Stress testing regime - stress tests

Base case, stress tests and application notes

Published under clause 13.236D of the Electricity Industry Participation Code 2010 (Code)

15 November 2019

Operations Development

708751-6

Contents

Tables

1 Introduction and purpose of this document

Introduction

1.1 In November 2011 the Electricity Authority (Authority) gazetted amendments to the Electricity Industry Participation Code 2010 (Code) to introduce a stress testing regime (referred to in the Code as Spot Price Risk Disclosure).

1.2 Clause 13.236D of the Code requires the Authority to publicise a notice setting out:

(a) a base case;

(b) one or more stress tests; and

(c) one or more methods for calculating a disclosing participant's target cover ratio.

1.3 This document was unchanged from its first publication in until 15 November 2019. The 15 November 2019 version includes a new, additional capacity based stress test to apply for the first quarter of 2020.

Purpose of this document

1.4 This document sets out the information required by the Code and provides direction to relevant participants on how to apply the stress tests.

1.5 Further background information on the stress testing regime is available on the Authority's website at http://www.ea.govt.nz/our-work/programmes/priority-projects/scarcity-pricing-default-buy-back/.

Structure of this document

1.6 This document provides direction under the following headings:

- Overview
- Electricity spot prices
- Electricity demand
- Hedging issues
- Electricity generation levels
- Target cover ratio

2 Application of stress tests

Overview for application of stress tests

2.1 Despite the introduction of the stress testing regime, participants retain full responsibility for making decisions on their level of exposure to spot prices, and for managing that exposure on an ongoing basis.

2.2 For this reason, the stress testing regime is intended to dovetail as far as possible with the arrangements that participants will already have in place for monitoring exposure to spot price risk. In particular, the Authority has sought to limit the level of prescription in the stress testing arrangements as far as possible, while still ensuring that disclosure is robust.

2.3 Application notes are in three broad categories:

- quantitative assumptions – where the Authority specifies matters that must be followed. These relate primarily to the average price projections to be used in base case and stress test scenarios;
- methodological direction – where the Authority sets out a methodology that it expects participants to follow. For example, the broad approach to be used to convert scenario prices referenced at Otahuhu to other nodes where participants buy or sell electricity. In this category, the Authority publishes summarised quantitative information (e.g. locational adjustment factors based on historic data) to save participants the task of recalculating estimates from raw data. Although the Authority expects most participants to use this summarised quantitative data, participants may generate their own data provided they remain consistent with the broad approach specified by the Authority. For example, a participant may have access to more detailed historic information than the Authority, and could use that information in preparing its own projections;
- qualitative direction – where the Authority provides direction of a non-quantitative nature. Participants must compile bona fide estimates consistent with this direction.

2.4 Table 1 provides a summary of the matters on which the Authority provides direction and the nature of that direction. The price requirements will be relevant to all disclosing participants, but other direction will only be relevant if operations extend into specific areas (demand, hedging or generation).

2.5 Direction being provided by the Authority is discussed in more detail in the following sections. All numerical data referred to can be found in the accompanying spreadsheet file named “Stress Testing – Supplementary Quantitative Data”.

Table 1 Overview of direction for stress tests and base cases

		Energy shortage stress		**Capacity shortage**	
		Stress test	Base case	Stress test	Base case
Price issues	Average level of prices				
	Locational adjustment factors				
	Temporal adjustment factors				
Demand issues	Participant overall level of demand				
	Demand shape for forecastable demand				
	Demand shape for mass market load				
	Demand response (general)				
	Demand response (public conservation campaign)		n.a.	n.a.	n.a.
Hedge issues	Firm hedging arrangements				
	Contingent hedging arrangements				
Generation issues	Hydro inflow levels			n.a.	n.a.
	Opening and closing hydro storage levels			n.a.	n.a.
	Hydro generation levels				
	Wind generation levels				
	Thermal/ geothermal levels				
Other	Target cover ratio				

Data for out-of-schedule stress test under clause 13.236G(1) of Code

2.6 If an additional stress test is requested that occurs within the quarter it applies to, it may be possible to use actual data for the earlier portion of the quarter, rather than relying on forecasts. Disclosing participants should take all reasonable steps to include such actual data.

2.7 Unless otherwise specified, it is only necessary to apply stress test scenarios from the date of the announcement of the out-of-schedule stress test.

2.8 In particular, participants should assume that elevated prices in an energy stress scenario only apply for future days in the quarter.

Electricity spot prices

2.9 The spot price assumptions in the base cases and stress tests are specified in base load equivalent terms at the Otahuhu node. To calculate the effect of the base case and stress tests on their operations, each participant must use spot price projections that are relevant to their operating locations and time profiles.

General principle

2.10 The Authority requires all disclosing participants to operate with common assumptions about spot price outcomes in the base case and stress test scenarios. For this reason, it has provided relatively detailed direction on spot price projections.

Specific direction

2.11 The Authority requires that disclosing participants comply with the following:

Adjustment factors for energy-related tests

2.12 To generate the spot price assumption for any specific node and time block, the Otahuhu scenario price must be multiplied by three adjustment factors. These adjustment factors are intended to account for:

- ‘regional’ price differences between Otahuhu and a reference node in one of five zones (these are the zones already used in the disclosure regime for electricity spot price risk management contracts)[1];
- ‘within region’ price differences between the zonal reference node and the specific node of interest; and
- temporal factors to account for load shape effects across the day and week.

2.13 For example, if the stress test assumption specified at Otahuhu is $400/MWh, the spot price assumption for a load at Wanganui that is typically operating at a steady level between 7am and 10pm on a winter weekday would be given by:

Otahuhu price assumption x Zone C regional factor x nodal factor for Wanganui x appropriate temporal factor

2.14 The Authority has published regional, within region, and temporal adjustment factors in spreadsheet form on the Authority’s website. Participants may use these published adjustment factors. Alternatively, they may develop more detailed adjustment factors if they wish, in which case they must follow the principles set out below:

- the base case adjustment factors must reflect average price patterns observed over the relevant time period specified in the Stress Testing Supplementary Quantitative Data spreadsheet (available at www.ea.govt.nz/dmsdocument/12575-stress-testing-supplementary-quantitative-data)[2];
- the adjustment factors for the stress tests are the same as for the base case, except for the regional adjustment factors (i.e. price patterns between Otahuhu and zonal reference

[1] Factors are given for winter and summer seasons. Winter is defined as Calendar Quarters 2 and 3.

[2] Some half hours (around 6) with unusual price outliers have been excluded to avoid significantly distorting the average.

nodes). These are based on price patterns observed in the relevant time period specified in the Stress Testing Supplementary Quantitative Data spreadsheet (available at www.ea.govt.nz/dmsdocument/12575-stress-testing-supplementary-quantitative-data),when there were significant north to south power flows. This is the predominant pattern of power flow that would be expected during an extended period of tight energy supply caused by a drought[3]), which is the basis for the energy-related stress tests;

- two sets of temporal price adjustment factors have been calculated based on historically observed patterns. The first provides adjustment factors for four time blocks (business day versus non-business day, and day time and night time[4] for each of these). The time block adjustment factors are suitable for participants with relatively simple load shapes. The Authority also provides adjustment factors to reflect mass-market demand (e.g. residential and commercial users), which typically has a strong within-day shape that is correlated to spot prices. Participants using this adjustment factor can apply it to their average level of mass market load (i.e. there is no need to forecast the shape of this load as it is already accounted for in the temporal adjustment factor).

Adjustment factors for capacity-related tests

2.15 The price adjustment factors for the capacity-related stress tests should reflect the price pattern expected during a period of tight capacity. For this reason, the capacity stress tests use adjustment factors for daytime hours on a business day (since the capacity shortage is assumed to occur during a time of peak demand). The adjustment factors are the same for the base case and for stress tests.

2.16 The adjustment factors that have been calculated on this basis are available in spreadsheet form on the Authority's website. Again, participants may use this data or may calculate their own adjustment factors, in which case they must adopt the principles set out above.

---

3 The regional price pattern for the 2nd and 3rd quarters of 2008 is taken as indicative of a typical extended dry period. Temporal and within region nodal adjustment factors may also vary during extended dry periods. However the temporal factors for winter 2008 are not significantly different from the five year average and so the latter are used as a reference. Also the winter 2008 nodal adjustment factors are not significantly different from the five year average in most cases so the latter can be used in most cases.

4 Non business days include weekends and public holidays, and the daytime period is the 15 hours from 7am to 10pm.

Electricity demand

2.17 Disclosing participants must estimate their electricity demand to calculate their projected wholesale electricity purchase costs in the base case and stress test scenarios. These estimates must account for locational and load shape issues, to the extent that they have a material effect on wholesale electricity purchase costs. Demand estimates must also take account of demand response in the stress test scenarios, where this is appropriate.

General principle

2.18 Each disclosing participant has a unique demand profile, which reflects the specific characteristics of its operations. For this reason, other than the specific areas of direction set out below, disclosing participants are responsible for estimating their demand, subject to a general requirement that the results should reflect bona fide estimates of outcomes expected in the base case and respective stress test scenarios. This means the estimates must take account of issues such as:

- existing sources of demand;
- commitments that alter demand from existing levels (e.g. customer acquisition campaigns, expected changes to production levels);
- seasonal factors that exhibit a relatively predictable pattern.

2.19 The Authority recognises that this approach provides participants with a degree of discretion. However, it notes that spot price risk disclosure statements are subject to independent audit if required by the Authority.

Specific direction

2.20 The Authority provides the following specific direction to disclosing participants:

Demand reduction associated with public conservation campaign

2.21 The energy stress tests may include a scenario where a public conservation campaign is in effect during part of the measurement period. If such a scenario is included in the stress tests, disclosing participants that are retailers must assume that their mass market demand component (i.e. load for customers on fixed price, variable volume contracts) is uniformly 8%[5] lower than in their base case projection for the weeks that a public conservation campaign is specified to apply. These participants must also include customer compensation payments (based on prevailing specified levels – for example $10.50 per week per customer account in April 2012) when calculating the projected net cashflow from operating activities for that stress test scenario.

Demand shape for capacity-related stress tests

2.22 The capacity-related stress tests assume that the adverse event coincides with a period of New Zealand peak system demand for the relevant quarter[6].

2.23 Disclosing participants with specific knowledge of their underlying electricity demand sources (e.g. major users) must estimate their projected load at such a time. This will constitute the

[5] This is the assumed average level of load reduction that was used when the customer compensation scheme was developed.

[6] In this context the peak demand is equal to the average demand over 8hrs (8-12am and 5-9pm) in two consecutive days. The demand level has been measured over the highest NZ peaks in each quarter over the last 12 years.

demand estimate for both the base case and stress test scenarios (unless there is demand response in the latter – see below for further discussion).

2.24 Disclosing participants without specific knowledge of their underlying electricity demand sources (e.g. retailers serving mass market customers) must estimate their projected load based on the projected average half-hourly load for the quarter, multiplied by an adjustment factor to reflect load shape at the time of system peak.

2.25 The Authority has estimated adjustment factors based on historic data[7] and these are available in spreadsheet form on the Authority's website. Participants may use this data or calculate their own adjustment factors, in which case they must adopt the principles discussed above.

Demand response levels and costs

2.26 In compiling load estimates for stress test cases, disclosing participants must incorporate the effect of demand response mechanisms where these can be relied upon with a high degree of assurance (e.g. due to direct control, contractual mechanisms, or based on demonstrated past experience).

2.27 Where demand response is assumed, it must take account of any factors that constrain or limit its effectiveness. For example, in the context of capacity-related stress tests, if a demand response mechanism requires two hours to activate, then a demand response must not be assumed during the first four trading periods of the stress test.

2.28 If demand response results in any change in costs or revenues relative to the base case for the disclosing participant, this must be taken into account when calculating the projected net cashflow from operating activities for that relevant stress test scenario. For example:

- a retailer's costs could increase if it is required to make payments to downstream electricity customers when demand response is activated; or
- an electricity user's net sales revenues may be lowered by reduced production levels.

[7] The calculated peak factors have been derived for total demand from the national grid (excluding direct connected customers where these can be identified easily) in a number of regions. The regions are consistent with those used in the Electricity Commission 2010 Statement of Opportunities. The published table summarises the factors for the main demand regions. Some small regions with unusual load patterns or significant embedded generation are not included.

Hedging issues

2.29 Disclosing participants must account for the effect of hedge contracts (electricity price risk management contracts) when estimating their projected net cash flows from operating activities in the base case and stress test scenarios.

General principle

2.30 Hedging arrangements take a wide variety of forms. For this reason, other than the specific direction set out below, disclosing participants are responsible for estimating the impact of hedge contracts on their cash flows, subject to a general requirement that the results must reflect bona fide estimates of outcomes expected in the base case and respective stress test scenarios.

Specific direction

2.31 The Authority requires that disclosing participants comply with the following:

Degree of firmness of hedge arrangements

2.32 Where disclosing parties have a firm hedging arrangement with an external party under which they are obliged to make, or can claim, payments which vary depending on spot price outcomes, then the effect of this arrangement must be accounted for when calculating projected net cash flows from operations.

2.33 Where disclosing parties do not have a legally enforceable hedging arrangement (e.g. because discussions about a prospective contract have not yet been concluded), the arrangement must not be taken into account when calculating projected net cash flows from operations.

2.34 These principles apply to arrangements that mitigate all forms of spot price risk, including locational price risk (e.g. financial transmission rights).

Contingent arrangements

2.35 Some arrangements contain provisions where the hedging effect is contingent on market conditions or the actions of a party. For example, an arrangement may require one party to give prior notice that it wishes to invoke a cap contract, and the hedging effect comes into operation after the notice period.

2.36 Disclosing participants that have provided such options must assume that counterparties exercise these options if they confer a financial benefit on that counterparty in the relevant base case or stress test (and vice versa). Similarly, disclosing parties that have the ability to exercise such options must include their effect when calculating net cash flows from operations if they consider that the option would be exercised in the relevant base case or stress test scenarios.

Availability of Financial Transmission Right (FTR) payments

2.37 Disclosing participants should consider whether the FTR Rentals Amount is likely to exceed the loss and constraint excess in the specified stress test and how this will affect any FTR payments they will receive.[8]

[8] See section 2.8 of "FTR Allocation Plan 2017"

Electricity generation levels

2.38 To calculate the effect of the stress tests on their positions, disclosing participants with generation resources must estimate their production levels for the base case and stress test scenarios.

General principle

2.39 Each disclosing participant with generation will have detailed information about the assets under its control. For this reason, other than the specific areas of direction set out below, disclosing participants are responsible for estimating their projected generation levels, subject to a general requirement that the projections must reflect bona fide estimates of outcomes expected in the base case and respective stress test scenarios. This means the estimates must take account of issues such as:

- availability of thermal fuel supplies;
- any expected transmission constraints likely to affect output levels; and
- planned changes in plant availability.

2.40 The Authority recognises that this approach provides participants with a degree of discretion. However, it notes that spot price risk disclosure statements are subject to independent audit if required by the Authority.

Specific direction

2.41 The Authority requires that disclosing participants comply with the following:

Hydro inflow levels for energy-related tests

2.42 For the base case, disclosing parties with hydro generation must assume mean inflows into their catchments based on historic data for the relevant quarter. This ensures broad consistency between assumed hydro inflows and spot prices in the base case.

2.43 For the stress tests, projected inflows for individual hydro generation catchments must reflect a national 1 in 20 year drought (and not normal conditions, or a 1 in 20 drought measured at the individual catchment level). Projected inflows for the main catchments for stress test scenarios have been estimated from historical data and these are published in spreadsheet form on the Authority's website.

2.44 These projections have been prepared by ranking historic inflow sequences for each quarter according to total inflows at the national level. The projected inflow for any specific catchment has been estimated based on the average of observed inflows for that catchment during the worst 10% of national droughts. This approach has been used rather than using the actual catchment inflow for the 1 in 20 national observation because the latter would place undue emphasis on one data point.

2.45 Participants with hydro generation may use the projections published by the Authority, or use the methodology above to determine their catchment level inflows during a 1 in 20 national drought.

Hydro generation starting storage for energy-related tests

2.46 For the base case, disclosing parties with hydro generation must assume their storage reservoirs are at the relevant mean level for the beginning of the coming quarter. This reflects the base case assumption that spot prices are at a broadly 'normal' level, irrespective of prevailing conditions (whether wet or dry). Projected starting storage levels for the main controlled reservoirs have been estimated from historical data and these are published in spreadsheet form on the Authority's website.

2.47 For the stress test scenarios, disclosing parties with hydro generation must assume their storage is at prevailing levels, adjusted for any expected change between the date of the estimate and the beginning of the relevant quarter (which must be no more than 20 working days and no less than five working days later).

Hydro generation closing storage for energy-related tests

2.48 For the base case, disclosing parties with hydro generation must assume their storage reservoirs track to the mean closing level for the quarter[9]. Again, this reflects the base case assumption that spot prices are at a broadly 'normal' level, irrespective of prevailing conditions (whether wet or dry).

2.49 For the stress test scenarios, disclosing parties with hydro generation must assume their closing storage is no less than a defined minimum level (see below) at the end of the relevant quarter. These minima have been set to provide a broad degree of consistency between closing reservoir levels and the spot price assumptions in the stress test scenarios.

2.50 For energy stress test scenarios, closing storage for any given reservoir must be at least equal to its share of the national storage level corresponding to the relevant hydro risk curve defined in the stress test. The national level of storage associated with each hydro risk curve is published by the system operator[10].

2.51 The relevant shares of national storage to attribute to each reservoir have been calculated by the Authority based on averages of actual data for the years when closing national storage was relatively low (the lowest 25% of observations). This information is published in spreadsheet form on the Authority's website.

Wind generation levels for energy-related tests

2.52 For the base case, disclosing parties with wind generation must assume mean output levels based on historic data for the relevant quarter. This ensures that generation levels are broadly consistent with the spot price projection in the base case.

2.53 For the stress tests, projected wind generation levels must reflect a national 1 in 20 year hydro drought. Where sufficient data is available, relevant participants must estimate projected wind generation levels based on the methodology described above for estimating hydro inflows in the energy-related stress tests. Where insufficient data is available to adopt this approach, relevant participants must assume mean levels of generation for the relevant quarter.

Generation levels for capacity-related tests

2.54 For the base case, disclosing parties with generation sources must estimate their projected output based on expected levels during a period of high demand for the respective quarter. In the case of non-controllable generation (e.g. wind and run of river hydro), disclosing parties must assume average levels of production for the relevant time of year.

2.55 For a capacity stress test without additional forced generation loss (i.e. loss of large thermal units or wind generation), generation levels for non-controllable generation must be the same as the base case. Disclosing participants with controllable generation sources (e.g. thermal and hydro

9 The Authority has published average storage levels for the main reservoirs at the start of each quarter. The average closing level for any quarter is the same as the average starting level for the following quarter.

10 See www.systemoperator.co.nz/hydro-status for more information.

dependent on storage reservoirs) must adjust projected generation levels to reflect their expected response during a capacity shortage. This adjustment must reflect any factors that would limit the amount or rate of increase of generation during an unexpected sudden capacity shortage. For example, this would include issues such as delays in starting uncommitted thermal units, releasing stored water for use in downstream generation etc.

2.56 For any capacity test with additional forced generation loss, disclosing parties that included generation from a thermal unit of 200 MW or more in the base case must assume zero generation from their largest thermal unit during the stress test period. Likewise, disclosing parties that included wind generation in the base case must assume that their largest wind farm has zero generation during the stress test period. If a disclosing party has generation from both a large thermal unit and a wind farm in the base, it must assume that the larger of the two sources (in average output terms) has zero generation in the stress test.

Target cover ratio

2.57 The Code requires disclosing participants to state whether or not they have an explicit risk management policy in respect of exposure to the wholesale market. If participants have an explicit policy, they must disclose their target cover ratio for each stress test calculated in accordance with the method publicised by the Authority.

General principle

2.58 The “target cover ratio” concept is intended to reflect a participant’s preferred level of hedge cover, as recorded in its risk management policy documents, rather than the actual level of cover at the time the stress tests are applied.

2.59 Where a participant has an explicit risk management policy that is already framed in ratio terms, it should be relatively straightforward to calculate a target cover ratio. However, the Authority recognises that some participants may not have an explicit risk management policy. Further, even where there is an explicit policy in place, it may not be possible to calculate a meaningful target cover ratio in some cases. The notes take account of these different situations.

Specific direction

2.60 The Authority requires that disclosing participants comply with the following:

Method for calculating target cover ratio

2.61 If a participant has no explicit risk management policy, it must enter “not applicable” in the relevant sections of the disclosure statement.

2.62 In all other cases, the participant must calculate the target coverage ratio, as the proportion of spot price payment obligations that, according to the explicit policy, must be covered by risk management mechanisms (whether physical or financial) that insulate the participant from spot price movements.

2.63 In this context, “spot price payment obligations” includes payments to the clearing manager for wholesale market purchases, and any obligation to make a payment that moves with the spot price. For example, if a generator sold a fixed price hedge to a counterparty, it would have a payment obligation to that counterparty that is linked to the spot price.

2.64 “Risk management mechanisms” encompasses any arrangement or resource that reduces or offsets the participant’s exposure to spot price movements. This includes financial hedges, generation resources and firm demand response arrangements.

2.65 Adopting this approach, if a major user has a policy of hedging at least 85% of its expected electricity purchases for the coming period with fixed price arrangements, it must disclose “0.85” as its target cover ratio (irrespective of its actual hedge position). Similarly, if it has a policy of having between 85% and 95% of purchases covered, the target cover ratio would be the mid-point of 0.9.

2.66 The ratio must also be determined for parties that are predominantly net sellers in the spot market (i.e. generators). However, it is important to note that the spot price payment obligation for these participants must be determined primarily by the hedges that they sell. For example, if a generator has a policy of selling no more than 90% of firm generation capability on fixed price arrangements, it must disclose “1.1” as its target cover ratio, since the required proportion of risk management mechanisms (generation in this instance) to spot price payment obligations (hedge sales in this instance) is 1/0.9.

2.67 Where a participant's risk management policy is not expressed in a form that sets a minimum or expected level of forward cover, it will not be feasible to calculate a meaningful target cover ratio. For example, this would be the case where a risk management policy set a minimum earnings threshold that should be achieved with a predefined level of probability. Given that the stress tests are not probabilistic in nature, it would not be possible to infer a target coverage ratio from a policy of this form.

2.68 In such instances, participants should enter "not feasible" in the Target Cover Ratio section of the disclosure form.

Appendix A Sample disclosure form (typical quarter)

Spot Price Risk Disclosure Statement provided pursuant to Subpart 5A of Part 13 of Electricity Industry Participation Code

	Quarter to which disclosure statement applies	Qtr/Year	
1	**Name(s) of Disclosing Participant(s)** *Include names of all Disclosing Participants if a consolidated statement is being submitted pursuant to clause 13.236C of Code*		
2	**Annual net cash flow from operating activities** *Based on most recent audited financial statements*	$m	
3	**Level of shareholders' equity** *Based on most recent audited financial statements*	$m	
		Stress Test Results	
		E1	**C1**
		Sustained drought (closing storage at 2% hydro risk curve)	**Unexpected short term capacity shortage**
4	**Increase/(decrease) in projected net cashflows from operating activities when the stress test is applied***	$m	$m
5	**Increase/(decrease) in projected value of electricity sold to the clearing manager when the stress test is applied***	$m	$m
6	**Increase/(decrease) in projected value of electricity purchased from the clearing manager when the stress test is applied***	$m	$m

** Calculated as the projected value when the respective stress test is applied, minus the projected value when the base case is applied. See Stress Testing Regime Guidance Notes ,Version 1.0 issued by the Electricity Authority for further information*

7	**Does the disclosing party listed in question 1 have an explicit risk management policy in respect of its exposure to the wholesale market?**	Yes / No	
8	**If the answer to 7 is Yes, what is the target cover ratio for each stress test?** *See Stress Testing Regime Guidance Notes ,Version 1.0 issued by the Electricity Authority for further information*	**Target Cover Ratio Results**	
		E1	**C1**
		Sustained drought (closing storage at 2% hydro risk curve)	**Unexpected short term capacity shortage**
	Signed by:		
	Position:		
	Dated:		

Appendix B Stress test and base case information

	Energy shortage stress tests		Capacity shortage stress test		
Reference code	E1	EB	C1	C2	CB
Nature of event	Sustained national drought (no public conservation campaign)	Base case for energy tests	Unexpected short-term capacity shortage at time of high demand	Unexpected short-term capacity shortage affecting North Island only	Base case for capacity tests
Key features of scenario	Average spot prices are $250/MWh for the coming quarter Opening national hydro storage based on prevailing conditions Hydro inflows based on 1 in 20 year national drought[11] Closing national storage equates to 2% hydro risk or less[12]	'Average' conditions apply Opening national hydro storage based on average conditions[13] Average hydro inflows prevail[14] Closing national storage equates to average conditions[15]	Spot prices are $10,000/MWh across 8 peak hours of one day	Spot prices are elevated in North Island across 8 peak hours of one day. The day must be a weekday during the period of overlap between the Pohokura outage and the HVDC maintenance scheduled in March 2019. HVDC flows are assumed to be zero in the 8 hour period[16]	'Average' conditions apply
Average level of prices	$250/MWh (time weighted average at Otahuhu)	$100/MWh (time weighted average at Otahuhu)	$10,000/MWh (time weighted average at Otahuhu)	North Island nodes - same price as C1 South Island nodes – same price as base case (CB).	$100/MWh (time weighted average at Otahuhu)

11 See paragraphs 2.39 to 2.41 for more detail

12 See paragraphs 2.45 to 2.47 for more detail. Information on hydro risk curves is published by the system operator and is available at www.systemoperator.co.nz/hydro-status

13 See paragraph 2.42 for more detail

14 See paragraph 2.38 for more detail

15 See paragraph 2.44 for more detail.

16 This assumption is necessary for the purpose of estimating any FTR payments.