Final elements of real-time pricing

Decision

27 September 2022

Executive summary

The Electricity Authority (Authority) has decided to amend the Electricity Industry Participation Code (Code) to settle the spot market on prices determined in real time.

The Authority has consulted on two previous occasions on the real-time pricing (RTP) design. In August 2017, the Authority consulted on the proposal to adopt real-time prices, set by the system operator's dispatch schedule. After considering submissions and further design work, the Authority consulted again in March 2019 on the remaining elements of real-time pricing. The 2019 consultation discussed three further developments of the RTP implementation: Dispatch Notification participation, instantaneous reserve shortfall pricing and a process for reviewing the default scarcity prices.

This third consultation sought feedback on the final elements of the RTP Code amendment. While the policy design decisions had been finalised during the Authority's 2019 RTP consultation, it was acknowledged that further refinements would likely be necessary as the Authority and its partners implemented RTP over the following 3 years.

There were 5 significant changes to the RTP Code amendment and 14 minor, technical and non-controversial changes proposed in this latest consultation. The Authority has decided to proceed with all the proposed changes and a further 3 technical and non-controversial changes that were a result of submissions.

Reserve deficit values

The Authority has decided to revise the prices that would apply during an instantaneous reserve shortfall. This decision aligns with operational change recommendations from the reviews following the 9 August 2021 demand management event.

Pricing error claim process

The Authority has decided to amend the pricing error claim process proposed in its 2019 RTP consultation. Responsibility for investigating an alleged pricing error will now fall on the Clearing Manager.

The Authority has also decided to clarify the definition of a pricing error to specify the circumstances under which final prices can be considered in error.

Real-time price calculation under a scarcity pricing situation

The Authority has decided to amend Clause 13.69B and add a new schedule to the Code that describes how scarcity pricing will be implemented in the real-time dispatch (RTD) schedule.

Dispatchable demand enhancements

The Authority has decided to amend the Code to reflect proposed enhancements to the Dispatchable demand regime.

Pricing publication when the system operator's primary modelling system is unavailable

The Authority has decided to amend the Code to describe the system operator's change in obligations to produce dispatch prices when their primary modelling system is unavailable.

Technical and non-controversial changes

The Authority has decided to make the 14 technical and non-controversial changes discussed in this consultation and 3 additional changes. These additional changes are the result of both submissions from this consultation and independent auditor review of both NZX and the system operator’s implementations of these Code provisions.

This decision paper concludes the Authority’s Code consultation process ahead of system go-live 1 November 2022.

Next steps

Following the publication of this decision, the Authority will finalise the consultation on the system operator’s policy statement with a decision expected in October 2022.

The transition to spot prices being calculated using the time-weighted average of published dispatch prices will happen at 00:00AM on 1 November 2022.

Forecast schedules that include trading periods from trading period 1 of 1 November will forecast prices based on RTP pricing outcomes for those periods from the 14:00 Price Response Schedule Long and Non-Response Schedule Long on 30 October 2022.

Dispatchable demand enhancements and dispatch notification participation will go-live April 2023.

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1.2 The Authority has consulted on two previous occasions on the real-time pricing (RTP) design. In August 2017, the Authority consulted on the proposal to adopt real-time prices, set by the system operator's dispatch schedule. After considering submissions and further design work, the Authority consulted again in March 2019 on the remaining elements of real-time pricing. The 2019 consultation discussed three further developments of the RTP implementation: Dispatch Notification participation, instantaneous reserve shortfall pricing and a process for reviewing the default scarcity prices.

1.3 This third consultation sought feedback on the final elements of the real-time pricing (RTP) Code amendment. While the policy design decisions had been finalised during the Authority's 2019 RTP consultation, it was acknowledged that further refinements would likely be necessary as the Authority and its partners implemented RTP over the following 3 years.

1.4 There were 5 significant changes to the RTP Code amendment and 14 minor, technical and non-controversial changes proposed in this latest consultation. The Authority has decided to proceed with all the proposed changes and a further 3 technical and non-controversial changes that were a result of submissions.

Significant changes to the RTP Code amendment

Reserve deficit values

1.5 The Authority has decided to revise the prices that would apply during an instantaneous reserve shortfall. This decision aligns with operational change recommendations from the reviews following the 9 August 2021 demand management event.

1.6 Table 1: Instantaneous reserve shortfall prices and quantities details the decided upon reserve scarcity prices and quantities.

Tranche	Fast instantaneous reserve contingent risk violation ($/**MW**/h)	Sustained instantaneous reserve contingent risk violation ($/**MW**/h)	Quantity (**MW**/h)
1	3,500	3,000	50
2	4,000	3,500	100
3	4,500	4,000	No limit

Table 1: Instantaneous reserve shortfall prices and quantities

1.7 The 2019 proposed SIR and FIR risk-violation values for CE reserve deficit are detailed in Table 2.

1.8 As the Authority noted in the 2019 real time pricing decision paper,[1] 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[2] and operational reviews of the 9 August 2021 demand management event.[3]

Table 2: 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

1.9 In considering these values, the Authority took note of both the operational reviews of the 9 August 2021 demand management event and submissions received on the 2019 RTP consultation. 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.

1.10 The revised reserve deficit prices will now prioritise an increased level of spinning reserve shortfall ahead of demand management while balancing the increased risk of an Extended Contingent event.

Pricing error claim process

1.11 The Authority has decided to amend the pricing error claim process proposed in its 2019 RTP consultation. Further development of the pricing systems and processes have highlighted the reduced role of the system operator's tools in the calculation of final prices.

1.12 The Authority has decided to retain the current deadline for submitting a pricing error claim of 12pm of the first business day following the publication of the interim price. Responsibility for investigating an alleged pricing error will now fall on the Clearing Manager. The Authority will retain the final decision as to whether to uphold or decline the pricing error claim following the clearing manager's investigation.

1.13 The Authority has also decided to clarify the definition of a pricing error to specify the circumstances under which final prices can be considered in error. Prices can only be considered in error if there was an error made in the calculation process performed by the clearing manager.

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

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

[3] 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/

Real-time price calculation under a scarcity pricing situation

1.14 The Authority has decided to add a new schedule to the Code that describes how scarcity pricing will be implemented in the real-time dispatch (RTD) schedule. Additional changes to Code clause 13.69B have been made to better reflect the design decisions made for the RTD schedule under a scarcity pricing situation.

Dispatchable demand enhancements

1.15 The Authority has decided to amend the Code to reflect proposed enhancements to the Dispatchable demand regime.

1.16 When calculating a dispatch solution, the system operator's market system 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. 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.

1.17 To manage this risk, the Authority has decided 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, the system operator will only be able to dispatch the load in increments of whole dispatchable demand bid tranches.

1.18 The Authority has decided to add a new entry field in Schedule 13.1, Form 6 to ensure interruptible load offers and dispatchable demand bids are co-optimised.

1.19 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.

1.20 The addition of a new field in Schedule 13.1 Form 6 for interruptible load offers will 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.

1.21 These enhancements will allow the scheduling and dispatch of dispatchable demand to better reflect the operational characteristics of the physical plant.

Pricing publication when the system operator's primary modelling system is unavailable

1.22 The Authority has decided to amend the Code to describe the system operator's change in obligations to produce dispatch prices when their primary modelling system is unavailable.

1.23 The system operator is obligated to publish a price to WITS[4] when a dispatch schedule is implemented. In the situation where the market system is unavailable (e.g. is on a planned outage or experiencing technical issues) the system operator utilises Stand-alone Dispatch (SAD) to produce dispatch instructions.

1.24 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 under these circumstances, but the Code was not drafted to permit it.

1.25 The Authority has decided to introduce a new clause, Clause 13.72A, to account for the circumstances 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.

Technical and non-controversial changes

1.26 The Authority has decided to make the 14 technical and non-controversial changes discussed in the third consultation and 3 additional technical and non-controversial changes. These 3 additional changes are the result of both submissions from this consultation and independent auditor review of both NZX and the system operator's implementations of these Code provisions.

The Authority decided to amend the Code in 2019

1.27 This third consultation builds on previous consultations to implement the objectives of the RTP proposal from the Authority's 2017 and 2019 consultations. The 2019 consultation finalised the policy design of the RTP implementation while acknowledging that some details would require further consultation prior to go-live.

1.28 The Code amendment attached as Appendix A implements RTP by:

(a) Changing the calculation of dispatch prices to better reflect the actions taken in real time to manage the supply of electricity, including actions taken during times of reserve and energy shortfall,

(b) Changing the calculation of settlement prices to incorporate those dispatch prices and provide better price certainty for participants,

(c) Enhancing the spot market participation options for demand side and small-scale aggregated resources through the introduction of Dispatch Notification Load and Generation (DNL and DNG respectively) and enhancements to the existing Dispatchable Demand regime.

1.29 This decision paper concludes the Authority's Code consultation process ahead of the RTP system go-live on 1 November 2022.

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

2 Background to the Authority's decision

Real-time pricing proposal consultation

2.1 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.[5]

2.2 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.

Proposal for the remaining elements of real-time pricing consultation

2.3 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.[6]

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

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

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

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

2.5 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.

2.6 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.

2.7 The Authority 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

2.8 The Authority 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). The Authority proposed this review should be at least once every five years.

2.9 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.[7]

2.10 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

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

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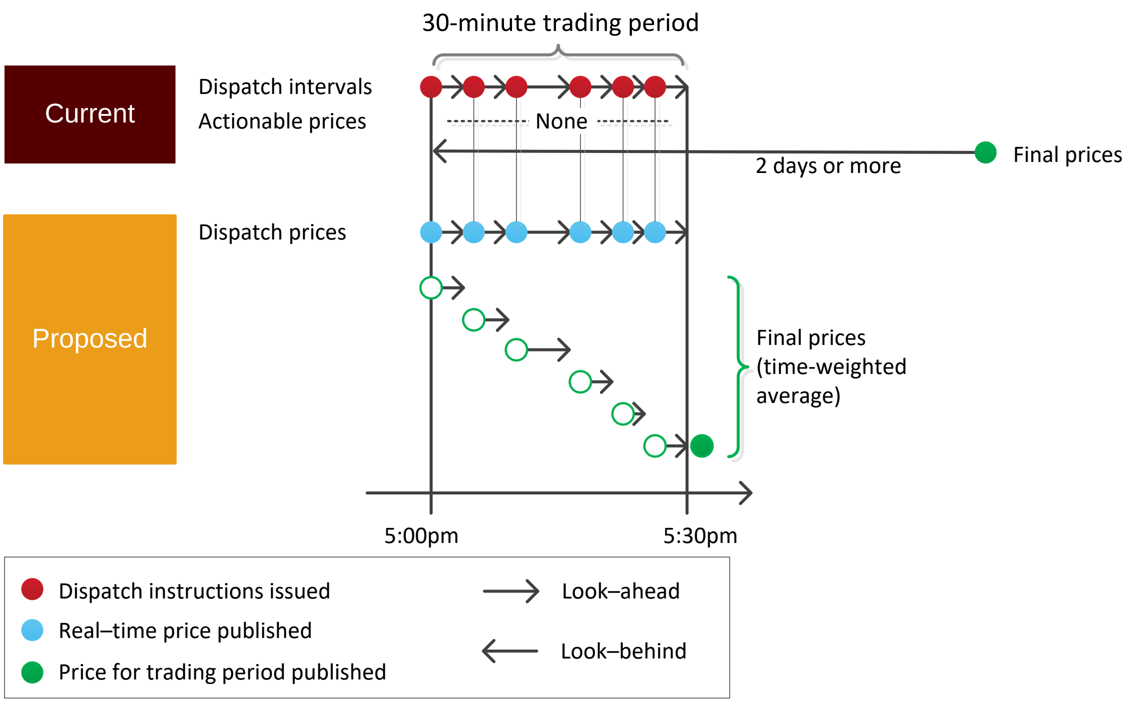
[7] Reference: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/decision-to-implement-rtp/

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

2.11 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'

2.12 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

Final elements of real-time pricing consultation

2.13 In the June 2019 decision paper, the Authority indicated that a final consultation on the RTP Code amendment would take place nearer the implementation date for the system changes.

2.14 The implementation of the system changes has highlighted areas of the 2019 Code amendment that needed refinement to better reflect the practicalities of moving to real-time pricing.

2.15 There were 5 significant changes to the RTP Code amendment and 14 minor, technical and non-controversial changes proposed in this latest consultation. The Authority has decided to proceed with all the proposed changes and a further 3 technical and non-controversial changes that were a result of submissions.

Significant Changes to the RTP Code amendment

Reserve deficit values

2.16 The Authority has decided to revise the prices that would apply during an instantaneous reserve shortfall. This decision aligns with operational change recommendations from the reviews following the 9 August 2021 demand management event. The revised reserve deficit prices will now prioritise an increased level of spinning reserve shortfall ahead of demand management while balancing the increased risk of an Extended Contingent event.

Pricing error claim process

2.17 The Authority has decided to amend the pricing error claim process proposed in its 2019 RTP consultation. Further development of the pricing systems and processes have highlighted the reduced role of the system operator's tools in the calculation of final prices. Responsibility for investigating an alleged pricing error will now fall on the Clearing Manager.

2.18 The Authority has also decided to clarify the definition of a pricing error to specify the circumstances under which final prices can be considered in error.

Real-time price calculation under a scarcity pricing situation

2.19 The Authority has decided to add a new schedule to the Code that describes how scarcity pricing will be implemented in the real-time dispatch (RTD) schedule. Additional changes to Code clause 13.69B have been approved to better reflect the design decisions made for the RTD schedule under a scarcity pricing situation.

Dispatchable demand enhancements

2.20 The Authority has decided to amend the Code to reflect proposed enhancements to the Dispatchable demand regime. These enhancements will allow the scheduling and dispatch of dispatchable demand to better reflect the operational characteristics of the physical plant.

Pricing publication when the system operator's primary modelling system is unavailable

2.21 The Authority has decided to amend the Code to describe the system operator's change in obligations to produce dispatch prices when their primary modelling system is unavailable.

Technical and non-controversial changes

2.22 The Authority has decided to make the 14 technical and on-controversial changes discussed in the May 2022 consultation and 3 additional changes. These 3 additional changes are the result of both submissions from this consultation and independent auditor review of both NZX and the system operator's implementations of these Code provisions.

Clarification of the ownership of the modelling system for reconciliation purposes

2.23 As part of the May 2022 consultation, it was proposed that, in Clause 15.15, reference to the system operator was replaced with the WITS manager with respect to the provision of points of connection status information to the reconciliation manager. The proposed wording resulted in ambiguity as to the ownership of the modelling system referred to in subclauses 15.15(a)(i) and (ii).

2.24 To clarify that the modelling system referred to is the system operator's, the Authority has decided to amend the proposed clause 15.15 as highlighted below:

> ***15.15 Notice of points of connection subject to outages or alternative supply***
>
> *No later than 2 hours after publication of final prices for all trading periods in a consumption period,—*
>
> *(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 system operator's 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 system operator's modelling system.~~; and~~*
>
> *~~(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.~~*

Inclusion of energy scarcity pricing tranches in the objective function

2.25 Early design discussions considered the energy scarcity price tranches, described in clause 13.58AA(2) of the proposed amendment, as constraint violation prices and the Code amendment was drafted on this basis. The software development process has seen the implementation of these prices evolve into a mechanism more like demand bid tranches.

2.26 An audit review of the objective function described in Schedule 13.3 of the Code has highlighted the need to reflect this design decision in the objective function description.

2.27 The Authority has decided to amend the objective function description in Schedule 13.3 of the Code as highlighted below:

Schedule 13.3

…

8 the objective function

(1) The objective function of the modelling system is described mathematically as:

…

Where

….

BP_{ij} is the **bid** prices corresponding to price band *i* of the **bid** for **purchaser** *j* where the relevant **bid** prices used here are formed from a combination of the following, as appropriate to the schedule being calculated:

(a) **Nominated bids**

(b) The values assigned under clause 13.58AA(2)

…

Generators to give grid owner half-hour metering information

2.28 The implementation of dispatch notification generation (DNG) is intended to allow the aggregation of otherwise un-offered resources to be offered into the market. These resources are expected to fall within the current *excluded generator* definition under the Code. As such they would not be expected to provide generation metering information to the grid owner.

2.29 The Authority expects the current processes for metering information submission to the clearing manager to be unchanged for resources offered as part of DNG.

2.30 The current drafting of Clause 13.136 only excludes unoffered generation from having to provide metering information. This potentially places an additional obligation on DNG to provide metering information where no obligation currently exists. This runs counter to the intent of DNG to minimise the compliance and technical burden on DNG participants.

2.31 The Authority has decided to amend Clause 13.136 to exclude a dispatch notification generator from having to provide metering data to the grid owner:

13.136 Offered embedded generators to provide half-hour metering information

(1) Using an **approved system** or by written notice, each **generator** must give the relevant **grid owner half-hour metering information** under clause 13.138 in relation to **generating plant**—

(a) that injects **electricity** directly into a **local network** or an **embedded network**; or

(b) if the **meter** configuration is such that the **electricity** flows into a **local network** without first passing through a **grid injection point** or **grid exit point metering installation**.

(1A) For the purposes of subclause (1), the relevant **grid owner** is—

(a) in relation to a **generator** (other than an **embedded generator**), the **grid owner** of the **grid** to which the **generator's generation** is connected; and

(b) in relation to a **generator** that is an **embedded generator**, the **grid owner** of the **grid** to which the **local network** to which the **embedded generator** is directly or indirectly connected, is connected.

(2) To avoid doubt, subclause (1) does not apply in respect of—

(a) any **unoffered generation**; or ~~or~~

~~(b) **electricity** supplied from—~~

~~(i) *[Revoked]*~~

~~(ii) a **type B industrial co-generating station**.~~

(c) a **dispatch notification generator**

3 The amendment promotes the Authority's statutory objective

3.1 The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

3.2 As New Zealand's economy moves towards greater de-carbonisation and electrification and the government climate change targets encourage further renewable generation investments, the need for real-time cost reflective pricing that promotes demand side and distributed generation participation in the market becomes critical.

3.3 The Authority decided to amend the Code to implement the real-time pricing changes in the June 2019 decision paper. The regulatory statement from the 2019 decision paper is reproduced below for reference.

Regulatory impact statement from the Authority's June 2019 decision to implement RTP

The amendment promotes competition, reliability and efficiency

3.4 After considering all submissions on the Code amendment proposal, the Authority believes the final Code amendment will deliver long-term benefits to consumers, as set out as follows.

Spot prices will be more actionable

3.5 Spot prices will become more actionable. That is, they will 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 will be more resource efficient

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

3.7 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.

3.8 Spot prices that are more actionable and more resource efficient will promote all three limbs of our statutory objective through:

(a) greater competition among and between generators and consumers (via voluntary demand response or more participation in dispatch), especially when spot prices are high

(b) a more efficient level of reliability in the power system as the system operator could come to rely equally on dispatchable demand bids and generation offers

(c) a greater level of operational efficiency in the wholesale market as calculating spot prices will no longer require extensive manual intervention.

3.9 More actionable and reliable prices send clearer signals for efficient long-term investment. Improved price signals will remove barriers and promote uptake of new technologies and new business models. For example, clearer price signals during peak periods promote efficient investment in technologies like battery storage, smart appliances, or other forms of automated demand response. Investing in these technologies is currently constrained by calculating spot prices after the fact — RTP reduces the guesswork and improves investment certainty.

The amendment is consistent with the demand response principles

3.10 In June 2018, we published an updated version of the guiding regulatory principles that should apply to demand response initiatives. Although RTP is not a demand response initiative per se, we expect it will provide significant benefits in this area. Table 3 assesses RTP's design against the demand response principles.

3.11 Overall, we conclude RTP's design is consistent with the demand response principles.

Table 3: Testing RTP's design against the demand response principles

Guiding principle	Assessment
Best-possible incentives: incentives to undertake demand response should reflect the marginal benefit of that response to the electricity system. Any payment for providing demand response should be funded by those benefiting from that response.	✓ RTP will promote more efficient pricing outcomes for the reasons set out in paragraphs **Error! Reference source not found.** and **Error! Reference source not found.**. Dispatch-lite will make it easier for smaller-scale purchasers and generators to directly influence spot prices. Purchasers participating in the spot market would not receive a payment for providing demand response but would avoid paying spot prices that exceed their willingness-to-pay by reducing consumption.
Openness: demand response should be able to participate in market arrangements, wherever practical. Anybody should be allowed to provide demand response services, including consumers and their agents. Demand response initiatives should not unreasonably restrict the technologies used to provide that response.	✓ More actionable spot prices under RTP will make it easier for consumers to participate in the spot market and react to spot prices in an efficient way. RTP does not restrict the technologies consumers can use to provide demand response. Dispatch-lite should enable greater participation in the spot market.

Guiding principle	Assessment
Choice: consumers should be free to choose when, how much, and by what technology they are willing to provide demand response, considering the costs and rewards they face. Consumers should be free to contract with third parties to provide demand response on their behalf. Any party buying demand response services should also be free to choose who, when, and how it is provided to them.	✓ Demand-response capability may be offered into the energy and reserve markets under RTP, and consumers can choose the most valuable use. RTP also allows dispatchable demand and dispatch-lite bids. Under RTP consumers are free to contract with third parties to provide demand response on their behalf.
Transparency: arrangements for demand response should provide transparent information, enabling consumers and other parties to: (a) assess the potential value of offering demand response in its various forms (b) make sound decisions about offering and using demand response.	✓ RTP will improve transparency by providing more timely and actionable price signals to demand response providers. Participating in dispatch-lite will better reveal the intentions of smaller-scale purchasers and generators.

Source: Electricity Authority

The benefits of the proposal are greater than the costs

3.12 The Authority has assessed the economic benefits and costs of the amendment, as set out in our 2019 paper. We expect implementing RTP will deliver significant net economic benefit.

3.13 Consumers and generators that can alter their operations at short notice will have much more reliable price signals to act on. These signals can guide their decisions about when to consume or produce electricity — accurate price signals will also enable those processes to be fully automated. Even participants that need more time to react will benefit from real-time prices that are reliable. In contrast, participants currently need to wait at least two days before final prices are published.

3.14 We estimate implementing RTP will produce operational benefits with a present value of $62 million over 15 years in the base case. Those benefits are from avoided generation costs of $79 million, less additional demand response costs of $17 million.[8] Our analysis is based on quantitative and qualitative benefits from RTP in the following categories:

(a) more efficient levels of demand-response (industrial and commercial consumers)

[8] The demand response cost arises because the variable costs consumers incur by using less electricity in response to dispatch prices can exceed the variable operating cost of the peaking generator being displaced. However, these costs to consumers are outweighed by the capital costs saved by avoiding investing in that peaking generator in the first place. For full details of our assessment of costs and benefits, see Appendix G of our 2019 consultation paper.

(b) more efficient levels of demand-response (residential consumers)

(c) more efficient levels of reliability

(d) more efficient generation scheduling and dispatch

(e) more effective risk management

(f) increased overall market confidence.

3.15 Implementing RTP requires significant changes to the market systems. Some of the associated cost will be offset by savings to the pricing manager function. Participants may also incur some implementation costs. The present value of these combined costs is estimated to be $12 million.

3.16 Overall, we expect RTP will produce net benefits with a present value of $50 million over 15 years in the base case. We also estimate net benefits in the upper and lower cases of $95 million and $15 million, respectively.

3.17 Section 6 and Appendix G of our 2019 paper details our assessment of these costs and benefits. That information superseded the earlier description of costs and benefits in our 2017 consultation, accounting for submissions on our 2017 paper. The revised quantitative cost-benefit analysis (CBA) from our 2019 paper is available at https://www.ea.govt.nz/dmsdocument/24931-revised-rtp-cost-benefit-analysis-model.

3.18 In its submission on our 2019 paper, MEUG queried whether our CBA assumes the full benefit of increased demand response under RTP occurs in the first year. It suggested while there may be many 'early adopters', others will wait to see how RTP progresses before committing resources to demand response.

3.19 We agree that demand response will develop over time. However, generation investment decisions are made over a long timeframe, and require predictions about future demand peaks. For this reason, we expect potential generation investments will be deferred once RTP is announced (even before implementation). We therefore consider the timing of savings from demand response in our CBA (avoided investment in generation) is conservative but plausible. We have therefore not revised our CBA further.

The amendment is consistent with regulatory requirements

3.20 The Code amendment is consistent with the requirements of section 32(1) of the Electricity Industry Act 2010.

3.21 The amendment is also consistent with the Authority's Code amendment principles: it is lawful, and it will improve the reliability and efficiency of the electricity industry for the long-term benefit of consumers. The Authority has clearly identified an efficiency gain and has used a quantitative cost benefit analysis to assess long-term net benefits for consumers.

4 The Authority considered the following matters in making this decision

4.1 We received submissions on our May 2022 consultation paper from the 3 parties listed in Table 4. Submissions are available on our website at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c19187.

Table 4: List of submitters

Submitter	Category
Mercury	Generator / retailer
Meridian	Generator / retailer
Solar Zero	Other

Submitters supported the incorporating the final elements of the RTP Code amendment

4.2 We consulted on 22 questions regarding the final elements of the RTP Code amendment. Submitters were broadly supportive of all the proposed changes though some questions were raised on specific aspects of the RTP amendment. These questions are discussed in the following section of this paper.

Further questions raised by Meridian

The definition of a pricing error should also include situations where the wrong inputs have been used

4.3 The "incorrect inputs" part of the definition was struck through to reflect the move from the status quo where final prices are calculated using a new market schedule to the RTP system whereby final prices are a time weighted average of the dispatch prices – no further schedules are created by the market system.

4.4 Under the status quo, it is possible that inputs to the final pricing schedule could be missed when the data was collated in preparation for calculating the schedule. For example, changes made to a transmission constraint in real-time were not picked up resulting in incorrect power flows and pricing outcomes that didn't reflect the system conditions at the start of the trading period. This would be classed as a pricing error at the moment.

4.5 Under RTP, there is no separate final pricing schedule, the final price is calculated as a time weighted average of published dispatch prices. The Code has been drafted to specifically exclude incorrect inputs to the dispatch schedule being considered pricing errors. The only "inputs" to the final price at each pricing node are the published dispatch price and the length of time that price was effective during that trading period. The intent of the new definition of a pricing error claim is to ensure that if the clearing manager uses prices that it shouldn't have or in some way calculates the price at a node incorrectly, then the time weighted averaging can be corrected.

4.6 Any incorrect inputs used in producing the dispatch schedules, and the resulting dispatch prices, would be covered as a breach of the Code on the system operator's part.

Scarcity pricing in the real-time dispatch process could benefit from doing a side-by-side model run using 9 August data

4.7 As described in Clause 3(1) of schedule 13.3AA, the real-time operation of the RTP scarcity pricing mechanism relies upon a snapshot of the profile of expected demand for all available future 5-minute periods being stored at the point that the system operator instructs the electrical disconnection of demand. This information is not routinely stored at present and could not be reconstructed with any certainty. This ambiguity would mean that the results of an RTP settings-based re-run of the forecast and dispatch schedules could only be taken as indicative at best and may provide misleading results at worst.

4.8 Following the operational reviews of the events of 9 August 2021, the system operator has made significant changes to the way that it manages the use of discretionary load during a grid emergency. This means that the actions taken under any future event, and the resulting pricing outcomes, are likely to be very different to those that could be modelled based on the actions taken by parties on the night of 9 August 2021.

4.9 The Authority considers that any re-run of the 9 August 2021 demand management event using the RTP markets settings and original market data would not produce results reflective of the real-time management of an actual event, were it to happen following the implementation of RTP. On this basis, the effort spent in producing such a re-run would not be justified by the level of confidence those results could provide to market participants.

Other technical comments on the drafting

4.10 Meridian also provided comment on two drafting discrepancies noted in the consultations paper.

4.11 In paragraph 5.28, the Authority notes the need to add a cross reference to Code clause 13.58A in clause 13.69AA but no cross reference is evident in the draft of 13.69AA provided. The cross-referenced clause should have been listed as 13.58AA, as reflected in the drafting of clause 13.69AA.

4.12 Meridian correctly notes that Code clause 13.137A already exists in the current Code and is not a new clause, as noted in paragraph 11.1 of the consultation paper. This was a drafting error in the consultation paper.

Further questions raised by Solar Zero

Responses to specific consultation questions

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

4.14 It is not clear as to the rationale for the 30MW limit for dispatch notification and where it applies. Does it apply at a generating station, GXP, an island or nationally?

4.15 The 30MW upper size limit for dispatch notification participation applies to a single asset and is related to the **excluded generating stations** definition in Clause 8.21 of the Code. Generation assets with an export capacity of less than 30MW are excluded from a number of technical obligations, including the need to provide full market offers and indications information to the system operator, unless specifically required to by the system operator.

4.16 Further detail on the technical requirements and approval process for dispatch notification participation can be found in the system operator's Policy Statement.

4.17 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?

4.18 The consultation document and the proposed Code changes do not address a key issue - how to handle data from multiple sites.

4.19 The dispatch notification participation mechanism is not intended to change any aspect of the metering requirements for the reconciliation process.

4.20 The Authority will require metering data for the monthly compliance checks on dispatch notification participants. In the 2019 *remaining elements of real-time pricing* consultation, the Authority noted that this check would be made using monthly reconciliation data. In principle, any appropriate quality data source may be used verify compliance with dispatch notifications with agreement from the Authority.

4.21 The possible need for Code change or market development to support

4.22 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?

4.23 Dispatch notification should not be limited to dispatchable demand and should be extended to dispatchable distributed generation.

4.24 The provisions discussed in the 2019 *remaining elements of real-time pricing* consultation expanded dispatch notification participation to include generation (DNG). At that time, Dispatch Notification load (DNL) participation was effectively limited to retailers under the definition of a **Purchaser.** This would have prevented non-retailer third party providers from being able to participate, limiting competition and potential innovation in the provision of flexibility services.

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

4.26 We suggest that the EA prepare a high level vision/roadmap document that outlines its vision for the power system of the future.

4.27 The Authority has two workstreams in flight that are developing a view of how the wholesale market will transition to, and operate under, a 100% renewables future.

4.28 The first of these, the Future Security and Resilience (FSR) project, is working with the system operator to identify transition risks to the wholesale market. The FSR project has released a draft roadmap[9] of investigation work required to assess potential security and resilience risks and propose solutions.

4.29 The Authority's Market Development Advisory Group (MDAG) is investigating how price discovery in the wholesale electricity market might operate once the New Zealand generation mix reaches 100% renewable[10]. The recommendations resulting from this work will be considered as part of the Authority's work program, in conjunction with the FSR work program.

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[9] https://www.ea.govt.nz/development/work-programme/risk-management/future-security-and-resilience-project/events/

[10] https://www.ea.govt.nz/development/advisory-technical-groups/mdag/mdag-price-discovery-project/

5 Next steps

5.1 The inclusion of the RTP pricing enhancements will be applied to all forecast schedules for trading periods from midnight (TP1) 1 November 2022

5.2 Spot market settlement on time-weighted average dispatch prices will go-live on 1 November 2022.

5.3 Dispatchable Demand and Dispatch Notification enhancements are scheduled for release April 2023

Appendix A Approved Code amendment