ELECTRICITY AUTHORITY
TE MANA HIKO

Final elements of real-time pricing

Code Amendment

Consultation paper

Submissions close: 5pm Tuesday, 19 July 2022

Tuesday, 07 June 2022

1 Executive summary

1.1 This paper seeks feedback on the Authority's proposal to amend the Code for the final elements of real-time pricing (RTP). This consultation follows on from the *Real-time pricing proposal*[1] consultation in August 2017, *Proposal for the design of the remaining elements of real-time pricing*[2] consultation in March 2019 and a decision paper, *Implementing spot market settlement on real-time pricing*[3] in June 2019.

1.2 The final elements consulted on in this paper are:

(a) an update to the reserve scarcity quantities and prices for contingent event reserve shortfalls, and surplus generation price

(b) change in how purchasers and generators cooperate with the system operator

(c) change in the process for claiming and investigating an alleged pricing error

(d) change in the process for interim prices becoming final prices

(e) an update to the definition for intermittent generating station

(f) enhancements to the dispatchable demand regime

(g) reinstatement of Code clauses associated with the clearing manager's access to metering data to calculate prudential requirements

(h) accommodation of scarcity pricing in the real time dispatch process

(i) an update to dispatch notification participation definitions, provisions and treatment of dispatch notification load bids and generation offers under a non-dispatch flag

(j) a provision for price publication when the system operator's primary modelling system is unavailable

(k) additional technical and non-controversial Code changes

1.3 The Authority will consider submissions on this consultation alongside submissions from previous consultations. A final decision paper along with Code amendment will be published in September 2022. RTP is proposed to go-live in November 2022.

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1 Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609.

2 Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972.

3 Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972.

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2 What you need to know to make a submission

Purpose of this document

This paper seeks feedback on the Authority's proposal to amend the Code for the final elements of real-time pricing. This consultation follows on from the *Real-time pricing* *proposal*[4] consultation in August 2017 and the *Proposal for the design of the remaining elements*[5] *of real-time pricing* consultation in March 2019. When making a submission, please consider the specific questions included in this document.

2.1 Industry feedback will inform the Authority's decision to amend and/or proceed with its proposal.

How to make a submission

2.2 The Authority's preference is to receive submissions in electronic format. Submissions in electronic form should be emailed to WholesaleConsultation@ea.govt.nz with '*Consultation paper –Final elements of real-time pricing* in the subject line.

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

(a) indicate in a cover note which part/s should not be published;

(b) explain why you consider we should not publish that part; and

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

2.4 If you indicate there is part of your submission that should not be published, the Authority will discuss with you before deciding whether to not publish that part of your submission. However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. The Authority will consult with you before releasing any material that you said should not be published.

When to make a submission

2.5 Please deliver your submissions by **5pm** on **Tuesday, 19 July 2022**.

2.6 This deadline allows six weeks for submissions. The Authority will acknowledge receipt of all submissions electronically. Please contact WholesaleConsultation@ea.govt.nz if you do not receive electronic acknowledgement of your submission within two business days.

Further information

2.7 The Authority's website contains useful background material about the Authority's previous work relating to the implementation of real-time pricing.[6]

2.8 Please direct any specific questions or queries to: WholesaleConsultation@ea.govt.nz.

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4 Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609.

5 Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972.

6 Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/.

3 The Authority is consulting on the final elements to the proposed design for real-time pricing

3.1 The Authority has made significant progress since the first discussions on real-time pricing (RTP) design in July 2017.

3.2 The Authority's previous RTP consultation papers and decision paper foreshadowed the significant changes to the current system and the requirement for a staged delivery approach over multiple years.

3.3 Industry stakeholders have been provided the opportunity to engage with the Authority in an iterative approach throughout the process of implementing RTP.

3.4 The most recent communication with stakeholders has been the *Real time pricing in*dustry *engagement sessions*[7] which covered the key market changes being delivered by the RTP project and reinforced what stakeholders can expect from a transition to RTP.

3.5 In this latest consultation paper, the Authority seeks the views from interested parties on the proposed Code changes for the final elements of RTP design. The final elements consulted on in this paper include the following:

(a) an update to the surplus generation price and reserve scarcity quantities and prices for contingent event reserve shortfalls

(b) change in how purchasers and generators cooperate with the system operator

(c) change in process for claiming and investigating an alleged pricing error

(d) change in the process for interim prices becoming final prices

(e) an update to the definition for intermittent generating station

(f) enhancements to the dispatchable demand regime

(g) reinstatement of Code clauses associated with the clearing manager's access to metering data to calculate prudential requirements

(h) accommodation of scarcity pricing in the real time dispatch process

(i) an update to dispatch notification participation definitions, provisions and treatment of dispatch notification load bids and generation offers under a non-dispatch flag

(j) a provision for price publication when the system operator's primary modelling system is unavailable

(k) additional technical and non-controversial Code changes

A reminder on why the Authority is looking at RTP

3.6 Spot prices provide information to consumers and participants, helping them make decisions such as whether to alter their controllable power use or make extra supply available.

3.7 At present, the spot prices published in real-time are only indicative. The final spot prices actually used to settle the wholesale spot market are not available until at least two days after real-time. Significant differences can sometimes arise between indicative and final

7 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/events/real-time-pricing-industry-engagement-sessions/

spot prices, and neither may fully reflect prevailing real-time conditions. These factors increase the likelihood that consumers and participants will make decisions they later regret.

3.8 To address these issues, the Authority is proposing to:

(a) modify the way real-time spot prices are calculated to ensure they more accurately reflect prevailing conditions on the power system

(b) use these more accurate real-time spot prices for settlement.

3.9 These changes will make spot price signals more accurate and actionable for all decision-makers.

Recapping the key elements of the previous RTP consultation papers and decision paper

3.10 In August 2017 the Electricity Authority (Authority) published a consultation paper titled *Real-time pricing proposal* detailing the proposed overall design for RTP in the wholesale market.[8]

3.11 **The Authority's August 2017 paper proposed the following key design elements:**

(a) spot prices would be calculated based on the information the system operator uses to dispatch the power system. This would ensure tight alignment between spot prices and actual system conditions

(b) the schedules used by the system operator to dispatch the system (run at approximately five-minute intervals) would be used to generate and publish 'dispatch prices'. Final spot prices would be calculated as the time-weighted average of the dispatch prices in each half-hour trading period. Participants would therefore be able to see information in real-time on how spot prices are evolving each half hour

(c) all demand quantities would be assigned a bid price. For demand that is explicitly bid into the market, the value would be set directly by the relevant purchaser. Pre-defined default scarcity values would apply to all other load. The default values would directly influence spot prices if there was insufficient resource (generation or voluntary demand response) being offered to meet expected demand

(d) to encourage consumers (or their agents) to directly participate as bidders in the spot market, we would introduce a new form of dispatchable demand for smaller purchasers (called 'dispatch-lite' in 2017, now referred to as 'dispatch notification')

(e) forecast prices would be calculated using the same methodology as real-time spot prices. This would increase the reliability of price forecasts, and help parties to make decisions in the lead up to real-time

(f) to provide a safeguard against unexpected errors, a modified form of the current error claim process would be retained. This would allow a spot price to be revised in the exceptional case where a material pricing error occurred. Otherwise, the spot prices published in real-time would be used for settlement.

8 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

3.12 In March 2019 a follow up consultation paper titled *Proposal for the design of the remaining elements of real-time pricing* consulted on three particular design elements, partly in response to matters raised in submissions on 2017 paper.[9]

3.13 **The Authority's March 2019 paper proposed the following additional design elements:**

The expansion of dispatch notification to include smaller-scale generation.

3.14 This resulted in dispatch notification participants being categorised against two general criteria: 'dispatch notification generation' for small-scale generation to participate in dispatch and 'dispatch notification load' for smaller purchasers to participate in dispatchable demand, with reduced cost and compliance requirements for both types of participation

Modifying the way spot prices are calculated during reserve shortfalls.

3.15 Today, indicative spot prices in real-time during reserve shortfalls are set to extremely high 'placeholder' values, purely signalling a shortfall is occurring. The actual prices used for settlement are calculated separately the next day using complex manual processing, with important shortcomings. This practise is clearly not suitable for RTP.

3.16 We proposed adopting a new model to determine prices for reserve under RTP. We would use a 'risk-violation curve', setting a rising price for reserve as the quantity of reserve shortfall grows, based on the economic cost of leaving risk sources uncovered. Prices would be more accurate and available in real-time, providing more reliable and timely information for decision makers. Prices assigned to the default scarcity tranches to allow for the dispatch process to always produce valid prices in real-time.

Scarcity pricing values should be reviewed every 5 years

3.17 We proposed to set an obligation in the Code for the Authority to review these scarcity pricing values periodically (or at any other time the Authority considers necessary). We proposed this review should be at least once every five years.

3.18 In June 2019 a decision paper titled *Implementing spot market settlement on real-time pricing* decided to amend the Electricity Industry Participation Code (Code) to settle the spot market on prices determined in real-time.[10]

3.19 The Authority's June 2019 paper proposed to implement RTP in the Code by:

(a) determining final spot prices from new 'dispatch prices' struck in real-time whenever the system operator issues dispatch instructions

(b) disestablishing the pricing manager role, as it will no longer be required

(c) applying scarcity pricing by default to all forecast demand, to ensure all demand has a price

(d) introducing new 'risk-violation curves' to handle shortfalls in instantaneous reserve

(e) revising the process for manually claiming a pricing error, reflecting the way spot prices will be determined under RTP

9 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972

10 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/decision-to-implement-rtp/

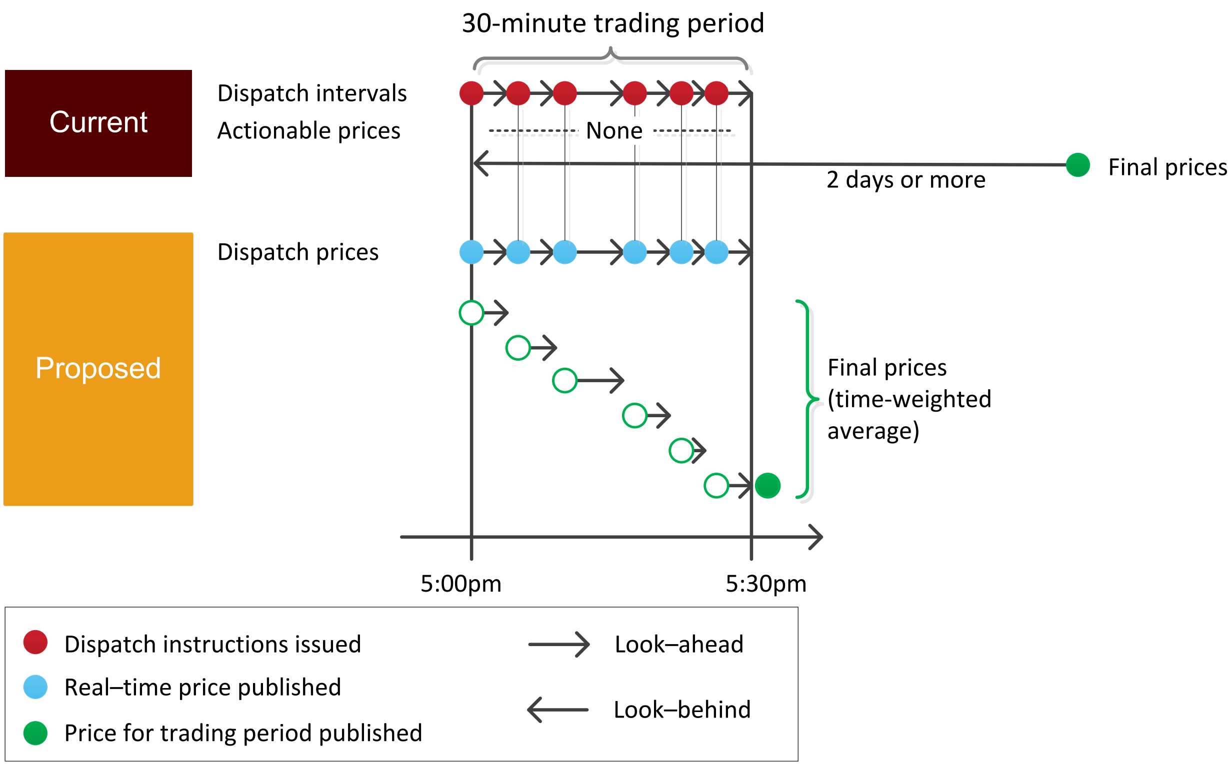
(f) fully integrating dispatchable demand into the system operator's real-time dispatch process

(g) extending arrangements for dispatch to make it easier for both smaller-scale purchasers and generators to participate — the Authority called this 'dispatch-lite'.

3.20 The term 'dispatch-lite' was later replaced by the term 'dispatch notification' or 'DNx' with the 'x' representing a wildcard depending on if it was generation or load being referenced. For example, 'DNL' represents 'dispatch notification load' and 'DNG' represents 'dispatch notification generation'

3.21 To provide a reminder for how the RTP pricing process will work, below in Figure 1 is a diagram comparing RTP with the existing pricing process.

Figure 1 The current pricing process compared with RTP



Source: Electricity Authority

4 The Authority has been further refining the RTP Code amendment through the software implementation phase of the project

4.1 The Authority has been working with our service providers to implement the policy decisions finalised in the 2019 RTP consultation. As expected in 2019, the practicalities of implementing the policy decisions have led to the need for some revisions of the proposed Code amendment.

4.2 The following sections discuss the proposed revisions. None of these proposed revisions impact the overall policy aims or outcomes of the RTP implementation.

4.3 Following this consultation, it is proposed the final version of the RTP Code amendment be gazetted in time for the RTP systems proposed go-live of 1 November 2022.

5 Contingent event reserve shortfall quantities and prices, along with the surplus generation price are being updated

5.1 Clause 13.58AA details the process for the system operator to assign price and quantity values.

5.2 The Authority proposes updated Contingent Event (CE) tranche quantities and prices, along with an updated surplus bus generation value.

Current dispatch processes and policies prioritise reserve deficit ahead of any demand curtailment

5.3 As discussed in our 2019 consultation paper,[11] on rare occasions generator reserve is sacrificed to meet the need for energy in the wholesale market. Where there are insufficient resources offered into the market, reducing reserve cover ensures that meeting the current demand requirement is prioritised over avoiding potential demand management should a significant energy source disconnect from the grid.

5.4 Typically, SPD will reduce the amount of generator reserve, also referred to as 'spinning reserve', dispatched, and instead dispatch the same capacity as energy to supply the current demand. In theory, this could continue until the only reserve dispatched is that provided by demand side participants as interruptible load and all offered generation is dispatched to supply energy.

5.5 In practice, the quantity of spinning reserve dispatched as energy would be limited by the over-riding requirement to ensure that the extended contingent event (ECE) risk is always covered. If the ECE reserve requirement is in deficit there is a risk that, should the HVDC Bipole trip, the dispatched reserve plus the available Automatic Under Frequency Load Shedding (AUFLS) cover would be insufficient to prevent the power system entering cascade failure and full black out of one or both Islands.

5.6 The reserve constraint violation prices currently employed by SPD ensure that the appropriate balance between CE reserve shortfall, ECE reserve shortfall and demand management are maintained.

The Authority and the system operator have reviewed the proposed reserve scarcity values

5.7 In the Authority's March 2019 consultation paper,[12] to provide actionable pricing in real time during a resource shortfall, two risk-violation curves were proposed to handle reserve scarcity. Submissions on the consultation supported the recommendation for a lower-price risk-violation curve compared to a higher-price risk-violation curve.

5.8 The risk-violation curve proposed accounted for CE reserve deficits for Sustained Instantaneous Reserve (SIR) and Fast Instantaneous Reserve (FIR).

[11] Page 24, para 4.9-4.11, https://www.ea.govt.nz/assets/dms-assets/24/249302019-RTP-consultation-paper.pdf

[12] Reference pg 40: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972

5.9 The 2019 proposed SIR and FIR risk-violation values for CE reserve deficit are detailed in Table 1.

Table 1 SIR and FIR risk-violation values for CE reserve deficit as consulted on in 2019

Tranche	FIR contingent risk violation ($/MW/h)	SIR contingent risk violation ($/MW/h)	Quantity (MW/h)
1	4,500	4,000	10
2	7,000	6,500	10
3	9,000	8,500	10
4	12,000	11,500	20
5	18,000	17,500	No limit

5.10 These 'lower price' risk violation curves were selected to move reserve prices through an intermediate step – elevated for a limited initial level of reserve shortfall, but not yet at full scarcity levels.

5.11 As the Authority noted in the 2019 real time pricing decision paper,[13] there is no perfectly 'right' combination of tranche prices and values due to the complex trade-offs required to implement them. The Authority and the system operator have reviewed these values in light of the system operator's current shortfall management policies, submissions on the 2019 real time pricing Code amendment[14] and operational reviews of the 9 August 2021 demand management event.[15]

The Authority proposes a revised set of risk-violation curves for CE reserve deficit

5.12 Submissions on the 2019 risk-violation curves were broadly supportive of adopting the lower-price risk violation steps. The removal of a quantity limit in the final tranche acknowledged concerns that, in the event of an energy scarcity event, all reserve that can be converted to energy, without risking potential cascade failure, should be converted ahead of wide-scale demand management.

5.13 In their 2019 submissions, EnelX, Transpower and Mercury noted that they believed that the current practice of dispatching all offered spinning reserve ahead of any demand management should continue.

5.14 Operational reviews of the 9 August 2021 demand management event have noted that the system operator should prioritise the disconnection of discretionary load ahead of consumer load where practicable. The system operator's practice of dispatching offered spinning reserve as energy to supply demand ahead of demand management was also confirmed.

Reserve deficits expose the power system to an increased risk of an AUFLS event occurring as fewer generating plant are fully covered by the dispatched reserve

5.15 The process of dispatching spinning reserve as energy to avoid demand management relies on the AUFLS scheme to protect the power system from cascade failure should

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[13] Page 32, para 4.117 https://www.ea.govt.nz/assets/dms-assets/25/253582019-RTP-decision-paper.pdf

[14] https://www.ea.govt.nz/assets/dms-assets/25/253592019-RTP-consultation-summary-of-submissions.pdf

[15] https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2021/electricity-authority-review-of-9-august-2021-event-under-the-electricity-industry-act-2010/

the risk plant trip. As more spinning reserve is dispatched as energy, it’s likely that the output of further generating plant will not be fully covered by the available reserve. As the number of exposed generators increases, the probability of a generator tripping leading to an AUFLS event happening increases.

5.16 Considering the North Island power system, the typical CE risk plant would be either Genesis’ Huntly unit 5 at a maximum of 403MW or the HVDC monopole transfer at a similar level, the next largest risk plant would typically be one or more of the Huntly Rankine cycle units at 250MW. Thus, the risk of a generator tripping causing an AUFLS event wouldn’t generally increase appreciably until a reserve deficit of greater than this 150MW risk margin is reached. Exactly how much more reserve deficit would be required to increase the risk of an AUFLS event would depend on the power system conditions at the time of the deficit, including the level of reserve cover provided by interruptible load.

5.17 A review of the dispatched RTD cases from 1 January 2014 to present found 245 dispatch cases with non-zero CE reserve deficits for either FIR or SIR spanning 80 distinct trading periods. 94% of the RTD cases recorded FIR deficits of 150MW or less and 89% of the cases recorded SIR deficits of 150MW or less.

5.18 Noting the 2019 submissions that proposed that all spinning reserve should be dispatched as energy ahead of any demand management, there is a strong case that demand management should occur at some point before too many generators are no longer fully covered by the dispatched reserve.

5.19 To preserve these priorities under real time pricing, the Authority is proposing to reduce the risk-violation prices to ensure that a combined FIR and SIR shortfall is priced below the first energy-scarcity price of $10,000/MWh. This would prioritise the dispatch of spinning reserve as energy ahead of forced consumer disconnection. However, the exact quantity of spinning reserve converted to energy in this way would be dependent upon the generation offers and the number of generators whose output is not covered by the dispatched reserve at the time of the shortfall.

5.20 Contact noted in their 2019 submission that the lower price risk violation curve had pricing below historic generation offers from plant of last resort, such as Whirinaki. Contact was concerned that this has the potential for emergency generation not being dispatched ahead of scheduling a reserve deficit.

5.21 The Authority notes that Whirinaki is not consistently offered at prices in excess of the proposed risk violation prices, this is particularly noticeable over evening peak trading periods. This suggests that the potential for SPD to schedule a reserve deficit ahead of dispatching Whirinaki is limited. For SPD to schedule a reserve deficit ahead of energy dispatch, the cost of the marginal energy offer plus the risk violation price for the relevant reserve type would have to be less than the offer price of the alternative energy source, this further reduces the risk.

5.22 The system operator will still be able to apply discretion to the dispatch solution to maintain compliance with their PPOs. Should the SPD solution schedule a reserve deficit and the system operator determine that the dispatch of a last resort generator is required to preserve system security, they will be able to apply a discretionary constraint to the solution to start the relevant generator.

5.23 The need to balance the risk violation prices against the possibility of not dispatching high priced reserve offers places a lower limit on the first risk violation tranche price. Dividing the 150MW risk margin between two lower priced risk violation tranches will provide the gradual increase in pricing signals to energy scarcity described in the 2019 real time pricing decision paper. A third, higher price, tranche can then remain without a limit on the level of reserve deficit to allow for further reserve deficit as it is needed and economically efficient.

5.24 Over 50% of the FIR deficits in the RTD cases studied were 50MW or lower, for SIR deficits this level of deficit was reflected in over 60% of cases. This suggests that a first risk violation tranche of 50MW will provide a scarcity price in the majority of cases. Setting the second tranche volume at 100MW allows the reserve price to escalate to the point that multiple exposed risk plant may become an issue. The final risk violation tranche maintains the lower violation prices from the 2019 risk violation proposal, with a combined FIR and SIR price below the first energy scarcity tranche price.

5.25 This maintains that, for a single risk setting plant or single reserve type shortage, the dispatch of spinning reserve ahead of actual demand management will still be prioritised. As the security situation worsens, either through the exposure of more risk plant or a scarcity of both FIR and SIR, some demand management may be a preferable security outcome.

5.26 Table 2 illustrates the revised proposal for the FIR and SIR risk-violation curves. The value discrimination between FIR and SIR shortfalls decided upon in the 2019 decision paper has been maintained.

Table 2 proposed revised SIR and FIR risk-violation values for CE reserve deficit

Tranche	FIR contingent risk violation ($/MW/h)	SIR contingent risk violation ($/MW/h)	Quantity (MW/h)
1	3,500	3,000	50
2	4,000	3,500	100
3	4,500	4,000	No limit

5.27 We will uphold the 2019 decision to review the reserve and energy scarcity prices at least every five years.

Cross-references for scarcity pricing are to be updated

5.28 Along with the amendments to Clause 13.58AA, a minor amendment is required for Clause 13.69AA (previously proposed in the June 2019 decision paper) to cross-reference Clause 13.58A and the scarcity pricing process set out in Schedule 13.3AA.

Proposed Code:

13.69AA System operator to assign price and quantity values

(1) In preparing each ***dispatch schedule****, the* ***system operator*** *must assign the price and quantity values—*

(a) set out in clause 13.58AA(2) for the expected profile of ***demand*** *under clause 13.69B(1)(d) for the demand at each* ***GXP*** *that is not the subject of a* ***nominated dispatch bid****; and*

(b) set out in clause 13.58AA(3) to the constraints specified in clause 12(5) of Schedule 13.3; and

(c) set out in clause 13.58AA(4) to the model parameters specified in in clause 1 of Schedule 13.2

*(2) Prices and quantities assigned in subclause (1) must be used in the **dispatch schedule** in accordance with the processes set out in schedule 13.3AA*

The ECE reserve deficit CVP will remain at $800,000/MWh

5.29 The ECE reserve deficit CVP is a signal that the security of the power system is at significant risk. The ECE risk, typically modelled as the loss of the HVDC Bipole, is large enough that it requires both instantaneous reserve and AUFLS provision to cover. The implication of an ECE reserve deficit is that there is insufficient dispatched reserve and AUFLS cover to prevent grid frequency from falling below 47Hz in the North Island or 46Hz in the South Island in the event of the sudden loss of the HVDC Bipole.

5.30 Should the HVDC Bipole trip while there is an ECE reserve deficit there is a high likelihood that the power system will enter cascade failure as generation protection relays trip to protect assets from damage at low grid frequencies.

5.31 By maintaining the ECE reserve deficit CVP, any dispatch solution that results in an ECE reserve deficit will be halted before publication of prices and dispatch instructions. This will allow the system operator to assess the schedule results and determine any corrective or discretionary actions needed to avoid the ECE reserve deficit with no impact on the market. At this point a new dispatch schedule would be produced and published without the ECE reserve deficit price.

The Authority proposes an updated surplus generation price

5.32 Schedule 13.3, Clause 16(2)(b) provides for the assignment of a $0/MWh price for when there is surplus bus generation infeasibility.

5.33 In the current process, surplus generation infeasibilities during SPD modelling incur an infeasibility value of negative $500,000 and occur much less often than deficit bus generation.

5.34 Surplus generation infeasibilities occur under 2 general circumstances:

(a) When SPD has to ramp down a generator at a rate faster than its offered down ramp rate in the face of another, higher priced, constraint; or

(b) When there is an outage that isolates a GXP or GIP and the residual metering indication or load forecast at that GXP or GIP has a small negative offset.

5.35 The Market system runs a post schedule processing[16] step to check the schedule outputs for errors or indications of issues that would require a manual review before publication. This process is also the point at which any adjustments, such as the assignment of prices related to disconnected GXPs and GIPs[17] (in accordance with Schedule 13.3, Clause 16(2)) is implemented.

5.36 In the rare situation where SPD has to ramp down a generator at a rate faster than its offered down ramp rate in the face of another, higher priced, constraint the Authority is proposing that a $0/MWh price is assigned to the GXP/GIP. If the down ramp rate

[16] Para 4.135 https://www.ea.govt.nz/assets/dms-assets/25/253582019-RTP-decision-paper.pdf

[17] Paras 4.69 – 4.75 https://www.ea.govt.nz/assets/dms-assets/25/253582019-RTP-decision-paper.pdf

breach were the result of a disconnected GXP or GIP then the disconnected node process would assign a non-zero price in accordance with the outage alignment process discussed in the 2019 decision paper.

5.37 The Authority proposes to use this post processing step to allow SPD to solve for surplus bus generation infeasibility using the negative $500,000MWh CVP but replace the bus price with $0/MWh prior to publication of the schedule results.

Proposed Code:

Schedule 13.3

…

16 Calculation of prices, marginal location factors and reserve prices

…

(2) The modelling system must assign:

(a) a ~~0~~ price for ***electricity*** *at each* ***grid injection point*** *and* ***grid exit point*** *that* ***is electrically disconnected*** *~~has no load or generation connected to it~~ in the modelling system and*

(b) a 0 price for electricity at each ***grid injection point*** *and* ***grid exit point*** *that* ***is*** *subject to a surplus bus generation infeasibility*

5.38 This change is required because under RTP, the prices from RTP solve, will be used as dispatch prices. Dispatch prices require to be both feasible and practical. The previous value of negative $500,000/MWh would not be practical for settlement.

Q1. Do you agree with the proposed revised FIR and SIR risk-violation values for CE reserve deficit? If not, why?

Q2. Do you agree with the proposed surplus bus generation value? If not, why?

6 Purchasers and generators will be permitted to revise bids and offers within the current trading period

6.1 RTP aims to foster efficient price signals for market participants and more accurately reflect the intentions of purchasers and generators in the spot market.

6.2 One feature of RTP is the design’s capability in facilitating revised bids and offers within a trading period. Despite this change, bids and offers can only be updated within their respective gate closure period if the participant has a bona fide physical reason for the change, as described in Code clause 13.19.

6.3 A technical limitation in the market systems has meant that any changes required for bona fide physical reasons within the current trading period have had to be manually entered as constraints by the system operator.

Purchasers will not be required to communicate with the system operator directly when they significantly change their demand in response to real time prices

6.4 Clause 13.96 requires purchasers to co-operate with the system operator to manage significant changes in un-dispatched demand in response to real time prices.

6.5 The current process requires purchasers to contact the system operator by telephone if there are significant changes in the purchaser's demand, that is not subject to a nominated dispatch bid, in response to real time prices.

6.6 Clause 13.96 will be impractical in a future grid where demand response (DR) and distributed energy resources (DER) introduce more frequent changes to demand in response to real-time prices. It is also likely that, given the expected increase in small scale DR and DER, the aggregate response at a single grid exit point may exceed the notification thresholds required in 13.96, but no single party will be responsible for the whole change, thus no notification will be required. Thus, it becomes impractical to require individual participants to notify the system operator of changes in demand that are likely to be occurring in aggregate at other grid exit points with no notification requirements.

6.7 The Authority proposes to revoke Clause 13.96 and no longer require purchasers to communicate by telephone with the system operator regarding increases or decreases to demand.

Proposed Code:

~~***13.96 Purchaser to co-operate with system operator to manage significant changes in demand response to real time prices***~~

~~*(1) This clause applies to a **purchaser** that wishes to increase or decrease its total **demand**, other than **demand** for a **dispatch-capable load station** for which a **nominated dispatch bid** is submitted, across 1 or more of its **grid exit points** in response to **real time prices** by—*~~

~~*(a) greater than 50 **MW** in any 15 minute period in the North Island; or*~~

~~*(b) greater than 30 **MW** in any 15 minute period in the South Island.*~~

~~*(2) If this clause applies, the **purchaser** must—*~~

~~*(a) advise the **system operator** by telephone of the increase or decrease at least 5 minutes before the change; and*~~

~~*(b) if instructed by the **system operator** by telephone, manage any such increase or decrease in accordance with the instructions.*~~

6.8 This change will allow the system operator to focus on other functions and better support the transition to a low-carbon future for the electricity wholesale markets.

Generators will be permitted to change offers within a trading period

6.9 Clause 13.18 details when revised offers are to be submitted.

6.10 In the Authority's June 2019 decision paper,[18] the draft Code did not allow participants to change their bids and offers within the current trading period, as it is not technically possible with the current scheduling and dispatch arrangement. Participants would instead need to telephone the system operator to inform them of their change in capability and a constraint would be applied for that participant in the current trading period.

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18 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

6.11 The Authority proposes to amend Clause 13.18(1) and revoke Clause 13.18(3) to allow for generators to revise offers within a current trading period under certain circumstances.

6.12 This proposal maintains the current gate closure periods for bids and offers. Removing the need to contact the system operator by phone to change bids and offers will allow for more efficient management of the power system.

Proposed Code:

13.18 When revised offer to be submitted

*(1) A **generator**, other than an **intermittent generator**, must immediately submit a revised **offer** to the **system operator** if~~, at any time before the trading period to which the offer relates,~~ the total **MW** specified in an **offer** exceeds, by more than 5 **MW**, the total **MW** that the **generator** expects to be capable of generating at the relevant **point of connection** to the **grid** for the relevant **trading period**.*

*(1A) A **generator**, other than an **intermittent generator**, may submit a revised **offer** to the **system operator** if the total **MW** specified in an **offer** exceeds, by 5 **MW** or less, the total **MW** that the **generator** expects to be capable of generating at the relevant **point of connection** to the **grid** for the relevant **trading period**.*

*(1B) The submission of a revised **offer** under subclause (1) or subclause (1A) does not relieve the **generator** of liability for breach of any other provision of this Code.*

(2) [Revoked]

*(3) ~~Subclause (1) does not apply after the beginning of the **trading period** to which an **offer** relates~~*

6.13 This change is required to allow generator offers to more accurately reflect generator capability in real-time. RTP overcomes the previous technical restrictions in revising generator offers within a trading period.

Q3. Do you agree with the proposed change to how purchasers communicate with the system operator for significant changes to demand bids? If not, why?

Q4. Do you agree with the proposal to allow generators, other than an intermittent generator to revise offers within a trading period for certain circumstances? If not, why?

7 The process for claiming and assessing an alleged pricing error will change

7.1 In the current pricing process, once interim prices are published on WITS,[19] participants have until midday the following business day to submit an email claim to the pricing manager, NZX, notifying of an alleged pricing error.

7.2 Typical pricing errors involve:

(a) an incorrect input being used in the calculation of an interim price or

(b) an incorrect process being followed in calculating an interim price, and

(i) that has a material effect on the claimant, and

[19] WITS stands for Wholesale Information Trading System and is the electronic portal used the New Zealand electricity energy markets.

(ii) that was either not signalled in dispatch prices or forecast prices, or was signalled in dispatch prices or forecast prices but that the claimant was unable to respond to.

7.3 In the Authority's June 2019 decision paper,[20] it was confirmed that the clearing manager will calculate interim prices and be responsible for making them final. The pricing manager role will be disestablished, as its principal function to produce the current ex-post final pricing schedule will cease under RTP.

7.4 The final pricing schedule will be dis-established and final pricing calculation will be an arithmetic process run by the clearing manager. Under this arrangement, it is no longer appropriate that the system operator be responsible for investigating pricing error claims.

7.5 The Authority is proposing to update the pricing error claim and investigation process to reflect this change in responsibilities.

The definition for 'pricing error' is to be updated

7.6 Part 1 Clause 1.1 of the Code sets out the definitions for key terms referenced in the Code.

7.7 The Authority proposes to update the definition for 'pricing error' to improve the interpretation for when dispatch price or dispatch reserve price are not made available on WITS.

Proposed code:

*(a) a~~n~~ **dispatch price** or **dispatch reserve price** ~~incorrect input~~ that was not made available on **WITS** being used to calculate the **interim price** or **interim reserve price**; or*

7.8 This re-wording is required to clarify the definition of pricing error and reduce the risk of the final pricing process being delayed on the basis of erroneous pricing error claims.

Q5. Do you agree with the proposal to update the definition for 'pricing error'? If not, why?

The obligation to comply with requests from system operator for pricing error claims will be removed

7.9 The following clauses are required to be updated to reflect the new pricing error claim process:

(a) clause 13.173 details the process the clearing manager must follow for when a pricing error claim is received

(b) clause 13.173A details how participants are obligated to respond to a system operator request for a pricing error claim

(c) clause 13.173B details the Authority's abilities to provide instructions to participants during a pricing error investigation

20 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

(d) clause 13.173C details the Authority's role in determining if a pricing error has occurred.

7.10 The Authority proposes to update Clause 13.173 to explicitly detail the clearing manager's role in a pricing error claim and its interactions with the error claimant, the Authority and the WITS manager, under RTP.

7.11 The Authority proposes to not introduce Clauses 13.173A and 13.173B as presented in the June 2019 decision paper's draft Code, because under RTP pricing error claims will no longer be associated with the system operator's role.

7.12 Instead, Clauses 13.173A and 13.173B are proposed to detail the process when pricing error investigation commences and the clearing manager's ability to request information error claimant or participant, respectively.

7.13 The Authority proposes to update Clause 13.173C to provide further clarification on the deadline for the Authority to make decisions and to account for the clearing manager replacing the system operator's role in a pricing error claim.

Refer to Appendix B for proposed Code changes.

7.14 The updates to Clauses 13.173, 13.173A, 13.173B and 13.173C are required to reflect the pricing error claim process under RTP, with the clearing manager taking over the role of the system operator's role in a pricing error claim.

Q6. Do you agree with the proposal to remove participant obligations, relating to the system operator and Authority requests during a pricing claim investigation? If not, why?

The pricing error claimant will no longer require to be materially affected

7.15 Clause 13.169 specifies that a pricing error claimant has to be materially affected by the pricing error.

7.16 In the current pricing error claim process, a claimant is required to be materially affected by the alleged error in order to be able to submit a pricing error claim. Materiality is a subjective measure – an error that may be material to a smaller participant may be immaterial to a larger one. Thus, the burden of monitoring for errors may fall disproportionately on smaller participants. It may also mean that larger, better resourced, participants may be prevented from claiming a pricing error as it is too small to affect them 'materially'.

7.17 The Authority proposes to revoke Clause 13.169 to remove this subjectivity from the ability to claim a pricing error.

Proposed Code:

~~***13.169 Error claimant materially affected by pricing error***~~

~~*(1) Subject to subclause (2), The **system operator** may only consider a claim an **error claimant** may only claim that a **pricing error** has occurred if the error claimant it considers it has been or will be materially affected by the **pricing error**.*~~

~~*(2) Subclause (1) does not apply in relation to a claim made by—*~~

~~*(a) the **Authority**; or*~~

~~*(b) any person who is not a **participant**.*~~

Q7. Do you agree with the proposal that the price error claimant no longer requires to be materially affected? If not, why?

Additional changes are required to previously proposed clauses

7.18 Clauses 13.170 and 13.170A, detail the method and timing for claiming a pricing error, and the clearing manager's right to investigate potential pricing errors, respectively.

7.19 In the Authority's June 2019 decision paper,[21] changes were proposed to both clauses however a revision of these changes is proposed to account for the clearing manager's role in pricing error claims and for the error claimant not requiring to be materially affected.

Proposed Code:

13.170 Method and timing for claiming pricing error has occurred

*To claim that a **pricing error** has occurred, an error claimant ~~**error claimant**~~ must—*

*(a) ~~complete the form set out in Form 9 of Schedule 13.1~~submit a **pricing error** claim to the **clearing manager** in such manner and form as the **clearing manager** may specify from time to time; and*

(b) include ~~sufficient~~ information in its claim ~~the form~~ to demonstrate—

*(i) that, except where the error claimant is the **Authority** or **system operator**, the error claimant ~~**error claimant**~~has been affected by the claimed **pricing error**; and*

*(ii) the basis for the claim that a **pricing error** has occurred; and*

*(iii) the **trading periods** affected by the claimed **pricing error**; and*

*~~(c) give the completed form to the **pricing manager**; and~~*

*(c) comply with paragraphs (a) and (b) ~~to (c)~~ no later than 1200 hours on the 1st **business day** following the **trading day** on which the ~~**pricing**~~ **clearing manager** made available on **WITS** the **interim price** or **interim reserve price** in respect of which~~contains~~ the **pricing error** has been claimed.*

13.170A Clearing manager may investigate potential pricing errors

*(1) The **clearing manager** may investigate a potential **pricing error**.*

*(2) If the **clearing manager** decides to investigate a potential **pricing error**, it must commence the investigation no later than 1200 hours on the 1st **business day** following the **trading day** on which the **clearing manager** made available on **WITS** the **interim price** or **interim reserve price** that is the subject of that investigation.*

7.20 The proposed changes ensure Clauses 13.170 and 13.170A are aligned with the related clauses associated with the pricing error claim process.

7.21 Along with the amendments to Clauses 13.170 and 13.170A, further amendments are required to Clauses 13.177 and 13.178 which detail the later stages in the pricing error claim process.

Proposed Code:

21 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

13.177 ~~Pricing~~ Clearing manager to implement Authority's determination

~~*(1)*~~ *Where the **Authority** ~~decides~~ advises the **clearing manager** of its determination that a ~~material~~ **pricing error** has occurred, the ~~**pricing**~~ **clearing manager** must, as soon as practicable after receiving the advice, —*

*(a) re-calculate the **interim price** or **interim reserve price** affected by the **pricing error** using—*

(i) the methodology described in clause 13.134A; and

*(ii) the **dispatch prices** and **dispatch reserve prices** specified in the notice given on **WITS** under clause 13.173C(2); and*

13.178 ~~Effect of making recalculated interim prices available~~ Further pricing error may be claimed or investigated in respect of revised interim prices

*(1) ~~(a) the **pricing manager** must do so by following the methodology required under clauses 13.135 to 13.179; and(b)~~ A person may submit a **pricing error** claim to the **clearing manager** under clause 13.170, or the **clearing manager** may decide to investigate a potential **pricing error** under clause 13.170A, in respect of a revised~~recalculated~~ **interim price** or revised **interim reserve price** made available on **WITS** under clause 13.177.*

Q8. Do you agree with the proposal to align Clauses 13.170 and 13.170A with the proposed pricing error claim process? If not, why?

Q9. Do you agree with the proposal to amend Clauses 13.177 and 13.178 to reflect the proposed pricing error claim process? If not, why?

8 The process for interim prices becoming final prices is changing

8.1 Clause 13.182A, 13.182B and 13.183 detail the process for interim prices becoming final prices for pricing error and non-pricing error scenarios.

8.2 In the current process a pricing error claim for a single trading period or multiple trading periods would result in all the final prices associated with the trading day of the claim, held as interim until the pricing claim is resolved.

8.3 The Authority proposes that under RTP, Clause 13.182A, 13.182B and 13.183, will specify that only trading periods that are associated with a pricing error claim will have final prices delayed for publishing. Unaffected trading periods during the trading day associated with the price error claim shall not be delayed in being published and interim prices shall be made final.

Refer to Appendix B for proposed Code changes.

8.4 Pricing error claimants will have until 12:00 the following business day of the trading day to submit a claim. Otherwise, all interim prices for the trading day will be automatically made final at 14:00 the following business day.

8.5 A rolling claims window based on the closing time of each trading period within a trading day was discussed during RTP design, however it was decided it would be difficult to implement and add unnecessary complexity to the process of publishing final prices for uncertain benefits. Instead, hard deadlines of 12:00 the following business day for pricing claims and 14:00 the following the business day for final prices being published are preferred.

8.6 Further clarification is provided in the Code to ensure it is clear only the trading periods affected by the pricing error claim will be held as interim and not published as final until the claim is resolved.

8.7 This change is proposed because the Authority believes there are no evident reasons for trading periods unrelated to the pricing error claim to be delayed in publishing. This is a benefit from the new RTP design because each interim and final price will be derived from distinct sets of dispatch schedules. Changes to the calculation of interim and final prices for a trading period will have no effect on subsequent trading periods.

Q10. Do you agree with the proposal that trading periods not associated with a pricing error claim should have final prices published without delays? If not, why?

9 The definition for intermittent generating station is being updated

9.1 Clause 13.3F details the approval process for dispatch notification generators.

9.2 In the Authority's June 2019 decision paper,[22] it was decided that generators can apply to be a dispatch notification generator if they offer under 30MW of capacity. It was expected that some existing intermittent generators may prefer to offer generation as a dispatch notification generator.

9.3 However, an intermittent generator approved as a dispatch notification generator would subject to the associated compliance requirements for intermittent generators. This could lead to conflicting compliance requirements and confusion.

9.4 It is proposed that the Code shall explicitly only allow the participants to offer as either intermittent generation or dispatch notification generation but not as both. Hence, participants will only need to comply with the Code requirements associated with a single definition.

Refer to Appendix B for proposed Code changes.

9.5 It is also proposed that the definition for an 'intermittent generating station' is updated to clarify that it excludes dispatch notification generators approved by the system operator.

Proposed Code:

intermittent generating station *means a* ***generating station*** *that relies on a variable resource that is not stored and in respect of which a generator has not been approved by the* ***system operator*** *under clause 13.3F* ***as*** *a* ***dispatch notification generator***

9.6 This clarification is required to exempt dispatch notification generators from Code compliance requirements for intermittent generating stations.

Q11. Do you agree with the proposal to exclude approved dispatch notification generators from the definition for intermittent generating station? If not, why?

22 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

10 The dispatchable demand regime is being enhanced

10.1 Changes are proposed to improve the scheduling and dispatch of dispatchable demand participants.

The definition of Binary load is being added to the Code

10.2 When calculating a dispatch solution, SPD currently treats demand bid tranches in the same way that it treats generation offer tranches in that they can be incrementally dispatched. This leads to dispatchable demand dispatch instructions that require a reduction of load corresponding to a partial bid tranche.

10.3 The reality of many industrial processes is that they cannot be partially reduced, they are either on or off. If an individual dispatchable demand bid tranche corresponds to a single industrial process, a partial tranche dispatch will lead to uncertainty on the participant's side as to how best to comply with the instruction:

(a) Exceed the level of compliance by switching off the entire process thereby reducing their demand further than required, or

(b) Make a bona fide claim to not comply with the dispatch instruction as they are not physically capable of doing so and not reduce their demand at all.

10.4 This uncertainty usually results in a phone call to the system operator to determine the most appropriate course of action for the participant given the current system conditions. While dispatchable demand participation has been low to-date, the enhancements implemented as a part of the RTP project are expected to bring an increase in participation. As participation increases, the likelihood of the system operator spending significant amounts of time discussing dispatchable demand instructions is high.

10.5 To manage this risk, the Authority is proposing to allow dispatchable demand participants to ask the system operator to model their load as Binary Load. Once a load is modelled as a Binary Load, SPD will only be able to dispatch the load in increments of whole dispatchable demand bid tranches. This change will ensure that dispatchable demand instructions accurately reflect the physical limitations of a participant's industrial processes.

Proposed Code:

<u>***binary load**, in relation to a **nominated dispatch bid**, means a quantity of **electricity** that corresponds to the **MW** specified in one or more entire price bands of the relevant **nominated dispatch bid***</u>

Binary loads are being optimised

10.6 Clause 13.40A details the scheduling and dispatch of binary load.

10.7 The Authority proposes to introduce Clause 13.40A to ensure binary loads are not dispatched if the quantity of electricity required cannot be fulfilled in a single price band relevant to the bid dispatch price.

Proposed Code:

13.40A Inter-relationship between reserve offers and nominated demand bids

*__**Reserve offers**__ __and__ __**nominated dispatch bids**__ __made under clauses 13.38(1) and 13.7(1) to (3) respectively, if they are in respect of the same plant, are inter-related in that the lower the__ __**demand dispatched**__ __or__ __**scheduled**__ __the lower the__ __**instantaneous reserve**__ __may be. The__ __**ancillary service agent**__ __must not be__ __**scheduled**__ __by the__ __**system operator**__ __and a__ __**dispatch instruction**__ __from the__ __**system operator**__ __must not be given the effect of which is that the__ __**instantaneous reserve**__ __exceeds the__ __**scheduled**__ __or__ __**dispatched demand**__ __quantity of__ __**dispatch-capable load station**__, as the case may be.__*

10.8 This change is required to ensure the dispatch model provides practical dispatch schedules and to provide binary load owners with certainty for their operations.

The modelling system and price calculation process is being updated for binary loads

10.9 The introduction of Clause 13.40A for the scheduling and dispatch of binary load has also led to changes in the modelling and price calculation for binary loads.

10.10 Schedule 13.3 Clause 17 details what the modelling system must take into account when calculating prices.

10.11 The Authority proposes the addition of Clause 17(d)(iii).

Proposed Code:

*__(iii) where the__ __**system operator**__ __has agreed to model a__ __**nominated dispatch bid**__ __for a__ __**dispatch-capable load station**__ __as a__ __**binary load**__, must only be scheduled to purchase the full quantity of__ __**MW**__ __specified in a price band-in the__ __**nominated dispatch bid**__ __(and not a quantity of__ __**electricity**__ __that corresponds to only part of the__ __**MW**__ __specified in a price band in the__ __**nominated dispatch bid**__) or 0MW. This subparagraph applies despite anything in subparagraphs (i) and (ii) and;__*

10.12 This addition in the Code is required for the modelling system to account for binary loads.

Interruptible load offers and dispatchable demand bids are being co-optimised

10.13 Along with the introduction of new scheduling and dispatch requirements for binary load, a new entry field for form 6 is proposed to ensure interruptible load offers and dispatchable demand bids are co-optimised.

10.14 In the current scheduling and dispatch process, a purchaser's demand can be offered as both interruptible load and bid as dispatchable demand. However, there is no co-optimisation of the two to ensure the purchaser's demand is utilised in such a manner that is practically possible. On occasions a purchaser can be scheduled and dispatched in a way that requires the same demand to be curtailed in response to the energy price but be consumed to provide interruptible load. This conflict of instructions requires clarification between the purchaser and system operator via telephone.

10.15 The Authority proposes to add a new field in Schedule 13.1 Form 6 for interruptible load offers, to ensure the dispatch-capable load station identifier is captured and associated with the interruptible load offer. Capturing this identifier will allow interruptible load offers associated with the same demand as dispatchable load offers to be co-optimised for scheduling and dispatch if requested by provider.

Proposed Code:

Dispatch-capable load station identifier (if applicable): ____________

10.16 This change is required to ensure consistent and secure results in scheduling and dispatch.

Q12. Do you agree with the proposed method for scheduling and dispatching binary loads? If not, why?

Q13. Do you agree with the proposal to introduce a new definition for binary loads, and the associated changes to the modelling and price calculation process? If not, why?

Q14. Do you agree with the proposal to co-optimise interruptible load and dispatchable load? If not, why?

11 The clearing manager is to access metering data for the calculation of prudential requirements

11.1 Clauses 13.136, 13.137, 13.138, 13.139, 13.140 and proposed new Clauses 13.137A, 13.140A, detail the requirements for generators to give the grid owner half-hour metering information.

11.2 Clause 13.145 and proposed new Clauses 13.141A, 13.141B, detail the information the grid owner must provide the clearing manager.

11.3 Under RTP the pricing manager role is disestablished, however the clearing manager retains the residual pricing manager function of calculating interim prices.

11.4 In the Authority's June 2019 decision paper,[23] all clauses relating to the grid owner providing grid metering information directly to the pricing manager or clearing manager were proposed to be revoked. At the time of the decision paper there was no apparent reason for the clearing manager to require information such as half-hour metering data and participant data because under RTP, dispatch was based on metered data.

11.5 However, after further consideration and discussion with the clearing manager, it was noted that the metering data is required by the clearing manager to calculate prudential requirements. The Authority proposes to reinstate and update clauses relating to the information flow between generators, grid operator and clearing manager. The clause updates reflect the revised requirements and timeframes for data provision for the prudential calculation process as opposed to the final pricing process.

Refer to Appendix B for proposed Code changes.

11.6 This change is required to ensure the clearing manager obtains half-hour metered data to calculate prudential requirements for participants.

Q15. Do you agree with the proposal to reinstate clauses related to information flow between generators, the grid operator and the clearing manager? If not, why?

23 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

12 Scarcity pricing has been accommodated in the real time dispatch process

12.1 Clause 13.69B details the inputs for dispatch schedule.

12.2 Under the proposed RTP design, when in an energy scarcity scenario, SPD will solve for price using the Real Time Dispatch Price (RTDP) solve process. This situation is referred to as an 'unsupplied demand situation' in the Code.

12.3 The RTDP process will split the RTD process to solve for two distinct circumstances:

(a) the dispatch instructions produced will reflect the actual load at the time of the instruction. This will ensure that system load and generation dispatch are in balance and that system frequency can be maintained within the normal operating band,

(b) the pricing solution will reflect the load that would have been in place if load management had not been instructed. This means that the load value for the pricing solve has to be adjusted to 'add back' the load that was disconnected as part of the energy scarcity solution. This 'add back' will only include the demand that SPD calculated it was unable to supply using the available generation offers.

12.4 This solve split will continue in the RTDP schedules until SPD determines that the current demand plus the 'add back' can be supplied by the available offers and scarcity pricing will no longer be in effect in the dispatch schedule. At this point, the system operator will be able to use their tools to determine when to restore the disconnected demand and at what rate to do so.

12.5 The Authority proposes to amend Clauses 13.69B(1)(d) and 13.69B(1)(e) to reflect the practice of adjusting the demand profile used to calculate dispatch prices by RTDP solve.

Proposed Code:

*(d) the expected profile of **demand** until the next **dispatch schedule** is produced by the **system operator,** where in an **unsupplied demand situation:***

*(i) the expected profile of **demand** used to calculate **dispatch instructions** and **dispatch notifications** must reflect the **demand** expected to be supplied by the available **offers** and,*

*(ii) the expected profile of **demand** used to calculate **dispatch price** must be adjusted for the **demand** that was unable to be supplied by the available **offers** that was assigned a value by the **system operator** under clause 13.69AA(a), in accordance with the processes set out in schedule 13.3AA*

*(e) the potential output of all **intermittent generating stations**, determined in accordance with subclause (4):*

12.6 This change is required in the Code to reflect how the market system has been designed to solve for dispatch and price under a scarcity scenario in RTP. Loads dispatched in a scarcity scenario are expected to pay prices that reflect scarcity.

12.7 Along with the above amendment to Clause 13.69B, existing Clause 13.71(3) is proposed to be appended to the end of Clause 13.69B.

Proposed Code:

(4) The system operator must, in determining the potential output of an intermittent generating station for the purposes of subclause (1)(e), use the following information:

(a) if the most recent dispatch instruction to the relevant intermittent generator for the intermittent generating station was not flagged, the actual output in MW of the intermittent generating station:

(b) if the most recent dispatch instruction to the relevant intermittent generator for the intermittent generating station was flagged, the greater of—

(i) the forecast of generation potential specified in the intermittent generator's final offer for the relevant intermittent generating station submitted under clause 13.18A; and

(ii) the actual output in MW of the intermittent generating station:

(c) if the intermittent generator and the system operator have agreed in writing that an alternative estimate may be provided, the alternative estimate of the potential output of the intermittent generating station provided by the relevant intermittent generator

A new schedule describing the RTDP pricing and dispatch process is being added

12.8 Schedule 13.3AA details the management of an unsupplied demand situation in the dispatch schedule.

12.9 Schedule 13.3AA is a new schedule proposed by the Authority to explicitly detail the process and calculations involved with accommodating scarcity pricing in real-time dispatch.

Refer to Appendix B for proposed Code changes.

12.10 The process can be summarised by the following key steps:

(a) calculate the unsupplied demand quantity and price values

(b) adjust dispatch load profile for unsupplied demand

(c) calculate dispatch prices accounting for both supplied and unsupplied demand.

12.11 This new schedule is required to ensure there is common understanding between the system operator and market participants on how prices will be determined under an unsupplied demand situation.

Q16. Do you agree with the proposal to accommodate scarcity pricing in the real-time pricing process? If not, why?

Q17. Do you agree that the proposed schedule adequately describes the RTDP pricing process? If not, why?

13 Features of dispatch notification participation are being updated

The dispatch notification load definition is being updated

13.1 In the Authority's June 2019 decision paper,[24] the draft Code introduced 'dispatch notification purchaser' as a defined term.

dispatch notification purchaser *means a* ***dispatchable load purchaser*** *that is approved by the* ***system operator*** *under Schedule 13.8 to operate a* ***dispatch-capable load station*** *as a* ***dispatch notification purchaser***

13.2 The definition precludes load aggregators from bidding demand response into the market. Given there is no need to provide separate reconciliation information for dispatchable notification purchasers, and load aggregators are participants under Section 5 of the Electricity Industry Act 2010. There are no obvious reasons to prevent load aggregators who are not purchasers from participating.

13.3 The Authority proposes to amend this definition so as to deem all references to 'purchaser' in relation to a dispatch notification load to include load aggregators.

13.4 The Authority also proposes to replace references to 'dispatch notification load participant' throughout the proposed draft Code to 'dispatch notification purchaser'.

Proposed Code:

dispatch notification purchaser *means a* ***dispatchable load purchaser*** *that is approved by the* ***system operator*** *under Schedule 13.8 to operate a* ***dispatch-capable load station*** *as a* ***dispatch notification purchaser****. For the purpose of this definition and for the purpose of all references to* ***purchaser*** *in relation to a* ***dispatch notification purchaser****,* ***purchaser*** *includes a load aggregator*

13.5 This change is required to ensure the definition for 'dispatch notification purchaser' does not restrict participation unnecessarily.

The treatment of dispatch notification load bids under a non-dispatch flag is being clarified

13.6 Clause 13.58A details the inputs for the price-responsive and non-responsive schedules.

13.7 Under the current dispatchable demand bid regime, a non-dispatch bid is treated as a fixed volume for scheduling purposes.

13.8 Dispatch notification load participants will use the same 'non-dispatchable' flag in their bids to signal periods when they do not wish to be subject to dispatch notifications.

13.9 However, it is proposed dispatch notification load bids will be treated differently from dispatchable demand bids when the 'non-dispatchable' flag is indicated.

(a) Dispatchable demand bid: fully bid volume is used for scheduling purposes and prices are ignored

(b) Dispatch notification load bid: bid volumes will be replaced with 0MW in scheduling and dispatch

[24] Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

13.10 When a dispatch notification load bid is signalled as non-dispatchable, the forecast load at the GXP the load is bid at will no longer be adjusted for their bid quantity. In effect they will become a variable part of the forecast load and will no longer be able to take part in the price discovery process for the periods they have signalled they are non-dispatchable.

13.11 The Authority proposes to amend Clause 13.58A to account for the handling of dispatch notification load bids when the 'non-dispatchable' flag is indicated.

Proposed Code:

13.58A Inputs for price-responsive schedule and non-response schedule

*(1) The **system operator** must prepare a **price-responsive schedule** using the following inputs:*

*(a) **offers** and **reserve offers**; and*

*(aa) the potential output of all **intermittent generating stations**, determined using the most recent **forecast of generation potential** for each **intermittent generating station** submitted under clause 13.18A; and*

*(b) **nominated bids** <u>(where, in the case of a **nominated non-dispatch bid** submitted by a **dispatch notification purchaser**, the relevant quantity is 0 **MW**)</u>; and*

*(2) The **system operator** must prepare a **non-response schedule** using the following inputs:*

*(a) **offers**, **nominated dispatch bids**, and **reserve offers**; and*

*(aa) the potential output of all **intermittent generating stations**, determined using the most recent **forecast of generation potential** for each **intermittent generating station** submitted under clause 13.18A; and*

*(b) **nominated non-dispatch bid** quantities <u>(where, in the case of a **nominated non-dispatch bid** submitted by a **dispatch notification purchaser**, the relevant quantity is 0 **MW**)</u>; and*

13.12 This change is required to account for the difference in obligations between dispatch notification load participants and dispatchable demand participants, when a 'non-dispatchable' flag is indicated. Dispatchable notification load participants have the contractual capability to opt out of dispatch instructions when desired.

Q18. Do you agree with the proposal to update the definition of dispatch notification purchaser to include load aggregators and virtual powerplants? If not, why?

Q19. Do you agree with the proposed method for handling dispatch notification loads under a non-dispatch flag? If not, why?

14 Provision is being made for pricing publication when the system operator's primary modelling system is unavailable

14.1 In the Authority's June 2019 decision paper,[25] Clause 13.69A was proposed to detail the considerations and timing for the system operator in preparing dispatch schedules.

14.2 However, the draft Code did not detail what information the system operator must publish when the primary modelling system for dispatch schedules is unavailable.

25 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

14.3 The system operator is obligated to publish a price to WITS[26] when a dispatch schedule is implemented. In the situation where the market system is unavailable (eg, is on a planned outage or experiencing technical issues) the system operator utilises Stand-alone Dispatch (SAD) to produce dispatch instructions.

14.4 The SAD tool is intentionally designed and built as the minimum viable product to produce dispatch instructions when other systems are unavailable, as such it does not receive the full set of updated inputs needed to calculate a dispatch price and does not have the capability to publish prices to WITS. The Authority's market design and June 2019 decision paper explicitly permits non-publication of prices from real-time dispatch in this scenario but the Code was not drafted to permit it.

14.5 The Authority proposes to introduce a new clause, Clause 13.72A to account for the scenario when the primary modelling system for dispatch schedules is unavailable and the system operator must issue dispatch instructions without the ability to publish a dispatch price.

Proposed Code:

13.72A Dispatch schedule primary modelling system unavailable

*(1) Where the **system operator's** primary modelling system for preparing and implementing a **dispatch schedule** is unavailable, the **system operator**—*

*(a) must issue **dispatch instructions** and **dispatch notifications** using the backup procedure specified by it from time to time and using the inputs available to it at the relevant time; and*

*(b) is not required to prepare a **dispatch schedule** that complies with the requirements set out in clause 13.69A(1)(a) and clause 13.69A(1)(b).*

*(2) When the **system operator** issues **dispatch instructions** in accordance with clause 13.72A(1), such **dispatch instructions** will be deemed to comprise a **dispatch schedule** for the purposes of clause 13.72(1)*

14.6 This change is required to ensure market dispatch is still Code compliant under RTP when the market system is unavailable.

14.7 Along with the proposed amendment to Clause 13.72A, a minor amendment is required for Clause 13.69A (previously proposed in the June 2019 decision paper) to cross-reference Clause 13.72A.

Proposed Code:

*(1) Except as provided in clause 13.72A, before each **trading period**, or as soon as practicable after the start of a **trading period**, the **system operator** must prepare a **dispatch schedule** for the **trading period**—*

Q20. Do you agree with the proposed provision for handling pricing publications during stand-alone dispatch? If not, why?

15 Technical and non-controversial Code changes

15.1 The Authority proposes to make the following technical and non-controversial changes to the Code as part of RTP implementation.

[26] WITS stands for Wholesale Information Trading System and is the electronic portal used the New Zealand electricity energy markets.

15.2 References to clauses yet to be gazetted in the latest version of the Code can be found in Appendix A (draft Code amendment) of the Authority's June 2019 decision paper.[27]

Dispatch marginal location factors are to replace existing marginal location factors

15.3 Part 1 Clause 1.1 of the Code sets out the definitions for key terms referenced in the Code.

15.4 The Authority proposes to revoke the terms 'interim marginal location factor' and 'provisional marginal location factor', and introduce a new term named 'dispatch marginal location factor'

Refer to Appendix B for proposed Code changes.

15.5 A location factor is the ratio energy prices at two different locations. Location factors can be used to adjust prices from one node to what it might be at another node or in another region.

15.6 This information is important for market participants when contemplating forward positions or when seeking to manage locational price risk. Location factors are required to be accounted for when calculating nodal prices in the modelling system (Schedule 13.3 Clause 17) and in the context of the hedge arrangement disclosure regime (Part 13 Subpart 5).

15.7 This change is required because the de-commissioning of the final pricing schedule makes redundant the need for interim and provisional marginal location factors. Instead, as interim and final prices will be derived from the dispatch prices published in real-time, interim and provisional marginal location factors will be identical to the average marginal dispatch locational factors. Final marginal location factors will be calculated in a same way as final prices in a time-weighted average approach.

Reserve offers may be re-offered to align with generator offer rules

15.8 Clause 13.46 provides the details for revising reserve offers during a trading period.

15.9 The Authority proposes that an ancillary service agent may revise a reserve offer any time before the 'end' of the trading period. This is a change from the current Code which only allows for a reserve offer to be revised before the 'beginning' of a trading period.

15.10 This change is required to align reserve re-offer rules with the generator re-offer rules for RTP.

15.11 The Authority also proposes the revoking of Clause 13.46 (3)(b) which sets a requirement that an inaccurate offer of MW in a published non-response schedule requires an ancillary service agent to provide a revised offer.

~~*the relevant **MW** specified in the **non-response schedule** most recently **published** by the **system operator** is not likely to be achieved by the **ancillary service agent** at the relevant **grid injection point**, **grid exit point** or **interruptible load group GXP***~~.

27 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

15.12 This change was previously discussed in the Authority's March 2019 consultation paper.[28]

Forecast prices and forecast reserve prices are to be used when dispatch prices and dispatch reserve prices are not available

15.13 Clause 13.134A details the methodology for calculating interim prices.

15.14 In 2019, the Authority noted that there may be situations where no dispatch schedule is published at the start of a trading period. This could be due to a planned or unexpected market system or communications outage. In these circumstances, it was proposed that the latest price-response forecast schedule prices received by the clearing manager be substituted until an update dispatch price is published.

15.15 In reviewing the 2019 drafting of clause 13.134A, it was noted that it is possible to publish a price-response schedule during a trading period where the first trading period is the current one. Under the 2019 drafting, this could lead to an interpretation whereby the price used to substitute for a lack of dispatch pricing was actually published after the start of the trading period to which it relates. This clearly undermines the intent that participants should be able to see and react to market prices in real time.

15.16 The intent of the drafting of 13.134A in 2019 was to indicate that the schedule prices to be substituted are those that were last published before the start of the trading period in question.

15.17 The Authority proposes that Clause 13.134A is amended to clarify which forecast schedule prices are to be used when no dispatch price or dispatch reserve price is available at the start of a new trading period.

Proposed Code:

*'…if there is no **dispatch price** or **dispatch reserve price** for t = 1 in a **trading period**, the **dispatch price** or **dispatch reserve price** (as the case may be) for the t =1 period is the **forecast price** or **forecast reserve price** in the most recent **price-responsive schedule** received by the **clearing manager** ~~at the time the **interim price** or **interim reserve price** is calculated~~ **prior to the start of the trading period**.'*

15.18 This addition in the Code is required to clarify that under RTP if dispatch prices are not available for the start of a new trading period, the latest price-response schedule published before the start of the trading period shall be used for dispatch.

Final price is to be used for the calculation of constrained on

15.19 Clause 13.204 details the calculation of constrained on amounts.

15.20 The Authority proposes that Clause 13.204(1)(c) calculates constrained on prices based on final prices, defined as P_f in 13.204(c), instead of dispatch prices as proposed in the 2019 Code amendment.

Proposed Code:

28 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609 Para 3.73 to 3.78

c) *the **clearing manager** must calculate the **constrained on amounts** for a **constrained on situation** described in clause 13.202(c) for each **ancillary service agent** for each affected price band in accordance with the following formula:*

$COC = Q_{con} * (P_o - P_f)$

where

*COC is the **constrained on amount** for an **ancillary service agent***

Q_{con} *is the ~~dispatched~~ **dispatched** quantity of **instantaneous reserve** in **MW** (calculated under paragraph (d)~~as set out below~~) from that price band in the **reserve offer** that was constrained on during a **trading period***

P_o *is the price offered for that price band by that **ancillary service agent** for the quantity* Q_{con}

P_f *is the **final reserve price** for that **trading period** at the **point of connection** on the **grid**; and*

15.21 The change ensures constrained on calculations are aligned with other constrained calculations in the Code. The preference is for constrained on calculations to be completed on a trading period basis using final prices and not at dispatch intervals using dispatch prices.

Reconciliation manager is to source data from WITS

15.22 Clause 15.15 details the process for notifications of points of connection subject to outages or alternative supply. The current process requires the system operator to supply this information to the Reconciliation manager from the final pricing schedule.

15.23 The Authority proposes that Clause 15.15(a) shall specify the WITS[29] manager instead of the system operator provides the reconciliation manager with disconnected node information.

Proposed Code:

*(a) the ~~**system operator**~~ **WITS manager** must give written notice to the **reconciliation manager** of the following:*

*(i) each **point of connection** to the **grid** that had no load or generation connected to it in the modelling system in the **consumption period**:*

*(ii) in relation to each **point of connection** referred to in subparagraph (i), the **trading periods** in the **consumption period** during which the **point of connection** to the **grid** had no load or generation connected to it in the modelling system.~~; and~~*

15.24 This change is proposed because currently the system operator provides the reconciliation manager with disconnected node information via the final pricing schedule. However, the WITS manager already receives disconnected node information from the dispatch schedule. There are expected efficiencies in the WITS manager formatting and providing disconnected node information data to the reconciliation manager instead of the system operator.

15.25 The Authority also proposes that Clause 15.15(b) is revoked.

Proposed Code:

29 WITS stands for Wholesale Information Trading System and is the electronic portal used transfer trading information in the New Zealand electricity energy markets.

~~*(b) each **grid owner** must give written notice to the **reconciliation manager** of the following:*~~

~~*(i) each **point of connection** to the **grid** that was supplied from an alternative **point of connection** in the **consumption period**:*~~

~~*(ii) in relation to each **point of connection** referred to in subparagraph (i), the **trading periods** in the **consumption period** during which the **point of connection** to the **grid** was supplied from an alternative **point of connection**.*~~

15.26 This change is proposed because Clause 15.15(b) is made redundant from the proposed change to Clause 15.15(a).

Schedule 13.3 Cl13(1) and Schedule 13.3B are being aligned

15.27 Schedule 13.3 Clause 13 details the adjustments to schedules to meet dispatch objective.

15.28 The Authority proposes that Schedule 13.3 Clause 13(1) shall consider the non-response schedule alongside the price-response schedule in adjustments to meet dispatch objective.

Proposed Code:

*(1) As soon as practicable after each **<u>price-responsive schedule and</u> non-response schedule** <u>has been completed</u> and each **dispatch schedule** has been <u>implemented</u> ~~completed~~, the **system operator** must give notice on **WITS** to **participants** of any <u>adjustments</u> ~~changes~~ required to the **<u>price-responsive schedule,</u> non-response schedule** or **dispatch schedule** (as the case may be) to meet the **dispatch objective**, including adjustments for—*

15.29 This change is necessary because the price-response schedule will be the primary mechanism for adjustments. Schedule 13.3B shall be updated to reflect this change.

Supply transformers are being included in system modelling

15.30 Schedule 13.3 Clause 11 details the constraints relating to the transmission system.

15.31 The Authority proposes that Schedule 13.3 Clause 11(c) revokes the restriction on supply transformers from being modelled in the system as a constraint.

Proposed Code:

*(c) the modelling system must calculate the **electricity** flows into individual transmission **lines** and flows into the connection points of transformers connected at the same **grid injection point** or **grid exit point** using an established DC power flow technique within the limitations imposed by the technique that—*

*(i) correctly adjusts flows for transmission system **losses**; and*

*(ii) correctly apportions flows in transmission system loops, whether or not those loops contain transmission **constraints***

~~*provided that the capacity of transformers through which **electricity** is supplied to a **grid exit point** is not included in the model unless the transformer may carry flows of **electricity** other than **offtakes** from that **grid exit point**.*~~

15.32 This change is required to align the Code's requirements for the modelling of transformers with actual practice by the system operator. Standard practice is for supply transformers to be modelled for security purposes; hence the Code should reflect this instead of prohibiting the modelling of supply transformers as a constraint.

The process for pricing error claim received or investigation commenced is being removed

15.33 Clause 13.173 details the process for when error claims are received.

15.34 The Authority proposes that reference to Clause 13.173(d) in Clause 13.173 (2) is revoked because Clause 13.173(d) will no longer exist in the latest proposed Code.

Proposed Code:

~~*'...and any **participant** to which clause 13.173(d) applies...'*~~

15.35 This is a correction to amend a previous Code drafting oversight.

The Authority may order the delay of interim prices being made final

15.36 Clause 13.184 of the Code allows for the Authority to flag interim prices as withheld.

15.37 The Authority proposes for the text '**available**' to be revoked from Clause 13.184's description. The proposed clause description is:

Proposed Code:

'13.184 Authority may order delay of interim prices becoming final prices ~~available~~'

15.38 This is a correction to amend a previous Code drafting oversight.

The calculation of prices, marginal location factors and reserve prices is being updated

15.39 Schedule 13.3 Clause 16 details the provision for disconnected nodes to be assigned a proxy price. This is necessary to reflect the fact that planned transmission outages do not occur on strict trading period boundaries i.e. every half-hour period.

15.40 The Authority proposes to revoke the cross-reference to Schedule 13.3B Clause 2 and assign proxy prices to the relevant forward or dispatch prices.

Proposed Code:

(3) The prices described in subclause (1) must be used—

*(a) for a **price-responsive schedule** or a **non-response schedule**, as—*

*(i) **forecast prices**; and*

*(ii) **forecast reserve prices**; and*

~~*(iii) **forecast marginal location factors**:*~~

*(b) for a **dispatch schedule** or for preparing the information referred to in Schedule 13.3B as—*

*(i) **dispatch prices**; and*

*(ii) **dispatch reserve prices**.*

15.41 This is a correction to amend a previous Code drafting oversight.

The terminology for '6 second' and '60 second' reserve is being made consistent

15.42 Currently, Clause 13.58AA, Schedule 13.2, Schedule 13.3 Clause 12.5 and Schedule 13.3B refers to the terminology '6 second' and '60 second' reserves.

15.43 The Authority proposes to replace the terminology ‘6 second’ and ’60 second’ risks and reserves with terminology ‘FIR’ and ‘SIR’ respectively to ensure consistency in terminology in other areas of the Code.[30]

Refer to Appendix B for proposed Code changes.

15.44 This is a correction to align terminology through Part 13 of the Code.

A purpose statement has been added to Schedule 13.3B

15.45 Schedule 13.3B details the information for schedules prepared by system operator.

15.46 The table in Schedule 13.3B summarises all information in schedules, both as contents and values to be published. Refer to Appendix B for proposed Code change.

15.47 The Authority proposes to introduce a purpose statement at the beginning of Schedule 13.3B to better clarify the context of the schedule.

Refer to Appendix B for proposed Code changes.

15.48 Along with the addition of a purpose statement, the Authority proposes to revoke the text ‘required’ in row 20.

Proposed Code:

‘scheduled level of ***fast instantaneous reserve*** *and* ***sustained instantaneous reserve*** *~~required~~ in each* ***island’***

15.49 This is a correction to amend a previous Code drafting oversight.

A clause reference has been updated for the ‘dispatched purchaser’ definition

15.50 Part 1 Clause 1.1 of the Code sets out the definitions for key terms referenced in the Code.

15.51 The Authority proposes to update a clause reference from Clause 13.81(2) to Clause 13.81 for the dispatched purchaser definition. This is because Clause 13.81(2) is proposed to be revoked, hence the reference is no longer accurate.

Proposed code:

(b) issued with a ***dispatch instruction*** *in accordance with backup procedures under clause 13.81~~(2)~~ for 1 or more* ***dispatch-capable load stations***

15.52 This is a correction to amend a previous Code drafting oversight.

The definition for ‘transmission security constraint’ is to be re-introduced

15.53 Part 1 Clause 1.1 of the Code sets out the definitions for key terms referenced in the Code.

30 ‘FIR’ is an acronym for ‘fast instantaneous reserve’ and ‘SIR’ is an acronym for ‘sustained instantaneous reserve’

15.54 In the Authority's June 2019 decision paper,[31] the definition for 'transmission security constraint' was proposed to be revoked, however it was determined the definition is still required under RTP.

15.55 The Authority proposes to re-introduce the definition for 'transmission security constraint', albeit revoke the references to Clause 15 in Schedule 13.3 relating to schedule of prices as it is no longer relevant under RTP.

Proposed Code:

> ***transmission security constraint*** *means a flow limit ~~covered by clause 15(d)(i) or (iii) of Schedule 13.3~~relating to the AC transmission system configuration, capacity and losses, including any adjustments that have been made in accordance with clause 13(2)(d) and (f) of Schedule 13.3, but excluding a flow limit set in relation to the* ***HVDC link***

15.56 This is a correction to amend a previous Code drafting oversight.

Q21. Do you agree with the proposed technical and non-controversial Code changes? If not, why?

16 The Authority's proposal has a positive net benefit for consumers

16.1 The Authority believes the cost benefit analysis from its *Real-time pricing proposal*[32] consultation in March 2019 remains valid. The changes to RTP as suggested in this consultation paper will have negligible effects on the cost benefit analysis conducted previously.

16.2 The 2019 benefit analysis identified quantitative estimates for three key benefits:

(a) Benefit 1: avoided generation investment by substituting more efficient demand response from industrial and commercial users

(b) Benefit 2: avoided generation investment by substituting more efficient demand response from residential users

(c) Benefit 3: more efficient levels of reliability.

Consumers will directly benefit from the real-time pricing changes

16.3 Consumers are expected to directly benefit from the changes implemented by the real-time pricing project. Those consumers that are able to provide demand flexibility resources to aggregators will benefit through enhanced retail offerings for their resources and reduced consumption during peak price periods.

16.4 The management of peak demand periods through DR and DER engagement in the wholesale market will reduce average wholesale prices and thus reduce risk premiums paid by retailers for hedge products. This is expected to translate to reduced retail rates for consumers.

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31 Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/decision-to-implement-rtp/

32 Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972.

16.5 The cost analysis considered the effect on the system operator, the clearing manager, the pricing manager, and participants. This included allowances for the direct costs associated with more efficient levels of demand response.

16.6 The analysis demonstrated significant net benefits of $50 million in the base case. The lower and upper cases also demonstrated positive net benefits. For completeness, it was noted these upper and lower cases were likely overstated due to the likely range of outcomes. This overstatement was caused by the compounding effect of multiple 'downside' or 'upside' assumptions in each case.

17 The Authority's proposed Code amendment is set out in Appendix B

17.1 The proposed Code amendment is provided in Appendix B.

17.2 The Authority recommends this consultation paper and associated Code amendment (Appendix B) is read in conjunction with the Authority's June 2019 decision paper[33] and its associated Code amendment (Appendix A).

Q22. Do you agree with the proposed drafting of the Code amendment? Any concerns or feedback?

18 Next steps

18.1 Below are the next steps proposed for the real-time pricing (RTP) project:

(a) a decision paper is proposed to be released after consultation – September 2022

(b) expected go-live for RTP – 01 November 2022

(c) expected go-live for Dispatch notification and dispatchable demand enhancements – early 2023

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
AUFLS	Automated under-frequency load shedding is the last line of defence before cascade failure of the power system
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
CVP	Constraint violation penalty
DCLS	Dispatch-capable load station, used to participate as dispatchable demand
Dispatch price	Under RTP, the prices for energy and reserve struck in real-time from the dispatch schedule would be known as 'dispatch prices' and 'dispatch reserve prices'
DSE	The system operator's Dispatch Service Enhancement project

[33] Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/decision-to-implement-rtp/

EMI	Electricity Market Information
FIR	Fast instantaneous reserve
ICCP	Inter-control center protocol
IL	Interruptible load, a type of instantaneous reserve
Net load	Net load at a point of connection (eg, a GXP, a consumer's meter) is the total of actual load minus any injection from embedded generation.
NRS	The forward non-response schedule
PRS	The forward price-responsive schedule
Regulations	Electricity Industry (Enforcement) Regulations 2010
SCADA	Supervisory control and data acquisition
SAD	Stand-alone dispatch
SIR	Sustained instantaneous reserve
SPD	The system operator’s scheduling, pricing, and dispatch system
VRP	Virtual reserve provider, used to resolve reserve infeasibilities in a final pricing schedule
WITS	Wholesale information and trading system

Appendix A Format for submissions

Submitter	

Question		Comment
Q1.	Do you agree with the proposed revised FIR and SIR risk-violation values for CE reserve deficit? If not, why?	
Q2.	Do you agree with the proposed surplus bus generation value? If not, why?	
Q3.	Do you agree with the proposed change to how purchasers communicate with the system operator for significant changes to demand bids? If not, why?	
Q4.	Do you agree with the proposal to allow generators, other than an intermittent generator to revise offers within a trading period for certain circumstances? If not, why?	
Q5.	Do you agree with the proposal to update the definition for ‘pricing error’? If not, why?	
Q6.	Do you agree with the proposal to remove participant obligations, relating to the system operator and Authority requests during a pricing claim investigation? If not, why?	
Q7.	Do you agree with the proposal that the price error claimant no longer requires to be materially affected? If not, why?	
Q8.	Do you agree with the proposal to align Clauses 13.170 and 13.170A with the proposed pricing error claim process? If not, why?	
Q9.	Do you agree with the proposal to amend Clauses 13.177 and 13.178 to reflect the proposed pricing error claim process? If not, why?	
Q10.	Do you agree with the proposal that trading periods not associated with a pricing error claim should have final prices published without delays? If not, why?	
Q11.	Do you agree with the proposal to exclude approved dispatch notification generators from the definition for intermittent generating station? If not, why?	
Q12.	Do you agree with the proposed method for scheduling and dispatching binary loads? If not, why?	
Q13.	Do you agree with the proposal to introduce a new definition for binary loads, and the associated changes to the modelling and price calculation process? If not, why?	
Q14.	Do you agree with the proposal to co-optimise interruptible load and dispatchable load? If not, why?	
Q15.	Do you agree with the proposal to reinstate clauses related to information flow between generators, the grid operator and the clearing manager? If not, why?	
Q16.	Do you agree with the proposal to accommodate scarcity pricing in the real-time pricing process? If not, why?	

Q17. Do you agree that the proposed schedule adequately describes the RTDP pricing process? If not, why? Q18. Do you agree with the proposal to update the definition of dispatch notification purchaser to include load aggregators and virtual powerplants? If not, why? Q19. Do you agree with the proposed method for handling dispatch notification loads under a non-dispatch flag? If not, why? Q20. Do you agree with the proposed provision for handling pricing publications during stand-alone dispatch? If not, why? Q21. Do you agree with the proposed technical and non-controversial Code changes? If not, why? Q22. Do you agree with the proposed drafting of the Code amendment? Any concerns or feedback?	

Appendix B Proposed Code amendment

Appendix C Regulatory statement

Objectives of the proposal

C.1 The proposed Code amendment seeks to make spot prices more actionable and resource efficient.

Spot prices would be more actionable

C.2 Spot prices would become more actionable. That is, they would provide information that parties can act on in real-time with much greater confidence. Currently, parties use indicative prices, which can be unreliable predictors of spot prices. Further, indicative prices may not always be published in real-time, especially when the system is under stress.

Spot prices would be more resource efficient

C.3 Spot prices would be more resource efficient. For example, consumers would be less likely to later think they would have preferred to consume less or more at the spot price. Likewise, generators would be less likely to regret generating less or more than they did.

C.4 At present, there is greater scope for these inefficiencies because spot prices do not necessarily reflect the resources used in real-time, and current arrangements discourage some parties from participating in the spot market.

The proposal's benefits outweigh its costs

C.5 The Authority has analysed the costs and benefits of the proposal and has determined that the proposal's benefits outweigh its costs. This analysis is set out in Appendix C.

The Authority has not identified other suitable means of addressing the objectives

C.6 The Authority assessed some options to address the objectives. However, the other options were not suitable for addressing the objectives. The selected proposal was best suited to address the objectives.

The proposal complies with section 32(1) of the Act

C.7 The Authority's objective under section 15 of the Act is to promote competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers.

C.8 Section 32(1) of the Act says that the Code may contain any provisions that are consistent with the Authority's objective and are necessary or desirable to promote one or all of the following:

Table 3: How the proposal complies with section 32(1) of the Act

a) competition in the electricity industry;	The proposal fosters greater competition between generators and consumers (via voluntary demand response), especially when spot prices are high.
b) the reliable supply of electricity to consumers;	The proposal encourages a more efficient level of reliability in the power system as the system operator

	could come to rely equally on demand bids and generation offers.
c) the efficient operation of the electricity industry;	The proposal introduces a greater level of operational efficiency in the wholesale market as calculating spot prices will no longer require extensive manual intervention
d) the performance by the Authority of its functions;	The proposal does not impact the performance by the Authority of its functions.
e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment would not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

The Authority has given regard to the Code amendment principles

C.9 When considering the proposal, the Authority has complied with its Consultation Charter[34] and has had regard to the following Code amendment principles, to the extent that the Authority considers that they are applicable.

Table 4: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful because it is consistent with the Authority's statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The proposal is consistent with principle 2 because it improves the operational efficiency and design of the spot market, reducing the likelihood for market failure.
3. Net benefits are quantified	The extent to which the Authority has been able to quantify the benefits of the proposal are set out in Appendix C.

34 Available at: https://www.ea.govt.nz/assets/dms-assets/14/14242consultation-charter.pdf.