Proposed Actions to Correct Undesirable Trading Situation 2019

Consultation paper

11 March 2021

Executive summary

Background – a UTS was found from 3 to 27 December 2019

In December 2020, the Electricity Authority (Authority) decided that an undesirable trading situation (UTS) occurred between 3 and 27 December 2019. A UTS is a situation outside the normal operation of the electricity market that threatens, or may threaten, confidence in, or the integrity of, the wholesale market. The UTS provisions of the Code oblige the Authority to attempt to correct such situations and restore the normal operation of the market.

The situation in December 2019 was exceptional. The South Island had extreme rainfall, record high inflows in South Island lakes and South Island hydro generators had to spill excess water to manage water levels and flows. Water was abundant, cheap and available for generation. The Authority considered the abundance of fuel (water) should have increased competitive pressure but the analysis of the UTS period undertaken by the Authority shows it did not. Water was spilled that could have been used to generate electricity. Had this generation been dispatched, the Authority's analysis indicates that there would have been a significant impact on electricity spot prices and North Island fuel (water) would have been conserved to deal with impending outages. As well as adversely impacting the spot market, excess spill in the South Island thus increased security of supply risks in the North Island.

In short, the Authority found that a confluence of factors reduced normal competitive pressure in the wholesale market during the period in question. This confluence of factors resulted in unnecessary spill and prices remaining abnormally high when compared against supply and demand conditions. The situation was of significant scale and duration.

Actions to correct – overview

When the Authority determines that a UTS exists it must attempt to correct the UTS and restore the wholesale market to normal operation as soon as possible.

This consultation paper identifies actions that could be taken by the Authority to correct the UTS that existed from 3 to 27 December 2019. The actions to correct being consulted on are directed at the specific UTS that occurred. Steps to prevent or mitigate similar outcomes in future would be dealt with through the Authority's usual Code amendment processes.[1]

In this case, the UTS led to outcomes including excess spill and prices far removed from underlying supply and demand conditions. The Authority currently considers that the most direct way to correct the UTS experienced in the wholesale market in December 2019 is to correct the spot electricity market payments made or received by approximating the spot market prices that would have prevailed if the UTS had not arisen. The Authority proposes to address the abnormally high wholesale market prices during the UTS period by capping the offers of certain South Island hydro generating plants.

The Authority has considered whether there are actions that could be taken to appropriately offset other negative consequences of the excess spill from South Island hydro dams, specifically for security of supply, but is currently of the view that no suitable actions are available to the Authority to correct these issues. Hydro storage is no longer at maximum capacity and excess spill is no longer occurring.

The Authority cannot perfectly resolve all consequences of the UTS that occurred in 2019. The proposed corrective actions that we are consulting on are approximate solutions, reflecting the

1 Later in the paper we summarise the components of our work programme aimed at improving outcomes in the wholesale electricity market.

scope of the Authority's powers as set out in the Code and limitations in the Authority's ability to identify and correct all consequences of the UTS. We seek feedback on the methodology used to derive the corrections; the magnitude of the corrective actions; their consequences; and their costs and benefits, as well as any alternative options to the approach we have proposed.

Actions to correct the spot market

As further explained in this consultation paper, the Authority is proposing that spot electricity prices and the prices of instantaneous reserves be reset for the period 3 to 27 December 2019 inclusive. The scale of the proposed price reset is guided by the offer behaviour in the spot electricity market that would have occurred if there had been no UTS and the market was operating normally. The proposed actions correct the UTS by setting certain South Island hydro generation offers to levels that reflect normal competitive pressures, in the context of an abundance of water to generate electricity.

The Authority is proposing to revise offers for nine South Island stations and rerun the market systems, to reset final prices at all nodes during the UTS period and to revise settlement. Some preliminary simulations have been performed to derive the (approximate) prices that would arise from the Authority's proposed actions to correct the UTS. The Authority has released a separate spreadsheet that details these prices.[2] The reset final prices would ultimately be determined by the pricing manager's use of the scheduling, pricing and dispatch (SPD) model, with revised offers as an input.

The Authority's baseline proposal is to revise offer prices at the following South Island generation stations on the Clutha/Mata-Au and Waitaki rivers: Aviemore, Benmore, Ōhau A, Ōhau B, Ōhau C, Clyde, Roxburgh, and Waitaki. Offer prices at Manapōuri and Tekapo A and Tekapo B were predominantly low during the UTS period, consistent with the abundance of hydro storage, and the Authority proposes to leave those original offers unchanged.[3]

The Authority proposes to correct the UTS and restore the normal operation of the market by capping offer prices for the period 3 to 27 December, inclusive, at $13.70/MWh for the generating stations noted above. The implications of these corrections for prices are illustrated in this consultation paper, together with an approximate estimate of the aggregate change in the cost of electricity for traders[4] in the South and North Islands (see Table 4 and Table 5). The methodology used to establish this offer price cap follows the approach used in the December 2020 UTS Final Decision Paper, with the calculation based upon the excess spill at Benmore.

In the baseline proposal, any generator that supplied electricity at offer prices above the reset final prices, and whose offers were not revised by the actions to correct, would be treated as being constrained on and would be compensated according to their original offers. Allowing constrained on is intended to mitigate the ancillary consequences of the actions to correct the UTS. In particular, constrained on is intended to ensure that thermal and other high-cost generators continue to be compensated for maintaining system security. However, generating stations whose offers have been revised would not be eligible for constrained on payments.

Actions to correct ancillary markets

Energy offers are made simultaneously with offers for instantaneous reserves. The proposed revision of energy offers would also flow through to prices for reserves. The Authority has considered additionally revising South Island instantaneous reserve offers. However, the

2 See also https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions.

3 We note that Ngāi Tahu refer to Tekapo as Takapō and Lake Manapōuri as Moturau.

4 Traders in the sense of Part 1 of the Code, meaning generators, retailers and purchasers.

Authority currently considers that revising some generation offers and therefore spot prices is sufficient to correct the UTS and revising instantaneous reserve offers is not required to restore confidence in the market. Settlement from reserves is an order of magnitude smaller than settlement of energy in the spot electricity market. Given the values involved, the Authority's current view is that actions in this market are not required to correct the UTS and restore the normal operation of the market. The Authority is also not proposing to revise outcomes for frequency keeping. The frequency keeping market is half the size of the instantaneous reserves market, and the Authority's current view is that actions in respect of frequency keeping are not required to correct the UTS, given its size relative to settlement in the spot market.

Actions to correct hedge markets

The Authority's current view is that hedge markets should be allowed to fully carry out their role of managing risk. The Authority proposes that the allocation of risk implicit in derivatives contracts should be determined by the voluntary agreements of contracting parties.

The Authority proposes that it would not use its powers under Part 5 of the Code in relation to financial derivatives. In particular, the Authority considers practical impediments mean it would be infeasible to use Part 5 of the Code to correct all hedge transactions, both during and in some cases before the UTS. The body of the consultation paper discusses over-the-counter (OTC) contracts, financial transmission rights (FTRs), and futures and options in more specific depth below. In summary, OTC contracts may or may not resettle, depending on their terms and conditions; hedge settlement agreements lodged with the clearing manager would resettle based upon the terms of the arrangements; FTRs are expected to resettle; and the outlook for futures and options would be determined by the ASX in conjunction with its own regulatory authorities, eg the Australian Securities and Investments Commission. The Authority cannot override the obligations that the ASX has in relation to its own regulatory and legislative framework. The ASX have indicated that, given the time that has elapsed, their preference would be to not re-settle their market.

Consultation on the actions to correct

The Authority is consulting on proposed actions that correct offers in the spot electricity market in order to correct the UTS and restore the normal operation of the wholesale market. The actions to correct are not intended to penalise individual traders, though the actions to correct may have financial consequences for them.

The paper briefly describes the factors that led the Authority to determine that a UTS occurred and then outlines the legal basis for actions to correct the UTS. It then outlines the options that have been identified and describes the Authority's proposed mechanism to calibrate the action to correct.

Given the complexity of the UTS, the array of options available to correct it, and the comprehensive submissions expected from participants, the Authority has arranged for a three-week cross-submission period immediately after the conclusion of this six-week consultation.

The Authority has asked the clearing manager, the FTR manager, the system operator, and the ASX to submit on the consultation paper on the actions to correct. Other submitters can then consider the information provided in later cross-submissions.

The compliance investigation and the development of the compliance framework

The Authority is investigating whether two generators complied with the Code's high standard of trading conduct (HSOTC) obligations during the UTS period.[5] This investigation uses different criteria, follows different processes, and is ongoing. We are not seeking submissions to inform the compliance investigation.

The Authority also notes that there is an ongoing review of the high standards of trading conduct provisions in the Code.

5 For a brief summary of the separate UTS and compliance processes underway, see https://ea.govt.nz/assets/dms-assets/27/October-2020-UTS-HSOTC-compliance-and-market-review-updated-summary.pdf.

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1. What you need to know to make a submission

What this consultation paper is about

1.1. The purpose of this paper is to consult with interested parties on the actions to correct the UTS that the Authority found to exist, in relation to the claim submitted on 12 December 2019.

1.2. The submissions received and the process to date have highlighted the complexity of this matter. We are committed to a thorough and robust process and for this reason we are seeking submissions to assist us in determining what actions should be undertaken to correct the UTS.

How to make a submission

1.3. Our preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to uts@ea.govt.nz with " Proposed Actions to Correct 2019 UTS—Submission" in the subject line.

1.4. If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

Postal address	Physical Address
Submissions Electricity Authority PO Box 10041 Wellington 6143	Submissions Electricity Authority Level 7, Harbour Tower 2 Hunter Street Wellington

1.5. Please note the Authority wants to publish all submissions it receives. If you consider that we should not publish any part of your submission, please

(a) Indicate which part should not be published

(b) Explain why you consider we should not publish that part

(c) Provide a version of your submission that we can publish (if we agree not to publish your full submission).

1.6. If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

1.7. However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.8. Please deliver your submissions by **5pm** on **27 April 2021**.

1.9. We will acknowledge receipt of all submissions electronically. Please contact the Authority info@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. The Authority has found that a UTS occurred in 2019

2.1. The Authority's assessment of the 2019 UTS is reported in detail in the final decision paper (which can be found here: https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/).

2.2. In brief, the Authority decided that a UTS occurred from 3 to 27 December 2019.

> "Having considered all of the evidence, the Authority has decided the situation was such that confidence in the wholesale market was, or may have been, threatened. We consider market outcomes during the UTS period were significantly different from what would reasonably be expected if the market had been operating normally. Our view is that reduced competition, caused by the confluence of factors at the time, allowed excess spill and prices to become separated from the underlying supply-demand conditions and remain higher than they should have given the abundant supply of water."[6]

2.3. In the rest of this consultation paper we refer to this 3 to 27 December period as the 'UTS period'.

3. The regulatory basis in the Code for corrective actions

3.1. The Authority has decided that the events of December 2019 constituted a UTS.

3.2. As defined in clause 1.1 of the Code, a UTS threatens, or may threaten, confidence in, or the integrity of, the wholesale electricity market, and is a situation that cannot be satisfactorily resolved by any other mechanism available under the Code (excepting the HSOTC provisions).

3.3. Under clause 5.2(1) of the Code, the Authority may take any action that it considers is necessary to correct the UTS, provided that such an action relates to an aspect of the electricity industry that it could regulate in the Code under section 32 of the Act. Clause 5.2(2A) of the Code notes that any directions to participants made as part of the actions to correct the UTS may be inconsistent with the Code but must not be inconsistent with the Act or any other law.

3.4. Under clause 5.5, the Authority must attempt to correct every undesirable trading situation and restore the normal operation of the wholesale electricity market as soon as possible (emphasis added). The Authority is not required, and is not able, to correct every immediate and forward-looking implication from the UTS. As noted in the Executive Summary, the Authority cannot perfectly resolve all of the consequences of the UTS that occurred in 2019 because of the irreversibility of some aspects – like the spill of water. The complexity of the market also makes it difficult to robustly identify all of the impacts of the UTS on outcomes that subsequently eventuated. The proposed corrective actions that we are consulting on are approximate solutions, reflecting the scope of the Authority's powers as provided for in the Code and limitations in the Authority's ability to identify and correct all consequences of the UTS.

3.5. Clause 5.2(1)(a) of the Code provides that the Authority may take any action necessary to correct the undesirable trading situation. Although not an exhaustive list, clause

[6] From the executive summary of *The Authority's final decision on claim of an undesirable trading situation*.

5.2(2) of the Code provides four examples of actions that the Authority could take to correct the UTS. These examples include:

(a) directing that an activity be suspended, limited or stopped, either generally or for a specified period:

(b) directing that completion of trades be deferred for a specific period:

(c) directing that any trades be closed out or settled at a specified price:

(d) directing a participant to take any actions that will, in the Authority's opinion, correct or assist in overcoming the UTS.

3.6. The Authority considers that the proposed actions set out in Section 5 below comply with the obligation set out in clause 5.5 of the Code and are in keeping with the examples laid out in clause 5.2(2)(c) and (d), as set out above.

3.7. Clause 5.3 of the Code requires the Authority to consult with the system operator if the action to correct a UTS may have an effect on system security. The Authority has engaged with the system operator on the proposed actions to correct though it does not currently consider that the proposed actions would affect system security.

3.8. In accordance with clause 5.2(1) of the Code, the Authority considers that the proposed actions are necessary to correct the UTS, ie, the situation that arose in December 2019. The 'actions to correct' do not seek to prevent or moderate future events. Future events or outcomes are more properly addressed through the Authority's responsibility for the Code. When, or if, the Authority considers that there should be changes to the Code to support competition, reliability and efficiency in the wholesale electricity market, such changes would be progressed through the Authority's usual consultation processes, consistent with the Authority's statutory obligations. In this vein, section 8 discusses components of our work programme that aim to improve outcomes in the wholesale electricity market.

3.9. As noted, there is also a separate process to determine whether offer behaviour was consistent with the high standard of trading conduct provisions that exist in the Code.[7]

4. Scope of actions to correct

4.1. One of the outcomes observed during the UTS period was excess spill that occurred at hydro generation stations in the South Island. The excess spill had security of supply implications for the North Island and simultaneously resulted in higher prices during the UTS period, particularly from 3 to 17 December.

4.2. The effects of the UTS on security of supply were of particular concern because the impending HVDC and Pohokura outages in 2020 meant that there were fewer options to maintain system security in the North Island. If the UTS had not occurred, the counterfactual outcome would have been higher North Island hydro storage levels from January 2020 onwards. This counterfactual state cannot be restored, nor can the Authority determine with any certainty when that increased storage would have been used to generate electricity or what the market (price) outcomes would have been when that water was released.

4.3. It is impossible to reverse everything that happened during the UTS period. In particular, the Authority considers that it is not feasible to un-spill the excess spill that

7 See clauses 13.5A and 13.5B from Part 13 of the Code.

occurred, nor unwind the attendant effects on North Island security of supply and the potential further flow-on impacts. Reflecting these difficulties, the Authority's proposed actions to correct the UTS primarily focus on the prices in the spot market that occurred during the UTS period, which the Authority proposes to revise. The Authority nevertheless seeks feedback on any feasible actions to correct that would address the excess spill that occurred, the implications for security of supply in the North Island and any other consequent effects.

Q1.	What, if any, actions should the Authority undertake to address excess spill, system security, and any other consequent effects? How would such actions address the objectives of Part 5 of the Code?

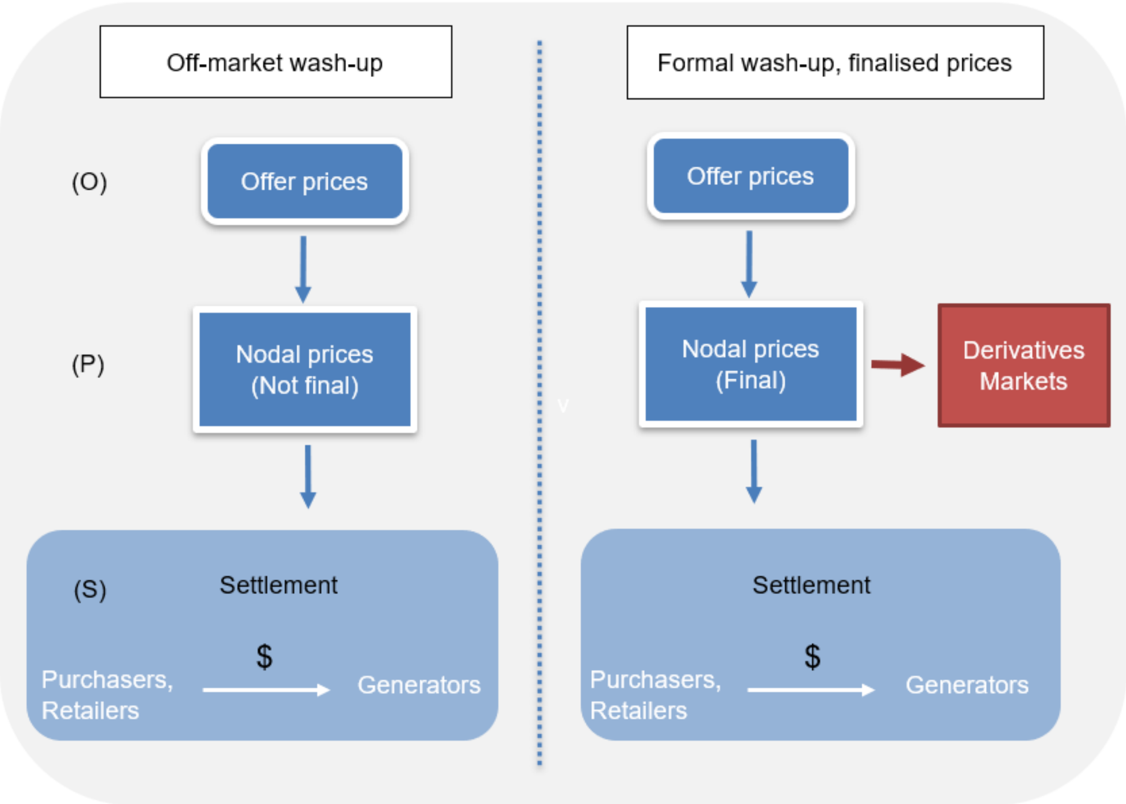
5. The Authority proposes to reset settlement for traders in electricity for the UTS period

5.1. A core function of the wholesale electricity market is to determine the final prices that purchasers pay or generators receive for electricity. Prices are a major determinant of settlement outcomes. The rest of the consultation paper focuses on the correction of prices and settlement during the UTS period. The proposed actions to correct the UTS aim to restore normal operation, and confidence, in the wholesale market.

5.2. Figure 1 provides a stylised representation of the determination of prices in the wholesale electricity market and illustrates important design choices for the actions to correct the UTS. The Authority could intervene at three points: at point (O) by revising offers; at point (P) by revising prices; or at point (S), directly affecting settlement between purchasers and generators.[8] If the Authority intervenes at (O) or (P) it could also decide to make the resultant prices final. In that second case, depicted on the right, the revision to final prices would have flow-on effects to at least some derivatives markets.

8 Note, the figure illustrates the usual settlement process in which retailers and purchasers pay generators. The actions to correct may result in payment flows in the reverse direction as generators re-imburse purchasers and retailers for excess payments. O for Offers; P for Prices; S for Settlement.

Figure 1: Stylised representation of options for resettlement of the wholesale market



5.3. Settlement payments and receipts are the product of price and volume for both generation and load. Hypothetically, volumes could also be revised alongside prices to influence settlement outcomes. Resetting volumes would likely result in the spilling South Island hydro generators receiving payments for energy they did not inject into the network and other generators would not be compensated for the electricity that they injected, implicitly penalising them for their participation in the market during the UTS period. The Authority currently proposes to calibrate settlement using the volumes originally dispatched. This approach is consistent with that taken to correct the 2011 UTS. Any perverse outcomes for the dispatched volumes of other generators would be addressed through constrained on payments.

Q2.	Do you agree that the Authority should seek to correct the UTS period by resetting the payments made/received by spot market purchasers and generators? (If not, please explain your reasoning.)

5.4. Payments made and received for electricity injections and off-takes could be reset by notionally adjusting offers and using these to reset final prices. The Authority proposes that generators be paid for their historical, dispatched generation but at revised final prices. (Constrained on payments would also be made to certain eligible generators, as discussed later in this paper.)

Q3.	Do you agree that the Authority should attempt to correct settlement during the UTS period by resetting prices in the electricity market?

Q4.	Do you agree that injection and off-take volumes should remain unchanged in any resettlement?

5.5. A key choice, when designing the actions to correct, is to determine whether final prices should be formally reset or whether an off-market 'wash-up' should be undertaken in which traders are required to make (or receive) side payments to the clearing manager without resetting final prices (see the left and right sides of Figure 1).[9] An off-market 'wash-up' that does not affect final prices would have different implications for derivative markets, since contracts in those markets depend on the final prices of the wholesale market.

5.6. If the wholesale market were operating normally, the derivatives market would also embody the prices that reflect normal competitive pressure. The Authority's current, preferred action to correct the UTS is to reset final prices so that these prices reflect 'normal' competitive pressures. By contrast, if an off-market wash-up was adopted, derivatives markets would be insulated from the correction of the UTS. Arguably a return to 'normal' market operation would require derivatives to incorporate the correction to the UTS, at least to the extent that derivatives contracts provide for this possibility. Additionally, if final prices are not reset as part of the actions to correct, then future assessments of 'normal' market pricing may incorporate prices from the UTS period that were not reflective of the normal operation of the market.

Q5.	Do you agree that the Authority should attempt to correct the UTS by revising final prices in the electricity market, rather than by an 'off-market' wash-up of spot electricity payments to and from the clearing manager?

The Authority proposes to reset offers to correct final prices and effect resettlement

5.7. In the rest of the paper we refer extensively to offers. Generally, these references will be to offers for the spot electricity market, as are usually provided to the Wholesale Information and Trading System (WITS) by generators. For a given trading period, offers from a generating station include up to five offer prices and five related offer volumes. These paired offer prices and offer volumes are referred to as bands. In the rest of the consultation paper a reset or revision of offers will mean an adjustment to offer prices or offer volumes or both.

5.8. As outlined in Figure 1, the Authority considers that there are three main options available to correct the UTS.

(O) reset offer prices and offer volumes from relevant hydro generation stations and use SPD to quantify resultant final prices, as discussed in 5.24 below, to inform revisions to settlement;

(P) reset [final] prices directly to inform revisions to settlement;

(S) reset settlement by requiring off-market, calculated re-imbursements from just key South Island generators, and remit these payments, eg to purchasers.

5.9. A variation on Option (O) was employed in the preliminary decision paper to understand how offer prices would need to change to fully absorb the excess spill from Benmore, using the Authority's vSPD model. The Authority's analysis, reported in the

9 Wash-up is used here in an informal sense and does not formally equate to the washup procedures outlined in subpart 6 of Part 14 of the Code.

final decision paper, found that a single offer price of approximately $13.70/MWh, common across the major South Island generators, would have been needed to clear the excess spill from Benmore during the UTS period.

5.10. Option (O) is the Authority's current preferred method to correct the UTS. Resetting offers enables the Authority to correct for the reduction in competitive pressure during the UTS period. Option (O) has three important features: it respects the transmission constraints that influence final prices at different nodes; it enables final price adjustment to flow through to all nodes; and in usual circumstances it ensures revenue from purchasers is sufficient to pay for the electricity that was generated. Later in paragraph 5.41 several methodologies are identified to calibrate corrections to energy offers and energy prices to restore normal competitive outcomes in the wholesale market.

5.11. Option (P) could also be used to adjust nodal prices, but a key challenge with this approach is to ensure that the price adjustments are mutually consistent and calibrated to appropriate magnitudes. Option (P) would be a greater departure from the normal market mechanisms that determine prices, and would be considerably less tractable than option (O), in particular it would require adjustments to reflect losses and constraints that would be difficult to determine without the use of SPD.

5.12. Option (S) would involve significant judgement to determine the magnitude of re-imbursements. Furthermore, although the offer behaviour of generators on the Waitaki and Clutha rivers is considered to be central to the resultant market outcomes, other generators also benefitted from those offers and the Authority currently considers that the UTS is best corrected by revising the payments made and received by <u>all</u> generators, retailers and other purchasers of electricity on the spot market.

5.13. The Authority considers that resetting prices as per (O) provides a more objective mechanism to determine the adjustments needed to correct the UTS than options (P) or (S). Option (O), by correcting offers from South Island hydro generators, clarifies the causal contribution of those offers and highlights that price spikes can occur despite the fact that the offers from South Island hydro generators are revised to a low level.

5.14. While it may be possible for the Authority to take no action to correct the UTS, provided it has attempted to do so as required by clause 5.5 of the Code, the Authority's current view is that option (O) would correct the UTS by restoring confidence in the wholesale electricity market and is therefore preferred to no action.

The Authority proposes to reset offer prices for generating stations on the Waitaki and Clutha rivers

5.15. As noted in the final decision paper, the Authority has concluded that a confluence of factors reduced the competitive pressure faced by the large South Island hydro generators. Correcting the offers made by relevant South Island hydro stations is one of the options identified above. During the UTS period, South Island hydro generators had access to high volumes of water, but there were substantial periods where this water was being spilled rather than used for generation.

5.16. The relevant South Island hydro generating stations include Aviemore, Benmore, Clyde, Manapōuri, Ōhau A, Ōhau B, Ōhau C, Roxburgh, Tekapo A, Tekapo B, and

Waitaki.[10] We discuss below why offers from three of these generating stations may not need to be modified, thereby potentially simplifying the actions to correct.

5.17. The Authority's current proposal is to correct the UTS by correcting the offers made by Meridian from its generating stations on the Waitaki river and to correct offers by Contact made at its generating stations on the Clutha/Mata-Au river, ie, the Authority is proposing to correct offers for all stations named above excepting Manapōuri and Tekapo A and B. (The inclusion or exclusion of other generating stations from the proposed actions to correct is discussed in more depth below.)

5.18. Meridian controls generation stations on the Waitaki River and is the largest generator in the South Island. In its final decision paper, the Authority considered that the confluence of factors led to a reduction in competitive pressure, and that there was a disconnect between offers from stations on the Waitaki and the supply and demand conditions that prevailed during the UTS period, given the abundance of water.

5.19. The Authority also proposes to reset offers for stations on the Clutha/Mata-Au River. These offers were also inconsistent with the abundance of water available for generation and contributed to the reduction in competitive pressure in the South Island.

5.20. Despite the general reduction in competitive pressure, offers from some South Island generating stations nevertheless remained consistent with normal levels of competition.[11] On that basis, the proposed actions to correct focus on a subset of generating stations.

5.21. As noted in figure 19 of the preliminary decision paper, the mean quantity-weighted offer prices (QWOPs) for Manapōuri were very low, below $2.50/MWh for the UTS period, though there were occasional spikes in QWOPs for several hours at a time. Offer prices that are very low are unlikely to affect any reset in final prices. Very low offer prices exert competitive pressure on other generators through volume even if they do not directly affect marginal prices. Low offers can be taken as given, thereby simplifying the actions to correct.

5.22. The Authority currently considers that offer behaviour at Tekapo A and B was consistent with these stations exerting normal competitive pressure on other South Island generators (see figures 37-39 in the preliminary decision paper), though their capacity to influence prices is limited by their nameplate generation capacity. Therefore, the Authority does not propose to reset offers from Tekapo A and B.[12]

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10 Offers could be reset for AVI2201 AVI0, BEN2202 BEN0, CYD2201 CYD0, OHA2201 OHA0, OHB2201 OHB0, OHC2201 OHC0, ROX1101 ROX0, ROX2201 ROX0, and WTK0111 WTK0.

11 The Authority has examined the offers of other South Island hydro generating stations, namely the Coleridge and Cobb stations, and considers that they were not materially modified in response to the decline in competition during the UTS period. These stations were also not cited in the original UTS allegation and are therefore unlikely to have threatened confidence.

12 We also note that there were historical outages for Tekapo and Manapōuri that might complicate corrections if an historical reference period were used to inform amendments to offers.

Q6.	If offer prices and offer volumes are reset, which hydro generating stations should have offers reset? (Please answer yes/no, with any additional supporting commentary.) a. Aviemore? f. Roxburgh? b. Benmore? g. Tekapo A, B? c. Clyde? h. Waitaki? d. Manapōuri? i. Other stations? e. Ōhau A, B, C?

The Authority proposes to leave offers in the North Island unchanged

5.23. During the UTS period, the offer behaviour of North Island generators was expected and normal, given the forthcoming outages. The value of water for North Island hydro generators was also non-zero given the need to conserve water for later generation. Consequently, the Authority does not propose to reset offer prices or offer volumes in the North Island.

Q7.	If offer prices and volumes are reset, do you agree that North Island offer prices and offer volumes should remain the same as originally submitted? (If not, please identify any alternative actions.)

The Authority proposes to cap offer prices to calibrate a reset of clearing prices

5.24. The Authority has identified several different mechanisms that could be employed to calibrate any reset of prices. These mechanisms include:

i.) correcting <u>offer prices</u> at the relevant hydro generating stations by placing a single <u>cap</u> on the maximum offer price that can be charged; offer volumes at the capped price would be computed by summing the original offer volumes that were offered at prices above (or equal to) the price cap; these revised offers would then be used to compute final prices via SPD;

ii.) correcting <u>offer prices</u> at relevant hydro generating stations to a single <u>level</u> with <u>offer volumes</u> reflecting the summed volumes originally offered in different bands; these revised offers would then be used to compute final prices via SPD;

iii.) correcting offer prices and offer volumes to levels based on offers in an historical ‘reference period’, where the reference period is reflective of normal competitive pressure in similar hydrological circumstances;

iv.) correcting offers by introducing offer prices and volumes that vary through time and by generating station;

v.) correcting South Island <u>final prices</u> at all South Island pricing nodes directly to levels that have been observed historically in similar hydrological periods;

vi.) correcting South Island <u>final prices</u> at all South Island pricing nodes directly to their average level (not conditional on hydrological conditions);

vii.) using offer price modelling by Contact, Genesis, and Meridian to assess ‘normal’ offer prices at the major hydro generating stations in the lower South Island.

5.25. For reasons outlined below, the Authority currently prefers mechanism (i) – a cap on offer prices to calibrate a final price correction. The Authority's current view is that it is preferable to correct offer prices, and offer volumes, and to feed those revised offers into the SPD model. In usual circumstances, SPD simultaneously ensures that transmission constraints are respected, and sufficient revenue is generated to remunerate generators for the dispatched electricity. Revising offers also enables appropriate final price revisions to propagate to all nodes. Correcting offer prices is analogous to the approach deployed to correct the UTS of 2011. In contrast, calibrating appropriate final price adjustments at all nodes is difficult if final prices are adjusted directly and would not utilise normal market mechanisms.

5.26. A cap on offer prices directly addresses the concern that offer behaviour led to high nodal prices that were inconsistent with the supply and demand conditions that prevailed during the UTS period. Placing a cap on higher-priced bands directly corrects higher-priced outcomes. Applying a cap on offer prices does not preclude prices dropping to low levels, as occurred in the latter half of the UTS period once demand fell.

5.27. Mechanisms (i), (ii), (iii), and (iv) are closely related. Mechanism (i) truncates the offer distribution, leaving offer volumes made at offer prices below the cap unchanged. In contrast, mechanism (ii) raises low offer prices and reduces high offers to the single offer price. Mechanism (iii) substitutes offer prices from a reference period for the offer prices during the UTS period and adjusts offer volumes so that appropriate volumes are offered at each offer price. Mechanism (iv) provides for time variation in offer prices and variation across generating stations.

5.28. Mechanisms (i) and (ii) rely on a single offer price adjustment common to all relevant generators. These mechanisms are comparatively simple to implement and to understand, but they do not embody the diversity of offering that is usually observed in the wholesale market, through time and across stations.

5.29. Mechanism (iii) incorporates the diversity of offers that is usually observed, but this approach is more complex, and the outcomes depend on modelling decisions made to adjust offers. Importantly, the Authority currently considers that there is no 'reference period' that appropriately approximates the hydrological conditions of December 2019. The South Island hydrological conditions most similar to those of December 2019 occurred in 1995 and 1958, prior to the start of the spot market. Furthermore, the transmission grid has evolved and market circumstances have changed, which would be expected to influence offer behaviour. Examples of these differences include grid design (such as the expansion of the HVDC link), grid outages, changes to gas supply, the greater prevalence of intermittent generation, and changes to resource management obligations and public conservation rules, amongst others.

5.30. Mechanism (iv) provides great flexibility in revising offers, but substantially increases complexity because there are 1200 half-hour trading periods in the UTS period, and there are nine generating stations whose offers are proposed for revision.

5.31. One possibility to determine a time-varying offer price revision would be to determine the price for each given trading period that would absorb the excess spill that was estimated to have occurred in that period. The Authority currently considers that variation in offers through time or across stations would imply a spurious degree of precision and would exaggerate the Authority's ability to fine-tune its intervention to correct the UTS. First, as noted in Meridian's submission on the preliminary decision paper, there is uncertainty about that magnitude of flows through spill gates: the NIWA[13] standard that Meridian follows endeavours to ensure that 95 percent of all flow values are within ±8 percent of the true flow value. The central limit theorem from statistics also implies that average flows are estimated more precisely (have smaller standard errors), providing support for a simpler approach that focuses on the average spill for the UTS period. Second, tuning the price to resolve the estimated excess spill for a given day requires a grid search across possible prices.

5.32. Replicating the analysis undertaken in the preliminary decision paper for 1200 trading periods would entail a material computational burden that the Authority considers may not be justified given the other approximations that would influence outcomes from the proposed actions to correct.[14] Relatedly, determining separate offer prices for the relevant stations also results in the 'curse of dimensionality', which amplifies the computational difficulty.[15] Finally, highly granular pricing would also come at substantial operational cost.

Q8.	Do you agree that resetting offer prices and volumes by imposing a cap is the preferred action to correct the UTS? If not, please identify preferred alternatives.

Q9.	If revisions to offer prices are to vary through time or across generating stations, how should the offer prices be determined?

5.33. Mechanism (v), adjusting final prices directly, is similar to (iii) in that it seeks to calibrate offer price adjustments to a period with similar circumstances, and replicates the simplicity of mechanisms (i) and (ii). However, it shares the disadvantages of these mechanisms, in particular the difficulty in finding a suitable reference period. As noted above, intervening directly with final prices (rather than offers) represents a substantial departure from the normal process that is used to determine final prices.

5.34. Mechanism (vi) would not be consistent with hydrological conditions and may not fully correct the UTS by restoring confidence in the wholesale market. Similarly, mechanism (vii) requires reliance on the offer price modelling of the major generator-retailers and may not receive general support as these entities may not be regarded as disinterested participants in such an exercise.

5.35. The Authority therefore proposes to adopt mechanism (i).

If final prices were set directly, how should they be calibrated?

5.36. The Authority is consulting on a baseline proposal to correct the UTS period by re-calibrating offer prices and offer volumes, by band, and then passing these offers back through SPD to determine the impact on final (or settlement) prices. An alternative

13 The National Institute of Water and Atmospheric Research is a Crown Research Institute.

14 One approximation is that the usual price discovery process prior to dispatch cannot be replicated in the actions to correct the UTS. Generators have knowledge about the conditions that they experienced in the UTS period and their ex post offer behaviour would likely differ from that in real-time. Similarly, it would be difficult to replicate the usual processes associated with Transpower's Simultaneous Feasibility Test (SFT) software, which revises constraints embedded in SPD.

15 For example, suppose that there are ten (discrete) possible prices in a single dimension, each of which is being assessed for optimality in a grid search, then each of those ten prices may need to be evaluated. With a two-dimensional price space, each with ten prices, there are 100 possible price combinations that need to be explored, and if the price space increases to three dimensions then there are 1000 possible price combinations, each of which could be optimal.

proposal is to reset final prices directly. For example, the final prices for South Island nodes could be calibrated to the prices that prevailed during a ‘wet’ reference period.

5.37. New Zealand has a nodal electricity system, and electricity flows from South Island generators to North Island consumers are an important feature of this system. Setting nodal prices directly may create concerns that the corrections might be mis-calibrated and might not properly reflect what would have occurred if generators in the South Island had faced normal competitive pressures and the market had also faced the pressures guiding North Island offer behaviour.

5.38. Resetting final prices directly may result in prices that are inconsistent with the transmission constraints that existed during the UTS period. Final prices are also normally computed using the SPD model and the baseline proposed action that focuses on offer prices more closely replicates normal pricing processes.

Q10. Do you consider that final prices should be reset directly? If so, how should they be calibrated?

The Authority proposes to calibrate the sum of offer volumes to that of the UTS period

5.39. The Authority proposes that revised offer volumes for each generator should aggregate to the level that the generator originally offered during the UTS period. The total volumes offered by generators during the UTS period reflected their underlying capacity at that time and incorporated planned outages and operational difficulties. Generators generally do not withhold capacity by curtailing the aggregate volume of their offers because the ‘safe harbours’ clause of the Code, clause 13.5B(1)(a), incentivises generators to offer all of their available generating capacity. To withhold electricity for profitability reasons, over and above the capacity issues just noted, generators match offer volumes with offer prices that they do not expect to clear. Although the Authority has concluded that there was ‘excess spill’ during this period, the corresponding ‘lost’ generation primarily reflected bands of offered generation at high offer prices that did not clear, rather than reflecting unoffered generation. The cap on offer prices proposed in this consultation paper directly addresses these higher-priced bands.

Q11. Do you agree that the aggregate offer volumes of each generating station should equal the aggregate amount offered by that station during the UTS period? Please describe any preferred alternatives.

The Authority proposes to cap offer prices at $13.70/MWh in accordance with the analysis of the UTS decision paper

5.40. The calibration of the offer price cap or the single offer price is a crucial decision for the actions to correct. Unfortunately, there is no pre-eminent methodology to guide the calibration. The Authority would need to exercise judgement to calibrate any proposed cap to restore confidence in the wholesale market.

5.41. The Authority has identified several methods to calibrate the offer price/offer price cap:

(a) the spill analysis in the final decision paper computed a single offer price of $13.70/MWh that would absorb the ‘excess spill’ at Benmore during the UTS;

(b) historical spot prices could be used to guide the single offer price or offer price cap by choosing an appropriate quantile; for example, the 5th percentile of daily spot prices in the Lower South Island between 1 January 2010 and 2 December 2019 was $18.30/MWh;

(c) historical spot prices during similar hydrological conditions could be used in a similar manner: the median historical daily price in the lower South Island when South Island hydro storage was above the 99th percentile was $29.59/MWh;

(d) offer prices could be calibrated to the final prices seen in the Lower South Island in the latter half of the UTS period, 18-27 December 2019, which averaged approximately $12/MWh;

(e) the claimants recommended, in their original letter of claim, that offers should be corrected by setting them to $5 "to reflect a near-zero water value plus a small O&M component"; this proposal could be slightly amended to $7.42/MWh, reflecting the South Island Mean Injection (SIMI) rate of $6.42/MWh from Transpower that applied in 2019/20 with an additional $1/MWh for other operating and maintenance costs.[16]

5.42. The Authority currently proposes to calibrate a cap on offer prices with method (a), as it connects the revised price to the spilling which the Authority considers may have threatened confidence in the wholesale market. This calibration directly connects the offer price cap to the excess spill that was occurring during the UTS period.

5.43. It is worth noting that the analysis used to derive that offer price was conservative, in that it only focused on absorbing spill at Benmore, and a lower offer price, closer to a measure of marginal cost, could be argued for given that spill was occurring much more broadly across the Waitaki and Clutha/Mata-Au river systems. Whether even lower prices would have been feasible, given resource management and operational constraints, is difficult to determine robustly. In contrast, the $13.70/MWh price was feasible in the context of the resource management obligations that were being managed on the Waitaki River. The $13.70/MWh offer price cap embodies a level of South Island generation that does not penalise South Island hydro generators for river management required by resource consents.

5.44. The Authority currently considers that a $13.70/MWh cap during the UTS period would appropriately calibrate the expected degree of competitive pressure, given the abundance of water, driving offer behaviour towards rather than to short-run marginal cost.

5.45. The other options described above illustrate where the preferred proposed option lies in the distribution of prices and illustrate how other mechanisms would result in offer prices or offer price caps at different levels. As has been noted, there is no pre-eminent methodology to calibrate the offer cap level, and a degree of judgement needs to be exercised.

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16 Parsons Brinckerhoff (2012), *2011 NZ Generation Data Update* estimated operating and maintenance (O&M) costs for hydro-electric generation on behalf of the Ministry for Economic Development. In 2020 dollars the Parsons Brinckerhoff estimate of variable O&M costs was $0.95/MWh, close to the $1/MWh used here. The recent *Hydro generation stack update for large-scale plant*, commissioned by the Ministry of Business, Innovation and Employment and produced by Roaring40s Wind Power Ltd, suggested a variable O&M cost of $8/MWh, taking the HVDC charge into consideration. The Authority's simulation using $7.42/MWh falls between these two estimates.

Q12.	Which of these mechanisms in paragraph 5.41(a) – (e), if any, should be used to calibrate 'corrected' electricity offer prices? (Please identify any other preferred alternatives.)

The Authority proposes to allow constrained on payments for generators whose offers have not been revised

5.46. The proposed correction methodology revises offers and results in lower final prices. Generators that have had their offers revised or that made offers at prices below the reset final prices would receive lower revenue (because the reset clearing price is now lower). The Authority proposes that generators whose offers have been revised would not be eligible for constrained on payments.

5.47. The original dispatch schedules from SPD in December 2019 may have dispatched some generators at prices above the reset final prices. Generators whose original offers were dispatched and whose offer prices were above the reset final prices could be treated as constrained on. In this part of the proposal, generators would be remunerated at least according to their offers, in accord with normal industry processes. The Authority currently considers that it is important to compensate high price generators for supporting system security and wants to ensure that the actions to correct the UTS do not create perverse incentives to withdraw from providing those services.

5.48. The Authority proposes that only generators that did not have their offers reset would be eligible for constrained on payments. Consumers would still be better off in aggregate because final prices would be lower, and the settlement costs fall for South Island generators with reset offers, while the costs associated with constrained on generation would be no higher than in the original settlement of the UTS period. The ramifications of allowing constrained on are reported later in this consultation paper.

5.49. An alternative would be to set constrained on for eligible generators to some notion of generator operating costs, rather than to the original offer prices. This approach to constrained on would be further from 'normal' market processes and would be more difficult to implement, as usual settlement processes would need to be augmented with cost information to guide the calibration of constrained on payments. If generators were compensated exactly at their marginal cost (rather than at their marginal offer prices) then they would be indifferent between supplying and not supplying energy (as the marginal profit from supply would be zero) and they could in principle withdraw from providing supply in similar future circumstance.

5.50. If constrained on occurs in relation to instantaneous reserves, the Authority proposes to treat it symmetrically to the options discussed above.

Q13.	Do you agree that generators, other than those with 'reset offers', that were dispatched to generate electricity at offer prices above the reset final prices should be treated as constrained on? (If not, please identify preferred alternatives.)

The Authority proposes to leave constrained off payments unchanged

5.51. The Authority is not proposing to revise constrained off payments. Under clause 13.201 of the Code constrained off payments are not made to generators, except in relation to ancillary service agreements, such as those associated with frequency keeping. Constrained off services such as interruptible load were also not central to the UTS allegation and the Authority's subsequent finding of the UTS. The Authority is currently of the view that extending the actions to correct to constrained off would not serve to restore confidence in the wholesale market.

Q14.	Do you agree with the Authority's proposal not to revise constrained off payments, associated with frequency keeping? (If not, please explain and identify any preferred alternatives.)

The Authority is not proposing to correct instantaneous reserve offers but proposes that final reserve prices and reserve settlement would both be revised

5.52. The co-optimisation of energy and reserves means that revisions to energy offers would normally propagate through to reserve prices. The Authority proposes that instantaneous reserve <u>prices</u> would be reset and reserve payments resettled, reflecting the revisions to energy offers.

5.53. Revising instantaneous reserve prices is a direct result of revising energy offers but it is an additional step to revise instantaneous reserve offers. The Authority does not currently consider that reserve <u>offers</u> need to be corrected to restore confidence in the wholesale market. Reserve prices were not raised as an issue during the UTS investigation, suggesting reserve offers did not pose a threat to confidence in the market. The Authority also notes that settlement for instantaneous reserves is two orders of magnitude smaller than settlement of the spot electricity market, and settlement for frequency keeping is roughly half that of instantaneous reserves. Table 1 reports the magnitude of settlement for various components of the wholesale electricity market, confirming the difference in scale between the spot and other electricity markets. The reported amounts reflect, in most cases, the amounts paid to generators.

Table 1: Energy market settlement – approximate annual magnitudes 2020

Component	Settlement ($M)
Energy (spot)	$4,500 million
Loss and constraint excess	$140 million
Instantaneous reserves	$30 million
Frequency keeping	$15 million

Source: Electricity Authority estimates.

5.54. Figure 2 illustrates that sustained instantaneous reserve prices in the South Island during the UTS period were unexceptional relative to history over the last two years. Daily SIR prices were below $3.50 for the entire UTS period.[17]

5.55. The prices for fast instantaneous reserves have more spikes but are largely unexceptional relative to recent FIR prices (see Figure 3).

17 At trading period frequency 97.8 percent of South Island SIR prices were below $5 and 84.5 percent of prices were below $2.50/MWh.

Figure 2: South Island sustained instantaneous reserve prices (daily)

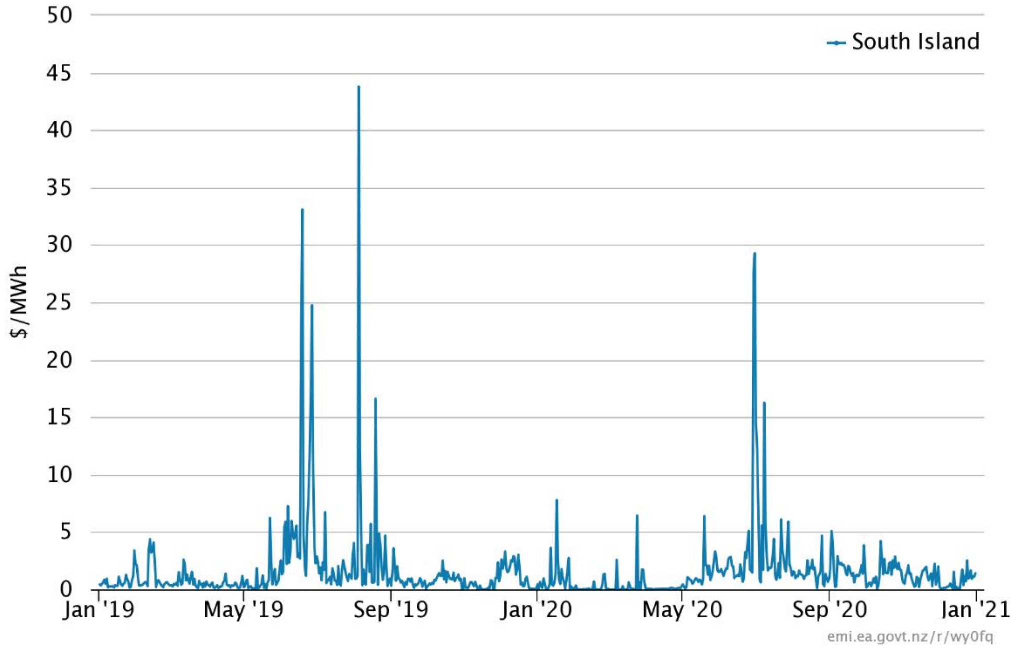
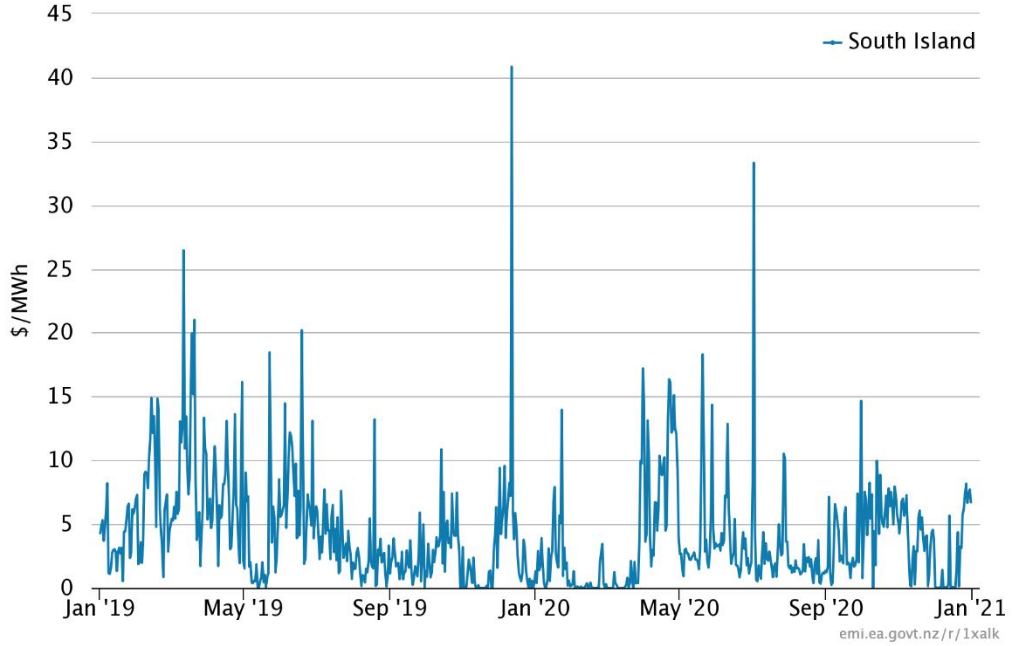


Figure 3: South Island fast instantaneous reserve prices (daily)



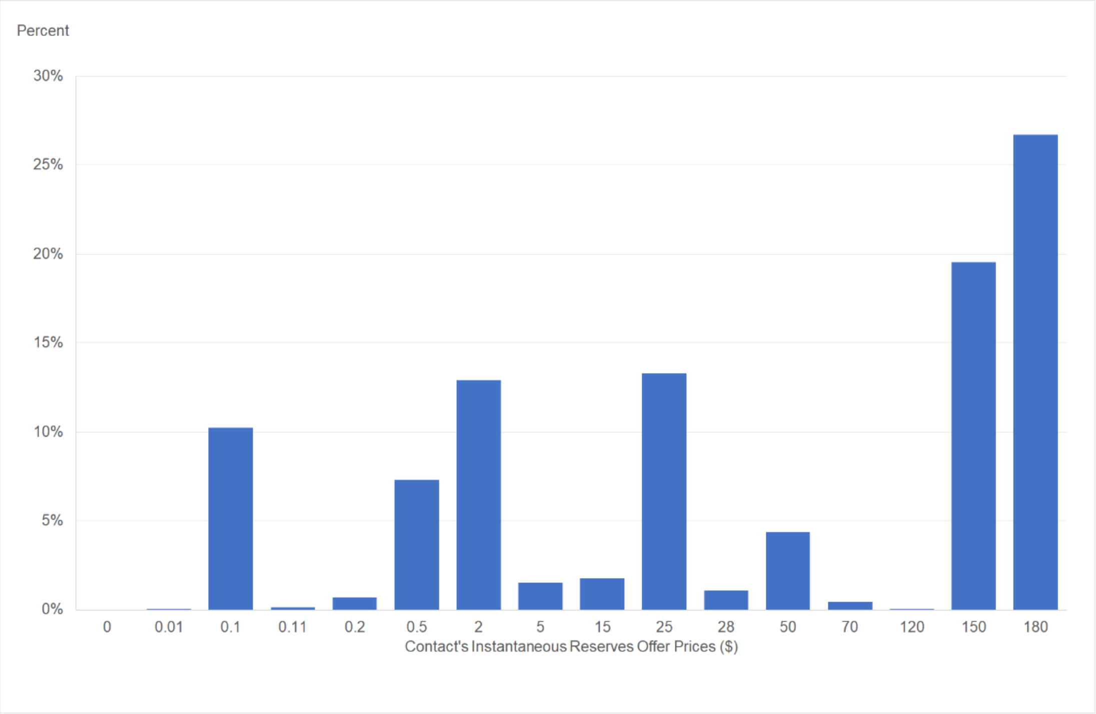
5.56. Maximum instantaneous reserve offer prices from the relevant South Island hydro generators during the UTS period are reported in Table 2. As the table makes clear, reserve offers were generally at low levels with the exception of offers at Roxburgh A and B and Clyde, consistent with Contact's efforts to avoid dispatch. Contact's South Island FIR settlements during the UTS were around 8 percent of the total FIR payments made during the UTS period across both islands.

Table 2: Maximum instantaneous reserve offer prices during the UTS period

Trader ID	Pricing Node	Maximum offer price ($/MWh)	Value-weighted offer price ($/MWh)
CTCT	ROX2201 ROX0	180.00	127.47
CTCT	ROX1101 ROX0	150.00	119.39
CTCT	CYD2201 CYD0	120.00	13.28
CTCT	CYD0331	0.11	0.11
GENE	TKB2201 TKB1	1.00	0.01
GENE	TKA0111 TKA1	1.00	0.59
MERI	BEN2202 BEN0	1.00	0.21
MERI	OHA2201 OHA0	1.00	0.25
MERI	OHB2201 OHB0	1.00	0.27
MERI	AVI2201 AVI0	1.00	0.07
MERI	OHC2201 OHC0	1.00	0.27
MERI	WTK0111 WTK0	0.02	0.02
MERI	MAN2201 MAN0	0.00	0.00

Source: Electricity Authority estimates.

Figure 4: Histogram of Contact's instantaneous reserve offer prices during the UTS period



5.57. If Contact's offers were to be revised then options would include adopting an average of instantaneous offer prices from competitors for the trading periods in question or taking a simple average of Contact's own offers in the lower half of their offer price distribution during the UTS period. Alternatively, an average of Contact's historical instantaneous reserve offers could be used to reset offers.

5.58. The Authority currently considers that revising instantaneous reserve offers would not assist in correcting the UTS. As shown below, the revised energy offers also serve to reduce fast instantaneous reserve prices in the South Island. The benchmark proposal is therefore not to adjust reserve offers. The Authority is nevertheless seeking feedback on whether to adjust offers in the instantaneous reserves market simultaneously with the revisions to offers in the spot electricity market.

Q15.	Should offers to the instantaneous reserves market during the UTS period be corrected? If so, how should instantaneous reserve offers be corrected?

The Authority is not proposing to amend the following ancillary services

Frequency keeping

5.59. The Authority is not proposing to revise outcomes for frequency keeping. The frequency keeping market is settled in a separate process that precedes dispatch in the spot electricity market. If the outcomes of the frequency keeping market were amended then constraints that influence outcomes in SPD would need to be amended, and the resulting complexities would increase costs and would not assist in restoring confidence in the wholesale market. As shown above, the frequency keeping market is half the size of the instantaneous reserves market, and the Authority's current view is that frequency keeping is of subsidiary importance in correcting the UTS, relative to settlement in the spot market.

Other ancillary services

5.60. For the avoidance of doubt, the Authority notes that it is not proposing to revise settlement of over frequency reserve, black start, or voltage support.

The Authority proposes to reset final prices and let derivatives markets adjust according to their terms and conditions

5.61. The Authority's proposal to correct the UTS involves resetting final spot prices. In turn, a revision to final spot prices would prompt some derivative contracts to resettle, though not necessarily all. Some derivatives contracts expressly allocate the risk of price resettlement between the parties to the contract. In other cases, the allocation of risk is not explicitly specified and must be inferred. In yet other cases the allocation of risk is opaque and would be subject to negotiation between the contracting parties.

5.62. The Authority sees no reason to void the allocation of risk voluntarily agreed by parties and proposes to take only limited actions under Part 5 of the Code in relation to derivatives contracts.

5.63. If the wholesale electricity market were operating normally, markets for financial derivatives, including bilateral 'over the counter' (OTC) forwards, financial transmission rights, and futures and options would adjust to reflect final prices in the spot electricity market. These financial derivatives are used by participants to manage their risk positions. Ideally, the settlement of derivative contracts should reflect the prices that would have prevailed if the UTS had not occurred.

5.64. Restoring the internal consistency between derivative and spot prices is however problematic for assets that are continuously traded.

5.65. Derivatives are part of a wider array of assets that entities choose amongst, reflecting their tolerance for risk and their preference for returns in different circumstances. The impact on participants of the UTS, and the actions to correct, depend on what financial hedges they own, the other assets in their portfolio, and their exposure to other streams of income.

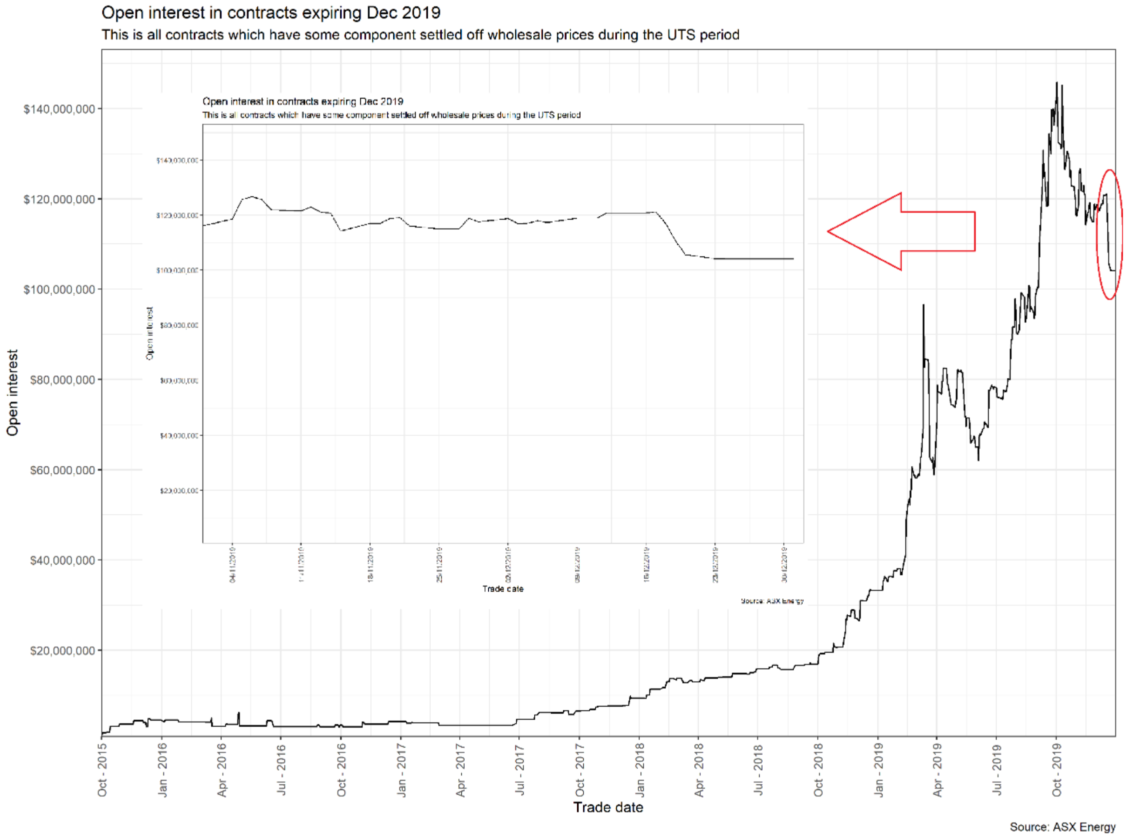
5.66. Assets embody forward-looking expectations of future outcomes and payoffs. As agents revise their beliefs about the future, the incentives to hold particular portfolios of assets evolve through time. The effect of both the UTS and the actions to correct on the expectations that underpin trading through time, would be impossible to unravel.

5.67. In practice, it is unclear how corrections should account for the dynamic losses and benefits that accrued in relation to trade (and the absence of trade) in derivatives through time – at the beginning of the UTS, when the UTS was announced, and when the UTS was concluded, to name a few key points in time.

5.68. Effecting some form of resettlement at a particular point in time – say the end of December 2019 – neglects the decision making and choices that were made prior to that point. (In contrast, the decision to consume in the spot electricity market is primarily determined by the cost-benefit analysis of a single period.) The Authority currently considers that it is not practical to resolve all the losses and gains, both intended and unintended, that arose through time in relation to financial derivatives. This is another area in which the proposed actions to correct would be an approximate and necessarily imperfect resolution of the UTS.

5.69. The problem can be illustrated by considering open interest in the futures market in the run-up to the end of 2019, at which point contracts for the December 2019 month and December 2019 quarter both settled. The main graph illustrates the up-tick in open interest for these contracts beginning in 2015. The inset illustrates the overall decline in open interest in December 2019, as holders of the contracts closed out their open positions. A resettlement solely for holders at the end of the period neglects individuals who traded out of the assets prior to 31 December 2019, even though their trades were affected by the confluence of events that affected pricing of those futures. This graph illustrates that any resettlement of contracts at a given point in time would be an imperfect correction of the UTS. The Authority currently considers that it is impractical to determine what prices should have prevailed for derivatives during the entire UTS period, as if the UTS had not occurred.

Figure 5: Open interest in futures contracts that settle in December 2019



5.70. Reflecting these difficulties, the Authority currently proposes to reset final prices and let derivatives market arrangements determine the extent to which the changes to final prices flow through to these markets. The Authority seeks feedback from interested parties on this proposal to inform the final decision. OTC contracts, FTRs and futures/options are discussed in turn below.

OTC contracts

5.71. As noted in the executive summary, the Authority does not propose to use its powers under Part 5 to override the allocation of risk voluntarily agreed by contracting parties. More specifically, the Authority does not propose to use its powers under Part 5 of the Code to require re-settlement of OTC contracts or conversely to require that they do not re-settle.

5.72. Rather, the terms of OTC contracts would determine whether the revision of prices prompted by the actions to correct would prompt resettlement. In some cases, resettlement of OTC contracts may be prompted by the revision of final prices and in other cases resettlement may be expressly voided by the terms and conditions that were agreed.

5.73. The Authority does note that if final prices were reset, then the clearing manager would resettle hedge settlement agreements in accordance with Part 14 of the Code.

Financial transmission rights

5.74. Locational differences in spot prices ordinarily drive the returns on financial transmission rights. As the actions to correct may alter final spot prices at the FTR nodes, either widening or narrowing locational spreads, the payments associated with FTRs for the month of December 2019, could also be amended. The basis risk introduced by the actions to correct could be simultaneously offset by amending FTR settlement.

5.75. The interplay between the UTS provisions and the FTR market has not been previously tested because the FTR market did not exist in 2011 when the last UTS was found to have occurred. The Authority is proposing to direct the FTR manager to recalculate rentals and provide that information to the clearing manager. Provided that final prices are reset, the FTR market is expected to resettle. The FTR participation agreement (clause 4) requires the participant to comply with provisions of the FTR allocation plan. And clause 2.7 of the FTR allocation plan,[18] specifies that the FTR hedge value (provisional) relates to "The final prices in $/MWh (published in accordance with Part 14 of the Code)". Consequently, resetting final prices is expected to change the value of FTR hedges.

5.76. Analysis from the Authority, reported in the consultation paper below, provides an estimate of the price changes at the FTR nodes for December 2019 and the magnitude of the resettlement from the preferred, proposed actions to correct.

ASX futures and options

5.77. Changes to final spot prices at Benmore and Otahuhu would ordinarily affect ASX futures prices. In principle, the actions to correct may alter spot prices at these nodes, potentially altering all derivatives payments for contracts that include December 2019.

5.78. Resettlement (or otherwise) of electricity futures traded would be determined by the ASX in conjunction with its own regulatory authorities, eg the Australian Securities and Investments Commission. The Authority cannot override the obligations that the ASX has in relation to its own regulatory and legislative framework. The Authority notes feedback from the ASX that, given the period of time since the relevant ASX settlement prices were confirmed, correcting their settlement prices (consequent to a revision of the wholesale market spot prices) could adversely affect the fair, orderly, and transparent operation of their exchange. That will ultimately be a matter for the ASX to consider. The Authority notes it has different obligations to those of the ASX and must attempt to correct the UTS as extensively signalled through this process.

5.79. As noted in the executive summary, the Authority has asked the ASX, the system operator, the FTR manager and the NZX to publicly submit on the proposed actions to correct to share their views with the public, in addition to those shared directly with the Authority.

Q16.	Do you agree with the proposed approach to treatment of derivatives for the purposes of correcting the UTS? Please explain your answer.

Q17.	Are there any additional, feasible and lawful actions that the Authority should or could undertake in relation to derivatives markets?

18 The FTR allocation plan can be found here: https://www.ftr.co.nz/ftr-allocation-plan.

Flow through effects from actions to correct – loss and constraint excess and obligations to consumers that transact at spot prices

5.80. Revised settlement prices in conjunction with the original volumes of electricity that were dispatched would change the amount of loss and constraint excess (LCE) for the UTS period. Analysis by the Authority indicates that the amount of LCE increases by around $0.3-0.8 million, conditional on the actions to correct the UTS.

5.81. For the month of December 2019, the FTR market was revenue sufficient, in the sense that sufficient funding was available from the auction income to cover the full price differences covered by each FTR. Thus, no call was made on LCE funds to support the FTR market.

5.82. Unused LCE plus any unused auction income, known as residual LCE, is paid to Transpower to distribute to transmission customers (which includes distributors, direct connect consumers and generators). The preliminary analysis of FTR pay-outs when the revised offer price is capped at $13.70/MWh is for total FTR pay-outs to be slightly lower than the original settlement. This means it is likely there would be additional auction revenue to be added to the residual LCE.

5.83. It is possible that resettlement of the spot market may result in changes to the proportion of LCE allocated to different transmission customers by Transpower. In particular, some customers may have originally received a level of residual LCE greater than that implied by resettlement. The Authority's proposal is to require customers to pay back any over-payments to Transpower and require Transpower to reallocate residual LCE in accordance with the resettlement implied by the actions to correct the UTS. The Authority would welcome feedback on this proposal or alternative approaches to address this potential issue.

Q18. How should the Authority use its powers under Part 5 in relation to LCE payments?

5.84. Some electricity consumers transact with retailers on fixed price terms, while others transact on floating price terms. Consumers with fixed-price contracts are somewhat insulated from the specific prices that arose during the UTS period,[19] but consumers on variable price terms are not. The Authority is seeking feedback on whether it should direct retailers to reimburse consumers with price terms that are directly connected to spot electricity rates.

Q19. Should the Authority use its powers under Part 5 of the Code to direct retailers to reimburse consumers that had contracts on variable price terms? What, if any, action should the Authority take in relation to variable price contracts?

Trader departures from the market, invoicing and other implementation issues

5.85. A small number of retailers have exited the retail market since the UTS period, but no generators have departed since the UTS. The Authority considers that these departures are not material for the proposed actions to correct, because the traders that are likely to owe payments to the clearing manager are still participating in the

19 We note that high spot prices even in sub-periods should ultimately flow through into longer run fixed prices. Furthermore, potential increases in volatility might also increase the risk premiums embedded in fixed price contracts.

market. It is likely that those parties that have left the market can be contacted regarding any monies owed to them.

5.86. The proposed correction of market prices and settlement would have financial implications for all generators, retailers, and purchasers. The Authority anticipates that implementing the resettlement process may take several months for the pricing and clearing managers to implement and audit.

5.87. Given that the financial payments involved may be reasonably large for some participants, and fall outside of usual billing cycles, the Authority proposes to provide a window of time for traders to meet their obligations stemming from the actions to correct the UTS, after they have been invoiced. The Authority notes that, given that traders have notice that payments may be required and given the time required for the operationalisation of resettlement, traders will have time to prepare for the liquidity implications of any payments they may be required to make.

Q20.	How should any resettlement arising from the actions to correct the UTS be implemented?

Q21.	If there is a resettlement, what window of time after invoicing should be allowed for traders to meet their obligations?

The mechanics of revising offers, final prices, payments, and receivables

5.88. The process proposed in this consultation paper to correct the UTS involves several steps:

(a) the Authority would determine revisions to offer prices and offer volumes for the 48 trading periods of each of the relevant days in the UTS period for the relevant generating stations;

(b) reset offers would be provided to the pricing manager who would then use their interface to the system operator's Scheduling, Pricing and Dispatch software to calculate revised nodal prices;[20]

(c) the wholesale information and trading system (WITS) would be used to publish the prices;

(d) the reconciliation manager would provide data on the electricity generated and consumed by traders, as recorded in December 2019;

(e) the Authority proposes to direct the FTR manager to recalculate rentals and provide that information to the clearing manager to enable the clearing manager to resettle FTR contracts for the period;

(f) the revised prices and original reconciliation data would be passed to the clearing manager to identify the payments that need to be made and received, adjusting for the payments originally made or received; the clearing manager would invoice traders for these amounts, and would make payments to traders who were owed money;

20 Transmissions constraints would be taken as given from the original UTS period.

(g) the clearing manager would be directed to scale revised settlement payments by a suitable interest rate to account for the delay;

(h) the Authority would provide information to the clearing manager about which generators are eligible for constrained on compensation and that compensation would also be resettled;

(i) the Authority would direct Transpower, as grid owner, to revise distributions of residual loss and constraint excess in relation to the UTS period to transmission customers (distributors, large consumers directly connected the grid, and generators);

(j) the Authority may instruct retailers to reimburse consumers that were on variable price terms for any over-payment during the UTS period.

Q22.	Please provide feedback on the operational implementation of the proposed actions to correct the UTS, including the interest rate that should be used to scale payments.

Summary of pros and cons of particular components for correcting the UTS

5.89. Table 3 summarises some of the pros and cons of components of the actions to correct. We note that some of the components discussed here could be combined. For example, an off-market wash-up could be combined with resetting offer prices and offer volumes, or it could be combined with resetting prices directly.

Table 3: The pros and cons of component parts of the actions to correct

Component of Action to Correct	Pros	Cons
Off-market wash-up of spot payments.	Few implications for derivatives markets, thus some simplicity gains.	Departure from usual pricing and reconciliation processes. Embeds non-normal pricing into price data. De facto prices divorced from derivatives prices.
Reset offer prices and offer volumes.	Directly corrects the past; consistent with usual pricing mechanism (eg SPD). Impact of correction respects transmission constraints and flows through to nodal pricing. Generators remunerated according to the actual energy dispatched.	Potential complexity from flow-through to derivatives. Outcomes for derivative pricing depend on contract terms.
Reset or cap offer prices to absorb spill.	Analytically simple. Relatively transparent price implications.	Single offer band or cap not consistent with usual diversity of offer behaviour. Requires assessment of clearing offer or appropriate cap.
Reset final prices directly.	Directly corrects the past.	Calibration of reset prices may need to be finessed to ensure revenue adequacy. May not respect transmission constraints and losses. Departure from conventional pricing mechanism using SPD.
Accepted offers above revised final prices treated as constrained on.	Does not penalise parties that were dispatched based on higher market-clearing prices. Maintains incentives for security of supply.	Higher costs to consumers than a 'normal' competitive outcome.
Use generator models to inform usual offer pricing.	Concordance with 'normal' offer behaviour.	Reliance on generator modelling may not restore confidence in the wholesale market.
Direct a reset of derivatives markets.	Offsets risks associated with UTS and actions to correct.	May only partially capture actions taken by parties during UTS period. May override agreed allocation of risk.
Revise instantaneous reserve offers.	Seeks to ensure instantaneous reserve offers are consistent with revised energy offers.	May not be a material consideration for confidence in the wholesale market. Additional complexity.
Revise frequency keeping offers.	Seeks to ensure frequency keeping offers are consistent with energy offers.	De minimis; unlikely to be a material consideration for confidence in the wholesale market. Additional complexity.

6. The quantitative implications for the wholesale market from the proposed actions to correct the UTS

The impact on the spot energy market

6.1. Figure 6, Figure 7 and Figure 8 illustrate the implications from applying two different offer caps (including the Authority's proposed option of a $13.70/MWh offer price cap) and a single flat offer price for the nine South Island hydro generating stations identified previously. The red lines illustrate the average prices that prevailed historically. The thicker blue lines illustrate the average price if the offer price caps or single offer price are implemented.

6.2. The qualitative properties of the offer cap adjustments are similar, though the lower offer cap results in somewhat lower final prices overall, when the cap binds. The figures also illustrate that spikes in prices occur in the South Island even with revised offers, reflecting the fact that South Island hydro generation offers are not the sole determinant of final prices.

6.3. Although not depicted, the outlook for North Island energy prices is much the same – reset North Island prices are lower than the prices that were originally finalised during the UTS period, particularly in the first half of the UTS period. As per usual, the reset North Island prices are higher on average than the reset South Island prices depicted here.

Figure 6: South Island average prices – offer price cap of $13.70/MWh

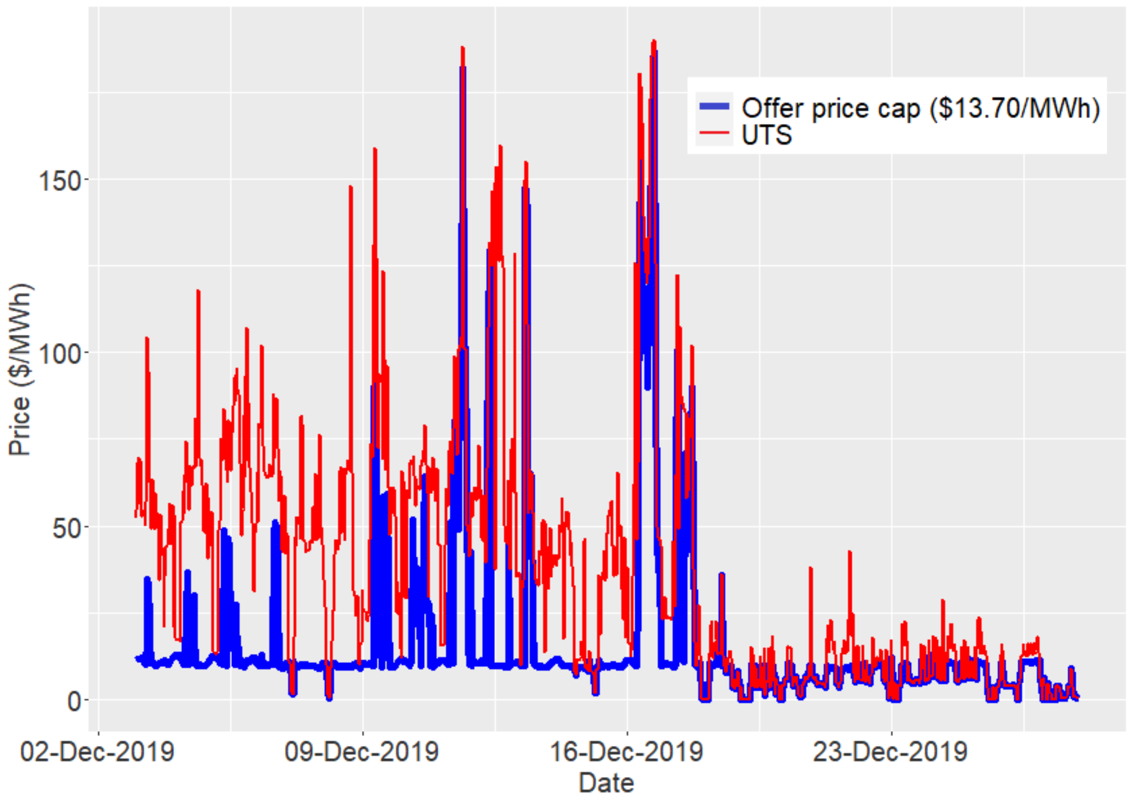
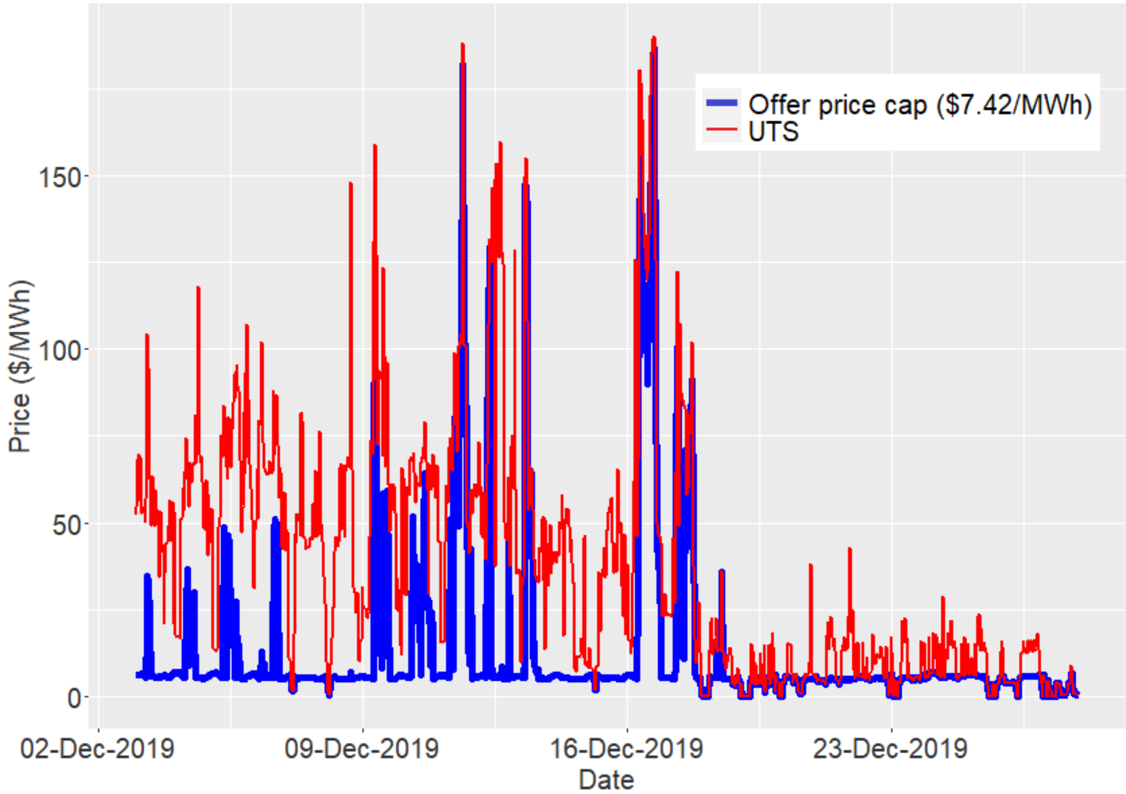
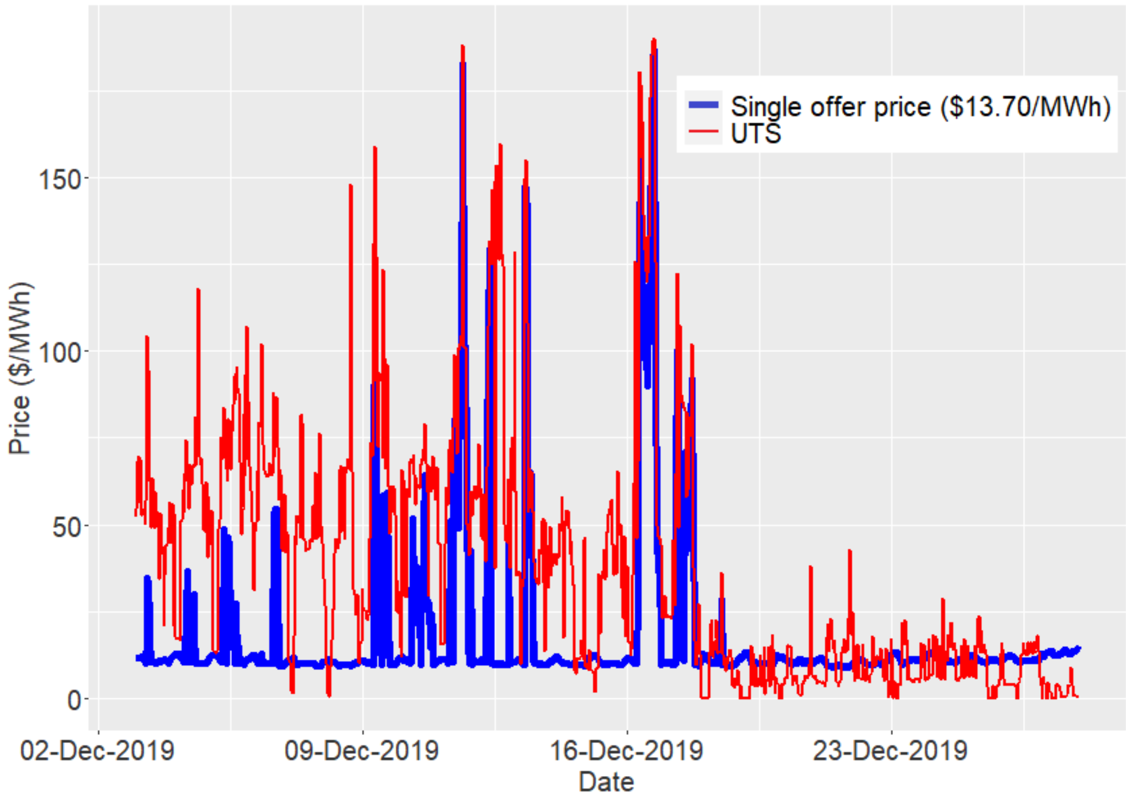


Figure 7: South Island average prices – offer price cap of $7.42/MWh



6.4. Figure 8 illustrates the average South Island spot prices when a single offer price is applied, rather than a cap. (In that case, low offer prices are increased to the single offer price and high offer prices are decreased to the single offer price.) This figure illustrates that such a correction would serve to increase prices for some trading periods in the latter half of the UTS period. The Authority currently considers that these increases would not correct the UTS and restore confidence in the wholesale market and prefers a correction based on an offer price cap.

Figure 8: South Island average prices – single flat offer price of $13.70/MWh



6.5. Table 4 illustrates average spot prices and average (fast and sustained) reserve prices for each of these corrections for the North and South Islands. In these and subsequent tables we report outcomes from different offer price caps. The offer price cap of $19.98/MWh and $7.42/MWh are symmetrically distributed around the $13.70/MWh offer price cap. These amounts illustrate the sensitivity of the outcomes to different calibrations. The $19.98/MWh calibration is also broadly similar to the 5th percentile of Lower South Island prices identified in paragraph 5.41 ($18.30/MWh).

6.6. The proposed revisions to offers result in a decline in prices in both the North Island and South Island. The reduction in prices reflects the fact that the confluence of events that affected competition for lower South Island hydro generators elevated prices above levels that were expected given the abundance of water.

6.7. The impact of these price reductions depends on the portfolio of assets owned by traders and their obligations to consumers. Generators that are not price hedged typically face declines in settlement revenues once the UTS is corrected. The impact on integrated retailers may be relatively modest, particularly if natural hedges are augmented with financial hedges. Retailers without hedges would benefit from reductions in generation costs, though these reductions may be offset by reductions in revenues if customers are also exposed to spot electricity prices and retailers pass spot electricity price changes to these customers. Overall, consumers benefit – directly if exposed to spot prices, or indirectly if on fixed prices, since the fixed prices embody expectations of spot prices. (In the long run, any reduction in spot prices should ultimately translate into lower fixed prices in a competitive retail market, though the direct effects from the correction of the UTS are likely to be negligible for consumers with fixed price contracts.)

Table 4: Market prices from actions to correct during UTS period

	Offer price cap $7.42/MWh	Offer price cap $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh	UTS Period
	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
Average North Island Price*	37.89	40.84	43.66	47.45	70.27
Average South Island Price*	19.82	23.59	27.03	31.40	55.43
Average Reserves Price North Island (FIR)**	6.83	6.84	6.92	6.91	7.98
Average Reserves Price South Island (FIR)**	1.56	2.00	2.33	2.55	5.51
Average Reserves Price North Island (SIR)**	1.81	1.85	1.91	1.94	1.85
Average Reserves Price South Island (SIR)**	0.81	0.92	1.04	1.14	1.66

Source: Electricity Authority estimates.
* Sum of load cost ÷ sum of load across trading periods.
** Simple average of trading period prices, arising from reset spot offers only.
The grey-shaded column represents the Authority’s proposal.

6.8. Table 5 illustrates the impact of four possible actions correcting the UTS based on offer caps (including the Authority’s proposed option of a $13.70/MWh cap on offer prices), alongside the historic outcome in the last column (labelled ‘UTS Period’). The table indicates the impact on the New Zealand electricity market. The table also illustrates the reduction in electricity cost arising from the adjustment of spot payments and reports the expected change in constrained on payments. The sum of the first two rows, across the North and South Islands, reports the reduction in energy cost in the spot market. As the table makes clear, the reduction in energy costs is substantial irrespective of the exact calibration of the offer cap. The reduction in the cost for energy on the spot market is between $61 and $88 million depending on the calibration of the proposed offer-cap correction. As noted in paragraph 6.7 above, the impact on purchasers may be lower depending on their hedging arrangements.

Table 5: Gross electricity costs for consumers from actions to correct

1.	Offer price cap $7.42/MWh	Offer price cap $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh	UTS Period
	($ m)	($ m)	($ m)	($ m)	($ m)
North Island Spot Electricity Costs	59.90	64.58	69.03	75.03	111.11
South Island Spot Electricity Costs	20.40	24.28	27.82	32.31	57.05
North Island Reserves Costs	1.23	1.24	1.26	1.27	1.39
South Island reserves costs	0.07	0.08	0.09	0.10	0.18
Constrained on payments	1.5	1.3	1.1	0.96	0.40
Total NZ costs (Spot + reserves + constrained on)	84.39	92.8	99.56	111.04	171.69
Loss and constraint excess	8.46	8.06	7.86	7.76	7.46

Source: Electricity Authority estimates.
Note: The grey-shaded column represents the Authority’s proposal.

6.9. Table 6 reports the notional HVDC flows across the HVDC link. These flows are notional in the sense that the settlement from the baseline proposal depends on the actual flows that occurred (as reported in the last row of the table). The table illustrates there were negligible flows across the HVDC from North to South, and that the proposed actions to correct would result in higher flows from South to North. As expected, the actions to correct based on lower offer price caps would result in higher (notional) flows from south to north across the HVDC. The maximum transfer from any of these actions would be just over 1000MW for a single trading period.

6.10.

Table 6: Notional HVDC flows from actions to correct (MW)

Action to correct	North to South (MW)	South to North (MW)
$7.42/MWh Offer Cap	0.08	607.15
$13.70/MWh Offer Cap	0.08	597.81
$19.98/MWh Offer Cap	0.08	584.99
$29.59/MWh Offer Cap	0.08	576.55
$13.70/MWh Single offer price	0.31	587.64
UTS	0.08	537.65

Source: Electricity Authority estimates.
Note: The shaded row represents the Authority's proposal.

The impact on the FTR market

6.11. To inform submissions on the FTR component of the actions to correct, this section summarises some of the implications for prices, and hence FTRs, for the month of December 2019. The hedge value of an obligation FTR depends on the average of the price differences between a source hub A and a sink hub B during a calendar month, irrespective of whether the price difference is positive or negative in a given trading period. The hedge value of an option FTR depends on the average of all positive price differences between a source hub and a sink hub for a given calendar month. These average price differences are reported in Table 7.

6.12. The average actual price difference for the UTS period for Benmore to Haywards (ie, Haywards price less Benmore price) was $4.09/MWh. For the simulations using an offer cap of $13.70/MWh, the average price difference between Benmore and Haywards was $8.93/MWh, and for the simulations using an offer cap of $7.42/MWh the average price difference was $9.81/MWh. (See the top row of the 'Obligations' part of the table.) The average price differences are also presented for Benmore-Otahuhu and Benmore-Islington. In general, inter-island price differences tend to increase as the cap on offer prices is reduced, but the within-island price differences tend to decrease.

6.13. Provisional hedge values were calculated as in the FTR Allocation Plan 2018:[21]

Option FTRs	Provisional FTR Hedge Value = $\frac{FV}{2} \times \sum_{t=1}^{T} \max\left(0, P_B(t) - P_A(t)\right)$
Obligation FTRs	Provisional FTR Hedge Value = $\frac{FV}{2} \times \sum_{t=1}^{T}\left(P_B(t) - P_A(t)\right)$
where	*is…*
t	Each Trading Period in the FTR Period, from the first (1) to the last (T). T will make allowance for the number of days in the FTR Period and any daylight saving adjustment that occurred in it
$P_A(t), P_B(t)$	The Final Prices in \$/MWh (published in accordance with Part 14 of the Code) at the Settlement Node at the Source Hub A and the Sink Hub B, respectively for Trading Period *t*
FV	The FTR Volume in MW
2	A factor to convert from the per MWh Final Prices to the half-hours in the Trading Periods

6.14. The total Provisional FTR Hedge Value for all option FTRs in December 2019, as originally settled, was $8.45m. From the simulations using a $13.70/MWh offer price cap, the Provisional FTR Hedge Value for all option FTRs in December was $8.31m, and it was $8.46m for the simulations using a $7.42/MWh offer price cap.

6.15. The total Provisional FTR Hedge Value for all obligation FTRs in December was $0.52m. The equivalent figure for the two simulations reported here was $0.32m and $0.29m respectively.

21 See https://www.ftr.co.nz/ftr-allocation-plan.

Table 7: Average price differences

FTR node combinations (SOURCESINK)	Offer Cap of $$7.42/MWh	Offer Cap of $13.70/MWh	UTS Period
	($/MWh)	($/MWh)	($/MWh)
Obligations (Average of all price differences)			
BENHAY	9.81	8.93	4.09
BENOTA	15.57	15.09	13.69
BENISL	1.51	1.76	3.95
All positive inter-island combinations	11.62	10.98	8.03
All positive SI only combinations	1.8	2.06	4.72
All positive NI only combinations	2.94	3.14	4.89
Options (Average of all positive price differences)			
BENHAY	9.95	9.06	4.26
BENOTA	15.57	15.09	14.02
BENISL	1.51	1.76	4.09
All positive inter-island combinations*	12.16	11.45	8.14
All positive SI only combinations**	1.8	2.06	4.72
All positive NI only combinations***	2.94	3.14	4.89

Source: Electricity Authority estimates.

The impact on the futures market

6.16. Under the proposal, the impact of the actions to correct the UTS on the futures market would depend on what actions (if any) the ASX determines it should take. The Authority has estimated the change in settlement of futures and options at the end of December, based on the open interest in contracts that end 31 December 2019. The Authority estimates that – if they were resettled – the change settlement in futures and options would be about $14 million in aggregate. The net effects on participants in the ASX market would likely be smaller if they operate on both sides of the market. Other hedge products may also offset positions in futures and options.

6.17. Table 8 reports a preliminary estimate of the change in resettlement (in $million) that would arise from resettling baseload futures and options contracts with a contract end-date of 31 December 2019. These amounts are separated by the Benmore and Otahuhu nodes for which contracts exist.

6.18. To be clear, the resettlement discussed here does not involve changing the strike prices that were agreed when the contracts were originated. The resettlement only affects the pay-outs at the conclusion or settlement of the contracts.

6.19. Many futures and option contracts would have been originated far in advance of the UTS period and would not have anticipated that spot electricity prices would be (or should be) low in December 2019, reflecting extreme hydrology. The Authority does not propose to attempt to over-ride the original terms of the agreements, which were voluntarily accepted well in advance of the UTS.

6.20. The appropriate action to correct becomes murkier for contracts that were agreed closer to or in the UTS period. For example, Retailer X may have seen high prices on 3 December, despite high storage levels, and felt obliged to buy a December future to protect themselves against high spot prices during the December month. Resettling that contract locks in the agreed cost for Retailer X even though prices then reflected the on-going UTS. Determining what beliefs should have underpinned the price of futures contracts in the absence of the UTS is impossible.

Table 8: Approximate change from resettling December 2019 futures/options contracts

Node	Change in settlement ($)	Change in settlement ($)	Change in settlement ($)
	Offer Cap Price $7.42/MWh	Offer Cap Price $13.70/MWh	Single Offer Price $13.70MWh
BEN	6.82 m	6.05 m	5.56 m
OTA	9.20 m	8.36 m	7.67 m

Source: Electricity Authority estimates.

The estimated distributional effects of actions to correct

6.21. Appendix A outlines the estimated distributional impact of the actions to correct the UTS. The tables variously describe the impact on traders of

(a) changes in energy (spot) payments;

(b) changes in instantaneous reserves;

(c) changes in constrained on payments;

(d) changes in constrained off payments; and

(e) changes in FTR settlement.

6.22. The impact of resettlement on OTC and ASX contracts is not reported due to the absence of data, so there is necessarily an incomplete picture of the net effect on generators, retailers, and purchasers. The tables for energy report the net effect on entities – many traders are responsible both for energy injections and energy off-takes.

Spot and instantaneous reserve market effects

6.23. The adjustments that occur in response to variant actions to correct are much as expected.

(a) Net purchasers pay less for energy.

(b) Independent generators repay excess revenues received during the UTS period.

(c) Net generators also make repayments; Meridian Energy faces the largest reduction in energy revenue, reflecting its generation and load profile.

(d) Integrated retailers with load balanced by generation (such as Genesis) are comparatively insulated from changes in prices.

(e) Settlement is affected across the country.

(f) Payments for instantaneous reserves are reduced.

6.24. These results are only partial, and attention also needs to be paid to the changes that arise in relation to constrained on and hedge markets.

OTC contracts

6.25. Information from the Electricity Hedge Disclosure system indicates that 423 contracts overlap with the UTS period. The Electricity Hedge Disclosure System does not provide enough information, particularly for options, to be able to infer the likely change in settlement that would arise if the actions to correct were to amend final prices.

Constrained on/off

6.26. Constrained on payments are in the order of $1 million if the proposed actions to correct are adopted. These payments are, not surprisingly, substantially higher than during the UTS period, but are still small relative to the reduction in energy costs. As previously noted, the primary purpose of these payments is to ensure generators are incentivised to offer sufficient generation to maintain security of supply. Constrained off payments are negligibly small in the broader context of the wholesale market.

FTRs

6.27. The consultation paper summarises the effects of the actions to correct on the changes in prices that affect FTR payments and computes the magnitude of the price adjustments. The estimated distributional impacts on traders of FTRs are reported in Table 14 in the appendix.

7. The Authority received suggestions about corrective actions in submissions on the preliminary decision paper

7.1. The Authority previously received feedback on actions that could be taken in response to the UTS in submissions on the preliminary decision paper and the supplementary consultation paper. Table 9 summarises the views expressed by submitters on actions to correct in those earlier processes. While the Authority has noted the earlier points made, it encourages all parties with views on the actions to correct to submit on this consultation paper, in light of the Authority's final decision paper on the UTS and to address the more specific issues raised in this paper.

7.2. Many of the suggested actions received in earlier submissions do not focus on correcting the outcome that occurred in 2019, but instead aim to provide better outcomes in future. The first two columns of the table below summarise the suggestions that were received, and the third column indicates whether the suggestions relate to the UTS that occurred in December 2019 or are focused on preventing or mitigating future UTSs. We note that, under the Code, actions under Part 5 of the Code must aim to correct the UTS that occurred, not future UTSs; actions that are narrowly focused on future UTSs do not meet the requirements of the Code. Nevertheless, such suggestions may be incorporated into the Authority's future work programme where appropriate. We note that anyone can propose an amendment to the Code (see https://www.ea.govt.nz/code-and-compliance/the-code/amendments/amending-the-code/ for more details).

Table 9 Comments from earlier submissions

Theme	Recommendations from Submissions on the Preliminary Decision Paper	Focused on 2019 UTS period?
The action to correct should be to reset prices	The **Claimants** stated that the Authority should recalculate final prices for 10 November to 16 January based on SRMC offer prices.	Yes
	New Zealand Steel Limited stated that the Authority needs to act expeditiously to rectify the financial imbalance that occurred.	Yes
More information disclosure is needed	**Mercury** argued that greater transparency around spill would assist to improve current trading arrangements. They also stressed that the Authority needs to progress key elements of its work programme, specifically trading conduct and information disclosure.	No
	Vector Limited (Vector) said that hydro operator spill, inflow and production data should be made easily accessible to the public. "The Authority should contract for hydro data…and publish it on the EMI website. The Authority should also implement spill reporting from the five main hydro generators." Vector also said that "The Authority should continue to develop tools or reports accessible on the EMI website that provide insights into competitive behaviour of the generators."	No
Unintended consequences of actions to correct	**Nova Energy Limited (Nova)** pointed out that if prices were reset below accepted offers, peakers that were running economically will now be running at a loss.	Yes
	Genesis argued that any remedy proposed should have careful regard to any distortionary signals it may send concerning expectations around future offering behaviour.	Yes
	Mercury urged the Authority to give careful consideration to potential unintended consequences from significant interventions.	Yes

	Mercury argued that this could undermine the competition, reliability and efficiency of the market over the longer term. Mercury also stated in its cross submission that it agreed with Nova that there would be unintended consequences if prices were reset. Specifically, "…in this case such a remedy would involve the imposition of below short run marginal cost revenues on Nova ex-post, which would not be an outcome expected under normal market conditions."	
The Authority's market monitoring should be increased	**Vector** said that the Authority should develop its monitoring and analysis to quickly identify potential problems and seek additional information from participants. Strong monitoring will assist in building confidence in the market. **Mercury** also said that the UTS claim demonstrated the need to further develop and maintain the Authority's market monitoring capabilities. **The Major Energy Users Group (MEUG)** in its submission to the supplementary consultation suggested that the Authority could publish correlation analysis in real-time to help inform whether a future UTS was arising.	No
Other	**Genesis** argued that considerable extra quantitative work would be required as part of the actions to correct (if the action to correct was to reset prices). Genesis supported a peer review and consultation process for this. Genesis also argued that any remedy should take careful account of human behaviour and the fact that decision makers acting in real time do not have perfect information. Genesis considered that "any proposed remedy should focus on attempting to arrive at what a workably competitive outcome would have been, rather than resetting prices to reflect the Authority's view of economic costs."	Yes
	MEUG noted that if the preliminary decision was upheld, there was no requirement that any action the Authority undertook should change prices. MEUG stated that one action the Authority could take would be to prioritise and speed up the work of MDAG and the follow-on consideration of recommendations from MDAG. What matters is that any actions decided on improve the long-term benefit of consumers. **MEUG** also argued that any action to correct needs to consider Meridian's ambivalent response to the warning letter sent by the Authority in response to the 2 June 2016 event.	Yes/No
	Nova suggests the Authority should investigate how resource consents under the RMA may be impacting on the electricity market. It is important that there is adequate generation flexibility.	No
	Trustpower thought that, to the extent that there are perceived issues relating to individual participants' offering behaviour, the Authority should consider individual remedies.	Yes

8. Current and future work to improve the wholesale market for the long-run benefit of consumers

8.1. While not part of the actions to correct under Part 5 of the Code, in this section we briefly summarise work that is being undertaken to improve the wholesale market for the long-term benefit of consumers.

8.2. As noted in the executive summary, generators' offer behaviour during the UTS period is being examined in relation to the HSOTC obligations specified in the Code (see clauses 13.5A and 13.5B and the definition of "pivotal"). This investigation involves assessment against different criteria in the Code, follows different processes, and is ongoing.

8.3. The Market Design Advisory Group (MDAG) has completed its review of these HSOTC provisions and has recommended the Authority adopt revised provisions.[22] The Authority prompted this MDAG review in November 2017. The Authority is consulting on proposed changes to the HSOTC provisions in February – March 2021. The Authority considers that the proposed conduct rules would reduce the risk of conduct that would cause a UTS in similar, future circumstances. The Authority intends to decide on whether it will amend the Code to introduce new trading conduct provisions by June 2021. The Authority will also continue to monitor whether trading behaviour meets the standards expected.

8.4. In 2019/20 the Authority began a review of wholesale market prices to determine whether prices had deviated from levels consistent with workable competition. The review has been delayed, reflecting competing priorities, including the UTS investigation, but the Authority intends to progress this project further in 2021.

8.5. In response to the Electricity Price Review, the Authority is also implementing a body of work to improve trust and confidence in the wholesale electricity market. This response includes work to:

- improve wholesale market information disclosure,
- enhance hedge market depth with improved market-making,
- consult on disclosure of internal transfer prices and segmented profitability, and
- improve market monitoring of contract prices and generation costs.

8.6. Although not directly part of the actions-to-correct, the Authority is also considering whether spill disclosure should be mandated in the Code, augmenting the voluntary disclosure that Meridian Energy is now undertaking,[23] and is beginning to consider the likely impact on the wholesale market of the conclusion of the virtual asset swaps between Meridian and Genesis and Meridian and Mercury in 2025.

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22 MDAG's recommendations paper, released 15 December 2020, can be found here: https://www.ea.govt.nz/assets/dms-assets/27/MDAG-review-of-trading-conduct-provisions-recommendations-paper.pdf.

23 See https://www.meridianenergy.co.nz/who-we-are/our-power-stations/lake-levels.

Appendix A The estimated distributional consequences for participants

A.1 The following table depicts changes in energy costs by participant. We note that these are only estimates of the gross changes and do not include any changes due to instantaneous reserves, constrained on or constrained off payments or, resettlement of OTC or forward hedge contracts. Final figures will be determined by the clearing manager.

Table 10: Estimated gross change in energy settlement by participants relative to UTS period ($)

	Offer price cap $7.42/MWh	Offer price cap* $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh	Single offer price $13.70/MWh
	Change in spot energy settlement ($)				
	Actions to correct – options				
	($)	($)	($)	($)	($)
Alinta	- 1,322,782	- 1,190,142	- 1,066,494	- 902,239	- 1,085,566
Auckland Commercial Solar	547	490	435	361	448
Body Corporate Power	1,798	1,619	1,450	1,224	1,482
Bosco Connect	39,303	35,914	32,670	28,280	33,313
Brooklyn Electricity	- 2,325	- 2,082	- 1,858	- 1,567	- 1,950
Cold Storage Nelson	40,066	35,931	32,151	27,302	32,777
Contact	- 5,512,786	- 4,928,590	- 4,385,385	- 3,643,597	- 4,613,820
Counties Power	-	-	-	-	-
EMHTrade	- 9,934	- 8,232	- 6,902	- 5,741	- 5,978
ENEL X NEW ZEALAND	-	-	-	-	-
Eastland Generation	- 410,066	- 367,800	- 328,526	- 276,488	- 332,336
Ecosmart New Zealand	- 129	- 127	- 127	- 131	- 120

	Offer price cap $7.42/MWh	Offer price cap* $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh	Single offer price $13.70/MWh
Ecotricity	215,586	194,986	175,614	149,891	179,815
Electric Kiwi	659,131	592,553	530,219	449,018	546,481
Flick	298,459	267,689	239,103	202,171	246,762
ForOurGood	2,198	1,986	1,786	1,520	1,820
Future New Zealand trading as Club	164,649	149,172	134,637	115,568	138,386
Genesis	- 252,990	- 269,206	- 274,439	- 257,542	- 326,368
Hanergy	2,071	1,891	1,719	1,488	1,751
ID Power	7,215	6,528	5,879	5,024	5,976
Kea	1,842	1,665	1,481	1,194	1,641
King Country	- 329,464	- 299,691	- 272,463	- 239,553	- 271,230
Lighthouse	1,593	1,450	1,314	1,133	1,347
Mercury	207,442	125,829	52,504	- 41,714	99,307
Meridian	- 12,927,316	- 11,382,120	- 10,016,521	- 8,365,296	- 10,440,960
New Zealand Aluminium Smelters	11,195,113	9,926,511	8,785,716	7,367,866	8,990,130
New Zealand Steel	2,564,675	2,304,213	2,060,457	1,734,127	2,099,594
Nga Awa Purua JV	- 2,422,132	- 2,174,936	- 1,944,698	- 1,640,089	- 1,969,877
Norske Skog Tasman	1,002,671	897,228	797,862	664,182	808,820
Northpower	-	-	-	-	-
Nova	2,118,922	1,902,398	1,703,333	1,444,703	1,740,159
OM Financial	-	-	-	-	-
Online	1,228,483	1,112,019	1,001,726	856,070	1,026,410
Opunake Hydro	- 1,570	- 2,250	- 2,731	- 2,841	- 3,865

	Offer price cap $7.42/MWh	Offer price cap* $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh	Single offer price $13.70/MWh
Orange Services	130	121	112	99	115
Pan Pacific Forest Industries	847,072	760,451	678,569	569,093	692,787
Paua to the People	6,663	6,018	5,395	4,575	5,538
Pioneer	- 98,582	- 77,762	- 60,920	- 43,621	- 55,091
Platinum Power Retail	101	92	84	73	86
Plus	- 724	- 674	- 629	- 574	- 649
Pre Pay	44,004	40,204	36,568	31,658	37,292
Prime	128,842	117,009	105,899	91,228	108,901
Pulse Alliance LP	671,206	613,373	558,233	485,221	579,142
Simply	- 128,263	- 114,322	- 101,608	- 85,604	- 105,566
South Pacific	86	80	73	65	75
Southpark Utilities	1,362	1,297	1,227	1,114	1,265
Stack Power	1,371	1,251	1,137	984	1,159
Switch Utilities	669,097	607,693	549,789	473,430	563,127
The Refining Company	762,283	685,026	613,028	517,587	620,936
TrustPower	1,202,975	1,158,730	1,099,548	976,857	1,218,601
Tuaropaki Power Company	- 1,739,305	- 1,560,780	- 1,394,508	- 1,174,638	- 1,413,221
WEL Networks	17,034	15,405	13,854	11,795	14,178
Wind Farms	- 258,347	- 233,662	- 210,193	- 177,247	- 207,737
Winstone Pulp International	506,453	455,912	408,301	344,815	413,892
Yes Power	7,572	6,763	6,029	5,098	6,222
eTrading	- 12,990	- 11,594	- 10,335	- 8,785	- 10,664

	Offer price cap $7.42/MWh	Offer price cap* $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh	Single offer price $13.70/MWh
Change in Loss and Constraint Excess	811,690	594,473	440,435	302,453	625,263

Source: Electricity Authority estimates.
Note: * The grey-shaded column represents the Authority's proposed action to correct the UTS. The last column reports outcomes for a single flat offer price, while the remaining columns report outcomes for offer price caps. A positive change in loss and constraint excess indicates an increase in LCE. (Decreases in generation costs more than offset the decreased payments by purchasers.)

A.2 Estimated change in instantaneous reserves revenues by participant

Table 11: Estimated change in instantaneous reserve revenues relative to UTS period ($)

	Cap offer price $7.42/MWh	Cap offer price $13.70/MWh	Cap offer price $19.98/MWh	Cap offer price $29.59/MWh	Flat offer price $13.70/MWh
Contact	-44,817	-38,928	-35,318	-31,765	-35,951
Counties Power	-3,052	-2,730	-2,244	-2,097	-2,172
ENEL X NEW ZEALAND	-140,005	-136,476	-117,843	-115,861	-130,875
Genesis	-39,320	-34,826	-27,244	-24,571	-26,370
Mercury	-42,068	-39,383	-33,862	-32,313	-31,413
Meridian	-183,698	-163,109	-144,787	-130,903	-156,060
Norske Skog Tasman	-32,318	-31,694	-24,091	-22,448	-27,096
Northpower	-315	-100	155	246	199
Trustpower	- 41,741	- 39,348	-36,304	- 36,462	- 38,958
Vector	- 148	1,381	3,390	4,828	1,808
Vector Wellington Electricity Network	- 624	- 401	-69	112	- 235
WEL Networks	- 8,947	- 8,536	-7,737	- 7,597	

Source: Electricity Authority Estimates.
Note: Parties with no change have not been reported. The grey-shaded column represents the Authority’s proposed action to correct the UTS.

A.3 Estimated change in constrained on payments

Table 12: Estimated change in constrained on payments relative to UTS period ($)

		Constrained on payments ($)			
Trader	Name	Cap offer price $7.42/MWh	Cap offer price $13.70/MWh	Cap offer price $19.98/MWh	Cap offer price $29.59/MWh
CTCT	OKI2201 OKI0	18,555	4	4	4
CTCT	SFD	51	18,130	17,637	16,771
CTCT	THI	15,773	51	51	51
CTCT	WHI2201 WHI0		15,609	15,453	15,090
GENE	HLY	209,950	162,227	123,698	73,258
GENE	TEK	532	24	22	20
GENE	TRO	84,884	81,336	76,849	67,917
GENE	WKA	5,265	5,244	5,189	5,008
KING	MHO0331 MHO0	9,544	8,802	8,087	7,127
MERI	MAN	102,182	72,223	41,934	12,247
MRPL	WTO	3,045	354,174	306,032	241,508
TODD	MKE1101 MKE1	6,466	2,796	2,483	1,950
TRUS	ARG1101 BRR0		5,947	5,487	4,788
TRUS	COL0661 COL0	45,913	6,057	613	1
TRUS	KUM0661 KUM0	15,454	11,477	7,521	2,380
TRUS	MAT1101 MAT0	83,240	74,332	66,310	57,918
TRUS	PTA	67,695	62,548	58,691	55,022
TRUS	STK0661 COB0	18,992	8,923	3,198	222

Source: Electricity Authority estimates.

Note: Constrained on payments to Contact and Meridian for the CLU and WTR generating stations have been excluded from the table because in the baseline proposal they are not eligible for constrained on. The grey-shaded column represents the Authority’s proposed action to correct the UTS.

A.4 Estimated change in constrained off payments to generators associated with frequency keeping

Table 13: Estimated change in constrained off payments to generators for frequency keeping relative to UTS period ($)

Trader	Block / Station	Offer price cap $7.42/MWh	Offer price cap $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh
CTCT	CLU	-3,807	-3,721	-3,598	-3,409
GENE	HLY	-4,041	-3,941	-3,794	-3,490
GENE	TRO	-908	-908	-908	-908
MERI	WTR	-3,366	-3,366	-3,110	-2,906
MRPL	WTO	-251	-251	-251	-251

Source: Electricity Authority estimates.
Note: The proposal is not to amend constrained off payments for generators.

A.5 Estimated change in FTR settlement by participant

Table 14: Estimated change in FTR settlement ($)

	Offer price cap $7.42/MWh	Offer price cap $13.70/MWh	Offer price cap $19.98/MWh	Offer price cap $29.59/MWh	Flat offer price $13.70/MWh
Haast	-771,260	-712,780	-653,460	-562,940	-651,760
Mercury	-153,660	-152,450	-145,760	-129,600	-116,850
OM Financial	-16,050	-19,820	-21,100	-20,390	-11,510
Meridian	36,260	-4,160	-27,670	-37,840	39,470
Genesis	8,380	4,380	1,960	20	8,060
Switch Utilities	9,480	8,620	7,860	6,520	7,820
MMA	16,760	15,160	13,800	11,550	15,090
Smartwin	19,770	16,650	14,250	11,630	16,840
Trustpower	82,330	67,100	55,660	44,680	69,300
Contact	284,200	212,630	162,640	118,760	223,930
Macquarie Equipment Finance	262,740	221,330	189,470	154,370	225,710

Source: Electricity Authority estimates.
Note: Rows ordered by size of first column. Parties with no change are not reported. The grey-shaded column represents the Authority's proposed action to correct the UTS.

Appendix B Format for submissions

Questions	Page
Q1. What, if any, actions should the Authority undertake to address excess spill, system security, and any other consequent effects? How would such actions address the objectives of Part 5 of the Code?	4
Q2. Do you agree that the Authority should seek to correct the UTS period by resetting the payments made/received by spot market purchasers and generators? (If not, please explain your reasoning.)	5
Q3. Do you agree that the Authority should attempt to correct settlement during the UTS period by resetting prices in the electricity market?	5
Q4. Do you agree that injection and off-take volumes should remain unchanged in any resettlement?	6
Q5. Do you agree that the Authority should attempt to correct the UTS by revising final prices in the electricity market, rather than by an 'off-market' wash-up of spot electricity payments to and from the clearing manager?	6
Q6. If offer prices and offer volumes are reset, which hydro generating stations should have offers reset? (Please answer yes/no, with any additional supporting commentary.)	9
a. Aviemore?	9
b. Benmore?	9
c. Clyde?	9
d. Manapōuri?	9
e. Ōhau A, B, C?	9
f. Roxburgh?	9
g. Tekapo A, B?	9
h. Waitaki?	9
i. Other stations?	9
Q7. If offer prices and volumes are reset, do you agree that North Island offer prices and offer volumes should remain the same as originally submitted? (If not, please identify any alternative actions.)	9
Q8. Do you agree that resetting offer prices and volumes by imposing a cap is the preferred action to correct the UTS? If not, please identify preferred alternatives.	11
Q9. If revisions to offer prices are to vary through time or across generating stations, how should the offer prices be determined?	11
Q10. Do you consider that final prices should be reset directly? If so, how should they be calibrated?	12
Q11. Do you agree that the aggregate offer volumes of each generating station should equal the aggregate amount offered by that station during the UTS period? Please describe any preferred alternatives.	12
Q12. Which of these mechanisms in paragraph 5.41(a) – (e), if any, should be used to calibrate 'corrected' electricity offer prices? (Please identify any other preferred alternatives.)	14
Q13. Do you agree that generators, other than those with 'reset offers', that were dispatched to generate electricity at offer prices above the reset final prices should be treated as constrained on? (If not, please identify preferred alternatives.)	14
Q14. Do you agree with the Authority's proposal not to revise constrained off payments, associated with frequency keeping? (If not, please explain and identify any preferred alternatives.)	15