Estimating the costs and benefits of the interim arrangements for inter-island reserve sharing

Information paper

12 November 2014

Market Design

Executive summary

Introduction / background

As well as increasing the capacity of the high voltage direct current (HVDC) link, the recent HVDC upgrade has introduced new control functionality that more tightly couples the two islands' power systems. This opens up the potential to better integrate the provision of frequency keeping (FK) and instantaneous reserve (IR) across the islands. This should:

- reduce the total quantity of FK and IR that needs to be procured nationally
- enable improved pooling of resources for both FK and IR, to enable the cheapest resources to be procured across the two islands.

The full scale of benefits for improved pooling of resources is only be realised by implementing national markets for FK and IR. However, implementing national markets will require substantial changes to the systems and tools used to procure energy, FK, and IR – principally the system operator's market model (Scheduling, Pricing, and Dispatch model or SPD) and reserve modelling tool (RMT).

This implementation will take several years to implement so the Authority proposed gaining some early benefit from the new controls through implementing 'interim arrangements'.[1] The methodology and tools used to procure FK and IR would be largely unchanged from the current separate island-based approaches. However, gains would be achieved by changing some of the parameters within the existing tools to reflect the gains made available by the new controls.

During testing of the new control system for the HVDC link, the system operator decided that it needed to increase the IR it procures to cover the loss of a single HVDC pole. This decision required the Authority to revise its estimation of costs and benefits for the projects to implement national markets for FK and IR.

This revision revealed a flaw in its previous approach to assessing the benefits of moving to national markets for FK and IR. The Authority previously considered the benefits separately for FK and IR. However, the costs and benefits of the interim arrangements, which are designed to take advantage of the implementation of the new control system, must be considered together for both FK.

This paper corrects this flaw by estimating the potential benefits and costs of the proposed interim arrangements and describing the likely implications for implementing national markets for FK and IR. It replaces previous estimates of the costs and benefits prepared by the Authority.

Evaluation of FK benefits

More tightly coupling the frequency of the two islands has already enabled a reduction in the total quantity of FK required to be purchased. Following initial tests, the system operator is trialling reducing FK requirements from a 50 MW band in the North Island

[1] http://www.ea.govt.nz/development/work-programme/wholesale/national-instantaneous-reserves-market/development/

and 25 MW band in the South Island, to 20 MW and 10 MW bands, respectively - i.e. a total reduction of 45 MW.

As well as reducing the operating costs of plant providing FK, a reduction of this magnitude could reduce energy costs by freeing-up plant which may be able to provide energy more cheaply. In the long-term, it could reduce the amount of spare capacity required.[2] The estimated value of these benefits is shown in the table on page iv below.

Offsetting this potential reduction in costs, may be an increase in governor action (and associated wear-and-tear costs) from generators. If there is an overall net increase in the reliance on governor action, this cost should be subtracted from the benefit of reduced FK procurement.

However, it is not yet clear whether or not there has been an increase in governor action overall. Therefore, this estimate of benefits and costs makes no account for it. Nevertheless, the Authority acknowledges there is work yet to do to understand the interaction between the procurement of FK and the existing obligations concerning governor action, particularly the potential for perverse incentives on parties to alter their governor settings in a way that may increase system costs. The Authority is considering these issues as part of its review of the obligations of generation assets to support frequency under normal conditions (which it is currently working on).

Evaluation of IR benefits

The system operator already takes some account for the fast instantaneous reserve (FIR) transferred across the HVDC link to counter frequency deviations. The new control system for the HVDC link includes new control modes that substantially increase the degree to which it does so.

However, a very conservative approach is proposed to reflect this in the interim arrangements. The net free reserve transferred across the HVDC from the old Summer / Winter levels of 25 / 50 MW is to be increased to 60 MW all year round. This should reduce the amount of FIR required to be procured within an island to cover an AC contingent event in the same island.

Offsetting this benefit will be a cost from *increased* IR purchases arising at times when it must cover the potential loss of a single HVDC pole (as opposed to the loss of a single generating unit). This is because the system operator has identified that, under the new control modes, the HVDC transfer varies substantially from the levels dispatched by the system operator. This has caused the system operator to increase the FIR and sustained instantaneous reserve (SIR) required to cover the loss of a single HVDC pole by 40 MW.

For example, if the HVDC were scheduled to transfer 600 MW northward, the system operator would require 640 MW FIR and SIR to cover the loss of a single HVDC pole.

Sum of benefits

Despite this disbenefit, qualitative analysis suggests that the overall cost-benefit of the interim arrangements is strongly positive. This is illustrated in the following table.

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2 The benefit of reduced capacity required to be held on the system will not be realised until the current situation of over-capacity disappears – which, according to the latest Annual Security Assessment, is not projected to occur until approximately 2022).

Table 1: Net benefit of proposed interim arrangements

	Annual impact over short-to-medium term ($m/yr)			15 years' $m PV (at 8% discount rate)		
FK benefit / (cost)						
Change in FK operating costs:	13.5			116		
Change in FK peak capacity requirement:	0			15		
Increased cost of governor action (2)	?			?		
IR benefit / (cost)						
IR operating costs	*Modulation risk (MW)*			*Modulation risk (MW)*		
Sum/Win NFR transfer on HVDC (MW)	***40***	***20***	***0***	***40***	***20***	***0***
25/50	-2.18	-0.84	0	-19	-7	0
60/60	-1.78	-0.63	0.26	-15	-5	2
Change in IR peak capacity requirement (1)	0	0	0	0	0	0
System implementation costs for interim arrangements (3)	-0.01			-0.05		
Overall benefit / (cost)	*Modulation risk (MW)*			*Modulation risk (MW)*		
Sum/Win NFR transfer on HVDC (MW)	***40***	***20***	***0***	***40***	***20***	***0***
25/50	11.3	12.7	13.5	112	123	131
60/60	11.7	12.9	13.8	115	125	133

(1) No benefit has been attributed to peak capacity requirements due to the fact that the interim arrangements will not reduce SIR requirements.

(2) It is not known whether FKC will result in a net increase in governor action. However, to the extent it does, the scale of potential cost increases are considered to be materially less than the scale of reduction in FK costs.

(3) The annual impact is an amortisation of the one-off implementation costs which are shown in the PV column.

FK and IR results_v01.xlsm

Implications for progression towards national markets for IR and FK

The Authority's analysis suggests that moving to national markets is likely to deliver substantial additional benefit beyond the levels expected from the interim arrangements. The extra benefits provided by a national market for IR includes:

- enabling the contribution of SIR transfer across the HVDC to be taken into account (noting that the interim arrangements will only account for FIR transfer)

- gaining the full quantity benefit of reduced IR procurement beyond the conservative values proposed for the interim arrangements
- gaining access to a nationwide pool of IR.

Provisional modelling using a mix of approaches suggests a national IR market would yield additional benefits of approximately $40 million, in present value terms, compared with projected development costs of between $3.0 and $4.8 million.

The question of a national market for FK is not so clear cut. If there is an on-going need to procure approximately ±30 MW of FK services, then provisional analysis suggests that the gains from implementing a national FK market (and introducing co-optimisation of FK with energy and IR) would outweigh the development costs.

However, the system operator has indicated that, as it becomes more experienced with the tighter frequency coupling of the two islands, it may be able to progressively reduce the quantity of FK services. Potentially this could reduce to zero, with frequency being actively kept within the normal band solely through governor action and re-dispatch. If this were the case, there would be no benefit in introducing a national FK market.

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1.1 As well as increasing the capacity of the HVDC link, the recent HVDC upgrade has introduced new control functionality that tightly couples the frequency of the two islands. This opens up the potential to more closely integrate the provision of FK and IR ancillary services across both islands.

1.2 This closer integration should:

(a) substantially reduce the total amount of FK and IR that the system operator procures

(b) enable improved pooling of resources for both FK and IR, to enable the system operator to procure the cheapest resources nationwide.

1.3 During testing of the new control system for the HVDC link, the system operator decided that it needed to increase the IR it procures to cover the loss of a single HVDC pole. This decision required the Authority to revise its estimation of costs and benefits for the projects to implement national markets for FK and IR.

1.4 This revision revealed a flaw in its previous approach to assessing the benefits of moving to national markets for FK and IR. The Authority previously considered the benefits separately for FK and IR. This suggests that it is possible to implement the new functions for the HVDC link for FK but not IR (or vice versa). As this is not the case, the costs and benefits must be considered together for both FK and IR.

1.5 Consequently, this paper:

(a) summarises the potential HVDC-related initiatives for FK and IR, including:

(i) the so-called interim arrangements, whereby the functionality to more tightly couple the two islands using the HVDC controls is implemented, but the market arrangements do not fully reflect a fully-integrated national procurement approach for FK or IR

(ii) the longer-term options for moves to fully national markets for FK and IR

(b) outlines a framework for evaluating the costs and benefits of the different options on an internally consistent basis

(c) presents an evaluation of the cost-benefits for the interim arrangements, with an associated recommendation about proceeding

(d) sets out the implications for the national FK and IR market initiatives.

1.6 The estimates in this paper supersede previous estimates of the costs and benefits prepared by the Authority on the interim arrangements and national markets.

2 Description of new HVDC control functionality

2.1 Until recently, the North and the South Island systems have been operated as two independent AC power systems. That is, the frequency in one island is not synchronised with the other.

2.2 The HVDC link was used to transfer power from one island to the other and provided some frequency stabilising through the spinning reserve sharing (SRS) control mode. The system operator takes some account for the transfer of reserve across the link in this control mode when procuring IR.

2.3 However, the new HVDC control system has two new operating modes that enable the frequency of the two islands to be tightly coupled and transfer even greater levels of reserve, even at low power transfer levels across the HVDC link.

2.4 The primary modulation control mode of the new HVDC control system is the frequency keeping and reserve sharing controller (FKC). This controller varies the flow of power across the link in response to frequency deviations in each island to keep the frequency of both islands tightly coupled. In other words, it operates in such a way that the HVDC link behaves much like an AC transmission link. This has the effect of physically transferring FK and IR (FIR *and* SIR) between each island irrespective of whether national markets have been implemented for the procurement of such services.

2.5 The second control mode is round power. Round power allows high levels of IR to be transferred in either direction at power transfer levels below the 30 MW minimum operating level of the poles. Round power refers to a configuration where the two HVDC poles operate in opposite directions to deliver an overall (net) transfer. For example, if one pole were to transfer 40 MW northwards, and the other pole to transfer 30 MW southwards, the net effect would be a transfer of 10 MW northwards.

3 Three effects of new functionality

3.1 Tightly coupling the frequency of the two islands using the HVDC has three effects on the procurement of both FK and IR:

(a) a reduction in the quantity of FK and IR procured

(b) being able to choose the cheapest source of FK and IR nationwide

(c) increased HVDC modulation risk increasing IR required to cover HVDC contingent event.

Reduction in the quantity of FK and IR procured

3.2 The nature of the reduction in the overall quantity is different between FK and IR.

3.3 For FK, there is a reduced overall need for FK MW across both islands due to increasing:

(a) diversity

(b) inertia

(c) governor response.

3.4 The diversity across the load and generation that causes frequency deviations is increased by tightly coupling the two islands. The need for FK is primarily due to load and generation deviating from the expected levels. In this respect, load and generation exhibit a range of variability and uncertainty.

3.5 At the level of an individual customer, the variability and uncertainty of load is extreme. However, as more and more customers are grouped together the proportional level of variability and uncertainty reduces – even if the absolute level increases. This is because those customers that may be consuming more than expected will be offset by other customers consuming less than expected. This diversity benefit increases as more and more customers are grouped together. Therefore, grouping the North and South Islands together will deliver increased diversity benefit. This diversity benefit also applies to generation deviating from expectations. For example, a wind farm that generates more than expected will tend to be offset by another wind farm generating less than expected.

3.6 The second factor driving a reduced need for FK is transferring inertia between the two islands. This has the effect of increasing the amount of inertia as a proportion of the MW deviation of load/generation from expected levels. This will slow the rate of change of frequency to such MW deviations.

3.7 The third factor is transferring governor response between the two islands. Again, this will increase the amount of governor response as a proportion of the MW deviation from load / generation. This will have the effect of governor response playing a greater role in correcting the frequency deviations, thereby reducing the need to procure specific FK resources.

3.8 For IR, the quantity to be procured can be reduced across both islands through sharing the resource that is required to meet an under-frequency event. A highly simplified example[3] can illustrate this:

(a) If the North Island risk is 400 MW (e.g. the loss of Huntly unit 5), and the South Island risk is 120 MW (the loss of a Manapouri unit), then present practice is to procure 400 MW of IR in the North Island, and 120 MW in the South Island – less a relatively small contribution from the other island via the HVDC.

(b) However, if the two islands are tightly coupled, then only 400 MW of IR needs to be procured overall. For example, only 280 MW may be procured in the North Island as the 120 MW in the South Island can be combined with this 280 MW to deliver an overall 400 MW response in the event of the largest possible risk occurring.

[3] In reality, this IR sharing benefit is more complex given that at times the potential loss of the HVDC itself (either a monopole or the bipole) will be the binding risk. It is not possible to count on IR being transferred from another island across the HVDC to cover against the loss of the HVDC itself. Further, the transferring of FIR across the HVDC link will not be instantaneous, but will be subject to some delay associated with the FKC operation. Accordingly, FIR from one island to cover a risk in another island will need to be de-rated by an ‘effectiveness factor’. However, for the purposes of illustrating the concept of IR sharing, these complications are not considered.

Choosing the cheapest resource

3.9 FK and IR providers incur different costs in operating when operating in a mode that can respond to counter small and large frequency deviations. By transferring resources between the two islands, it is possible to choose the cheapest resource overall based on the conditions of the time.

3.10 For example, to meet a given national requirement to provide FK or IR resources, it may be cheapest at some times to provide the majority of such response from South Island providers, while at other times it may be more cost-effective to predominantly choose North Island providers. However, this ability to choose the cheapest resource nationally is only possible after developing national markets for IR and/or FK. Both services will continue to be procured separately in each island under the interim arrangements.

Increased modulation risk reduces benefits

3.11 Tightly coupling the islands causes actual transfer levels between the islands to vary from the quantity modelled by the system operator to a greater degree than before. This potential deviation is referred as modulation risk. As a consequence of the increase in the modulation risk, the system operator has determined that it must increase the quantity of IR it should procure to cover the loss of a single HVDC pole (DC contingent event).

3.12 This is discussed in more detail on page 12 later in this report, and in Appendix A, which considers the specific issue of potential impacts on system capacity requirements.

4 Evaluation of the costs and benefits of the interim arrangements

4.1 There are a number of potential economic benefits from reducing the quantity of FK or IR required:

(a) ***reduced running costs*** of plant operating in a mode that can deliver FK or IR

(b) ***reduced costs of generating electricity*** - this could happen if plant that is freed-up from providing FK or IR, instead generates electricity and displaces more costly generation sources

(c) ***reduced costs of holding spare generating capacity*** on the system to provide FK or IR services at times of capacity scarcity

(d) ***enabling more productive uses of electricity*** by reducing prices to consumers.

4.2 The nature and potential scale of these effects is examined in detail in this section – firstly for FK, and then for IR.

FK benefits and costs

4.3 With respect to FK, the most significant benefit will be a reduction in the overall quantity of FK required. Without FKC, the system operator has procured ±50

MW of FK in the North Island, and ±25 MW in the South Island. Following the recent tests of FKC, the system operator is presently trialling procurement of ±20 MW of FK in the North Island and ±10 MW in the South Island.

Reduced running costs operating in FK mode and reduced costs of generating electricity

4.4 Plant operating in FK mode can incur increased operating costs in the form of:

(a) increased wear and tear from cycling machines up and down

(b) potential reduced efficiency from operating the plant at lower or higher output than would otherwise have been the case (although for hydro units their optimal efficient operating point is generally at 85% to 95% of full load).

4.5 There may also be a net increase in electricity generation costs if plant is dispatched out of merit to operate at part load in the energy market for FK purposes. For example, assume the fuel and non-fuel variable operating and maintenance (VOM) costs of the marginal plant for energy is $50/MWh. If it was necessary to instead dispatch a plant whose fuel and VOM costs were $55/MWh at part load in order to deliver FK services, there would be a net increase of $5/MWh in generation costs.

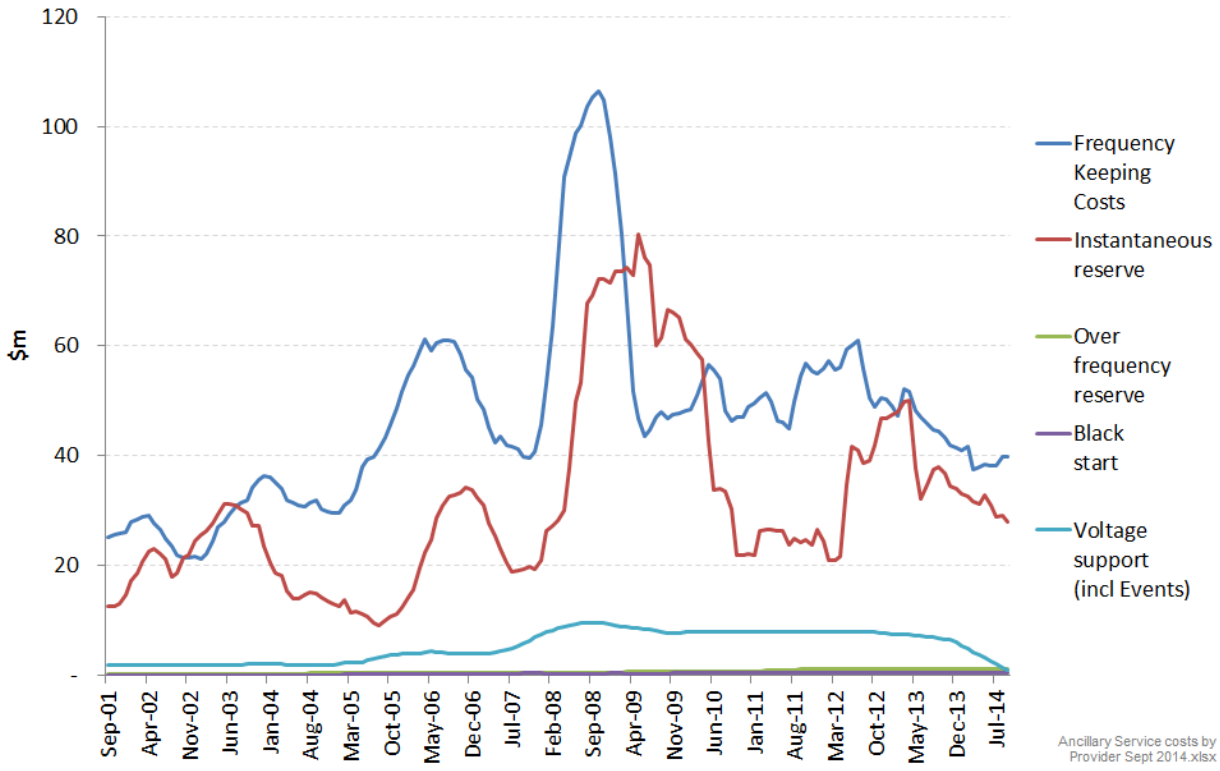
4.6 A variety of different approaches have been used to estimate the scale of cost reduction from a 45 MW reduction in FK procurement.

4.7 An analysis published in May 2014[4] of the benefits of a National FK market using vSPD estimated that a 10 MW reduction in quantity would result in a reduction of FK and energy costs of approximately $3 million per year.

4.8 This may seem conservative compared with historical FK costs of approximately $45 million per year as illustrated by Figure 1 below.

4 "*National Frequency Keeping Market Recommendations Paper*" By the Wholesale Advisory Group (WAG), May 2014

Figure 1: Historical rolling 12 month ancillary services costs



Source: Authority analysis using system operator data

4.9 If these historical costs were used as a basis to estimate the benefit of reducing FK quantities then savings of at least $6 million per year would be expected for a reduction of 10 MW.

4.10 However, historical FK *payments* to FK providers are considered to be considerably higher than the underlying *cost* of FK provision due to the fact that FK procurement has not been co-optimised with energy and IR.[5] The vSPD analysis estimated the underlying resource costs on a co-optimised basis.

4.11 Accordingly, the Authority has estimated the benefit from reducing FK by 45 MW using the $/MW saving from the May 2014 analysis. This is estimated to be $13.5 million per year. This is a simplified assumption given that it assumes that the cost curve is linear and that the savings from 45 MW is 4.5 x the savings from 10 MW. However, it is not considered that this will result in a substantial mis-estimation of the scale of potential cost savings.

Reduced costs of holding spare generating capacity

4.12 The $13.5 million estimate in the previous section is largely based on the avoided operating costs of plant operating in FK mode and/or generating electricity.

4.13 In the long-term, a reduction in FK requirements is also likely to result in an additional cost saving relating to avoided peak capacity requirements.

5 A quick comparison of the relative per MW price of FK and IR in New Zealand compared with the NEM suggests this is the case. The historical NZ prices suggest that FK costs approximately eight times as much to provide as IR. The relative price difference is substantially less in the NEM (wholesale electricity market in Eastern Australia), which co-optimises all their frequency control ancillary services with energy.

4.14 If there is a requirement to have ‘X’ MW of FK response at times of peak demand, this will give rise to a need to increase the amount of capacity held on the system by X MW. This capacity requirement will be additional to the amount of capacity required to meet energy requirements at these times of capacity scarcity.

4.15 Therefore, reducing the MW quantity of FK response required at times of peak should deliver an equivalent reduction in the quantity of capacity required to be held on the system.

4.16 The marginal source of peak capacity is considered to be an open cycle gast turbine (OCGT). Even though an OCGT is extremely unlikely to provide FK services, building an OCGT will free-up existing plant which is more suitable to provide FK services.

4.17 The carrying cost of an OCGT is estimated to be $145/kW/year.[6]

4.18 Reducing the FK requirement by 45 MW should therefore deliver savings of $6.5 million per year, with a 15 year present value (PV) of $58 million (using an 8% discount rate).

4.19 However, only the North Island is considered to be capacity constrained for the foreseeable future. Accordingly, only the reduction in North Island FK procurement is likely to yield savings in capacity carrying costs. North Island FK procurement is currently 50 MW, but is proposed to be reduced to 20 MW with FKC – a saving of 30 MW. This reduces the annual savings to $4.3 million, and the PV benefit to $39 million.

4.20 Further, in the short-to-medium term, the potential for cost savings from reduced peak generation capacity are likely to be substantially reduced due to the current state of relative system over-capacity. The 2014 Annual Security Assessment indicates that new capacity will not be required to address North Island peak capacity adequacy requirements until at least 2022.

4.21 Accordingly, the PV of 30 MW of avoided North Island peaking capacity requirements is estimated to be reduced to approximately $15 million.[7]

Enabling more productive uses of electricity

4.22 As well as reducing the resource *costs* of providing FK services, there may be a reduction in *prices*. Much of the impact of reduced prices will be a wealth transfer between producers and consumers, and is therefore not the primary consideration for this economic evaluation.

4.23 However, a reduction in prices can yield an increase in economic efficiency through enabling additional productive uses of electricity.

4.24 This is stylistically represented in Figure 2 below which illustrates how a reduction in price from P1 to P2 results in an increase in consumption from Q1 to Q2, with the scale of economic benefit represented by the shaded triangle. This triangle represents the value of the economic use of the electricity, less the cost of producing it – assuming that the price is set equal to the cost of production.

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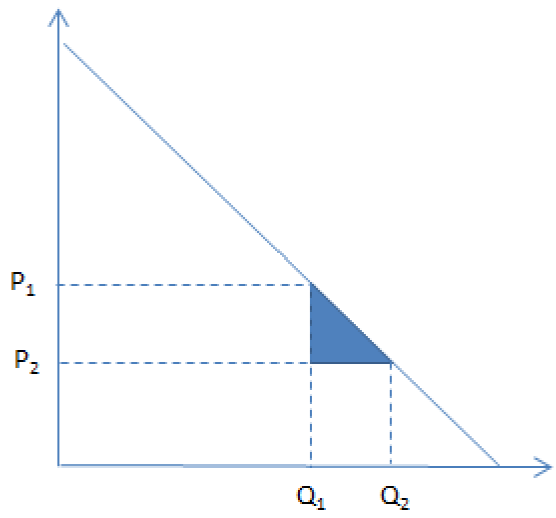
6 Based on work undertaken by the Electricity Authority for the scarcity pricing initiative.

7 This assumes that there are no benefits of avoided peaking capacity requirements for the first seven years of the fifteen years present value calculation i.e. benefits of avoided peaking capacity only start to be realised from 2022.

Figure 2: Illustration of the increased allocative efficiency arising from a reduction in price resulting in an increase in demand



4.25 Using an estimate of the price elasticity of demand (PED) enables the slope of the demand curve to be approximated.

4.26 Currently the Authority uses an estimate of PED of -0.26. This means that for a 1% change in price there would be a 0.26% change in demand in the opposite direction.

4.27 The Authority's high-level estimate of the increase in New Zealand's electricity consumption arising from FK costs is $27 million per year less due to the quantity reduction of FK purchases. This $27 million is simply pro-rating the annual average FK costs of $45 million per year by 45 / 75 (being the proportionate reduction in FK achieved through turning on FKC).

4.28 The average price of electricity sales (shown in line (c) in Table 2 below) includes <u>all</u> components of electricity price faced by New Zealand consumers – i.e. including generation, networks, and retail cost-to-serve.

Table 2: Estimate of the increase in allocative efficiency due to a reduction in frequency keeping costs

(a)	Total Electricity demand (TWh)	40
(b)	Total electricity sales ($m)	6,000
(c)	Average price ($/MWh): (b)÷(a)	150
(d)	Reduction in FK costs ($m)	27
(e)	% reduction in price: (d)÷(b)	-0.45%
(f)	Reduction in price ($/MWh): (e) * (c)	-0.68
(g)	Price elasticity of demand	-0.26
(h)	% increase in quantity: (e) * (f)	0.12%
(i)	Increase in quantity (TWh): (a) * (g)	0.047
(j)	Increase in allocative efficiency ($m): -0.5*(i)*(f)	0.016
(k)	15 year PV (@ 8% discount rate) ($m)	0.14
		NIRM_diag_v01.xlsm

4.29 As can be seen, the potential increase in allocative efficiency due to a reduction in prices is several orders of magnitude smaller than the potential increase in productive efficiency associated with reducing the direct costs of providing FK services estimated in the previous subsections.

Potential increases in costs associated with increased governor action

4.30 Offsetting these potential gains from a reduced quantity of FK being procured, are potential increases in costs from parties providing governor action in response to frequency fluctuations.

4.31 With reference to paragraph 3.3, it is not clear how much of the reduction in required FK quantities because of FKC is due to the benefits of increased diversity and pooling inertia, and how much is due to pooling governor action. To the extent it is the latter, this may increase the costs of those parties providing such governor response.

4.32 Tests of FKC resulted in the South Island Waitaki hydro scheme in particular increasing the amount by which its governors responded to frequency deviation. This is because the standard deviation of South Island frequency increased following the introduction of FKC, with the HVDC controls pushing more work into South Island generators – of which the Waitaki machines tend to be the most responsive.

4.33 However, offsetting this increased effort from the Waitaki scheme has been a reduction in governor action by the North Island Waikato hydro scheme which, prior to FKC, was more active in responding to frequency deviations in the North Island.

4.34 If the increase in wear-and-tear costs for the Waitaki scheme is offset by an equivalent reduction in such costs for the Waikato scheme, there will be no net increase in governor-related costs associated with the introduction of FKC – although there will be a wealth transfer between parties.

4.35 It is not clear whether this is the case, or whether there has been an overall net increase, or even a net decrease, in costs associated with governor response as a result of the introduction of FKC.

4.36 The Authority has not done any detailed analysis on this. However, if there has been a net increase in governor-related costs, it is considered likely to be less than the estimated benefits from reduced FK purchases. This is because some significant proportion of the ability to reduce FK procurement has been through the diversity and inertial pooling benefits outlined in paragraph 3.3.

4.37 However, non-FK governor action is not a paid-for service, but is instead provided ‘free’ via generator AOPOs. Changes in governor response associated with the introduction of FKC may increase visibility of the issue associated with the burden of FK falling disproportionately on a small number of generators with particularly responsive generators.

4.38 It is possible that if such generators are not compensated, or if generators can avoid AOPO requirements without facing any cost, it may introduce perverse incentives on parties to alter their governor settings in a way which would be detrimental to system costs overall. Some generators are responding to the private incentives on them and introducing dead bands into their governor settings to avoid undertaking as much governor action, even though from a national public perspective such actions may increase overall system costs.

IR benefits and costs

4.39 As discussed in section 2, turning on FKC will result in:

(a) benefits realised by enabling FIR to be transferred from one island to another to cover the within-island AC risk

(b) costs incurred through increasing the modulation risk, and thus increasing the quantity of within-island FIR that will be needed to cover the risk of the HVDC itself.

4.40 Each of these is described further below.

Benefits from enabling FIR to be transferred from one island to another

4.41 Prior to FKC being turned on, the system operator conservatively estimated the response generators provide to counter a frequency deviation in the other island. This reduces the requirement for within-island FIR to be procured to cover the within-island AC risk. The inter-island reserve response is treated as net free reserve (NFR) within RMT, which has the effect of reducing the amount of within-island FIR required to cover the AC risk.

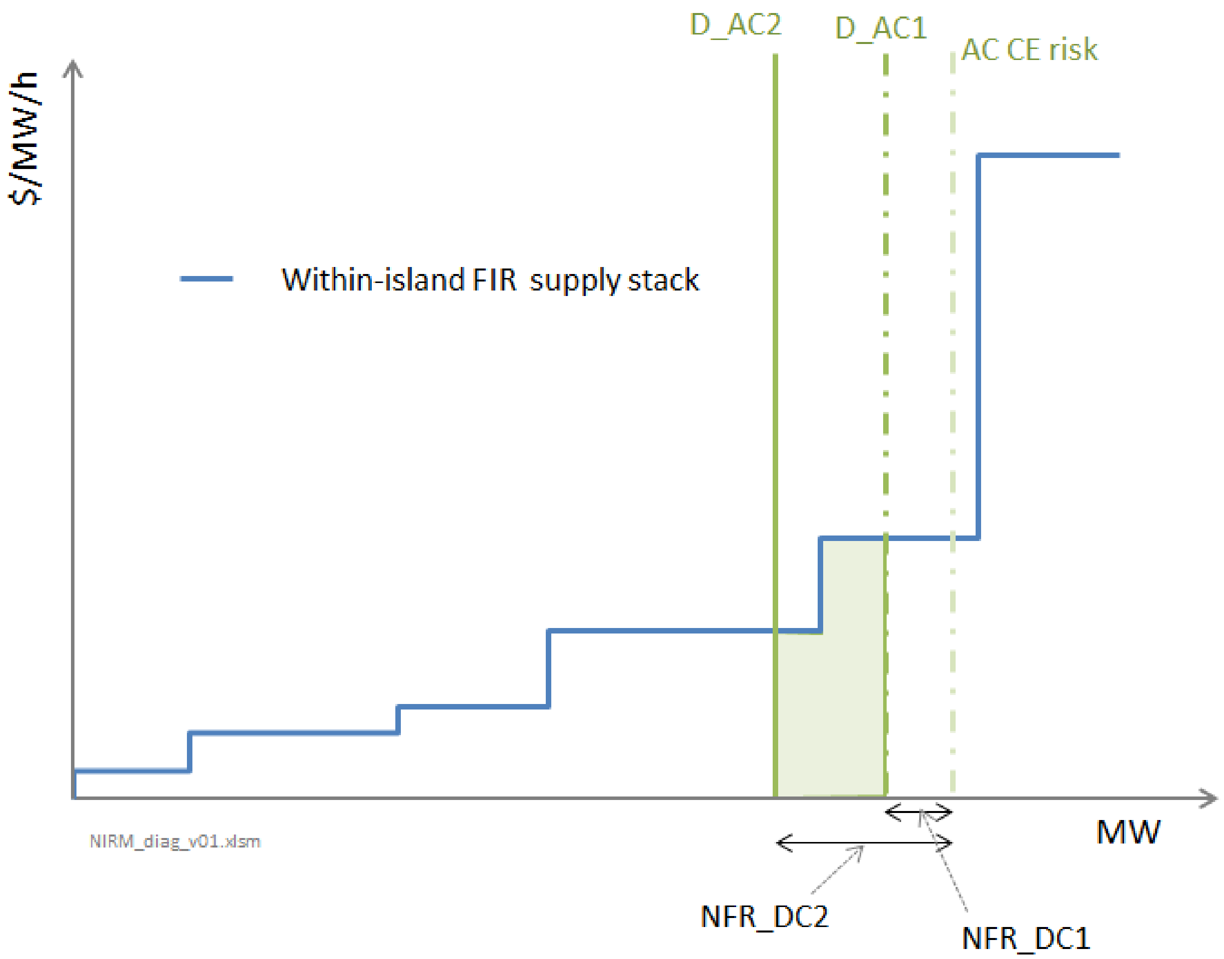
4.42 The level of NFR is modelled as 25 MW in summer and 50 MW in winter.[8]

4.43 With FKC turned on, there is much greater scope for generation in one island to respond to frequency deviations in the other. However, the existing tools cannot model this response dynamically. Until a national market is developed, the Authority is proposing to reflect this increased response by simply making a conservative increase in the NFR quantity assumed to be delivered across the link for FIR procurement. It is not proposed under the interim arrangements to alter the means by which SIR is procured.

4.44 It is proposed that the summer / winter NFR contribution is increased from the current 25 / 50 MW levels to 60 / 60 MW. This increase in NFR from the HVDC effectively reduces the residual demand for within-island FIR to cover the largest within-island AC risk. This is illustrated in Figure 3 below.

[8] This summer / winter split is intended to conservatively reflect the different amounts of inertia that is available to be delivered across the link at different times.

Figure 3: Illustration of the benefit from an increase in FIR capable of being transferred across the HVDC under the interim arrangements[9]



4.45 Figure 3 illustrates that the quantity of FIR required to cover the AC CE risk is reduced by the NFR over the HVDC, giving a residual demand for FIR to cover the AC risk. D_AC1 represents the residual demand for FIR under current arrangements, and D_AC2 represents the residual demand for FIR under the interim arrangements after the NFR from the DC is increased.

4.46 In situations where the AC risk is the binding risk (more details are given on page 13), the reduced requirement for within-island FIR to cover the AC risk will result in a reduction in costs represented by the green shaded area.

4.47 As further detailed on page 13, the extent to which this actually reduces the quantity of FIR procured depends on which of the following risks is greater:

(a) the within-island AC risk (in which case the improved HVDC FIR transfer effect described above will reduce FIR procurement)

(b) the potential loss of a HVDC pole – the DC CE risk – which, as described in the next subsection, will result in an increase in FIR costs.

9 Note: For the purposes of illustration, this diagram ignores the NFR from within-island inertia.

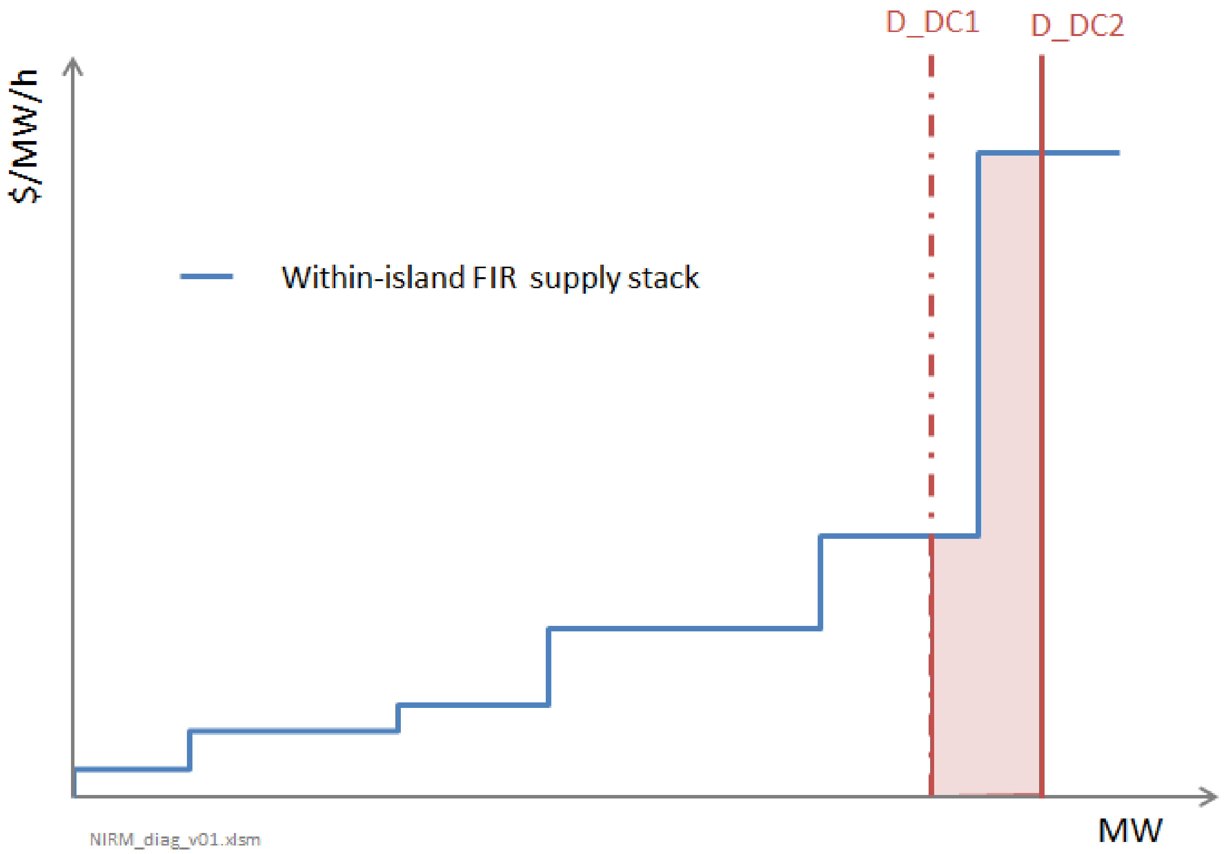
Costs from increased modulation risk

4.48 Offsetting the benefit of increased FIR transfer is a cost arising from the modulation risk of the HVDC. The potential for the HVDC to be operating at a higher level than its dispatch point needs to be taken into account when procuring IR to cover the risk of the HVDC *itself* tripping and causing an under-frequency event.

4.49 For example, consider a situation where the HVDC is dispatched at a level which prior to FKC gives rise to a requirement for 500 MW of within-island IR to cover the potential loss of a single HVDC pole (the DC CE risk).

4.50 After FKC is turned on, the HVDC may move away from its dispatched set point by ± 40 MW. This means it would be appropriate for the system operator to subsequently procure sufficient IR to cover a DC CE risk of 500 + 40 = 540 MW. This is illustrated in Figure 4 below.

Figure 4: Illustration of the cost associated with increasing the demand for within-island FIR to cover the risk of the HVDC tripping at increased transfer levels



4.51 In the example shown in Figure 4, the impact of increasing the risk associated with HVDC transfer will require a greater quantity of within-island FIR to cover the DC CE risk, illustrated by the demand for FIR to cover the DC risk shifting from the line D_DC1 to D_DC2. If the DC CE risk is the binding risk, the extra FIR that will need to be procured will result in an increase in costs illustrated by the red shaded area.

4.52 Further, this increase in IR required will also apply to SIR procurement to cover the DC CE risk (not shown in this illustration).

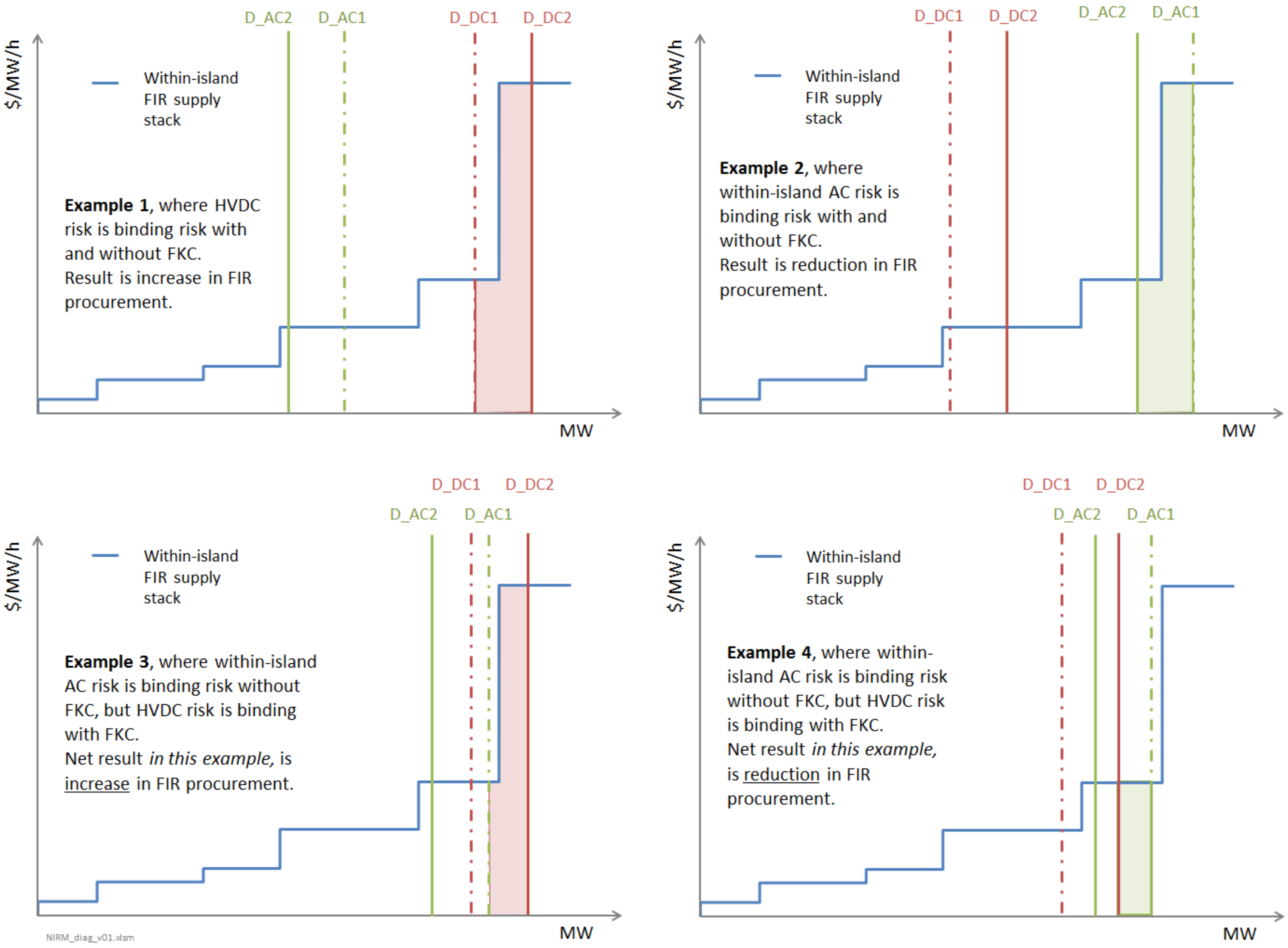
4.53 The system operator is still determining the likely extent to which FKC will move the HVDC off its set point within a despatch period, and thus what should be an appropriate quantity to add to the HVDC transfer to reflect this risk. Based on experience to date with the FKC trial, the system operator, in its report of 22 October 2014, has provisionally proposed that the DC risk be increased by 40 MW. However, this view may change with increased experience of operating with FKC.

Net impact on FIR procurement

4.54 In any given trading period, the net impact of these two different effects on FIR procurement (i.e. allowing greater FIR to be transferred to cover within-island AC risks, versus increasing the size of the HVDC risk required to be covered within the island, will depend on which risk is binding in terms of determining the quantity of within-island IR to be procured.

4.55 This is illustrated in the diagrams in Figure 5 below.

Figure 5: Illustration of possible net impacts of FKC on FIR procurement costs under interim arrangements



4.56 Example 1 shows a situation where the DC CE risk is the binding risk both with and without FKC. In such situations, the impact of FKC will always be an increase in FIR costs, illustrated by the shaded red area. Plus, as described above, it could also result in an increase in SIR costs, although this is not illustrated.

4.57 Example 2 shows a situation where the within-island AC CE risk is the binding risk both with and without FKC. In such situations, the impact of FKC will always be a decrease in FIR costs, illustrated by the shaded green area.

4.58 Examples 3 and 4 show situations where the within-island AC CE risk is the binding risk without FKC, but the DC CE risk becomes the binding risk with FKC. The net effect can either be an increase in FIR costs (illustrated by the shaded red area in example 3) or a decrease in FIR costs (illustrated by the shaded green area in example 4), depending on the relative sizes of the risks.

4.59 In general, the increased modulation risk will have the effect of increasing the proportion of time that the DC CE is the binding risk for the procurement of FIR *and* SIR. It should also be appreciated that the DC CE risk will be binding at times of high transfers, which generally correlates with periods of high IR and energy costs. It is therefore possible that the cost impact of the modulation risk could be greater than the benefit of the increased FIR transfer, even if the DC CE risk is the binding risk for less of the time than the AC CE risk.

No assumed benefit from enabling SIR transfer

4.60 For the procurement of within-island SIR to cover the within-island AC risk, no contribution from the other island was assumed with the old HVDC controls.

4.61 With FKC switched on, the HVDC can transfer more SIR from one island to the other. The Authority understands the new version of RMT being used by the system operator can be altered to account for SIR shared across the HVDC link.

4.62 However, for the purposes of this cost-benefit evaluation of the interim arrangements, no benefit has been ascribed to reduced SIR procurement.

Potential long-term benefit of reduced capacity on the system

4.63 The analysis on page 4 sets out that a reduction in the quantity of FK required at times of peak demand will likely result in a reduction in the amount of capacity required to be held on the system over the long term.

4.64 Similarly, a change in IR requirements at times of peak demand could also result in a likely change in the amount of capacity required to be held on the system over the long term.

4.65 Analysis in Appendix A demonstrates that, at times of peak demand, the HVDC is unlikely to be operating at high transfer levels, and therefore the AC CE risk will be binding. Therefore, FKC will have a beneficial effect in terms of being able to reduce FIR procurement.

4.66 However, this benefit of reduced FIR procurement may not result in any reduction in IR costs in the long term if it is likely SIR is the binding requirement dictating overall provision of IR resources.

Net IR cost / benefit

4.67 To estimate the overall impact of the interim arrangements on IR procurement costs the Authority used its vectorised version of SPD (referred to as vSPD), which provides identical results to the version of SPD the pricing manager uses. Using a year of historical data (for the period August 2013 to July 2014), the Authority varied two parameters:

(a) The extent to which modulation risk may move the HVDC away from its set point, and thus the amount by which the DC risk will need to be increased. This has the effect of increasing the demand for within-island IR to cover the HVDC risk. Three scenarios were considered: ±40 MW; ± 20 MW; and 0 MW (i.e. no increase in modulation risk, being the status quo).

(b) The extent to which the assumed net free reserves transfer across the HVDC can be increased from the current levels to reduce the requirement for within-island FIR to cover the AC risk. Two scenarios were considered: the Status Quo 25 / 50 MW; and 60 / 60 MW.

An increase to above 60 / 60 MW was not considered given time constraints on the analysis.[10]

4.68 The results from the Authority's analysis are shown in Table 3 below

Table 3: Modelled impact on IR costs from interim arrangements

		Annual impact over short-to-medium term ($m/yr)			15 years' $m PV (at 8% discount rate)		
IR benefit / (cost)							
IR operating costs		*Modulation risk (MW)*			*Modulation risk (MW)*		
		40	*20*	*0*	*40*	*20*	*0*
Sum/Win NFR transfer on HVDC (MW)	*25/50*	-2.18	-0.84	0	-19	-7	0
	60/60	-1.78	-0.63	0.26	-15	-5	2
Change in IR peak capacity requirement (1)		-	-	-	-	-	-

(1) No benefit has been attributed to peak capacity requirements due to the fact that the interim arrangements will not reduce SIR requirements.

FK and IR results_v01.xlsm

4.69 The table shows that the costs from the increased modulation risk impacting on the DC risk are estimated to outweigh the benefits of increased net free reserves transfer across the HVDC to meet the AC risk.

4.70 This result initially seems intuitive given that:

10 An earlier piece of work provisionally indicated that there could be even greater benefit from increasing the transfer limit above this 60/60 level by artificially increasing the assumed South Island AC risk. However, work on this suggestion was considered to be more complicated than was supported by the scope for the project.

(a) the DC risk will be binding at times of high HVDC transfers

(b) energy and IR resources will tend to be most scarce (and thus most costly) at such times of high transfers

(c) the increased DC risk will affect FIR *and* SIR procurement, whereas the increased NFR transfer benefit will only affect FIR procurement.

4.71 Therefore, purely from an IR perspective, the interim arrangements appear to result in a net system cost increase for the modulation risk and NFR parameters.

4.72 However, there are a number of caveats to this conclusion:

(a) with increased experience, it is possible the system operator may decide to reduce the modulation risk from the currently proposed level of 40 MW

(b) for the reasons set out in Appendix A, it is potentially the case that the proposed summer / winter NFR contribution of 60 / 60 MW is overly conservative

(c) it is likely that the vSPD analysis will over-estimate the cost impact of FKC on IR procurement.

4.73 Therefore, the scale of modelled cost increases may be materially less than what actually happens, or what needs to happen.

Costs to implement interim arrangements

4.74 It is understood that the costs to implement the interim arrangements will be very low. FKC and round power have already been tested as part of the commissioning of the HVDC and are both operating (albeit that FKC is in trial mode).

4.75 Therefore, the only changes required for procuring FK and IR are parameter changes within the existing procurement systems and processes, i.e.:

(a) setting the North Island / South Island FK procurement requirement to be 20 / 10 MW, rather than the current 50 / 25 MW

(b) increasing the summer / winter net free reserve assumption for FIR transfer across the HVDC from 25 / 50 MW to 60 / 60 MW

(c) setting the HVDC modulation risk for determining the amount of IR required to cover the loss of the HVDC to 40 MW.

4.76 None of these parameter changes will require much cost to put into effect. For the purposes of this cost-benefit evaluation, a cost of $50,000 has been assumed – representing the cost of studies to determine whether the proposed parameter levels are appropriate and the system operator implementation costs.

Evaluation of overall cost-benefit of interim arrangements

4.77 To estimate the overall cost-benefit of the interim arrangements, the estimates of the impact on FK procurement costs were combined with the estimates of the impact on IR procurement costs. These overall results are set out in Table 4 below.

Table 4: Estimated overall cost-benefit of the interim arrangements

		Annual impact over short-to-medium term ($m/yr)			15 years' $m PV (at 8% discount rate)		
FK benefit / (cost)							
Change in FK operating costs:			13.5			116	
Change in FK peak capacity requirement:			0			15	
Increased cost of governor action (2)			?			?	
IR benefit / (cost)							
IR operating costs							
		Modulation risk (MW)			***Modulation risk (MW)***		
		40	***20***	***0***	***40***	***20***	***0***
Sum/Win NFR transfer on HVDC (MW)	***25/50***	-2.18	-0.84	0	-19	-7	0
	60/60	-1.78	-0.63	0.26	-15	-5	2
Change in IR peak capacity requirement (1)		0	0	0	0	0	0
System implementation costs for interim arrangements (3)			-0.01			-0.05	
Overall benefit / (cost)							
		Modulation risk (MW)			***Modulation risk (MW)***		
		40	***20***	***0***	***40***	***20***	***0***
Sum/Win NFR transfer on HVDC (MW)	***25/50***	11.3	12.7	13.5	112	123	131
	60/60	11.7	12.9	13.8	115	125	133

(1) No benefit has been attributed to peak capacity requirements due to the fact that the interim arrangements will not reduce SIR requirements.

(2) It is not known whether FKC will result in a net increase in governor action. However, to the extent it does, the scale of potential cost increases are considered to be materially less than the scale of reduction in FK costs.

(3) The annual impact is an amortisation of the one-off implementation costs which are shown in the PV column.

FK and IR results_v01.xlsm

4.78 Overall, the benefits from reduced FK procurement costs are projected to significantly outweigh any modelled increases in IR procurement costs and any increases in costs associated with increased governor action.

4.79 Accordingly, there would appear to be a strong case for moving ahead with the interim arrangements.

5 Potential benefit of developing national markets

5.1 The cost-benefit set out in the previous section established that the benefits from the interim arrangements are likely to materially outweigh the costs.

5.2 This section considers whether it is likely that progressing towards development of full national markets for IR and/or FK will deliver additional benefits that are likely to outweigh the additional development costs.

National IR market

5.3 Implementing a national market for IR would reduce costs, over and above those being delivered by the interim arrangements. It would reduce the:

(a) quantity of IR procured by:

(i) accounting for the significant quantities of SIR that can be transferred across the HVDC (the interim arrangements do not account for SIR transfer)

(ii) more accurately accounting for the FIR that can be transferred (the interim arrangements include only a conservative estimate)

(b) cost of IR procured by making it possible to procure the cheapest source of IR (both FIR and SIR) nationwide.

5.4 The ability to take account of the transfer of SIR is likely to be particularly significant given that, as discussed on page 23 in Appendix A, SIR will increasingly be the binding requirement driving the overall requirement for IR provision as FIR is reduced.

5.5 The ability to account for the transfer of SIR as well as FIR is likely to be particularly valuable at times of peak demand. It is possible that at times of peak North Island demand, 110 MW of North Island IR could be displaced by South Island IR.[11] Using the framework set out on page 7, which takes into account the current state of overcapacity, a reduction in peak capacity requirements of this magnitude is estimated to have a present value of $25 million.

5.6 On top of this capacity benefit are likely to be operating cost reductions for the provision of IR and energy. A provisional analysis using vSPD indicates that these could be in the order of $1.75 million per year, which equates to a 15 year present value of $15 million.

5.7 The costs of developing a NIRM are estimated to be between $3.0 and $4.8 million. The Authority has not conducted sensitivity analysis as the net benefit is so large (over $35 million).

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[11] This has been estimated by assuming that 120 MW of IR will need to be procured in the South Island to cover the loss of a Manapouri unit, and that this 120 MW could be used to provide IR for the North Island – reducing the need to procure North Island IR at such times of capacity scarcity. The 120 MW has been reduced by an ‘effectiveness factor’ of approximately 10% to take account of the fact that the speed of response of FIR across the link is not quite as fast as FIR delivered within island.

National FK market

5.8 Whether it is worth progressing with development of an national FK market will depend on the extent to which there remains a need to procure FK services. As set out on page **Error! Bookmark not defined.**, the system operator has indicated that it may be possible to reduce FK procurement further – potentially eliminating the need to procure FK at all and relying instead on inertia, governor response, and real time dispatch to replace FK services.

5.9 To the extent that FKC avoids the need to procure FK services entirely, there may not be any benefit in developing a full national FK market. Existing island-based procurement approaches would be sufficient to cover the instances where the HVDC may be unavailable.

5.10 However, if it is necessary to continue to procure a material quantity of FK services:

(a) there could be merit in moving to a national FK market

(b) additionally, (or potentially alternatively) there could be benefit in making the changes necessary to enable procurement of FK to be co-optimised with procurement of energy and IR.

5.11 If there continued to be a need to procure 30 MW of FK services, a significant element of the benefit of a move to a NFKM could be the ability for the entire FK requirement to be met by South Island providers at times of peak demand. In the long-term this would result in a 20 MW saving in system capacity requirements given that the currently proposed interim arrangements require 20 MW of FK services to be purchased in the North Island.

5.12 Using the same framework as set out on page 7, which takes into account the current state of over-capacity, this should deliver a benefit of $10 million (PV).

5.13 If there continued to be a need to procure 30 MW of FK services, there are also likely to be substantial additional benefits in terms of optimising the provision of FK provision between the islands at other times, and also introducing the co-optimisation of FK with IR and energy.

5.14 The May 2014 analysis for the WAG indicated that this was likely to be the case for the FK quantity scenarios it considered. However, no specific analysis has been undertaken of these benefits for a scenario where there is a requirement for 30 MW of FK capability.

5.15 On balance, if there continues to be a need to procure 30 MW of FK services, it is likely that the benefits of developing a NFKM and co-optimisation of FK with energy and IR will outweigh the costs of development. Further, there could possibly be significant synergies associated with undertaking the modifications of market systems (i.e. SPD, RMT, etc.) for NFKM and/or FK co-optimisation at the same time as making the changes required for a national IR market.

5.16 However, given the uncertainty, it is appropriate the Authority first consider what level of FK services is likely to be required with FKC following the outcome of the FKC trial.

Appendix A Consideration of the change in peak capacity requirements due to FKC altering the need for IR

A.1 As set out from page 10 in the main paper, the new HVDC control system provides both a benefit and a cost when considering the procurement of IR:

(a) the quantity required to cover an AC contingent event decreases because the system operator can be less conservative in accounting for the reserve sharing available across the HVDC link

(b) the quantity required to cover a DC contingent event increases (by 40 MW) because the system operator has to account for the HVDC transfer being higher than expected by SPD - FKC modulation risk.

A.2 The net impact of these two effects on system peak capacity requirements will depend on which of these two factors will dominate at times of peak demand. This will be driven by the likely transfer levels across the HVDC at times of peak demand.

A.3 If the HVDC is likely to be operating at high northward transfers at peak periods it is likely that the HVDC contingent event will be the binding constraint. This will cause an increase in North Island FIR procurement at times of peak demand.

A.4 If the HVDC is operating at low northward transfer or even southward transfer at times of peak demand, it is likely that the within-island AC contingent event will be the binding constraint. This will cause a reduction in FIR procurement at times of peak.

A.5 A stand-alone exercise considered the maximum potential northward HVDC flow at times of peak North Island demand, and thus the DC contingent event risk at times of peak. This equals:

(South Island coincident peak generating capacity – South Island Demand at NI peak) * (1 - HVDC losses) =

(2,850 MW – 2,100 MW) * (1 – 0.08) = 690 MW.

A.6 This figure of 690 MW represents the HVDC extended contingent event (ECE) risk – i.e. the loss of the bipole – and is supported by examination of historical HVDC flows at times of peak demand shown below.

A.7 The loss of a single pole is considered to be the DC CE risk. When the HVDC link is operating at high transfer levels, it will spread the transfer evenly over both the HVDC poles, i.e. 345 MW per pole. However, because of the ability for the HVDC to 'self-cover' for the loss of one pole (by increasing output on the other), the DC CE is not 345 MW, but instead only 110 MW.[12]

A.8 With the increased modulation risk of 40 MW, the bipole (ECE) and single pole (DC CE) risks will increase to 730 MW and 150 MW respectively.

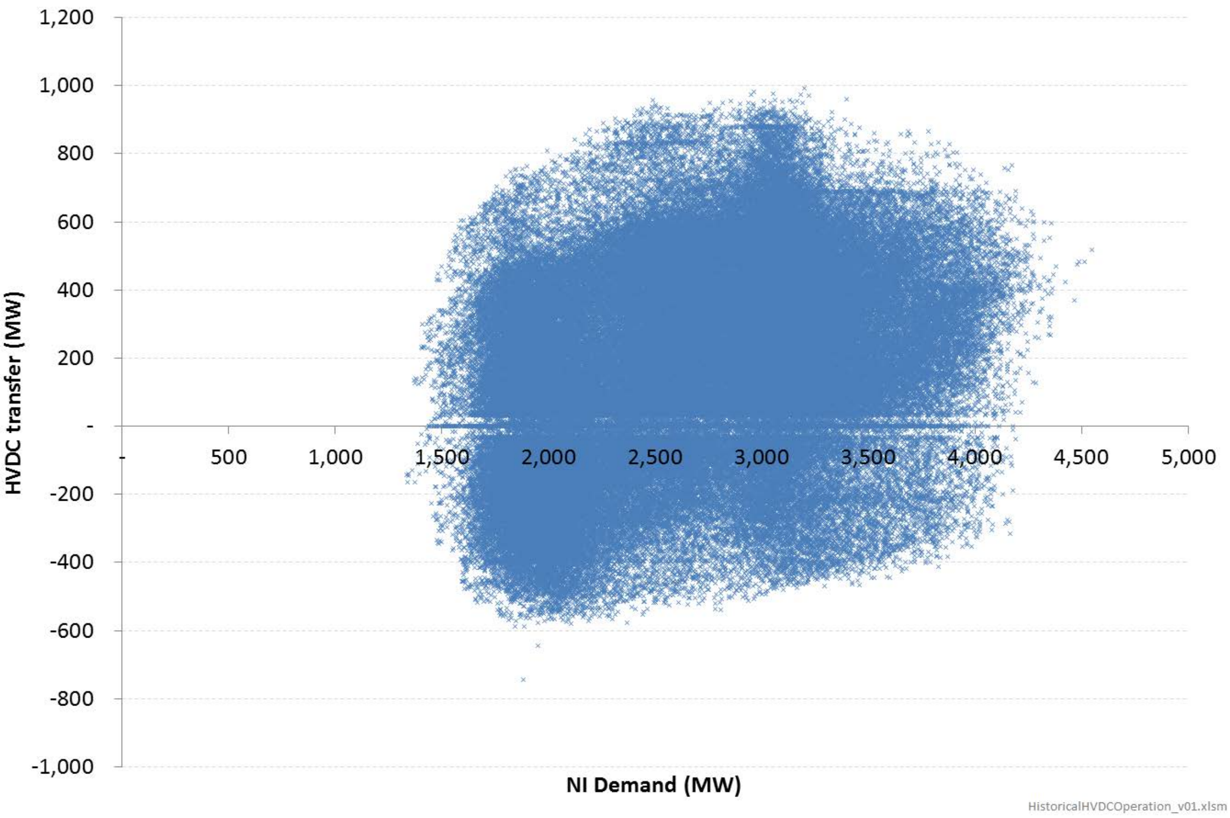
A.9 At times of peak demand it is likely that the largest within-North island AC contingent event risk (AC CE) will be the loss of a CCGT operating at full

[12] If the HVDC is operating at part load and one pole trips, it is possible for the other pole to ramp up to compensate. If the HVDC is transferring 690 MW north, this will be spread evenly between the two poles at 345 MW each. If the higher rated pole (Pole 3) were to trip, pole 2 would ramp up to its overload rating of 580 MW to compensate. This is known as self-cover, There would be a need to have at least 110 MW of North Island FIR to cover the potential loss of a single HVDC pole in this situation.

capacity. This is likely to be Huntly unit 5 operating at a capacity of 400 MW, which is well above the single pole DC CE risk, including the increased modulation risk, of 150 MW.

A.10 Given the large quantity of transfer required for a DC ECE to bind, the impact of the increased modulation risk of 40 MW is not expected to have a material effect on the cost of IR.

Figure 6: Historical half-hourly HVDC transfer and concurrent North Island demand



Source: Electricity Authority (data is for the period 1 January 2005 to 30 September 2013)

A.11 Even though power is most valuable at times of peak demand (i.e. periods where demand is greater than 4,000 MW) the HVDC has not been operating at full capacity.

A.12 Looking forward, HVDC flows at times of peak may change due to changes in South Island generation and demand. It is not considered that there will be any significant new generation built in the South Island in the short to medium term. This is because of the relatively subdued demand growth projected for New Zealand, combined with the fact that the most cost-effective new generation options appear to be geothermal in the North Island.

A.13 To the extent that South Island demand grows at peak, this will progressively reduce the amount of HVDC transfers at times of peak. This is considered relatively likely given that peak demand has been growing at a faster rate than overall demand.

A.14 Offsetting this could be the closure, or scaling back, of the Tiwai smelter. In this, scaling back to 400 MW is considered relatively likely from 2017 under the terms of the new contract between Rio Tinto and Meridian. This would have the effect of increasing potential flows across the HVDC by 180 MW * (1-8%) = 165 MW. This would increase the DC CE to 202.4 MW.

A.15 This is still less than the AC CE.

A.16 If the smelter were to close altogether, giving rise to a further 400 MW * (1-8%) of transfer, the DC CE would rise to 570.4 MW. This is greater than the AC CE and thus would become the binding risk.

A.17 While reduction of Tiwai demand to 400 MW is considered likely, complete closure is considered much less likely. Accordingly, on balance, the HVDC is unlikely to be the binding constraint at times of peak demand. Therefore the effect of FKC on IR requirements at peak is likely to be beneficial, and lead to a net reduction in system capacity requirements.

A.18 There are also two other factors that need to be considered in relation to the likely impact of FKC on the demand for IR in the North Island at times of peak demand.

A.19 Firstly, as set out on page 7, the current state of relative system over-capacity will mean that any changes in IR requirements at times of peak will be unlikely to translate into changes in peak capacity costs in the short-to-medium term. The 2014 Annual Security Assessment indicates that new capacity will not be required to address North Island peak capacity adequacy requirements until at least 2022. As such, any change in IR requirements at peak will not result in a reduction in peak capacity costs until this time.

A.20 Secondly, any change in FIR alone may have limited effect on the overall requirement for IR. This is because SIR will increasingly become the binding requirement on the need for plant to provide IR – given that most providers of FIR can also provide SIR. Given that there will be no change on the approach to procuring SIR under the interim arrangements, there may be limited or no impact on the amount of capacity required to provide IR at times of peak demand.

A.21 This issue was analysed in more detail in a paper released by the Wholesale Advisory Group (WAG): "*Potential gains from altering reserve procurement arrangements - A WAG Briefing Paper*", 5 June 2014

A.22 On balance, given this SIR effect, no benefit has been attributed to the interim arrangements reducing peak capacity requirements through reduced FIR procurement.

Glossary of abbreviations and terms

Authority	Electricity Authority
CE	Contingent event for which IR is procured
Code	Electricity Industry Participation Code 2010
ECE	Extended contingent event, which is covered by the combined resources of IR procured and obligations to provide extended reserve obligations provided for in Part 8 of the Code
FIR	Fast instantaneous reserve, an IR product that halts the fall in frequency following an event that causes the frequency to fall below 49.25 Hz
FKC	Frequency keeping controller – the primary control mode for the HVDC link that tightly couples the AC power systems in each island
HVDC or DC	High voltage direct current
IR	Instantaneous reserve, an ancillary service comprised of FIR and SIR products
MW	Megawatt
NFKM	National frequency keeping market
PV	Present value, used to discount value of future benefits and costs
Round power	Operating mode for the HVDC link where each pole transfers power in the opposite direction to achieve the net transfer desired
SIR	Sustained instantaneous reserve, an IR product that restores frequency above 49.25 Hz following the operation of FIR