Wholesale Advisory Group

Instantaneous Reserve Event Charge and Cost Allocation

WAG discussion paper

11 October 2016

Note: This paper has been prepared for the purpose of discussion within the WAG. Content should not be interpreted as representing the views or policy of the WAG or the Electricity Authority.

Contents

Introduction from the WAG chair

"The allocation of reserve costs is topical - the national market for instantaneous reserves (NMIR) went live in October, and the Authority has already asked for the WAG's advice on the need for possible interim changes to cost allocation under the NMIR while we develop our recommendations on a principled solution for the long-term.

This request followed insight from the Authority's own consultation process that allocating IR costs nationally under a NMIR could be even further from "causer pays" than continuing with the current practice of allocating IR costs based on the island from which they were procured.

The move to a national market creates challenges for determining how to allocate costs between islands in a way that best reflects "causer pays". The drives to allocate at least some costs nationally, also creates tensions with regards to the suitability of the current general allocation approach – pro-rata above a de minimis. However, moving away from this current approach, could result in significant wealth transfers and raises the risk of possible unintended consequences. This is a tricky balancing act – particularly as the introduction of the NMIR will inevitably result in change and wealth transfers, whichever cost allocation approach is chosen.

This paper seeks your input on how best to allocate IR costs – both between islands under the NMIR, and generally between different sized risk-setters – in a way that is consistent with the Authority's Statutory Objective.

In this, the WAG notes that there is significant inherent complexity with this issue – driven by the complex dynamics of the HVDC as both IR provider and risk setter, and the inter-relationship between the energy markets and the different portfolio effects on different participants.

Notwithstanding the complexity of the issues, it is also important to develop proposals that are proportionate to the benefits that they offer – although reserves currently cost approximately $40m per year, the estimated present value of benefits from changing the arrangements are of the order of $10-20m, and subject to a significant degree of uncertainty.

To this end we would be interested in your views on how to ensure that the costs of securing these potential benefits, including possible unintended consequences, do not exceed the actual benefits of a change."

John Hancock

Independent Chair, Wholesale Advisory Group

Wholesale Advisory Group membership:

The members of the WAG at the date of the publication of this paper are:

John Hancock (Chair)

Phillip Anderson

Neal Barclay

John Carnegie

James Collinson-Smith

Stephen Drew

Alan Eyes

Chris Jewell

Stephen Peterson

What this paper is about

Instantaneous reserve (IR) is procured to cover the risk of the loss of a large generation or supply asset. Efficient outcomes are not just driven by how IR is *procured*, but how the costs of procurement are *allocated*, because the cost allocation can influence the actions of parties that cause the need to procure (and use) IR.

The Wholesale Advisory Group (WAG) is undertaking a 'first principles' review of the approach to allocating instantaneous reserve costs, and the event charge regime. Its aim has been to determine if the existing arrangements are consistent with the Authority's statutory objective.

The WAG has come to a view on some issues, but is not yet at the point of proposing changes to the existing arrangements. It seeks stakeholder feedback to aid its consideration.

The WAG considers that current arrangements harbour the potential for inefficient outcomes

The existing arrangements for allocating IR costs, in many respects are consistent with an 'exacerbators pay' principle. The WAG considers that this remains appropriate: Allocating costs to exacerbators is practical, and ensures that parties who give rise to common costs internalise those costs, and are hence incentivised to minimise them through their own decision making; including operational and investment decisions.

However, the WAG has identified a number of aspects of the current cost allocation approach, which dull the marginal cost signal to the causers of the need for IR, and may result in inefficient long-term plant investment and retirement decisions. The key potential problems are:

- **The pro-rata approach** dulls the IR cost allocation to the largest units causing the need for IR to be procured
- **The pass-through of costs under the transmission pricing methodology (TPM)** dulls cost signals that might influence investment decisions, because it does not provide a half-hourly signal and it may not be allocated to the right parties.
- **Assets presenting secondary event risks** (e.g. AOPO-non-compliant plant) do not consistently face the extra IR costs they cause.

Further, a national market for instantaneous reserves (NMIR) was introduced in October 2016. This allows up to 220 MW of IR to be transferred from one island to the other at times. This enables a significant reduction in the overall quantity of IR that needs to be procured across both islands, and means we can draw on the cheapest IR across both islands.

In the interim, cost allocation under the NMIR will continue with the current island-based approach to cost allocation. i.e. the costs of reserve procured in an island are allocated to the risk-setters in that island – irrespective of whether the reserve is being used to cover the risk in the *other* island. The WAG anticipates that this will be acceptable in the short-term, as it is unlikely to create any perverse incentives on participants to withhold energy or IR capacity. However, its effective 'cost-to-provider', rather than 'cost-to-causer', nature means the island-based approach does not send efficient investment and retirement signals, and is therefore not an appropriate approach in the long-term.

In considering alternative cost allocation options, the WAG notes that there is significant inherent complexity with this issue – driven by the complex dynamics of the HVDC as both IR provider and risk setter, and the inter-relationship between the energy markets and the different portfolio effects on different participants. In this respect, moving to allocate some or all costs nationally will further expose some of the tensions associated with the current pro-rata approach to cost allocation.

The event charge regime

The WAG has decided that the event charge regime should not be retained in the long-term as it:

- does not meaningfully incentivise plant reliability
- would not facilitate more efficient procurement of interruptible load (IL), were it amended to facilitate event-based procurement.

However, it has yet to come to a common view as to whether temporarily re-allocating the event charge to IR providers would appropriately support IL in the short term, pending improvements to the IR procurement approach so that it better recognised faster-acting IR providers.

The WAG has identified the ideal approach in principle, but is yet to identify the ideal approach in practice

The WAG has identified a number of potential changes to the arrangements, and provided its interim assessment of their merits. These potential changes include:

- changing the general cost allocation from a pro-rata to runway approach
- altering the 60 MW de minimis
- capturing / altering the cost allocation to plant posing secondary risks

The first two changes could result in significant wealth transfers and possible associated unintended consequences, yet the scale of benefits are subject to significant inherent uncertainty. This is because the benefits of changing the cost allocation both *drive* and *are driven by* the future state of the system. In particular, the decisions of a few individual participants (e.g. the owners of the Tiwai aluminium smelter, or the HVDC) could drastically impact the scale and scope for benefits, as could the outcome of some issues that are currently being worked through by the Electricity Authority (e.g. the TPM).

Generally, the WAG does not support significant changes, given uncertain benefits.

However, some changes to reflect the new NMIR are necessary. To this end, the WAG has identified five potential ways to allocate costs across the two islands. It considers the option that best reflects the conflicting contribution of the HVDC may deliver the best long-term outcomes, in terms of incentivising efficient decisions about both plant size and location. It is also likely to be most durable to system changes, which are likely to see the HVDC increasingly drive IR procurement. However, the effectiveness of such an approach will be influenced by the TPM, and calls into question the durability of continuing with a pro-rata approach to allocating costs generally.

The WAG's findings, and the key issues it is yet to resolve, are summarised in the following diagram.

Allocation of IR costs

The current cost allocation dulls the signal to parties causing the need for IR.

An approach based on first principles would be different from the current approach – but would also be exacerbators-pay

It would:

- **allocate costs on a 'runway' basis**, rather than a pro-rata basis, as it provides a more marginal signal
- **allocate IR costs relating to HVDC transfers on a half-hour basis**, rather than relying on the transmission pricing methodology to allocate costs
- **allocate additional IR costs caused by secondary risks to the asset owners**, whereas currently the signal provided to these parties is ad hoc or absent entirely

At best, aligning with these might improve generation investment decisions by a maximum of $19m.
More efficient decisions about:

- when to retire assets (≈ $5m)
- where to locate new generation (≈ $4m)
- the technical capability of generation (≈ $10m)

But:

- the benefits are highly uncertain and, implementing some changes could offset any potential benefits
- there would be implications for sunk assets, and possible unintended outcomes
- complexity for little benefit should be avoided

Significant changes are not preferred given the degree of uncertainty

However:

Allocating costs on an island-basis is not optimal under the new NMIR

The cost allocation should reflect the HVDC's role in contributing to and constraining IR sharing between islands

But:

- this may create tensions with a pro-rata approach
- its efficiency will be impacted by cost pass-through under the TPM

What changes will allow us to realise most of the benefits without the full cost/risk?

Event charge regime

The event charge has never been fully implemented as originally intended

The purpose it currently serves – being to incentivise reliability - is unlikely to provide benefits that exceed the costs of administering it

Achieving its original (but never implemented) purpose – to support IL providers in recovering event-based costs – would not incentivise more IL in a way that provided net benefits.

-> *the risks faced by IL are small, and should not prevent cost recovery over time*

-> *potential approaches to paying providers on an event-basis either result in lower rewards for providers, or inappropriately high costs and risks for the wider market*

The event charge should not be retained in the long-term

But:
There may be a short-term period where the IR market does not provide a sufficient return to incentivise IL participation. This could have inefficient outcomes in the longer-term.

Should the event charge be modified, and used on a short-term basis to bridge this gap?

1 Introduction

1.1 The WAG is reviewing the instantaneous reserve cost allocation and the event charge regime

In May 2015, the Electricity Authority (Authority) requested the advice of the WAG on whether the current arrangements for allocating instantaneous reserve (IR or 'reserve') costs and the event charge regime are optimally consistent with the Authority's statutory objective.

This paper contains the preliminary findings from the WAG's review of these arrangements.

The WAG notes the introduction of a national market for instantaneous reserves in October 2016. This paper was prepared prior to that introduction.

1.2 The WAG wants your feedback

The purpose of this paper is to seek feedback on the findings of the review. The WAG has come to a view on some issues, but is not yet at the point of proposing changes to the existing arrangements. It seeks stakeholder feedback to aid its consideration on issues where it is unsure of the ideal outcome.

If you wish to make a submission, the information required to do so is provided on the following page.

1.3 What happens next?

The WAG will consider all submissions on this discussion paper and publish a summary of the feedback received.

With the support of the information provided in submissions, the WAG will make recommendations to the Authority about how it should alter the arrangements.

The WAG hopes to report back to the Authority by March 2017.

1.4 Relationship to other work streams

The WAG's project is related to other projects currently being undertaken by the Authority. Specifically, it is related to the Authority's:

- **review of how IR is procured**. That review will likely result in different IR procurement costs arising. It is the purpose of this WAG review to address how best those costs should be allocated.[1]
- **implementation of a national market for instantaneous reserves (NMIR)**. The Authority considered changes to the IR cost allocation so that costs arising under the NMIR would be allocated nationally, rather than between islands as they have been under the island-based IR market.[2] However, the Authority decided not to make any changes in the short-term, pending a more comprehensive review of IR cost allocation in the whole.
- **review of the transmission pricing methodology (TPM)**. Under current IR cost allocation arrangements, the HVDC attracts IR costs, which the grid owner passes on via the HVDC interconnection charge under the TPM. The review of the TPM is likely to alter the parties that are ultimately allocated IR costs relating to the HVDC.

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[1] There is one area of cross-over, which is the consideration of the potential to pay interruptible load its event-based costs, funded by the event charge. This is addressed in section 7.

[2] The Authority consulted on these changes in March 2016. See http://www.ea.govt.nz/dmsdocument/21124

HOW TO MAKE A SUBMISSION

This discussion paper is published by the WAG and the WAG will be responsible for considering submissions received.

Submissions should be received by 5.00pm on **22 November 2016**.

If possible, submissions should include responses to the questions the WAG has included in this discussion paper (refer Appendix A).

Electronic submissions are preferred

The WAG prefers submissions in electronic format (in Microsoft Word).

Submissions should be emailed to wag@ea.govt.nz with "Review of IR Event Charge and Cost Allocation" in the subject line.

Submissions can be made in hard copy

If you do not wish to send your submission electronically, you must post a hard copy of your submission to one of these addresses:

Submissions
WAG Chair
c/- Electricity Authority
PO Box 10041
Wellington 6143

or

Submissions
WAG Chair
c/- Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860
Fax: 0-4-460 8879

Sending a hard copy is not necessary if you have sent your submission electronically.

IF YOU INTEND TO MAKE A SUBMISSION

The Authority will acknowledge receipt of submissions

The Authority, on behalf of the WAG, will acknowledge receipt of all submissions electronically.

Please contact the Submissions Administrator at the Authority if you do not receive electronic acknowledgement of your submission within two business days.

The WAG intends publishing all submissions

Please note that the WAG intends publishing all submissions it receives. This is the usual practice with submissions.

If you consider that we should not publish any part of your submission, please indicate what part, and set out the reasons why you consider we should not publish it.

If you indicate that there is a part of your submission that should not be published, we will discuss it with you. We will ask whether you can provide us with a version that we can publish (if you have not already done this).

Submissions are subject to the Official Information Act

Please note that all submissions we receive, including any parts that we may not have published, can be requested under the Official Information Act (OIA). This means that we would be required to release them unless good reason exists under the OIA to withhold them.

We will normally consult with you before releasing any material that you had identified should not be published.

2 Context: Current IR procurement and cost allocation arrangements

2.1 The fundamentals of IR and how it is procured

Instantaneous Reserve is an ancillary service procured to maintain frequency following the sudden loss of power from a generator or the HVDC. IR is currently procured:

- as part of a wider frequency risk management framework, which includes asset owner performance obligations (AOPOs) and extended reserves
- from generators and interruptible load (IL) providers
- by the system operator on behalf of all participants, under contracts with providers. Providers then compete amongst each other in the spot market every half hour to provide IR, which determines reserve prices
- in quantities sufficient to protect against the more pressing of:
    - a 'contingent event' (CE) – being the loss of the largest *single* generating unit or a single pole of the HVDC
    - an 'extended contingent event' (ECE) – being the loss of *multiple* assets (e.g. both poles of the HVDC), which will be managed by IR in conjunction with extended reserves (principally AUFLS); or
    - as otherwise deemed necessary by the system operator to ensure system security
- as two separate products:
    - fast instantaneous reserve (FIR)
    - sustained instantaneous reserve (SIR) [3]
- separately for each island – although from November 2016, the system operator will model the ability of the HVDC link to transfer up to 220 MW of IR when procuring it, thereby enabling IR to be procured on a national basis
- in a way that is co-optimised with energy within the Scheduling Pricing and Dispatch (SPD) software, such that the least-cost mix of resources is dispatched to meet both energy and reserve requirements each trading period.

Therefore, IR is procured through a competitive one-way market. However, this means that costs arise with no identified counter-party and they must be allocated to somebody.

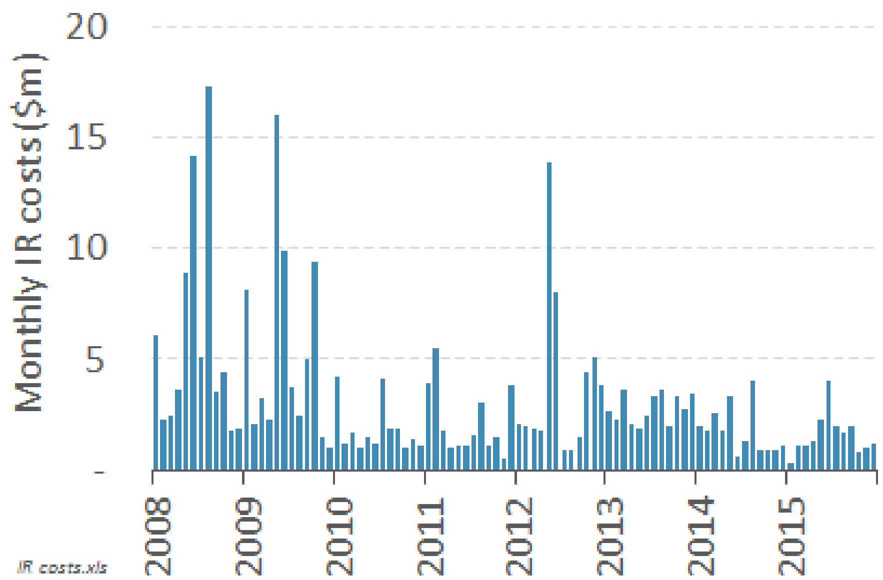
[3] In 2015 the WAG recommended to the Authority that it investigate changes to how FIR and SIR are procured. In particular, it noted that advances in computational capabilities may mean that there is no longer a need for two separate products, and that it may be more efficient to procure a single "area-under-the-curve" product.

2.2 Characteristics of IR costs

As shown in Figure 1, during the period from 2008 to 2015, IR costs:

- averaged $3m per month, or $38m per year
- were highest in 2008, and spiked again in 2012, because hydro inflows were very low. This meant:
    - southward transfer on the HVDC, which led to a scarcity of FIR in the South Island
    - a high reliance on large North Island thermal generators, which led to a scarcity of SIR in the North Island.
- were otherwise generally low from 2010 on, because of a general over-supply of generation capacity, and hence ample IR.

Figure 1: Monthly instantaneous reserve costs from 2008 to 2015



2.2.1 The HVDC has a significant role in the IR market

The HVDC has an interesting role in the IR market, because it:

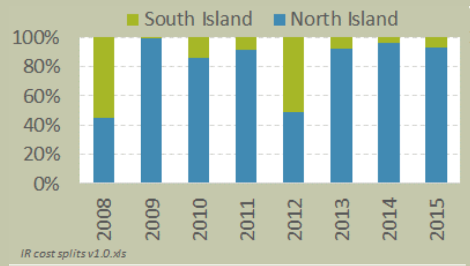
- presents an under-frequency event risk that causes a need for IR.
- supports IR providers in meeting IR requirements across both islands

The HVDC's role in the IR market has become particularly significant since changes were made to its capability in 2013.

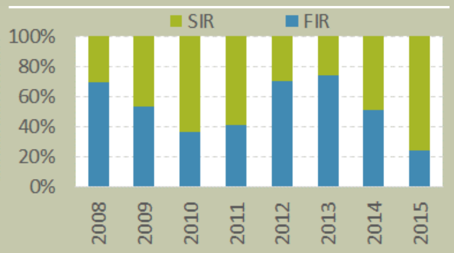
- the improved functionality facilitates new IR procurement opportunities, including a national market for instantaneous reserves (NMIR), with up to 220 MW of reserve able to be shared between the islands.
- the increased transfer capability *creates* additional IR procurement requirements.
- IR requirements mean we generally won't realise the full capability of the HVDC – i.e. the IR requirements to cover the risk of the loss of the HVDC generally constrain the link from transferring at full capacity.

As will be seen in the body of this report, the complex nature of the HVDC as both causer of the need for, and provider of, IR makes the design of arrangements which send an appropriate cost signal to participants challenging.

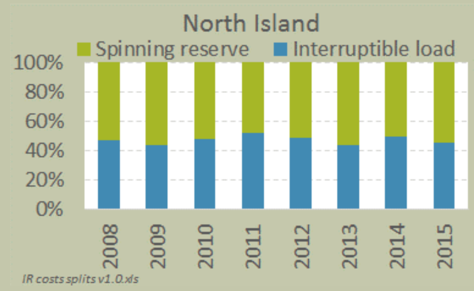
IR costs are generally higher in the North Island than in the South Island, except when there are high South transfers on the HVDC



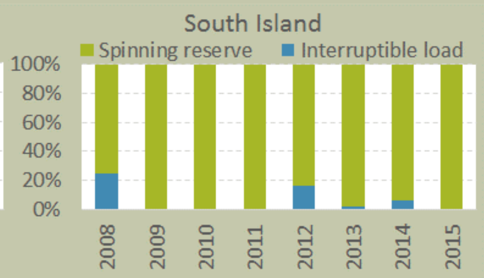
IR costs are split relatively evenly between FIR and SIR over time.



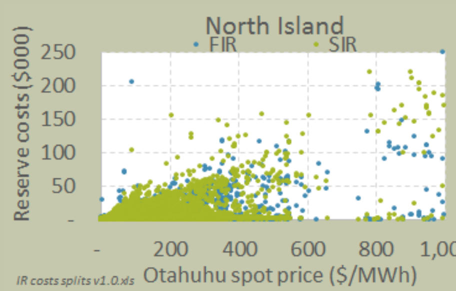
Interruptible load accounts for around 40% of North Island costs…



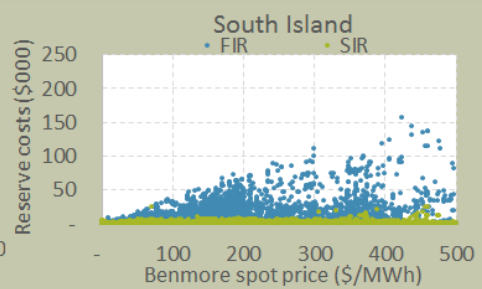
but less than 10% of South Island costs



IR costs are correlated with energy prices at times



SIR prices are generally low in the South because it is less scarce



2.3 The current approach to allocating IR costs

Costs are currently allocated via two components:

a) **An availability charge**: this seeks to allocate the known instantaneous reserve costs to parties that are ‘potential causers’ of an under-frequency event, and that hence drive the need to procure instantaneous reserve.

b) **An event charge**: this seeks to incentivise plant reliability by requiring plant that trips and causes an event to pay an administered event-based charge.

2.3.1 The availability charge allocates procurement costs:

The availability charge allocates total IR procurement costs in each half hour to generators and the HVDC owner, in proportion to the quantity that each generating unit and the HVDC injected into the grid during that half hour, over a de minimis threshold of 60 MW.

It is calculated and allocated separately for the North Island and the South Island.

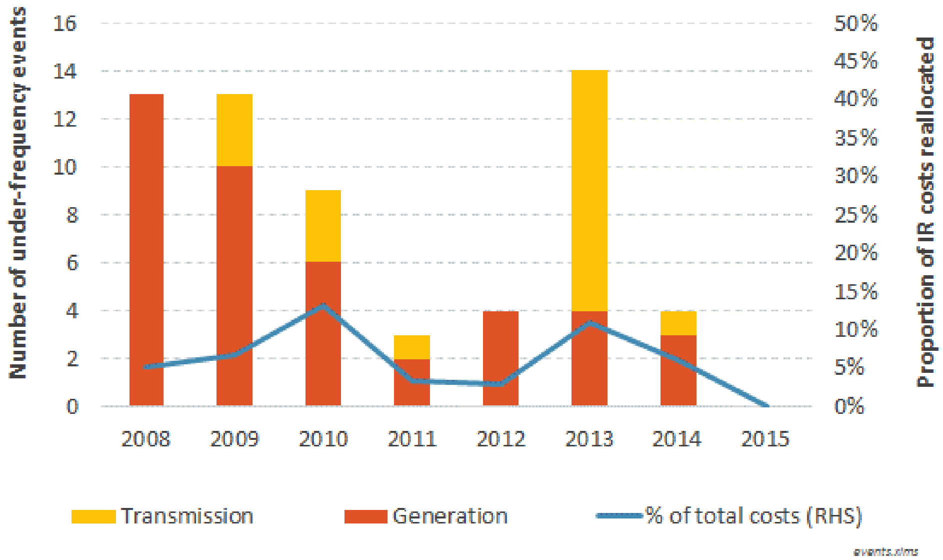
2.3.2 The event charge is an additional charge for causing an event

The event charge is:

- an administered charge set at a fixed $1,250 for every megawatt above 60 MW that is lost in an event
- paid by the ‘primary causer’ of an event, which will either be a generator or the grid owner
- rebated on a proportional basis to parties that paid the availability costs during the billing month in which the event occurred, and the two preceding months. Under this approach, the causer of an event will likely receive back some portion of the event charges it incurs.

The number and size of under-frequency events varies from year to year, depending on particular circumstances. For example, multiple events in 2013 were a result of the HVDC pole 3 commissioning, whereas there were no under-frequency events in 2015.

Figure 2: Re-allocation of IR costs through the event charge[4]



It is potentially the case that the trend towards a lower number of events may continue due to:

- fewer large units on the system following the retirement of Otahuhu B, two Huntly Rankine units, and Southdown – noting that it is the loss of the largest units on the system that is most likely to cause under-frequency events
- the upgrade to the HVDC, which is likely to improve its reliability
- an increasing likelihood that future generation investment will be focussed on smaller-sized units (i.e. wind farms, geothermal stations, and open-cycle gas turbines).

[4] Note: event and event cost data sourced from system operator self-review reports. The event causers for 2006 are not differentiated. Costs relating to an event in 2008 were not available.

2.4 Rationale behind current arrangements

Until 1999, IR costs were allocated to large generators using a 'runway' method (see section 6.1.1). However, some participants opposed that approach because it made no distinction between reliable and unreliable assets.

In 1998, the Instantaneous Reserve Steering Committee conducted a review of the IR cost allocation arrangements, ultimately recommending the current approach, which was implemented the following year.

At the time the current arrangements were established:

- investment in CCGTs was on the horizon, which presented a new and significant frequency management risk
- there were no obligations on the grid owner to make its assets available (now included in Part 12 of the Code)
- wind generation was not present to a material extent on the system
- the Reserve Management Tool (RMT) for scheduling reserve had not been developed
- the HVDC had a lower capacity, greater operational constraints, and less sophisticated controls/features.

Furthermore, when the current arrangements were established, the sector was governed by multi-lateral contractual arrangements, rather than being subject to regulation, and IR cost recovery was the subject of considerable dispute and legal challenge. This meant that the resulting arrangements reflected a mutually agreeable approach to allocating costs that was achieved via negotiation between these parties (Transpower, ECNZ, and Contact), rather than principally being driven by a regulatory objective to deliver efficient price signals to parties driving the need for IR to be procured.

Only minor amendments have been made to the allocation since its introduction in 1998.

Other amendments have been considered, but were not pursued.

Table 1 outlines how the arrangements have development over time.

Table 1: Development of current IR cost allocation arrangements over time

Year	Development	Outcome
1998	Instantaneous Reserve Steering Committee report proposed current IR cost allocation methodology, to replace an existing 'runway' approach that was causing industry disputes	Current regime introduced. Review envisaged that IR providers could be procured based on their event-based costs, but this was never implemented due to design challenges.
2000	Review of all ancillary service cost allocation arrangements, conducted under new Multi Agreement on Common Quality Standards	Retained regime with minor amendments – ie, secondary events excluded from event charge regime.
2004	Electricity Governance Rules (EGRs) introduced	Existing contractual arrangements ported into new regulatory regime.
2004	Review of event charge regime, in response to concerns about increasing $/MW event charge – which was previously set annually to try and recover half of all IR costs from event charges.	Retained event charge, but revised it to a fixed $1,250/MW amount
2005	Review of how costs are allocated to parties with dispensations from under-frequency AOPOs.	No changes pursued.
2007	Exemptions from event charges provided to various asset owners.	Grid owner (HVDC), Genesis (e3p), and Mercury (Nga Awa Purua), Contact (Stratford OCGTs) granted temporary exemptions to prevent overly cautious operation.
2010	Review of how event causer is determined, to address concerns about protracted legal process to determine causer.	Definition of causer in the EGRs clarified, and more specific processes for event causer determination introduced.
2010	Electricity Industry Participation Code 2010 (Code) introduced	Existing arrangements retained under new regulatory regime.
2012	Review of how IR costs associated with asset commissioning are allocated.	Proposed change to allocate costs to causers, but not pursued due to implementation difficulties.
2013	Code amendment request to rebate event charges to reserve providers (including IL), rather than potential causers of an event.	Authority deferred proposal, due to significant cost and potential for adverse effects.
2016	National Market for Instantaneous Reserves (NMIR) developed and implemented.	From October 2016, reserve can be procured in one island to meet a risk in either or both islands

3 What aspects of the IR cost allocation arrangements may be resulting in inefficiencies?

The IR cost allocation arrangements have been identified as an issue worthy of review since the early 2000's based on concerns with a number of aspects:

- The pro-rata approach was highlighted as potentially distorting the price signal to causers of the need for IR.
- The original intent when the IR cost allocation arrangements were first developed was for the event charge to be a pre-cursor to full event-based procurement. However, this never eventuated.
- A growing number of 'special case' instances were identified where parties which contribute to the need for IR avoid some or all of the cost allocation.

As well as addressing these issues, there are a number of specific triggers which suggest a review now is timely:

- The forthcoming introduction of the national market for instantaneous reserves (NMIR) for procurement raises question as to whether continuing with island-based cost allocation is appropriate.
- A number of recent changes to the configuration of the NZ system (HVDC upgrade, thermal retirements), have altered the pattern of New Zealand's IR risk profile, with other potentially significant changes possible in the future (more thermal retirements, Tiwai closure, further HVDC upgrades). Further, the configuration of the New Zealand system is significantly different to when the current IR cost allocation arrangements were first developed – including a shift in new-entrant technology away from large-unit sized CCGTs towards smaller unit-sized wind and geothermal.
- Potential changes to the TPM will alter how HVDC-related IR costs are allocated
- A participant has proposed a rule change relating to the treatment of the event charge

The WAG has evaluated the IR cost allocation and event charge regime for consistency with the Authority's statutory objective, which is:

> *"to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."*

The WAG has identified a number of areas where the current cost allocation approach may not be achieving the Authority's statutory objective.

- The general approach for cost allocation. Specifically, the pro-rata approach to cost allocation is likely 'dulling' the price signal to the causers of IR, which may result in long-term inefficiencies in plant investment.
- HVDC-related issues. Specifically:
  - The current island-based approach to cost allocation may distort the price signal to causers of the need for IR following the introduction of the NMIR. As well as long-term investment inefficiencies, there may be short-term operational inefficiencies.
  - The way in which HVDC-related IR costs are passed-through to market participants may dull the price signal to such parties. This may cause long-term investment inefficiencies.

- There are a number of 'Special cases' where the general approach for cost allocation fails to capture causers. This may result in long-term investment inefficiencies and some operational inefficiencies.
- The event charge regime may not be achieving its current purpose in terms of meaningfully incentivising improved plant reliability, and is certainly not achieving its original intended purpose – to be part of a broader event-based procurement approach to facilitate

Q.1. Do you agree with our identification of the problems with current arrangements?

Section 6 of this paper addresses the first three aspects under the broad heading of 'cost allocation'.

Section 7 addresses the event charge, given its predominantly procurement focus is different in nature to the cost allocation aspects of the other three issues.

But first, sections 4 and 5 set out:

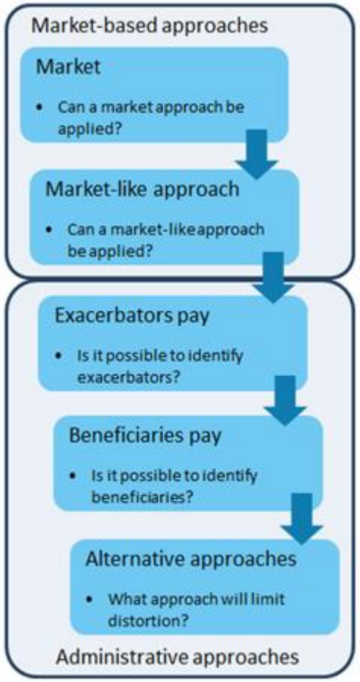
- the framework for considering the merits of IR cost allocation approaches; and
- the high-level principles that cost-allocation should aim to achieve.

4 Framework for considering merits of IR cost allocation

4.1 The WAG has drawn on the Authority's framework

In providing advice to the Authority, the WAG must ensure that any recommendations it makes are consistent with the Authority's statutory objective. This is because the Authority can only make changes to the arrangements that are consistent with its statutory objective.

Figure 3: Hierarchy of preferred approaches to cost allocation



In pursuing its statutory objective, the Authority has previously developed a hierarchy of preferred approaches to allocating costs, as illustrated in Figure 4.

This hierarchy reflects that 'efficiency' and 'reliability' involves facilitating:

- efficient investment decisions, by providing incentives that ensure participants make the right investments, in the right amount, at the right time
- efficient operational decisions, by providing incentives that ensure participants properly trade-off costs and benefits when deciding how to operate their assets

By considering the arrangements through a 'competition, reliability and efficiency' lens, and drawing on the Authority's hierarchy of preferred approaches, the WAG can ensure that any recommendations it makes to the Authority will be of maximum practical value.

4.2 WAG's approach to reviewing the cost allocation

In considering the merits of the IR cost allocation, the WAG has started from first-principles.

It has therefore identified in section 5, the basic principles that should ideally be applied in allocating IR costs.

In section 6, the WAG has then compared the existing approach and possible alternatives against these principles, to identify what (or even whether) changes would be most likely to achieve the Authority's statutory objectives. In doing so, it has taken account of potential limitations set by the practical realities of the sector.

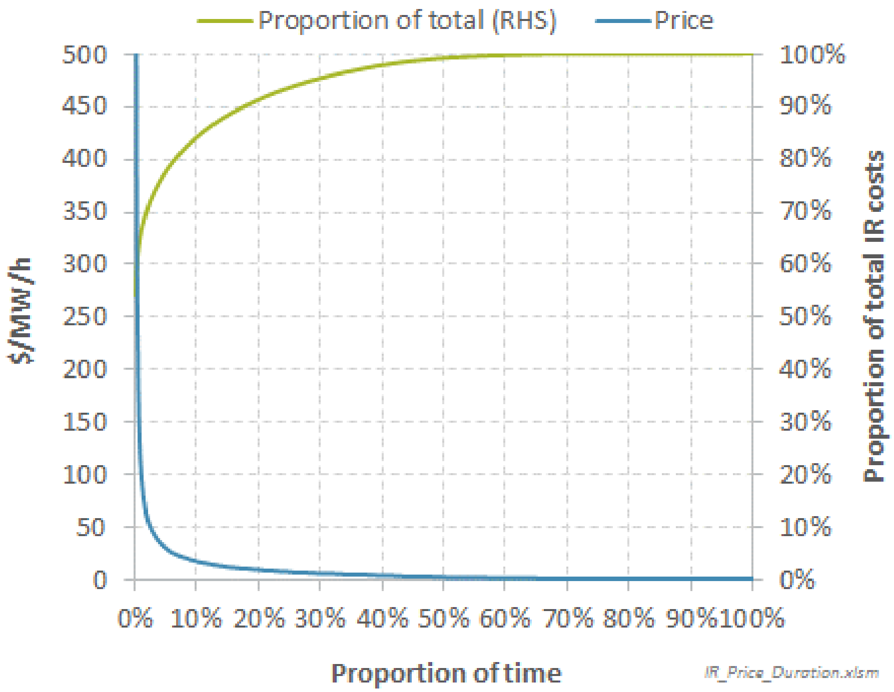
The event charge has been considered separately from the allocation of procurement costs, and is discussed in section 7.

4.3 Benefits have been assessed based on the potential impact on the need for capacity

As Figure 4 highlights, the principal costs associated with the need to procure IR, are costs that arise during times of general capacity scarcity.[5]

[5] With the new HVDC, in particular its ability to self-cover up to relatively high transfer levels, it is not considered that a dry-year would give rise the very high IR prices that were seen during the 2008 and 2012 dry-year events.

Figure 4: IR price duration curve from 2008 to 2015



For the majority of the time the costs of procuring IR are relatively low, reflecting the relatively low operating costs of spinning turbines in a mode where they can provide IR.

However, at times of capacity scarcity, prices rise significantly, reflecting the cost of needing capacity to provide IR at a time when capacity is also scarce for the provision of energy.

Accordingly, the cost-benefit assessment has principally focussed on the impact of potential changes on the amount of IR required at times of capacity scarcity.

The WAG has assumed that the marginal source of capacity at times of peak demand is an open-cycle gas turbine (OCGT).[6] While an OCGT may be unlikely to provide IR, it could operate to meet energy requirements, releasing other forms of generation (e.g. hydro) to provide IR instead.

The Electricity Authority has previously estimated that the carrying costs of an OCGT are approximately $145/kW/yr. These costs are significant when spread over relatively few periods of capacity scarcity.

The potential scale of value from reducing peak capacity requirements can be material. A 10 MW reduction in the amount of capacity required at peak would translate to $1.45m per year, which in present value terms is approximately $12m over 15 years.

4.4 Benefits assessed on impact on contingent event risk

This analysis focusses on the extent to which cost allocation influences the contingent event (CE) risk – being the potential loss of the largest single asset (individual generator, or single pole of the HVDC).

This is because the risk of the simultaneous loss of multiple assets (known as the extended contingent event, or ECE), is principally

[6] Interruptible load (IL) can be much cheaper than building a new OCGT. However, it has been assumed that IL is not the marginal source of capacity at times of peak demand. This is because most load that is suitable for providing IL is generally already being controlled at times of peak demand, in order to avoid peak energy and network costs – making it unavailable to provide IL. The WAG notes that the current TPM affects demand-side participants' incentives to provide IL at times of peak demand, which may change under a revised TPM.

An OCGT is considered to be the cheapest form of generation to provide capacity at times of peak, as this type of generation has the lowest capital and fixed O&M costs compared with other generators, and therefore is the most economic form of generation to be built but only used infrequently (i.e. during the few periods of capacity scarcity).

addressed by the procurement of extended reserves such as AUFLS, with IR only being procured to top up extended reserves in certain situations. The intended design of the extended reserves regime is such that sufficient extended reserves should be available to address the ECE at times of capacity scarcity. Accordingly, consideration of the ECE risks is not a focus of this analysis.

5 Principles for allocating IR costs

5.1 The WAG identifies two high-level principles

The WAG considers there are two principles that should ideally be followed in allocating IR costs.

1. Costs would be allocated to parties causing the need for IR

2. The cost allocation would send a marginal signal

5.2 Principle 1: Costs would be allocated to parties causing the need for IR

Drawing on the Authority's economic framework for decision making, set out in section 4.1, the WAG considers that an exacerbators pay basis is most appropriate for allocating instantaneous reserve costs.

Because system stability is a common good, it is not considered practicable to develop market-based arrangements for cost allocation.

An exacerbators pay basis is hence the next best approach, if it can be implemented efficiently. Allocating common costs to exacerbators or causers ensures that they internalise those costs for their own decision-making, including both:

- operational decisions in terms of whether, and at what price, to offer their plant into the market
- investment decisions as to whether to build and/or retire plant.

IR is procured because assets injecting or transmitting energy fail from time to time, and can potentially cause frequency to decline beyond secure limits. Fundamentally, any injecting and transmitting assets that cause the need for IR to be procured should be allocated IR costs.

By making parties exposed to the IR-related costs they cause, their own cost-minimisation objective should also result in a minimisation of common costs. Therefore:

- in the short-term, parties will make efficient decisions about what price to offer their assets into the market
- in the long-term, they will make efficient asset investment and retirement decisions, e.g. they might develop assets with smaller generating units, if the IR-related costs of larger unit sizes would outweigh any benefits from economies of scale.

5.3 Principle 2: Causers would receive a marginal cost signal

Parties need to see a *marginal* price signal in relation to their actions to achieve efficient outcomes. Parties facing marginal prices can determine whether the marginal value they will gain from producing (or consuming) an extra increment of the product will outweigh the marginal costs they incur from this extra production (or consumption).

In the case of IR, assets causing the need to procure IR need to be allocated the marginal IR cost of increasing their injections. They can then determine whether the extra revenue they will earn from the extra output will outweigh the extra costs they will incur (with costs including IR costs and other operating costs such as fuel).

As well as applying to short-term asset operational decisions, this will also apply to asset investment and retirement decisions. Expectations of the cumulative IR cost allocation over the life of the asset will inform decisions about what unit configuration to develop, and when assets should be built or retired.

Q.2. Do you agree with these basic principles for allocating IR costs?

6 How 'principled' is the current approach?

The WAG has identified three broad areas where the current IR cost allocation approach is not consistent with (either partly, or not at all) the principles set out in section 5:

1) The general approach to allocating costs
   - Pro-rata vs runway
   - De minimis
2) HVDC-related issues:
   - allocating costs under the new NMIR
   - treatment of costs arising from the HVDC risk
3) Allocating costs arising from assets presenting secondary risks

6.1 The general approach to allocating costs

6.1.1 The current pro-rata approach does not provide a marginal signal

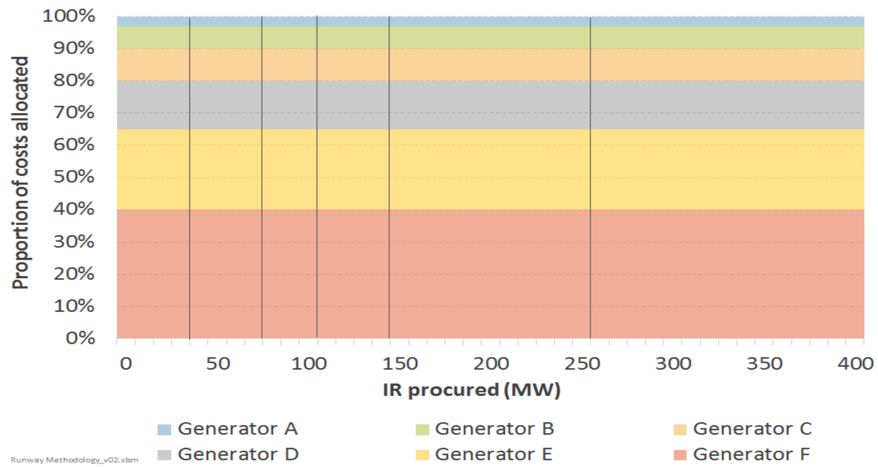
The current approach generally allocates costs to assets that are injecting or transmitting energy, who are the parties that generally cause the need for IR to be procured in each half-hour. Therefore, at a high-level, the current approach allocates costs to causers, and is hence broadly consistent with the first principle.

However, the current pro-rata approach is considered to dull the price signal to the very largest risks on the system which determine the amount of IR that needs to be procured, and is thus considered inconsistent with the second principle.

To illustrate this, consider a hypothetical 1,000 MW system of six generators, A to F, with MW outputs of 40, 70, 100, 150, 250, 400. If all generators were operating at full output the amount of IR that would need to be procured would be 400 MW – being the size of the largest risk.

Figure 5 illustrate how the costs from procuring this 400 MW of IR are allocated under the current pro-rata approach.[7]

Figure 5: Illustration of cost allocation under a pro-rata approach



Runway Methodology_v02.xlsm

This pro-rata approach does not reflect how costs arise, and does not provide a marginal cost signal to the largest units that are driving the need for IR.

If the largest asset is operating at 400 MW, and the next largest is operating at 250 MW, the largest asset is giving rise to a need to procure an extra 150 MW of IR *than would otherwise be the case.*

Alignment with the WAG's identified principles would see the incremental costs associated with this extra 150 MW of IR

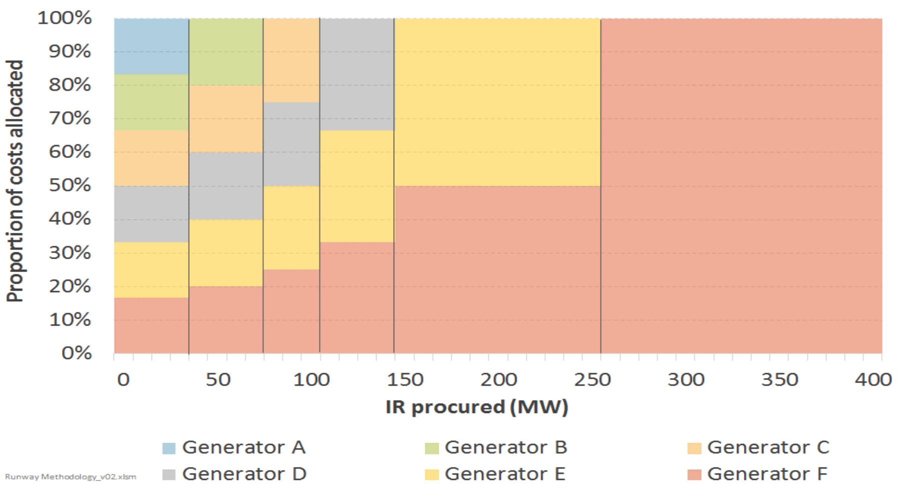
[7] For the purposes of the illustration set out in Figure 5to Figure 7 a de minimis is not applied as it is an additional complication which would detract from the illustration, yet does not fundamentally change the nature of the different outcomes.

procurement allocated *solely* to this largest causer. The costs associated with the other 250 MW of IR procurement would be *shared* between the largest unit and other units on a similar basis.

This approach to cost allocation is referred to as a 'runway' approach, as it is the basis on which airport landing fees are allocated, to recover the costs associated with building the runway.[8]

For the same hypothetical 1,000 MW system as used for Figure 5, Figure 6 illustrates how the costs associated with each MW of procured IR would be allocated under a runway approach.

Figure 6: Illustration of cost allocation under a runway approach

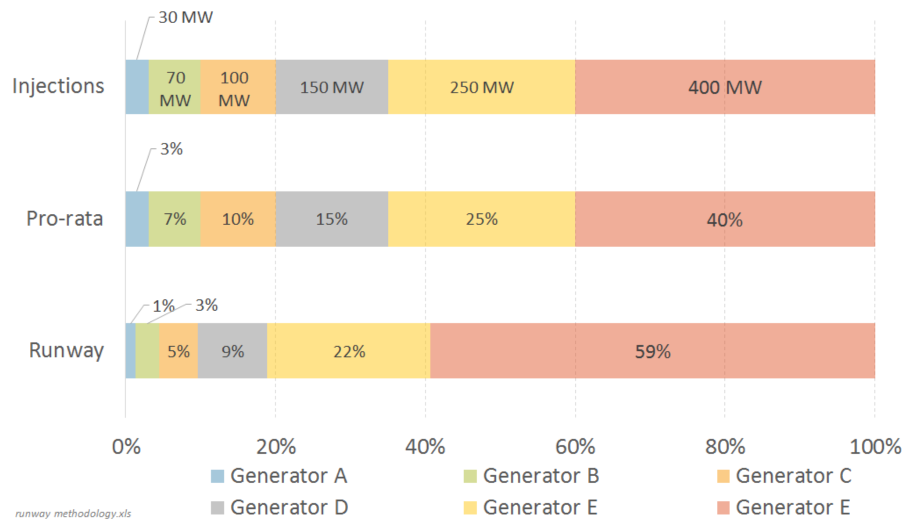


[8] For example, if only the very largest planes use the full length of the runway, and the next largest only use 70% of the runway, then the cost of recovering the 30% of the runway required for the very large planes is solely recovered from these very large planes, who also share in the recovery of the costs for the remaining 70% with the other planes.

Figure 7 illustrates the differences in the total allocation of costs under a runway and pro-rata approach.

This shows that a pro-rata approach can materially reduce the cost allocation to the largest generator that is determining how much IR is procured. By extension, a pro-rata approach also increases the allocation of costs to smaller generators.

Figure 7: Comparison of cost allocation outcomes



If a party giving rise to IR costs does not face the full consequences of their decisions, there is the potential for higher-cost outcomes to occur because of:

- Operational inefficiencies

  In theory, larger units may be offered into the market whose ability to meet energy requirements at a lower cost than alternatives, may be outweighed by the increased IR costs they cause.

However, in practice, operational inefficiencies are largely prevented by the Scheduling Pricing and Dispatch (SPD) tool:

- SPD determines the least-cost combination of plant to meet demand, and automatically chooses the optimal output of generation and IR procurement simultaneously, based on energy and reserve offer prices.
- This co-optimisation allows the largest unit on the system to be scaled-back if the increase in energy costs are outweighed by the reduction of IR costs. This mimics the outcome that should theoretically occur through participant's energy and reserve offers, if participants were faced with the full incremental costs of IR.

Thus, apart from some 'special case' situations associated with plant that presents secondary risks (addressed in section 6.3), it is not considered that the current pro-rata cost allocation approach will give rise to operational efficiencies.

The WAG has also considered whether different cost allocation approaches under the NMIR could potentially cause operational inefficiencies in terms of incentivising parties to inefficiently withhold energy or IR capacity. It has concluded that, although different cost allocation approaches could give rise to long-term issues in terms of investment/retirement incentives on causers of the need to procure IR, there do not appear to be clear and immediate risks of perverse incentives to inefficiently withhold energy or IR capacity. This includes if the current island-based approach were to continue in the interim, pending development of a more permanent solution.

Q.3. Do you agree that continuing with island-based cost allocation after the introduction of the NMIR is unlikely to create perverse incentives on parties to inefficiently withhold energy or IR capacity?

- Inefficient investment / retirement decisions

  In the long-term, larger plant may be held on the system than would be least-cost given the consequent IR procurement requirements.

  This is because, at times of capacity scarcity, SPD is constrained in its ability to scale-back the largest risk. Accordingly, in the long-term, having large risks on the system will increase the need for capacity to provide IR at times of capacity scarcity. If the cost of large risks is not properly signalled at such times, inefficient investment and retirement decisions may result.

  Thus new larger units may be built (and/or existing large units may not be retired) whose lower $/MWh energy costs should, in principle, have been outweighed by the costs of the increased capacity required that needs to be held on the system to meet IR requirements at times of capacity scarcity.[9]

The current approach to IR cost allocation may impact on generation investment and retirement decisions in a way that, in the long-term,

[9] It is inherently the case that the energy costs of smaller-sized alternatives would be greater, because otherwise the larger units would anyway be displaced by these cheaper alternatives and the effect of poor IR cost allocation would be irrelevant.

results in more capacity being held on the system than if a more principled approach were used.

There are three types of investment / retirement decision that could be impacted by the IR cost-allocation approach:

- influencing the size of new-build plant
- influencing the retirement of existing large plant
- influencing the island location of plant (new-build, and retirements)

The WAG has considered each of these three issues to determine the potential scale of investment inefficiencies that could occur from the current pro-rata approach is.

Possible impact on new-build plant size.

It is potentially the case that if a runway methodology had been in place during the last 20 years, the unit size of the CCGTs – which predominantly drive New Zealand's IR capacity requirement at peak – would have been smaller. The developers of those assets may have concluded that the lower energy costs from the economies of scale of large units may have been outweighed by the increased IR costs they would have been allocated. Were such outcomes to have occurred, it would have been a more efficient outcome for New Zealand as a whole.

However, looking forward, it is considered that the pro-rata approach is unlikely to result in less efficient decisions about the size of new generation.

This is because technology has changed over the past 20 years, such that the most economic forms of new generation are geothermal and wind farms. As is illustrated in Figure 8, these have unit sizes which are substantially less than the remaining thermals, and less than the likely transfer levels of the HVDC at times of capacity scarcity.

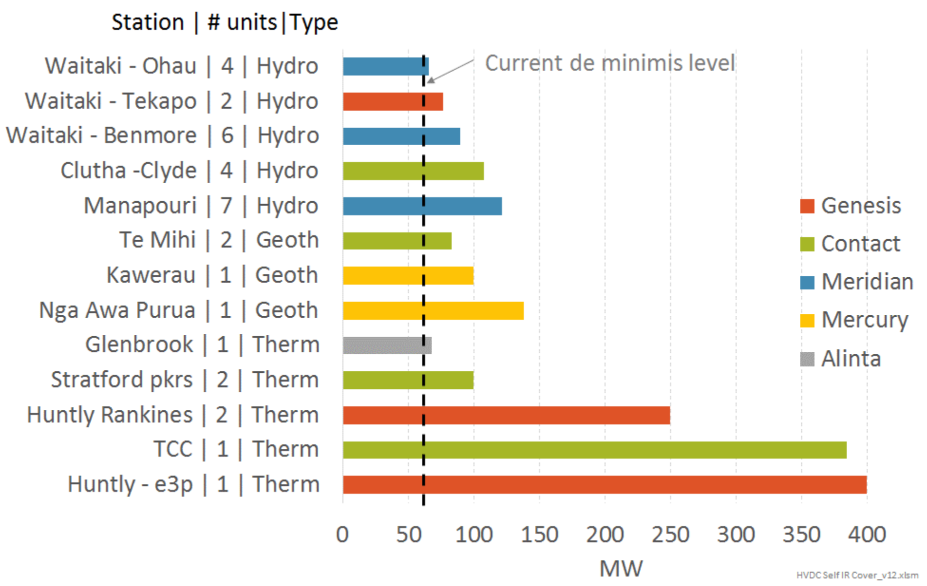
Barring the emergence of an unanticipated technology or situation[10], it is unlikely that any new generating unit will be developed that is larger than the current largest unit – the 400 MW e3p CCGT.

Possible impact on plant retirement

As Figure 8 shows, there are two generating units (the CCGTs) that are substantially larger than the next largest units (the two Huntly Rankines), and these are substantially larger than the remaining units on the system.

[10] Possible large technologies include nuclear power, or even larger gas-fired power stations. However, neither seem plausible given the economics of nuclear, and the expectations around substantially increased CO_2 prices.

Figure 8: Existing large-scale generating units in New Zealand



A runway methodology would better reflect that these large plant are driving the need for extra capacity to be held on the system. Exposure to these costs could result in these units retiring earlier than they would otherwise have done, particularly if large North Island generators continue to set the risk at times of capacity scarcity, and thus are allocated the greatest share of costs. High-level analysis set out in Appendix B estimates that earlier retirement of the CCGTs could result in reduced capacity needing to be held on the system, delivering savings with an estimated present value of $4.5m – although this is subject to considerable inherent uncertainty.

As an aside, this opportunity to deliver IR-related capacity savings from influencing a few plant retirement decisions stems from New Zealand's relatively unusual distribution of unit sizes. i.e. most overseas systems have a large number of similarly-sized large units providing baseload power, thereby providing little opportunity to make IR-related capacity savings from retirement of any one of these large plant.

Possible impact on island location of plant

The analysis in Appendix B highlights that the capacity savings from the retirement of the large CCGTs are likely to be limited due to the fact that the HVDC will likely set the risk at times of capacity scarcity at a level which is greater than the size of the remaining smaller units – and potentially greater than the current CCGTs if the Tiwai aluminium smelter were to retire.[11]

The size of the HVDC risk will be driven by the relative geographical disposition of generation and demand between the two islands.

In this respect, it is considered that a runway methodology could deliver efficiency benefits through influencing decisions about the location of new generation. Thus, if the HVDC were to become the largest risk at times of capacity scarcity, a runway methodology which better allocated the IR costs to the HVDC – and which were then passed-on to the market participants whose collective actions were driving HVDC flows – could influence the location decision of new plant. For example, if two possible new wind generation projects – one in the North Island and one in the South – were relatively finely

[11] Under current arrangements, it is generally the case that the balance between SI generation and demand at times of capacity scarcity is such that there is insufficient SI generation to enable large levels of northwards transfers across the HVDC. As such, the HVDC is not the binding constraint at such times. However, if the Tiwai smelter were to retire, there would be much more surplus SI capacity to send north at times of capacity scarcity. At such transfer levels, the HVDC would set the risk – although if a fourth cable were developed which increased its ability to self-cover, this may not be the case. (Noting that, to the extent that the HVDC does become the binding constraint, development of additional North Island IR may be a cheaper remedy than developing a fourth HVDC cable.)

balanced, a runway methodology which allocated a greater share of costs to the HVDC could tilt the location decision in favour of the North Island scheme (which wouldn't increase the HVDC transfers at peak), rather than the South Island scheme (which would tend to increase HVDC transfers at peak).

The analysis in Appendix B suggests that the present value scale of benefit could be approximately $4m – although this too is subject to considerable inherent uncertainty.

Summary considerations of pro-rata versus runway

The WAG considers a runway approach to be the more principled approach to allocating costs in that it better approximates the 'true' marginal price signal to parties causing the need for IR. The high-level cost-benefit analysis also indicates it could deliver some cost-savings of the order of $9m through influencing plant investment and retirement decisions.

However, the WAG has come to a provisional view (subject to considerations relating to the national market for IR detailed on page 30) that it would not be appropriate to move to a runway approach for general cost allocation. This is based on three key considerations:

- **The estimated net benefit is modest, and subject to significant uncertainty.** As set out in Appendix B, there is a very large degree of uncertainty in the benefits estimate, not least due to some significant inherent uncertainties relating to factors such as the retirement of the Tiwai smelter.
- **There may be potential for unintended adverse outcomes.** The WAG was concerned that the greater allocation of costs that the largest generator(s) would see under a runway approach could result in them retiring the unit(s) earlier than would be economic.

  While the WAG acknowledged this would be a market failure (in that a plant was retired which was of fundamentally greater value than the plant that would replace it), and didn't identify any specific aspects of market design that could give rise to such a failure, it was concerned that large changes to cost-allocation could result in poor management decisions
- **It may affect regulatory certainty.** As is illustrated in Figure 9 and Figure 10, a move to a runway methodology could result in material wealth transfers between market participants. Some WAG members were concerned that 'changing the rules' for existing long-life assets may negatively impact on market participants' perception of regulatory certainty – with possible detrimental impacts on future investment in the market as a whole.

Figure 9: Modelled potential share of future IR costs under pro-rata approach[12]

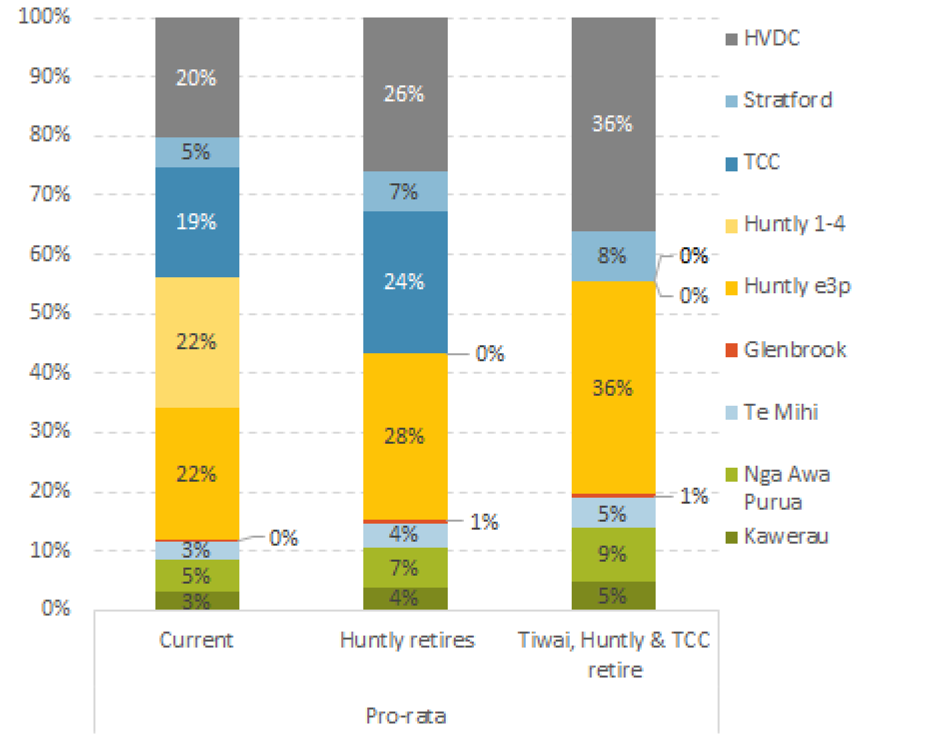
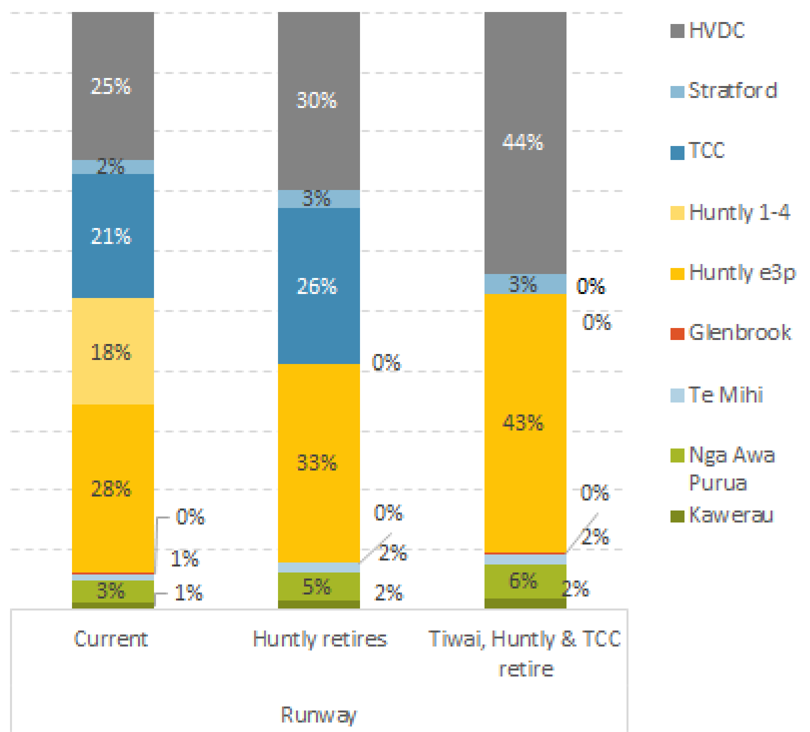


Figure 10: Modelled potential share of future IR costs under runway approach



Given this uncertainty, and the potential for unintended consequences, the WAG's current view is that it would not be prudent to move to a runway approach for the general cost allocation. The WAG's view is guided by the Authority's code amendment principle 4 - *Preference for Small-Scale 'Trial and Error' Options:*

When the quantitative cost-benefit analysis of Code amendment options demonstrates a positive net benefit relative to the counterfactual, but is inconclusive about which is the best option.

[12] This simple analysis assumes that the carrying costs of the necessary capacity to meet IR requirements at times of peak are all incurred when all assets are operating at their maximum (eg, times of peak demand). It assumes the comparatively lower operational costs are incurred based on the assets' average output.

The Authority will weight these principles in accordance with their relevance and significance for each proposal.

However, there may be opportunities to realise the majority of the benefits of a runway approach, in a way that avoids a large amount of the potential costs and risk.

In this respect, the WAG has considered a couple of potential sub-options, but has yet to come to a view as to whether these would deliver benefits that would outweigh their costs:

- Grandfathering the pro-rata approach for existing plant, but introducing a runway approach for new plant. This mixed approach would necessarily result in the composite outcome being crude approximations of pure applications of each approach, and would have to be sustained for very long periods.
- Introducing a runway methodology progressively over time. E.g. in year one 80% of costs allocated pro-rata and 20% runway, progressively moving after a number of years to 100% of costs allocated via runway.

Unit-based versus station-based dynamics and the relationship with the NMIR

The one caveat to the above conclusion that it would not be appropriate to move to a runway approach because of wealth transfer concerns, is that the introduction of the NMIR will inevitably create significant wealth transfers. The magnitude of those wealth transfers will not just depend on the different options for allocating costs between *islands*, but also on whether a pro-rata or runway approach is used for generally allocating costs between risk-setters *within* an island. These tensions may reduce the arguments for not making changes that will cause wealth transfers. This sub-section details how the NMIR dynamics impact on the pro-rata vs runway considerations.

One of the consequences of the pro-rata approach is that it can result in a station comprised of a large number of medium-sized units being allocated a greater share of IR costs than a station comprised of a single large unit – even though the total quantity of IR being procured may be driven by the size of the large single unit station.

As well as dulling the price signal to this large unit (and thus moving away from a cost-to-causer situation), such outcomes are likely to be regarded as inequitable by the owners of the multi-medium-sized-unit station.

Where outcomes are grossly inequitable, there is the tendency for adversely affected parties to agitate for change. As a consequence, market designs which deliver inequitable outcomes are less likely to be durable than those which are generally acknowledged to be 'fair'.

The fact that the current pro-rata approach has endured for so long may be as a result of a happy coincidence whereby New Zealand's IR 'market' has to-date actually been <u>two</u> markets: A North Island market and a South Island market. The coincidence is that the risk profile is largely similar across the main risk-setting participants in each island:

- In the North Island it is / has been[13], a few single-large-unit stations (principally: e3p, TCC, Otahuhu B)
- In the South Island it is comprised of a few multi-medium-unit stations (principally: Manapouri, Clutha, Benmore)

With this profile of risk setters in each island, the pro-rata approach to cost allocation within each island has not resulted in grossly inequitable outcomes.

[13] Noting that there have been some retirements of large thermal stations recently.

However, a move to allocate some or all of the costs nationally under the National Market for Instantaneous Reserves (NMIR) – as detailed further in section 6.2.1 – will start to expose the inequity of a pro-rata approach.

The prime example of this is the 7 x 120 MW Manapouri station which will get allocated a greater share of IR costs than a 400 MW CCGT station, even though the amount of reserve needed to cover the loss of any of Manapouri's units is 120 MW, whereas the CCGT requires 400 MW of reserve to be procured.[14] Figure 11 on page 32 gives further illustration of how national IR procurement costs would be shared under a pro-rata and runway approach.

Q.4. What are your views on the merits of moving to a runway methodology (or its sub-options)?

6.1.2 Having a de minimis is broadly consistent with a cost-to-causers principle

At the moment, assets whose output is smaller than a 60 MW 'de minimis' level are not allocated any IR procurement costs.

Having a de minimis is considered consistent with the first principle that costs should be allocated to causers of the need for IR to be procured, because loss of injection/transmission below a certain threshold would not cause an under-frequency event of a size requiring IR.[15]

As such, the WAG believes continuing with a de minimis is *generally* appropriate. (Noting that, as set out in section 6.3, it is not appropriate for assets presenting secondary event risks.)

However, it is possible that the *specific level* of the current de minimis (i.e. 60 MW), may not be reflective of today's system, given that it was based on analysis a long time ago.[16]

Further, the de minimis level can have significant impacts on how IR costs are allocated between parties. This is illustrated by Figure 11, which shows the hypothetical share of IR costs that generating units and the HVDC would receive:

- under a pro-rata and runway approach to cost allocation
- with different de minimis levels
- assuming all were operating at full capacity
- under a national approach to allocating costs under the NMIR – as detailed further in section 6.2.1.

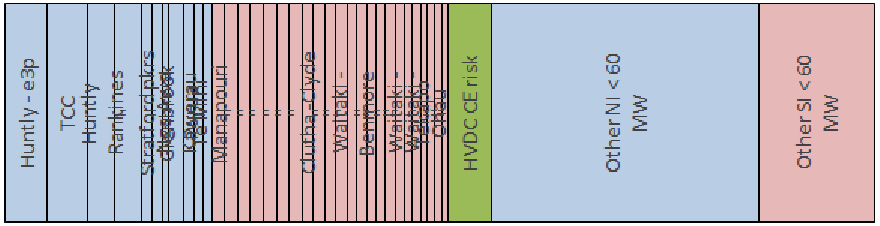
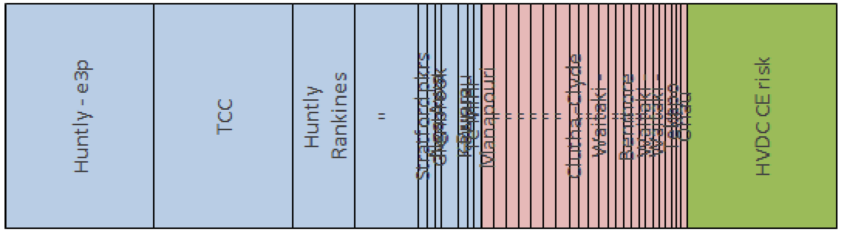
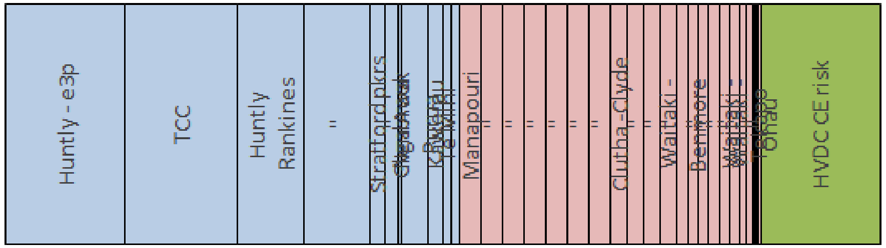
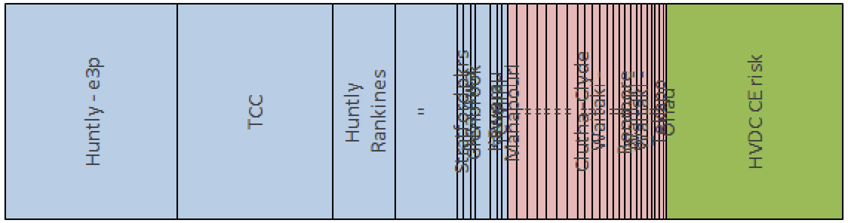
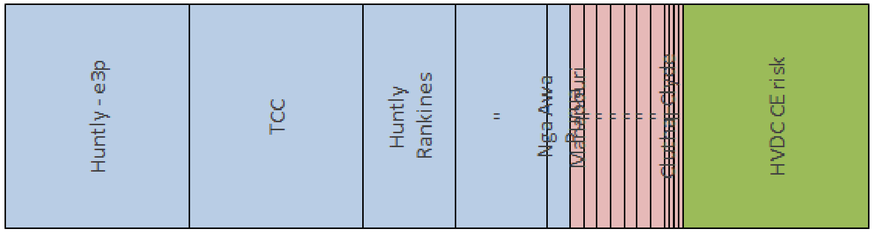
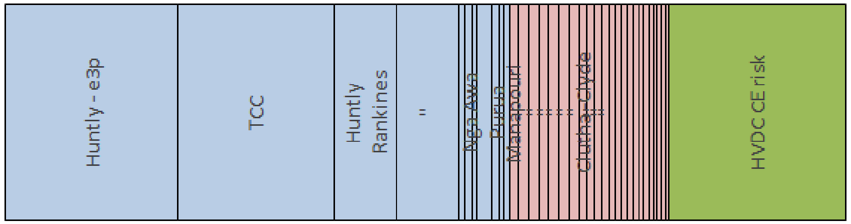
In this figure, North Island plant are shaded blue, and South Island plant are shaded pink.

[14] The amount of output from the Manapouri station used for pro-rata cost allocation purposes would be 7 x (120 – 60) = 420 MW, whereas for the CCGT it would be 400 – 60 = 340 MW. (Noting that the de minimis is 60 MW).

[15] Relatively small losses will be compensated for by frequency keeping and governor response, with re-dispatch enabling frequency to be restored to the normal range.

[16] In this respect, it is not clear the extent to which the 60 MW de minimis was based on fundamental systems analysis at the time, or was a reflection of the 'negotiation' dynamic of the development of such arrangements as mentioned in section 2.4.

Figure 11: Illustration of impact of different de minimis levels for Pro Rata and Runway (under national allocation)[17]

De - minimis	Pro Rata allocation (status quo)	Runway allocation
0 MW		
60 MW (status quo)		
100 MW		

[17] Assuming 900 MW HVDC transfer level = 402 MW NI DC CE risk. Note that assets below 60 MW have been excluded from the zero de minimis runway allocation.

Therefore, there may be merit in the system operator reviewing whether the 60 MW level remains appropriate.

However, to the extent that a different de minimis is more appropriate, it is likely that the scale of benefit (in terms of altered retirement / investment decisions) would be small – particularly if a runway approach were to be implemented.[18] Indeed, having a de minimis would likely be inconsistent with a runway approach.

Q.5. Do you agree that a de minimis should continue and, if so, at what level?

6.2 HVDC-related issues

As is set out earlier, in terms of instantaneous reserves, the new HVDC is a complicated asset:

- When operating at high energy transfer levels it can ***cause the need for IR*** to be procured in the receiving island to cover the risk of the loss of one or both poles;
- It can ***provide IR,*** by enabling the transfer up to 220 MW of IR from one island to the other. From November 2016 this will enable a national market for instantaneous reserves (NMIR) to be implemented.

There is also the potential for the HVDC to be augmented further through the development of a fourth cable which will provide an extra 200 MW of transfer capacity to pole 2. From the perspective of IR, the key implication of this is that it would increase the extent to which the HVDC could self-cover[19], and thus enable higher energy transfers before giving rise to a need to procure IR.

Based on the above, it is important to get the HVDC / inter-island IR cost allocation and associated incentives correct to ensure that market participants and Transpower (as HVDC owner) make the right decisions:

- Market participants need to be incentivised to:
  - offer their generation, reserves, and demand into the market in such a way that results in least-cost outcomes. Specifically, to ensure that IR-related inter-island dynamics do not result in perverse incentives to inefficiently withhold energy or reserve capacity from the market; and
  - make appropriate investment decisions, particularly as regards to which island to develop additional:
    - generation, taking into account the impact on HVDC transfers and the extent to which the HVDC becomes the binding risk at times of capacity scarcity.
    - IR capability (spinning reserve or IL)
- Transpower, in its role as grid owner[20], needs to be incentivised to:

[18] As illustrated in Figure 11, under a runway approach small plant would already pick up a smaller share costs compared to a pro-rata approach, so the effect of the size of de minimis on cost allocation outcomes would be much smaller.

[19] Self-cover is where the potential loss of one pole can be covered by the other pole quickly ramping up to compensate. E.g. if the HVDC were transferring 400 MW north, this would be spread evenly with each pole transferring 200 MW. If one of the pole were to fail, the other would be able to rapidly increase transfer up to 400 MW.

At the moment, the 500 MW size of pole 2 limits the extent of self-cover that the HVDC can undertake. Increasing the size of pole 2 to 700 MW (the size of pole 3) would increase the amount of self-cover that could be undertaken.

Note, self-cover is different to the HVDC transferring IR from one island to the other.

[20] Transpower's role as *system operator* clearly has an impact on IR procurement outcomes, and a number of stakeholders have suggested that lower cost IR outcomes

- make all HVDC capacity available to the market; and
- make appropriate investment decisions about the future configuration of the HVDC – particularly whether to develop a fourth cable.

With respect to Transpower's incentives, the WAG considers that there do not appear to be incentive issues with respect to Transpower in its role as grid owner, because:

- Transpower faces strong regulatory incentives to make existing HVDC capacity available. In particular it is obligated under part 12 of the Code to make the full capacity of the HVDC available to the market.[21]
- Transpower is incentivised under the Part 4 framework to make any new investments that would pass a public net benefit test. Thus, to the extent that the costs of a fourth cable were less than the projected economic benefits, in terms of altered energy and capacity outcomes *taking account of any IR impacts*, then the regulatory framework would incentivise Transpower to undertake that investment.

With respect to incentives on market participants, the WAG has identified two main issues:

- the approach for allocating IR costs between islands under the national market for instantaneous reserves (NMIR)
- the way in which IR costs allocated to the HVDC are passed on to market participants.

Each of these issues is addressed in turn.

6.2.1 Allocating IR costs between islands under the NMIR

With the introduction of the NMIR, IR is going to be procured nationally, but costs are currently allocated on an island basis. This will likely distort the price signal to causers of the need for IR.

For example, if the largest risk is the loss of a 400 MW North Island CCGT, but 220 MW of the procured IR is located in the South Island, the North Island generator(s) will only be allocated the costs associated with the 180 MW of IR procured in the North Island.

As well as potentially affecting long-term investment and retirement decisions (including which island future generation is located), stakeholder submissions to the recent Authority consultation on this issue[22] raised the possibility that the inter-island IR cost allocation approach could alter participants' energy and IR offers into the market.

At its August meeting, the Authority Board decided to defer making changes to the cost allocation until the WAG completes this comprehensive review of the arrangements. This decision was on the grounds that:

- stakeholders had identified undesirable outcomes with a simple national allocation approach;
- it could not identify any material risks from continuing with an island based-approach in terms of perverse incentives on participants which

could be achieved by altered procurement practices with regards to the HVDC (e.g. allowing for a greater amount of overload capacity (running the HVDC at higher transfer levels for short periods of time) on the HVDC when procuring IR). However, IR costs are allocated to the *owner* of the HVDC, and thus considerations of system operator incentives are not relevant to the cost allocation considerations.

[21] This Code obligation was introduced after Transpower withdrew HVDC capacity at a time when the old HVDC was suffering reliability issues, and Transpower wished to limit exposure to the event charge.

[22] "*Proposal to alter the way availability costs are allocated*", 8 March 2016

could have immediate and material impacts on the energy or IR markets; but

- continuing with an island approach to cost allocation was unlikely to be the best long-term solution.

Accordingly, it asked the WAG to consider the issue of cost-allocation under the NMIR – both in terms of whether there may be immediate perverse outcomes from continuing with an island-based approach, and in terms of what the most appropriate long-term solution is likely to be.

In addressing this issue, this section:

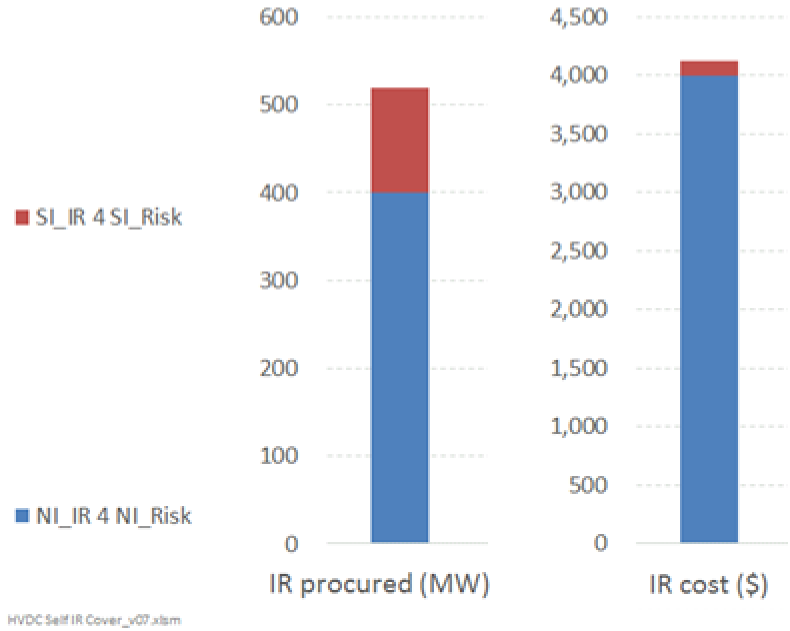
- describes the 'mechanics' of how the NMIR will operate
- describes potential options for cost allocation under the NMIR
- evaluates the merits of those options.

Overview of the 'mechanics' of the NMIR

If the HVDC is not able to transmit IR from one island to another, an IR risk in an island must be managed by procuring IR *in that island*. Thus if the largest CE risk is a 400 MW CCGT in the North Island, and a 120 MW Manapouri hydro unit in the South Island, then the amount of IR procured from each island would be 400 MW and 120 MW, respectively, with the costs for each island allocated to the potential causers in each island.[23]

This situation is illustrated in Figure 12, which also shows the overall cost outcome if IR is only \$1/MW/h in the South Island, but \$10/MW/h in the North Island – these simple scenario values being chosen for the purposes of illustration.

Figure 12: Simple illustration of island-based procurement

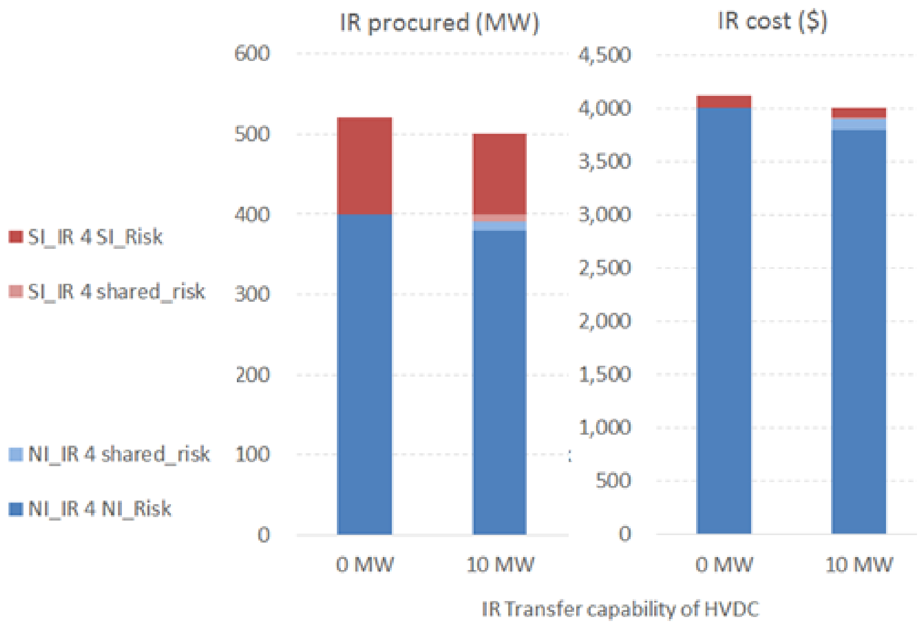


The introduction of the new FKC controller on the HVDC, makes it possible to transfer IR from one island to another, up to the technical limit of IR transfer that the FKC controller can achieve. This raises the possibility that IR procured in one island can be 'shared', and cover a risk in both islands.

[23] This is a simplified example which ignores some of the 'fine detail' of the realities of operating both the old and new HVDC – e.g. the ability of the old HVDC to transfer up to 60 MW of 'IR-like' response from one island to the other. However, for the purposes of illustrating the implications of the NMIR it is not necessary to consider such sophistications.

To illustrate this, Figure 13 below builds on the example of Figure 12 above, and shows the effect if the FKC controller were able to transfer a notional small amount of IR – 10 MW in this example.[24]

Figure 13: Impact of ability of FKC controller to transfer 10 MW of IR



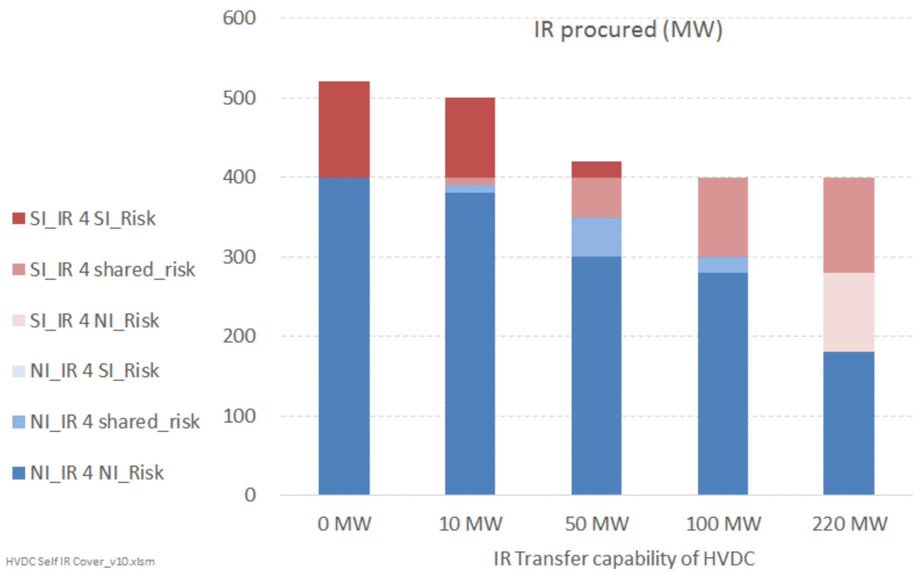
With the HVDC being able to transfer 10 MW of IR, the NMIR enables 10 MW less of IR needing to be purchased in each island.

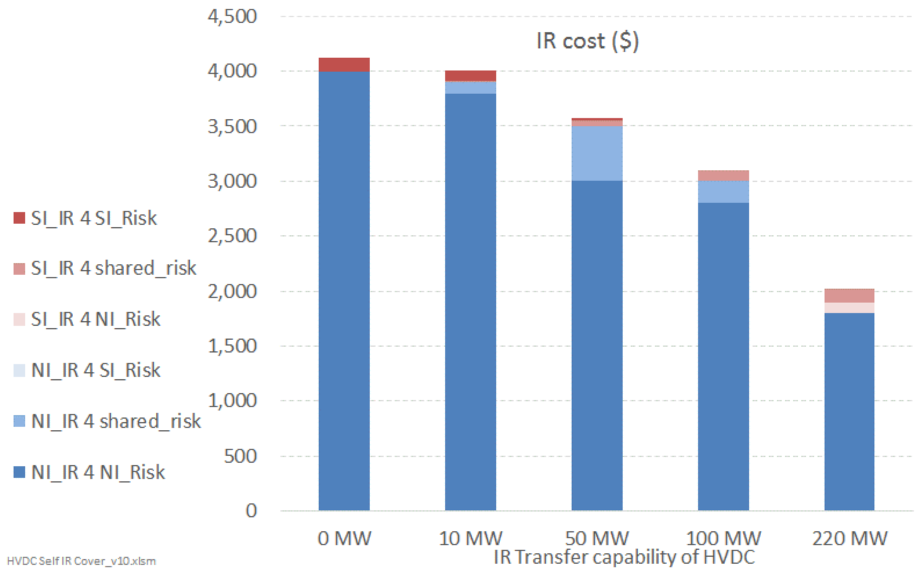
[24] This simplified example ignores the fact that losses across the HVDC, coupled with the fact that the speed of response of the FKC in delivering IR is not instantaneous reducing its 'effectiveness', means that 10 MW of IR procured in one island will not equate to 10 MW of reduced IR requirement in the other island but could be 8 MW. However, this 'fine detail' is an unnecessary complication for considering the fundamental concepts of cost allocation under the NMIR.

The shading of the graph distinguishes between IR which has to be procured in an island to solely manage that island's risk, and IR which is procured and 'shared' between the islands.   This is relevant for considering cost-allocation approaches.

The actual technical ability of the FKC controller is much greater than the 10 MW in the above example. Figure 14 builds on the previous examples, and illustrates the impact of progressively greater amounts of IR being capable of being transferred across the HVDC – again for this scenario, all IR is cheap ($1/MW/h) in the South Island but expensive ($10/MW/h) in the North Island.

Figure 14: Impact of greater amounts of IR sharing across the HVDC





For low levels of IR transfer capability, each island will share the same amount of IR as the other. However, at greater levels of IR transfer capability, situations start to emerge where different amounts of IR will be shared in each island. For example, with reference to Figure 14, in the situation where 100 MW of IR can be transferred across the HVDC, 100 MW of IR is procured in the (cheap) South Island, all of which can be shared to also cover the North Island risk. This means that 300 MW needs to be procured in the North Island, only 20 MW of which needs to be shared to also cover the South Island risk.

Furthermore, in the example where 220 MW of IR can be transferred, a situation emerges where

- 220 MW of IR is procured in the South Island, of which
  - 120 MW is effectively covering the SI risk and also being shared with the North Island to cover some of its risk
  - 100 MW is not being 'shared' but is solely being procured to cover the North Island risk.
- 180 MW of IR is procured in the North Island – being the 400 MW risk less the 220 MW transferred from the South Island. None of this 180 MW is shared with the South Island, but is solely procured to cover the North Island risk.

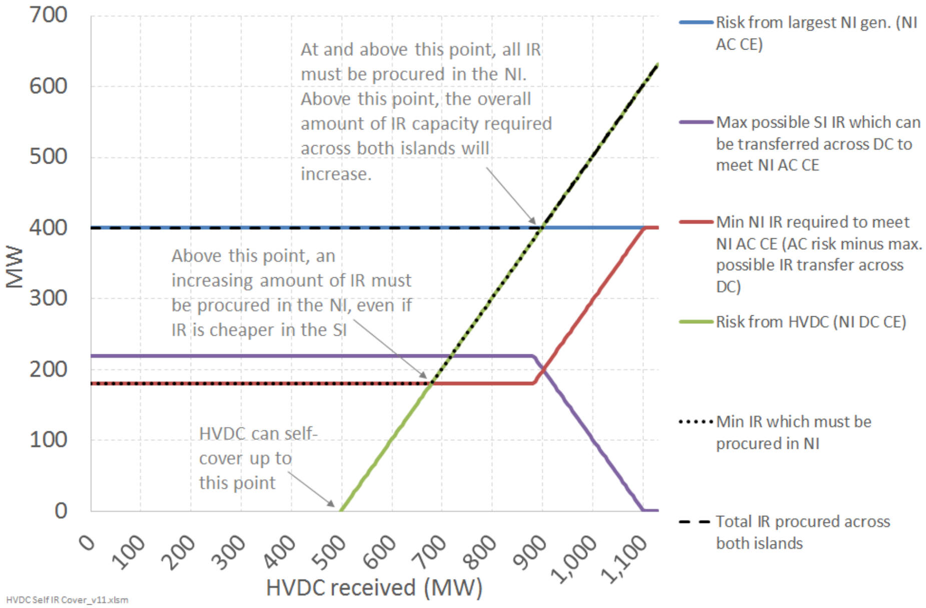
These different situations highlight that the physical limitations of the HVDC to transfer IR mean that the new NMIR will never be completely 'national'. i.e. there will almost always be situations where some relatively expensive reserve needs to be procured in a particular island (generally the North Island because that is where the large thermal units are located) because there are technical limitations on the amount of IR the HVDC is capable of transferring from one island to the other. This constraint is relevant for consideration of the merits of different cost allocation approaches.

The above examples have focussed on situations where the HVDC is transferring *energy* at relatively low levels. This means it is able to transfer IR up to its maximum technical capability, plus it is not creating an IR risk in its own right in the receiving island.

However, as Figure 15 illustrates, once the energy transfers across the HVDC increase above a certain point (≈ 500 MW for its current configuration), the HVDC is not completely able to self-cover for the risk of losing one pole.[25] This creates a receiving island DC CE risk, which grows linearly as energy transfers rise above the maximum self-cover point.[26]

A DC CE risk can only be met by IR procured in the receiving island. This has significant implications for the NMIR because at high levels of energy transfer across the HVDC, IR must be procured in the receiving island, irrespective of whether it is cheaper in the other island.

Figure 15: North Island IR impact of different HVDC energy transfers[27]



To illustrate this, Figure 16 below builds on the last example shown in Figure 14 – i.e. the HVDC is technically capable of transferring 220 MW, and South Island IR is much cheaper than North Island IR. However, Figure 16 examines the impact of different levels of South→North *energy* transfers across the HVDC.

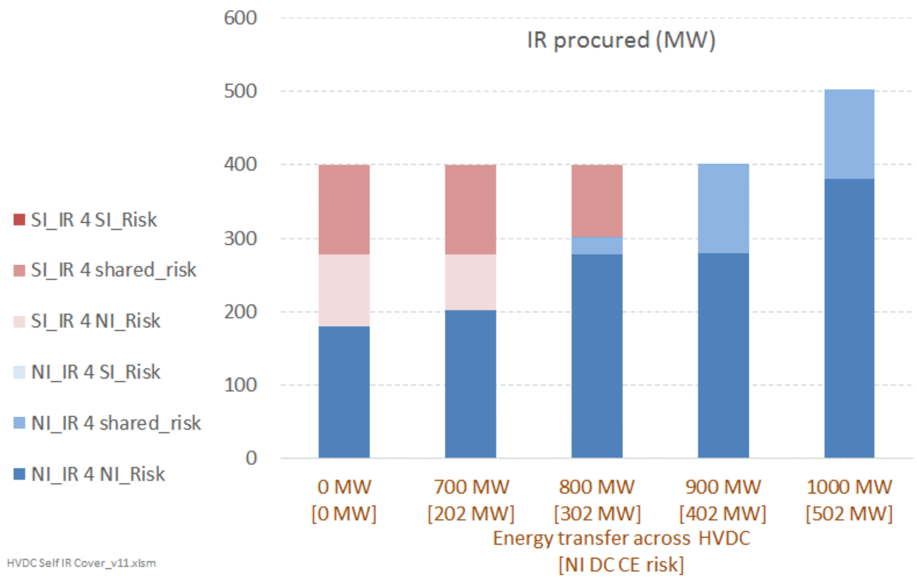
[25] Footnote 19 explains how the HVDC can self-cover.

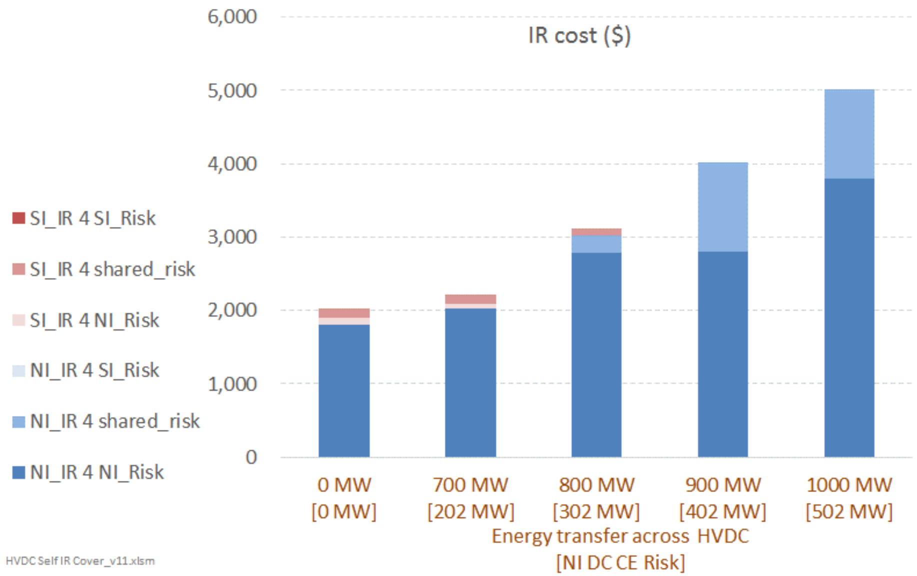
[26] The dynamic illustrated in Figure 15 means it is also the case that at times of capacity scarcity, the HVDC will not operate at energy transfers above 900 MW. This is because operation above 900 MW will increase the overall amount of capacity required on the system due to the fact that the DC CE risk would become greater than the AC CE risk. The optimisation of SPD +RMT would therefore schedule outcomes which minimised overall capacity requirements.

If a fourth HVDC cable were built providing an extra 200 MW of capacity on the second pole, this would push the green line (NI IR to meet DC CE risk) 200 MW to the right. This would increase this effective cap on the HVDC energy transfer at times of capacity scarcity to 1,100 MW.

[27] The DC contribution to meeting the NI AC CE falls once the energy transfer passes the maximum capacity of the DC minus the technical IR transfer limit of the DC. It reaches zero once the DC is transmitting energy up to the maximum capacity of the link – i.e. it is completely 'full' transmitting energy and has no additional space to transfer IR.

Figure 16: Impact of high HVDC energy transfers on IR procurement





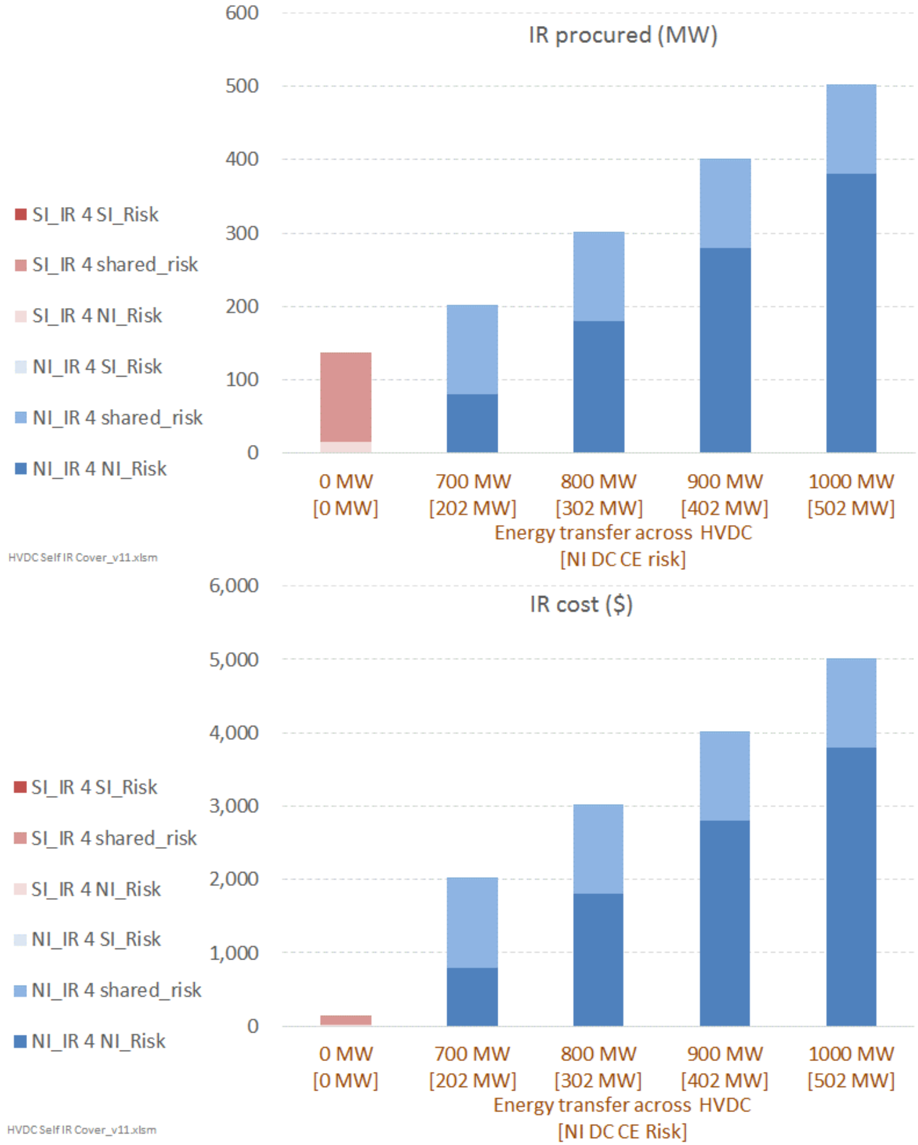
From Figure 16, we can see that:

- HVDC energy transfers can affect the overall amount of IR required. For HVDC energy transfers below 900 MW, 400 MW of IR capacity is required across both islands – though the island from which the IR must be procured varies with differing levels of energy transfer. However, for HVDC energy transfers above 900 MW, the overall amount of IR required starts to increase, due to the dynamics shown in Figure 15 and discussed in footnote 26 on page 38.
- HVDC energy transfers below the maximum self-cover level (i.e. less than 500 MW) don't alter NMIR procurement outcomes - i.e. the outcome for the 0 MW *energy* transfer situation in Figure 16 is identical to the 220 MW technical *IR* transfer situation in Figure 14.
- A minimum of 180 MW of IR will be procured in the North Island, given the size of the North Island risk and the 220 MW technical IR transfer limit of the HVDC. However, above a certain level of energy transfer, the IR procured in the North Island becomes greater than this minimum, in order to cover the NI DC CE. For example, if the HVDC is operating at 700 MW of transfer, the NI DC CE is 202 MW. The higher HVDC energy transfer has caused the need to procure an extra 22 MW of IR in the North Island, when it would otherwise have been procured from the South Island at lower cost.
- The ability to procure cheap South Island reserve is progressively reduced as energy transfers increase the need to cover the NI DC CE. Once the NI DC CE is greater than the NI AC CE, there is no ability to purchase *any* cheap South Island reserve. (Noting that any North Island reserve procured to cover the NI DC CE will be used to cover the South Island SI AC CE).

The examples illustrated in Figure 12 to Figure 16 have been developed with the scenario of the largest AC risk being a North Island 400 MW CCGT. At some point in the future it is likely that these thermal units will retire. This may be decades away, or it may be a lot sooner (e.g. if the Tiwai aluminium smelter were to retire).

In order to aid consideration of the durability of cost allocation arrangements to potential changes in system conditions, Figure 17 shows the impact of HVDC flows in a future where there are no large thermal units – i.e. both the remaining CCGTs and both the remaining Huntly Rankine units have retired. In such a future, the largest North Island AC risk would be the 138 MW Nga Awa Purua geothermal unit, and in the South Island it would be one of the 120 MW Manapouri units.

Figure 17: Impact of HVDC in a future with no large thermals



As can be seen, in this future where there are no large thermals, if there are no energy flows on the HVDC then the total amount of IR procured is set by the largest AC risk – being the 138 MW Nga Awa Purua geothermal in the North Island. That risk would be covered by IR procured from the cheapest source (the South Island in this example).

However, once HVDC energy transfer levels start to rise, the overall quantity of IR procured, and the island which it must be procured from, very soon become driven by HVDC energy transfer levels.

As an aside, it has been suggested that with such a risk profile – i.e. one very large risk (the HVDC) and lots of small risks (the individual generating units) – it may be appropriate to re-consider whether it is economic to continue to cover this sole large risk with IR rather than AUFLS.

Certainly the economics of carrying spare generating capacity to provide IR are very different if it is to cover the potential loss of half-a-dozen large risks, rather than one large risk. Further, such a practice would facilitate the HVDC operating to its full energy transfer capability at times of capacity scarcity, rather than being constrained to below this level due to IR limitations.

As such, this suggestion may have merit, and is indeed the practice in other jurisdictions – i.e. sufficient IR is only procured to cover the (numerous) medium-sized risks rather than the (few) very-large risks.

However, such considerations are procurement-related, and thus outside the scope of this IR cost-allocation evaluation. The only relevance to this exercise is with regards to the durability of cost allocation arrangements. i.e. to the extent that such a procurement change were made, it would ideally be the case that the cost allocation arrangements would be able to allocate the altered IR procurement costs in a consistent fashion without needing to make future changes.

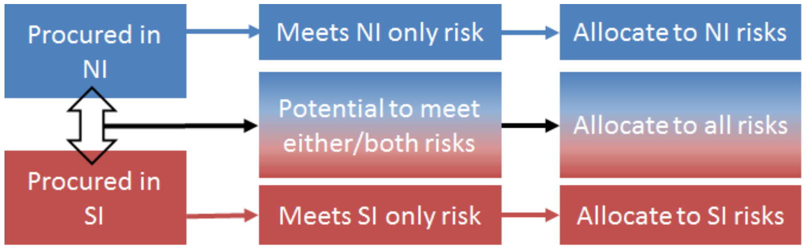
Potential cost allocation options

A number of potential NMIR cost allocation approaches have been identified. The first three were raised as options in the Authority's March 2016 consultation, but the other two are new options that have been developed as part of this work.

1. ***Island-based*** cost allocation (i.e. the status quo). The costs of any IR procured in an island are solely allocated to risk setters in that island, irrespective of whether any of that IR was covering the AC risk in the other island. Costs would then be divided among risk setters *within* that island based on the general cost allocation approach (i.e. currently pro-rata).

2. ***National*** allocation. All IR procurement costs are allocated across all risk setters across both islands, based on the general cost allocation approach (i.e. currently pro-rata).

3. ***Factored by HVDC reserve sharing limits***. This was "Option C" in the Authority's March 2016 consultation. Under this approach, if 450 MW were procured across both islands, and the HVDC were capable of transferring 220 MW, the North Island risk setters would be solely allocated a (450-220) / 450 share of these costs (which would then be shared between them based on the general cost allocation approach). The remaining 220 / 450 share would be allocated among all risk setters using the above national allocation approach.

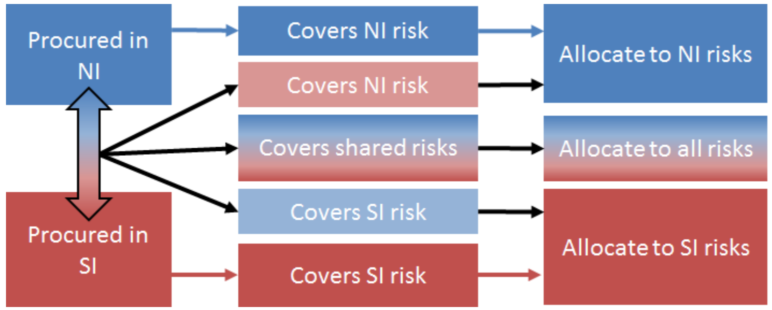


4. ***'Cost-to-island-causers'.***

- Any costs *solely* attributable to covering an island's risk would be allocated to that island's risk setters. i.e.
  – IR procured solely to meet the risk in the island it is procured from. This may either be due to:
    ◦ physical limitations of the HVDC to transfer IR from the other island to cover the AC risk in the island; or
    ◦ the need to cover the receiving island DC CE.
  – IR procured in the other island, solely to meet the risk in the risk-setting island.
- Any IR that is procured in an island, and which can be used to cover both islands' risks, would be allocated among all risk setters using the national allocation approach.

For example, with reference to Figure 16, and the situation where the HVDC is transferring 800 MW of energy:

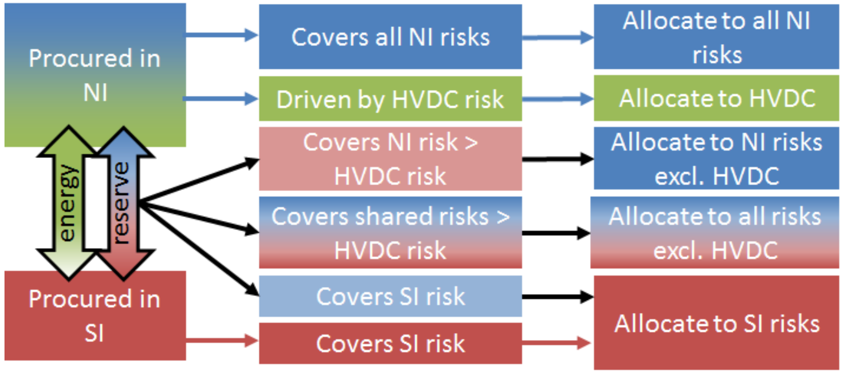
- the North Island risk setters would be solely allocated the cost of the 302 MW procured in the North Island for the purposes of covering the North Island risk.[28]
- the additional 22 MW of North Island reserve that could be shared with the South Island to also cover the South Island risk would have its costs allocated on a national basis to all risk setters across both islands
- the costs of the 98 MW of South Island reserve which could be used to cover both the South and North Island risks would also be allocated on a national basis.



5. ***'Cost-to-HVDC-then-to-AC-island-causers'.*** This approach builds upon the cost-to-island causer approach, by acknowledging the special nature of the HVDC. Specifically, the level of HVDC energy transfer doesn't just influence the overall quantity of IR that must be

[28] This 302 MW is because the NI DC CE risk is 302 MW. If the HVDC were operating at low energy transfer levels, there would still be a need to procure 180 MW of reserve in the North Island to cover the 400 MW AC CE due to the 220 MW limitation of the HVDC to transfer IR. (i.e. 400 – 220 = 180)

procured, but it can dictate which island *location* the IR must be procured from. As such, this approach identifies any IR whose procurement location is solely dictated by operation of the HVDC, and allocates the associated costs to the HVDC. It thenallocates other costs in a way that is broadly (but not exactly) on a 'cost-to-island-causer' basis.



This cost allocation approach is further explained by Figure 18. It builds on the example of Figure 16, to identify IR that is procured because of the HVDC's energy transfers. With reference to Figure 18, cost allocation under the 'Cost-to-HVDC-then-to-AC-island-causers' approach would occur as follows:

– Identify IR that had to be procured in the receiving island *because of the HVDC energy transfer*, and allocate the costs of procuring it solely to the HVDC. In the example of 800 MW of HVDC energy transfer, this would be 122 MW (the green bar).[29]

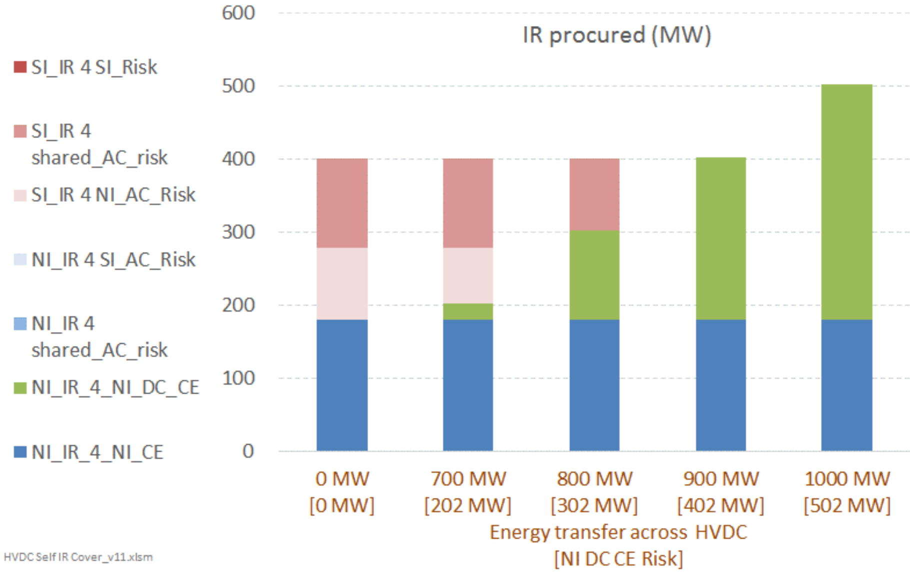
– Identify any other IR that can only be procured from a specific island due to physical limitations on the HVDC transferring IR, and allocate the costs of procuring it solely to that island. This would subsequently be split between AC risks (i.e. generators) *and the HVDC* using the general allocation approach (i.e. currently pro-rata). In the example of 800 MW of HVDC energy transfer this would be 180 MW (the blue bar).

– Allocate all remaining IR costs to the AC risks (i.e. generators), *but not the HVDC*, using the cost-to-island-causer approach outlined above. i.e. the HVDC does not give rise to the need to procure IR in the sending-energy-island, so would not be allocated costs from procuring that IR. In the example of 800 MW of HVDC energy transfer, this would relate to the 98 MW of South Island IR that could be used to cover the SI AC CE and the NI AC CE (but not the NI DC CE).

[29] This 122 MW is calculated as follows:

- The NI DC CE risk is 302 MW. This necessitates that 302 MW of IR is procured in the North Island
- If there were much lower HVDC energy transfers, only 180 MW of IR would be procured in the North Island to cover a 400 MW AC CE risk. The HVDC would contribute the remaining 220 MW (its max) by transferring lower-cost IR from the South Island.
- Essentially, the high energy transfer level of the HVDC has prevented the procurement of 122 MW of cheaper South Island IR.

Figure 18: Identifying IR solely attributable to HVDC



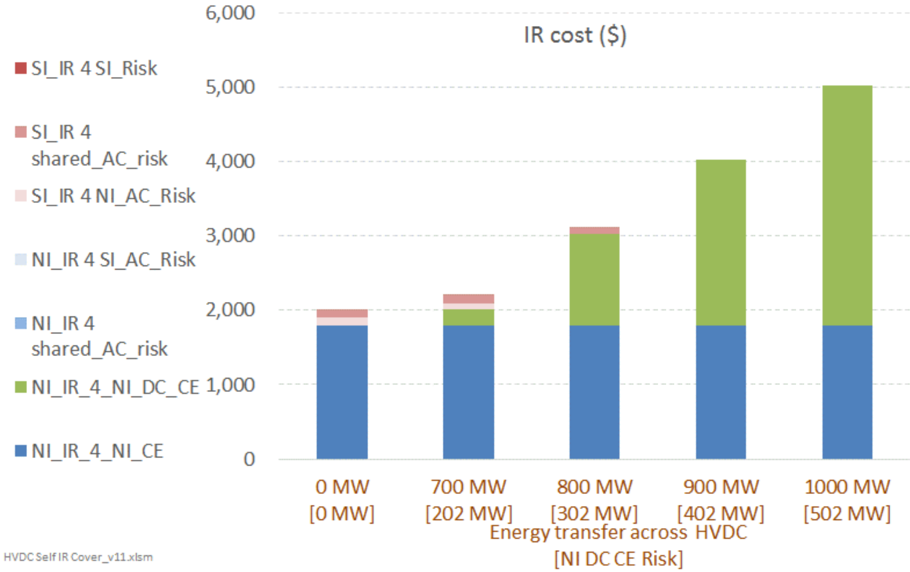
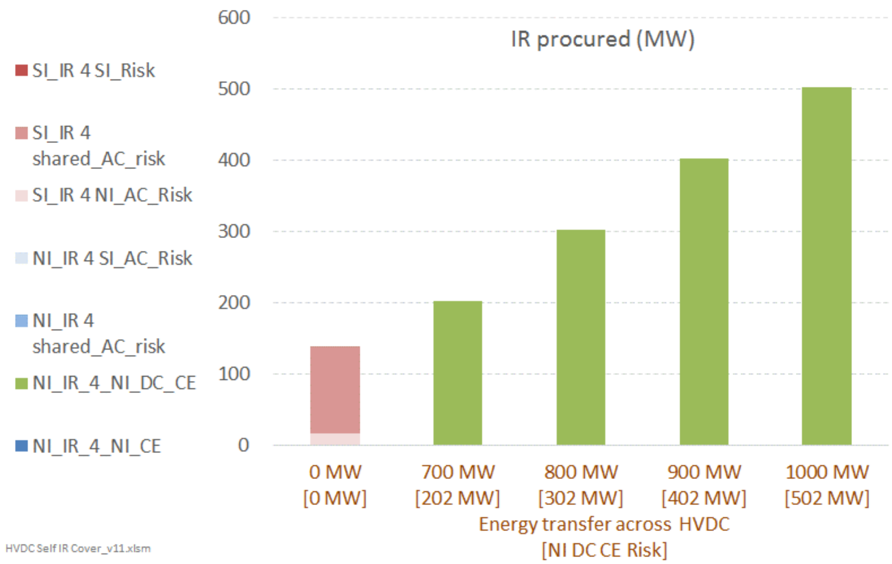
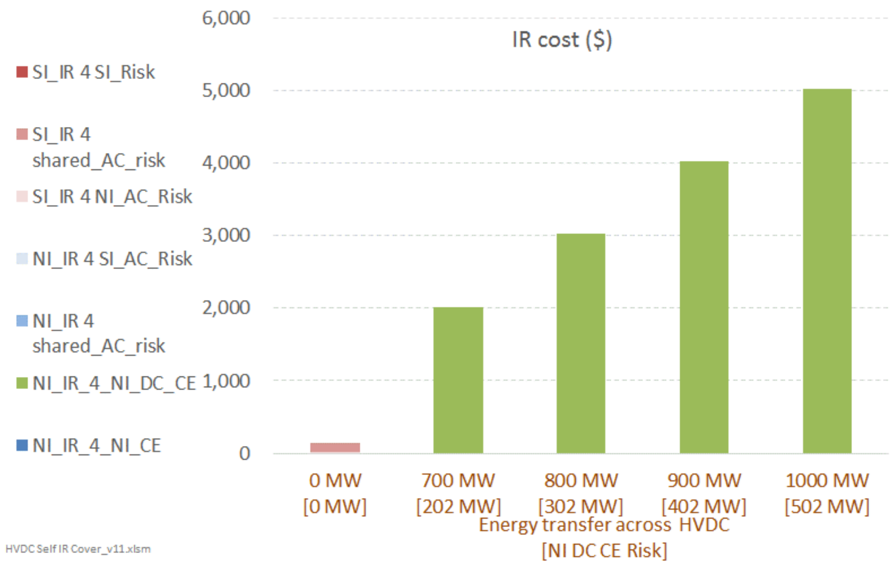


Figure 19 illustrates how this outcome would differ in a future where there are no large thermal units (i.e. the scenario first explored in Figure 17).

As can be seen, in such a future, this cost allocation option would see IR costs predominantly allocated to the HVDC, once energy transfer levels rose above the level where the HVDC could self-cover.

Figure 19: HVDC-attributable IR costs in a future without large thermals





Q.6. Are there other cost allocation options that you think should be considered?

Evaluation of cost allocation options

The WAG has evaluated the five different cost allocation options in terms of the extent to which they meet the principles set out in section 5, i.e, whether they:

- allocate costs to parties causing the need for IR. As set out above, this causation has both a quantity dimension and a *location* dimension – i.e. some risks dictate which island IR must be procured from as well as the overall quantity.
- send a marginal signal

Island-based is not considered to meet these principles, as situations can arise when IR would be procured in one island, solely to meet the risk in the other island, yet this other island risk would not be allocated the cost. Likewise, if more 'shared' IR is procured in one island than the other, island-based allocation would not appropriately reflect the extent of sharing. This would reduce the cost signal to the main IR causer.

A ***national*** cost allocation approach is not considered to be a good reflection of an exacerbators-pay approach either. This is because South Island risk setters would be allocated a share of any North Island IR that was procured solely to manage the North Island risk, given the technical limitations of the HVDC to transfer IR. Again, this would reduce the cost signal to the North Island causers.

Allocation ***Factored by HVDC reserve sharing limits*** starts to be a better approach in that it seeks to reflect some of these dynamics. However, it is relatively 'crude' in identifying costs which are solely attributable to risks in one island, versus costs to cover risks in either island. As such, it can also dull the signal to the largest causers of the need for, *and location of*, IR to be procured.

The ***cost-to-island-causer*** approach is better in this respect. However, the main drawback with this approach is that it doesn't send a marginal signal to the HVDC that indicates the IR cost implications of high HVDC energy transfers.

The ***Cost-to-HVDC-then-to-AC-island-causers*** approach is considered to most closely meets the principles of sending a marginal signal to causers, as it addresses the 'special' nature of the HVDC in terms of its impact on the ability to be procure the cheapest IR across the two islands.

The WAG has also considered the *practicality* of the options, in terms of whether they meet two other desirable attributes:

- Not being excessively complex (and hence costly) to implement.
- Whether they are durable in terms of being able to accommodate changes to system configuration or IR procurement approaches.

In terms of complexity, none of the options are considered to be excessively complex or costly to implement. Even the most complex option (Cost-to-HVDC-then-to-AC-island-causers) can be represented algebraically, and thus would be computationally trivial to implement for cost allocation purposes in the clearing and settlement engine. Similarly, all options require exactly the same inputs, all of which are currently provided to the clearing and settlement engine. To the extent that cost allocation options are relatively simple to implement in clearing and settlement engines, they should similarly be relatively simple to implement within participants' trading decision-support tools.

In terms of durability, it is considered likely that the HVDC could progressively become the dominant factor driving IR procurement in New Zealand, as the large thermal plant are progressively retired. This may take a couple of decades, or could happen much sooner if the Tiwai aluminium smelter were to retire. Nonetheless, it is considered that options that don't appropriately recognise the impact of the HVDC in driving IR procurement will be less durable than those that do. In this respect, the Cost-to-HVDC-then-to-AC-island-causers option may be most durable.

The WAG has also undertaken some analysis to indicate how costs would be split between the islands and the HVDC, for each of the cost allocation approaches, under a number of different market scenarios.

This analysis indicates how cost allocation outcomes will vary between the options, and shows that different options will send materially different cost signals to the causers of the amount (and location) of IR that needs to be procured.

Figure 20 and Figure 21 show the outcomes for these different options, with:

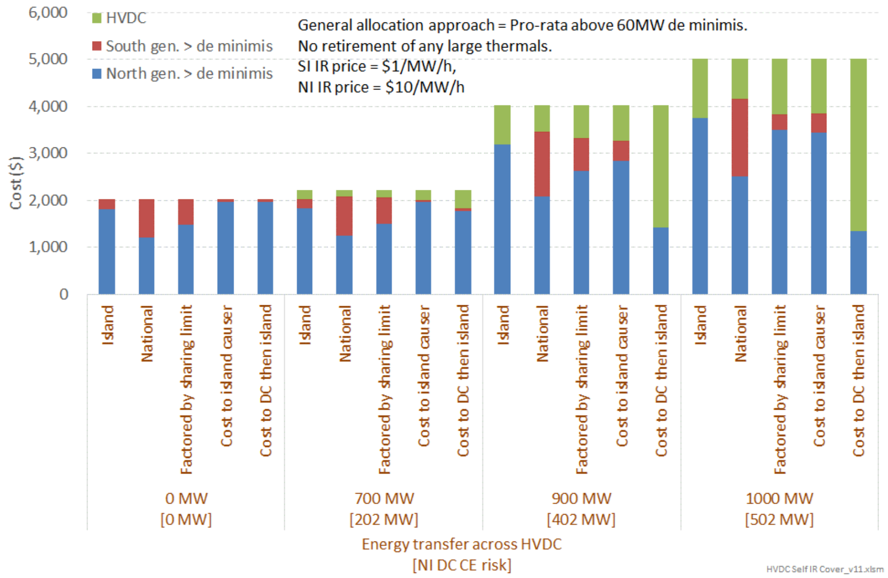
- varying HVDC energy flows – illustrated by the x-axis of each graph
- different assumptions about IR price separation between the islands. The top graph in each figure has the same assumption about price separation that has been used through-out the earlier discussion ($1/MW/h in SI, $10/MW/h in NI). The bottom graph considers a situation where there is *no* price separation (both islands have IR prices at $10/MW/h).
- different assumptions about whether the four large thermal plant remain in operation (the 2 remaining CCGTs and the 2 remaining

Rankine units). Figure 20 addresses the scenario where there are no thermal retirements, and Figure 21 shows the outcomes for a future where all four large thermals have retired.

All the calculations in these figures are based on the current *general* approach to cost allocation (i.e. pro-rata above a 60 MW de minimis). Thus, any costs that are allocated nationally, would be shared among all national risk setters above de minimis basis on a pro-rata basis. Similarly, any costs allocated to an island would be shared among that island's risk setters on this basis.

Figure 22 and Figure 23 address exactly the same situations as for Figure 20 and Figure 21 but instead apply a runway approach to the general allocation. As set out in section 6.1, the pro-rata approach 'dulls' the marginal cost signal to the largest risk-setter, who dictates the quantity of IR that needs to be procured. Figure 22 and Figure 23 highlight that this effect would be exacerbated by some of the cost allocation approaches.

Figure 20: Pro-rata general approach & no thermal retirement



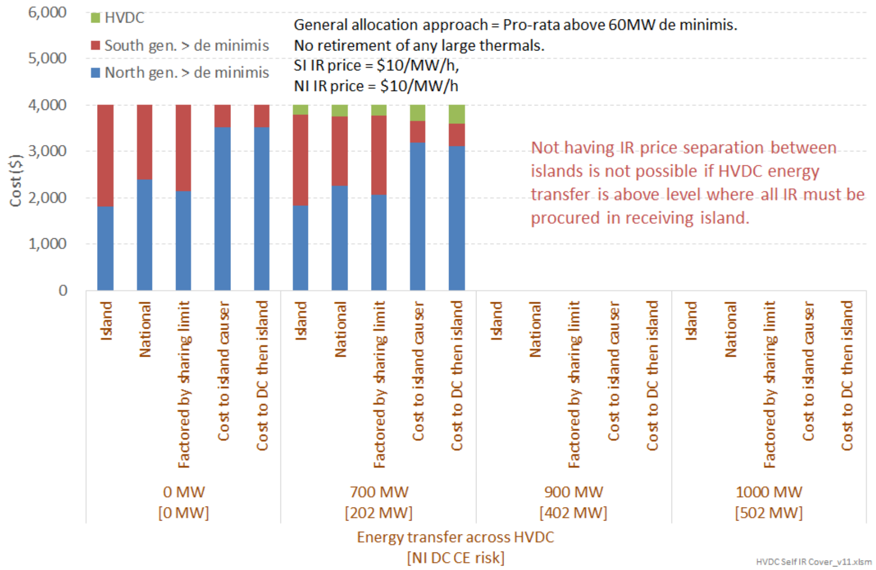
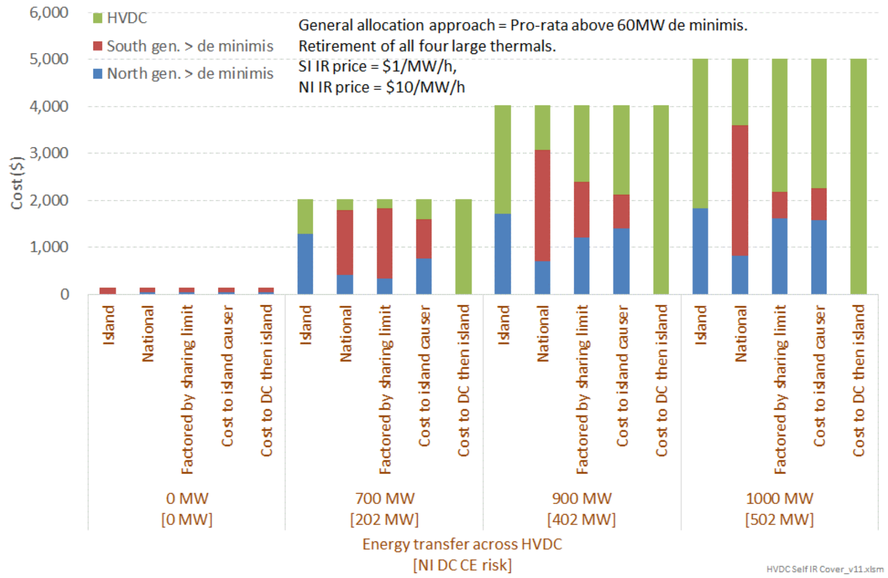


Figure 21: Pro-rata general approach with thermal retirement



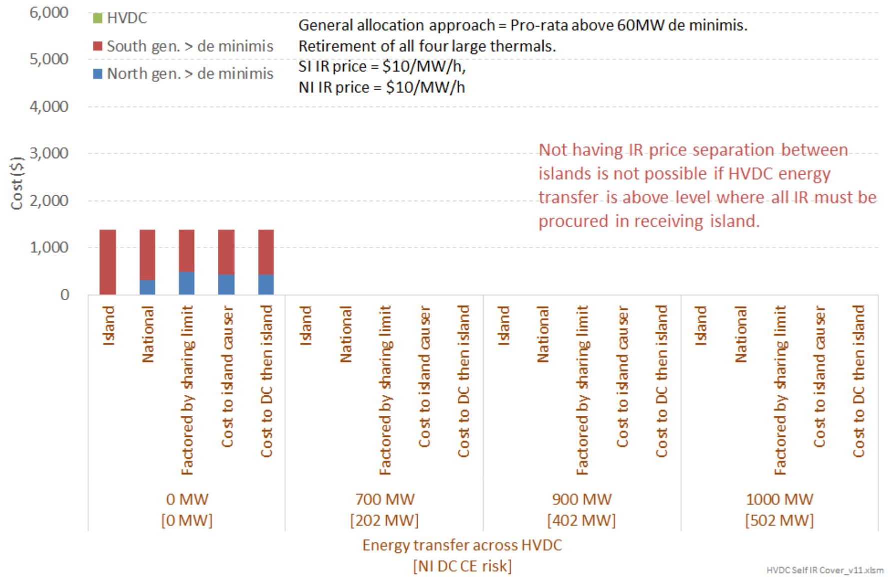


Figure 22: Runway general approach & no thermal retirement

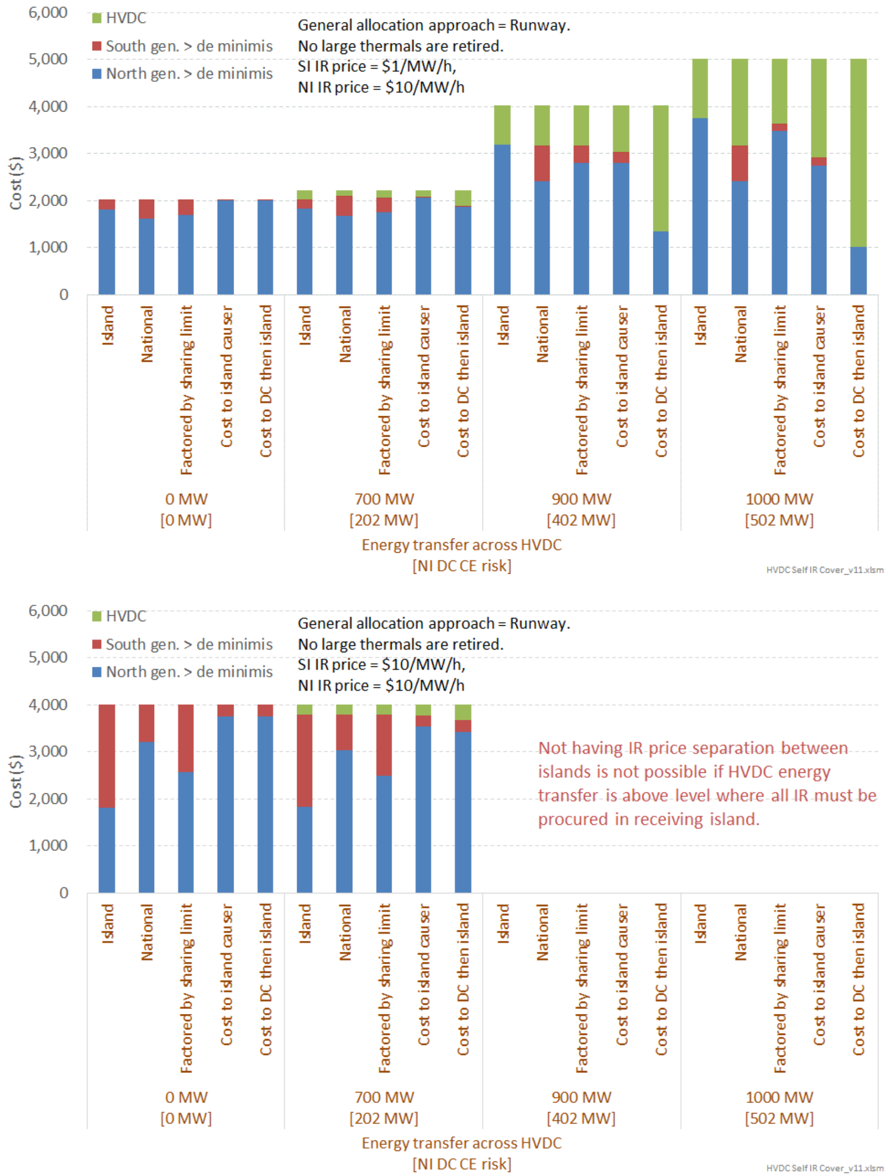
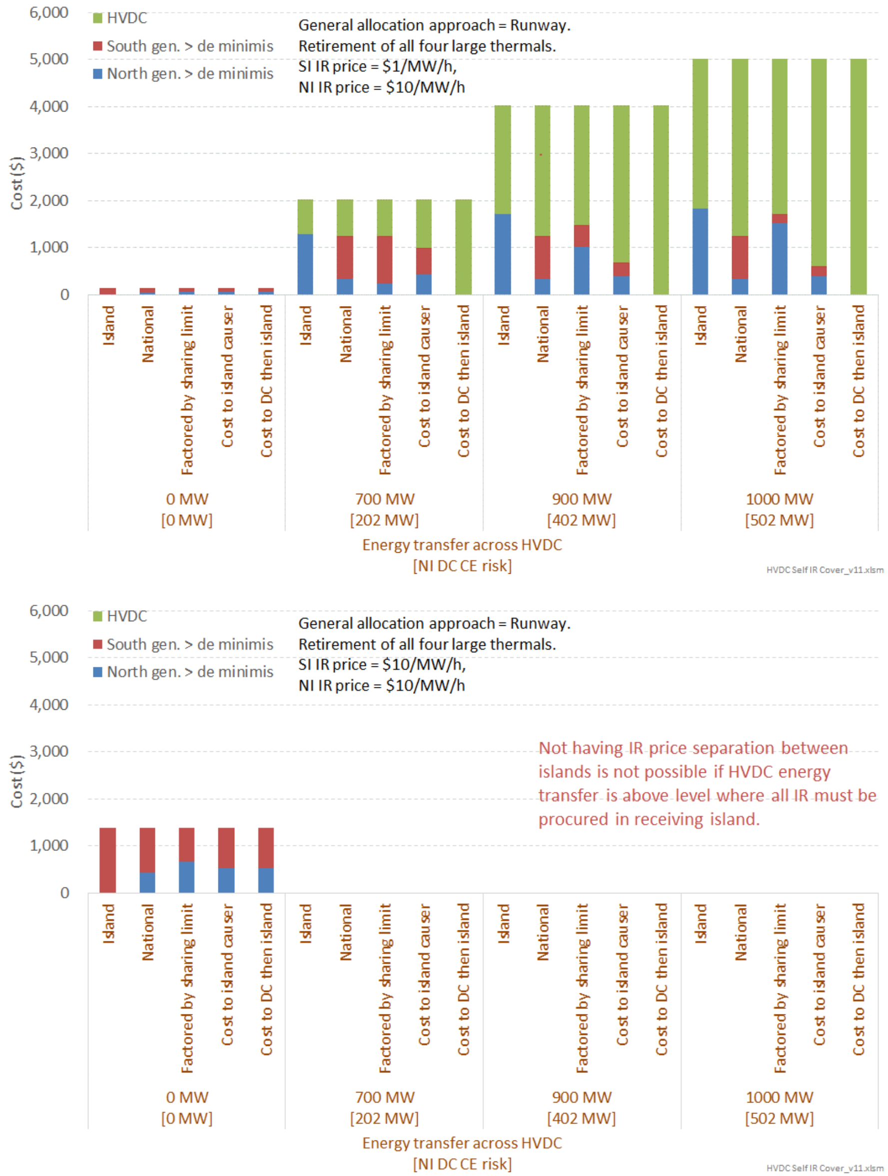


Figure 23: Runway general approach with thermal retirement



As the above figures illustrate, there are considerable differences in cost allocation outcomes between the different options for the different situations considered.

In the long-term this is likely to affect the price signal to causers (direct and indirect) of the need for the amount *and location* of IR to be procured:

- Large generators (particularly in the North Island)
- Parties whose actions are causing the level of energy transfer across the HVDC.

Not sending a marginal IR price signal to these causers could have an impact on long-term investment / retirement decisions. In particular, the form of NMIR cost allocation is likely to influence the decisions as to which island new generation is located. Thus, in a future where HVDC energy transfers are dictating both the quantity and location of IR procurement, it would be appropriate to send a signal that indicates that additional South Island generation would exacerbate this situation, whereas North Island generation would ameliorate it.

As set out above, from first principles, it would appear that option 5 (allocating costs to the HVDC then AC island causers) would be the option which best sent a signal to the underlying causers of how much, and where, IR needs to be procured.

Q.7. Which option do you think sends price signals to underlying causers of the need for, and location of, IR to be procured in a manner which best meets the cost allocation principles of section 5?

Q.8. Do you think the choice of general cost allocation approach (i.e. pro-rata versus runway) has a bearing on which option for cost allocation under the NMIR would be most appropriate?

However, the effectiveness of this option (and indeed the other options) at sending a price signal to the underlying causers relies on costs allocated to the HVDC being passed-on to the parties causing the high levels of HVDC energy transfers in an efficient manner. This pass-through is currently achieved through the transmission pricing methodology. However, it is not clear that the current and potential future TPMs achieve this 'accurately'. The implications of this are discussed in section 6.2.2 below.

Q.9. To what extent do you think the choice of best option is affected by the effectiveness of how costs allocated to the HVDC are passed-on to 'underlying causers' of the level of energy transfer across the HVDC?

As well as considering which options send the most appropriate price signal to causers of the need for (and location of) IR to be procured, the WAG has also considered whether the different cost allocation outcomes may have other consequences which affect the efficiency of market outcomes:

- Whether options may have an impact on the *provision* of IR. i.e. whether some options may dis-incentivise (or even over-incentivise) the provision of IR; and
- Whether options may give rise to perverse incentives on parties to inefficiently withhold energy and/or IR capacity.

With regards to both of these issues, the WAG has not yet undertaken specific modelling to examine the issues. However, it has reached the following high-level provisional conclusions.

- With respect to the provision of IR, it is considered that the principal mechanism to incentivise the provision of IR are the arrangements for IR procurement and the consequential IR *prices* that will emerge from such arrangements.

  Thus, if IR is scarce in the North Island, say, this should be reflected in higher North Island IR prices which should incentivise the development of additional IR resources in that island.

  It is not clear that IR cost allocation would materially alter the extent of IR-price-driven provision of IR resources.

- With respect to the potential for perverse incentives on parties to inefficiently withdraw energy or IR capacity, no potential situations have been identified whereby such outcomes could occur to a material extent as a result of cost allocation outcomes.

  In particular, given the imminent situation of going live with the NMIR but continuing with island-based cost allocation on an interim basis, neither the WAG or the stakeholders who have been engaged with, could point to material adverse outcomes being likely to emerge in this situation.

  As such, it is considered likely that moving ahead with the NMIR will deliver significant economic benefits in terms of improved procurement outcomes, even if island-based cost allocation may not send the best long-term signal to causers of the need for, and location of, IR to be procured.

Although these provisional conclusions suggest that IR cost allocation approaches are unlikely to materially impact on parties' energy or IR offers, and thus be unlikely to result in undesirable market outcomes, it is worth noting a numbers of points:

Firstly, there are clearly opportunities for some parties to withdraw IR capacity at times to maximise their individual returns:

- South Island reserve providers are incentivised to not swamp the market with so much cheap IR that *IR* price separation occurs across the HVDC. However, withholding some IR capacity to prevent IR price separation is rationale behaviour that is:
  a) Unlikely to lead to material inefficiencies (in the same way that similar behaviour to prevent energy price separation across the HVDC is observed to be a regular feature of generator offers that has not been deemed to be sufficiently detrimental to market outcomes that it warrants intervention)
  b) Unlikely to be affected by cost allocation outcomes.
- Some North Island reserve providers that are long on generation may be incentivised to withdraw IR capacity to *cause* an energy constraint across the HVDC and consequent price separation. However, such actions:
  – would be taking advantage of a pivotal position that could invite regulatory scrutiny; and
  – Are unlikely to be influenced by cost allocation approaches. Indeed, the incentive exists at present under current IR procurement. Moving to a NMIR will tend to reduce the ability of parties to take such actions.

Secondly, different options are likely to result in differing degrees of exposure to IR prices which could alter different participants' risk positions. This may alter some participant's appetite to seek IR hedge cover from IR providers, and may also alter the extent to which they seek to go long on load in particular islands. However, it is not clear that such outcomes would result in material differences in the total amount of IR or energy that is provided to the market. Thus, it is not considered likely that a party exposed to IR prices would be willing to pay materially more for hedge cover than the expectation of outturn IR prices (plus some risk premium).

Thirdly, no situations have been identified where IR cost allocation options could incentivise participants to withdraw energy in such a way that would result in material differences to total energy and/or IR costs.[30] In particular, it is generally the case that the loss of energy revenue will outweigh any gain in terms of reduced IR cost allocation.

In this vein, it does not appear likely that IR cost allocation could materially magnify a participants' incentives to take advantage of a pivotal energy position, and thus make it more likely for such outcomes to occur.

Lastly, it should be noted that all the above conclusions as to the nature of impact of IR cost allocation on energy and IR offers are *provisional* subject to undertaking specific modelling of the various situations that are likely to occur. Such modelling is unlikely to be trivial as it will need to take account of various phenomena:

- The gearing effect that can occur with relative IR and energy pay-offs. (For example, withdrawing 1 MW of energy will lose a participant 1 MW of energy sales, but only gain that participant a share in the MW reduction of IR cost allocation that may occur).
- Portfolio effects across energy and IR; and
- Addressing the potential for energy and/or IR price separation across islands.

Given the provisional nature of these conclusions, the WAG is particularly keen to hear from stakeholders who believe that different cost allocation options *will* have a material impact on energy or IR offers. To the extent that parties believe this to be the case, the WAG would like to be see this demonstrated in a tangible format via some worked examples in a spreadsheet, or similar.

Q.10. Do you believe that some IR cost allocation options could materially impact on participants' incentives to offer energy and IR to a degree that could have material outcomes on these markets?

Q.11. If yes, which options are likely to give rise to such outcomes, and could you provide worked examples demonstrating such effects?

6.2.2 How IR costs allocated to the HVDC are passed on to market participants

As described in footnote 19 on page 33, at low levels of transfer, the HVDC is able to 'self-cover' for the potential loss of one of its poles.

[30] A situation was identified where a party could gain from withdrawing a medium-large sized thermal (i.e. not the largest thermal) from providing energy and instead provide such capacity as IR at times when energy and IR prices were very similar. Thus, a similar revenue would be earned from the capacity (IR revenue rather than energy revenue) and the party would benefit from a reduction in IR cost allocation. However it should be noted that:

a) This strategy is only beneficial to the party if it doesn't have material cost consequences to the market overall – i.e. if the action were to lead to significant price difference between energy and IR it would likely be not profitable

b) It is likely only profitable as a consequence of cost allocation being undertaken on a pro-rata rather than runway basis. (Noting that SPD will automatically make this trade-off for the very largest thermal risks, and a pro-rata allocation sends an increased price signal to medium-large risks).

However, above certain transfer levels, there is insufficient spare capacity on each pole to completely cover the loss of the other pole, and some IR will need to be procured in the receiving island to cover the amount of transfer capacity which can't be self-covered.[31]

At such times, the HVDC is considered a causer of the need for IR, and it is allocated a share of IR costs.

At first sight, this may seem appropriate in that Transpower (as HVDC owner) is responsible for ***investment decisions*** for the HVDC – it influences the reliability of the HVDC, and the capacity and configuration of the asset itself.

However, Transpower has limited ability to influence ***how the HVDC operates***, and hence the size of the risk it presents in each half-hour. This is because it:

a) **is obligated under part 12 of the Code** to make the full capacity of the HVDC available to the market, and is therefore unable to withdraw capacity in order to limit the risk it presents

b) **has little influence over demand[32], and no responsibility for generators' energy and reserve offers,** which fundamentally determine the operation of the HVDC. It therefore cannot influence whether or not the HVDC is utilised in a way that is least-cost from a system perspective (noting that transfers will be co-optimised within SPD, based on generators' energy and reserve offers).

[31] Note: As detailed in section 4.4, this analysis focusses on the contingent event risk of the HVDC (known as the 'DC CE'), being the loss of a *single* pole. The loss of both poles (the extended contingent event, or 'DC ECE') is not considered because sufficient extended reserves (principally AUFLS) should be available to address the ECE at times of capacity scarcity.

[32] Its demand response programme being the primary way it can influence demand.

Fundamentally, therefore, it would seem appropriate for those market participants (generation and demand) whose collective decisions result in the transfers across the HVDC, to be sent appropriate signals as to the IR consequences of such transfer levels.

Not sending such signals risks inefficiencies:

- In the short-term through inefficient offers of energy and IR into the market. However, it is considered that the co-optimisation undertaken by SPD will largely eliminate operational inefficiencies.
- In the long-term through inefficient plant investment and retirement decisions which will influence the extent of transfers across the HVDC. For example, were the HVDC to increasingly become the binding risk setting IR procurement requirements at times of capacity scarcity, it would be important to signal the cost implications of that to market participants such that the relative IR-related costs of locating future plant in the south or north island were properly factored into participants' decision-making.

This issue is likely to grow in importance as the analysis presented in section 6.2.1 indicates that the proportion of IR costs which are driven by the operation of the HVDC is likely to grow significantly in the future.

At the moment, the HVDC-related IR costs that are signalled to market participants are a function of number of aspects of market design:

- The broader allocation arrangements that determine what IR costs are allocated to the HVDC. This is a function of
  - The general approach to cost-allocation (i.e. pro-rata vs runway).
  - The approach taken to allocating costs between assets located on the two islands under the national market for IR (NMIR).
- How IR costs which are allocated to the HVDC are passed-on to market participants.

The 'right' approach will depend on all the above aspects being implemented correctly.

This section only considers the last issue – i.e. how best to pass-on the costs allocated to the HVDC to the market participants whose collective actions resulted in the level of HVDC transfers – given that sections 6.1.1 and 6.2.1 have previously addressed the broader allocation issues (pro-rata vs runway, and NMIR allocation approaches) which determine how IR costs are allocated to the HVDC.

At the moment, costs which are allocated to the HVDC are passed-on to market participants via the transmission pricing methodology (TPM) in that Transpower includes all such IR costs within the broader 'bucket' of HVDC costs that it recovers via the TPM.

Under the current TPM, these costs are ultimately allocated to South Island generators, based on their half-hour historical anytime maximum injections (HAMI). However, there are a number of changes to the TPM which will alter this cost-allocation:

- Following Transpower's Transmission Pricing Operational Review, the basis for allocating costs to South Island generators will change from being based on their HAMI injections to being allocated to South Island generators based on their South Island mean injections (SIMI). This change will formally begin from 1 April 2017 and take four years to fully implement. However, it has effectively already been put into operation, as the time period from when SIMI measurements are taken started earlier in 2016.
- The allocation will change again under the Authority's TPM Review. The exact change and the timing of that change have yet to be determined. However, the Electricity Authority has signalled that it considers the current approach to recovering HVDC costs to be inefficient and discourages use of the HVDC. Under its May 2016 proposal[33], HVDC costs (including IR costs allocated to the HVDC) would instead be recovered by two charges; an 'area-of-benefit' charge placed on generation and load, relating to the net benefits received from the HVDC; and a postage stamp, capacity-based 'residual' charge on load customers.

Using the HVDC TPM as the means by which HVDC-related IR costs are passed on to market participants implicitly assumes that the cost-drivers behind the capital and operating costs of the HVDC are the same as the drivers behind the HVDC-related IR costs.

i.e. It assumes that the most efficient means of passing on costs to those parties who caused the HVDC to be built will be broadly the same as the most efficient means of passing-on IR-related costs to those parties who determine how it is used in any half-hour and the IR consequences of such use.

In considering this issue, the WAG came to the view that using the TPM to pass-through HVDC-related IR costs may result in some 'dulling' of the price signal to the market participants whose collective actions are causing the level of transfers in each half-hour. Thus, although IR-costs are concentrated in a relatively small number of periods of scarcity, the TPM (current and proposed) doesn't allocate HVDC costs to participants on a half-hour-by-half-hour basis, but rather based on other historical measures. This will cause some distortion to the marginal price signal that should theoretically flow through to causers of the need for IR.

However, the WAG notes that:

- The Authority has spent considerable effort in analysing the efficiency of different forms of transmission pricing, and that IR costs

[33] Consultation Paper: Transmission pricing methodology: issues and proposal

will have been included within the broader component of costs considered in this process.

- It is not clear whether the TPM-basis for allocation is likely to result in grossly different overall IR allocations compared with a theoretically 'correct' approach which allocated the HVDC-related IR costs to the market participants causing HVDC transfers for a given half-hour. Undertaking such an evaluation could require considerable effort.
- If HVDC-related IR costs were not recovered via the TPM, it would be necessary to develop new systems and processes to recover the costs via other means. The WAG noted some differences in views as to the underlying causers of the HVDC's energy transfer levels.
  - One view was that HVDC-related costs should be allocated to <u>all</u> sending-island generators (i.e. to ignore de minimis considerations). This would treat the South Island as a 'super generator' causing an IR risk because of its injection into the North Island. This would be consistent with an approach which identified a large wind farm as an IR risk due to the potential failure of its connection asset, even though its individual units are below the de minimis. Likewise, it could be considered consistent with allocating IR costs arising due to a single large generator on the grounds that the generator is responsible for its output.

    Were this approach to be taken, it is understood that allocating any HVDC-related IR costs to all sending island generators would be relatively trivial to implement from a systems perspective.
  - Another view was that the HVDC's operation is the result of the inter-play of all generation *and demand* parties across *both* islands. Allocation solely to sending-island generators would not be consistent with that view. As the TPM process has highlighted, identifying the underlying 'causers' of the HVDC operating at a particular level under this framework would not be a trivial process.
- The potential scale of benefit arising from improved investment efficiency from altered HVDC-related IR cost recovery is unlikely to be large. Thus, the analysis in Appendix B suggests a potential benefit of the order of $2m – largely from influencing which island new generation is located – but this is likely to be subject to significant inherent uncertainty.

Based on all of the above, the WAG considers that there is not a strong-enough case to recommend moving from recovering the HVDC-related IR costs via the TPM to some alternate, yet-to-be-determined, approach.

Q.12. Do you agree that HVDC-related IR costs should continue to be allocated to the HVDC owner and passed-on to market participants via the TPM, and do you have any observations about the interim allocation of IR costs under the NMIR?

6.3 Allocating additional costs arising from secondary risks

At times, the system operator will exercise its discretion to procure additional IR, over and above the amount that would be required to cover the largest risk. This is because some assets don't comply with AOPOs, and can potentially fail as a result of another asset's failure (i.e. they present a secondary event risk).

There are three types of assets whose operation can require the system operator to procure additional reserve:

- Assets that are undergoing commissioning, so are yet to prove they are compliant with AOPOS

- Assets that cannot meet certain AOPOs, and have received a dispensation from complying with them
- Assets that are less than 30 MW in size, are 'excluded' from complying with AOPOs[34]

Although these assets are causing increased IR costs at times, the current cost allocation approach doesn't consistently pass-on the costs to these causers. As is detailed in the following sub-sections, this gives rise to the potential for higher costs arising from inefficient investment decisions about asset capability (i.e. compliance with AOPOs), and/or inefficient operation.

6.3.1 IR cost allocation for commissioning assets

At present a 70 MW plant that had yet to prove its compliance with the under-frequency AOPOs would result in the system operator procuring an additional 70 MW of IR during the periods when it was being commissioned. However, under the general cost allocation approach, particularly the 60 MW de minimis, it would only receive a minimal cost allocation.

Further, unlike primary risks, the market dispatch systems (RMT + SPD in combination) are unable to scale-back dispatch of commissioning plant, leading to the potential for operational inefficiencies and higher prices (IR and also potentially energy) in such periods. This did occur during the commissioning of one of the Stratford peakers operated by Contact Energy, when such commissioning was undertaken at a time when IR was relatively scarce, leading to significant price increases for a few periods.

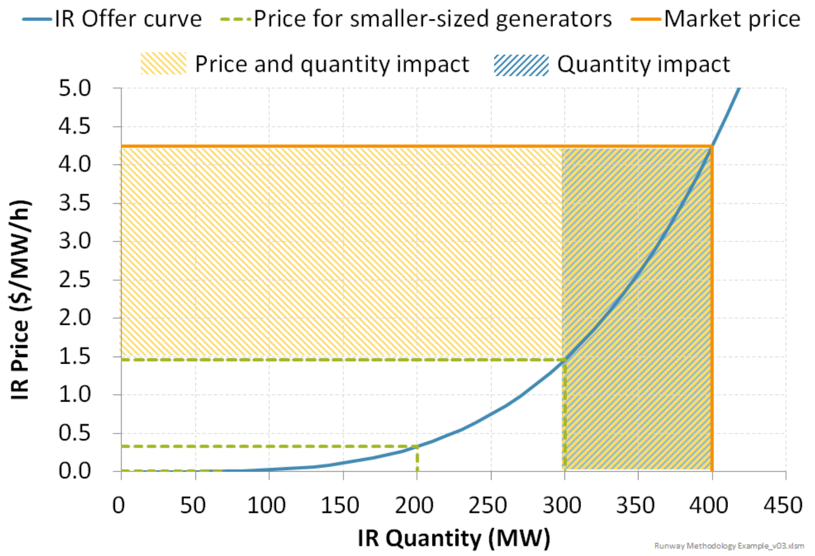
[34] Section 8.21 of the Code

That said, it is considered that these operational inefficiencies would largely involve wealth transfers (in terms of prices during commissioning being higher than they would otherwise be), rather than major economic costs. This is because commissioning tests are unlikely to occur during periods of genuine capacity scarcity in a way that would result in a sustained increase in the amount of capacity being held on the system.[35]

Given the potential for operational inefficiencies and higher market prices during periods of commissioning, the first-best cost allocation option for sending the correct price signal would be to pass-on costs in a way which reflected both the additional quantity of IR procured, and the price impact of such additional procurement. This is shown as the yellow hatched area in Figure 24 (note that this overlaps the blue hatched area) which illustrates the impact of a 100 MW plant presenting an additional risk, on top of a 300 MW primary risk.

[35] Thus, in the Stratford peaker example, it is understood that the higher prices were not because of insufficient capacity being built, but because a number of existing units happened not to be available at the time of the commissioning.

Figure 24: Hypothetical IR cost-supply curve



This approach may be relatively costly to implement (in that it would require re-running the pricing algorithm to reflect the price impact of the secondary risk).

Accordingly, a second-best approach may be to implement a simple variant on the standard quantity-based runway approach described in section 6.1.1. i.e. with reference to the example shown in Figure 24, the asset would receive a 100 / 400 share (shown as the blue hatched section in Figure 24), plus the asset would also receive costs from being allocated its 'normal' share of the other 300 MW, based on the general cost allocation approach (whatever it may be).

This quantity-only runway approach would be relatively easy to implement if the general approach had been changed from pro-rata to runway.

It may still be relatively easy to implement even if the general approach remains pro-rata, as only clearing & settlement systems need to be changed and changes to the cost-allocation algorithm shouldn't be that complex. However, it would be inconsistent in principle with the general approach.

The WAG's general view is that changes to cost-allocation for commissioning assets should be implemented if the costs of the change are likely to be less than the economic benefit. Moreover, it does not believe there are the same issues regarding potential unintended consequences and regulatory certainty that applies to changes to the general cost allocation approach.

Q.13. Do you think cost-allocation for commissioning plant should: a) continue as is; b) change to be quantity-and-price-runway-based without application of a de minimis; or c) change to be quantity-runway-based without application of a de minimis?

Q.14. Do you think a change to allocating costs to commissioning plant on a runway basis should only occur if general cost allocation were to move to a runway basis?

6.3.2 IR cost allocation for plant receiving dispensations

Clause 8.31 of the Code states that assets that receive a dispensation from an AOPO are to be allocated 'readily identifiable and quantifiable costs'. The intent behind this is to ensure that such parties face the costs of the actions and thus can weigh up the private benefits to them of not investing money in asset capability versus the public costs that their non-compliance would cause.

At the moment, there are two different types of AOPO dispensations that give rise to increased IR procurement costs.

- Plant with dispensations with the ***under-frequency AOPOs*** set out in clause 8.19 of the Code. At the moment, the only significant plant with such dispensations are the CCGTs that are unable to comply with the AOPO relating to maintaining output if system frequency falls below 47.5 Hz – noting that this will only occur during an extended contingent event (ECE).[36]
- Plant with dispensations from the newly-created ***voltage fault-ride-through AOPO***. This currently only applies to some wind farms.

Both such situations can give rise to the system operator procuring more IR. In the case of non-compliance with the voltage AOPOs this is due to a supply interruption that can give rise to a frequency disturbance also giving rise to voltage disturbance.

However, at the moment, the Code only specifies the dispensation cost approach for plant that are non-compliant with the under-frequency AOPOs. Thus, clause 8.31(c) of the Code specifies that such plant should be allocated costs equal to the 0.5 multiplied by the IR price multiplied by their output. If the extra costs are due to non-compliance with ECE-related AOPOs (as is the case for all the under-frequency dispensations issued to-date), this is unlikely to be reflective of the true extra costs arising because of the AOPO non-compliance. This is because AUFLS are likely to cover the majority of the ECE risk and the extra risk from this non-compliant plant may make the amount of IR required to cover the ECE to be only a small amount greater than the amount of IR required to cover the CE.

In contrast, there is no dispensation cost allocation approach specified for plant that are non-compliant with the voltage fault-ride-through AOPO.

The first-best option for addressing these situations would be to allocate costs based on a quantity-based-runway approach as described previously on page 57 in relation to addressing the extra reserve required to cover commissioning assets. In the case of non-compliance with CE-related AOPOs, this is relatively straightforward, being equal to the output of the asset. In the case of non-compliance with ECE-related AOPOs this is slightly more complex.[37]

The WAG's general view is that changes to cost-allocation for plant with dispensations assets should be implemented if the costs of the change are likely to be less than the economic benefit.

However, in considering this, the WAG notes that:

- There are unlikely to be material operational inefficiencies from such outcomes as: the dispatch tools (RMT + SPD) have the ability to scale back CCGTs if that is the most efficient thing to do; and, the (close-to) zero SRMC nature of wind means it is unlikely to be cost-effective to scale such plant back at these times;

[36] Some South Island wind schemes also have dispensations from maintaining frequency during a South Island ECE. However, South Island reserve costs arising from the ECE are very low.

[37] For example, consider a situation of two 400 MW plant which are non-compliant with the ECE-related AOPOs. At times, this extra 800 MW of risk may cause the residual ECE-risk after taking account of AUFLS to be greater than the CE risk, and thus cause more IR to be procured than is needed to cover the CE. If this extra IR requirement is only 50 MW greater than that required for the CE, how would you allocate this 50 MW between the two plant?

- The scale of investment cost inefficiency is not considered to be great, as poor cost allocation outcomes generally occur during periods when the ECE is binding, which, as set out in 4.4, are generally not periods of capacity scarcity;

Accordingly, the scale of economic benefit from a complex solution may be smaller than the costs of implementing it. Thus, for plant with voltage-fault-ride-through dispensations, a 'crude-proxy' approach similar to (or the same as) that currently applies to plant with under-frequency dispensations could be appropriate.

Q.15. What cost-allocation approach do you think should apply for plant with under-frequency and voltage-fault-ride-through dispensations?

6.3.3 Assets excluded from complying with AOPOs

Earlier this year it became apparent that a 15 MW South Island wind farm was not compliant with the AOPOs relating to maintaining output even when frequency is > 48 Hz. Given that the system operator has no visibility or certainty as to how much the station is likely to be producing at any moment in time, it has had to assume that it may be operating at full output at any moment in time, and thus is procuring an extra 15 MW of reserve to cover the CE at all times. This will likely drive extra capacity being held on the system which, could be quite costly – approximately $10m present value for this 15 MW plant if this situation were to continue indefinitely based on the estimate set out in Appendix B.

However, this non-compliance is <u>not</u> in breach of the Code, as clause 8.21 specifies that plant smaller than 30 MW are excluded from the under-frequency AOPOs.

It is not clear what the intent was behind such a blanket exclusion, but it is considered unlikely that the intent was to allow 'small-to-medium' sized generating stations (i.e. between 5 to 30 MW in size) to avoid CE-related AOPOs.

The WAG has not considered this issue in detail, or come to a view on the options to address it, other than agreeing that non-compliance which gives rise to the system operator purchasing extra IR to cover a CE is likely to be very costly, and should be avoided wherever practicable. In this, it has identified a number of potential options:

1) Relying on the existing remedy within the Code to these situations. Namely, under clause 8.38 of the Code, the Authority is able to direct assets below 30 MW to comply with AOPOs, following a request from the system operator if it has been unable to satisfactorily work with the non-compliant generator to resolve the matter.

   Invoking clause 8.38 could set a precedent that would inform potential future small generation developers.

   However, always relying on this back-stop could potentially be cumbersome, and for very small generation (e.g. < 1 to 5 MW) it could become impractical to administer. Further, it is not clear what would happen if the plant was unable to comply with such a direction.

2) Reducing the 30 MW threshold in section 8.21 of the Code for 'excluded generating stations' to some lower number. This may only be appropriate down to some lower number, but for very 'small' stations (e.g. below 1 to 5 MW) it may become impracticable.

3) Allocating costs to excluded plant in the same way as for dispensation holders, for all assets down to some lower MW level. However, this may not deliver any benefit relative to the above

option of reducing the 30 MW exclusion level to this lower MW level, but would likely be more costly to implement.

4) Ensuring that technical standards (e.g. for inverters) for very small generation are appropriate. However, determination and policing of such standards would fall outside of the Code and the remit of the Authority.

Thus, on the face of it, altering IR cost allocation (option 3 above) does not appear to be the best means of addressing this particular issue.

Q.16. What measures do you think should be implemented to address small generation plant that are currently excluded from the need to comply with frequency-related AOPOs?

7 Review of the Event Charge

7.1 There are two potential purposes for the event charge

There are two potential purposes for having an event charge regime:

a) incentivising asset reliability

b) paying interrupted assets for costs incurred in an event.

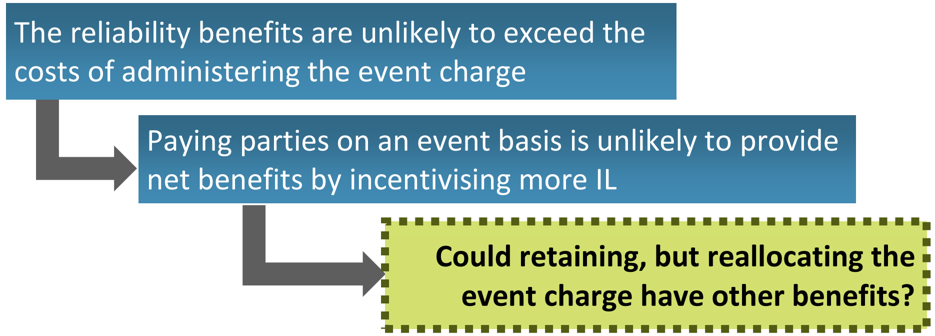
As currently designed, the event charge regime serves the former purpose. It was originally intended that the regime would be extended to also achieve the latter, but this never progressed.

With this in mind, section 7.2 discusses whether the reliability incentives provide sufficient justification for retaining the event charge.

Section 7.3 discuss the case for extending the event charge regime.

As the WAG has summarised in the figure opposite, and at the end of each sub-section in **yellow boxes**, neither the reliability incentives, nor any benefits from paying parties on an event-basis appear to provide sufficient justification for retaining the event charge.

However, a suggestion has been made to the WAG that the event charge be retained in order to bridge a short-term period where there may be a high risk of IL exiting the reserve market. This is discussed in section 7.4. The WAG has yet to form its view on this idea, and is interested in submitter views.



7.2 It does not appear worthwhile to retain the event charge to incentivise asset reliability

The principal function of the event charge regime in its current form, is to signal the consequences of causing an event to participants – and thus incentivise them to take actions to improve reliability.

However:

a) There are more significant incentives to be reliable

The event charge regime may not incentivise generators and the HVDC owner to take actions to improve their reliability *over and above actions that they would already be likely to take.*

Parties have various other incentives to be reliable. Specifically:

- *Generators:*

  Generators already face incentives to have reliable plant because trips give rise to repair costs, lost income, and costs under hedge contracts. These can be particularly significant where a generating unit takes several hours to re-start, and/or prices spike following an event.

High level analysis of the likely cost-benefit trade-off facing generators suggests that the added incentives from the event charge are likely to be negligible.[38] Generators have made representations to the WAG to this effect.

- *HVDC owner:*

  Exposure to the event charge gave rise to Transpower withdrawing HVDC capacity in 2006 during concerns about the reliability of the link.

  However, since that time, changes have been made to Part 12 of the Code to require that Transpower makes the full capacity of the HVDC available to the market. Further, Transpower faces incentives to be reliable under the price-quality regulation from the Commerce Commission.

  It is not considered that exposure to the event charge will meaningfully improve Transpower's incentives to be a prudent operator of the HVDC.

b) There are other regulatory remedies to address unreliable plant

When the event charge was first introduced in 1999, there were fewer regulatory 'tools' that the system operator could call upon to incentivise reliability.

Now, there are a variety of remedies that can be used to address situations including:

- penalties for breaching the Code
- the system operator's ability to prevent or restrict operation of plant if it has just cause to be concerned about the plant's reliability – e.g. following a series of events.

c) There are costs associated with administering the event charge

The event charge regime has costs associated with its administration – in particular, from the system operator having to determine an event causer, and any associated legal challenges around that determination.

d) There may be potential for perverse incentives

Exposing generators to an event charge could affect their incentives about how they operate their plant. For example, generators might withdraw their plant from operation for fear of incurring an event charge if they were to trip.

If the event charge is not an accurate reflection of the cost of events – and it is not clear that it is[39] - then this would result in inefficient outcomes.

It was partly due to concerns about these perverse incentives (and the administration & legal costs), that the Authority decided not to include an event charge for the new Extended Reserves Regime. [40]

[38] This analysis considered how much extra cost would need to be spent on maintenance (i.e. more time on outages doing maintenance, more personnel etc.) in order to meaningfully reduce the number of forced outages each year and thus the associated event charge. It is considered that more money would need to be spent on maintenance-related costs (particularly from the increased unavailability of the plant due to the longer maintenance) than could be gained from reducing the event-charge-related penalties.

[39] The $1,250/MW charge is an estimate of the likely interruption costs of IL providers. A fixed estimate must necessarily be incorrect, given that the amount and cost of IL provided can vary significantly over time – particularly between low and high-priced IR periods. Further, the estimate was developed in the first half of the last decade based on the information available at the time. It is possible that changes to the provision of IL over the intervening years may make this estimate relatively 'inaccurate'.

[40] See, for example, section 5.9 of *"Efficient procurement of extended reserves – draft Code amendment Consultation Paper"*, 3 April 2014

In summary, it would appear that the event charge could be causing costs that outweigh questionable reliability benefits.

The WAG does not consider that the event charge should be retained in order to incentivise reliability

7.3 Extending the event charge is unlikely to provide net benefits

7.3.1 The event-charge regime was originally intended to reimburse interrupted assets

When the current event charge regime was introduced in 1999, it was originally intended that it be extended so that IR providers could be procured based on their event-based costs. This would mean that providers of IR could compete to provide IR, be selected, and be paid, on the basis of offers relating to the costs they incur in an event (instead of, or as well as, their costs from being available to provide reserve). These event-based costs would then be passed onto the party whose plant failed by way of the event charge.

A number of design challenges needed to be overcome before event-based offers could be accommodated[41], and the idea has not since progressed any further.

Event-based procurement has recently been considered by the system operator and the Authority in another workstream considering changes to IR procurement. In its report[42] the system operator concluded that *"Due to the complexity, inferred cost in development and uncertainty of benefits of this proposal, it is not recommended to further investigate this idea"*.

7.3.2 Paying providers on an event basis was suggested to increase participation by IL providers

The original rationale for extending the event charge was that paying IL on an event basis would reduce their risks from participating, and thus encourage more IL to participate.

Every 1 MW of IL brought forward onto the system, could deliver NPV benefits of approximately $300k.[43]

In more recent times it has been suggested that more IL would participate in the market if it could be paid on an event-basis.

7.3.3 IL providers face some risk, but it is low, and extending the event charge is unlikely to remove it efficiently

At the moment, in order to participate in the IR market on an availability basis, IL providers must determine a risk-weighted availability offer price from:

a) the costs they incur if they are interrupted in an event

[41] Based on recommendations made by the Instantaneous Reserve Steering Committee in 1998. The implementation issues included the need to upgrade SPD and other IT systems, and a possible need to change the New Zealand Electricity Market rules (now superseded by the Electricity Industry Participation Code 2010).

[42] "New Instantaneous Reserve Products", 24 May

[43] This assumes avoided peak capacity costs of $145/kW/yr and a 20% 'firmness' factor of IL at peak, plus avoided IR variable costs of $1/MW/hr. The NPV is based using 8% discount rate over 15 years. If the system is in a situation of over-capacity, the avoided capacity costs (which account for almost 85% of the benefit) will be discounted.

b) the likelihood of an event occurring – which is inherently uncertain, and which they must estimate.

This creates some risk around cost recovery if their estimate of the likelihood of an event is too low.

However, it is unlikely that uncertain event frequency will prevent IL providers from fully recovering their costs over time. Their participation should be profitable, as long as:

- their estimation of the number of events per year is accurate on average. They will only lose money if they *systematically* under-estimate the number of events, and there does not appear to be a reason why that would happen.
- they submit offers at their risk-weighted cost of interruption, and disarm their load if they are not cleared to provide reserve. This ensures that they are only cleared if IR prices exceed their likely costs over time.

The analysis in Appendix C sets out that:

- Paying IR providers on an event-basis would result in either:
  - IL providers earning less than is currently the case, if a pay-as-bid approach was used. This is because IL providers earn the majority of their revenue by being infra-marginal during periods of capacity scarcity.
  - risk creating extreme event-based costs (in the order of hundreds of millions of dollars) if providers were paid the equivalent of the marginal availability price, and an event were to occur during a period of high IR prices. This would create massive wealth transfers, with the obvious potential for inefficient outcomes.
- Participating on an availability basis is likely to be profit maximising for IL providers, and unlikely to result in them not earning sufficient revenue to recover their costs. The only instance where this would not be the case is if they were to systematically under-estimate the probability of an event over a sustained period (i.e. several years). It is not clear that such systematic under-estimation would be likely
- The only situations where IL providers are likely to under-recover their costs is if they persistently submit zero-priced offers, or do not disarm when they are not cleared. This substantially increases their risk of participation. It would also be economically inefficient; Because they bid below their cost, they can displace resources that might have been able to deliver the IR service at a genuinely lower cost - e.g. it would not be economically efficient to call on interruptible load with relatively high interruption costs in a low IR price period, when the alternative IR resource could be spinning a few hydro turbines at very low cost. It is not clear that arrangements need to be changed to address the risks of parties who are participating in the market in this fashion.

The WAG does not consider that event-based payments to providers of IR would have net benefits

7.3.4 Risks of participation could be minimised by other means

The likelihood of an event occurring is an inherent risk, and it is not clear why parties other than the IL providers should bear that risk.

However, the risk could be minimised by ensuring that the assessment of the event frequency, which IL providers currently make themselves, is made using the best information available.

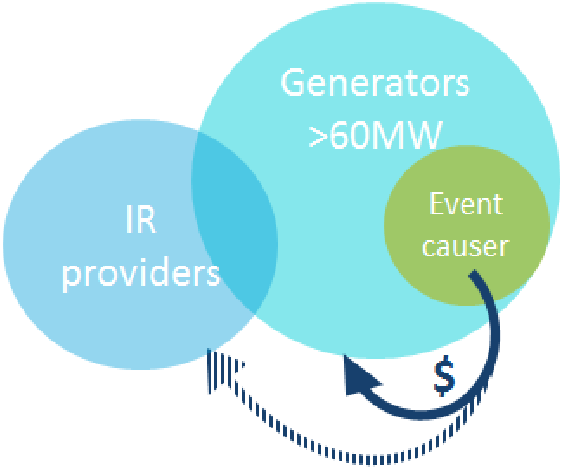
It is likely that the system operator has better information on which to estimate the likelihood of an event, and hence would probably make a better estimate than almost any other participant. The system operator has itself indicated that this is likely to be the case.[44]

Allowing participants to rely on a system operator estimate of the event probability could have some benefits because it would:

- minimise the likelihood of IL being cleared at times when the event risk is high, and vice versa
- reduce the costs of participation for IL participants.

It is likely that a relatively simple assessment could be made at low cost, and either:

- made available for IL participants to use in making their offers
- applied by the system operator to IL participants' interruption costs, which they could submit in place of an offer, which could then be fed into the market systems as usual.



However, it is not clear whether improved estimation of event probability would result in much more IL being brought to the market. It would generally only affect whether an IL provider was cleared at times when IR prices are relatively low; at higher priced times, the likelihood of an event would generally have to be very high to price IL out of the market.

[44] "New Instantaneous Reserve Products", 24 May

7.4 Redistributing the event charge could bridge a short-term period of low incentives for IL participation

7.4.1 The event charge could be redistributed to IR providers

The event charge is currently rebated back to potential event causers that paid IR costs during the month of an event, and the two preceding months.

One participant has suggested that the event charge instead be rebated to IR providers, largely to correct perceived 'imbalances' in the procurement of IR.

<u>The WAG is yet to form a view on this proposal.</u>

The argument that has been put forward for a change in the approach to rebating the event charge, is that:

- the event charge makes the outcomes for spinning reserve and IL providers inequitable, which disadvantages IL in competing to provide reserve:

	Costs and income from providing reserve
Spinning reserve	**Costs = operating costs of providing reserve** **Income = spot market receipts + event charge rebate**
Interruptible Load	**Costs = outage costs** **Income = n/a, but avoided consumption costs**

- IL provides a faster response than most spinning reserve, so contributes more to halting frequency decline following an event, yet currently this superior performance is not recognised in terms of receiving higher payments in the FIR market.

- IL's participation may be threatened by increasing competitive pressure in the reserve market, and the potential retirement of the large industrial loads that typically provide IL.
- As discussed, the WAG's view so far is that the two potential reasons for having an event charge do not provide a compelling case for retaining it. This would address the concerns about inequitable outcomes.
- Furthermore, the different response of IR providers has previously been considered by the WAG[45], and is currently the subject of the Electricity Authority's Review of IR Markets project. That project is looking into an Area Under The Curve (AUTC) approach to procuring reserve, which would account for the faster response of IL. However, the project will take time to complete, and the exact outcome is unclear at this stage.

Given the delay until AUTC can be established, the event charge could be used as an interim measure to reward faster-responding IR providers, and ensure it can remain competitive.

However, adopting such an interim measure would have to be in the long-term benefit of consumers. Table **2** on the following page outlines a framework for considering if this might be the case, outlining the various positions put forward by different WAG members.

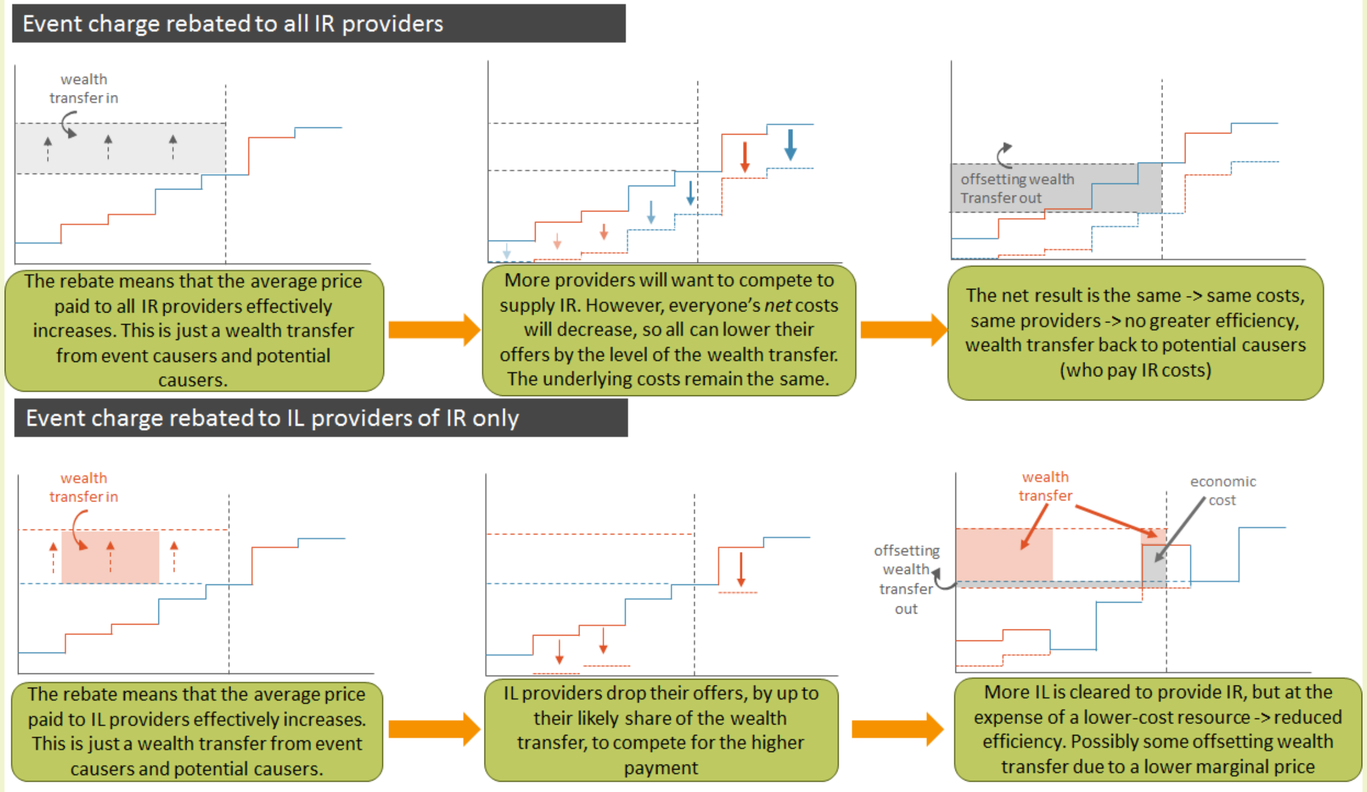
Q.17. Do you think the event charge should be retained, and if so, on what basis?

[45] See http://www.ea.govt.nz/dmsdocument/19196

*Table **2: Framework for considering if using the event charge to support IL participation in the short term could have net benefits***

Criteria for interim measure	Case for:	Case against:
IL providers are unable to recover their costs from current IR procurement?	IL providers are facing heightened competition to provide a shrinking quantity of required reserve because: • IR costs have also been subdued during a recent period of over-supply of generation • The National Market for Instantaneous Reserves is expected to reduce IR requirements by around 60 MW at peak. This may mean they are cleared less often, and earn less when they are.	IL is able to recover its costs from availability offers: • IL's availability offer reflects outage costs & event probability • This allows for full cost recovery if the estimated event probability is reasonably accurate over time, and IL is able to automatically arm and disarm depending on if they are cleared to provide reserve. • The majority of available revenue can be earned from being cleared in a small number of periods of capacity scarcity. IL is unlikely to be priced out of the market at these times.
FIR is currently scarce, or is likely to become scarce before an improved procurement approach can be implemented?	• Since 2012, around 20-30 MW of IL has been removed from the market in the North Island, and around 10 MW in the South Island. - This loss of IL affects both FIR and SIR. - It includes retirement of load by at least two large industrial consumers. • Consistently high HVDC transfers could set a higher FIR requirement, which may make it a scarcer resource. If the Tiwai aluminium smelter were to close, there would be high transfers on a regular basis. • IR costs are driven by the need for capacity to meet demand at times of peak. Encouraging faster IR will only reduce costs meaningfully if FIR is more scarce than SIR at these times. If it is not more scarce, SIR will continue to drive IR costs at times of peak. WAG's Review of IR Market's project concluded that FIR can be scarce at times of peak, depending on the state of system.	• WAG's Review of IR Market's project concluded that SIR can also be scarce at times of peak, depending on state of system. If the scarcity of one is mitigated, the other will quickly become binding. • At times of peak: - more inertia and governor response, which generally results in a lower FIR requirement - large plant is more likely to be operating at its maximum, which means SIR requirements are likely to be high, and hence may be more scarce - HVDC transfers are likely to be moderate, because South Island demand limits what can be transferred to the North Island, so is unlikely to drive high FIR requirements - Around 55% of IL turns itself off pre-emptively at times of peak demand to avoid high spot or transmission prices. This makes both FIR and SIR more scarce at times of peak demand.

Re-distributing the event charge will result in an efficient increase (or avoided decrease) in IL provision.	• As shown in the diagram below, rebating the event charge to IL providers only could encourage more IL. There would be an economic cost associated with this, which would need to be offset by benefits.	• There has only been one under-frequency event since 2014 (in May 2016). The FKC controls of the HVDC mean that governor response is playing a greater role in stabilising system frequency. Prior to the commissioning of the FKC controls, there were around 9 events on average. These are often spurred by periods of asset commissioning, and there are currently no new investments planned. Using the event charge to better reward IL may not provide much of any additional reward over a short-term horizon. • As shown in the diagram below, rebating the event charge to all IR providers is unlikely to improve relative outcomes for IL providers, so will not incentivise participation.



Appendix A. Questions for submitters

Q.1. Do you agree with our identification of the problems with current arrangements? ....

Q.2. Do you agree with these basic principles for allocating IR costs? ....

Q.3. Do you agree that continuing with island-based cost allocation after the introduction of the NMIR is unlikely to create perverse incentives on parties to inefficiently withhold energy or IR capacity? ....

Q.4. What are your views on the merits of moving to a runway methodology (or its sub-options)? ....

Q.5. Do you agree that a de minimis should continue and, if so, at what level? ....

Q.6. Are there other cost allocation options that you think should be considered? ....

Q.7. Which option do you think sends price signals to underlying causers of the need for, and location of, IR to be procured in a manner which best meets the cost allocation principles of section 5? ....

Q.8. Do you think the choice of general cost allocation approach (i.e. pro-rata versus runway) has a bearing on which option for cost allocation under the NMIR would be most appropriate? ....

Q.9. To what extent do you think the choice of best option is affected by the effectiveness of how costs allocated to the HVDC are passed-on to ‘underlying causers’ of the level of energy transfer across the HVDC? ....

Q.10. Do you believe that some IR cost allocation options could materially impact on participants’ incentives to offer energy and IR to a degree that could have material outcomes on these markets? ....

Appendix B. Estimating benefits from a change in approach

Benefits from improved decisions about when to retire assets

In futures where the NI AC CE is the largest risk (i.e. a large generator), the retirement of both the CCGTs through better signalling the IR cost implications of such risks could reduce the peak capacity requirement by up to 150 MW (being the difference between the 400 MW size of e3P and the 250 MW size of the Huntly Rankine units). Using the $145/kW/yr estimate of the carrying cost of capacity set out in section 4, this would translate into a saving of $22m/yr.

In practice the present value of such savings achieved through a move to a runway methodology would be likely to be a lot less than this:

- The CCGTs would only retire early as a result of the runway methodology if the plant that would need to replace them to provide energy were not substantially more expensive, such that the savings in IR-related capacity costs were not outweighed by higher energy costs. This effect will reduce, or potentially, completely negate, the value of any capacity savings. It is not known the extent to which this may be the case. Accordingly, the potential savings have been downgraded by a factor of 50%, although it should be appreciated that this is subject to a significant degree of uncertainty.
- The value of such savings should only count for the length of time when such different outcomes were to occur. Thus, if the altered IR cost allocation were to result in plant being retired three years earlier than they would otherwise have, any capacity savings should only count for three years. The potential benefits have been downgraded by a factor of 50% to reflect the uncertainty about whether asset retirement would be brought forward, although this too is significantly uncertain.
- It is likely that such altered retirement outcomes would occur some significant time in the future (i.e. of the order of 15 years' or so given the likely length of remaining economic life for e3p). Accordingly, the scale of savings has been discounted by 15 years, although here too there is uncertainty as to when such altered outcomes may occur.
- The size of the NI DC CE at times of capacity scarcity could be greater than 250 MW. This would limit the size of reduction in risk from the retirement of the largest NI generators. The potential savings have been downgraded by a factor of 75% to reflect this factor, although this too is subject to significant inherent uncertainty, noting that the following factors will significantly impact on HVDC transfers at peak, yet many are materially uncertain: whether the Tiwai smelter will retire, the extent of development of peak load control in the South Island, the extent of future generation development in the South Island, whether a fourth cable is developed for the HVDC.

Taking all of the above factors into account, high-level analysis (summarised in Table 3 below) suggests that the scale of capacity benefit of reduced North Island capacity from a runway methodology is likely to have a present value of approximately $4.7m.

Table 3: Estimation of benefits from improved decisions about asset retirement

Capacity saved by retirement of CCGTs (MW) (i.e. size of e3p – size of Huntly: 400 – 250 MW)	150 MW
Cost of capacity	$145/kW/yr
Total cost saving per year	$22 m/yr
Factor reflecting uncertainty about whether retirement would be brought forward	50%
Factor reflecting uncertainty about whether HVDC transfers will necessitate similar amounts of North Island capacity	75%
Factor reflecting that energy from new generation that replaces the retired assets will be higher cost	50%
Total Factor of uncertainty	19%
Estimated benefits (15 yrs NPV, 8% discount)	**$4.7 m**

Benefits from improved decisions about where to locate new generation

In futures where the NI DC CE is the greatest risk (e.g. a future where Tiwai were to close), the extent to which IR costs are allocated to the HVDC could influence the location of new generation capacity and thus the amount of risk.

For example, consider a future where there is a need to develop 100 MW of new capacity to meet demand growth, and the two most economic options are two potential wind farms – one in the South Island and one in the North Island.

If the NI DC CE were the binding risk, and using the wind firmness factor of 20% used by the Authority and system operator for determining capacity adequacy, then locating the wind farm in the South Island would give rise to an additional capacity requirement of 20 MW in the North Island to cover the increased likely NI DC CE at times of capacity scarcity.

However, if the wind farm were located in the North Island, no additional capacity to provide IR would be required.

The extent to which such outcomes are more likely to be realised as a result of a runway methodology rather than the present pro-rata approach, and the present value of such outcomes, will be factored by:

- the extent to which new generation capacity may *anyway* be located in the North Island (noting that all new Geothermal prospects are in the North Island, and all new gas-fired peaking generation will need to be located in the North Island). The potential benefits have been reduced by a factor of 28% to reflect this uncertainty. This is based on the system operator’s annual security assessment for 2015. Table 8 of that document suggests that 6,100 GWh of new generation is likely to be located in the North Island, and 1,700 GWh in the South Island.
- the likely timing of new generation investment requirements. Thus, if new baseload generation is unlikely to be required for another 5 or more years, the present value of altered generation investment outcomes will need to be discounted by at least this amount. The potential benefits from better location decisions are assumed to start after a 5 year delay.
- The extent to which the supply / demand balance and the HVDC configuration, would result in the NI DC CE being the largest risk. Thus, a future where Tiwai stays operating and there is significant SI demand growth, or a future where a fourth HVDC cable is built will

be unlikely to have the NI DC CE being the largest risk. The potential benefits have been reduced by a factor of 25% to reflect this significant uncertainty.

- The fact that the current pro-rata methodology will provide a material signal, and it is the effect of the incrementally greater signal from a runway methodology that needs to be evaluated. The potential benefits have been reduced by a factor of 50% to reflect this.

Using the same basic framework as was used to calculate the benefit of altered large NI plant retirement decisions, a high-level estimate set out in the following table suggests the present value of a runway methodology as it applies to the location decision of new generation would be approximately $4.4m.

Table 4: Estimation of benefits from improved decisions about generation location

Annual growth of generation (current generation * 1.5% annual growth as per system operator annual security assessment 2015)	0.64 TWh
Wind capacity required to meet growth assuming 40% capacity factor	183 MW
Firmness of wind at peak (20% based on system operator assumption)	37 MW
Cost of capacity	$145/kW/yr
Carrying cost of capacity to meet demand growth each year	$5.3 m/yr
Factor reflecting that the pro-rata approach will provide a material signal	50%
Factor reflecting uncertainty about whether HVDC transfers will set the risk, and drive the need for North Island capacity	25%
Factor reflecting that generation is likely to be more economic in the North Island anyway	28%
Total Factor of uncertainty	4%
Annual benefit for affecting location decision each year	$0.2 m
Estimated benefits (5 year delay, 15 yrs NPV, 8% discount)	**$4.4 m**

Building on from this, evaluation of the potential benefits of a better approach than the TPM for passing on to market participants the IR costs allocated to the HVDC suggests that the scale of benefit may be relatively small. Assuming that the TPM will send a reasonable signal, the above benefits have been factored by half to reflect the incremental benefit of a better approach to passing through the HVDC-related IR costs to market participants.

Benefits from incentivising improved technical capability of generation

As set out in section 6.3.3, plant which are below 30 MW are excluded from having to comply with under-frequency AOPOs, and there is one 15 MW South Island wind plant that has been identified as not complying with CE-related AOPOs. Using the same basic framework as above, the carrying cost of the system operator being required to procure an extra 15 MW of IR at all times is estimated to have a present value of around $10 m NPV. However, this is subject to some uncertainty. The basic calculation is outlined in Table 5.

Table 5: Estimation of cost of additional 15 MW risk in South Island

Size of plant	15 MW
Cost of capacity	$145/kW/yr
Benefit from avoided cost of capacity to meet higher IR requirement	$2.2 m/yr
Factor reflecting uncertainty about whether HVDC North transfers will set the risk, and IR procured in the North Island will meet all South Island IR	75%
Estimated benefits (3 year delay, 15 yrs NPV, 8% discount)	**$10 m**

Appendix C. Analysis of benefits for IL providers from being paid on an event-basis

Uncertain event frequency does not prevent cost recovery

The rationale for event-based procurement is that it allows IL providers to be paid in a fashion that is more closely aligned to their costs – which largely arise when they are interrupted following an event.

To participate in the IR market on an availability basis, IL providers will determine a risk-weighted availability offer price from:

- the costs they incur if they are interrupted in an event
- the likelihood of an event occurring – which is inherently uncertain, and which they must estimate.

This creates some risk around cost recovery if their estimate of the likelihood of an event is too low.

However, it is unlikely that uncertain event frequency will prevent IL providers from fully recovering their costs over time. As long as their estimation of the number of events is accurate on average, then their participation should be profitable. They will only lose money if they systematically under-estimate the number of events.

Additional uncertainty from not being able to limit participation to profitable periods should be internalised

Some interruptible load providers have removed themselves from the market because of uncertainty about their ability to recover their interruption costs. However, it is understood that these providers did not have the ability to automatically ‘arm’ and ‘disarm’ their load, depending on whether they are cleared to provide reserve or not.

If an interruptible load provider:

- **is able to automatically arm and disarm**, they are able to offer in their true risk-weighted costs of interruption in each half hour, and only be cleared if prices meet or exceed those costs. They will avoid interruption in any period they’re not cleared. As suggested by Figure 4, they only need to limit their participation to a relatively small number of periods to receive most of the available revenue.
- **cannot automatically arm and disarm**, they might choose to stay armed, offer into the reserve market at zero so they are cleared in all periods, and take whatever income results. This means they would have to manage uncertainty additional to the event probability: that being, whether average availability prices will be high enough to recover their interruption costs.

  The risks of participation for these parties are substantially increased, and they face the very real prospect of making a loss. However, it is not clear why any party other than the interruptible load provider should bear this risk, given it can be managed by investing in improved technology.

  Furthermore, if IL providers take this approach, because they bid below their cost, they can displace resources that might have been able to deliver the IR service at a genuinely lower cost.

Extending the event charge is unlikely to have net benefit

The WAG has identified two potential approaches to providing event-based payments, but does not consider either to be appropriate. Specifically:

- **A ‘pay-as-bid’ approach** where IL providers were paid their event-based offer if an event occurred. This approach would:

- completely eliminate the risk of participation for interruptible load providers
- come at the expense of a substantially lower reward, because the majority of revenue for IR providers is achieved from being infra-marginal during the relatively infrequent periods when IR prices reach high levels at times of capacity scarcity
- encourage providers to offer in above their costs to maximise their revenue. This generally results in higher prices than if parties were to offer in at their actual costs of interruption, and can act as a barrier to entry because parties need to put more effort into setting their offers.

- **A marginal price approach.** IL providers use the event frequency to turn their event costs into an availability offer. This approach would do the opposite calculation, in order to determine an event payment from the marginal availability offer. This approach:
  - would similarly eliminate the risk of participation for IL providers.
  - could result in astronomical payments if an event were to occur during a period of capacity scarcity when reserve prices were high. For example, if 100 MW were interrupted following an event, and the reserve price was $10,000/MW/hr, this would result in an event charge of $146 million (assuming a probability of 6 events per year). This would incentivise inefficiently high levels of IL, and wealth transfers of this size would clearly create negative impacts.
  - also mean payments were very volatile over long time-frames.

Calculated example

To illustrate these effects, a simple example has been developed. It tests different outcomes for interruptible load providers based on different bidding strategies and the extent to which expectations of the likelihood of an event, and outturn instantaneous reserve prices were different to reality. The key components of the analysis are as follows:

- Average instantaneous reserve prices *across* the year could be one of three values: Low = $2/MW/hr, Med = $6/MW/hr, High = $10/MW/hr.
- These instantaneous reserve prices *during* the year were assumed to follow the same type of distribution as in Figure 4 on page 20. i.e. an exponential type shape.
- The number of events in the year could similarly be Low, Med, or High, being 4, 8, and 12, respectively.
- Every combination of interruptible load providers' expectations and actual outturn for both instantaneous reserve prices and number of events was tested. (e.g. the interruptible load provider expected instantaneous reserve prices to be High but they turned out to be Low, etc.) This gave 81 different scenarios.
- For each scenario, three different offer strategies and payment approaches were tested:
  - bid zero and receive the outturn availability payment
  - bid the expected equivalent availability cost based on the expected number of events per year, and dis-arm if not cleared. Receive the outturn availability payment
  - bid 150% above the expected interruption cost, dis-arm if not cleared, and get paid an event payment on a pay-as-bid basis if cleared and an event occurs.
  - The table below shows the results of the analysis for interruptible load providers with three different interruption costs

($1,000/MW/event, $5,000/MW/event, and $10,000/MW/event).

Table 6: Illustration of earnings achieved from different interruptible load offer strategies and payment approaches

Interruption cost ($/MW/event)	Achieved earnings in year across the 81 "expected vs actual" scenarios ($/MW/yr)								
	Bid zero			Bid expected cost and arm/disarm			Pay as bid + bid 150% above expected cost		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
1,000	5,520	44,560	83,600	12,569	48,494	85,048	460	1,480	3,000
5,000	-42,480	12,560	67,600	2,379	38,658	78,044	700	4,200	10,200
10,000	-102,480	-27,440	47,600	-4,389	30,299	71,257	0	5,600	16,200

SC_Misc_IR_CostAlloc_v01.xlsx

As can be seen, if interruptible load providers are not able to arm/disarm and must bid zero, their risks of participation are substantially increased, with achieved average earnings being a lot lower, and the very real prospect of actually making a loss.

The other key take-away from this analysis is that a pay-as-bid approach would mean that interruptible load providers would never make a loss. However, their expected average earnings would be substantially less, as they would miss out on all the payments from being infra-marginal at times of high instantaneous reserve prices.