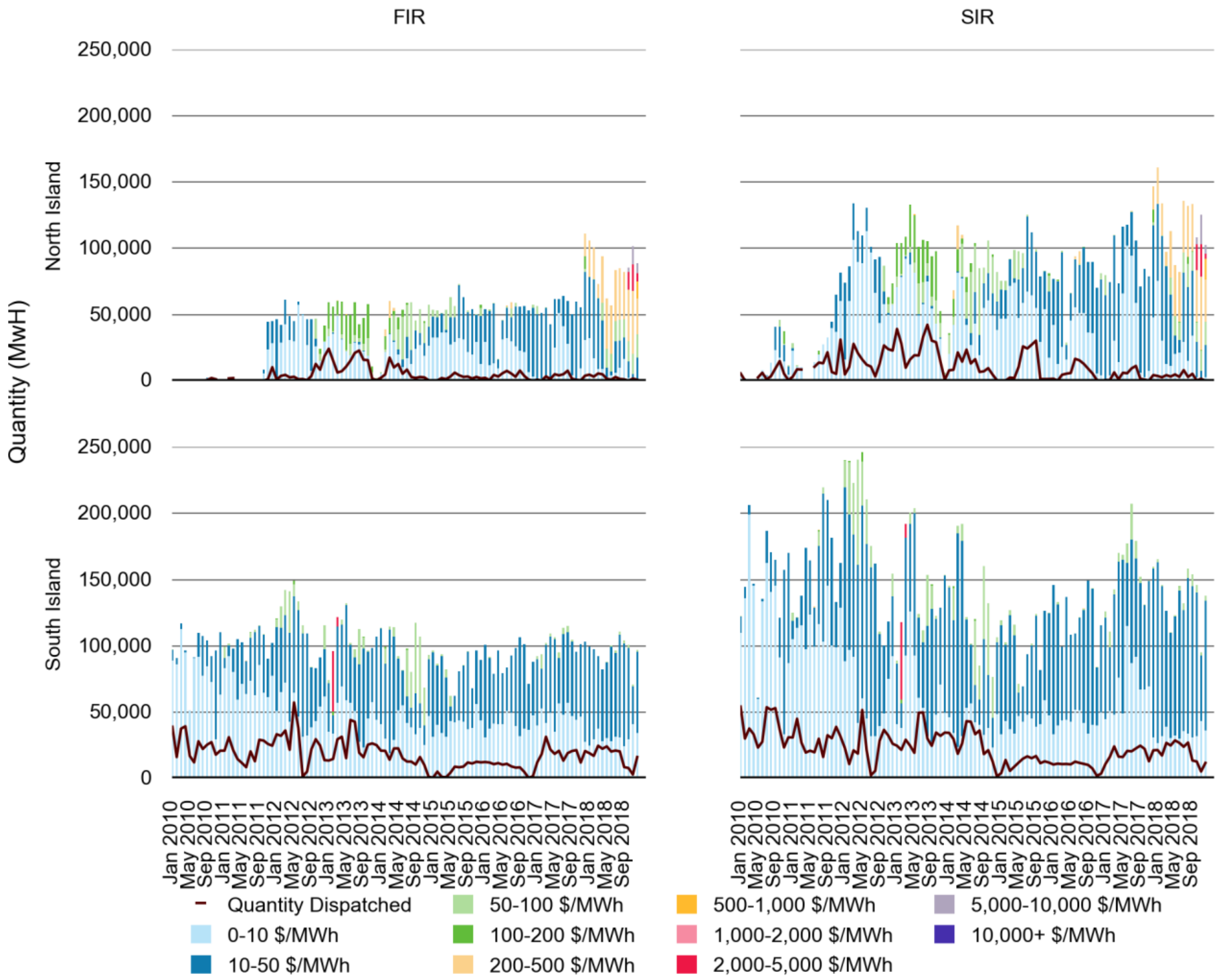
7.2 Contact offers reserve in both the North and South Island. The analysis of its offer behaviour suggests that it increased its offer prices in the North Island in an attempt to increase the reserve price and reserve revenue, especially in the South Island.

Figure 13: Contact's quantity of dispatched reserve



7.3 The quantity of reserve Contact dispatched dropped in the North Island with both the bi-pole and the NMIR introduction. In the South Island quantity of reserve dispatched dropped when the bi-pole was introduced but increased again after NMIR was introduced. The combined effect was more of Contact's reserve revenue coming from South Island reserve after NMIR was introduced.

Figure 14: Instantaneous reserve offers from Contact



7.4 Figure 14 shows the quantity of reserve offered by price bands. In the South Island there is some indication of a reduction in offers at the $0–10/MWh band and a decrease in the higher bands with more of their offers focused in the $10–$50/MWh range.

7.5 In the North Island the NMIR saw a drop in the quantity offered at 0–10 $/MWh price, and more offered at higher price bands especially the $200–500 $/MWh price band.

7.6 From the time NMIR began Contact's average load weighted offer in the North Island increased by about $51 for FIR and $60 for SIR. There could have also been an increase in the average load weighted offers after the bi-pole was re-introduced by about $46 for FIR and $14 for SIR, but these are less statistically significant.

Table 5: Impact of NMIR and bi-pole on Contact's load weighted offers in North Island

Type	Change	Mean	Confidence Interval	Standard Error	P value
FIR	Bi-pole	$45.58	($13, $78)	$16.57	0.006
	NMIR	$51.40	($19, $84)	$16.55	0.002
SIR	Bi-pole	$14.18	(-$2, $30)	$7.96	0.075
	NMIR	$59.85	($44, $75)	$7.96	<0.001

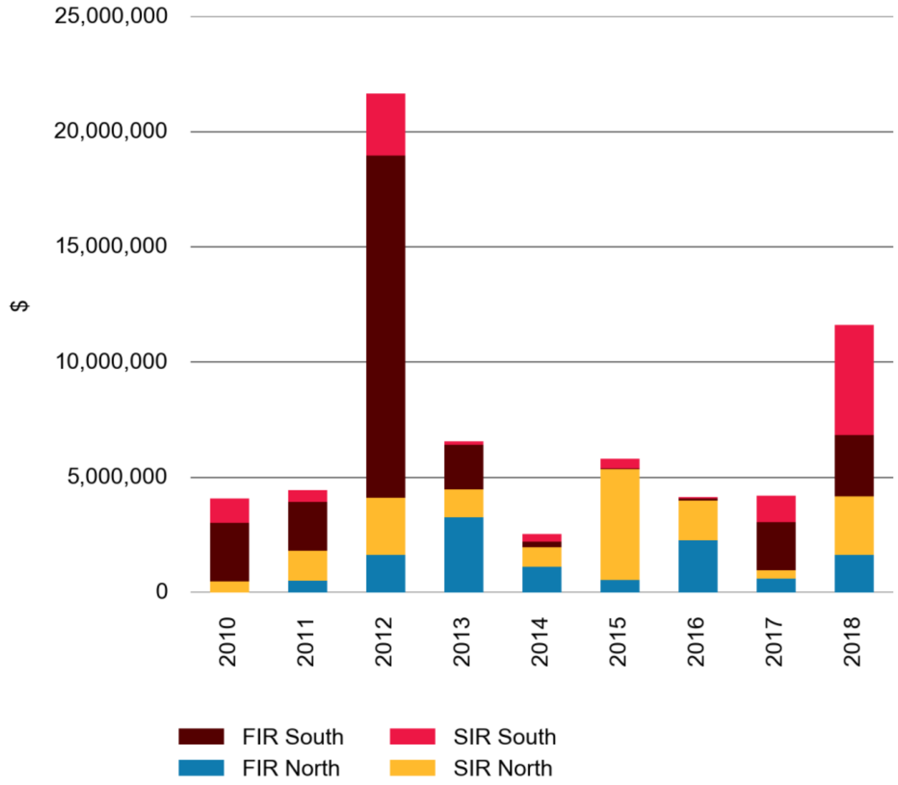
7.1 The quantity dispatched in the North Island reduced after the introduction of NMIR, so the increase in average offer price was not due to a decrease in competition in the North Island. Instead, it may have been an attempt to drive up prices of reserve in both the North and South Island to increase reserve revenue from the South Island.

Table 6: Impact of NMIR and Bi-pole on Contact's load weighted offers in South Island

Type	Change	Mean	Confidence Interval	Standard Error	P value
FIR	Bi-pole	$23.50	(-$5, $53)	$14.69	0.110
	NMIR	-$5.87	(-$35, $23)	$14.67	0.689
SIR	Bi-pole	-$18.98	(-$33, -$5)	$7.12	0.008
	NMIR	-$11.27	(-$26, $3)	$7.38	0.126

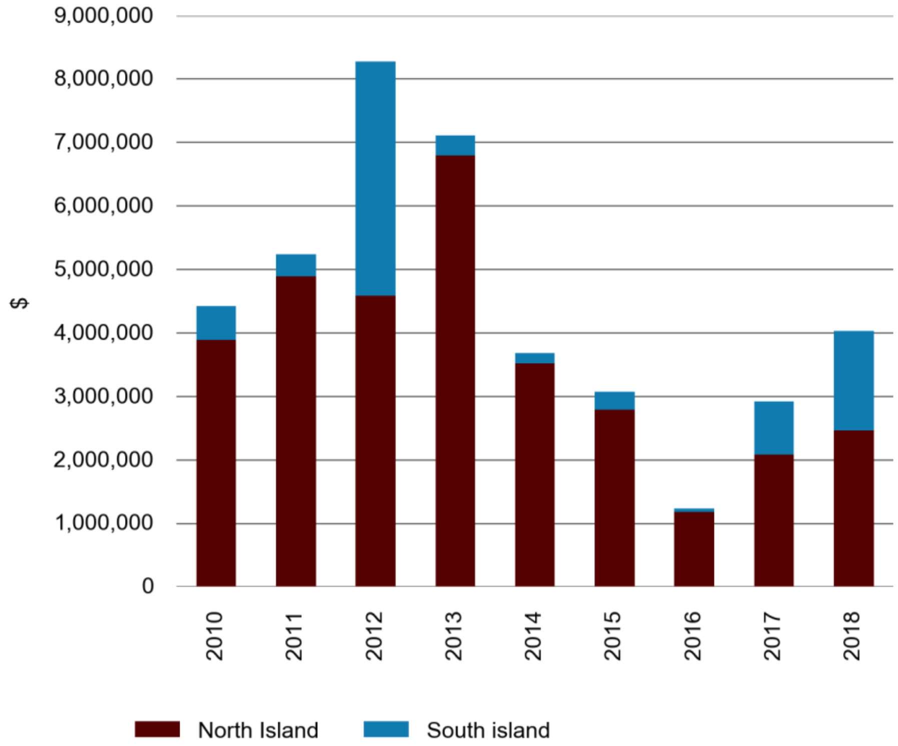
7.2 The introduction of the NMIR did not have any significant change on Contact's load weighted offers in the South Island. The bi-pole may have reduced Contact's average weight loaded offer price for SIR by about $19.

Figure 15: Contact's revenue from reserve payments



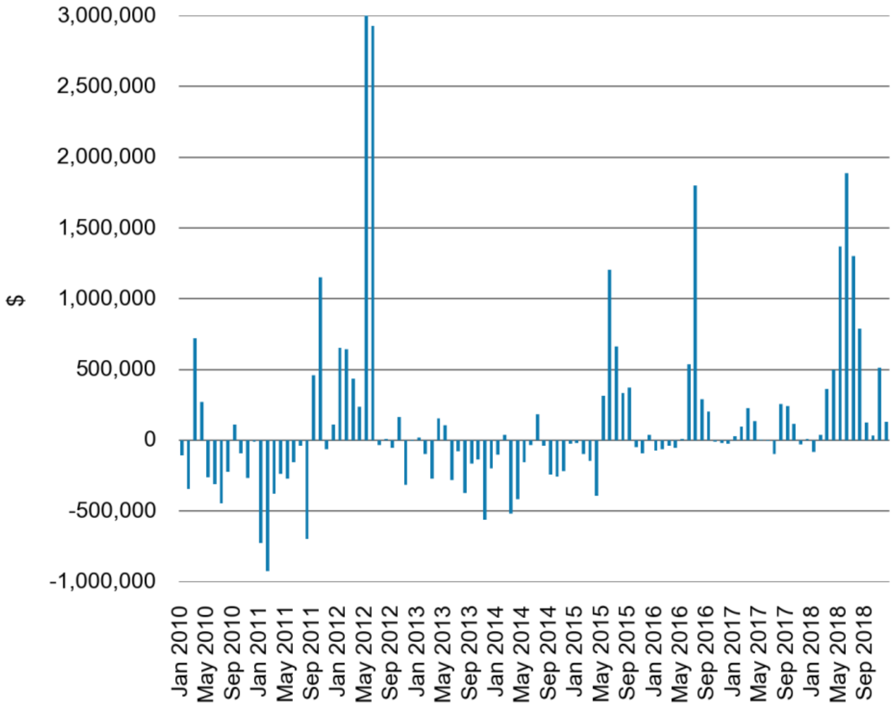
7.3 The introduction of the bi-pole saw Contact reduce the income it received from the South Island significantly. When the NMIR started Contact's revenue from the South Island increased. Overall revenue did not change significantly because of NMIR. 2012 and 2018 were the highest revenue years, which also correspond with periods of high energy prices in both these years.

Figure 16: Contact's payments for reserve to cover generation risk



7.4 Contact also had an obligation to pay for reserve to cover the risk of their large generation units. This is calculated separately for the North and South Islands, and the NMIR did have the impact of increasing Contact's payment obligation in the South Island. The decrease in payments in the North Island are due to a decrease in generation from large units in the North Island, Otahuhu B (380 MW capacity) generated less in 2014 and 2015 than previous years and was closed in September 2015.

Figure 17: Contact's net revenue from reserve market

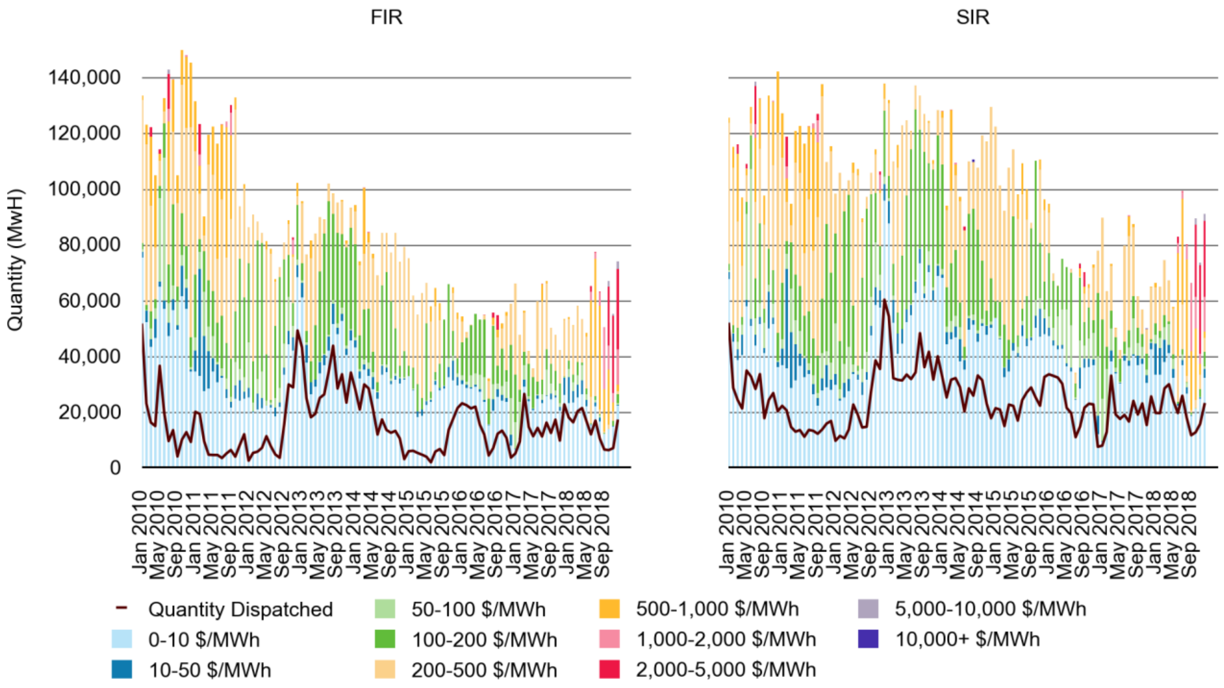


7.5 Contact's net position in terms of the reserve market has changed from most often being net negative, meaning Contact paid more to cover the cost of reserve than it received for providing reserve, to more often being net positive. The change in position was driven both from a decrease in generation from large North Island units and from an increase in price and quantity of reserve dispatched in the South Island, and this supports the evidence that Contact increased reserve offers in the North Island to increase South Island reserve prices.

Mercury

7.6 Mercury offered reserve in the North Island only. The analysis of its offer behaviour suggests that it kept its first few tranches at a low price to continue being dispatched in the North Island, but increased the last few tranches so it could push up prices in at least some trading periods to increase revenue from reserve.

Figure 18: Instantaneous reserve offers from Mercury



7.7 The quantity of reserve dispatched from Mercury was volatile of the time period with no clear change as a result of the introduction of the bi-pole and the NMIR. This could be because Mercury kept the quantity it offered at $0–10 $/MWh at a similar level.

7.8 After the bi-pole came into operation the total quantity of reserve offered decreased, especially with increased sharing of FIR and SIR across the bi-pole. This decrease came from offers over $50/MWh.

7.9 When the NMIR started there was a decrease in the amount offered between $50–200 MWh and an increase in offers at prices higher than $200/MWh

Table 7: **Impact of NMIR and bi-pole on Mercury's load weighted offers North Island**

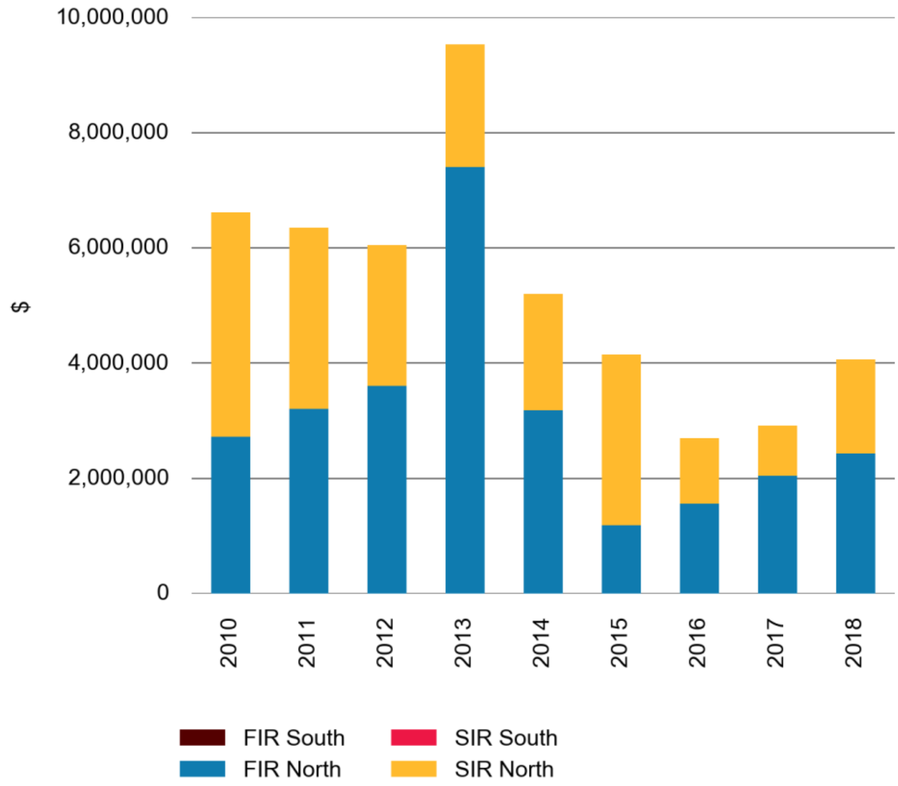
Type	Change	Mean	Confidence Interval	Standard Error	P value
FIR	Bi-pole	-$154.97	(-$210, -$99)	$28.31	<0.001
	NMIR	$78.42	($23, $134)	$28.24	0.005
SIR	Bi-pole	-$125.37	(-$152, -$99)	$13.54	<0.001
	NMIR	$47.51	($20,$74)	$13.55	<0.001

7.1 The introduction of the bi-pole lead to a decrease in the load weighted offer price of about $155 and $125 for FIR and SIR respectively. This aligns with the decrease in offers over $50/MWh.

7.2 After the NMIR Mercury' load weighted offer price increases by around $78 and $48 for FIR and SIR respectively. This was caused by movement of offers not from the lowest price band $0–10/MWh, but from the middle price bands $50–200 MWh to the very high prices $200/MWh+.

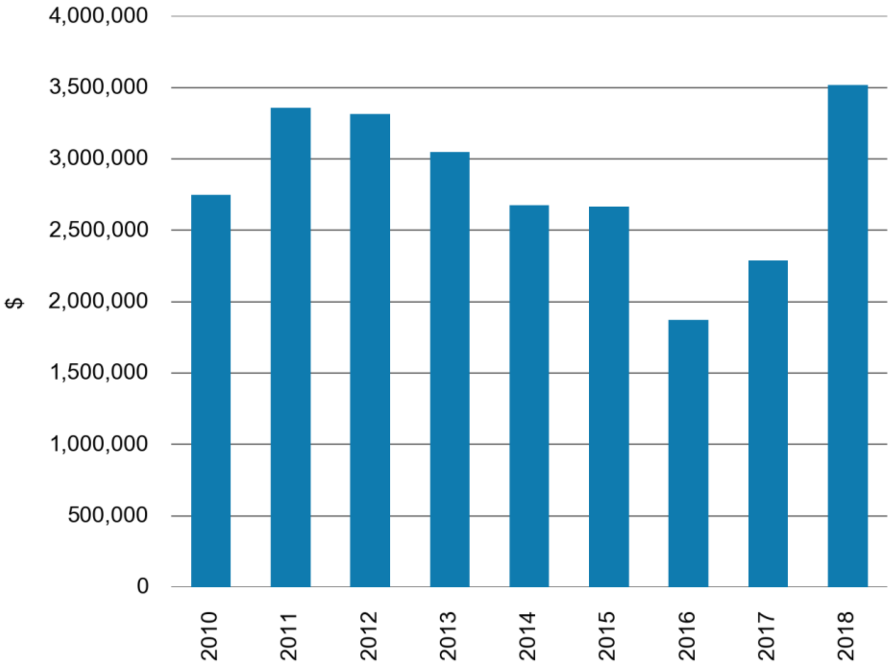
7.3 With the introduction of NMIR, North Island reserve could be substituted with South Island reserve which increased the competition for reserve. It seems that Mercury has remained competitive by continuing to dispatch their low cost reserve at or close to marginal cost.

Figure 19: Mercury's revenue from reserve payments



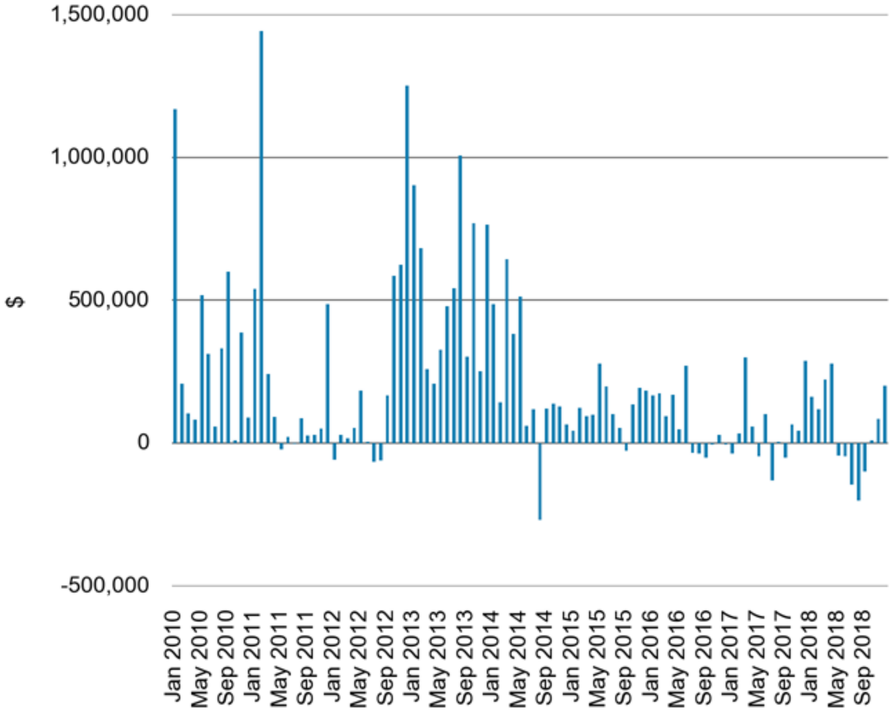
7.4 Mercury increased the price of their last few tranches significantly. This meant that when most of their reserve needed to be dispatched they would receive a much higher price. Mercury's revenue for providing reserve has decreased since the changes began in 2013.

Figure 20: Mercury's payment for reserve to cover generation risk



7.5 Mercury also has requirements to pay for reserve to cover the risk of their larger generation units. The cost of reserve to cover Mercury's generation risks fell in 2016 but then rose again.

Figure 21: Mercury's net revenue from reserve market

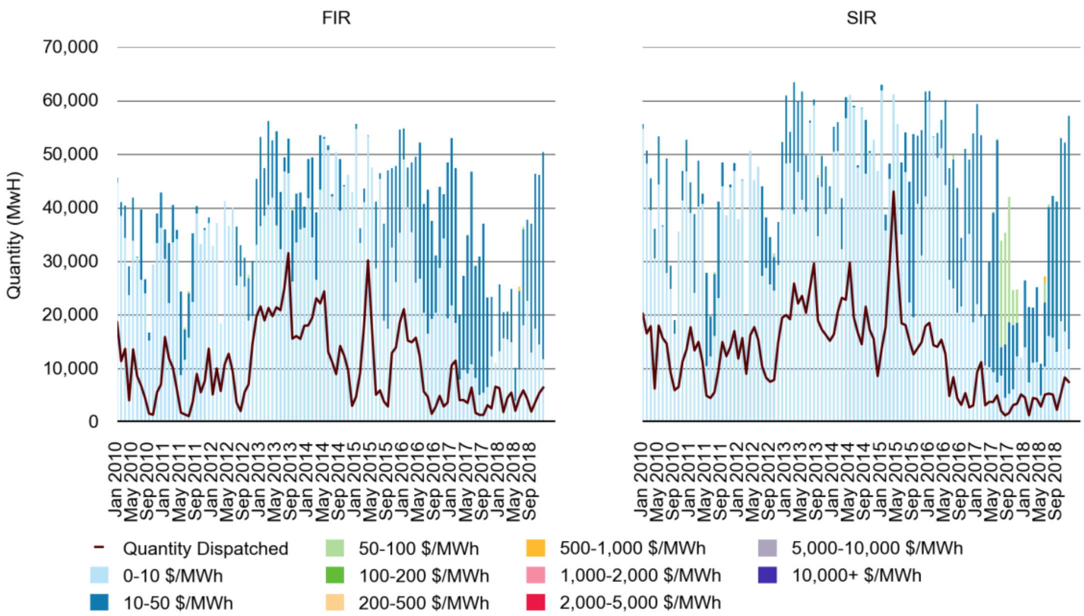


7.6 This impacted on their net position from reserve switching from more commonly receiving income from providing reserve, to having more periods where they had to pay for reserve. This may be another reason that Mercury continued to offer most of their reserve relatively cheaply, to keep prices lower when they were in a net negative position in relation to reserve. However, when most of their reserve was being dispatched and they were in a net positive position they would want higher prices, resulting in them pushing up the price for their last tranches.

Trustpower

7.7 Trustpower offers reserve in the North Island only. It may have changed their offer behaviour in an attempt to increase the price as their quantity dispatched decreased.

Figure 22: Quantity of reserve dispatched from Trustpower



7.8 The quantity of reserve dispatched by Trustpower dropped in concurrence with the NMIR being introduced. This also aligns with the general analysis which showed the total quantity of reserve dispatched in North Island dropped after introduction of NMIR.

7.9 After NMIR was introduced we see a drop in the quantity that Trustpower was offered at the $0–10/MWh price band, and an increase in the higher price bands, namely $10–50/MWh and $50–100/MWh.

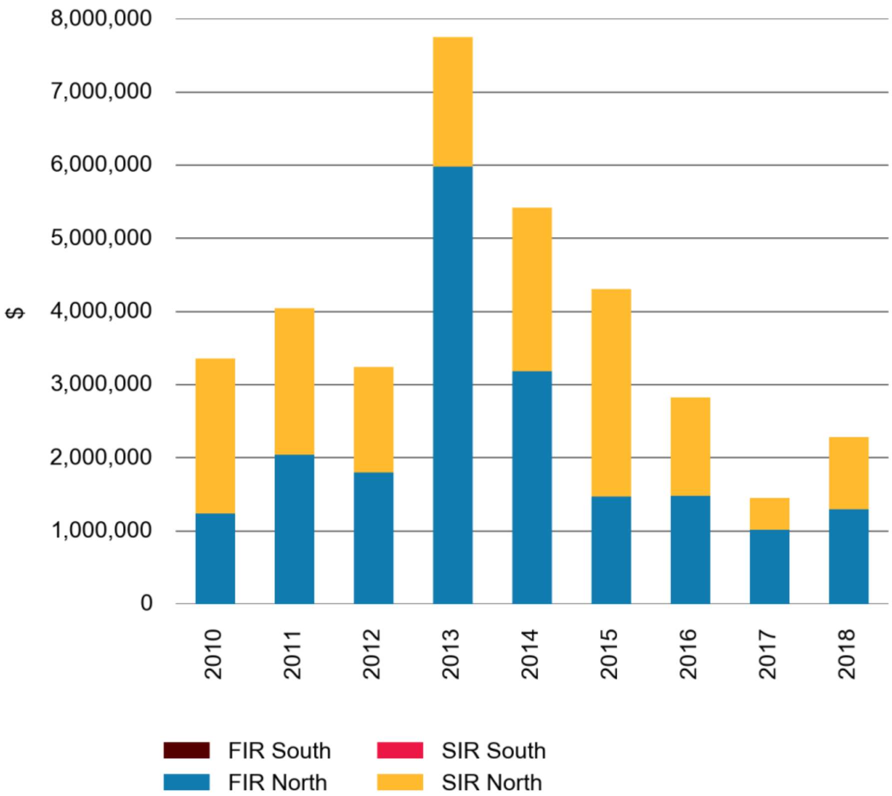
Table 8: **Impact of NMIR and bi-pole on Trustpower's weight loaded offers**

Type	Change	Mean	Confidence Interval	Standard Error	P value
FIR	Bi-pole	-$2.04	(-$6, $2)	$1.72	0.239
	NMIR	$6.58	($3, $10)	$1.72	<0.001
SIR	Bi-pole	$6.03	($4, $8)	$1.02	<0.001
	NMIR	$7.00	($5, $9)	$1.02	<0.001

7.10 After the NMIR their load weighted offer price increase by around $7 for both FIR and SIR. The change we see in Trustpower's offers is not as aggressive as we see in Contact's or in Mercury's.

7.11 Trustpower's changes to their offers may have been an attempt to alleviate a drop in quantity of reserve dispatched by increasing the price. However, it would not have wanted to increase their offer price by too large an amount so as not to decrease the amount dispatched even further.

Figure 23: Trustpower's revenue from reserve payments



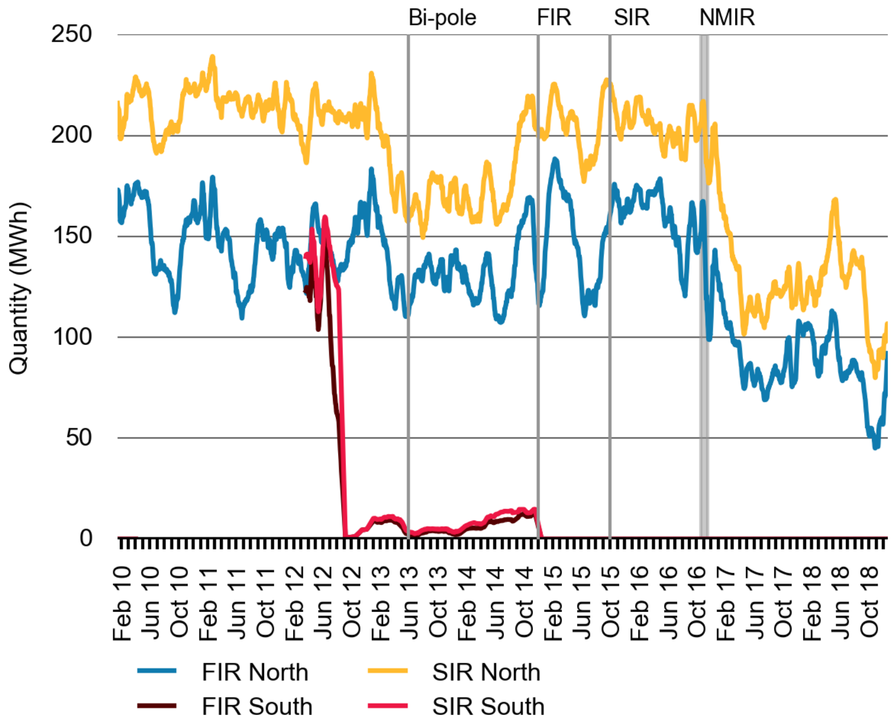
7.12 Trustpower's revenue from reserve decreased after the introduction of NMIR with lower revenue in 2017 and 2018 than any other year since 2010. Unlike Mercury and

Contact, most of Trustpower's generation is from units smaller than 60MW, so its payments for reserve were less than $100,000 a year. Therefore Trustpower was always in a net positive position in the reserve market and therefore always wants the highest price for a given level of reserve dispatched.

Interruptible Load

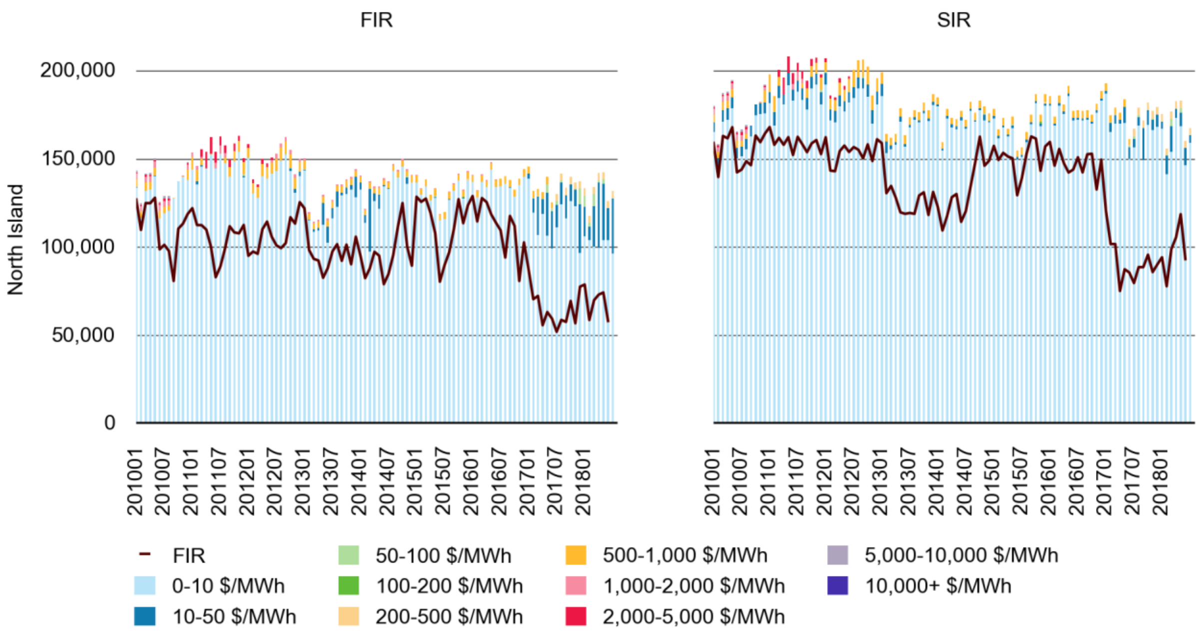
7.13 The analysis of interruptible load (IL) found that while many changes were in line with the changes in the overall market, they weren't all necessarily driven by the introduction of NMIR. Many commercial users contracted their IL to either EnerNOC or Genesis who has different strategies when offering IL into the market. We also found changes to Norske Skog's IL offers that may have been due to business decisions unrelated to the reserve market; therefore, we did not include IL in our analysis of offer changes, but we present them here for a complete picture of the reserve market.

Figure 24: Quantity of Interruptible load dispatched



7.14 Figure 24 shows the average quantity of IL dispatched per trading period. While some IL was dispatched in the South Island between 2012 and 2014, mostly in response to the low storage situation in 2012, most of IL is based in the North Island so we have confined our analysis to the North Island. The quantity of IL dispatched dropped in the lead up to the Bi-pole being introduced, but then increased again about two years later. The quantity dispatched then dropped with the introduction of NMIR, which is in line with the drop in the overall drop in reserve dispatched from the North Island when NMIR was introduced.

Figure 25: Quantity of IL offered and dispatched, excluding Norske Skog



7.15 Figure 25 shows the offer distribution for the North Island, in 2017/2018 more offers for FIR fell into the $10–$50 per MWh price range and less in the $0–$10 MWh band. The quantity of FIR dispatched also fell at this time, which is consistent with both the changes in the offers and NMIR being introduced.

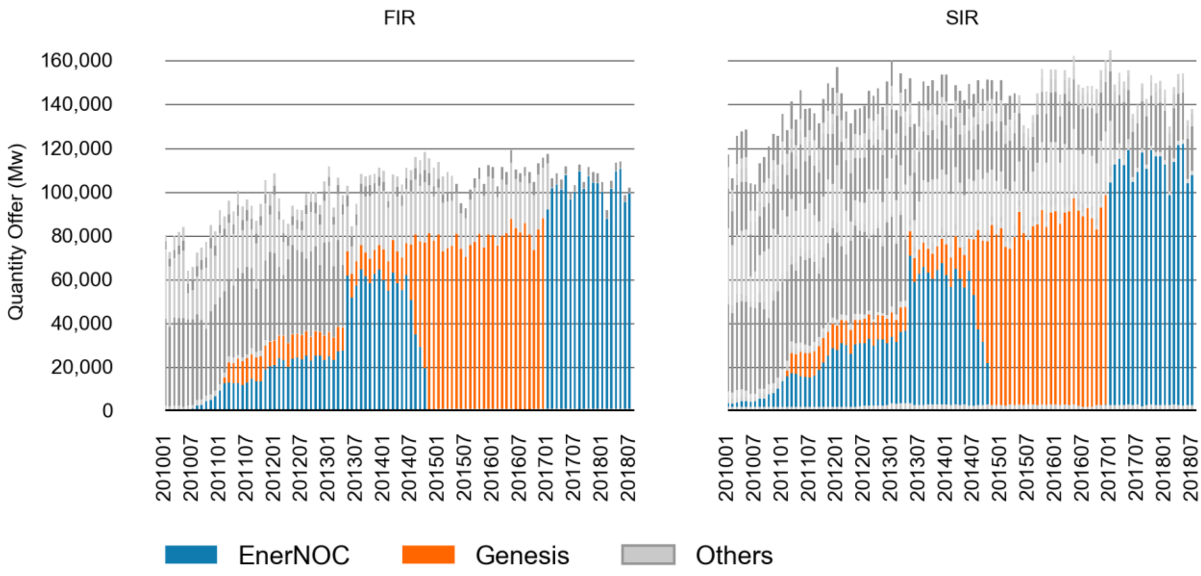
Table 9: Impact of NMIR and Bi-pole on IL's weight loaded offers

Type	Change	Mean	Confidence Interval	Standard Error	P value
FIR	Bi-pole	-$0.16	(-$2, $2)	$0.68	0.819
	NMIR	$5.13	($3, $7)	$0.68	<0.001
SIR	Bi-pole	$3.40	($2, $5)	$0.57	<0.001
	NMIR	-$2.67	(-$4, -$1)	$0.57	<0.001

7.1 Table 9 shows the regression results for interruptible load. For FIR there is no indication of a change to offers with the introduction of the Bi-pole, but average offer values increased after the introduction of NMIR by around $5. This is consistent with seeing offers moved from the $0–10 $/MWh band to the $10–50 MWh band.

Interruptible Load has been offered increasingly by a service provider

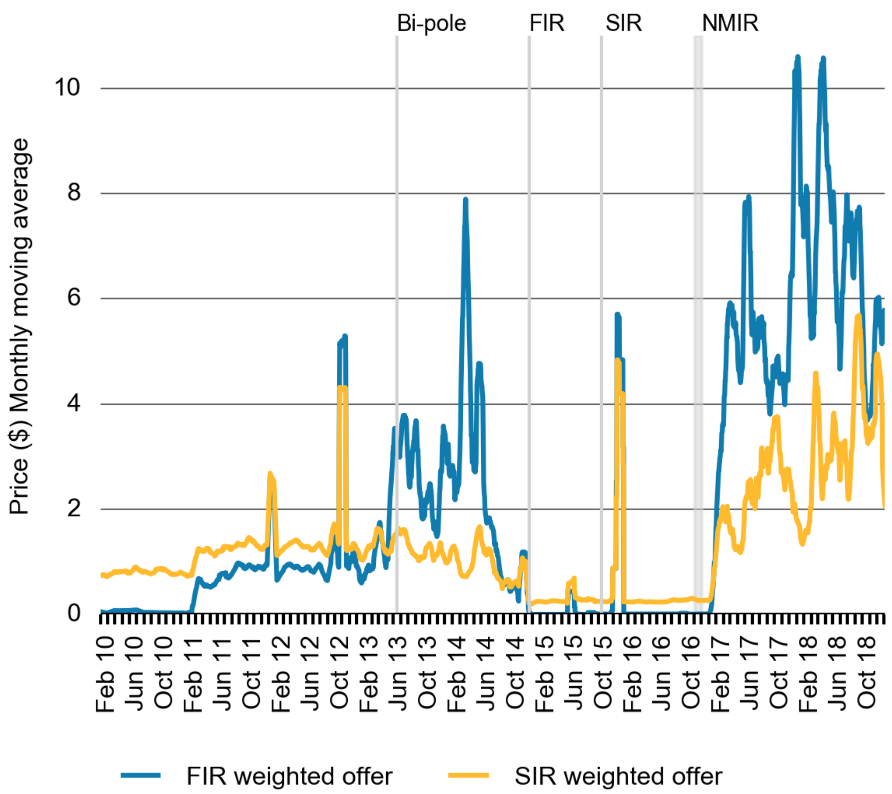
Figure 26: Quantity of interruptible load dispatched by trader, excluding Norske Skog



7.2 Genesis started offering IL in 2011 until 2017. Genesis is not a power user but a gentailer; it must have had contracts with commercial load users to offer IL into the market on their behalf. In 2015 and 2016 Genesis was offering the majority of IL for FIR and SIR.

7.3 EnerNOC is an ancillary service supplier and not a power user themselves; instead they made offers on behalf of IL providers. The amount of IL they offered grew from 2010 until 2014, but they offered no IL in 2015 and 2016, the years Genesis was offering the majority of IL. In 2017 and 2018 EnerNOC were offering the majority of IL into the market, especially in the FIR market. It looks like many commercial users switched from EnerNOC to Genesis and then back to EnerNOC when choosing which supplier to act on their behalf.

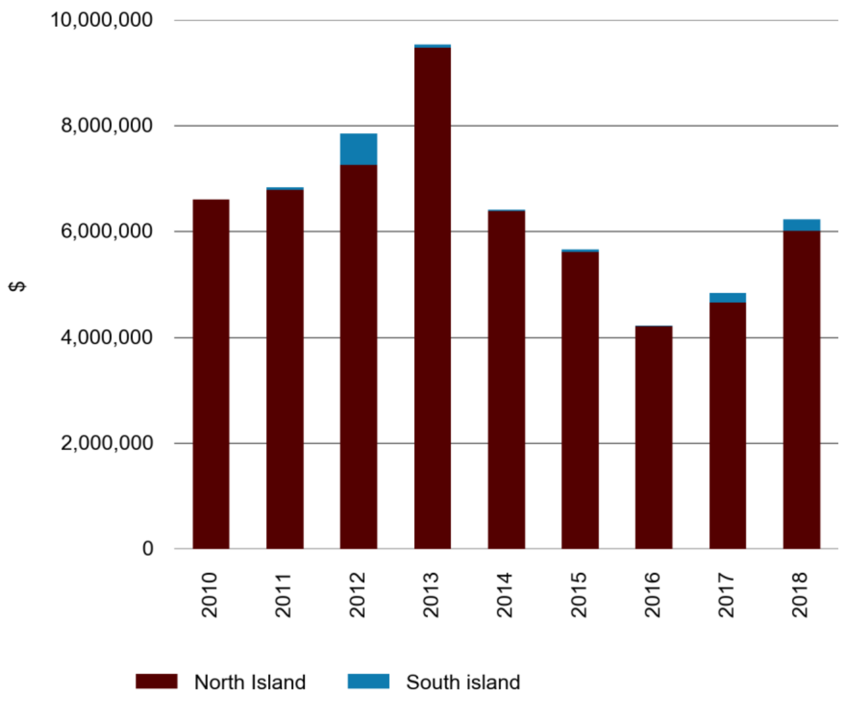
Figure 27: Average load weighted offer price for Interruptible Load, excluding Norske Skog



7.4 The period with the lowest load weighted offer price, in 2015 and 2016, coincides with when Genesis was offering the majority of IL to the market, and the periods with higher prices coincide with when EnerNOC was offering the majority of IL to the market.

7.5 Genesis had large payment obligations in the reserve market, especially for the Huntly units, with payments for reserve ranging from between $4 million to $10 million a year (Figure 28). Offering interruptible load at a low price was likely done as a strategy to lower their cost for reserve.

Figure 28: Genesis' payment for reserve to cover generation risk



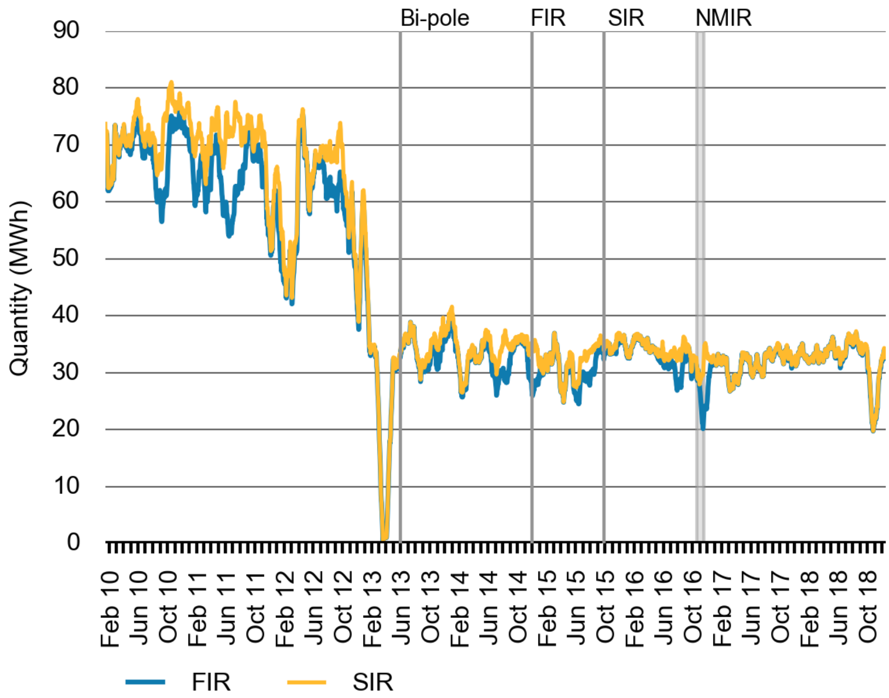
7.6 These changes helped keep the price of reserve low in the 2015 and 2016, and contributed to the increase in price at the beginning of 2017 shortly after the national market began. This was one reason these changes were excluded from the analysis of offers earlier, for it helped determine that the changes in the IL market were not the main drivers of these changes.

Norske Skog Tasman Ltd

7.7 Norske Skog Tasman Ltd is a paper mill company who participates in the energy wholesale market both through IL and dispatchable demand.

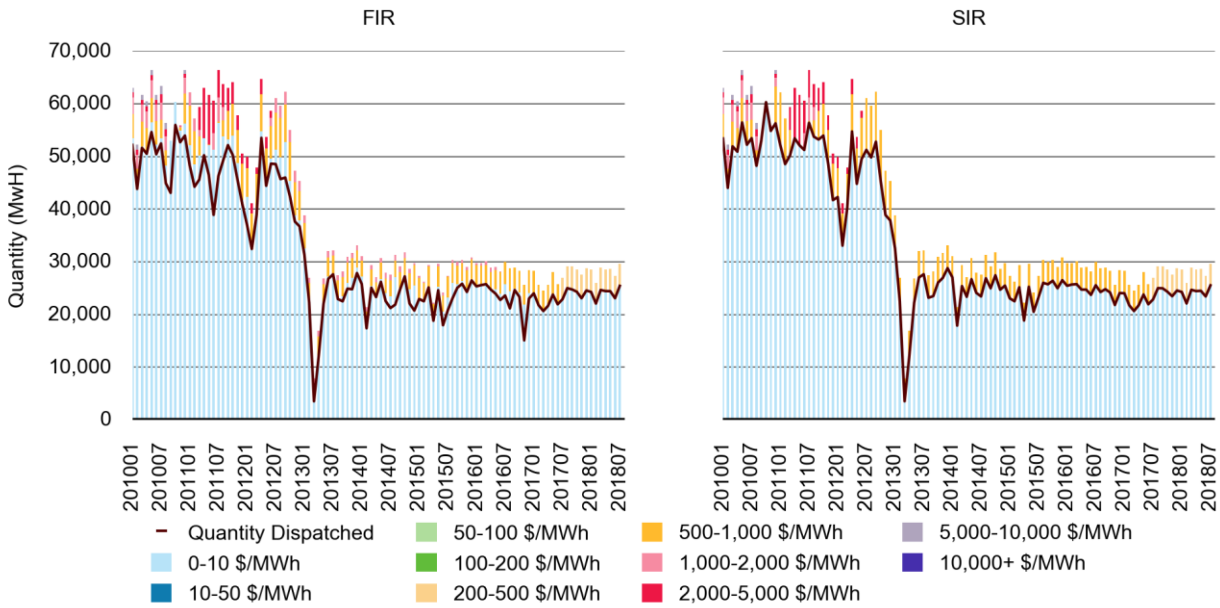
7.8 Some of their processes must always run, but other processes can be turned off and on as needed.

Figure 29: Norske Skog's quantity of reserve dispatched



7.9 Prior to 2013 they usually dispatched between 60 and 80 MWh but at about the time the bi-pole began operation they dropped dispatch to between 30 and 40 MWh of both FIR and SIR.

Figure 30: Quantity of offers and dispatch for SKOG



7.10 Figure 30 shows the reduction in the quantity offered for interruptible load, which is what led to the drop in quantity dispatched. Norske Skog stopped running one of their paper machines in 2013 which may have impacted the amount of interruptible load they could offer in, as their interruptible processes may not have been running as often.

7.11 In terms of the impact on the market, if this had occurred during the status quo running of the HVDC than it would have led to an increase in price of reserve. This may have had an impact in keeping the price of FIR higher for longer than otherwise, but had no visible effect on SIR.

7.12 Again, these changes were left out of the analysis of the changes to offers so as not to disturb the results with a large change that coincided with the bi-pole change but likely was not related to this change.

Conclusion

7.13 The national market for instantaneous reserve was successful in obtaining the desired outcome of increasing the efficiency of the reserve market without sacrificing security. The total level of reserve needed dropped in response to reserve sharing between the Islands and the national market saw more reserve dispatched from the South Island which traditionally has cheaper reserve.

7.14 The exact value of the economic benefit is difficult to calculate. The CBA estimated it was about $1.5 million per annum, but this was based on assumptions about offers not changing in response to the national market. Our analysis found that offers did change in response to the national market, which makes it difficult to update the estimated benefit of $1.5 million per annum.

7.15 In line with the above, the cost of reserve procurement, when controlled for the cost of energy, did decrease as a result of reserve sharing. The national market led to higher prices in the South Island, as predicted, but the changes in offers kept the North Island prices high enough to maintain overall revenue of reserve. As evidence shows that economic costs did decrease, the stable revenue implies that there was a wealth transfer from large generators who are net purchasers of reserve to the generators and power users who are net providers of reserve.