Normal frequency asset owner performance obligations

Consultation Response Paper

Date: 18 November 2014

Contents

1. Authority is responding to submissions on possible Code amendments

1.1 The Authority has consulted on Code amendments

1.1.1 In June and July 2014, the Electricity Authority (Authority) consulted on a proposed amendment to the Electricity Participation Code 2010 (Code). The purpose of the consultation was to clarify generators' asset owner performance obligations (AOPOs) relating to their contributions to maintain frequency in the normal band[1] (proposed Code amendment).[2]

1.1.2 In this paper, we summarise submissions and outline how we intend to respond.

1.2 Further engagement is warranted

1.2.1 After discussions with the system operator, the Authority has decided to engage further with affected parties, particularly generators and the system operator, via a workshop to:

(a) explore matters raised in submissions

(b) consider new information from the system operator's frequency-related developments that is relevant to the AOPOs

(c) decide the how to progress the identified problem.

1.2.2 In parallel with the Authority's consultation, the system operator has continued work on a number of frequency-related developments. In particular, the multiple frequency keeping (MFK) project and testing of high voltage direct current (HVDC) link's frequency keeping control system (FKC) are relevant to the proposed Code amendment.

1.3 Next step will be an industry workshop

1.3.1 The Authority, in conjunction with the system operator, plans to hold an industry workshop in early December 2014 to provide submitters with the opportunity to discuss issues raised in this paper. Details of the workshop will be announced in the Authority's Market Brief in November.

1.3.2 Following the workshop, the Authority, after discussion with the system operator, will decide how to progress the normal frequency AOPO Code amendment (which may include further consultation) and the timetable for doing so.

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[1] 48.8 to 50.2 Hz.

[2] http://www.ea.govt.nz/dmsdocument/18134.

2. The proposed Code amendment

2.1 What is the problem the Authority sought to address?

2.1.1 Frequency keeping is co-ordinated by the system operator to maintain system stability. Total frequency keeping costs for 2013 were approximately $41m. Improving the efficiency of frequency keeping, and frequency management more generally, promotes efficient operation of the electricity industry, which is one of the limbs of the Authority's statutory objective.[3]

2.1.2 The Authority has an on-going programme of work to make frequency keeping more efficient and subject to greater competition, which is expected to apply downward pressure on costs. The system operator is also working on a number of frequency-related initiatives.

2.1.3 The system operator manages frequency using a combination of the market and non-market mechanisms listed below in order of response times:

(a) the generator AOPOs in part 8 of the Code – a mandated service, not procured in a half hourly market or on a fixed quantity fixed price basis

(b) multiple frequency keeping – a paid for service procured in a half hourly market

(c) real-time dispatch – generator 5-minute re-dispatch within the 30-minute dispatch cycle.

2.1.4 The Authority and the system operator have identified that the mandated generator AOPOs are ambiguous. Generators' varying interpretations of the AOPOs mean that not all generators adhere to the same rules or have the same competitive advantages and disadvantages. Some generators are able to avoid costs by imposing them on others. The resulting playing field for new investment is not level and competition is diminished.

2.1.5 The Authority's proposed Code amendment sought to remove ambiguity in the Code as a first step towards creating incentives for asset owners to invest in plant capability that contributes to a stable system frequency.

[3] The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers (s 15 Electricity Industry Act 2010).

2.2 Further views on the problem

2.2.1 The Authority has given further thought to the problem definition and looked at other possible solutions. An alternative approach is to develop market-based solutions that would remove the need for mandated performance obligations. Possible high-level alternatives are detailed in section 5.

2.3 Eight submissions received

2.3.1 The Authority consulted on the proposed Code amendment in June and July 2014. Eight stakeholders made submissions, as indicated in the table below.

Generators	Direct consumers	Distributors	Other
Contact Energy Genesis Energy Meridian Energy Mighty River Power Nova Energy Trustpower	None	None	Transpower Sam Viscovic (independent)

2.3.2 The submissions are available from the Authority website[4] and are summarised in Appendix A. Some submissions contained confidential material. The Authority has not published this material but has considered the material when formulating this response paper.

Submissions confirm ambiguity in the current Code

2.3.3 Most submitters agreed, either explicitly or implicitly, that there is ambiguity in the way normal frequency AOPOs are expressed in the Code. The variety of interpretations of the Code inferred from submissions further supports this conclusion.

3. Issues raised in submissions

3.1 Key issues raised

3.1.1 Two submitters, Mighty River Power and Transpower, supported the Authority's proposed Code amendment, although both suggested drafting changes to address particular issues identified in their respective submissions.

[4] http://www.ea.govt.nz/development/work-programme/wholesale/normal-frequency-generator-asset-owner-performance-obligations/consultations/#c12809

3.1.2 The remaining six submitters did not support the current form of the Code amendment proposal. Submissions suggested that further work is required to:

(a) consider technical and drafting issues, for instance:

(i) gaining a better understanding of current generator performance and extent of possible inefficiencies

(ii) refining the Code drafting

(iii) considering whether the range of characteristics of different classes of generation should be taken into account

(iv) considering the possible implications for dispatch, security and ancillary services

(v) refining the cost-benefit analysis

(b) address regulatory uncertainty around aspects of the dispensation process, including:

(i) the criteria for considering applications for a dispensation from generator normal frequency AOPOs

(ii) the magnitude, calculation basis, and timing of a possible cost allocation imposed in the future on generators with dispensations

(iii) the resources, costs and timing for processing dispensation applications that would likely arise if the Code amendment went ahead as proposed

(c) consider transition issues such as:

(i) approach and timing for transition to the new AOPOs (including testing and agreeing settings with the system operator) if the Code amendment were to proceed

(ii) the implications of/for other frequency development initiatives such as MFK, national frequency-keeping market and FKC

(iii) alternative development pathways such as delaying the Code amendment until other initiatives are complete.

3.1.3 The Authority also notes that several submitters expressed the view that there was a lack of engagement with generators before the consultation paper was issued.

3.1.4 The Authority has sought advice from the system operator on technical matters and on issues relating to the dispensation process overseen by the system operator. The Authority has drawn on this advice in formulating the responses set out in this paper.

3.2 Technical and drafting issues

Current generator performance and extent of possible inefficient outcomes due to ambiguity in AOPOs

The proposal

3.2.1 The Authority and the system operator identified that aspects of the normal frequency management arrangements are ambiguous. These aspects relate to generator AOPOs in Part 8 of the Code to contribute to maintenance of frequency in the normal band.

3.2.2 The Authority considered that the lack of clarity adversely affects generator compliance outcomes and creates unnecessary costs due to regulatory uncertainty for generators, the system operator, and the Authority for the following reasons:

- Generators make investment and operational decisions about normal frequency obligations using inconsistent assumptions about their obligations. The requirements are not specified clearly enough to result in efficient outcomes. There is no incentive for investors to take into account the costs their non-compliance imposes on others.
- The system operator does not have the information it needs to accurately assess overall generator contribution to normal frequency management. With a complete assessment of contribution, the system operator could:
  - more accurately calculate instantaneous reserve requirements
  - better assess the extent of generator non-compliances and any identifiable costs associated with those non-compliances
  - better assess system performance and security risks.

3.2.3 The Authority proposed the Code amendment (refer to paragraph 3.2.12 for details) to correct the ambiguity and thereby deliver more efficient outcomes, particularly for system frequency.

Feedback

3.2.4 Submitters were divided on whether the problems the Authority has identified with the current AOPOs create inefficient outcomes.

3.2.5 Some submitters agreed with the Authority's view that there are inefficient outcomes. In particular, Mighty River Power stated that:

> *'The current wording of the AOPOs does allow for generators to contribute less to frequency correction in the normal band... without penalty by deliberately reducing governor sensitivity (by introducing dead bands).'*

3.2.6 Transpower also supported the Authority view, stating:

> *'... we support the intent to assist all parties to have a consistent interpretation of asset owner performance obligations. Such consistency in interpretation is necessary to support broader Authority initiatives to reduce frequency keeping costs and maintain system security. The contribution that governor action plays in the frequency market is also key to the implementation of the National Frequency Keeping initiative. Clarifying the capabilities of generator governor response to frequency deviations will also assist the System Operator with its procurement and operational management of frequency keeping.'*

3.2.7 Some submitters disagreed with the Authority's view that there are inefficiencies, for instance Contact Energy stated that:

> *'There are no efficiencies to be gained from removing ambiguity in generator obligations. Obligations are largely known at present and if not, are clarified with the [system operator] on a case by case basis.'*

3.2.8 Nova Energy acknowledged the ambiguity, but considered that the inefficiencies were over-stated:

> *'While there is some ambiguity with the current wording in the Code, the potential existing inefficiencies would appear over-stated as... the System Operator currently obtains relevant information (e.g. applicable dead band) via mandatory ACS* [asset capability statement] *submission/updates... the system operator currently reviews and agrees governor settings with the asset owner whenever relevant changes are made...'*

3.2.9 Some submitters were not convinced either way and considered that further analysis is required.

Authority response

3.2.10 In response, the Authority notes the following:

(a) Submissions confirm the Authority's view that generators have differing interpretations of their obligations. Even considering technology differences, some generators appear to be contributing disproportionately more than others to frequency management. This adversely affects plant efficiency and competitive outcomes.

(b) The system operator has confirmed that some generators do clarify obligations on a case-by-case basis, but stresses that not all generators do so. Further, it appears that some generators consider that they comply with their interpretation of the existing Code, and therefore would not see the need to seek clarification from the system operator.

(c) Contrary to Nova's submission that dead band information is required to be supplied in an asset capability statement, this is currently not the case.

(d) The Authority also considers that there are new AOPO-related issues not discussed in the consultation paper that have come to light since the system operator has started testing FKC (refer to section 4).

3.2.11 The Authority considers that the current lack of clarity adversely affects generator compliance and creates unnecessary costs. This is due to regulatory uncertainty for generators, the system operator, and the Authority, for the reasons set out in paragraph 3.2.2 above. The Authority acknowledges, however, that the quantum of possible efficiency gains from clarifying the AOPOs is uncertain, and would need to be weighed against the costs of achieving that clarity. The Authority agrees that it would be useful to gain a better understanding of current generator performance and compliance levels.

Refining the Code drafting

The proposal

3.2.12 As described in the consultation paper, the key elements of the proposed Code amendment can be summarised as follows:

Part 8 clause 8.17	• amendments to clarify that generators must actively contribute to maintaining frequency when frequency is within the normal band, and not just respond to frequency movements outside the normal band
Schedule 8.3 Technical Code A clause 5	• including a dead band of +/- 25 mHz around 50 Hz • amending the droop requirement to be set as low as is practical and no more than 7% • including a requirement that proportional gain and integral gain be set as high as practical • amendments to oblige generators to agree settings that can affect the performance of the governor (e.g. droop, gain) with the system operator
Part 1 Definitions	• defining droop

Feedback

3.2.13 Submitters raised a number or queries and issues about the proposed Code amendment. Some of these related to core elements of the proposal, particularly the dead band, while others were minor drafting matters. Matters raised included:

(a) the appropriate size of dead band, whether it should vary for plant with different characteristics, how it should be expressed, and so on

(b) the definition of 'droop' and of 'gain'

(c) the use of phrases such as 'as low as is practicable' and 'as high as practicable', and how these subjective requirements will be assessed

(d) drafting a more specific requirement for the HVDC rather than including the HVDC with generator requirements.

Authority response

3.2.14 The Authority has noted the matters raised in submissions but has not addressed them at this stage. This is because the Authority intends engaging further with affected parties before deciding how best to proceed with the Code amendment.

3.2.15 The matters raised will form part of the agenda for the industry workshop the Authority intends to hold. The Authority will consider the drafting issues raised, before the workshop. The Authority has also referred relevant aspects of the submissions to the system operator to enable it to consider these before the workshop.

Considering the characteristics of different generation capabilities and technologies

The proposal

3.2.16 The Authority's proposed Code amendment was designed to apply across all types of generation (wind, thermal, hydro, etc.), as is the case for AOPOs generally in the Code, rather than set out different AOPO requirements for each generation type. The proposal did not differentiate between existing and new generation.

Feedback

3.2.17 Several submitters expressed the view that the AOPOs should recognise the different characteristics of different plant. For instance:

> *'The code is failing to address the fundamental problem that not all types of plant are capable or suited to the provision of frequency support demanded by the Code. The proposals fail to recognise that there will be some ~770MW of base load geothermal plant unlikely to be able to provide frequency support in the manner required by the Code, and increasing quantities of solar/PV will further exacerbate the situation.'* (Trustpower)

> *'...the dead band needs to be more reflective of the capabilities of existing plant.' (*Meridian)

‘The proposed code change is incompatible with some important technical matters, such as governor system settings and optimising plant capabilities for different generation technology characteristics.’ (Genesis Energy)

‘Dead bands and droop should be regulated based on the type of plant as preferentially using the most capable plants will minimise overall maintenance and energy wastage costs as well as being more effective.’ (Viscovic)

‘We suggest that the expectations on the HVDC and generators are differentiated consistent with each asset’s operational practicalities.’ (Transpower)

Authority response

3.2.18 The Authority acknowledges that the ability of plant to contribute to maintaining frequency in the normal band varies with characteristics such as generation technology, age and plant settings. However, the Authority considers that, to the extent practicable:

- generator AOPOs should not be plant specific, inherently favouring one technology over another
- the dispensation regime is the appropriate mechanism for addressing non-compliance on a case-by-case basis.

3.2.19 This was a fundamental design principle underlying the original common quality arrangements. For instance, the under-frequency AOPOs do not differentiate between types of generation, and the under-frequency dispensations that some generators hold provide the means of accommodating varying levels of capability.

3.2.20 While the Authority supports this design principle, it acknowledges that some submitters have concerns about the uncertain potential for costs to be allocated as a condition of a dispensation. This is discussed later in section 3.3. The Authority may consider the possibility of technology-specific criteria for the granting of dispensations from normal frequency AOPOs until an appropriate basis for allocating costs is available. However, the Authority notes that a number of dispensations have been granted without such criteria in other situations where:

- the cost of full compliance would be excessive and
- it has not yet been practical to identify costs imposed on others because of the non-compliance.

Possible implications for dispatch, security and ancillary services

Feedback

3.2.21 Genesis Energy and Contact Energy expressed concerns that the proposed Code amendment could have adverse implications for some or all of dispatch, security, reliability and reserves. For instance:

> *'... compliance with the proposed changes is likely to create adverse impacts to the dispatch objective, and overall system reliability because the proposal does not take account of the technical incapability of significant generation capacity to meet the new requirements, nor the offer decisions that it is likely to incentivise.'* (Genesis Energy)
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> *'The proposed change imposes a uniform approach that can only be met by some hydro generators. Some non-hydro plants could apply settings to meet the proposed changes. But doing so will decrease plant reliability, which will in turn raise potential security of supply risks for the market.'* (Genesis Energy)
>
> *'The consultation paper fails to consider any potential impacts of the proposal on reserve and dispatch compliance. Energy, reserve and frequency dispatch are interrelated and integral to supporting the PPOs [Principal Performance Obligations], and to achieving the dispatch objective. A change in one element should automatically trigger a review as to whether other products may be detrimentally affected. Those changes should also be considered as part of cost benefit analysis.'* (Genesis Energy)
>
> *'While the provision of unrestricted FGC* [free governor control] *from hydro generation is likely to be feasible in the majority of cases (for existing hydro plant), unrestricted FGC from geothermal or CCGT generation could increase the risk of plant tripping, affecting security and reliability of supply... Older thermal plant in particular may not be able to respond without significant consequences for reliability and maintenance costs. The cumulative impacts of this requirement will also accelerate major plant maintenance costs.'* (Contact Energy)
>
> *'The proposal will have an adverse effect on generator asset owners when complying with a MW dispatch instruction. In the past there have been queries from the [system operator] as to why fast acting plant is off dispatch. The mismatch between actual and the dispatched amount was due to fluctuations in system frequency and therefore reducing the dead band, increasing gains, and reducing droop settings will only aggravate this issue. The* [system operator] *will need to account for this when monitoring and enforcing compliance.'* (Contact Energy)

Authority response

3.2.22 The Authority has considered the concerns expressed by Genesis and Contact, and has referred these to the system operator for its views.

3.2.23 The Authority would be concerned if the proposal were to increase the risk of some generators tripping as a consequence of trying to respond to normal frequency variations. Assessing such risks requires detailed engineering knowledge of individual plant. However, the Authority notes that relatively small governor dead-bands are required in other jurisdictions, where frequency variations tend to be smaller and less volatile than in New Zealand, frequency excursions outside permitted dead-bands occur regularly.

3.2.24 The Authority acknowledges that the speed of normal frequency changes is relatively fast in New Zealand, given the small size of the power system (and more so if generator governors are unresponsive to normal frequency variations). However, if there were a genuine risk of a particular generator tripping due to the speed of normal frequency changes in New Zealand, the Authority notes the proposal that "*droop be set as low as practical and proportional and integral gains be set as high as practical*" would come into play (subject to possible drafting refinements).

3.2.25 In relation to the possibility of the proposal affecting dispatch compliance, the Authority notes that the governors of some generating units currently have small dead-bands and are responsive to normal frequency variations. The system operator has indicated that it considers the level of effort in monitoring compliance of these generators with dispatch instructions is similar to that involved in monitoring other generators.

3.2.26 Further, the Authority notes that dispatch compliance under clause 13.82 of the Code already takes into account the obligation for generators to make the maximum possible contribution to maintain frequency in the normal band required under clause 8.17. In effect, dispatch compliance is measured at a reference frequency of 50 Hz.

3.2.27 In relation to potential interactions between the dispatch objective, reserves, and frequency keeping arrangements, the Authority considers this warrants some further exploration. In light of the above discussion and given the ability to seek dispensations where the cost of full compliance would be excessive, the Authority considers it unlikely that the proposal would affect offer incentives and the dispatch objective.

3.2.28 The Authority acknowledges that operating with a small dead band could affect the amount of spinning reserves some generating units would be able to offer. However, if that were to occur, it would not affect the system operator's ability to meet its PPOs. In fact, if generation did not respond at all until the frequency fell below 49.8 Hz, the starting frequency assumptions in the system operator's reserve management tool would need to be made more conservative - to take account of a wider distribution of frequency in the normal band.

Refining the cost-benefit assessment

The proposal

3.2.29 The consultation paper set out the Authority's initial high-level (and largely qualitative) cost-benefit assessment and set out its preliminary view that the benefits identified are likely to significantly exceed the costs. However, it invited affected stakeholders to make submissions on the costs, including providing quantitative estimates, of the proposed Code amendment as part of the consultation process. The Authority acknowledged it might be appropriate to revisit the assessment of the costs and benefits of the proposed Code amendment after it considered submissions.

Feedback

3.2.30 Submitters have responded to the Authority's invitation for affected stakeholders to make submissions on possible costs of the proposed Code amendment. Responses include categories of costs to be included, quantitative estimates of some key costs (e.g. compliance and implementation costs), and concerns with the cost-benefit assessment generally.

Authority response

3.2.31 The Authority is considering the information provided, and intends including this as an agenda item for the workshop. The information will also be helpful in deciding the appropriate next steps for this initiative.

3.2.32 The Authority notes, however, that some of the costs estimated in submissions are unlikely to be incurred because generators are able to seek dispensations to avoid unreasonably high compliance costs. The Authority considers dispensation and cost allocation issues in the next section.

3.3 Regulatory uncertainty around aspects of the dispensation process

Dispensation criteria and cost allocation issues

Proposal

3.3.1 The dispensation provisions in the Code provide a mechanism for generators to avoid unreasonably high compliance costs, provided the system operator can meet its PPOs despite the non-compliance. The system operator is responsible for considering dispensation applications.

3.3.2 The Authority acknowledged that, if the proposed Code amendment proceeded, certain aspects of the dispensation regime could give rise to some adverse outcomes when applied to a mass (re-)application for dispensations from generators' normal frequency AOPOs.

3.3.3 The Authority considered establishing a modest cost allocation signal and including this in the Code amendment proposal or in published dispensation cost allocation guidelines for the system operator. This could provide clarity and certainty for generators and the system operator. However, the Authority:

(a) was concerned that including an administrative cost allocation in the Code amendment would increase implementation costs and complexity, and may lead to unintended outcomes[5]

(b) considered it more appropriate to look at generator dispensation cost allocation as part of a wider review of the manner in which frequency keeping costs are recovered following implementation of a national frequency keeping market

(c) noted that generators holding dispensations are aware that they may be subject to a cost allocation in the future, as this is a standard condition the system operator imposes whenever it grants a dispensation without an associated cost allocation.[6]

3.3.4 On balance, however, the Authority believed that it would be better to maintain a watching brief on dispensation outcomes, and only take further action (such as developing cost allocation guidelines in advance of the proposed cost allocation review) if the nature and extent of the dispensations showed that there was a need for such intervention.

Feedback

3.3.5 Transpower supported the Authority's proposal to maintain a watching brief, submitting:

> *'We think that the 'watching brief' proposed by the Authority to monitor the extent to which generators apply for dispensations is appropriate at this stage. A 'watching brief' will help reveal dispensation trends and help the Authority to assess whether further intervention, for example cost allocation, is appropriate.'* (Transpower)

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5 For instance, a generator might not be able to comply with the maximum droop setting but be able to contribute significantly through its gain settings beyond the minimum Code requirement. However, there may be no incentive for the generator to do so if it incurs penalties for its droop non-compliance.

6 In such circumstances, the dispensation stipulates that a cost allocation may be imposed in the future if circumstances change or new information becomes available.

3.3.6 Several submitters, however, expressed concerns about the uncertainty of possible dispensation cost allocation in the future. Some submitters were also concerned that the absence of a cost allocation now may incentivise more generators to seek dispensations, and therefore reduce generator contributions to maintenance of normal frequency. For instance:

'Our view is that if the asset is unable to comply, then in order for the asset owner to make an informed decision to apply for a dispensation for the lifetime of the plant, they would need to know these costs in advance. An indication of what these costs would look like would be very useful and in our view is an important input into the CBA. These additional operating costs would be reflected in the marginal price through offers.' (Contact Energy)

'Meridian recommends the Authority delay the introduction of a maximum allowable dead band until such a time as it is ready to propose an accompanying compensation regime. This will ensure that generators have appropriate information to make the trade off between complying with a dead band obligation and seeking a dispensation.' (Meridian Energy)

'... Our main concern is that some generators may choose not to comply as there are no on-going costs associated with applying for dispensations. The proposed framework does not provide incentive to meet compliance (provide responsive governors or machines) and at the same time does not penalise non-compliance. This could result in a surge of dispensations which would hinder the potential benefits outlined in the consultation paper. (Mighty River Power)

'Nova understands that dispensations will be available, but there is still no guarantee that these will provide sufficient concessions to reduce the overall costs on generation to less than the market benefits expected from the new settings. ... [Nova] suggests that the System Operator be asked to consider pro-forma applications for dispensation, based on the proposed limits, before the Code is amended. In this way the costs might be better recognised and taken into account before the new limits are locked-in.' (Nova Energy)

3.3.7 Contact Energy, also proposed a grand-fathering arrangement for existing non-compliant plant:

'When introducing new technical requirements we think that it is unreasonable to assume that the AO [asset owner] *has a choice to comply or to dispensate [sic], as these requirements were not specified at the time of build. This may be more reasonable for new connections as these can be specified in advance. We would suggest a grandfathering clause for existing plant which would exonerate that plant from complying and requiring a dispensation.'* (Contact Energy)

Authority response

3.3.8 Specifying technical performance obligations is a common feature of grid operating codes around the world, as it is a lower cost means of procuring such capabilities than through ancillary services markets. This is the purpose of the AOPOs and associated Technical Codes in the New Zealand Code. Importantly, the equivalence and dispensation provisions in the Code provide alternatives to full compliance where the cost is excessive or there is an opportunity for innovation in the means of achieving compliance.

3.3.9 Mandating common technical requirements and allowing asset owners to trade-off the cost of full compliance with the cost of alternatives ensures a 'level playing field' when asset owners make investment and operational decisions while avoiding excessive compliance costs. This is particularly important where the nature of certain types of generation technology (e.g. wind generation) make it impractical to comply with some obligations.

3.3.10 Ideally, in seeking a dispensation, a generator would be able to trade-off the costs it would incur in complying with the AOPO against the incremental costs imposed on others if the dispensation were to be granted. However, it is impractical at present to determine such incremental costs, for example because frequency keeping quantities are largely fixed. The Authority still considers that this is best addressed in the planned frequency keeping cost allocation review, as other frequency related developments progress, and that it should maintain a watching brief on dispensations in the meantime.

3.3.11 However, the Authority is open to considering the possibility of interim measures, such as an administered cost allocation and/or establishing criteria for dispensations (for example, technology-based criteria). Any such measures would be developed with significant input from the system operator and in consultation with affected parties. The form for such measures could range from (voluntary) guidelines through to specific provisions in the Code.

3.3.12 The Authority proposes that discussion of possible interim measures be a key agenda item for the intended industry workshop.

3.3.13 In relation to the suggestion of a grand-fathering clause in the Code for existing non-compliant plant, the Authority notes the following:

(a) The existing Code does not contain grandfathering clauses for AOPOs or technical code requirements other than for 220 kV protection systems.

(b) Grandfathering mechanisms were considered during the original common quality development process as a means of addressing non-compliance for existing plant in the transition to the new common quality arrangements. Grandfathering was eventually rejected in favour of a transitional dispensation regime.[7]

3.3.14 The Authority considers that a blanket grandfathering arrangement for existing non-compliant plant does not provide the appropriate incentives for generators in relation to operation and maintenance of their assets, and that it is likely to lead to inefficient outcomes. The Authority remains of the view that the existing dispensation process provides an appropriate mechanism for considering non-compliance issues. However, it notes that the possibility of providing a longer time frame to bring non-compliant assets into compliance or to obtain a dispensation (refer section 3.4 below) would be similar in effect to granting transitional dispensations.

Code provisions for considering dispensation applications

Proposal

3.3.15 The Authority did not propose any amendments to the existing generic dispensation provisions in the Code.

Authority response

3.3.16 Submitters' concerns with the regulatory uncertainty surrounding the dispensation process have prompted a closer examination of the existing drafting of these generic dispensation provisions. The Authority notes that there is some ambiguity regarding the drafting of two clauses, in particular clauses 8.29 and 8.31. These are considered in turn below.

3.3.17 As input to its consideration, the Authority has engaged further with the system operator to gain a better understanding of its interpretation and application of the existing provisions. The Authority has also reviewed original industry working group papers dating back to the time that the dispensation regime was first designed in the Grid Security Committee (GSC) forum.[8]

Clause 8.29 – Right to apply for approval of equivalence arrangement or grant of dispensation

3.3.18 Clause 8.29 enables an asset owner to apply to the system operator for an equivalence arrangement to be approved or a dispensation to be granted, if the asset owner "cannot comply" with an AOPO or a technical code obligation. The meaning of the words "cannot comply" are roughly equivalent to "unable to comply", or "incapable of complying".

7 Transitional dispensations expired after a fixed period. Asset owners either then applied for a 'normal' dispensation (or equivalence arrangement) or brought the asset into compliance.

8 The GSC was an industry body appointed to oversee development of the Multilateral Agreement on Common Quality Standards (MACQS) that was the forerunner to the existing common quality provisions in the Code.

3.3.19 However, conceptually this will rarely be the case for an asset owner. It will almost always be possible for the asset owner to comply. The motivation behind applying for an equivalence arrangement or dispensation will usually be that the costs associated with complying are prohibitive or unreasonable, or that the changes that would have to be made to systems and equipment would be so extensive as to mean that it is not feasible or not practical to comply.

3.3.20 In light of this, the most credible interpretation is to regard the equivalence arrangement and dispensation approval clauses in the Code as being designed to enable asset owners to operate in a compliant way in such circumstances. Accordingly, read the words “cannot comply” in clause 8.29 may, depending on the circumstances, as meaning that it would be unreasonably expensive for the asset owner to comply, or that it is not feasible or not practical for the asset owner to comply.

3.3.21 Whether this is in fact the case for a particular asset owner is a matter of judgment. The Authority believes that the Code leaves that judgment to the system operator to make, and considers that this is appropriate.

Clause 8.31 – Grant of dispensations

3.3.22 The header text in clause 8.31(1) specifies the circumstances in which the system operator must grant a dispensation to an asset owner who has or will have assets or a configuration of assets that do not comply with an AOPO or a technical code. Those circumstances are that the system operator:

(a) has a reasonable expectation that it can continue to operate the existing system and meet its principal performance obligations despite the non-compliance of the assets; and

(b) the system operator can readily quantify the costs on other persons of the dispensation.

3.3.23 If these conditions are not met, for example because the system operator is not able to readily quantify the costs on other persons of the dispensation, the system operator may not have the ability under the Code to grant the dispensation.

3.3.24 In addition, clause 8.31(1) specifies the only circumstances in which the system operator is able to grant a dispensation. The clause sets out what the system operator “must” do, but does not give the system operator any discretion to grant dispensations in other circumstances.

3.3.25 The Authority will consider clarifying clause 8.31, should this be required.

Processing normal frequency AOPO dispensation applications

Feedback

3.3.26 A number of submitters expressed concerns with aspects of the process for the anticipated number of dispensation applications that would emerge if the Code amendment were to proceed. Concerns included:

(a) the costs associated with applicants preparing applications and the system operator considering the applications

(b) the availability of suitable resources for applicants and for the system operator, particularly resources required for testing plant and agreeing settings

(c) the timetable for dispensation applications.

Authority response

3.3.27 The Authority acknowledges the issues raised in submissions. The cost issues are considered alongside other aspects of the preliminary cost-benefit assessment (refer section beginning at para 3.2.29 above).

3.3.28 Issues related to resource availability and timing are considered in the following section on transition issues.

3.4 Transition issues and the relationship with relevant development initiatives

Approach and timing for possible transition

Proposal

3.4.1 The Authority acknowledged that, if the proposed Code amendment were to be adopted, generators would need a period of transition before any amended Code obligations came into force. Enough time would be needed for generators to assess their compliance with the amended obligations under the proposed Code amendment and to take any corrective action. This might include one of the following:

(a) no action, as the generating assets already comply with the amended Code obligations

(b) agree new settings with the system operator in order to comply with the amended Code obligations

(c) apply to the system operator for a dispensation from the amended Code obligations[9]

(d) apply to the system operator for approval of an equivalence arrangement as an alternative means of complying with the amended obligations.

3.4.2 The transition period would also involve significant system operator input, particularly if generators needed to agree new settings, or if the system operator needed to consider new dispensation applications.

3.4.3 The Authority proposed a transition period of eight months. It considered that this struck an appropriate balance between allowing a reasonable time for generators and the system operator to take the actions required, while not unreasonably delaying the benefits the Authority considers the Code amendment would deliver.

Feedback

3.4.4 Most generators responded to the Authority's invitation to comment on the proposed eight month transition period – all considered the proposed transition period to be substantially shorter than necessary given the nature of the amendments proposed and the implementation activities that would be required. For instance:

> *'The eight month transition period is not reasonable. If it is possible to make the required plant changes to become compliant then the lead time for achieving this may be in excess of two years. For minor changes and testing, it would be more sensible and efficient to do these during scheduled maintenance periods to avoid additional outages of generation thus reducing supply and imposing additional costs to purchasers. We would suggest a transition period of two to five years.'* (Contact Energy)
>
> *'If a maximum allowable dead band is introduced, Meridian will need to consider additional plant investment or proceed with seeking dispensations for a majority of our plant. We consider this process is likely to take at least 12 months (and will be further influenced by alignment with existing budget cycles).'* (Meridian Energy)
>
> *'This will depend on the assessment of our existing governors to see if they are capable of complying and what action(s) are required to make them compliant. The proposed 8 months may be unrealistic as work involved in carrying out testing, settings changes, and applying for*

[9] There are a number of dispensations already in place relating to generators' normal frequency obligations. As these relate to specific Code obligations, most, if not all, would no longer be valid if the proposed Code amendment came into force. The system operator advised the Authority that it is now a standard condition of dispensations that they lapse if the underlying Code obligation is amended. Earlier dispensations may not have this condition; however, there is provision in the Code for the system operator to revoke a dispensation.

dispensations (as required) will require a lot of resources (internal and external) that other Generators may also require the services of.... Mighty River Power proposes a transition period of 3 to 5 years or with the next round of Routine Testing. (Mighty River Power)

'Too short considering: Likely number of non-compliant generators; Availability of skilled resources (including OEM) capable of undertaking the governor commissioning tests required following required system enhancements; OEM lead-times where control system modifications are required; and System operator resource required to review and approve resulting changes, before and after implementation.' (Nova Energy)

'The proposed eight-month transition period is inadequate. This will not provide sufficient time to carry out necessary inspections, works and testing as required. Should the Authority decide to progress on this basis, Trustpower will not be able to comply. A minimum period of two years would be more appropriate.' (Trustpower)

3.4.5 Transpower, in its capacity as system operator, did not comment on the proposed transition duration, other than to estimate that (depending on the volume of dispensations received) two to three months of the proposed eight months would be needed to assess revised settings and process potential dispensation assessments.

Authority response

3.4.6 The Authority acknowledges the concerns expressed by generators in their submissions on the proposed transition period. It will defer a decision on an appropriate alternative until there is greater certainty about specifying the amended AOPOs and the extent of non-compliance.

3.4.7 The Authority intends engaging with affected parties on this matter as part of the intended industry workshop.

Implications of/for other frequency development initiatives

Proposal

3.4.8 As noted in the consultation paper, the Authority has been working with the system operator over recent years to enhance competition in the frequency keeping market and, more generally, to improve the efficiency of normal frequency management. In addition to this review of normal frequency AOPOs, key initiatives in the on-going programme of work include:

- national market for frequency keeping (current)
- multiple frequency keeping (complete in the North and South Islands)
- removal of in-band constrained on and off payments to frequency keepers (current)

- frequency keeping cost allocation review (future)
- normal frequency PPO review (future)

Feedback

3.4.9 Several submitters noted the link between the Code amendment proposal and other frequency development initiatives.

3.4.10 One submitter, Transpower, supported the Authority's rationale for progressing the Code amendment now:

> *'... we support the intent to assist all parties to have a consistent interpretation of asset owner performance obligations. Such consistency in interpretation is necessary to support broader Authority initiatives to reduce frequency keeping costs and maintain system security. The contribution that governor action plays in the frequency market is also key to the implementation of the National Frequency Keeping initiative. Clarifying the capabilities of generator governor response to frequency deviations will also assist the System Operator with its procurement and operational management of frequency keeping.'* (Transpower)

3.4.11 Other submitters consider that the link with other frequency development initiatives means that the Code amendment should not be progressed at this time. For instance:

> *'It is important to mention the Authority is currently conducting a number of other projects simultaneously to improve the efficiency of FK and reserve markets. Genesis Energy supports those initiatives to reduce the cost of FK and reserve market. There is no clear reason why the Authority should rush this proposal through. Our particular concern is that implementing this change concurrently with other proposed changes will mask the true costs and, more importantly, reduce the overall benefit of the improvements to FK market.'* (Genesis Energy)

> *'Genesis Energy strongly recommends the Authority focus on existing initiatives, such as implementation of the multiple frequency keeping and the national FK market, that have the potential to deliver actual benefit to the market, and to consumers.'* (Genesis Energy)

> *'Meridian considers Option 2 (deferring Code amendments pending other developments relating to normal frequency) is preferable to Option 1, as: it would provide time to collect information on the physical limitations and frequency keeping contribution of existing plant, allowing for a more informed assessment of the problem and a more informed solution; and it would provide for the concurrent development of a new frequency keeping obligation and an associated compensation regime, which would provide a much clearer framework for generators to trade off the costs of compliance with the costs of dispensations, resulting in*

better investment decisions.... Meridian considers the foregone benefits of deferring Code amendments will be low given the extent of dispensations expected to be sought.' (Meridian Energy)

'The Authority has initiated a number of changes to the frequency-keeping market, and there are still a number to come.... Appropriate time has not been provided to determine whether efficiency gains have been delivered from earlier changes.' (Trustpower)

'Trustpower believes some of the frequency control measures recently introduced, along with other initiatives in the pipeline (such as those discussed at the recent EEA Conference), should be given time to develop fully and bed-in prior to implementing the changes proposed... We wonder whether a wider holistic review of frequency keeping is necessary. Assessing the impact of the changing dynamics of the electricity grid looking forward and addressing these issues, rather than the piecemeal approach adopted in this consultation, may be more appropriate.' (Trustpower)

Authority response

3.4.12 The Authority acknowledged the linkages between the normal frequency AOPO and a number of other initiatives. These linkages are one of the drivers for progressing the Code amendment, rather than a reason for delaying until other initiatives relating to normal frequency are completed.[10] The Authority expressed the view that the lack of clarity and information regarding normal frequency AOPOs could reduce the anticipated benefits of the Authority's frequency keeping development initiatives, particularly those related to competition in the frequency keeping market.

3.4.13 Some submitters described the proposal as being rushed and developed in parallel with other initiatives, and said that time should be allowed to assess outcomes of the other initiatives. In practice, the initiatives are coupled to the extent that it would be inefficient to progress each in an independent timeframe. Two key initiatives are supported by prerequisite enablers as set out in the table below.

[10] Delaying the Code amendment pending other developments was an alternative explicitly considered in the Authority's consultation paper (Option 2 in section 5.3 of that paper).

Key Initiative	Enabler Initiative
National market for frequency keeping	Multiple frequency keeping
	Normal Frequency AOPOs
	Removal of in-band constrained on/off payments to frequency keepers
Frequency keeping cost allocation review	National market for frequency keeping
	Normal frequency principal performance obligations review

3.5 Consultation process

Engagement on Code amendment

Feedback

3.5.1 Several submitters expressed concerns with the Authority's approach to consultation in the lead up to publishing the Code amendment proposal. For instance:

> *'... it would be useful if proposals such as this could be consulted on through workshops as were the AUFLS changes.'* (Contact Energy)

> *'The process of this consultation was not well managed... Given the cost significance and impacts of wide generations, we would expect a better industry engagement prior to this consultation. There was little mention by the Authority on this matter since 2010.'* (Genesis Energy)

> *'Generally speaking, Trustpower is not supportive of the proposed changes outlined in the Consultation Paper and believes little, if any, industry consultation or analysis of costs has been undertaken to support the proposed changes.'* (Trustpower)

Authority response

3.5.2 The consultation itself is the opportunity to engage with participants. While the Authority acknowledges the concerns expressed by some submitters, the scope of the proposal is more confined than that of other much larger initiatives such as the extended reserves AUFLS changes. The intent of the proposal is to clarify the existing asset owner performance obligations, rather than creating entirely new obligations.

3.5.3 However, the proposal has raised significant concerns by submitters. These are one of the drivers behind the Authority deciding it should engage further with affected parties before deciding the next steps. An industry workshop is a key element of this.

4. New information from system operator development initiatives is relevant

4.1 System operator has been progressing MFK and FKC

4.1.1 Now that MFK is available in both islands, the system operator has been able to test FKC on the HVDC link. FKC provides strong coupling between the island systems and allows a common frequency to be controlled in both islands.

4.1.2 FKC has the effect of increasing both the load diversity and inertia sharing between islands. The system operator is able to regulate the common frequency with a significantly smaller national band of frequency keeping than the current 75 MW band (50 MW in the North Island and 25 MW in the South Island).

4.1.3 Following initial testing, the system operator has started a period of trial operation, as from 16 October 2014, with a national frequency keeping band of 30 MW (20 MW in the North Island and 10 MW in the South Island).

4.2 System testing results have implications for normal frequency AOPOs

4.2.1 The system operator has observed that with the operation of MFK and FKC, generators with responsive governors appear to be more active in responding to frequency deviations. Not all tests were conclusive but some showed an increase in HVDC and generator off-dispatch. The effect of increasing off-dispatch is that plant is moved away from its most efficient dispatch point for more of the time.

4.2.2 The system operator will collect and analyse additional data during the period of the trial to assess the impact of FKC on off-dispatch. Initial indications are that the off-dispatch of the HVDC and certain responsive plant is accentuated by the different interpretations of the normal frequency AOPOs.

5. Alternative approaches to the AOPOs

5.1.1 The generator AOPOs require generating units larger than 30 MW to be fitted with speed governors with specific performance capabilities. The purpose of these AOPOs is to ensure that the system operator can:

(a) maintain and operate a stable interconnected power system

(b) meet an acceptable standard of quality for frequency.

5.1.2 The Code mandated a number of auxiliary services (including the requirement for generators to have speed governors). At the time the Code (and its predecessors) was drafted, market based approaches for delivering these services were not considered to be practical or economic.

5.1.3 MFK and FKC appear to be causing responsive governors to be more actively engaged in regulating frequency deviations. If this effect continues, frequency keeping duty will permanently shift away from the MFK market towards mandated governor response.

5.1.4 In view of this evolving situation, and issues raised with the current AOPO approach by asset owners, the Authority considers it should widen the scope of the AOPO review. A mandated approach may not be the most efficient way to acquire any additional governor response potentially required by the system operator to meet its objectives.

5.1.5 A wider review would consider alternative market-based approaches designed to signal the true cost of maintaining frequency stability and quality. Such approaches may include:

(a) A simple assessed cost allocation or payment for services provided below or above a mandated level of performance.

(b) Providers paid in proportion to the level of performance provided and there would be no mandated level of performance.

(c) Recovery of MFK payments based on an exacerbator pays methodology. Under this methodology, the response of generators and loads to frequency deviations would be monitored and used to determine causer pays amounts. Both generators and loads that operate in a way that helps to correct frequency deviations would receive a low cost allocation while those that cause frequency deviations would receive a higher cost allocation[11].

5.1.6 A wider review is likely to include work to develop a more definitive frequency quality standard. The current standard is based on the simple objective of maintaining frequency in the normal band. A more prescriptive

[11] This is similar to a regulating reserve cost allocation approach used in the National Electricity Market in Australia.

approach would specify how much of the time frequency must remain in the normal band.

5.1.7 A standard of this type would allow the system operator to more accurately determine the optimal mix of FKC, governor response, MFK and re-dispatch required to meet its objective to maintain a defined frequency quality standard.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
AOPOs	asset owner performance obligations set out in Part 8 of the Code
Authority	Electricity Authority, the regulatory body established under the Act
Code	Electricity Industry Participation Code 2010
dead band	a frequency range within which a generator's speed governor will not respond to frequency movements
droop	a mechanism which changes the apparent output set point of a generator as a proportional response to frequency changes
FKC	the frequency keeping modulation control function on the HVDC bipole control system
frequency keeping	an ancillary service the system operator contracts for to assist in managing frequency inside the normal band
governor	a device used to measure and regulate the speed of a machine
integral gain	in a closed-loop feedback control system, the constant (Ki) applied as a multiplier to the integral of instantaneous error with respect to time, to adjust output.
Hertz or Hz	Hertz, the unit of measure for frequency
IR	instantaneous reserve, an ancillary service the system operator contracts for to assist in managing frequency disturbances outside the normal band
normal band	the frequency band between 49.8 Hz and 50.2 Hz (also referred to as normal frequency)
normal frequency asset owner performance obligations	specific AOPOs that only apply to generators that contribute to the maintenance of frequency within the normal band, set out in clause 5 of Technical Code A of Schedule 8.3
off-dispatch	a shift from nominal dispatch as a result of governor droop response

proportional gain	in a closed-loop feedback control system, the constant (K_p) applied as a multiplier to the instantaneous error to adjust output.
PPOs	principal performance obligations, the system operator obligations in Clause 7.2 of the Code
Spinning reserve	extra generating capacity that is synchronised but not dispatched.
system operator	the person who ensures the real-time co-ordination of the electricity system

Appendix A Tabular summary of submissions received

Summary of submissions

This appendix provides a tabular summary of matters raised in submissions. The submissions are available in full from the Authority's website.[1] Submissions were received from the following parties:

Generators	Direct consumers	Distributors	Other
Contact Energy Genesis Energy Meridian Energy Mighty River Power Nova Energy Trustpower	none	none	Transpower (as grid owner and system operator) Sam Viskovic (independent)

Some submitters have set out their views a cover letter in addition to (or instead of) providing answers to the consultation questions. In some instances this duplicates or summarises their responses to the consultation questions. In other instances the cover letter raises additional matters for the Authority to consider.

The consultation paper incorrectly listed seven questions in Appendix B (format for submissions) and eight questions in the body of the paper. Some submitters responded to one set of questions and some to the other. As a result, some submitters have not answered the extra question (question 1 in the body of the paper[2]).

Some submitters have provided confidential material that the Authority has considered in formulating its response, but this material has been withheld from publication.

The Authority has adopted the following approach when compiling this tabular summary of submissions:

- the first table in this summary of submissions is based on the eight questions as numbered in the body of the consultation paper
- material from a submitter's cover letter that is closely related to a particular consultation question has been included alongside their response to that consultation question
- for those submitters who responded to the shorter set of questions and did therefore not answer the missing question, the Authority has, where reasonable to do so, pointed to other aspects of the submission that would appear to be relevant to the missing question
- the second table in this summary of submissions is based on material from submitters' cover letters that does not necessarily relate closely to a consultation question
- confidential material has been excluded from this summary of submissions.

[1] http://www.ea.govt.nz/development/work-programme/wholesale/normal-frequency-generator-asset-owner-performance-obligations/consultations/#c12809

[2] The additional question asked "Do you agree that the problems identified with the current generator AOPOs are creating inefficiencies?"

Table 1 – Submitter Responses to Questions in the Consultation Paper

Submitter	**Comments**
Q1:	**Do you agree that the problems identified with the current generator AOPOs are creating inefficiencies?**
Contact Energy	*[Contact did not provide a specific response to this question]* *[from Contact's response to Q7]* There are no efficiencies to be gained from removing ambiguity in generator obligations. Obligations are largely known at present and if not, are clarified with the SO on a case by case basis. *[from Contact's cover letter]* Section 2.3.2 mentions a regulatory cost due to uncertainty in generator investment. Our view is that at present there are minimal issues with clarity on technical compliance. Requirements are clearly known and when new equipment is specified or if there is any uncertainty, the SO is consulted with. This cost is insignificant and it is speculative to say generator compliance costs will be reduced as the cost to comply with the proposal would outweigh this significantly. This section also mentions that the SO would benefit by having more clarity on asset owner information in order to better assess system security. We believe that this is not a reason to change the Code and the most efficient way to achieve this would be through a change to the asset capability statement (ACS). If the SO are unsure what the gain settings, droop, or dead band are, then additional fields can be added to request that information. Contact believes that the assumptions and inputs into the cost benefit analysis are incorrect and would need to be revised to include the flow on costs to purchasers. As it stands asset owner costs that significantly affect the outcome of the CBA have not been considered, while the stated benefits, which we believe are questionable, could be achieved through more efficient means.
Genesis Energy	*[Genesis did not provide a specific response to this question]*
Meridian Energy	Meridian agrees the requirement to "maintain" frequency within the normal band could result in differing interpretations of this requirement. However, we consider there is a lack of information with respect to how generators are currently complying with this Code obligation and what physical plant limitations may exist. As such, we do not consider it is possible at this point to say conclusively that the current AOPOs are creating inefficiencies.
Mighty	Yes. The current wording of the AOPOs does allow for generators to contribute less to frequency correction in the normal band (49.8 – 50.2

Submitter	Comments
River Power	Hz) without penalty by deliberately reducing governor sensitivity (by introducing dead bands).
Nova Energy	No. While there is some ambiguity with the current wording in the Code, the potential existing inefficiencies would appear over-stated as: • The System Operator currently obtains relevant information (e.g. applicable dead-band) via mandatory ACS submission/updates; • The System Operator currently reviews and agrees governor settings with the asset owner whenever relevant changes are made (to governor or ACS); • The proposal would allow a generator to apply for a dispensation negating to a certain extent creating the desired 'level playing field' for all generators, though it is noted that future costs may be imposed on dispensation holders. (Nova supports the dispensation approach where a generator has valid reasons for not complying with the relevant frequency-related AOPO). Further, the System Operator / Authority appear to have taken an overly theoretical, high-level review of issues without consideration of some of the wider potential practical or physical considerations. E.g. Assuming 2,000 MW of compliant generation connected to system with conservative (slow response) collective droop of 7% produces collective 60 MW response to 0.1 Hz system frequency deviation from load change. What will be the collective system response and will it meet desired objective? Or would there be momentary over-correction in system frequency triggering possible generation hunting and exacerbating system frequency fluctuation? The analysis from the TASC-011 has been based on two specific governor models, modelled in apparent isolation to the grid. Rather than undertake robust system-wide studies (where demand dynamics also come into play, requiring an accurate system load model) to assess the complete system impacts, TASC-011 and the Authority propose to implement the Code changes (at considerable implementation cost) and then monitor system frequency deviation distribution to determine whether changes have been effective and/or efficient. Further robust analysis should be undertaken to assess complete collective system-wide impacts and cost-benefits prior to implementation of the proposal.
Transpower	Yes. Generator governor response is required to help manage frequency and without this contribution demands on the frequency keeper are increased. Logically the situation will deteriorate if new generators do not provide governor response to return frequency to 50 Hz and existing generators either seek dispensations from this requirement or do not respond. *[from Transpower's covering letter]* Support clarity for asset owner performance obligations We support the intention of the Code change proposal which reflects the recommendations of a review of normal frequency keeping made

Submitter	Comments
	under the Technical Advisor Service Contract (TASC). In particular, we support the intent to assist all parties to have a consistent interpretation of asset owner performance obligations. Such consistency in interpretation is necessary to support broader Authority initiatives to reduce frequency keeping costs and maintain system security. The contribution that governor action plays in the frequency market is also key to the implementation of the National Frequency Keeping initiative. Clarifying the capabilities of generator governor response to frequency deviations will also assist the System Operator with its procurement and operational management of frequency keeping.
Trustpower	The code is failing to address the fundamental problem that not all types of plant are capable or suited to the provision of frequency support demanded by the Code. The proposals fail to recognise that there will be some ~770MW of base load geothermal plant unlikely to be able to provide frequency support in the manner required by the Code, and increasing quantities of solar/PV will further exacerbate the situation. Asset owners with certain plant types cannot, and will not, provide frequency support and will apply for dispensations. Other owners may choose not to comply with requirements, saving wear and tear on their plant. This will demand a larger proportion of frequency response is placed on a smaller number of asset owners, without appropriate reward. Perhaps the key element should be focusing on alternative mechanisms and incentivising market participants to provide cost-effective solutions.
Viskovic	The market imposed over a natural monopoly is causing inefficiencies with Asset Owners incentivised to game any regulatory environment.

Q2:	**Do you have any comments relating to the drafting of the proposed Code amendment? Please provide comments and suggested drafting improvements with reference to specific parts, schedules and clauses of the draft proposed Code amendment set out in Appendix A.**		
Contact Energy	**Reference**	**Submitter's Comment**	**Alternative Drafting**
	Schedule 8.3 (c)(iv)	Contact is of the view that requiring units to operate with governor gains that are set "as high as practical" is not sensible. For example, in the context of hydro-units it is usual to select governor gain parameters such that the frequency/speed control loops have sufficient gain/phase margin. This is often achieved via Nyquist testing (only applicable to hydro-units).	is tuned to provide swift response to frequency changes; and does not adversely affect the plant

<table>
<tr><td></td><td></td><td>Furthermore, the identification of the actual proportional and integral gain parameters/values in a modern digital governor (particularly of thermal units) is difficult. And in some cases governor vendors take the view that the governor code is proprietary.</td><td></td></tr>
<tr><td></td><td>Part I, Preliminary provisions 1.1</td><td>Contact is of the view that the proposed definition of droop remains ambiguous, as it does not indicate whether the droop value is inclusive/exclusive of a frequency dead-band.</td><td>Droop means the ratio of the steady-state change in frequency, expressed as a percentage of 50Hz (from the edge of a frequency dead-band), to the steady-state change in the power output of a generating unit, expressed as a percentage of the generating unit's rated gross output (MCR)</td></tr>
<tr><td></td><td>Schedule 8.3 (d)</td><td>The new clause requires generators to obtain approval of actual governor settings, in the form of proportional/integral gain and droop. Given the complexity of modern governors the discovery of these settings is often difficult and it is usual for generators/ vendor's to supply simplified power system models. Contact is of the view that the original clause (d) of The Code is more practical than the proposed change.</td><td>None. Retain the current code.</td></tr>
<tr><td></td><td>Schedule 8.3.5 (1)(b)(iii)</td><td>none</td><td>none</td></tr>
<tr><td></td><td colspan="3">[from Contact's cover letter]

Previous submissions on the change to dead band requirements

In Contact's previous submission on the Electricity Commission's consultation paper 'Normal Frequency - Generator Asset Owner Performance Obligations - Frequency keeping Cost Allocation 2010' Contact made its views clear on unrestricted free governor control (FGC); essentially a reduction in dead band. Our comments were:
While the provision of unrestricted FGC from hydro generation is likely to be feasible in the majority of cases (for existing hydro plant), unrestricted FGC from geothermal or CCGT generation could increase the risk of plant tripping, affecting security and reliability of supply.
Older thermal plant in particular may not be able to respond without significant consequences for reliability and maintenance costs. The cumulative impacts of this requirement will also accelerate major plant maintenance costs.
Where geothermal and thermal plants are operating at maximum levels there is limited scope for FGC and is limited to only one direction (i.e. would only back off when load reduces).</td></tr>
</table>

	• It does not seem reasonable to impose additional obligations beyond what is already effectively provided for through the reasonable endeavours of the operators of those assets within the normal band for frequency. Contact's views on this matter, i.e. that we did not support the change, remain unchanged. In our view the statement made on page 17 of section 4.2 in this consultation that 'earlier submissions around dead band reduction where other views were expressed' is an understatement as four out of the five generator submissions at the time opposed this change. There are practical reasons as to why asset operators have existing settings in place and these are discussed further in this submission.
Genesis Energy	*[Genesis did not provide a specific response to this question]* *[from Genesis' letter]* Genesis Energy supports the Authority's initiatives to improve the efficiency and competitiveness of the frequency keeping (FK) market. However, we strongly oppose the proposed changes in this consultation paper because the cost, to the market and market participants, outweighs the possible benefits envisaged by the Authority.
Meridian Energy	The proposal to introduce a maximum allowable dead band of ±0.025 Hz is incompatible with a majority of Meridian's plant. Given the substantial degree of non-compliance which would result, and/or the significant cost implications, we do not consider the Authority's current proposal to be appropriate. Meridian recommends the Authority delay the introduction of a maximum allowable dead band until such a time as it is ready to propose an accompanying compensation regime. This will ensure that generators have appropriate information to make the trade off between complying with a dead band obligation and seeking a dispensation. It will also provide additional time for the Authority (and System Operator) to gather information on the physical limitations and frequency keeping contributions of existing plant, which will help inform what an appropriate dead band limit would be. If the Authority decides to progress with introducing a specific maximum allowable dead band into the Code at this point in time, the dead band needs to be more reflective of the capabilities of existing plant. Any maximum allowable dead band should only be applied to plant with a settable dead band. Plant with an inherent dead band, which cannot be altered without substantial cost, should be automatically exempt. *[from Meridian's cover letter]* The proposed changes to normal frequency Asset Owner Performance Obligations (AOPOs) will have significant cost implications for Meridian and/or result in widespread non-compliance by our generation plants. In particular, the proposal to introduce a maximum allowable dead band of ±0.025 Hz is incompatible with a majority of Meridian's plant. We expect other generators will be in a similar position. We therefore do not consider the Authority's current proposal to be appropriate. Meridian recommends the Authority delay the introduction of a maximum allowable dead band until such a time as it is ready to propose an accompanying compensation regime. *[from Meridian's cover letter]* Given the substantial degree of non-compliance which would result, and/or the significant cost implications, Meridian considers a maximum

	allowable dead band of ±0.025 Hz is not appropriate. Establishing a dead band limit that requires widespread dispensations would achieve little additional benefit in the frequency keeping contribution of existing plant while imposing significant administration costs on the industry. Furthermore, we question whether it is appropriate to use the AOPOs to minimise the quantity of frequency keeping support procured through market arrangements.		
Mighty River Power	Yes. See below.		
	Clause	**MRP Comment**	**MRP Alternative Drafting**
	8.17	Mighty River Power's understanding has been that this has always been the intent of the code.	
		Intent is agreed. However, the statement about making a contribution "to correct frequency" requires some additional criteria. Correct to what? 50Hz?	…contribution to correct frequency to nominal 50Hz while the …
	Schedule 8.3 Technical Code A - Assets 5 (1) c	What is the definition of "equivalent system"? Since all the requirements in this clause are relative to a speed governor, why is this required?	
	Schedule 8.3 Technical Code A - Assets 5 (1) c (i)	"provides stable performance" evidenced how? Is the suggested criterion in the Companion Guide for Testing of Assets a good minimum?	...provides stable performance with minimum gain margin of 3dB and minimum phase margin of 25°.
	Schedule 8.3 Technical Code A - Assets 5 (1) c (ii)	Is the proposed dead band range intended as a maximum input parameter for the governor only, or as the measured response of the entire unit? The method of measurement encompasses the entire unit? (i.e. System frequency vs. Servomotor movement).	
		Dead band (as measured across the entire unit) is expressed in percentage terms of nominal frequency, not above and below nominal frequency; so should be specified as one figure. e.g.	…has a dead band not greater than 0.05Hz or 0.1%.

		0.05Hz or 0.1% As an input parameter for the governor, it is often specified in terms of % above, and/or below nominal frequency.	
		If the proposed dead band range is intended to be a maximum as measured across the entire unit (i.e. inherent dead band plus selected value as set in governor), then we believe this requirement is too stringent for every generating unit to comply with.	
	Schedule 8.3 Technical Code A - Assets 5 (1) c (iii)	The term "droop" is not specific enough. Does it refer to Permanent Droop, which is an adjustable parameter on the hydro governor? Or, is it referring to Speed Regulation (also commonly called "Power Droop") which is not directly adjustable, but is proportionately less than the Permanent Droop setting. From elsewhere in the consultation paper (Page 18 of 39) it seems that what is being discussed is Power Droop, however on that page it commences discussion with describing "Permanent Droop". For consistent definitions, it is recommended that they should be drawn from IEEE or ASME industry standard documents (e.g. IEEE Std 125; ASME PTC 29).	
		Also, the statement "set as low as practical" raises a question about who decides what is practical, and for whose benefit. The limit of 7% implies that any setting between 0 and 7% is compliant.	
		There is some discussion in the paper (page 18 of 39, last paragraph) that implies if this (Permanent or Power Droop) setting is set low, the unit will be more responsive. Although, it has some effect on how far (the extent) a unit will change output to in the fullness of time, it has little to do with how responsively it will happen. This is much more dependent on the parameters that affect transient behaviour like the PID (Proportional, Integral, Derivative) gain settings; or Temporary Droop and Dashpot Time Constant on a mechanical governor.	

		Therefore, the wording should relate to whichever droop is selected. Permanent Droop will always be proportionally more than Speed Regulation. Therefore, if the proposed maximum 7% refers to Power Droop, the maximum Permanent Droop could - stay at 10%, as it was in previous versions of the EGRs or Code.	
	Schedule 8.3 Technical Code A - Assets 5 (1) c (iv)	Old mechanical governors could well have been only PI controllers, but modern digital electronic governors are at least PID, if not PIDD, controllers. Therefore, some mention of Derivative gain should be included along with the Proportional and Integral Gains. Taking into consideration the earlier requirement in 5 (1) c (i) about stable performance, there needs to be some qualification criteria around the statement "set as high as practical". Stable performance can range from just stable to very stable. So what is the acceptable minimum margin of stability (phase and gain)?	
	Schedule 8.3 Technical Code A - Assets 5 (1) c (v)	Having the freedom to add more dead band selectively in the controller (up to a maximum value) in addition to whatever inherent dead band there already is in the entire control (governor to wicket gates) will exacerbate non-linearities.	
	Schedule 8.3 Technical Code A - Assets 5 (1) d	To be able to run a unit under governor control and have it steady enough to synchronise to the system, requires that governor parameters are already adjusted to values that will give the unit adequate stability at speed-no-load. It is very likely that these (off-line) parameter settings will also give adequate stability when the unit is first synchronised and paralleled to the grid. However, subsequent stability (on load) testing will confirm whether the on-line settings can be relaxed a little to yield stable, but more responsive, behaviour. To cater for some of the older mechanical governor plant, there are more parameters that could be included in the list and "droop" should be more specifically defined.	…including, but not limited to Permanent Droop, Temporary Droop, Dashpot Time Constant, Proportional Gain, Integral Gain, Derivative Gain, etc., prior to:
	[from Mighty River Power's cover letter] Mighty River Power supports the Electricity Authority's view on the need to amend the frequency obligations and related technical code in the		

	EIPC. However, we do have a few concerns regarding the framework chosen to introduce the change and wording of the proposed code. We understand that there are some generators that cannot or may not be able to comply with the proposed changes. Our main concern is that some generators may choose not to comply as there are no on-going costs associated with applying for dispensations. The proposed framework does not provide incentive to meet compliance (provide responsive governors or machines) and at the same time does not penalise non-compliance. This could result in a surge of dispensations which would hinder the potential benefits outlined in the consultation paper.
Nova Energy	Schedule 8.3, 5(1)(c)(i): 0.025 Hz is too narrow. Setting to 0.1 Hz would provide benefits sought by Authority over existing arrangements while reducing implementation costs and risk. Schedule 8.3, 5(1)(c)(iii) and (iv):"as low as is practicable" and "as high as practicable" is still subjective wording. What are the assessment criteria to be applied by System Operator? *[from Nova's covering letter]* The Authority notes that there are significant benefits expected from the proposed code changes. What is not so clear is the potential cost to generators that may be incurred in complying with the new operating requirements. Adopting generator settings to operate to a dead-band of +/- 0.025 will have a significant cost to some forms of generation, in particular cogeneration plants that are required to maintain steam pressures for industrial processes. Fuel supplies and ambient air temperatures can also mean that open-cycle gas turbines will also require continuous adjustments to meet the tighter limits. Nova understands that dispensations will be available, but there is still no guarantee that these will provide sufficient concessions to reduce the overall costs on generation to less than the market benefits expected from the new settings. Nova expects that there is an optimal 'dead zone' range; i.e. a point where the benefits of a tighter limit are balanced against the costs to generation of operating to the tighter conditions, and the potential for collective generation hunting against load or frequency changes is minimised. Nevertheless, Nova suspects that the demand-side frequency deviations will always occur at a faster rate that generators can respond, so system frequency oscillations within the normal band will always be present and generation will just continually play catch-up. It is not clear that the Authority has given enough consideration to these details. Nova therefore suggests that the System Operator be asked to consider pro-forma applications for dispensation, based on the proposed limits, before the Code is amended. In this way the costs might be better recognised and taken into account before the new limits are locked-in.

<table>
<tr>
<td>Transpower</td>
<td>
Yes, see below.

1. Clause 8.17. We suggest that the expectations on the HVDC and generators are differentiated consistent with each asset’s operational practicalities.

<table>
<tr><td>8.17 for Generators</td><td>8.17 (a) for HVDC</td></tr>
<tr><td>Each generator (while synchronised) must at all times ensure that its assets, other than any generating units within an excluded generating station, make the maximum possible injection contribution to correct ~~maintain~~ frequency while the frequency is within the normal band (and, otherwise, to restore frequency to within the normal band). Any such contribution must be assessed against the technical codes.</td><td>The HVDC owner must at all times ensure that its assets make the maximum possible contribution to maintain frequency within the normal band (and, otherwise, to restore frequency to within the normal band). Any such contribution must be assessed against the technical codes.</td></tr>
</table>

2. The term “equivalent mechanism” in Schedule 8.3, Tech Code A, 5(1)(c) is confusing as it may be misinterpreted as meaning an equivalence arrangement.

[from Transpower’s cover letter]

We consider that further clarification is necessary to reflect the practicality of frequency maintenance expectations of the HVDC owner at clause 8.17. Under the current drafting the HVDC is compliant with the fast FSC (Frequency Stabiliser Control) modulation that acts to reverse an excursion of frequency on either island, and the slow SRS (Spinning Reserve Sharing) modulation that acts to return the frequency of both islands back to within the +/- 0.2 Hz band if possible.

The proposed wording in 8.17 is problematic for compliance because the HVDC does not create any energy to be able to “correct” both frequencies, and any action by the HVDC controls to “correct” one island frequency will adversely affect the other island frequency. We have suggested drafting (at question 2) that separates HVDC from generator requirements.

[from Transpower’s cover letter]

Support watching brief to monitor dispensation process

We think that the ‘watching brief’ proposed by the Authority to monitor the extent to which generators apply for dispensations is proportionate at this stage. A ‘watching brief’ will help reveal dispensation trends and help the Authority to assess whether further intervention, for example cost allocation, is appropriate.

One issue that we are mindful of is the possibility that generators who are currently code compliant (but may not be under the newly-clarified compliance obligations) may pursue a dispensation rather than taking steps to ensure continued compliance. A step change in dispensation
</td>
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	applications, depending on the extent of the issue, would have implications on frequency keeping costs, system security[3] and implementation of the National Frequency Keeping initiative[4]. It would also have implications for System Operator resourcing.
Trustpower	*[Trustpower did not provide a specific response to this question]* *[from Trustpower's cover letter]* Generally speaking, Trustpower is not supportive of the proposed changes outlined in the Consultation Paper and believes little, if any, industry consultation or analysis of costs has been undertaken to support the proposed changes. The ramifications of some of the proposed changes will have a far-reaching impact on some asset owners, while other owners may choose to hide behind dispensations and exempt themselves from the various obligations. Indeed, we believe there is a wider issue in terms of the increasing amounts of plant that are unsuitable for providing frequency support. The paper does not address this in any way. Trustpower believes some of the frequency control measures recently introduced, along with other initiatives in the pipeline (such as those discussed at the recent EEA Conference), should be given time to develop fully and bed-in prior to implementing the changes proposed. We wonder whether a wider holistic review of frequency keeping is necessary. Assessing the impact of the changing dynamics of the electricity grid looking forward and addressing these issues, rather than the piecemeal approach adopted in this consultation, may be more appropriate.
Viskovic	Schedule 8.3 (5) (1) (c) (ii) and (iii). Dead bands should be proposed based on monitored real measurements of response also ensuring governors are responding, identify the worst performing and not penalise the best. Dead bands and droop should be regulated based on the type of plant as preferentially using the most capable plants will minimise overall maintenance and energy wastage costs as well as being more effective. The limits of the system to adapt to new generation should be understood before it is connected.

Q3:	**What comments do you have on the Authority's proposal for an eight-month transition period?**
Contact Energy	We suggest a minimum of two years to align with maintenance outages and lead times for equipment. The eight month transition period is not reasonable. If it is possible to make the required plant changes to become compliant then the lead time for achieving this may be in excess of two years. For minor changes and testing, it would be more sensible and efficient to do these during scheduled maintenance periods to avoid additional outages of generation thus reducing supply and imposing additional costs to purchasers. We would suggest a transition period of two to five years. *[from Contact's cover letter]*

[3] An increase in dispensations means that there is less of the faster - responding governor action to support the frequency keeper, which in turn puts more reliance on the frequency keeper to maintain frequency inside the normal band.
[4] The National Frequency Keeping initiative is reliant on the behaviours sought in this technical clarification from generators across both islands. A consequence of generator governor response from a limited number of generators may move those generators and HVDC link off their set points which in turn will create a mismatch between the reserves scheduled to cover the HVDC and its actual set point.

	Dispensations and Transition Period Sections 4.4.2 and 4.4.7 refer to dispensation related costs or costs that may be imposed in the future. Our view is that if the asset is unable to comply, then in order for the asset owner to make an informed decision to apply for a dispensation for the lifetime of the plant, they would need to know these costs in advance. An indication of what these costs would look like would be very useful and in our view is an important input into the CBA. These additional operating costs would be reflected in the marginal price through offers. When introducing new technical requirements we think that it is unreasonable to assume that the AO has a choice to comply or to dispensate, as these requirements were not specified at the time of build. This may be more reasonable for new connections as these can be specified in advance. We would suggest a grandfathering clause for existing plant which would exonerate that plant from complying and requiring a dispensation.
Genesis Energy	*[Genesis did not provide a response to this question]*
Meridian Energy	If a maximum allowable dead band is introduced, Meridian will need to consider additional plant investment or proceed with seeking dispensations for a majority of our plant. We consider this process is likely to take at least 12 months (and will be further influenced by alignment with existing budget cycles). Given the currently proposed dead band will result in widespread dispensation applications, the Authority should also give consideration to the time required by the System Operator to process a large number of applications. We therefore consider an eight-month transition period to be too short. *[from Meridian's cover letter]* We understand the Authority sees the introduction of a maximum dead band as a first step, with a later phase being to introduce compensation arrangements for those generators holding dispensations. We understand the Authority may await the development and implementation of a national frequency keeping market (with an associated transition to marginal pricing for frequency keeping) before finalising any compensation arrangements. Meridian recommends the Authority delay the introduction of a maximum allowable dead band until such a time as it is ready to propose an accompanying compensation regime. This will ensure that generators have appropriate information to make the trade-off between complying with a dead band obligation and seeking a dispensation. It will also provide additional time for the Authority (and System Operator) to gather information on the physical limitations and frequency keeping contributions of existing plant, which will help inform what an appropriate dead band limit would be.
Mighty River Power	This will depend on the assessment of our existing governors to see if they are capable of complying and what action(s) are required to make them compliant. The proposed 8 months may be unrealistic as work involved in carrying out testing, settings changes, and applying for dispensations (as required) will require a lot of resources (internal and external) that other Generators may also require the services of. Mighty River Power proposes a transition period of 3 to 5 years or with the next round of Routine Testing.

Nova Energy	Too short considering: • Likely number of non-compliant generators. • Availability of skilled resources (including OEM) capable of undertaking the governor commissioning tests required following required system enhancements. • OEM lead-times where control system modifications are required. • System operator resource required to review and approve resulting changes, before and after implementation.
Transpower	Depending on the volume of dispensations received, the System Operator estimates that 2-3 months of the proposed eight months is needed to assess revised settings and process potential dispensation assessments. *[from Transpower's cover letter]* SO component of allocated timeframe The transition period allocated to this work in the proposal is a combined eight month period for both asset owners and the System Operator. The work over this period has to allow for asset owner settings' changes followed by System Operator assessment of compliance. Depending also on the volume of dispensations received, the System Operator estimates that 2-3 months is needed to assess revised settings and process potential dispensation assessments.
Trustpower	The proposed eight-month transition period is inadequate. This will not provide sufficient time to carry out necessary inspections, works and testing as required. Should the Authority decide to progress on this basis, Trustpower will not be able to comply. A minimum period of two years would be more appropriate.
Viskovic	*[Viskovic did not provide a specific response to this question]*

Q4:	**What costs do you anticipate that affected parties, particularly generators, may face in transitioning to the new regime if the proposed Code amendment were to proceed?**
Contact Energy	Contact estimates $764k for compliance testing. Transition costs are unknown at this stage (if applicable).
Genesis Energy	*[Genesis did not provide a specific response to this question]* *[from Genesis' letter]* **Cost of compliance is significant for most generators in New Zealand**

	The paper fails to account for the significant operational and technical costs to generators that will be imposed by compliance with the change. Very few generators are currently able to comply with the proposed performance obligations without significant changes to how they operate their assets. We understand that even some of the existing hydro generation in New Zealand will face unnecessary costs to alter their existing operation to comply. It is also harmful to the life of thermal plants, as we indicated in our submission in 2010. A copy of this submission is attached.[5] We also understand that wind and geothermal generation are unable to comply due the nature of their plant. Therefore, not only will the proposed change impose additional cost to energy production and therefore incentivise inefficient generation decisions, but it also may also be a wealth transfer exercise from one generator (those whose assets cannot meet the standard) to another (those who can).
Meridian Energy	As described in the cover letter: • forced compliance with a ±0.025 Hz dead band at Meridian's hydro assets is estimated to incur costs of **$6 million** (with compliance not guaranteed). • compliance with a ±0.025 Hz dead band at Meridian's West Wind and Te Uku wind farms would incur an additional half-life refurbishment cost of around **$30 million** and an annual energy loss of up to **13 GWh**. In the case that dispensations are agreed for all Meridian's plants, our primary cost will be associated with applying for dispensations (and any cost associated with a future compensation regime). *[from Meridian's cover letter]* None of Meridian's existing hydro stations (7 sites, 35 units) have a *settable* dead band in the control system. However, all hydro units have an *inherent* dead band as a result of mechanical backlash. The inherent dead band ranges from ±0.015 Hz to ±0.060 Hz. It cannot be altered without a complete governor/machine rebuild. *[from Meridian's cover letter]* At a dead band limit of ±0.025Hz, as proposed in the consultation paper, it is estimated that 70% of Meridian's hydro units would be unable to comply, and would need to request dispensations. Should such a dead band be made mandatory (without provision for dispensations), we estimate it would cost approximately $250,000 per unit to attempt to adjust the inherent dead band at each of our non-compliant units. This would equate to around **$6 million** in total. As we expect most other generators to have a similar level of non-compliant plant, it is likely a proportion of these costs would be recovered through the wholesale market. Further, undertaking such adjustments would have uncertain outcomes. As such, even following the imposition of these costs, it could not be guaranteed that Meridian's plant would comply with such a dead band limit. *[from Meridian's cover letter]* Wind plant impacts

5 Available from the Authority's website http://www.ea.govt.nz/dmsdocument/7939

	Of Meridian's existing wind farms, only West Wind and Te Uku have governors. Turbines at our Te Apiti and White Hill wind farms do not have governors and therefore are unable to provide frequency support. Due to the nature of New Zealand's wind resource, and the location of our turbines, the pitching systems in our generators are more active than is the case in most other countries. In effect, pitching controls currently operate at the limit of their designs. Enforcing tight governor dead bands at West Wind and Te Uku will result in increased pitching activity. This activity will be well beyond the limitations of the equipment. Operating Meridian's wind turbines in this manner will trigger maintenance activities not normally required within the life of a wind farm. This would be broadly equivalent to a half life refurbishment on a hydro or thermal plant. It would entail a major change to Meridian's current maintenance practices. Meridian expects the costs of this additional refurbishment at our existing sites with governor function could be around **$30 million**. Further, tight governor dead bands are expected to reduce generation from Meridian's wind farms by forcing turbines to operate away from maximising the wind resource. Meridian calculates annual lost energy as a result of a dead band limit of ±0.025Hz could be up to 13 GWh, or roughly 2% of production at West Wind and Te Uku. Meridian considers these impacts could be sufficient to discourage future wind farm developers from choosing to install governors at their wind farms. In a worst case situation, such a requirement may discourage investment in wind generation. These outcomes would clearly be counter to the Authority's objectives. This potential dynamic efficiency impact should be account for in the Authority's cost-benefit analysis.
Mighty River Power	1. Consultant fees for settings changes 2. Testing and modelling 3. Additional business Interruption 4. Dispensations (as required)
Nova Energy	Compliance testing and governor modification/upgrade particularly where OEM or specialist engineering resource required. Potentially in excess of $50,000 per generator where opportunity cost considered.
Transpower	No comment (we understand this question is primarily addressed to generators).
Trustpower	The consultation is lacking any detailed analysis on the cost implications to the proposed Code changes. Where testing is required to determine or adjust settings in line with new Code requirements, significant costs (both financial and manpower) will be involved. This is not only for individual generators but contractors and System Operators. Should an asset owner choose not to respond to frequency in the manner required by the Code, thereby saving costs in terms of O&M on assets, how are other asset owners to be recompensed for the additional burden placed on their assets? Whether there is sufficient resource available is another issue not identified in the Consultation Paper. In addition, this reflects back to our

	response for Question 2 [means Question 3] above, regarding an appropriate transitional period.
Viskovic	*[Viskovic did not provide a specific response to this question]*

Q5:	**What on-going costs, relative to the status quo, do you anticipate that that affected parties, particularly generators, might incur if the proposed Code amendment was to proceed?**
Contact Energy	EOH [equivalent operating hours] costs for our thermal plant will increase by around $3.5m per year. This amount would be added to the marginal cost of plant increasing cost for purchasers. There will be increased periods where the units will be on outage resulting in a reduction in supply, again increasing purchaser costs. The implications of these [increased EOH] costs to purchasers would be two-fold: • Firstly this cost would be reflected in the marginal price through offers; • Secondly, there will be increased periods where the units will be on outage. This is likely to result in a reduction in supply and higher spot prices that will further increase purchaser costs and reduce system security. In addition to this, as mentioned in section one above, there is an increased risk of a trip when operating at a reduced dead band. We do not agree with section 3.2.2 which attributes a reduction in wear and tear costs or EOH to decreasing movement in primary plant. Initial wear and tear is incurred to get to that state. Our view is that this decreasing movement is unlikely to occur as plant that do not comply currently, are unlikely to comply in the future as the asset owners are likely to seek dispensations. Geothermal plant face an additional cost associated with the proposal. As these units are base loaded, they will only react downwards reducing market supply and potentially operating these units in a range that the plant is not designed to, again reducing reliability.
Genesis Energy	*[Genesis did not provide a specific response to this question]* *[from Genesis' letter]* **Cost of compliance is significant for most generators in New Zealand** The paper fails to account for the significant operational and technical costs to generators that will be imposed by compliance with the change. Very few generators are currently able to comply with the proposed performance obligations without significant changes to how they operate their assets. We understand that even some of the existing hydro generation in New Zealand will face unnecessary costs to alter their existing operation to comply. It is also harmful to the life of thermal plants, as we indicated in our submission in 20101. A copy of this submission is attached. We also understand that wind and geothermal generation are unable to comply due the nature of their plant. Therefore, not only will the proposed change impose additional cost to energy production and therefore incentivise inefficient generation decisions, but it also may also be a wealth transfer exercise from one generator (those whose assets cannot meet the standard) to another (those who can).

Meridian Energy	See response to Question 4.
Mighty River Power	1. Application fee for renewal of dispensations (where dispensations are not granted for the duration of life of plant). 2. If geothermal machines are required to back off on power output to provide spare capacity for frequency keeping, costs will be incurred due to: 3. Loss of generation revenue 4. Cost of fuel when vented. 5. IPPC (carbon tax) costs due to the need to continuously vent geothermal steam 6. Additional wear and tear
Nova Energy	**Steam Turbines.** For most steam turbines the turbine governor can control only one parameter at a time, (e.g. MW or steam backpressure or steam inlet pressure or steam flow rate), If the primary parameter being controlled is not MW, which is often the case with steam turbines running in a cogeneration configuration, then the governor droop needs to have a dead-band wide enough to ensure that the turbine steam flow is not being affected by grid frequency excursions. If the dead-band is not wide enough, there is increased risk of the turbine control becoming unstable or the primary controlled parameter being forced out of specification on a regular basis.
	Gas Turbines Gas turbines typically have a number of different control modes, with the control system selecting the appropriate control mode based on both operator selections and plant parameters. Typically there will be a kW control mode to control turbine output at part load, a Temperature control mode to maintain the turbine hot section within allowable limits, and speed control modes for each of the turbine shafts. The kW control mode would typically have kW droop configured as part of that control mode. The operating mode that allows continuous operation at maximum output, and also has the highest thermal efficiency is Temperature control. However, when operating in Temperature control mode, further increase in output is prevented so there is no droop response to a grid under-frequency event, and to ensure stable operation there will be a small dead-band before the GT will back off load in an over-frequency event. Strict compliance with the proposed rule change would therefore require continuous operation in kW control mode, at a slightly reduced output and reduced efficiency. Operation in kW control mode very close to maximum output potentially exposes the GT hot section to increased thermal cycling at high temperatures, potentially increasing maintenance costs. Excessive wear rates have been observed on some new generation components before a control dead-band was introduced. If left unchecked, the scheduled 50,000 hour component replacement would most likely been required before 5,000 hours operation. Although it isn't clear, the draft rules suggest that generating plant must normally be running at slightly less than full output so that there is

	some “spinning reserve” available for when frequency dips below 50Hz. If this is the intention it isn’t clear how much “spinning reserve” is required.
Transpower	No comment (we understand this question is primarily addressed to generators).
Trustpower	There will likely be a requirement to revisit many stations and retest assets should this amendment be passed, even though a significant amount of resource has been allocated to addressing the previous testing and modelling requirements. This will also impact financially. Also the timescales are insufficient – see Question 2 [means Question 3] above.
Viskovic	5 million per annum additional maintenance (using figures from a report for the Electricity Commission) for an ineffective response from a single CCGT (running continuously). Lost generation from wind and geothermal and costs for aero derivative GTs in terms of maintenance and wasted fuel.

Q6:	**What comment do you have on the Authority’s evaluation of the alternatives and the cost-benefit assessment of the preferred Code amendment (the proposal) set out in sections 5.3 and 5.4?**
Contact Energy	Contact has concerns on the assumptions contained in the proposals CBA. While the Authority acknowledges that the full costs are not known and this is a high level assessment we feel that in order for the output of the cost/benefit analysis to be valid, even at a high level, the cost to asset owners must be considered. We believe this is significant. Section 5.4.5 states that “other” costs are difficult to estimate, we feel that this could have been quantified by the Authority approaching asset owners prior to consultation to gain feedback on the inputs into the CBA. Section 2.1 mentions a reduction in total frequency keeping (FK) costs to $41m in 2013, these costs are down from $80m in 2008 and will decrease further with MFK nationally. Our view is that the effect of the proposal on reducing these FK costs will be secondary to the other initiatives already in place [as discussed above]. Cost savings to FK of $1.5m year are stated. We believe this benefit will easily be outweighed by the additional summated cost EOH costs borne by generator market participants that will be added to the marginal cost of plant, ultimately increasing the cost for purchasers. FK costs have halved in the last five years and these will decrease further with MFK nationally. Our view is that the effect of the proposal in reducing FK costs is secondary to other initiatives already in place. Section 5.2 mentions enhanced competition amongst generators competition. [As mentioned above,] the situation is unlikely to change from the status quo.
Genesis Energy	*[Genesis did not provide a specific response to this question]* *[from Genesis’ letter]* Genesis Energy supports the Authority’s initiatives to improve the efficiency and competitiveness of the frequency keeping (FK) market.

	However, we strongly oppose the proposed changes in this consultation paper because the cost, to the market and market participants, outweighs the possible benefits envisaged by the Authority. In particular: • **The proposal fails to consider the costs of implementing the change to AOPOs.** In particular, it fails to take account of the unique characteristics and capabilities of existing New Zealand generation assets. Compliance costs will increase significantly for a large number of existing generators. This, in turn, leads to doubts whether there are any benefits at all – or whether the proposal is simply a wealth transfer between service providers. • **The proposal threatens the reliability of supply.** The key purpose of the AOPOs is to ensure system security. However, compliance with the proposed changes is likely to create adverse impacts to the dispatch objective, and overall system reliability because the proposal does not take account of the technical incapability of significant generation capacity to meet the new requirements, nor the offer decisions that it is likely to incentivise. Benefits not quantifiable We are also concerned that the qualitative assessment of benefits, relied upon for this proposal, is not credible. We are not convinced there is a positive trade-off between the potential savings from narrowing FK band in the longer term (as intended in theory) versus the realisation of actual costs on generation asset owners arising from compliance with the change. There will be an adverse impact to reserve market and energy dispatch The consultation paper fails to consider any potential impacts of the proposal on reserve and dispatch compliance. Energy, reserve and frequency dispatch are interrelated and integral to supporting the PPOs, and to achieving the dispatch objective. A change in one element should automatically trigger a review as to whether other products may be detrimentally affected. Those changes should also be considered as part of cost benefit analysis.
Meridian Energy	Meridian considers Option 2 (deferring Code amendments pending other developments relating to normal frequency) is preferable to Option 1, as: • it would provide time to collect information on the physical limitations and frequency keeping contribution of existing plant, allowing for a more informed assessment of the problem and a more informed solution; • it would provide for the concurrent development of a new frequency keeping obligation and an associated compensation regime, which would provide a much clearer framework for generators to trade off the costs of compliance with the costs of dispensations, resulting in better investment decisions. Meridian considers the foregone benefits of deferring Code amendments will be low given the extent of dispensations expected to be sought. We consider the Authority's estimate of benefits is highly uncertain. Without precise information on the frequency keeping contribution of existing plant within the normal band, it is difficult to have confidence in any estimation of a reduction in frequency keeping costs.
Mighty River Power	No immediate cost implications or on-going cost for non-compliance (or seeking dispensation) could hinder potential benefits of the code change. Parties could seek dispensation where they choose not to comply, as opposed to where they cannot comply. Mighty River Power understands that some fuel types may not be able to comply with some aspects of the proposed code change; however there may be an opportunity for other parties to benefit from this.

Nova Energy	As per Q1 above, further detailed system modelling is required before a robust cost-benefit assessment can be completed.
Transpower	We appreciate the Authority has recognised it may need to revise its cost benefit assessment following submissions, which may change the decision.
Trustpower	The assessment of options is flawed. Stating Option 2 would not achieve the objective is inappropriate. If the Authority published an interpretation of generator obligations, then surely this would provide clarity as to what the exact meaning of the Code was and define what, if any, level of dead band was permissible. Presumably this would ensure no generator operated a dead band and greater equality in terms of support to frequency management would be delivered. The "cost benefit assessment" in Section 5.4 and 5.5 is not particularly comprehensive and does not appear to make sense. Section 5.4.4 talks about a frequency-keeping requirement reduction of 5%. What does this relate to? Section 2.1.2 indicates frequency-keeping costs of $41M; 5% of this is $2.05M not the $1 to 1.5M quoted in 5.4.4.
Viskovic	The need for a 25mHZ dead band and additional maintenance costs have not been addressed and they represent the heart of any cost benefit analysis. Closing the loopholes in governor settings will prevent further gaming of the system. *[from Viskovic's cover letter]* The Electricity Authority's preliminary view that the amendments will improve the efficiency and competitiveness of the industry for the long term benefit of consumers is incorrect, however I think the amendments can be adjusted to reach the efficiency and consumer benefit objectives despite the market.

Q7:	What comment do you have on the Authority's assessment of the proposed Code amendment against the requirements of section 32(1) of the Act?
Contact Energy	Section 5.2 mentions enhanced competition amongst generators. We believe the current situation is unlikely to change. While hydro will be compliant, large thermals will not be, and geothermal will not be applicable. Based on this, these benefits are irrelevant. An increase in EOH due to increased wear and tear results in increased maintenance outages and an increased risk of trip which reduces reliability of supply. The EOH cost increase and a reduction of supply in the market will increase purchaser costs reducing efficiencies in the market and any perceived gains in FK cost reduction. There are no efficiencies to be gained from removing ambiguity in generator obligations. Obligations are largely known at present and if not, are clarified with the SO on a case by case basis.
Genesis Energy	*[Genesis did not provide a response to this question]*
Meridian Energy	As already noted, Meridian considers there is a lack of information with respect to how generators are currently complying with this Code obligation and what physical plant limitations may exist. As such, we do not consider it is possible at this point to say with confidence that the current AOPOs are creating inefficiencies. We therefore disagree with the Authority's assessment.
Mighty River Power	No comment.
Nova Energy	No comment
Transpower	No comment.
Trustpower	No comment.
Viskovic	Obligating Asset Owners to provide ancillary services will reduce costs to consumers (which should be the Electricity Authority's only mandate), as long as the feasibility of such proposals are understood prior to implementation. A similar approach could be taken with the reserve market to improve efficiency of the industry for consumers and security of supply.

Q8:	**What comment do you have on the Authority's assessment of the proposed Code amendment against the Code amendment principles?**
Contact Energy	*Principle 2 – Clearly Identified Efficiency Gain or Market or Regulatory Failure*: As per our response to Q6 [i.e. Q7], our view is that there are no efficiencies to be gained around obligations and reduction in purchaser costs with this proposal. *Principle 3 – Quantitative Assessment:* As per Q5 [i.e. Q6] response, our view is that without considering the cost to asset owners and the flow on effect of these, an accurate CBA cannot be made.
Genesis Energy	*[Genesis did not provide a response to this question]*
Meridian Energy	Meridian does not consider that the proposal meets Principle 2, in that there is not a clearly identified efficiency gain or market or regulatory failure. Further, the Authority has not complied with Principle 3 in that it has not completed a quantitative cost benefit analysis. Meridian considers completing a quantitative cost benefit analysis in this case is possible, however it would require the Authority to first gather information on the frequency keeping performance and physical limitations of current generation plant. At a minimum, Meridian considers the Authority needs to update its cost benefit analysis with cost information provided through submissions to this consultation.
Mighty River Power	No comment.
Nova Energy	No comment.
Transpower	We agree.
Trustpower	The Authority has initiated a number of changes to the frequency-keeping market, and there are still a number to come. Appropriate time has not been provided to determine whether efficiency gains have been delivered from earlier changes. Assessment of proposed changes does not seem robust and has been carried out at a high level. No assessment of the cost impact on generators is available for review or analysis.
Viskovic	*[Viskovic did not provide a specific response to this question]*

Other comments in Submissions (sorted by Submitter)
Contact Energy
Compliance with dispatch instructions The proposal will have an adverse effect on generator asset owners when complying with a MW dispatch instruction. In the past there have been queries from the SO as to why fast acting plant is off dispatch. The mismatch between actual and the dispatched amount was due to fluctuations in system frequency and therefore reducing the dead band, increasing gains, and reducing droop settings will only aggravate this issue. The SO will need to account for this when monitoring and enforcing compliance.
Finally in the future it would be useful if proposals such as this could be consulted on through workshops as were the AUFLS changes.
Genesis Energy (did not respond directly to any of the Authority's questions)[6]
Genesis Energy strongly recommends the Authority focus on existing initiatives, such as implementation of the multiple frequency keeping and the national FK market, that have the potential to deliver actual benefit to the market, and to consumers.
Absence of consideration to technical inability will have impacts on reliability of supply. <u>Technical inability not acknowledged by proposed code changes</u> The proposed code change is incompatible with some important technical matters, such as governor system settings and optimising plant capabilities for different generation technology characteristics. This highlights a lack of understanding by the Authority of the diverse types of controllable dispatched generation plant and how they operate. In our earlier submission we identified the technical barriers inherent in the proposed change. The proposed change imposes a uniform approach that can only be met by some hydro generators. Some non-hydro plants could apply settings to meet the proposed changes. But doing so will decrease plant reliability, which will in turn raise potential security of supply risks for the market.
AOPOs should prioritise system security We consider the Authority's intention to improve the market efficiency via proposed code change may violate the role of AOPOs. As per Clause 8.16 of the Electricity Industry Participation Code 2010: "…*The establishment of performance obligations and technical standards for asset owners to assist the system operator in complying with principle performance obligations….*" A hydro governor system is quite different from a thermal plant governor system, and it is this diversity that is reflected in the competition, reliability and efficiency realised in the market. The existing AOPOs provisions recognise this diversity. Ultimately, the proposed Code change will have negative impacts to system reliability. It is not the most efficient way to purse uncertain FK cost reduction by modifying AOPOs.

[6] Information classified as confidential by Genesis Energy has been excluded from this summary.

The process of this consultation was not well managed Given the cost significance and impacts of wide generations, we would expect a better industry engagement prior to this consultation. There was little mention by the Authority on this matter since 2010. Without knowing non-compliance cost allocation methods and clear guidelines of applying equivalence such a change can induce an inefficient market outcome and introduce regulatory uncertainty. We understand the Authority’s reasoning on maintaining a watching brief on dispensation outcomes. However, the lack of assurance on cost of non-compliance is an open risk to any generator business. It is not a viable option for a commercial decision to be based on an unknown cost. Further, the definition of “causers” discussed in the consultation paper is not well defined which leads to different interpretations and confusion. The Authority should not take those concerns lightly.
Areas that merit greater attention It is important to mention the Authority is currently conducting a number of other projects simultaneously to improve the efficiency of FK and reserve markets. Genesis Energy supports those initiatives to reduce the cost of FK and reserve market. There is no clear reason why the Authority should rush this proposal through. Our particular concern is that implementing this change concurrently with other proposed changes will mask the true costs and, more importantly, reduce the overall benefit of the improvements to FK market.
Meridian Energy
Purpose of AOPOs As stated in clause 8.16 of the Code, the purpose of AOPOs is to “assist the System Operator in complying with the principle performance obligations” (PPOs). The System Operator’s PPOs are primarily concerned with system stability and security. In Meridian’s view, it is not the objective of the AOPOs to *minimise* the quantity of frequency keeping support which needs to be procured, provided the PPOs are being met. We are concerned that the Authority’s proposal seeks to extract additional frequency keeping support through the AOPOs for free (but at significant cost to generators), rather than procuring this support through the ancillary services procurement process. Such an approach departs from the cost allocation principles of exacerbator or beneficiary pays.