Meridian Submission

Preliminary decision on claim of an undesirable trading situation

18 August 2020

This submission by Meridian Energy Limited (**Meridian**) responds to the Electricity Authority's preliminary decision on claim of an undesirable trading situation (**UTS**) released on 30 June 2020 (**the preliminary decision**).

Attached to Meridian's submission are expert reports from

- Sapere Research Group – *The Authority's preliminary decision of an undesirable trading situation: An economic perspective* (**Sapere Report**); and
- The Brattle Group – *New Zealand Electricity Authority's Preliminary Decision on UTS* (**Brattle Report**).

The submission is divided into the following Parts:

- Chief Executive's foreword
- Part A: Executive Summary
- Part B: The events of November 2019 to January 2020
- Part C: Spot market outcomes were not unusual
- Part D: HVDC risk was not a major factor
- Part E: The Authority has misinterpreted and misapplied the UTS test
- Part F: The issue of pricing during spill is a Code amendment issue
- Part G: Attachments

For any questions relating to this submission, please contact:

Jason Woolley, General Counsel, DDI: +64 4 381 1206

Sam Fleming, Manager Regulatory and Government Relations, DDI: +64 4 803 2581

Meridian Energy Limited
Level 2, 55 Lady Elizabeth Lane
PO Box 10-840
Wellington 6143
New Zealand
Phone +64-4 381 1200
Fax +64-4 381 1272
www.meridianenergy.co.nz

Chief Executive's foreword

The events covered in the Authority's preliminary decision were, in hydrological terms, extraordinary and exceptional. They are unlikely to be repeated for many years.

The mean total inflow into Lake Manapōuri during November and December 2019 was the highest since records began in 1932 and resulted in the second highest lake levels ever recorded for Manapōuri. In the Waitaki catchment, total Benmore inflows in December were the second highest on record and, over the period 25 November to 15 December records of total Waitaki inflows show these events were the wettest in 90 years, more than 22% wetter than the next wettest in 1995. In parts of the South Island, rivers burst their banks, inundating some areas and damaging electricity transmission and other infrastructure.

Meridian's focus throughout the period was on the safe management of the flood and doing everything we reasonably could to minimise risks to people, structures and properties in our catchments. For the first time in our history we spilled water from every single one of our hydro structures. At the same time, December saw us achieve record levels of hydro electricity production. Meridian generated more electricity in December than we have ever previously generated in December, even more than when Meridian also owned the two Tekapo stations in the Waitaki.

As we do after every significant weather event, we have taken a critical look at how we operated during the late 2019 flood events to see what we can learn and improve on in future. There are some improvements that Meridian can and will make for future events to ensure we maximise the use of water as a precious renewable resource. However, based on our review, we also believe that throughout the December 2019 events we operated consistently with the electricity market rules and consistently with the normal operation of that market.

Other parties disagree. In the middle of these events and while we were still continuing to manage them to the best of our ability, a claim was submitted to the Electricity Authority (Authority) that both Meridian and Contact's conduct was, in wholesale electricity market terms, deficient. The claimants said Meridian and Contact had been in breach of the trading conduct provisions in the Electricity Industry Participation Code (Code) since 10 November 2019 and the nature and scale of this breach was such that it was also an undesirable trading situation or UTS under the Code. In essence they said Meridian and Contact were spilling too much water. One of the claimants, Haast Energy Trading, also took the opportunity to complain to Environment Southland about environmental impacts of Meridian's handling of the events. That complaint was rejected.

The Authority's preliminary decision treats the allegation of a UTS as separate from the trading conduct allegations. In respect of the UTS allegation it largely rejects the claims made. However, the Authority does take issue with the market impacts of Meridian's conduct over the course of 16 days from 3 to 18 December 2019. In summary, the Authority's preliminary decision states that spot market outcomes did not meet the Authority's expectations of a power system with abundant cheap fuel. The preliminary decision relies heavily on mathematical analysis and modelling of the relevant period undertaken by the Authority's market performance team during the six months since the relevant flood events came to an end and with perfect hindsight.

For the reasons set out below, Meridian believes the Authority's preliminary decision is wrong. One error the Authority makes is to overstate the amount of spill that could have been avoided. This is because the modelling undertaken for the preliminary decision fails to take into account planned generation outages, and is calculated across the entire month of December, rather than during the alleged UTS period (between 3 and 18 December). After correcting these errors in the Authority's modelling, the total volume of "avoidable spill" that might have been collectively avoided by the three main South Island hydro generators is 12.2 GWh. This is less than a third of the 41 GWh referred to in the preliminary decision, and in terms of the flood Meridian was handling at the time, less than half a percent of the amount of water that Meridian either ran through its generation stations or spilled in December and less than 0.3% of the water that South Island generators were collectively dealing with in December. The volumes of spill in question are less than the margin of error on spill reporting.

This error in turn causes the Authority to significantly overstate the difference between actual wholesale market settlement prices over the period and the theoretical or counterfactual market settlement prices that might have applied had this spill been avoided. This (incorrect) theoretical price difference number has inevitably been seized on by some of Meridian's competitors and misreported by the media. Unfortunately this has helped perpetuate the myth that the difference between actual settlement values and counterfactual settlement values somehow represents a measure of Meridian profit or cost to consumers under the counterfactual.

The Authority’s clear statement that most consumers are not affected by the supposed price difference as they are on fixed price contracts (and therefore not exposed to the wholesale market) has been conspicuously and predictably absent in most media reporting. In fact, Meridian estimates that 91% of wholesale market purchasers are generator-retailers that are physically hedged and of the remainder, most will be financially hedged. On this point and the point in the previous paragraph, reporting of the preliminary decision has led to inaccurate claims from some of Meridian's competitors that many consumers were substantially out of pocket.

In terms of application of the Code, through this preliminary decision the Authority appears to have effectively rewritten the established definition of what a UTS is and in doing so has contradicted previous decisions and market analysis issued by the Authority. It would not be reasonable practice for a regulator to carry this through to the final decision.

In summary, and as discussed below, Meridian’s view of the events covered in the Authority’s investigation is that they do not reveal any evidence of any threat to, or loss of confidence in, the wholesale market. Similarly, they do not reveal evidence of any threat to the integrity of the wholesale market. There was accordingly no UTS arising from these events. To the extent there has been any loss of confidence in current market arrangements (and we do not believe there has been) we suspect the real cause to be the misreporting of the comments and figures in the Authority’s preliminary decision.

Neal Barclay
Chief Executive

Table of contents

Part A: Executive Summary

On 12 December 2019 the Electricity Authority (Authority) received a claim from seven participants including Haast Energy Trading and Electric Kiwi that a breach of the trading conduct provisions in the Electricity Industry Participation Code (Code) had begun on 10 November 2019 and was continuing at the time of the claim. The claimants alleged that the nature and scale of the high standard of trading conduct breach was such that it also qualified as an undesirable trading situation or UTS.[1]

The Authority's preliminary decision largely rejected the claim but took issue with South Island hydro generation over the course of 16 days from 3 to 18 December 2019. In summary, the Authority's preliminary decision stated that spot market outcomes did not meet the Authority's expectations of a power system with abundant cheap fuel in light of its ex-post modelling of 'ideal' offer prices for the period, and that the departure of spot market outcomes from the Authority's expectations may have reduced confidence in the spot and forward markets.

Context for the event (Part B)

The events being investigated by the Authority are related to exceptional weather conditions that created significant safety risks for the communities and environments in which Meridian operates. The total inflows into several catchments were amongst the highest, if not the highest, since records began.

Meridian used its best endeavours to manage the weather events in real time based on our experience of managing similar but less extreme situations. Meridian took a conservative approach to manage the flood safely and mitigate the risks to communities, property, and structures in our catchments. Managing the flood was Meridian's priority at the time and we did not adopt novel trading tactics in the midst of this event. We sought safe and simple operations that would manage downstream flows. We behaved in the same way as Meridian and other hydro generators have done, consistently, for the last nine years. Further contextual detail for these events is set out in Part B of this submission.

[1] The complaint documentation only uses the terms integrity and confidence when citing the Code. That the very claimants who identified this supposed UTS did not articulate the link to confidence or integrity is telling.

Ultimately Meridian generated more electricity in December 2019 than any previous December on record (including when Meridian owned and operated the two Tekapo power stations).

The Authority's preliminary decision is wrong for four key reasons. These are set out below, and expanded on in further detail in Parts C to F of this submission.

Spot market outcomes were not unusual (Part C)

The events being investigated by the Authority did not cause unusual outcomes in the spot market. As noted in the appended Sapere Report, an outcome that is *consistent with the normal operation of the wholesale market* cannot, and does not, undermine market confidence and does not constitute a UTS.

Spilling and making non-zero price offers is consistent with the normal operation of the wholesale market: The offer behaviour of Meridian (as described in Part B) is completely consistent with behaviour in the workably competitive electricity market. Throughout the last decade there have been many times in which a hydro generator has been spilling but offering at non-zero prices. This is not an idealised perfectly competitive market where the only rational response is to offer at the level of short run generation costs.

The Authority incorrectly modelled 'avoidable spill': All the modelling undertaken for the preliminary decision fails to take into account planned generation outages, and is calculated across the entire month of December, rather than during the alleged UTS period (between 3 and 18 December). The Authority's modelling significantly overstates “avoidable spill” and after correcting the errors in the Authority’s modelling the volume of "avoidable spill" is 12.2 GWh, less than a third of the 41 GWh referred to in the preliminary decision.

Actual 'avoidable spill' fell in the margin of error for spill reporting: The 12.2 GWh is less than 0.5% of the water Meridian had to deal with in December 2019 and less than the margin of error on Meridian’s spill reporting that was provided to the Authority.

Consumers were not affected by the conduct: Contrary to media reporting and claims from some of Meridian's competitors, most consumers were not impacted by these events. Consumers do not generally purchase from the wholesale market. The vast majority of consumers are on fixed price contracts with retailers, and those retailers in turn manage the fluctuations in the wholesale market. The period in question did not deliver high prices out of the range of usual hedging arrangements. The fact that the claimants would like to have profited from even lower wholesale prices, based on ex-post modelling with perfect hindsight, is not a reason to find a UTS.

Prices discovered via the New Zealand wholesale electricity spot market are by nature very volatile. If the Authority resets prices during 3 to 18 December 2019 the impact on average South Island prices for the financial year to June 2020 would be $0.8/MWh. This level of price variance is immaterial and would not flow through to retail prices. By contrast, average spot prices between the 2018 and 2019 financial year lifted by more than $50/MWh as a result of issues with North Island thermal generation, which were also the subject of a UTS complaint (a complaint that was rejected by the Authority).

The HVDC risk was not a major factor and generators managing transmission constraints with offers is normal market behaviour (Part D)

The preliminary decision suggests a UTS may have occurred between 3 and 18 December 2019 because Meridian was offering to avoid price separation across the HVDC.

Managing basis risk through generation offers is part of the normal operation of the wholesale market. The Authority's previous investigations of this behaviour have indicated it is not a UTS. Given the precedent of previous Authority decisions and the transparency with which generators have managed basis risks, it is inconceivable that continuation of this conduct could in any way threaten confidence in the wholesale market.

Even if we pretend for a moment that offering to avoid price separation across the HVDC would constitute a UTS, the HVDC risk was not a major factor in Meridian's decision making during the 3 to 18 December 2019 period because:

- for most of the 3 to 18 December period, the HVDC transfer did not exceed 85% of maximum and would therefore not have been visible to Meridian as a potential constraint;
- the HVDC was only at risk of binding in 2.7% of trading periods between 3 and 18 December; and
- for 11 out of 16 days of the 3 to 18 December 2019 period, Meridian was long on generation in the North Island relative to our North Island contract position, and so had no incentive to cover any North Island basis risk.

The Authority has misinterpreted and misapplied the UTS test (Part E)

The Authority has misinterpreted and misapplied the UTS test. That test has always required aberrant behaviour or a dysfunctional market. The Authority has watered down that test by transforming it into a test that looks to whether the market is meeting the Authority's hypothetical and subjective expectations of a workably (or close to perfectly) competitive market.

Similarly, in the preliminary decision the Authority has effectively enforced its view that pricing to manage constraints is improper, through the use of the UTS provisions. Through this process, the Authority has equated "inefficiency" (or, more accurately, less than perfect efficiency), as "affecting confidence in the wholesale market". That approach swaps out the concept of a UTS as an unusual market situation that can be immediately recognised and requires immediate rectification, for the Authority's ex-post constructed and modelled view of how the market should have acted under close to perfectly competitive market conditions, for every trading period, every day.

The preliminary decision relies on the Authority's own prior warning letter to require Meridian to act in a way that is artificially 'blind' to constraints and price separation. The UTS regime does not require that outcome. The Authority has bent the UTS rules to reach its desired result.

The Authority's preliminary decision is so vague and unclear as to what amounts to a UTS that market participants are left to guess as to whether their pricing approaches will amount to a UTS or not. The preliminary decision fails to isolate the specific actions, either alone or in combination, that amount to a UTS. Rather, the entire period of 3 to 18 December 2019 is said to constitute a UTS. Market participants are unable to identify what offer prices would have avoided such a finding. Some figure between Contact's offers and Meridian's offers potentially represents an unknown tipping point. This uncertainty makes market participants liable to repeat the behaviour the preliminary decision considers amounts to a UTS.

The Authority's interpretation of the UTS regime imposes an unrealistic view of competition in a dynamic and complex market. The result of the Authority's view would find aberrant certain differences between its idealised spot market and actual market offers. Such a result is inconsistent with the UTS regime's role as a rule of last resort to restore normal market operation and the concept of workable competition in the Electricity Industry Act 2010.

The Authority's introduction of a quantitative threshold between Contact's actions and Meridian's is also confusing, inconsistent with the Code, and inappropriate. Rather than adopting the qualitative threshold required by the Code's terms, that is something aberrant or dysfunctional, the Authority has left market participants in the dark as to the application of the Code. It is now not clear when behaviour is material enough to constitute a UTS nor whether Meridian's behaviour or market outcomes caused the finding of a UTS. The problems associated with this uncertain threshold are compounded by the use of quantity weighted offer prices (QWOP) – a blunt averaging tool, liable to distortion and irrelevant to the actual prices settled through the period in question. The Authority's reliance upon QWOP rather than actual offers has led to the wrong conclusion in this case and may lead to unintended and perverse consequences in future.

Finally, the Authority's preliminary decision-making process was flawed because it adopted a novel approach to assessing market confidence and integrity. The Authority abandoned the traditional and accepted objective measures (such as the usual regression analysis of the ASX futures market reaction) in favour of measuring offer behaviour against its own subjective expectations. The Authority’s expectations are not an appropriate or reasonable measure of market confidence or integrity. The market's true confidence, as measured through, amongst others, prudential requirements or material change in the trading of risk management products such as FTRs and ASX New Zealand Electricity Futures, was given insufficient or no weight.

Perversely, the Authority finding a UTS in this case would not only misinterpret and misapply the Code but also lead to the kind of loss of confidence in the market that a UTS finding is designed to restore. Such a finding would be inconsistent with previous UTS decisions made by the Authority and that lack of consistency would erode confidence in the wholesale market as generators would not know how to offer their generation.

The issue of pricing during spill should be addressed by a Code amendment process (Part F)

The Authority's approach to this UTS preliminary decision suffers from procedural failings.

As noted by Sapere:[2]

[2] Sapere Report, paragraph 84

> "Market participants are not responsible for adjusting their actions to ameliorate imperfections in the market design. If the Authority is convinced of the merits of its analysis, then the appropriate course is for it to introduce a rule change."

If the Authority really thought the behaviour was so detrimental to market outcomes, it has had ample opportunity to regulate behaviour and there is a *Code amendment process* available to it. That process would allow stakeholder participation, a proper evaluation and weighing of the efficiency benefits and detriments, and the likely flow on effects for consumer retail pricing. If the result of the consultation and regulatory assessment demonstrated a Code change to be net efficient (which is not Meridian's view) then any rule would be carefully calibrated to achieve that efficiency.

By contrast, when the Authority *applies* the Code, as in an investigation into whether a UTS has arisen, it must leave its reform agenda out of its judicial role. In its preliminary decision, the Authority has strayed into its 'optimisation' rule-making role, rather than applying the plain language and intent of the Code provisions as they stand, in its judicial 'rule-applying' role. To avoid this sort of role confusion, the judicial function for Code breach allegations has generally been granted to the Rulings Panel rather than the Authority. The UTS provisions are unique in that they are one of the few parts of the Code where the Authority itself performs a judicial function.

This flaw in the Authority's preliminary decision is evident in the treatment of numerous examples of similar offer prices across the market, during spilling. Those other examples were not found to be a UTS. A known area of concern must trigger a Code reform process, not a UTS finding. A UTS analysis that does not consider those prior examples fails to properly take into account the market's expectation in relation to the relevant offer behaviour, and so also fails to properly evaluate any alleged impact on market confidence.

Meridian suggests that if the Authority wants to reform the normal operation of the wholesale market then the correct approach would be to consider Code changes such as:

- finalisation of any Code changes based on the recommendations of the Market Development Advisory Group's (MDAG) to replace the current high standard of trading conduct provisions; or alternatively
- rules for the construction of offer stacks for spilling hydro generation – any rules would need to be flexible enough to allow for a range of different operational, environmental and hydrological constraints while still meeting any expectations of

the Authority in terms of the level of offer prices for generation volumes that can be sustainably generated throughout any spill period.

Meridian strongly believes the Code change process to be the appropriate way to deliver any reform of normal market operations as the process delivers greater certainty and requires both a cost benefit analysis and stakeholder engagement to suitably test any proposals.

Part B: The events of November 2019 to January 2020

Meridian's conduct during the investigation period was a response to an exceptional weather event. Meridian was focused on ensuring the safety of our employees and the environments and communities in which we operate.

Market conditions prior to the inflow events

Prior to the period of the alleged Code breach and UTS, the wholesale spot market was influenced by low hydro storage and ongoing gas supply concerns. At the start of November 2019 national hydro storage was below average for the time of year. Uncertainty continued in the gas market and therefore in relation to thermal generation in the wholesale electricity market. There was an unplanned reduction in gas production at Kupe in late September and early October, and a planned outage of Kupe from 30 October to 27 November 2019. National demand in the last quarter of the 2019 calendar year was also higher than the average for the last 10 years. Because of the tightening of supply and increased demand, wholesale market prices prior to December were generally above the long-term average (wholesale prices for New Zealand in October averaged $131/MWh, in November $110/MWh, and in December $61/MWh).

Further to this, prior to and during the alleged UTS period, thermal output in the North Island was extremely low (less than 25% of available capacity) despite market prices being above analyst disclosed running costs of many of the thermal plants.

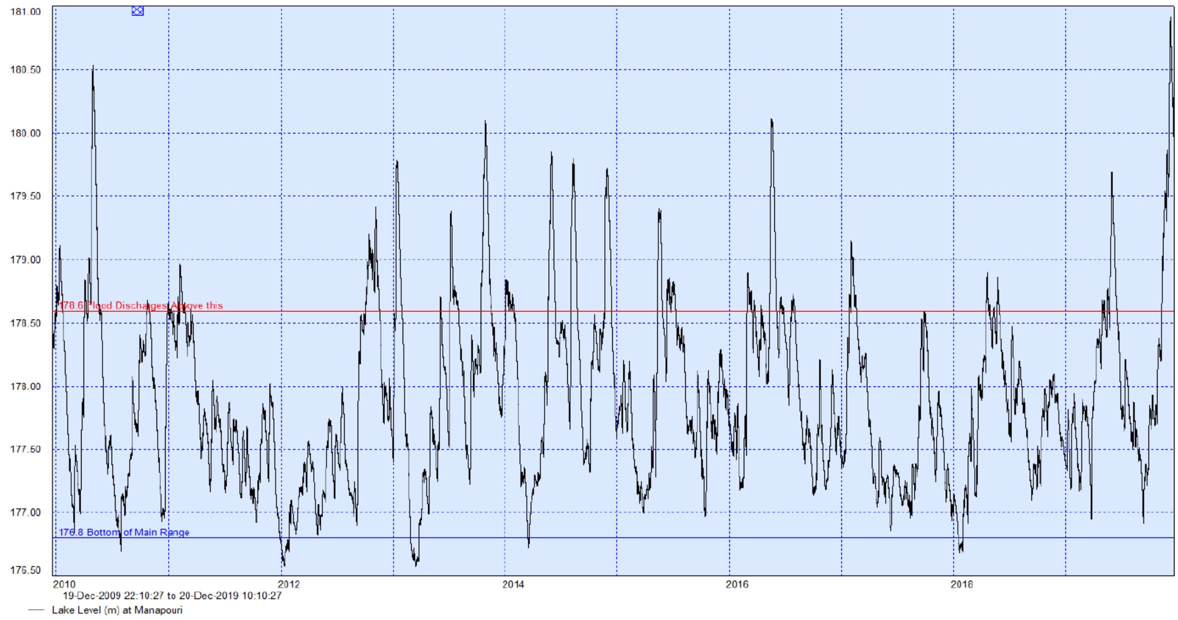
The catchments Meridian operates within

For both of Meridian's South Island hydro schemes (Manapōuri and Waitaki) some spill is inevitable and unavoidable because of the volatile and unpredictable nature of inflows and the limited storage capacity in the various hydro lakes.

Manapōuri

The Manapōuri scheme is fed by two lakes – Te Anau and Manapōuri. Both lakes have very little storage capacity compared to the inflows they receive. It is common to receive inflow events that result in spill down the Lower Waiau River. The enabling environmental legislation for the Manapōuri scheme is designed such that regular large flows are expected down the River, much like what would occur in a natural and uncontrolled state. Figure 1 below shows the level of Lake Manapōuri since 2010, including frequent large inflow events necessitating spill (above the red line). As can be seen, the December 2019 inflow event resulted in the highest lake levels recorded since 2010 and in fact, lake levels were the second highest ever recorded.

Figure 1: Lake Manapōuri levels 2010 to 2020



Waitaki

The Waitaki scheme is a chain of eight power stations (six controlled by Meridian) with three lakes in the headwaters – Tekapo, Pūkaki, and Ōhau – connected by a series of canals and rivers. Lake Tekapo is not managed by Meridian. Lake Pūkaki (and to a lesser extent Tekapo) has significant storage capacity but spill is still unavoidable on occasion. When Lake Pūkaki spills, the flows bypass the canals that feed the three Ōhau stations at the top of the chain and instead enter Lake Benmore.

Lake Ōhau has little storage capacity and a narrow operating range. Control gates feed Lake Ōhau water into the canal system and through all of the three Ōhau power stations, A, B, and C. When the level of Lake Ōhau is above 520.25m, the Ōhau Canal gate flow must be at least 170 cumecs. This requires minimum generation at Ōhau A, B and C of 227MW. When the level of Lake Ōhau is above 520.4m, two things occur:

- Ōhau Canal gate flow must be 200 cumecs. This requires minimum generation on Ōhau A, B and C of 267MW.
- Water will begin to flow uncontrolled over the weir, into the Upper Ōhau River, and then into Lake Ruataniwha. This water must then be generated though both Ōhau B and Ōhau C or spilled from the Ruataniwha Spillway into Lake Benmore.

In addition to Lake Ruataniwha, there are small storage lakes above the next three power stations in the mid-Waitaki – Benmore, Aviemore, and Waitaki. High inflows in the headwaters of the scheme are generally accompanied by high tributary flows into Lake Benmore, for example from the Ahuriri River, raising the generation required to pass this water (in addition to Ōhau C discharges and any spill from lakes Ruataniwha, Pūkaki and Tekapo) though the Benmore, Aviemore and Waitaki power stations. At times, it is not possible to generate with all these uncontrolled inflows and mid-Waitaki spill will occur at some or all of the three stations. When we can, Meridian prefers to spill from Aviemore and Waitaki as they are less efficient stations.

The record setting flood event

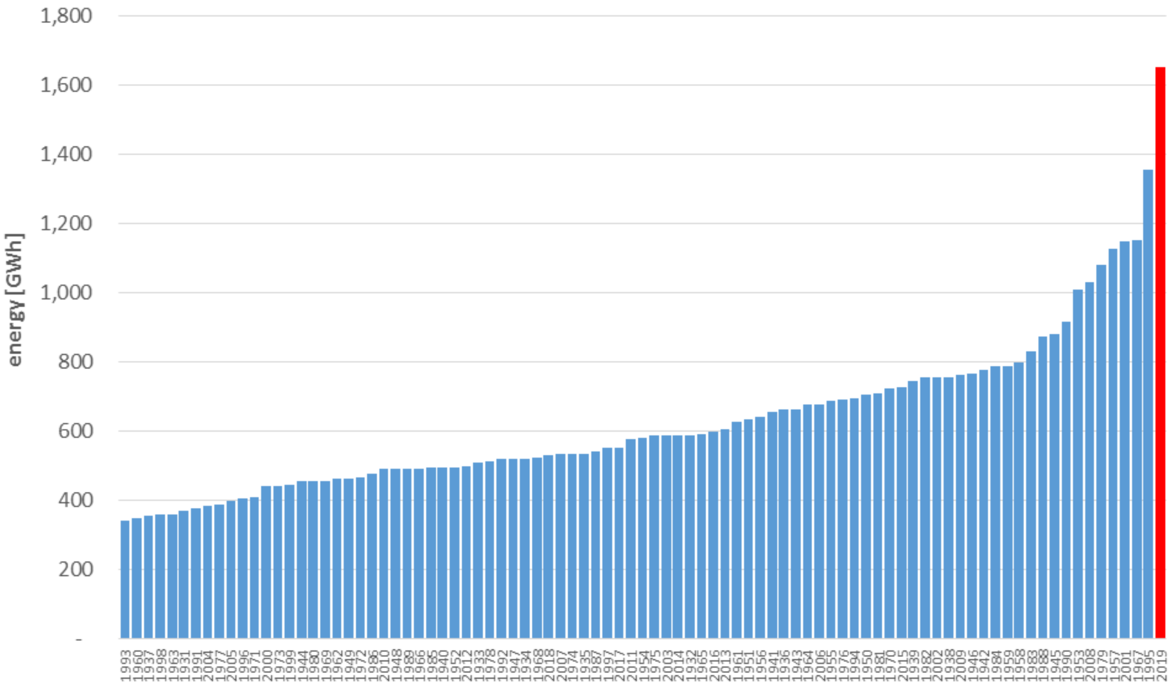
The events being investigated by the Authority are related to exceptional weather conditions that created significant safety risks for the communities and environments in which Meridian operates.

The mean total inflow into Lake Manapōuri during November and December 2019 was the highest since records began in 1932. This resulted in the second highest lake levels ever recorded for the Manapōuri scheme.

Inflows were also exceptional in the Waitaki catchment. Total Benmore inflows in December 2019 were the second highest on record, since records began in 1965. Total inflows at Benmore are a good measure of how much water Meridian is dealing with as it sums inflows from Lakes Ōhau, Pūkaki and Tekapo as well as Benmore tributaries. Measured in terms of energy, NZX hydro data in Figure 2 below shows that not only was this period of inflows[3] in 2019 the wettest event recorded, it was *significantly* wetter – 22% more than the next wettest event record back in 1995.

[3] Note the period 25 November to 15 December is when most inflows occurred and, because of storage, precedes the dates when spill occurred from Lake Pūkaki.

Figure 2: NZX hydro Waitaki inflows 25 November – 15 December



The inflows across Meridian's two catchments were the result of two distinct rainfall events that swept the country. The first in November initiated spill from Manapōuri Lake Control on 9 November 2019. Manapōuri spill volumes peaked on 8 December, following a second, significant inflow event and spill continued until 16 January 2020. Spill from Lake Pūkaki was only initiated by the second event. Pūkaki spill began on 8 December 2019 and continued until 31 December 2019. Levels at Lake Pūkaki increased rapidly and far more than was forecast. At the start of December there was still around 400 GWh of storage headroom in Lake Pūkaki and Pūkaki spill did not seem likely.

High inflows into Lake Tekapo (operated by Genesis) began on 3 December 2019 and the lake exceeded its seasonal maximum control level on 7 December 2019. At this point spill from Lake Tekapo began and continued through to 30 December 2019, peaking at an average of up to 170 cumecs, adding significantly to the water arriving in Lake Benmore that Meridian was required to manage.

Collectively these events resulted in Meridian simultaneously spilling water from every hydro structure under its control. This is the first time in Meridian's history that this has occurred.

Minimisation of safety and environmental risks

Meridian used its best endeavours to manage the weather events in real time based on our experience of managing similar but less extreme situations. Meridian's priority was to manage our dams and gate control structures in a way that minimised safety and environmental risks. We do this by adopting safe and simple operational settings that achieve stable flows downstream. Meridian's trading tactics primarily seek to implement those operational settings.

Revenue was not Meridian's priority during this period and offer tactics during this period did not deviate from Meridian's standard approach during periods of spill over the last nine years.

Meridian has over 40 resource consents for the Waitaki scheme, which stipulate maximum lake levels, design flood levels, maximum discharge rates, flow change rates, and mandatory flows. Collectively these consents are designed so that natural hazards like floods are managed in such a way that dams do not fail and the risk of harm to people and property downstream is minimised.

Transmission limitations

Transmission constraints affected generation at both Manapōuri and throughout the Waitaki chain during the period of the allegations. For example:

- From 25 to 29 November, an outage on the NMA_TWI circuit constrained Manapōuri generation. Meridian's analysis was that this would constrain Manapōuri generation to 650 MW. However, on 25 November the forward schedules showed this constraint to limit Manapōuri generation to around 450 MW and in real time the system operator constrained back Manapōuri generation to around 415 MW. A system operator modelling error was subsequently found to be double counting the 50 MW load at Tiwai for the fourth pot line and unnecessarily increasing the severity of the constraint. This error has been self-reported by the system operator[4] as a Code breach and corrected, meaning that when the same outage occurred on 9 December generation was less constrained.

[4] Letter to the Electricity Authority Compliance Team from Transpower, dated 19 December 2019.

- On 8 December, flooding of the Rangitata River caused extensive damage to nine transmission towers and an outage on Transpower's ISL_LIV_1 circuit. This outage was to be in place until the implementation of a temporary solution by Transpower on 27 March 2020. The ISL_LIV_1 outage causes an overload of AVI_BEN_1 for the loss of AVI_BEN_2 (and vice versa) effectively limiting total generation from Aviemore and Waitaki stations at that time to around 200 MW, compared to the nameplate capacity of 325 MW for the two stations combined. This constraint is sensitive to the level of Clutha and Manapōuri generation, which were both generating significant volumes at the time.

- For short periods on 18 November and between 6 and 7 December the system operator issued Customer Advice Notices for electrical storms and reclassified risk on several transmission circuits affecting Manapōuri generation.

- Meridian generation was also limited for short durations by the bi-pole capacity of the HVDC link and by Southland export constraints.

Operational limitations

During the November and December inflow events, several of Meridian's generating units were on outages, limiting generation output. For example:[5]

- Unit 6 at Ōhau A station was on a long-term outage for half-life refurbishment (this outage also limits canal flows and generation capacity at Ōhau B and Ōhau C).

- Benmore station had several outages across November 2019 for cooling water project work, including a full station outage on 24 November.

- Unit 4 at Manapōuri was out from October 2019 because of bearing issues and remains out to this date.

There are also various hydrological constraints and resource consent requirements that limit Meridian's ability to generate.[6]

---

[5] Full outage information was posted to POCP.
[6] Appendix C of the preliminary decision briefly summarises some of these.

Meridian generation volumes and offers

Over December 2019 Meridian generated 1150 GWh from its hydro stations, spilling around 1300 GWh. This was the most hydro generation for the month of December in Meridian's history (we generated even more than we did back in the years when Meridian also operated the two Tekapo stations). Allegations that Meridian should have generated slightly more should be seen in this context.

In general, Meridian's offer strategy during the period in question sought the dispatch of high volumes of hydro generation. In broad terms, Meridian's offers can be divided into three tranches:

- A large portion of Meridian's generation is offered into the market at prices close to zero so that it is highly likely to clear and cover Meridian's contracted sales.
- In respect of generation length (in excess of contracts), Meridian makes offers intended to deliver optimal modelled generation volumes and prices. Due to competition in the market, Meridian's objectives are not always achieved by our offers, such is the nature of price discovery through a market with many participants and motivations.
- Meridian offers some volumes of generation at higher prices that are not intended to clear, for example, to:
    - maintain steady and certain downstream flows to manage risks to people and properties downstream during a flood event;
    - meet operational constraints of plant (e.g. to avoid moving spill gates continuously in a way which they are not designed to do);
    - avoid the dispatch of generation volumes that cannot be sustainably generated because of hydrological constraints; or
    - mitigate revenue risks such as those associated with price and volume trade-offs and locational prices as a result of transmission constraints.

Meridian considers its offer strategy to be economically rational behaviour. Offering in this way is entirely expected in the workably competitive New Zealand electricity market where there are no requirements to offer based on costs and no capacity payments to generators. Meridian and other generators have implemented these tactics for many years.

Part C: Spot market outcomes were not unusual

The events being investigated by the Authority did not cause unusual outcomes in the spot market, and are accordingly incapable of undermining the integrity of, or confidence in, the wholesale market.

The preliminary report states that all else being equal, when hydro generators in the lower South Island are spilling, the Authority expects to see (amongst other things) the following spot market outcomes:

- lower offer prices because the opportunity cost of water is zero for spilling generators;
- South Island spot prices to fall because of these lower offers; and
- South Island spot prices to separate from North Island spot prices if transmission limits are reached, or if not, low prices in both Islands.

While the false expectation of price separation is dealt with in Part D below, this Part of Meridian's submission addresses whether its offer prices were unexpected during this period of spill and points out errors with the Authority's modelling of the spot market outcomes – in particular, the Authority's over-estimate of "unnecessary spill".

Spilling and making non-zero price offers is consistent with the normal operation of the wholesale market

The Authority's conceptual approach omits key features of the wholesale electricity market, including that:

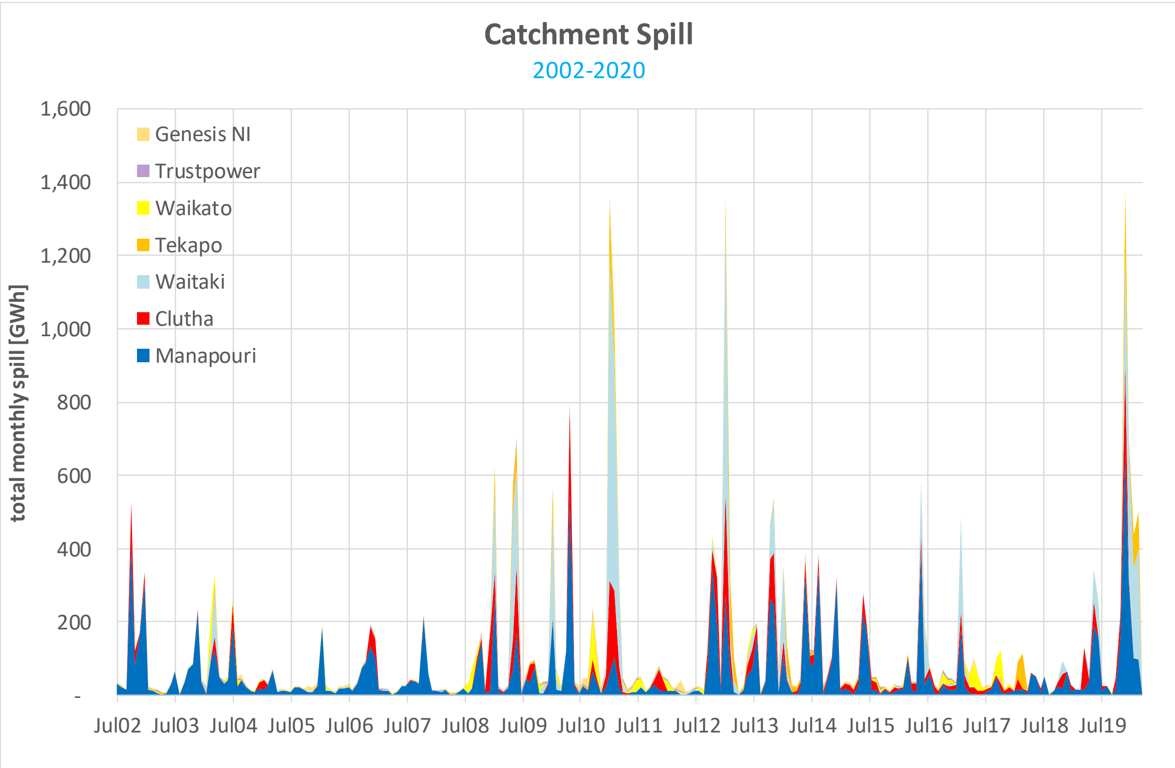
- the spot market pays uniform prices to generators and, although it is formally a gross pool, it operates like a balancing market;
- generation is highly concentrated regionally;
- some generators are poorly diversified regionally and by broad fuel categories;
- short-term demand responses are very inelastic at low-to-moderately-high spot prices;
- it is difficult for generators to accurately predict, more than a few days ahead of real-time, changes in their demand and supply (e.g. hydro inflows and wind levels); and
- financial transmission rights (FTRs) and ASX electricity futures contracts are rather coarse instruments for managing certain spot market risks.

When these features of the spot market are taken into account, it is very predictable that there are times when offer prices will not fall to the low levels that might be "expected" despite spill occurring.

These predictions are supported by observable spot market behaviour. (Conversely, the actual market behaviour and outcomes are not accounted for by the idealised model used by the Authority to form its "expectations".)

There are many historic instances of spill by different generators. These regular spill events are shown below in Figure 3. Up to 2017, hydro generators voluntarily reported their volumes of spill and the data is in the Authority's hydrological modelling dataset. From that point onward, the non-Meridian spill in Figure 3 is estimated based on inflows and generation capacity assumptions.

Figure 3: Monthly spill by generators 2002-2020



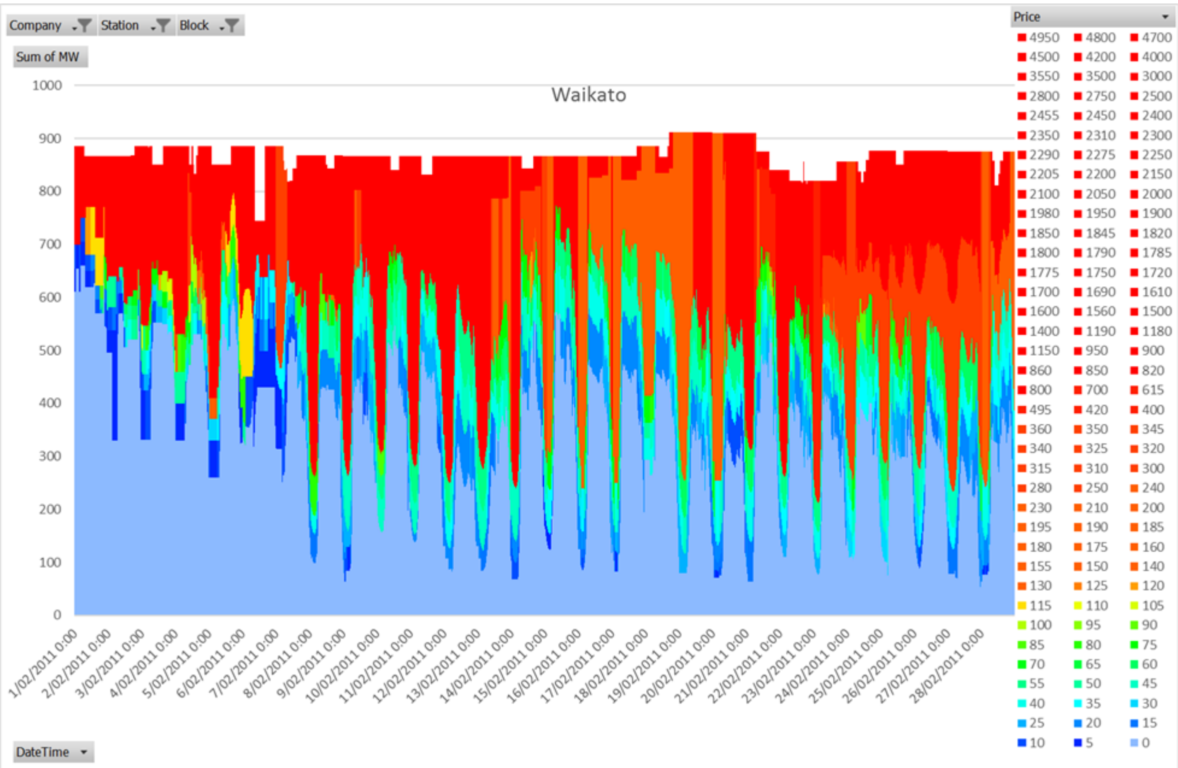
Each instance of spill is an example of offer pricing during spill. If the Authority was to look at any of these in detail, it would find that hydro generators do not offer their generation based on a bottom up assessment of their costs, they offer their generation into workably competitive markets and are economically rational in seeking to generate high volumes at prices the market will support, while also factoring in market conditions and operational constraints.

Commonplace strategies in this regard include:

- non-clearing tranches at high prices during periods of spill;
- backing off generation volumes overnight while demand is lower by placing some volumes in higher priced tranches;
- some generators at times removing non-clearing tranches from the offer stack entirely (proving that QWOP provides minimal insight into offer behaviour); and
- offering some volumes at a price just below that of the next available source of generation from a competitor (this is economically rational behaviour and is to be expected in the New Zealand electricity market where there are no price caps, no requirement to offer based on costs, and no capacity payments).

To give one example, Figure 4 illustrates non-zero offer prices during spill by Mighty River Power. For context Mighty River Power reported spilling the equivalent of 46 GWh of water during February 2011.

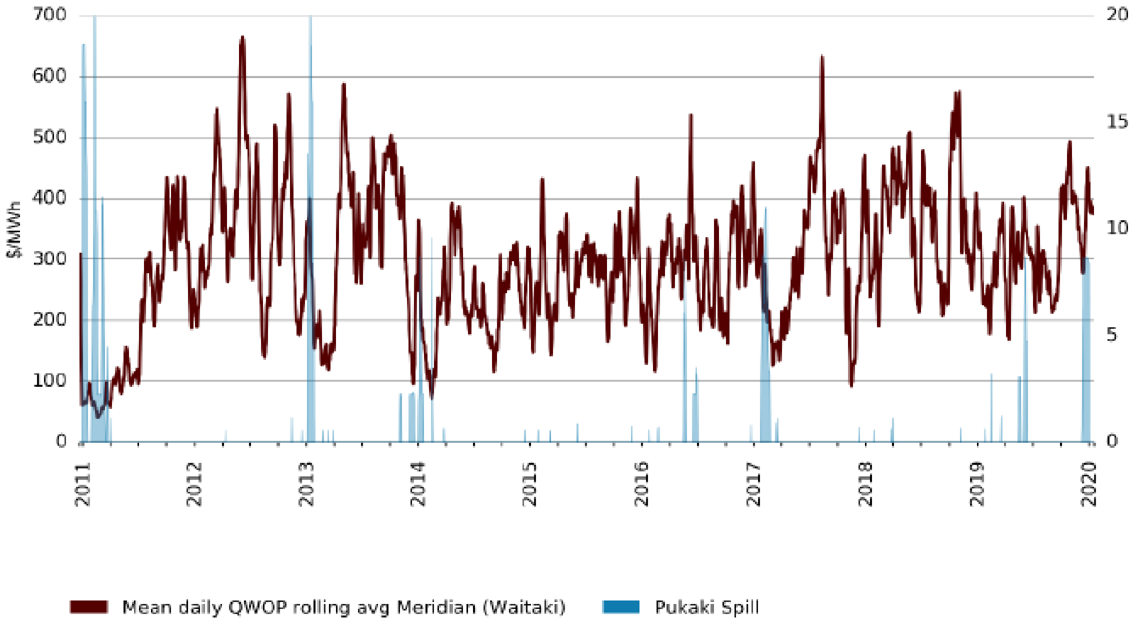
Figure 4: Mighty River Power offers for the Waikato scheme during February 2011 spill



In this example, Mighty River Power's offer behaviour is economically rational and reflects the trading strategies consistently implemented by hydro generators during spill periods for many years. This is part of the normal operation of the New Zealand wholesale market.

The Authority's own preliminary decision also identifies a range of instances of Pūkaki spill over the last 9 years where offers on average were broadly consistent with offers during December 2019. The Authority's chart is duplicated below in Figure 5.

Figure 5: QWOP rolling mean and Pūkaki spill



The Authority overlooks the many spill pricing examples in recent history and points to early-2011 QWOP as an example of what it "expects" offer prices to look like during times of spill. This is unreasonable. The Authority's own more recent QWOP data shows that spill pricing varies significantly but never reflects short run generation costs. Prices are instead discovered through competition in the market and will be dependent on the behaviour of other participants and overall conditions at the time. Critically, this has been the case for many years, with the Brattle Report concluding that[7]:

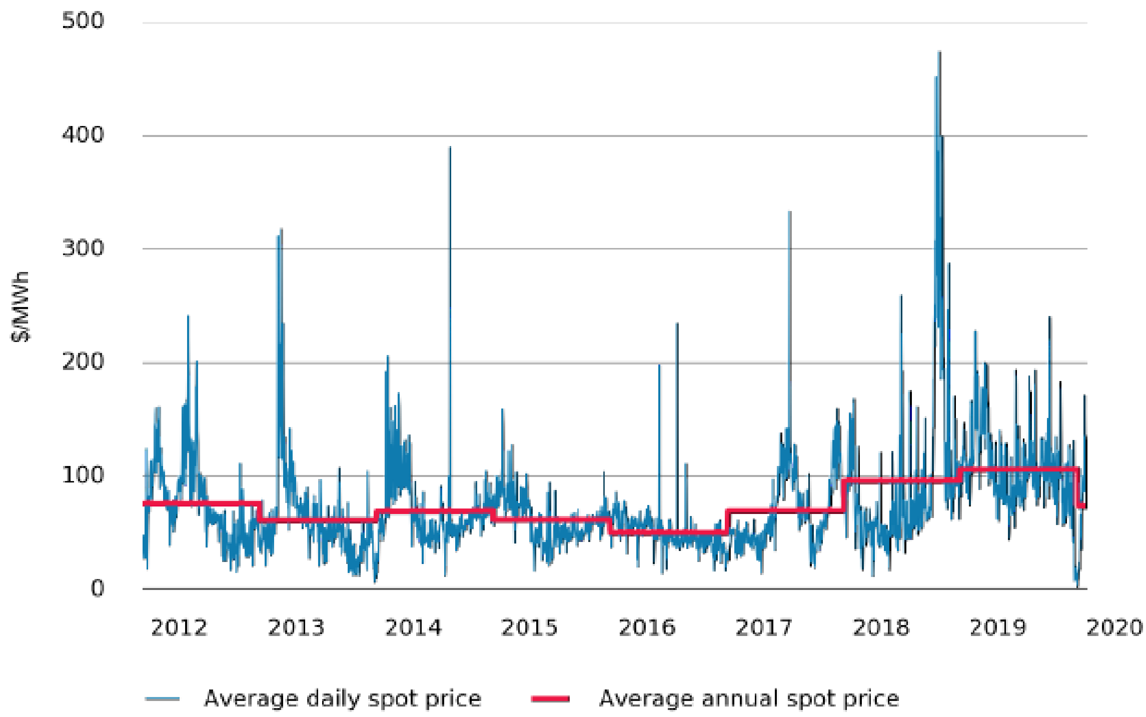
> [I]n 2019 Meridian actually offered a higher amount of generation at less than $10/MWh compared with previous spill periods. In December 2019, Meridian offered 1,123 GWh of energy at less than $10/MWh, which was 8% higher than the average of 1,037 GWh offered at that price range during the previous three spill periods.
>
> …
>
> Meridian's offers in December 2019 were consistent with its offers during those previous periods of high spill, and therefore consistent with Meridian's strategy and their normal market operations for the last several years.

[7] Brattle Report, at 17-18.

If the Authority now finds a UTS in this case it will be reforming the market to establish a new normal. This would be contrary to the intent of the UTS provisions which is to restore the normal operation of the market.

Prices going into this late 2019 period were relatively high on average, as they had been since spring 2018 (wholesale prices for New Zealand in October 2019 averaged $131/MWh, in November $110/MWh, and in December $61/MWh). It is therefore not surprising that prices did not fall quite as low during spill in 2019 as they did in previous instances of spill. The relatively higher market prices seen since 2018 are illustrated in Figure 6 below.

Figure 6: Average daily and annual spot prices since 2012



Meridian was able to generate record volumes in late 2019. Meridian competed to be dispatched and generate those volumes, but was doing so in generally higher market price conditions. Meridian did not expect prices to remain as high as they did prior to 18 December 2019. However, this was not solely because of the way Meridian offered its hydro generation, which was broadly consistent with the approach Meridian has always taken over the past nine years.

There were significant errors in the Authority's modelling

There are significant errors in the modelling undertaken by the Authority. These errors affect the materiality of avoidable spill as well as the Authority's modelling of prices and therefore have an impact on the assessment of whether any UTS occurred. The Authority has already acknowledged that the modelling of "avoidable spill" in the preliminary decision failed to take into account plant outages at the time. Below, Meridian notes other weaknesses in the modelling undertaken by the Authority.

All the modelling undertaken for the preliminary decision is in respect of the entire month of December 2019. There appears to be no relationship between the modelling and the Authority's preliminary decision that a UTS occurred between 3 and 18 December.

Meridian has recreated the Authority's model and, after taking into account plant outages and the date range of the preliminary UTS decision, the volume of spill that the Authority's methodology indicates could have been avoided is 12.2 GWh - not 41 GWh.

After correcting for errors, the volumes in question are not material

For context, Meridian generated 1150 GWh of hydro power during December 2019 and spilled around 1300 GWh over the same period. South Island hydro generators in total generated around 1850 GWh and spilled 1870 GWh in December 2019. This means that the 12.2 GWh of "avoidable spill" is 0.3% of the water that South Island hydro generators were managing in December 2019 or less than 0.5% of the water Meridian had to deal with in December. For context, this is well within the margin of error on Meridian's spill reporting as provided to the Authority. Meridian's data quality standard for the measurement of flow via spill gates and weirs is the same as the NIWA standard for open channel flow derived from a rating. Namely, that 95% of all values will be within +/- 8% of the actual value. This margin of error reflects the challenges of flow rating, which contains a number of sources of error including headwater level measurement.

The lower GWh spill number has flow-on implications for the South Island hydro offer prices that would be required to clear that volume and the market prices that would result in the Authority's perfect hindsight scenario. By rerunning the Authority's virtual scheduling pricing and dispatch tool (vSPD) with price overrides for South Island hydro generators when spilling, Meridian estimates (using the same methods as the Authority) that 12.2 GWh of additional hydro generation could be dispatched if offer prices for all South Island hydro generation were reset at around $35/MWh when spilling rather than $6.35/MWh.

The difference in market clearing prices and total settlement would also decrease significantly once these errors are taken into account. Meridian's modelling using the Authority's methodology indicates that with a $35/MWh South Island hydro offer reset, market prices for 3 to 18 December 2019 would average:

- $55.59/MWh at Benmore; and
- $76.55/MWh at Otahuhu.

This is not far off the final prices actually observed of $72.81/MWh at Benmore and $92.65/MWh at Otahuhu. It is hard to see how estimated final price differences of $16 to $17/MWh could undermine confidence in the market and therefore support a finding of a UTS, given the variability in monthly averages that is generally expected in the market. When one takes a step back, the impact of a price override at $35/MWh would be negligible in the context of annual average prices and the expected volatility of wholesale prices year on year.

Figure 7: Average BEN and OTA prices by FY compared to variation with price override

	Average Price	
FY	**BEN2201**	**OTA2201**
2010	64.73	72.25
2011	38.95	53.45
2012	105.00	89.93
2013	60.96	72.84
2014	58.55	70.94
2015	67.42	73.55
2016	56.84	65.93
2017	60.20	64.30
2018	75.72	82.48
2019	125.45	145.49
2020	91.14	108.73
2020 with $35/MWh Offer Reset	90.34	107.98

Most consumers were not and will not be impacted by 3 to 18 December 2019 pricing

As the Authority is aware, consumers do not generally purchase from the wholesale market and are on fixed price contracts with retailers that insulate them from any changes in the wholesale market. Accordingly, regardless of the Authority's final decision, most consumers will not pay higher prices for electricity as a result of the events of December 2019. This is contrary to misrepresentations made by some of Meridian's competitors.

Further, Meridian estimates that 91% of wholesale market purchasers are generator-retailers that are physically hedged and of the remainder, most will be financially hedged.[8] However, the difference in total settlement value has also been deliberately misrepresented by some of Meridian's competitors and misreported by the media as a measure of Meridian profit or cost to consumers under the hypothetical scenario – it is neither. By publishing a hypothetical total settlement number for a South Island hydro offer reset while simultaneously calling out only Meridian's offering, the Authority helped to perpetuate these myths. There is no link between the counterfactual reset and Meridians offers, and the number used in the preliminary decision is based on modelling errors.

Regardless of any change in market settlement, Haast Energy Trading (Haast) and its related company Electric Kiwi (both companies being directly or indirectly majority-owned by offshore investors based in the United Kingdom) are motivated to complain about a lack of price separation because of their interest in speculation on the FTR market. Haast was the largest trader of FTRs by volume in 2019 and actively speculates on the extent of price separation between different locations on the New Zealand grid. It should go without saying that limiting the ability of generators to manage locational price risks would be of significant benefit to Haast as an FTR speculator. The FTR market is funded from the pool of loss and constraint excess (the surplus created in the electricity market once purchasers have been invoiced and generators have been paid) and there is no obvious justification for allowing FTRs to be purchased as a form of market speculation.[9]

The Authority needs to be alive to these motivations and understand that there is no downside or cost for a UTS complaint, meaning regardless of their substance, complaints will continue with high frequency. Speculators and small retailers have made UTS allegations in three of the last four years. To date, all these claims have been dismissed by the Authority. However, the reputation of the New Zealand electricity market is constantly called into question reducing trust in the sector and eroding confidence, regardless of the merits of these claims.

[8] If the Authority's $80 million estimate of financial impact was correct, then after accounting for modelling errors, an offer override of $35/MWh for all South Island hydro would result in market prices of $55.59/MWh at Benmore and $76.55/MWh at Otahuhu with a lower difference in total settlement value, closer to $30 million. If 91% of participants are physically hedged this reduces any potential financial impact to less than $3 million (the benefits and costs of which would be shared across all generators and wholesale purchasers).

[9] The Authority could further consider whether speculators in the finitely sized FTR market are in the best interests of consumers, when they drive up the prices of risk management products.

Part D: HVDC risk was not a major factor

The Authority's preliminary decision states that Meridian was offering in such a way as to ensure the HVDC was not constrained – "We consider pricing offers to avoid the HVDC risk binding may contribute to threatening confidence in, and the integrity of, the wholesale market."[10]

Meridian notes that:

- contrary to the Authority's findings in the preliminary decision, preventing the HVDC from binding was not a significant factor in Meridian's decision making during 3 to 18 December 2019;
- in any event, managing basis risk through generation offers is:
    - part of the normal operation of the wholesale market; and
    - has never previously been found by the Authority to constitute a UTS; and
- the preliminary decision appears to arbitrarily distinguish between the HVDC and other transmission constraints.

HVDC risk was not a significant factor in Meridian's decision making

While the Authority states "evidence shows Meridian was offering in such a way as to ensure the HVDC was not constrained"[11] there is very little HVDC analysis in the preliminary decision. The Authority instead seems to rely on a statement in Meridian's operational reporting that refers to "maintaining DC limits" which would typically mean that Meridian was looking to do what it could to maximise HVDC transfer while, like other generators at all times, being conscious of dynamic transmission limits and constraints we face, the price signals they send us and the impact they have on the volumes we are able to generate.

We observe that the wording in the preliminary report "offering in such a way as to ensure the HVDC was not constrained" overstates the degree to which Meridian is able to influence the HVDC, bearing in mind the following uncertainties:

- generation volumes from other South Island generators; and
- the fact that HVDC transfer changes constantly as it is impacted by the level of demand and by the actions of other generators (including North Island reserve providers).

[10] Electricity Authority *Preliminary Decision* (2020) page iv.
[11] Electricity Authority *Preliminary Decision* (2020) page iii.

Rather than doing any HVDC analysis, the preliminary report notes the statement in Meridian's operational reporting (and a similar acknowledgement from Contact) and takes it as fact that that is what was occurring at all times. The preliminary report seems largely concerned with the fact that the Authority previously advised[12] Meridian that it does not agree with using offers to manage transmission constraints and in pursuing this point fails to look at what was actually occurring on the HVDC.

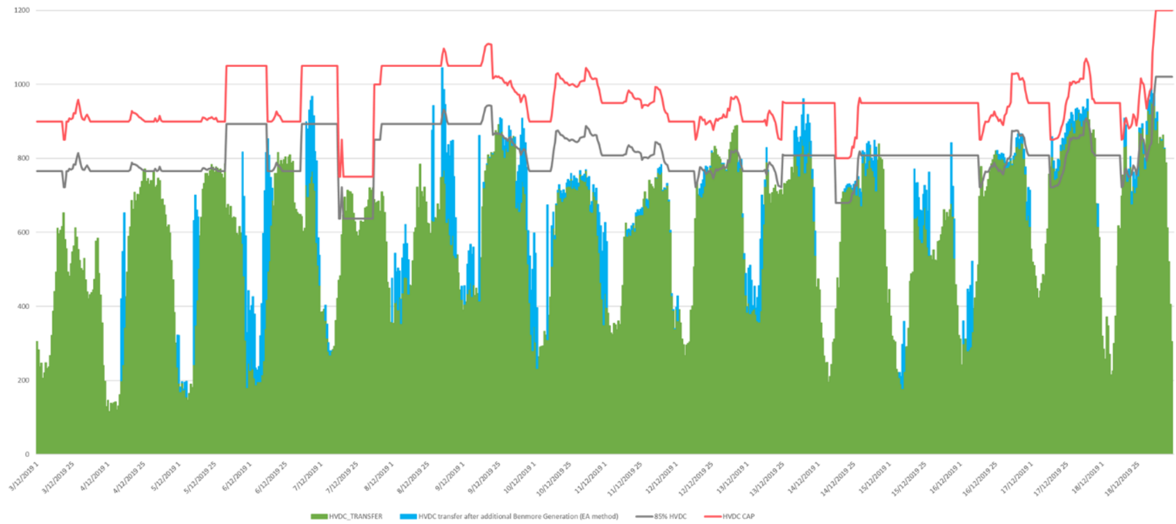
In terms of Meridian's trading, Meridian focused on dispatching high volumes of hydro generation while managing downstream flood flows and operational limitations during the period. When Meridian was short to its contract position in the North Island and HVDC flows were close to capacity Meridian's offers were conscious of HVDC constraints. However, for much of the period 3 to 18 December the HVDC constraint was not a risk and Meridian was long in the North Island. As shown below in Figure 8, the HVDC constraint was not a risk for most of the 3 to 18 December period identified in the preliminary report, in either the real-world scenario or in the Authority's prefect hindsight counterfactual. In fact, most of the time, HVDC transfer was not even within 85% of maximum and would therefore not have been visible to traders as a potential constraint in forward schedules:

- In the base case, real world scenario actual HVDC transfers were:
    - greater than 85% of the HVDC maximum on only 17.2% of trading periods from 3 to 18 December; and
    - within 50 MW of the HVDC maximum on only 1.3% of trading periods from 3 to 18 December.

- In the Authority's counterfactual scenario with additional Benmore generation, hypothetical HVDC transfers were:
    - greater than 85% of the HVDC maximum on only 22.4% of trading periods from 3 to 18 December; and
    - within 50 MW of the HVDC maximum on only 2.7% of trading periods from 3 to 18 December.

[12] This was done via a letter, which had no legal effect. The letter and its implications are discussed in detail below at page 35 and in Part E of this submission.

Figure 8: HVDC transfers and maximums



Therefore, even if all the additional generation the Authority "expected" was actually dispatched, the HVDC constraint would only be visible to traders as a potential risk in 22.4% of trading periods and would only actually be at risk of binding in 2.7% of trading periods. In the majority of trading periods the HVDC was unconstrained and was not a factor in play.

If the management of transmission constraints is key to the finding that Meridian's offer behaviour constituted a UTS then the Authority will need to be more granular in its analysis and identify trading periods where the HVDC was at risk of constraining and Meridian's behaviour could therefore be said to be managing the risk.

In addition, for 11 out of 16 days of the period 3 to 18 December 2019, Meridian was long on generation in the North Island relative to our North Island contract position (there were high levels of wind generation) and therefore Meridian had *no incentive* to cover any North Island basis risk at those times and was ambivalent to the HVDC constraint.

In these circumstances it is difficult to see how the preliminary decision could attribute a UTS to Meridian's supposed management of basis risk – particularly in the absence of any actual trading period by trading period analysis by the Authority establishing that the HVDC constraint was a factor and that Meridian was exposed to North Island basis risk. To take the most extreme example, the three trading periods from 17:00 to 18:30 on 11 December 2019 and the trading period starting 07:30 on 12 December 2019 are all periods in which South Island generation and HVDC flows were the same under both the real-life base case and the $0.01 offer reset.

It was previously recognised by the Authority that managing basis risk through generation offers is part of the normal operation of the wholesale market

The UTS preliminary decision is the latest development in a long-standing industry debate as to whether locational price risks are more efficiently managed via generator offers or via hedge products. However, in a series of papers the Authority has previously indicated (including in a UTS context) that managing transmission constraints is part of the normal or ordinary operation of the wholesale market. Those previous decisions are set out below.

2008 Contact spill

Appendix E of the Authority's 2016 UTS decision refers to a 2008 case study in which the Tiwai smelter had a transformer failure on 9 November 2008, reducing load by approximately 170 MW.[13] Following this load reduction, and as a result of transmission constraints out of the lower South Island, Contact spilled 85 GWh over the last five weeks of December 2008.

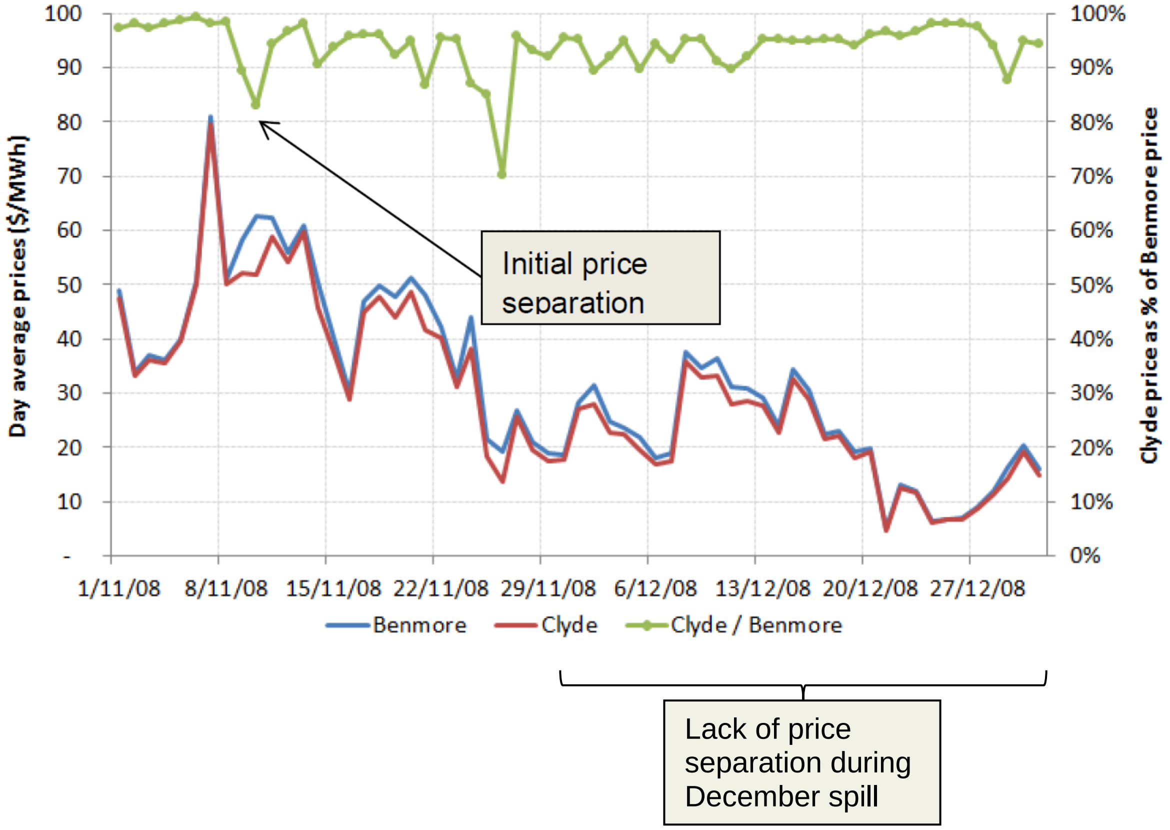
Figure 9: Contact hydro spill reporting for late 2008

TOTAL	*Values are expressed in gigwatt hours*												
Week ending	5-Oct-08	12-Oct-08	19-Oct-08	26-Oct-08	2-Nov-08	9-Nov-08	16-Nov-08	23-Nov-08	30-Nov-08	7-Dec-08	14-Dec-08	21-Dec-08	28-Dec-08
Plant	3.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	4.00	4.00	4.30	0.40
Obstruction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Inflow	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60	0.00
Regulatory	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Contractural	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Recreational	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost	3.70	0.10	11.00	0.60	0.00	0.00	0.00	0.00	0.00	6.10	17.50	27.50	12.10
Economic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission Constraint	3.30	0.00	1.90	0.00	0.00	0.00	0.00	0.00	6.28	31.90	13.90	5.20	26.80
Hydraulic Constraint	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	10.70	0.10	12.90	0.60	0.00	0.00	0.00	0.00	7.68	42.00	35.40	37.60	39.30
Energy Produced	95.65	93.87	89.13	78.04	71.44	64.56	68.07	78.98	77.31	75.10	74.52	73.26	69.97
Spill/Inflows %	11.19%	0.11%	14.47%	0.77%	0.00%	0.00%	0.00%	0.00%	9.93%	55.92%	47.50%	51.32%	56.17%

Despite the volumes of water spilled, price separation did not occur in December 2008 as shown in Figure 10 below.

[13] https://www.ea.govt.nz/dmsdocument/21184-uts-2-june-2016-decision-paper

Figure 10: Electricity Authority's analysis of basis risk management during the 2008 Tiwai transformer outage



The Authority concluded that "offers were likely managed by one or more parties given the nature of the situation and the lack of price separation in the data" and that this was no different to more recent management of transmission constraints saying, "basis-risk management through managing spot offers has been an active strategy for some time."

2011 UTS

In 2011, in the context of a UTS claim against Genesis, Mighty River Power stated that it lifted offer prices on one side of a transmission constraint "to lift prices in the region of a large proportion of our generation to reduce the price separation across the constraint to the north".[14] The Authority's 2011 UTS decision noted that this was "a logical reaction to the high prices" at the time.

2013 Market Performance Review

The Authority in its 2013 report said:[15]

[14] https://www.ea.govt.nz/dmsdocument/10844-uts-committee-final-decision-on-uts-and-actions
[15] https://www.ea.govt.nz/dmsdocument/15431-increased-electricity-spot-and-hedge-price-enquiry

> "… we observed high energy offer prices at Manapouri resulting in reduced output during periods of spill in January 2013. Meridian has indicated that during these periods, offer prices for Manapouri took into account the transmission outages and the resulting security constraints in the Southland region, so that the dispatched generation at Manapouri was at a level where these constraints did not bind."
>
> "We estimated the potential additional generation that could have been supplied from Manapouri during these periods of high inflow spill, had lower priced energy offers been provided at Manapouri. These simulations used the vSPD model with Manapōuri energy offer prices set to $0.01/MWh and included the transmission security constraints in the Southland region. The simulations indicate that an additional 19GWh of energy could have been scheduled from Manapouri during the 20 days of high inflow spill at Manapouri."
>
> "While such a strategy may have been beneficial to Meridian, there is a net efficiency loss in the market when lower cost hydro energy is not dispatched and also not stored for later use… The Authority considers this as an issue with the current market design where participants are incentivised, probably more than they should be, to minimise within-island basis risk."

No UTS was found or even alleged in 2013. The Authority explicitly identified offer pricing during spill to manage transmission constraints as an issue with *market design*, i.e. the design of the market incentivised this behaviour and a Code change would be necessary to reform the market design. Seven years later, the Authority is still yet to reform market settings in respect of offer pricing during spill that manages transmission constraints.

2 June 2016

It was alleged that Meridian offers over the evening peak on 2 June 2016 caused both a UTS and a breach of the high standard of trading conduct (HSOTC) provisions in the Code. Meridian had increased offer prices for some volumes of generation to mitigate basis risk that might result if the HVDC constraint were to bind during a period of high North Island prices.

In respect of the UTS component of the claim the Authority decided relatively quickly (as ought to be the case) in its decision of 16 August 2016, that there was no UTS on 2 June 2016 because there was no evidence that the existing levels of confidence in, or integrity of, the wholesale market were threatened, or may have been threatened, by the situation. The Authority's reasons for the decision included:[16]

> "Meridian's offer behaviour was not an unusual response for a market participant facing the risk of financial loss as a result of the tight and uncertain market conditions that existed in the North Island over the relevant trading periods. There is evidence that a similar approach is also used by other industry participants to manage the risk of financial loss when faced with similar scenarios of basis (or locational) price risk. That this type of offer behaviour has occurred regularly in the past, without creating a UTS, suggested that the behaviour alone was not sufficient to warrant a UTS finding."

If the current preliminary UTS decision is confirmed, it will reverse or limit the effect of this 2016 UTS decision. The Authority needs to address this contradiction and explain what has changed since 2016 – certainly the market rules in the Code have not changed to expressly prohibit generation offers that seek to manage basis risk, nor have the UTS provisions changed (under which the behaviour was previously deemed not to give rise to a UTS).

On the HSOTC component of the 2016 claim, the Authority decided, on 4 May 2017 not to refer the HSOTC complaint to the Rulings Panel. In so doing, the Authority wrote a letter to Meridian:

- expressing the opinion that its offers on 2 June 2016 had in its "clear view" breached a HSOTC; but also
- acknowledging that there were disparate opinions[17] as to whether Meridian complied, and that the HSOTC Code provisions might require clarification.

In response, Meridian's Chief Executive at the time wrote to the Authority Chair on 27 June 2017, saying that Meridian disagreed with the letter and that it was wrong in law. Meridian also put out a press release saying the same thing. Meridian urged the Authority to reform the Code to address the uncertainty created and was entirely transparent that Meridian's position "remains unaltered in terms of the legal position and in similar situations we will continue to act in a way that is both appropriate from a legal perspective and protects the interests of our shareholders."[18]

[16] https://www.ea.govt.nz/dmsdocument/21184-uts-2-june-2016-decision-paper
[17] The difference of opinion was not just between the Authority and generators. Even within the Authority the investigator appointed could not find evidence that the HSOTC provisions had been breached and the Authority's independent expert also did not consider there to be a breach. The Board's letter ignored both of those expert opinions.
[18] Letter from Mark Binns, Meridian Chief Executive to Brent Layton, Electricity Authority Chair (27 June 2017).

Meridian was not the only generator to transparently declare that offers to manage transmission constraints are part of the normal operation of the market. Mercury also wrote to the Authority and said that:[19]

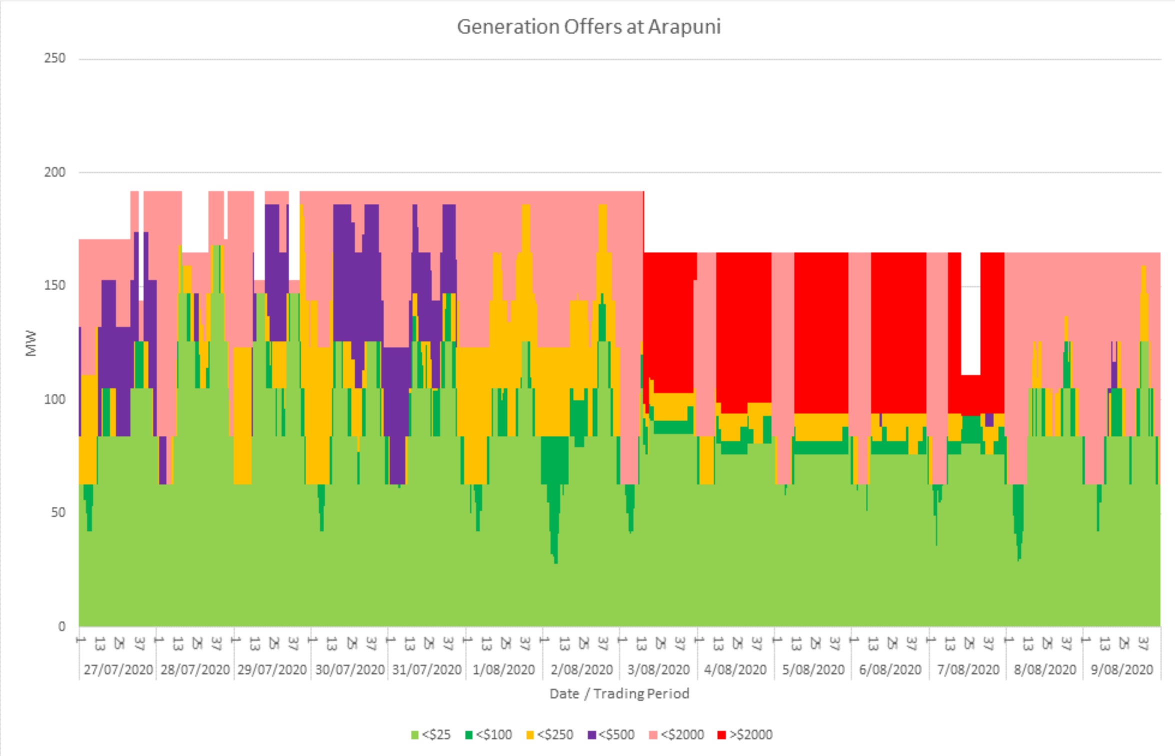
> "…a gentailer managing wholesale risk on behalf of its customers by taking action to close an adverse price gap through managing its energy offers … is an entirely appropriate risk management approach and is consistent with promoting the long term interests of consumers."

Clearly Contact also used this approach in the above 2008 example and according to the preliminary report at paragraph 11.18, Contact told the Authority that offers in the current case were structured to prevent constraints binding and the consequent price separation.

Examples are also clearly visible in the market right now. From 3 to 7 August 2020 a combination of outages around Bombay and Hamilton (BOB_HAM_1, BOB_HAM_2, ARI_BOB_1, HAM_T9) resulted in a constraint on the two ARI_KIN transmission lines. If the constraint was to bind it is likely that a spring washer situation would result and Mercury's Arapuni prices would drop close to zero or potentially to negative prices. To manage this constraint Mercury moved significant generation volumes into a higher top tranche offer priced at over $2000/MWh (see the offer stack below at Figure 11), effectively using non-clearing tranches to reduce output and prevent the constraint binding. Mercury needed to limit Arapuni generation to around 86 MW to prevent the constraint binding and to prevent the low prices at Arapuni that would result. This was economically rational behaviour by Mercury and is entirely expected.

[19] Letter from Fraser Whineray, Mercury Chief Executive to Carl Hansen, Electricity Authority Chief Executive (19 May 2017).

Figure 11: Mercury Arapuni offers 3-7 August 2020



The above examples all show that generators have been entirely transparent with the Authority for over a decade that managing basis risk through generation offers is part of the normal operation of the market. The Authority has acknowledged this and its multiple investigations of this behaviour have never found it to constitute a UTS. Given the precedent of previous Authority decisions and the transparency with which generators have managed basis risks, it is inconceivable that continuation of this conduct could in any way threaten confidence in the wholesale market. Rather, the conduct is entirely to be expected and it comes as a surprise that the Authority would suggest otherwise.

Meridian's trading behaviour was consistent with its own standard practice during times of spill and for that matter consistent with what we understand to be the practice of other hydro generators. No New Zealand generator, to our knowledge, is deliberately and artificially 'blind' to transmission constraints in making its offers (during times of spill or otherwise). As noted in the appended Sapere Report:[20]

> The Authority's consternation at generators offering in such a way as to ensure transmission constraints do not bind echoes a long-standing market design debate. That generators routinely offer in this manner in energy only markets is now a matter of

[20] Sapere Report, paragraph 83.

historical record, at least in New Zealand and Australia. There are good reasons for viewing these offer strategies as in the long-run interest of consumers.

Arbitrary distinction between the HVDC and other transmission constraints

According to the preliminary decision “the Authority does not think offers should be used to manage transmission constraints” because doing so “undermines the rationale for nodal pricing by dampening locational price signals” and “effects [sic] efficiency”. However, this analysis seems to only apply to HVDC transmission constraints and in respect of the circuit between Aviemore and Benmore the preliminary decision states that managing that circuit in a conservative way was appropriate given the set of circumstances Meridian faced. It is therefore unclear from the preliminary decision how generators are supposed to distinguish between transmission constraints that can and cannot be managed through generation offers.

Part E: The Authority has misinterpreted and misapplied the UTS test

Introduction

The term undesirable trading situation is defined in Part 1 of the Code to mean "any situation—

(a) that threatens, or may threaten, confidence in, or the integrity of, the wholesale market; and

(b) that, in the reasonable opinion of the Authority, cannot satisfactorily be resolved by any other mechanism available under this Code (but for the purposes of this paragraph a proceeding for a breach of clause 13.5A is not to be regarded as another mechanism for satisfactory resolution of a situation)".

Part 5 of the Code then sets out the regime for dealing with a UTS. Clause 5.1(2) includes examples of what the Authority may consider to constitute a UTS. Clause 5.1A states that "the Authority must not commence an investigation if more than 10 business days have passed since the situation, which the Authority suspects or anticipates may be an undesirable trading situation, occurred." Clause 5.2 sets out the actions that the Authority may take to "correct" a UTS, while clause 5.5 provides that the Authority must attempt to correct and restore normal operation as soon as possible.

The Authority's preliminary decision finds that a UTS occurred between 3 and 18 December 2019 because spot market outcomes "differed markedly – for a sustained period – from what we expect given the underlying supply and demand conditions, and the scale of this difference is large".

The Authority's expectation in the preliminary report is to see lower offer prices and more hydro generation rather than spill. The Authority estimates there was excess spill equivalent to 55MW of generation capacity throughout December 2019 (41 GWh over the course of December). The Authority's modelling suggests this "unnecessary spill" would have been dispatched as generation at offer prices of $6.35/MWh.[21]

[21] Issues with this modelling are addressed in Part C of this submission.

The Authority's preliminary decision was that in isolation the combination of offering behaviour and resource consent issues at Manapōuri, the Clutha stations, and Tekapo was not significant enough to constitute a UTS. However, the Authority's Chief Executive stated explicitly in the public briefing that the Authority considers Meridian's behaviour was material enough to constitute a UTS and that:

- offer prices at Meridian's Waitaki stations were much higher than at other stations in the South Island throughout the investigation period; and
- Meridian was offering in such a way as to ensure the HVDC was not constrained – "We consider pricing offers to avoid the HVDC risk binding may contribute to threatening confidence in, and the integrity of, the wholesale market."[22]

The Authority's preliminary decision also notes that "efficiency in an economic sense is achieved when price equals cost in a competitive market" and that "efficiency in economics also refers to the use of the lowest cost technology to produce outputs. In the electricity industry this usually means using the lowest cost fuel source. As set out above, when a hydro station is spilling, the opportunity cost of the water is zero. The use of this abundant low-cost fuel is maximised when spill is minimised… Low cost South Island generation would then displace higher cost North Island generation as more energy flows over the HVDC. This means lower prices for consumers."[23]

While the Authority is unclear on what legal test it is applying or what factors mean that it is satisfied here, it appears that its core concerns were that:

- Meridian's short-run marginal cost (SRMC) was very low during the relevant time period because spilt water has a zero opportunity cost;
- Meridian's offers should have reflected this SRMC which would have produced a different set of spot market outcomes (including lower South Island prices, higher HVDC flows and less spill); and
- that in constructing offers to reflect this SRMC, Meridian should have been blind to any costs associated with price separation due to binding of the HVDC constraint.

It is unclear from the preliminary decision whether any one of the following factors would constitute a UTS or whether it is all these factors *collectively* that constitute a UTS:

- hydro offer prices not as low as the Authority expects during spill;

[22] It is clear from the preliminary decision that Contact was also offering in this way "… generators structured their offers to prevent the constraints binding and the consequent price separation. Contact has told us this is the case, and Meridian's weekly Perform Reports contain direction to prevent transmission constraints." Nevertheless, only Meridian is criticised for this in the preliminary decision.
[23] Electricity Authority *Preliminary Decision* (2020) page 24

- South Island spot prices that do not fall during periods of spill;
- generators offering in an attempt to ensure that transmission constraints do not bind and drive price separation on either side of the constraint; and
- failing to minimise spill.

The Authority has also not identified trading periods between 3 and 18 December when some, none, or all the four factors above applied, nor has it clearly said which of those factors or combination of those factors must be present in a trading period to constitute a UTS.

The Authority says that an outcome that is different from what it might expect means that confidence in the market may be threatened, and accordingly its preliminary view is that there was a UTS.

This represents a very different approach to that taken by the Authority in the past. It would force generators to second guess the Authority's view of their short run costs in order to offer in a way that avoids the risk of a UTS finding. The Authority has in the past been careful to allow the market to perform the price discovery role, whereas the present approach is a form of shadow price control.

As set out in detail below, Meridian's position is that the Authority's interpretation and application of the UTS provisions is unlawful for the following reasons:

- a test of "spot market outcomes that do not meet the Authority's expectations" is inconsistent with the text and purpose of the Code;
- behaviour that is part of normal market operations cannot be found to be a UTS as the Authority has previously acknowledged;
- the test applied in the preliminary report is different to that used previously by the Authority, is subjective, and in reality seeks the optimisation of the wholesale market rather than correction of a UTS;
- the test applied in the preliminary report is arbitrary; and
- even if "meeting the Authority's expectations" was the test for a UTS, the Authority fails to properly apply the principle of workable competition.

Any new approach which requires generators to offer in accordance with SRMC (and to disregard the impacts of price separation as a relevant "cost") is a fundamental shift in the market and can only be introduced via a Code change process following the statutory requirements for consultation and a cost benefit assessment as set out in Part F below.

A test of "spot market outcomes that do not meet the Authority's expectations" is inconsistent with the UTS text and purpose

UTS complaints tend to arise about once a year. And only one such complaint has been upheld by the Authority in the past. The UTS provisions have only been applied when there has been a major departure from normal market operations and the market has become dysfunctional.

In contrast, in the preliminary decision, the Authority has radically transformed the UTS test into a question of whether the spot market met the Authority's expectations.[24] The Authority concluded that because the spot market outcomes "differed markedly from what we would have expected" the confidence in, or integrity of, the spot market was under threat.[25] That conclusion was then sufficient to undermine the forward markets as well due to their "close link".[26]

The Authority's interpretation is inconsistent with the text, purpose and context of the Code. The text of the UTS definition clearly sets a high threshold for finding such a situation. Mere difference from the Authority's expectations does not reach that threshold. Similarly, that expectations test is inconsistent with the purpose of the UTS regime. The UTS regime exists as a rule of last resort to fix aberrant behaviour or serious market disfunction. The purpose of the UTS regime is not, and never has been, to apply the Authority's expectations of spot market efficiency.

Definition of a UTS

The term "undesirable trading situation" is defined in the Code as a situation "that threatens, or may threaten, confidence in, or the integrity of, the wholesale market".

The Code provides the following examples of what may constitute a UTS:

- manipulative or attempted manipulative trading activity;
- conduct in relation to trading that is misleading or deceptive, or is likely to mislead or deceive;
- unwarranted speculation or an undesirable practice;
- material breach of any law;

[24] Electricity Authority *Preliminary Decision* (2020) pages 12–14.
[25] Electricity Authority *Preliminary Decision* (2020) page 14.
[26] Electricity Authority *Preliminary Decision* (2020) page 14.

- a situation that threatens orderly trading or proper settlement; or
- any exceptional or unforeseen circumstance that is contrary to the public interest.

The adjectives chosen are uniformly significant: "manipulative", "misleading", "deceptive" and "unwarranted". Even "exceptional or unforeseen" circumstances are insufficient on their own. Rather, the examples suggest they would need to be "contrary to the public interest" before amounting to a UTS. Even if one of these examples were met, clause 5.1(3)(b) requires that the definition of a UTS also be met. That means that even a material breach of law may not be a UTS as it may not threaten confidence in, or integrity of, the market.

Purpose

The UTS scheme was enacted to provide a rule of last resort to fix those occasions when the wholesale market is not operating in accordance with the Code. This is evidenced by the UTS definition in the Code itself, which stipulates that Part 5 of the Code does not apply to any situation that can "satisfactorily be resolved by any other mechanism available under this Code".

The Code as a whole provides a carefully calibrated regulatory regime, comprising detailed and specific obligations that participants must comply with in a range of potential situations that could arise in the market. The “wholesale market” is defined and created through these provisions. For example, the Code does not cap wholesale offers, nor does it require offers to match short run marginal costs. However, the electricity market is complex and dynamic and so, from time to time, undesirable trading situations could arise which are entirely unforeseen, and therefore incapable of being corrected by the current Code.

These situations, which the High Court has identified as "typically … 'one off' events of relatively short duration"[27], are the mischief to which the UTS regime responds. Conversely, the UTS regime is not designed to tweak the market design or as a substitute for the Code amendment process to prescribe new rules for offer behaviour.

The appended Sapere Report considers the underlying economic rationale for the UTS provisions and finds that “UTS provisions exist in market rulebooks to cover unforeseen or exceptional situations.”[28]

---

[27] *Bay of Plenty Energy Limited v the Electricity Authority* HC Wellington CIV-2011-485-1371, 27 February 2012 at [218].
[28] Sapere Report, paragraph 81.

Context

The focus on the correction of genuine market disfunction is confirmed by the context that sits around the definition of a UTS.

The Code establishes the power to find a UTS as an *urgent* restorative power to return the wholesale market to the position before the UTS developed. Clause 5.2 sets out the actions the Authority may take to "correct" a UTS. Similarly, clause 5.5 requires the Authority to "correct and restore normal operation as soon as possible". That is, it is designed to remedy a dysfunctional situation, not to evolve market trading rules.

This is also consistent with the 10 day time limit for a UTS complaint. The decision to implement a ten-day time limit was made on 17 June 2013 with the Authority stating that "a time limit should provide more confidence that the UTS provisions can only be invoked in extreme circumstances" and noting that "the UTS provisions should not be relied upon as a fix-all in place of Code amendments".[29]

Normal market operation is a UTS safe harbour that has been disregarded by the Authority

A UTS is a situation outside of normal market operations

The Authority's consistent view (at least until this preliminary decision) has been that "…a UTS **must be** a situation outside of the normal operation of the wholesale market".[30] Meridian agrees with this approach.

For example, in its decision on the events of 2 June 2016, the Authority stated that "…the situation was within the normal operation of the wholesale market, so does not threaten, or may threaten the existing level of confidence in, or the integrity of, the wholesale market."[31] This meant the situation could not be a UTS.

[29] https://www.ea.govt.nz/dmsdocument/15156-decision-paper-uts-provisions-amendment
[30] See Electricity Authority *Final decision on the UTS of 26 March 2011* (2011) page 9; Electricity Authority *Decision on claim of an undesirable trading situation* (2016) page 3; and Electricity Authority *Decision on claim of an undesirable trading situation* (2018) page 9.
[31] Electricity Authority *Decision on claim of an undesirable trading situation* (2016) page 32.

The Authority went on to state:[32]

> "The situation was within the normal operation of the wholesale market because: (i) Meridian's offer behaviour was not an unusual response for a market participant facing the risk of financial loss as a result of the tight and uncertain market conditions that existed in the North Island over the relevant trading periods. There is evidence that a similar approach is also used by other industry participants to manage the risk of financial loss when faced with similar scenarios of basis (or locational) price risk. That this type of offer behaviour has occurred regularly in the past, without creating a UTS, suggested that the behaviour alone was not sufficient to warrant a UTS finding..."

This means that there is an effective 'UTS safe harbour' for market participants who are acting within normal market operations. This concept reflects the proper boundaries of the UTS regime.

Meridian's offering behaviour is clearly within normal market operations

As set out in detail in the Brattle Report[33], Meridian's offering behaviour during the period 3 to 18 December 2019 was clearly within normal market operations. Not only have Meridian and other market participants acted in the same way previously (on multiple occasions), but so too was Contact over this same period. Of real concern in the preliminary decision is the Authority's failure to engage with what is part of normal market operations.

As discussed above in Part C, spot market outcomes were not unusual in late 2019 and there are many examples of similar offers during periods of hydro spill.

The Authority fails to analyse the many spill pricing examples in recent history and points to early-2011 as an example of what it "expects" offer prices to look like during times of spill. In the context of a UTS investigation this is unacceptable. Even the Authority's own QWOP data shows that spill pricing varies significantly but never reflects generation costs, as prices are discovered through competition in the market and will be dependent on the behaviour of other participants and overall conditions at the time. Critically, this is how the market normally operates. To find a UTS now would be contrary to the normal market operations safe harbour that has rightly been an integral part of previous UTS investigations.

---

[32] Electricity Authority *Decision on claim of an undesirable trading situation* (2016) pages iii and 32.
[33] Brattle Report, at 12-18.

The Authority has previously found that similar conduct was not a UTS

Not only was Meridian's behaviour consistent with normal market operation, but the Authority itself previously considered similar conduct and concluded that it was not a UTS. As noted above in Part D, Meridian's offers in respect of transmission constraints over December 2019 are similar to its offers in June 2016 where the Authority found that there was no UTS. Part D of this submission refers to a number of examples of similar offers from a range of generators, none of which were found to constitute a UTS.

One of the reasons for assessing events against normal market operations is that New Zealand's wholesale electricity market is workably competitive, with low barriers to entry and/or expansion. In workably competitive markets there may be periods where high prices arise, but this is expected to induce longer-term competitive responses such as the entry of new participants or existing participants building additional capacity.

Cognisant of these considerations, the Authority has carefully calibrated its regulatory response in its previous finding of a UTS, which was in regard to the events of 26 March 2011, commonly called 'Super Saturday'. Relevantly, Contact unexpectedly withdrew 425MW of supply from the spot market on 25 March. In that finding, the Authority emphasised the critical role played by Transpower's demand forecast errors. As these errors were so large at exactly the same time that Genesis' was unexpectedly net-pivotal and its offer prices were exceptionally high,[34] the price forecasts were extraordinarily inaccurate.[35] This meant the market did not operate as it would be expected to operate if the price forecasts had been remotely accurate,[36] and other participants were unable to adjust their behaviour or manage their risk on the hedge market. The combined effects of that confluence of events were so large that it threatened or may have threatened trading on the wholesale market and precluded orderly trading or proper settlement of trades.[37]

---

[34] Recall that Genesis offered its Huntly generation at around $20,000/MWh, which resulted in spot market prices of around $20,000/MWh in the upper North Island region for about eight hours on 26 March.

[35] Transpower's demand forecasts under-predicted demand by more than two standard deviations, which meant that Transpower's scheduling, pricing and dispatch (SPD) model predicted demand in the upper North Island would be met without the need to dispatch Genesis' $20,000/MWh offers.

[36] For example, the demand side had no realistic opportunity to reduce their demand ahead of extraordinarily high spot prices. The extraordinarily inaccurate price forecasts also appeared to misinform Contact, as it proceeded with its Stratford plant outages for the weekend.

[37] The Authority stated a core reason for this conclusion was "Genesis Energy's generation offers set the market prices for Hamilton and regions north of Hamilton during trading periods 22 to 35 on 26 March 2011 and parties exposed to prices in the wholesale market for electricity in those regions had good reason to believe the exceptionally high offer prices at Huntly for those trading periods would

Test applied is subjective and in reality amounts to an amendment to trading rules

The usual approach to assessing whether there was a UTS

Normally in considering a UTS, the Authority has carried out an event study by looking at a range of objective indicators of confidence in, and integrity of, the wholesale market. Event studies are well respected and supported by significant literature. They allow analysis of derivative markets (including volumes, prices and participation) to see whether they change in any way immediately before, at, and after an event occurs. Such movements can show, objectively, whether there was any loss of confidence in the wholesale spot market. This is done by analysing trade data in derivative markets. Those markets rely on confidence in the spot market to build liquidity and trade. Therefore, adverse impacts on confidence will be seen in the derivatives market response.

In previous UTS investigations, the Authority has also considered whether there had been an increase in prudential requirements or material change in the trading of risk management products such as FTRs and ASX New Zealand Electricity Futures.[38]

In respect of November 2019 to January 2020, there is no evidence that prudential requirements over the relevant trading periods were inconsistent with normal market operations (prudential requirements have decreased between October and the period of the allegations as would be expected with reducing spot prices).

FTR pricing movements can reflect a change in opinion in the market of the likely flow or constraint between two nodes. The market opinion of flow or constraint can be used to infer changes in market confidence. Meridian has analysed FTR prices for Benmore and Haywards, and Invercargill and Benmore options before and after the period of the allegations. We consider these to be within a normal level of variability.

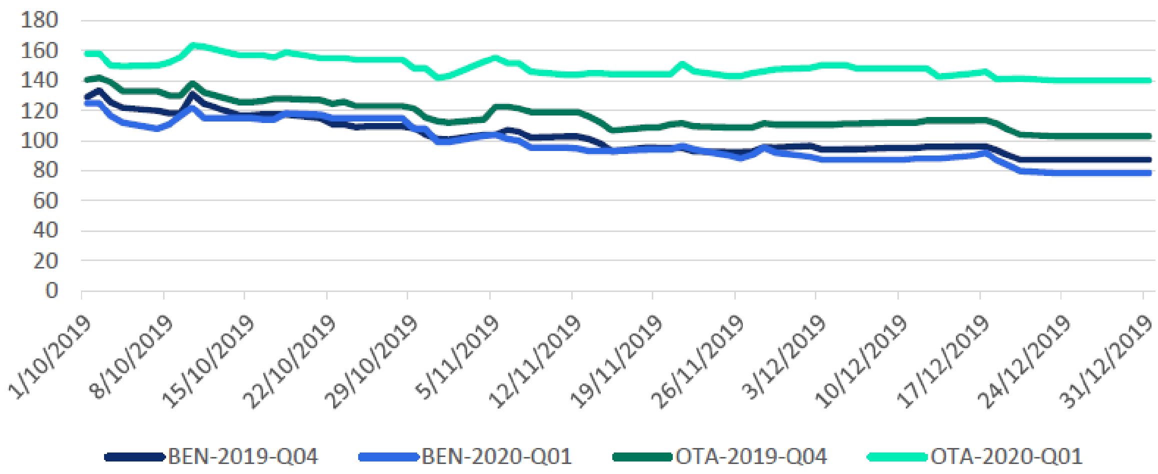
The ASX futures market operated normally throughout the period of the allegations with no suggestion that market confidence was threatened. Figure 12 below shows that ASX prices did not change due to the start of South Island spill (as might have been be expected if confidence in the wholesale market was threatened).

---

not translate into market prices, until it was too late for them to take actions to avoid incurring liability to pay the prices…" (Electricity Authority, 2011, page 2).

[38] Electricity Authority *Decision on claim of an undesirable trading situation* (2016) page 10.

Figure 12: ASX closing prices BEN and OTA, Q4 2019 and Q1 2020



Given the lack of observable impact other than what would reasonably be expected in a major inflow event, there is no objective evidence that Meridian's offers while spilling, threatened or may threaten, confidence in, or the integrity of, the wholesale market. The Authority ought to have considered this objective evidence.

The Authority equates a loss of confidence with any outcome that differs from its expectations

In contrast to its historic approach of considering objective evidence of a loss of confidence, here the finding of a UTS was based on the Authority's subjective assessment of *how the market should have behaved.* That is, in the current investigation the Authority considers that any divergence from its expectations will produce inefficient outcomes (compared with a more competitive market) and that this means that the event will lead to a loss of confidence or integrity unless corrected.

This approach wrongly disregards the settled meaning of a UTS (a dysfunctional market) and the settled objective approach to assessing a lack of confidence (event studies) and replaces both steps with a subjective test of whether market outcomes diverge sufficiently from the Authority's "expectations".

This is a highly subjective approach and is inconsistent with a proper legal interpretation of the Code provisions. The Authority has failed to explain why it has adopted a radically different approach to assessing whether a UTS has occurred. The Authority simply notes it is difficult to assess confidence in the wholesale market, but that has always been the case and the Authority’s traditional, objective assessment approach has previously been adequate.

Rather, the Authority's new approach starts from the wrong place. It does not ask if there is a threat to confidence in, or the integrity of, the wholesale market in fact and look to objective measures. Instead, the Authority asks what would improve confidence and responds that confidence would improve if everything in the market met the Authority’s expectations, implicitly, because such a hypothetical market would have "better outcomes". That is, it is not asking whether confidence has been threatened, but whether confidence might be higher by creating a new market conduct rule through the UTS provisions.

The Authority seeks to enforce a warning letter issued under a different prohibition and process, in preference to properly applying the UTS provisions

At paragraphs 12.22–12.29, the Authority’s preliminary decision concludes that Meridian should not use offers to manage transmission constraints. It finds this amounts to a UTS not because it meets the definition of a UTS (indeed this conclusion is not linked to the UTS definition at all), but rather because the Authority, in a different role and for a different purpose, had previously told Meridian it considered the practice should not occur.

The Authority's reliance on the warning letter is incorrect for three reasons.

First, the Authority's previous comments were made in the context of the Authority's HSOTC jurisdiction, rather than as part of a UTS investigation. The HSOTC and UTS parts of the Code are very different. The HSOTC regime considers the conduct of an individual market participant. By contrast, the UTS regime is focused on correcting a situation that has arisen in the market as a whole. The use of comments made by the Authority in the context of considering Meridian's trading conduct in isolation, as evidence to support a preliminary conclusion that a UTS has arisen in the wholesale market, is inappropriate.

Second, despite conducting an in-depth review of Meridian's conduct in 2016 and expressing its disapproval of Meridian using offer prices to manage transmission constraints, the Authority found that there was no UTS.[39] Against that backdrop, the Authority’s preliminary decision that near-identical conduct in late 2019 now constitutes a UTS is contradictory and inconsistent.

---

[39] Electricity Authority *Decision on claim of an undesirable trading situation* (2016).

Third, the prior views the Authority expressed in a letter sent to Meridian on 8 May 2017 were never concluded views tested and established through proper processes. They were views expressed about compliance with the HSOTC provisions in a case where the Authority disagreed with the findings of its own appointed investigator and expert, discontinued the investigation, and decided not to refer the matter to the Rulings Panel. The Rulings Panel, not the Authority, is the only body with legal standing to determine whether a Code breach has occurred. The view expressed by the Authority in its letter of 8 May 2017 has no legal status. Meridian rejected the view in the letter at the time and still does.

In its preliminary decision, the Authority ignores its prior decisions on what constitutes a UTS, yet it elevates its prior views expressed in a letter that it had no proper basis to issue, to the level of precedent. The letter becomes the basis for finding a UTS – not because the UTS definition is met in the current case – but because Meridian acted in breach of the views expressed in the letter. In doing so, the Authority has inappropriately given its prior untested opinions the force of Code provisions, *replacing the actual test* in the Code. The substitution is plainly improper.

If the Authority wishes to establish that market participants should not use offers to manage transmission constraints then it must do that by way of amendment to the Code. Through that process, the Authority would also be accountable to conduct a proper evaluation and transparent consideration of any inefficiencies and other consequences that may result from such an amendment, including:

- impacts on incentives to invest (including in renewable generation that typically has a lower fuel cost but high investment cost and risk); and
- long-term consumer outcomes.

Attempting to bring about such fundamental changes to the normal operation of the New Zealand electricity market by way of ad hoc and untested 'warning' letters and now a preliminary UTS decision of itself, threatens confidence in the wholesale market and is outside the proper scope of the Authority's powers.

Test applied is arbitrary

The Authority's test for a UTS – divergence from Authority expectations – is arbitrary in three senses:

- It is not clear what offer prices when spilling would constitute a UTS. In particular, the line between Contact's and Meridian's offers is not obvious. Market participants need to know how to behave to avoid a UTS.
- The preliminary decision appears to require participants to offer in a way that will avoid a level of spill that is "too large". What would be considered "too large" is undefined and seemingly unrelated to the scale of a flood event.
- Finally, the use of QWOP is inappropriate. As a blunt averaging tool, it can be readily distorted and is not illuminative of the behaviour that amounts to a UTS.

It is not clear what offer prices when spilling would constitute a UTS

The Authority's expectations are formed from a starting point of spilling generators having zero opportunity cost of water:[40]

> "All else being equal, when hydro generators in the lower South Island are spilling, we would expect to see lower offer prices because the opportunity cost of water is zero for a spilling generator—this does not imply a zero offer price because of other costs of generating".

The Authority does not specify what a generator's offer should look like or even the sorts of costs that a generator may take into account when forming offers during a time of spill (except for expressing the opinion that generators should effectively be blind to some costs, namely the costs of transmission constraints). We consider it an unwarranted assertion that generators must make offers based on their costs in order to not threaten confidence in the wholesale market. The New Zealand electricity market has always allowed for a dynamic process of price discovery through competitive offers and there has never been any requirement to offer based on costs, irrespective of how those costs might be quantified.

Even putting aside this concern for now, the preliminary decision is inadequate in terms of providing any certainty of what is expected by the Authority and what would restore confidence in the market because it does not identify offer prices that *would* be acceptable and maintain market confidence. Offer prices somewhere around Contact's offers do not constitute a UTS, while offer prices for Meridian's Waitaki generation do constitute a UTS according to the preliminary decision. The preliminary decision does not say where between these two sets of offer stacks might be acceptable and all generators are left guessing and

[40] Electricity Authority *Preliminary Decision* (2020) page 24.

must manage this uncertainty somehow when offering generation during spill events that will inevitably occur in future.

According to the Authority, Contact:[41]

> "… offered high priced tranches throughout the flood. Contact's offers meant it was dispatched at lower levels overnight, meaning this is when most spill occurred. These higher priced offer tranches are not consistent with what we would expect from a spilling hydro generator, and the high overnight offers are inconsistent with the screen cleaning and gate operations …".

And:[42]

> "From about 19 December it [Genesis] started to be dispatched less overnight due to larger volumes being offered at higher prices. This is inconsistent with what we would expect from a spilling hydro generator."

Despite finding the same issues with Contact and Genesis offers when spilling, the Authority's Chief Executive states that only "Meridian's behaviour was material enough to constitute a UTS".[43] That approach adds a new materiality analysis meaning that a small amount of the newly discovered undesirable behaviour is acceptable but at a certain unspecified scale or severity the same conduct will no longer be acceptable and will constitute a UTS.

The Authority has not given any clear indication of the offer prices during spilling that would and would not meet its new materiality test. The dividing line between offer prices when spilling that do and do not give rise to a UTS must presumably rest somewhere between the offer prices for Contact's Clutha generation and offer prices for Meridian's Waitaki generation.

---

[41] Electricity Authority *Preliminary Decision* (2020) page 72.
[42] Electricity Authority *Preliminary Decision* (2020) page 72.
[43] This statement was made outside of the preliminary decision itself and as part of the presentation of the preliminary decision – it is therefore unclear to what extent the singling out of Meridian is part of the Authority's preliminary decision. In terms of process, the Authority should make its position clear in official documents and presentation materials ought to be consistent with the official documents.

It is not clear how much "avoidable spill" might constitute a UTS

The preliminary decision estimates a quantity of "avoidable spill" in December 2019 and goes on to state that "even at the lowest end of the range, this level of waste is **too large** to be the result of ordinary market processes."[44] The Authority's claim of a large scale deviation from their competitive benchmark primarily reflects the length of the flood event rather than a normalised measure of deviation. This leaves market participants in a position where they must not only make offers priced somewhere between what Contact and Meridian offered from 3 to 18 December 2019, but also that participants must offer to avoid a level of spill that is "too large", seemingly regardless of the scale of the flood event.

QWOP is an arbitrary measure

Rather than assess actual offers in each trading period the Authority seems to have based its assessment of offers on a blunt average measure – quantity weighted offer price (QWOP) rather than actual offer stacks. This QWOP measure is highly influenced by factors that have little or no impact on market clearing prices. For example, Meridian and other generators commonly offer volumes of generation to cover contracted load at prices close to zero, i.e. $0.01/MWh. The preliminary decision notes that "offer prices increased from December 12 onwards"[45] but by "offer prices" the Authority means QWOP averages and from 12 December 2019 the change in QWOP is driven by reductions in Meridian's contracted load and therefore less generation offered at $0.01/MWh to cover that contracted load.

Most generators also have high priced tranches that are not intended to clear. These tranches are priced anywhere between $200 and $6000 and are not expected to clear unless something unexpected happens in the market, Meridian's tranches around $900 are unremarkable in this context. QWOP will shift significantly based on non-clearing offer prices, all of which have no effect on market prices. For example, if a generator priced non-clearing volumes in a $200 tranche rather than a $900 tranche, QWOP would drop significantly without any change in market outcomes. During 3 to 18 December Meridian could have repriced non-clearing tranches to one third of actual offers without changing any market outcomes (market prices would still clear below these tranches in every period) and Meridian QWOP would decrease significantly and look like the Contact QWOP which was not deemed to constitute a UTS.

[44] Electricity Authority *Preliminary Decision* (2020) page [emphasis added].
[45] Electricity Authority *Preliminary Decision* (2020) page 58.

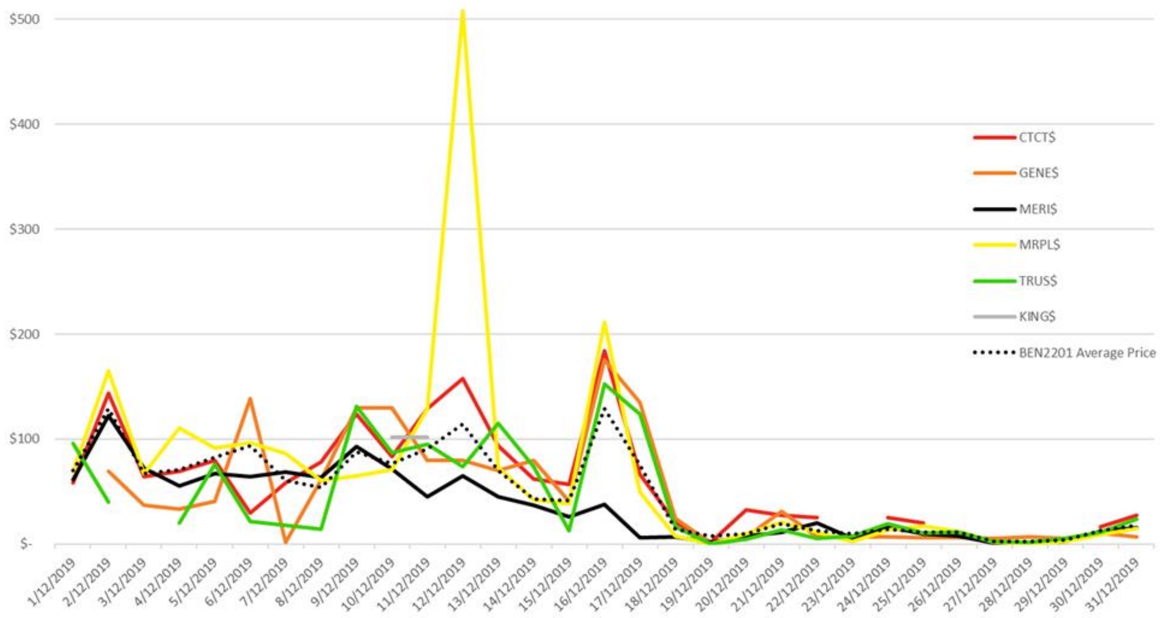
In the 2010/11 event that the Authority offers as an example of how QWOP ‘ought’ to look during spill, Meridian used high price tranches in the same way as it did in December 2019. However, non-clearing tranches were priced at around $200-$500/MWh in 2010/11 compared to around $900 in December 2019. In both cases, clearing prices were nowhere near those top tranches. If Meridian’s non-clearing offers over the period of the alleged UTS were adjusted to have the same high-priced tranches as in 2010/11, QWOP would indeed be lower but market prices would be unchanged. In contrast, if Meridian had offered *all* generation at $84/MWh (the QWOP during the 2010-11 spill event), the QWOP analysis would obviously not change but one would expect market clearing prices to be much higher on average.

QWOP provides very limited information about actual offers, behaviour, or outcomes for consumers because it is so heavily skewed by contracted volumes offered at close to zero and non-clearing volumes offered at high prices.

The safe harbours of the trading conduct provisions encourage offering all available generation capacity, even volumes not intended to clear. The Authority’s QWOP analysis perversely promotes the opposite behaviour – Meridian could simply not offer high priced tranches at all, removing those volumes from the offer stack. This would dramatically lower QWOP, again with no impact on market clearing prices or outcomes for consumers.

For these reasons any QWOP analysis is, at best, unhelpful and, at worst, confounding. The Authority could alternatively look at the average prices at which generators were marginal and at which their offers were setting market prices. As shown in Figure 13 below, the average prices at which Meridian’s offers were marginal were generally below the rest of the market.

Figure 13: Average prices at which each generator was marginal in December 2019



The Authority fails to correctly apply the concept of workable competition

Previous UTS decisions have focussed on the long term rather than short term spot market outcomes

In deciding 26 March 2011 was a UTS, the Authority did not relate Genesis' offers or the resulting spot market prices to the SRMC of Genesis' Huntly units, but rather re-set Genesis' offer prices to $3,000/MWh, reflecting the Authority's estimates of the marginal value of demand response or the long run marginal costs of a new entrant generator.

The Authority knew the $3,000/MWh price greatly exceeded the SRMC of Huntly generation, which it thought was about $80-$120/MWh. It took this approach because it agreed that a generator temporarily exercising its pivotal pricing power was consistent with the wholesale electricity market being workably competitive. In other words, prices greatly divorced from SRMC are not a basis for finding a UTS has occurred.

The Authority's finding that a UTS occurred on 26 March 2011 was not about expecting highly competitive outcomes to prevail in every trading period or other short periods of time in which competitive entry and capacity expansion responses are infeasible.

This approach is further reinforced by the fact the Authority introduced separate Code provisions to achieve more efficient pricing outcomes when a generator is pivotal (the HSOTC provisions). Rather than use its very broad discretion to re-set market prices under UTS provisions, the Authority developed those provisions to try to leverage the competitive forces operating during non-pivotal trading periods to constraining generator price offers during pivotal trading periods. The HSOTC provisions avoid the regulator making any assessment of prices relative to SRMC or indeed LRMC.

In contrast, the preliminary decision focusses on short term pricing and outcomes

In the preliminary decision, the Authority uses a competitive market framework to describe what it means by market fundamentals.[46] It sets out various behaviours or outcomes it would expect from a competitive energy-only spot market when the opportunity cost of water is zero, and then proceeds to show that observed behaviours or outcomes were inconsistent with each of these expectations. This is effectively a focus on SRMC because the opportunity cost of water forms part of the SRMC of a hydro generator. In particular, the Authority states:[47]

> "All else being equal, when hydro generators in the lower South Island are spilling, we would expect to see:
> (a) lower offer prices because the opportunity cost of water is zero for a spilling generator—this does not imply a zero offer price because of other costs of generating
> (b) South Island spot prices to fall because of these lower offers
> (c) South Island spot prices to separate from North Island spot prices if transmission limits are reached, or if not, low prices in both Islands
> (d) More energy to flow over the HVDC because of lower South Island spot prices
> (e) Spill to be minimised subject to consent conditions and the level of demand and HVDC capacity that prevailed at the time"

The Authority states that these expectations follow logically from the reduction in the opportunity cost of water to zero when it cannot be stored, and proceeds to explain they are indicators of various forms of efficiency. From there onwards, the Authority focuses on the short term performance of the spot market and seeks to estimate the inefficiencies arising from spot market outcomes deviating from their short run competitive benchmark.

The Authority proceeds on this basis to identify the outcomes it would expect to see when hydro generators in the lower South Island are spilling, including "lower offer prices because the opportunity cost of water is zero for a spilling generator".

[46] Electricity Authority *Preliminary Decision* (2020) pages 12-13 and 24.
[47] Electricity Authority *Preliminary Decision* (2020) page 24.

The preliminary decision also says that this expectation is an indicator of spot market efficiency and that "efficiency in an economic sense is achieved when price equals cost in a competitive market." This essentially acknowledges that the Authority is seeking to use the UTS provisions in the Code to impose optimised market reforms that would hold generators to a perfect competition standard in which each generator's offers must be based on short run costs at any given point in time.

The UTS preliminary decision also exemplifies a misunderstanding of the Authority's statutory objective. The Authority's own interpretation of its statutory objective is instructive, particularly the discussion on the words "*promote competition* … for the *long-term* benefit of consumers" in the extracts below:[48]

> "The Authority interprets *competition* to mean *workable or effective competition …*"
>
> "The Authority interprets *promoting competition* to mean exercising its functions to facilitate or encourage stronger competition. The Authority is not focussed on the conduct of individual participants with respect to competition in the electricity industry as this is the responsibility of the Commerce Commission. Rather the Authority is focussed on improving the arrangements in the electricity industry to promote competition. Promoting competition does not mean achieving a certain level of competition."
>
> "In regard to *long-term benefit*, the Authority considers that its primary focus is to promote dynamic efficiency in the electricity industry, which includes taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in the electricity industry, by both suppliers and consumers…"

The Authority expands on its view of the workable competition standard in its market performance review of the high price event of 2 June 2016. According to the Authority "a market is dynamically efficient in a workable competition sense if it tends towards an efficient equilibrium over time."[49] Similarly the Authority states that "workable competition is a dynamic view of markets that encompasses prices deviating from long term equilibrium levels as long as barriers to entry are low so that, in the long term, prices move towards

[48] https://www.ea.govt.nz/dmsdocument/9494-interpretation-of-the-authoritys-statutory-objective-february-2011
[49] https://www.ea.govt.nz/dmsdocument/23044-market-performance-review-high-prices-on-2-june-2016 page 26.

competitive levels."[50] Meridian agrees that workable competition is the correct interpretation of the Authority's statutory objective and considers it wrong in law for the Authority to effectively seek perfect competition outcomes at any particular point in time via a UTS investigation.

Any UTS finding based on an expectation of SRMC pricing at a chosen point in time (perfect competition) would also be inconsistent with High Court precedent. In 2011, in the context of a UTS claim against Genesis, the Authority expressly rejected the suggestion that Genesis should have priced at SRMC, in that case saying a:[51]

> "…generator should be able to price up to the economic alternative of the buyer, which would approximate the LRMC of a new entrant generation option or the opportunity cost of electricity for consumers (i.e. the price at which demand response occurs)."

That decision was appealed but upheld by the High Court, with the Court quoting and approving the above statement.[52] The Authority reset prices over the relevant period at $3,000 MWh which was calculated to be approximate cost of demand response or new entrant generation.

It is well established by New Zealand case law that the workably competitive market construct does not enable predictions to be made as to short run market outcomes, rather it is a theory about the tendencies of such markets over time. As the High Court noted in the *Wellington International Airport Limited* case:[53]

> "Of course, firms may earn higher than normal rates of return for extended periods. On the other hand, firms may earn rates of return less than they expected and less than commensurate with the risks faced by their owners when they made their investments. They may even make losses for extended periods. Prices in workably competitive markets may never exactly reflect efficient costs, including a normal rate of return."

[50] As above, page 27.
[51] Electricity Authority *Final decision on the UTS of 26 March 2011* (2011) page 47.
[52] *Bay of Plenty Energy Limited v the Electricity Authority* HC Wellington CIV-2011-485-1371, 27 February 2012 at [301].
[53] *Wellington International Airport Ltd & Ors v Commerce Commission* [2013] NZHC 3289, 11 December 2013 at [19].

However, a fall in the opportunity cost of water does not necessarily result in a fall in spot market prices in a workably competitive market

The Authority's conceptual approach explicitly discusses limited and fixed transmission capacity in the short run. It also implicitly incorporates the effects of limited and fixed generation capacity in the short run. But it appears to omit or significantly downplay other key features of the wholesale electricity market, including that:

- the spot market pays uniform prices to generators and, although it is formally a gross pool, it operates like a balancing market;
- generation is highly concentrated regionally;
- some generators are poorly diversified regionally and by broad fuel categories;
- short-term demand responses are very inelastic at low-to-moderately-high spot prices;
- it is difficult for generators to accurately predict, more than a few days ahead of real-time, changes in their demand and supply (e.g., hydro inflows and wind flows); and
- financial transmission rights (FTRs) and ASX electricity futures contracts are rather coarse instruments for managing certain spot market risks.

The spot market pricing regime is critical to interpreting observed offer prices and strategies. The New Zealand spot market pays uniform prices to generators, which means they receive the market price for their output rather than their offer price. The main alternative is pay-as-bid pricing, which would pay generators their offer price for each tranche of dispatched generation. Although both pricing regimes can produce similar equilibrium price outcomes, offer strategies are likely to be very different. For those reasons, the observed outcomes during the supposed UTS period are in fact consistent with ordinary market operations. If the Authority wishes to change market operations it can do so by Code amendments. The potential for Code amendments is discussed further in Part F below.

Other "effects" not caused by Meridian's offer behaviour

The Authority took an overly simplistic approach to causation in the dynamic and complex wholesale market. By holding all other things equal, the Authority was engaged in a theoretical exercise removed from the true market operation had Meridian had different offer prices.

In its assessment of "unnecessary spill", the Authority also considered that extra generation by Meridian (instead of spilling) would have displaced North Island generation, and that the electricity grid as a whole was less resilient during planned HVDC and Pohokura outages during the first quarter of 2020 because of Meridian's conduct. It fails to engage with the market's reaction to any such change in Meridian's behaviour. Further, Genesis may have reduced offer prices at Huntly to ensure it cleared to cover its contract book. With such a response, no displacement would have occurred, but the Authority's approach instead assumes a static market.

In any event, Meridian could not have been expected to plan its offer prices in preparedness for what hydro storage North Island assets operated by other generators would have access to in the first quarter of 2020. The ultimate levels of hydro storage were determined by numerous factors, including the generation decisions of other North Island generators, demand levels, and the level of rainfall in the Taupō catchment. In that regard, the nexus between the December 2019 situation and the reduction in North Island storage is simply too remote for it to properly be considered as arising due to (or even contributing to) a UTS finding.

For completeness, the assertion by Haast Energy Trading and other claimants that Meridian's "unnecessary" spilling caused an increase in greenhouse gas emissions is also too remote a consequence to be properly considered as part of the Authority's UTS decision. The Authority appears, rightly, not to have placed any weight on that aspect of the complaint in its preliminary decision. The New Zealand emissions trading scheme has more to do with greenhouse gas emissions than Meridian's offer prices.

Conclusion

The Authority is unclear on what legal test it is applying and on what factors (or combination of factors) might in any given trading period constitute a UTS. Lack of clarity on what constitutes a UTS does not increase confidence in the wholesale market, in fact it has the opposite effect.

The Authority says that an outcome that is different from what it might expect means that confidence in the market may be threatened. This represents a very different approach to that taken by the Authority in the past. It would force generators to second guess the Authority's view of their short run costs in order to offer in a way that avoids the risk of a UTS finding. The Authority has in the past been careful to allow the market to perform the price discovery role, whereas the present approach is a form of shadow price control.

For the following reasons, Meridian considers the Authority's preliminary decision to be based on a misapplication of the UTS provisions in the Code:

- a test of "spot market outcomes that do not meet the Authority's expectations" is inconsistent with the text and purpose of the Code;
- behaviour that is part of normal market operations cannot be found to be a UTS as the Authority has previously acknowledged;
- the test applied in the preliminary report is different to that used previously by the Authority, is subjective, and in reality seeks the optimisation of the wholesale market rather than correction of a UTS;
- the test applied in the preliminary report is arbitrary; and
- even if "meeting the Authority's expectations" was the test for a UTS, the Authority has failed to properly apply the principle of workable competition.

Any new approach which requires generators to offer in accordance with SRMC (and to disregard the impacts of price separation as a relevant "cost") is a fundamental shift in the market and can only be introduced via a Code change process following the statutory requirements for consultation and a cost benefit assessment as set out in Part F below.

Part F: The issue of pricing during spill is a Code amendment issue

This Part of Meridian's submission outlines:

- how the Authority has confused its Code making and UTS functions;
- the proper process under the Electricity Industry Act 2010 to implement market reforms; and
- proposes some potential ways forward for the Authority's reforms should it wish to establish a new normal for the New Zealand wholesale electricity market.

If the Authority wants to reform the normal operation of the wholesale market then the Code change process is the right way to go about this. The process allows for adequate consultation and requires an assessment of the costs and benefits to consumers in the long-term. Meridian encourages the Authority to consider Code changes to progress its market reform agenda rather than ad hoc UTS decisions that provide no certainty for participants and undermine confidence in the market.

The Authority has confused its Code making and UTS functions

The Authority's preliminary decision has strayed into a regulatory role and seeks to optimise the market rather than "correct" a UTS. In doing so, the Authority has misunderstood the crucial distinctions between its rule-making and its rule-applying functions.

As noted in Part E above, when the Authority decides whether a UTS has arisen it is applying the Code as a judicial body, the Code tells it to "correct" a problem and "restore the normal operation of the wholesale market". The Code therefore requires the Authority when deciding on a possible UTS to clearly articulate how the events during the alleged period depart from the "normal operation of the wholesale market". However, in the preliminary decision, the Authority has instead endeavoured to create a new normal for the wholesale market.

As noted elsewhere in this submission, the market behaviour that formed the basis of the preliminary UTS finding is normal, economically rational market behaviour, about which generators have been very transparent over the years. The preliminary decision finds that such normal, rational behaviour is no longer appropriate. A new normal is therefore proposed whereby market participants must read this preliminary decision, not the Code, to understand how they can act in the market.

In its preliminary decision the Authority has strayed from its rule application role into its rule making role. This misunderstanding of its roles can also be seen in the Authority listing the UTS investigation as part of its "wider suite of work that promotes wholesale market competition" including its "review of market making, work on the profitability of the retail arms of the generator-retailers, and the work on the trading conduct rules being performed by the Authority's Market Development Advisory Group".[54] A UTS decision is not part of a suite of regulatory work that the Authority does as a regulatory rule-maker to optimise the wholesale market. Rather, the Authority's UTS decision-making function is a different role in which it applies the pre-existing Code to particular allegations. The Authority has fallen into the error it previously identified:[55]

> "… the UTS provisions should not be relied upon as a fix-all in place of Code amendments."

The preliminary decision proposes changes that could only be implemented via a Code change process

A UTS is defined as something *outside the normal operation of the market* that threatens confidence in the market, but here it seems the Authority has found a UTS because it *wants the market to operate differently* to the way it has in the past. Changing the way the market operates is the Authority's prerogative as regulator, but if it wants to see that kind of reform it needs to assess whether such a change would actually benefit consumers in the long term and, if it believes it would, amend the Code governing market operations.

The Code change process would also help to define the scope of any proposed new rules on offer behaviour. For example, whether the rules are specifically about offer prices during hydro spill, or whether the rules would also affect:

- offer prices for wind and solar generation;
- offer prices for any other generation where SRMC is close to zero; or
- offer prices for all generation regardless of SRMC.

[54] https://www.ea.govt.nz/about-us/media-and-publications/media-releases/2020/wmid-consultation-media-release/
[55] Electricity Authority *Decision on claim of an undesirable trading situation* (2018) page 11.

The Code change process could also consider these costs and benefits of, and consult on, different materiality thresholds if a certain level of impact on the market is required before behaviour is deemed to be in breach of any rule.

The mechanism in the Electricity Industry Act 2010 for Code amendments has the advantage of a clearly defined regime, including a without prejudice investigation and consultation not constrained to the facts of a particular allegation or time period. Such a process ensures appropriate weight and consideration is given to both the benefits and detriments of any proposed Code amendment. This robust process maximises the chance that the Code will be amended in such a manner that achieves the Authority's statutory objective of "promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers". A UTS investigation by its very nature is intended to restore confidence in the wholesale market as soon as possible and therefore is not the appropriate vehicle through which to deliver fundamental *changes* to the market design. The Authority should not seek to reform the market and establish a new normal via a back-door of warning letters or UTS decisions.

Fundamental to market confidence is clarity of the Code and ensuring the Code sets out clearly how the Authority wants the market to operate. A gap has seemingly opened up between the current Code and the Authority's expectations. Meridian is very keen to see this gap closed for the benefit of all market participants. The Authority needs to provide more certainty to the market and Meridian suggests that amendments to the current Code may provide this clarity. We hope to work with the Authority to rectify this issue.

Specific Code amendments

It would be a fundamental change to the market if generators were forced to:

- construct offers based on their costs (except for costs associated with basis risk); and/or
- be artificially blind to some of their costs (locational price risk) when constructing offers.

Such reform would need to be implemented through a Code change process where the costs and benefits are properly assessed. The Authority has not done this. Meridian is not convinced rule changes along those lines would result in a long-term benefit to consumers but that is the debate that should be had about reform of the Code, not as part of a UTS investigation.[56] As the Brattle Report concluded[57]:

> If the Authority wishes to change precedent and force generators to offer at SRMC under selected circumstances, there are other market design changes that may need to be considered to ensure that generation resources can recover their capacity costs. The Authority would need to study different design options or modifications best suited for the New Zealand market. A change in the New Zealand energy only market design is best achieved through a comprehensive review of market design options, rather than through a UTS investigation.

The changes sought by the claimants and supported by the preliminary decision are consistent with statements made by the Authority's Market Development Advisory Group (MDAG), which includes a complainant amongst its membership. Earlier this year, MDAG put out a consultation paper proposing significant reforms of the HSOTC rules. The alternative proposed in that consultation paper included an implication that all generators would need to make offers based on their costs. That would be a fundamental reform, destroying the price discovery function of the current market and replacing it with centrally controlled quasi-price regulation that would have a range of unintended consequences.[58]

While Meridian disagreed with aspects of the MDAG proposal, at least the debate was being had in the proper context of a market reform process. The Authority will be required to test the MDAG recommendations and undertake a cost-benefit analysis to determine whether reform options are in the long-term interests of consumers.

If the Authority wants to adopt MDAG's approach and mandate cost-based pricing, then the Authority needs to be transparent about that, amend the Code, and communicate that to

---

[56] As an aside the Authority's views on generators' offers to manage transmission constraints fail to recognise the significant investments made by generators (for example in plant, people, resource consents, and health and safety) to provide a physical hedge to manage volatile spot market risks. Meridian believes that requiring higher levels of hedge cover as an alternative to allowing participants to utilise their physical generation assets will drive up costs to consumers and significantly reduce the appetite for retail competition in areas of high basis risk.
Meridian does use risk management products to manage locational price risks. However, the risk management products available in the hedge market, including those in the financial transmission rights ("FTR"), Australian Securities Exchange ("ASX"), and Over the Counter ("OTC") markets are not always sufficient in their range and scope to cover locational price risks of the kinds Meridian experiences. Meridian would also face additional costs to cover its risk in this way and those additional costs would inevitably be passed on to consumers.

[57] Brattle Report, at 41.

[58] See Meridian's submission to MDAG: https://www.ea.govt.nz/dmsdocument/26735-meridian-submission-mdag-hsotc-discussion-paper

market participants. Instead, it appears that the Authority has applied some of the early thinking from an incomplete market reform process to the current UTS investigation. In doing so, the Authority has inappropriately given the MDAG's views the force of Code provisions.

The Authority would be better to provide clarity through a Code amendment. The most obvious way to implement any reform of the way that generators' offer would be to propose changes to the HSOTC provisions in Part 13 of the Code, after any recommendations from MDAG are eventually delivered to the Authority.

As we have said in submissions to MDAG, Meridian considers the current trading conduct provisions to be unworkable and agrees that there is a need for change. Meridian tentatively supports MDAG's proposed option of a counterfactual test so that offers must be consistent with offers that the generator or ancillary service agent would have made where no generator or ancillary service agent could exercise significant market power. That tentative support is conditional on several changes to the drafting as pointed out in our submission.[59] The drafting proposed by Meridian for Part 13 of the Code would be as follows:

> Where a **generator** submits or revises an **offer** for a **point of connection** to the **grid**, that **offer** must be consistent with **offers** that the **generator** would have made where no **generator** could exercise significant market power in the relevant market.

Alternatively, if trading conduct provisions do not achieve the outcomes the Authority "expects" then the Authority could consider a contained Code provision that set out the Authority's expectations in respect of hydro generation offers when spilling. The Code provisions could be carefully crafted so that they would only apply during periods of spill and would not detrimentally affect the operation of the wholesale market at other times. Meridian could help the Authority to construct rules on how to develop an offer stack for spilling hydro generation. Any rules would need to be flexible enough to allow for a range of different operational, environmental and hydrological constraints while still meeting any expectations of the Authority in terms of the level or cap on offer prices for generation volumes that can be sustainably generated throughout a period of spill.

If clear changes to the market rules are introduced, Meridian can and will abide by them. Until that time, Meridian will strongly oppose any attempts to implement market reforms via UTS findings. Doing so would result in a UTS lottery, where generators face significant

[59] https://www.ea.govt.nz/dmsdocument/26735-meridian-submission-mdag-hsotc-discussion-paper

uncertainty on what is and is not acceptable. This would not be best practice for a market regulator and a UTS finding in this case would diminish (rather than restore) confidence in the wholesale market.

Part G: Attachments

Sapere Report

Brattle Report