Real-time pricing proposal

Consultation paper

Submissions close: 26 September 2017

1 August 2017

Executive summary

We are seeking views on our proposal to determine and publish final prices for the spot market in real-time—we call this 'real-time pricing' (RTP). RTP would provide parties with timely and reliable information on the prices they will pay or receive for their spot market transactions.

There is a case for changing the way spot prices are calculated and published

Spot prices for energy and instantaneous reserve are determined in the wholesale electricity market. At present, the spot prices published in real-time are only indicative. The pricing manager publishes final prices for any given day at least two days after real-time. These indicative prices are normally a sound guide to final prices, but large differences can arise—especially when the system is under stress. This makes spot prices uncertain, making it harder for parties to make efficient real-time decisions about their consumption and generation.

In 2016, we published an information paper that proposed moving to RTP, presenting four options for people to consider. We preferred the dispatch-based option, with an estimated net benefit of $58 million. Our proposal received broad support, with submitters recognising the net benefits, so we undertook to develop a detailed dispatch-based RTP option for consultation.

This paper fulfils that commitment and provides:

a. details of our proposed dispatch-based RTP arrangements

b. how a transition to RTP might occur

c. the regulatory impact statement for the proposal, including an updated assessment of the benefits and costs

d. amendments to the Code required to introduce RTP.

We propose spot prices would be set by the system operator's dispatch process in real-time

We propose to adopt real-time prices set by the dispatch schedule the system operator uses to issue dispatch instructions. This typically occurs every five minutes or so. We call these 'dispatch prices', because they are derived from the dispatch process in real-time. We propose the final price at a node for each trading period would be the time-weighted average of these dispatch prices. These prices would be published in real-time, as they are created.

An important part of the move to adopt real-time pricing is that all load at every node would have a price. These prices would be set either by bids for load quantities submitted by purchasers, or by default scarcity values assigned to the rest of the load. We propose using scarcity values in a range between $10,000/MWh to $20,000/MWh. The system operator would issue a grid emergency notice if load assigned a default scarcity value is not fully scheduled; ie, if the dispatch schedule indicates some or all of this load must be curtailed. As a result, the current scarcity pricing provisions would no longer be needed and would be removed.

Because all load would have a price assigned, the scheduling, pricing, and dispatch processes would be aligned—the system would always be able to find a solution in real-time. Dispatch prices would be set either by the offers of generators or by the bids of purchasers, including load assigned default scarcity values. This in turn means there would no longer be any 'infeasibilities' or other provisional price situations, so the current provisional pricing process would no longer be needed. Participants would be able to trust and respond to the prices they see in real-time. Similarly, we also propose that shortages of instantaneous reserve would be priced slightly below the lowest scarcity pricing value ($10,000/MWh).

We want to encourage consumers (or their agents) to directly participate in the spot market. To help achieve this aim, we are proposing a new form of dispatchable demand for small bid purchasers. We call this 'dispatch-lite'. Parties approved for dispatch-lite would have lighter compliance obligations, but would not be eligible for constrained on and off payments. Existing dispatchable demand would be dispatched from the dispatch schedule rather than the non-response schedule (NRS) as it is today. Dispatch-lite would be dispatched from the dispatch schedule in the same way. Because prices would be set by the dispatch process, dispatchable demand purchasers would no longer need to provide metering data to the pricing manager the next day. Dispatchable demand would continue to be eligible for constrained on and off payments. Both dispatchable demand and dispatch-lite could set spot prices.

If it is not adopted separately before RTP is implemented, we propose allowing participants to rebid or reoffer within a trading period, provided they meet existing limitations (only for bona fide physical reasons or a grid emergency). This would enable the dispatch process to set prices that best reflect the actions the system operator takes to manage the power system.

To guard against material pricing errors, we propose retaining a modified form of the interim pricing period. We propose the system operator would manage the process to assess any claim of a material pricing error.

This RTP design would make the pricing process much simpler, and most of the pricing manager's functions would cease to exist. We propose the clearing manager takes over the remaining functions: calculating and publishing interim prices from dispatch prices, managing the change of status from interim to final prices, and maintaining the database of prices.

Our proposed RTP design requires significant changes to Part 13 of the Electricity Industry Participation Code 2010 (Code). Many of these changes are to remove the current processes that determine prices looking backward, leading to the delay and uncertainty in final prices. We have drawn heavily on the experience of other electricity markets overseas that use RTP in developing these changes.

We have updated our estimate of benefits and costs

Aligning final prices with the dispatch process the system operator uses to securely manage the power system in real-time means that:

a. participants would have information close to real-time about the prices they will pay or receive for the energy and reserves they buy or sell—prices will be more certain

b. final prices would be more efficient by better reflecting actual system conditions, because they will be calculated from the prices set by the dispatch process

c. the pricing process would be simpler, and easier for participants to understand

d. generator offers or purchaser bids on the margin would set spot prices.

Forecast schedules would also be made more consistent with final pricing (eg, assigning default scarcity values to load not already bid by purchasers). This means that forecast, real-time (dispatch), and final prices would be closely aligned, unless there is a real physical difference between forecast and actual conditions.

We expect RTP to unlock significant benefits. Consumers and generators that can alter their operations at short notice would have much more reliable price signals to guide their decisions.[1] Further, even participants that need more time to react will benefit from real-time prices that are reliable. In contrast, participants currently need to wait up to two days before final prices are published.

Better integrating dispatchable demand and introducing a 'dispatch-lite' option should further facilitate efficient demand response by consumers.

We think RTP would help 'future proof' the electricity market. New technologies like battery storage and smart appliances make it easier for parties to react to prices, but they are unable to fully capture this benefit if prices are calculated after the fact as they are today.

We estimate implementing RTP would produce total benefits with a present value of $77 million over 15 years in the base case. 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)

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.

Implementing RTP would require significant changes to the market systems. The system operator has estimated these changes will cost between $7.6 million to $11.0 million.[2] The clearing manager and financial transmission rights manager have identified additional costs of $1.3 million to $1.8 million costs to their systems. There would also be offsetting savings of $1.1 million to $2.7 million (in present values) from discontinuing the pricing manager functions. We do not expect any material net increase in ongoing costs for participants.

Overall, we expect RTP to produce net benefits of $53 million in the base case, with upper and lower case estimates of $114 million and $19 million.

Next steps and timetable

At this point we are seeking stakeholder views on our proposal to adopt RTP and the draft amendments to the Code. We will consider submissions and confirm or alter the elements detailed in this paper.

If the Authority decides to implement RTP, we expect it will take around four years after that point to complete the transition.

1 Gate closure rules will continue to apply to relevant parties under RTP. Gate closure is now one hour before the relevant trading period, as of 29 June 2017.

2 Although not strictly needed to implement RTP, we also propose system changes to enable use of ION meter data, and bid/offer revisions within trading periods. These changes have an additional cost of approximately $0.2 million.

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What this consultation paper is about

1.1 Spot prices for energy and instantaneous reserve are determined in the wholesale electricity market. At present, the spot prices published in real-time are only indicative. The pricing manager publishes final prices for any given day at least two days later. These indicative prices are normally a sound guide to final prices, but large differences can arise—especially when the system is under stress. This makes spot prices uncertain, making it harder for parties to make efficient real-time decisions about their consumption and generation.

1.2 In 2016 we published an information paper that proposed moving to RTP, presenting four options for people to consider.[3] We preferred the dispatch-based option, with an estimated net benefit of $58 million. Our proposal received broad support, with submitters recognising the net benefits, so we undertook to develop a detailed dispatch-based RTP option for consultation.

1.3 This paper fulfils that commitment and provides:

(a) details of our proposed dispatch-based RTP arrangements

(b) how a transition to RTP might occur

(c) the regulatory impact statement for the proposal, including an updated assessment of the benefits and costs

(d) amendments to the Code required to introduce RTP.

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How to make a submission

1.5 The Authority invites you to make a submission on this paper.

1.6 Please note the Authority wants to publish all submissions it receives. If you consider that it should not publish any part of your submission, please indicate which part, set out the reasons why you consider the Authority should not publish it, and provide a version of your submission that the Authority can publish (if it agrees not to publish your full submission).

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

1.8 However, please note that all submissions the Authority receives, including any parts that it may not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release them unless good reason existed under the Official Information Act to withhold them. The Authority would normally consult with you before releasing any material that you said should not be published.

1.9 The Authority would prefer to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to

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3 See our May 2016 consultation paper at http://www.ea.govt.nz/dmsdocument/20599, and our August 2016 decision paper at http://www.ea.govt.nz/dmsdocument/21128.

submissions@ea.govt.nz with 'Consultation Paper—real-time pricing proposal' in the subject line.

1.10 Do not send hard copies of submissions to the Authority unless it is not possible to do so electronically. If you cannot or do not wish to send your submission electronically, you should post one hard copy of the submission to either of the addresses provided below or you can fax it to 04 460 8879. You can call 04 460 8860 if you have any questions.

Postal address

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Physical address

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Deadline for delivering a submission

1.11 You should deliver your submission by email or otherwise so it is received by **5pm** on **26 September 2017**. Please note that late submissions are unlikely to be considered.

1.12 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

2 We want spot prices to be more actionable and more efficient

Spot prices are currently published with lag of two days or more

2.1 Spot prices are currently published at least two business days after real-time, as illustrated in Figure 1. These prices determine payments between buyers and sellers for spot market sales and settle electricity risk management contracts, such as futures contracts.

Indicative spot prices are unreliable for making decisions in real-time

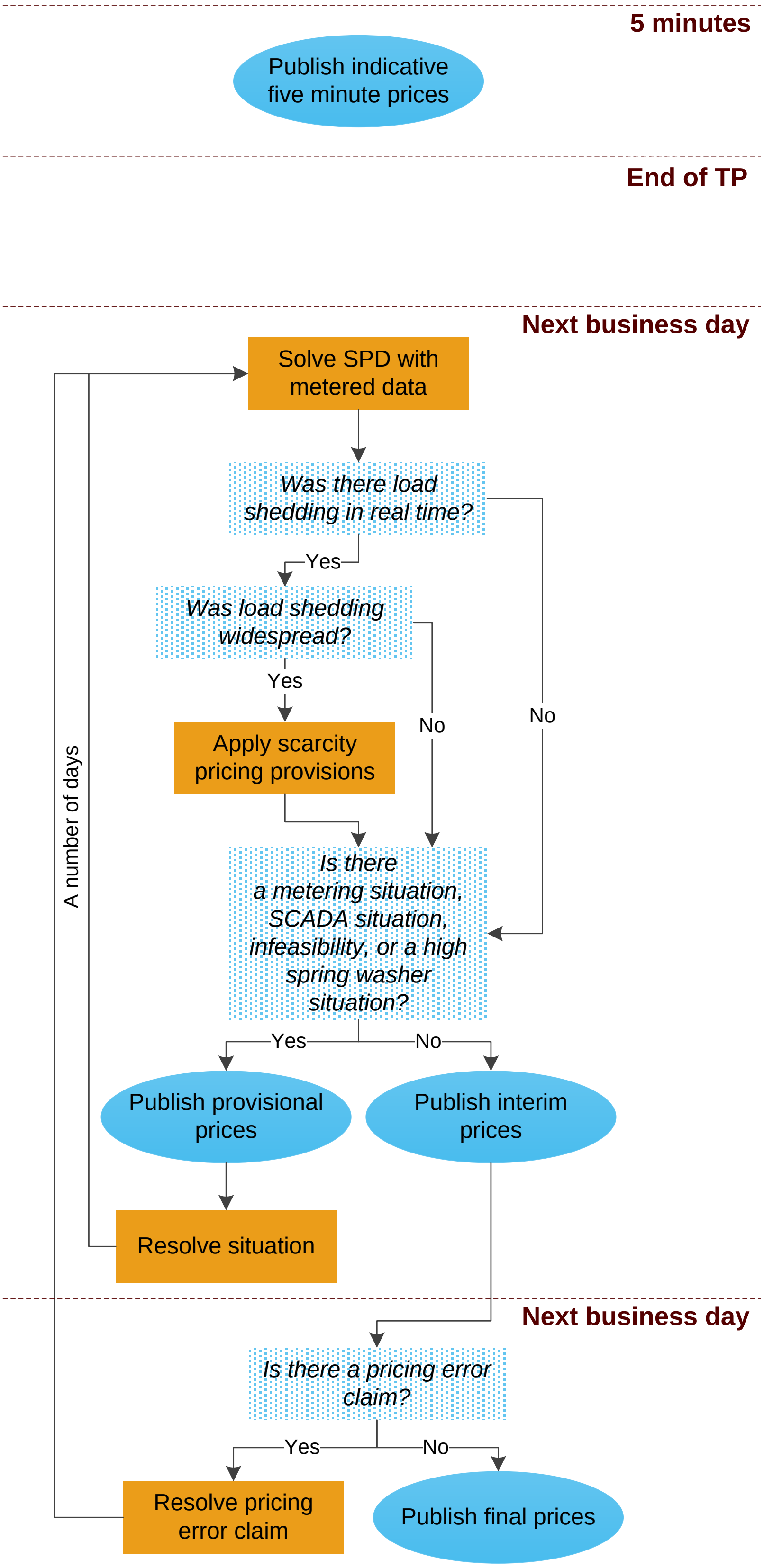
2.2 Because prices become final only after at least a two-day time lag, parties making operational decisions must instead rely on the indicative prices published in or close to real-time (called ‘five-minute prices’).

2.3 These indicative five-minute prices are normally a sound guide to likely spot prices. However, sometimes they can be very poor predictors, with differences to the final price over $1,000/MWh on occasion. This is most likely to occur when the power system is under stress—when access to reliable price signals matters most. Further, the Code (clause 13.88) requires the system operator to make only reasonable endeavours to publish existing five-minute prices if the information is available to calculate them. This means these indicative prices are not always available.

2.4 The original rationale for the time lag in finalising prices was to provide an opportunity to address ‘anomalies’ and material errors in interim prices, such as providing the most accurate metering data. While such situations can still occur, arrangements are now much more robust than when the spot market commenced two decades ago.

2.5 In any case, it is not clear that calculating prices based on information after the fact necessarily makes them more appropriate for settlement purposes. Prices based on real-time conditions are arguably more appropriate, because those are the prices that participants typically use to make their short-term decisions.

Figure 1: Final prices are currently published at least two days later



Source: Electricity Authority

The current arrangements undermine efficiency

2.6 Current arrangements make it harder for participants to make good decisions. Participants do not know whether five-minute prices are accurate—especially when the system is under stress. This uncertainty compromises efficiency in three ways:

(a) It compromises efficient levels of demand-side participation. Consumers may decide to use power based on five-minute prices, but later find the final price is more than they were willing to pay (ie, exceeds the level at which they would have preferred to reduce consumption). Likewise, they may reduce consumption based on five-minute prices, but later regret that if final prices turn out to be lower than expected.

(b) It compromises efficient generating decisions because generators have poorer information for short-term planning. This is especially important for generators facing important short-term decisions such as whether to get a unit ready for operation, and for smaller generators that are self-dispatched.[4] For example, spot prices may turn out to be lower than a generator's willingness to generate.

(c) It compromises efficient trading of electricity risk management contracts. Uncertainty about the likelihood and magnitude of occasional price spikes complicates risk management decisions and makes it less likely that risks are borne by the parties best able to manage them.

2.7 The existing arrangements can also compromise efficiency when participants make decisions to retain and invest in new assets:

(a) Prices may not fully reflect some actions that degrade normal security and have an associated cost. For example, emergency load shedding directed by the system operator under Part 8 of the Code will lower demand, which then reduces spot prices.[5] Under the current scarcity pricing rules that came into effect on 1 June 2013, spot prices are not adjusted to reflect the costs of emergency load shedding unless there is an island-wide shortage—an event expected to be very rare.[6]

(b) There are provisions in the Code to adjust spot prices after the fact in some circumstances (eg, to resolve 'infeasibilities'), making them even more uncertain. Participants may consider these adjustments tend to reduce prices when the system is under stress, given that prices are determined days after real-time. By then, the imperative to offer resources immediately has passed.

2.8 The current arrangements also hinder innovation. Technology change (such as batteries or appliances with communication devices) is making it easier for parties to respond to changing system conditions. However, such parties may only be able to capture the full potential of this innovation if prices are recalculated in response to changing system conditions.

4 Generators that are self-dispatched have discretion to alter their level of output in real-time.

5 Emergency load shedding is provided under Technical Code B of Schedule 8.3 of the Code.

6 An explanation of scarcity pricing and the values assigned during scarcity events is available on the Authority's website at http://www.ea.govt.nz/operations/wholesale/spot-pricing/scarcity-pricing/.

2.9 Finally, under existing arrangements, a large spike in spot prices could occur without being signalled in any forecast prices. This could trigger a major loss of market confidence.

New Zealand's arrangements are unusual

2.10 New Zealand's arrangements for determining and publishing spot prices are unusual. In other electricity markets, spot prices are determined and published just before or after real-time.[7] This means participants in these markets have greater confidence in spot prices and the financial consequences of their decisions.

2.11 Having different arrangements to other markets is not necessarily a bad thing. However, there is no clear reason why New Zealand's final pricing should be different.

3 The elements of the proposed real-time pricing design

3.1 This section describes our proposed RTP design. The system operator sets out further detail in its TAS060 report, attached as Appendix B. The full form of the proposed Code amendments for the RTP design is set out in Appendix C.

Our design philosophy is to align prices with real-time dispatch

3.2 The basic philosophy behind the design is that final pricing should align with the system operator's real-time dispatch process as far as possible. The system operator would continue to focus on operating the system securely. This alignment would mean that:

(a) participants have information close to real-time about the prices they will pay or receive for the energy and reserves they buy or sell—prices will be more certain

(b) spot prices are derived from the marginal generator offer or dispatchable demand bid in each 'dispatch interval' (the length of time between issuing a set of dispatch instructions and replacing them with fresh instructions)

(c) prices reflect the actions taken to balance supply and demand on the power system.

3.3 Our proposal seeks to achieve these goals while minimising complexity and the cost of changing market systems. Nevertheless, the RTP proposal will require extensive changes and we discuss these below.

RTPs would be derived from the system operator's dispatch process

3.4 The system operator currently calculates dispatch schedules at five-minute intervals, or more often if required. It uses this information to create dispatch instructions, but no price information from the schedules is currently published close to real-time. To be clear, these dispatch schedules are separate from the indicative five-minute prices calculated after the fact.

3.5 We propose dispatch schedules would generate 'dispatch prices'. These dispatch prices would reflect the interaction of offered generation and demand bids in real-time. As we discuss from paragraph 3.14, all demand quantities would have an associated bid price. These prices would be specified by the bids of the relevant purchaser, or by the system operator assigning default scarcity values.

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[7] The Authority has not identified any other electricity market where final prices are published with a sizeable delay after real-time.

3.6 Dispatch prices will be set either by the offers of generators or by the bids of purchasers, including load assigned default scarcity values. This in turn means ‘infeasibilities’ and the other provisional price situations would no longer occur under RTP (ie, SCADA, metering, and high spring washer situations).[8] The current provisional pricing process will therefore no longer be needed. These situations are the times when price certainty is often particularly important for participants.

3.7 Each new set of dispatch instructions the system operator issues would generate new dispatch prices, and the Wholesale Information and Trading System (WITS) would immediately publish these prices.

Q1. Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.

The spot price for a trading period would be the time-weighted average of dispatch prices

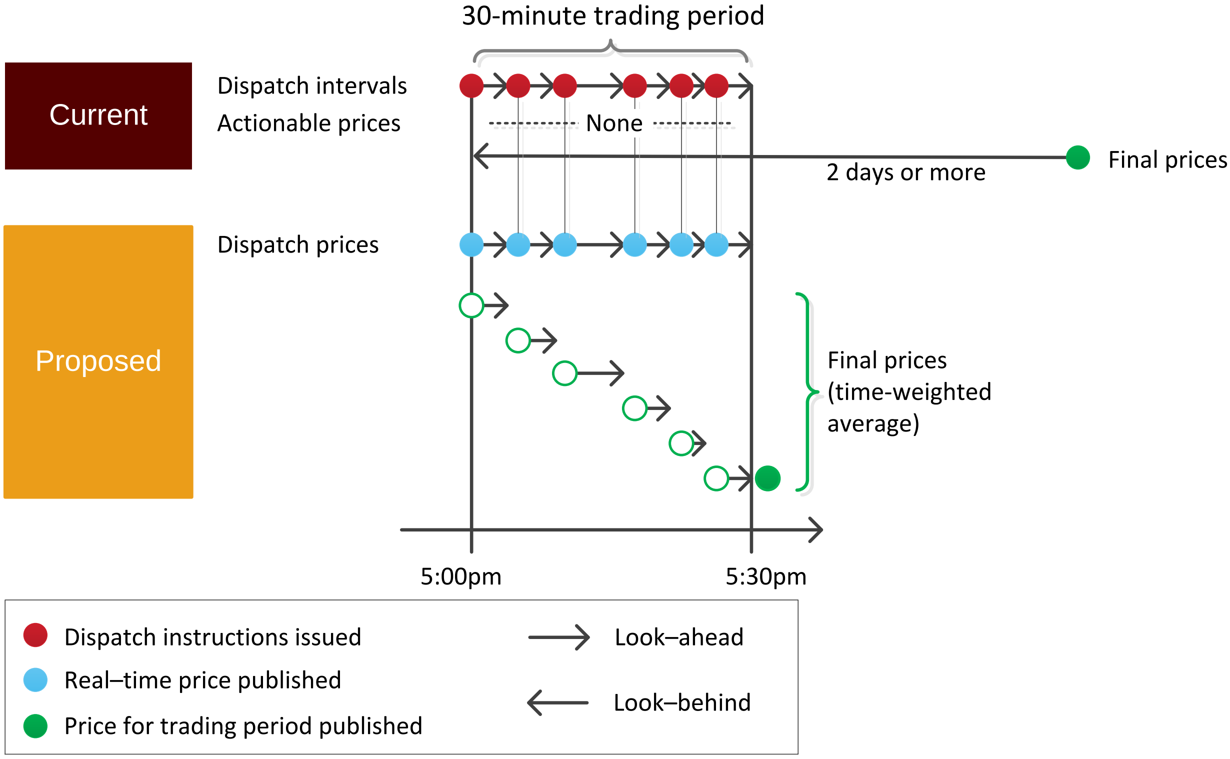
3.8 Dispatch prices would be calculated for all grid nodes in each dispatch interval.[9] These intervals normally last around five minutes, but can be shorter or longer depending on when the system operator decides fresh dispatch instructions are needed. Fresh instructions are always issued at the start of each 30-minute trading period.

3.9 Making each trading period the same length as individual dispatch intervals would require extensive modification to wholesale metering and settlement systems. We therefore propose to continue calculating final spot prices for each 30-minute trading period, as shown in Figure 2. This means spot prices for each trading period need to be calculated from the relevant dispatch prices issued in that period.

8 High spring washer situations are discussed further in paragraph 3.60.

9 Nodes refer to either grid exit points (GXPs) or grid injection points (GIPs).

Figure 2: The current pricing process compared with the RTP proposal



Source: Electricity Authority

3.10 We considered four options to calculate these spot prices:

(a) *The median value of dispatch prices at a node during a trading period*. The median is a good measure when the extremes of a statistical distribution are less important than the middle. This isn't the case for electricity pricing, as extremely low and high prices are important. Using the median could also result in some dispatch prices within a trading period having no effect on the spot price. This could lead to undesirable outcomes, such as behaviour in the last dispatch interval of a trading period having no effect on the spot price.

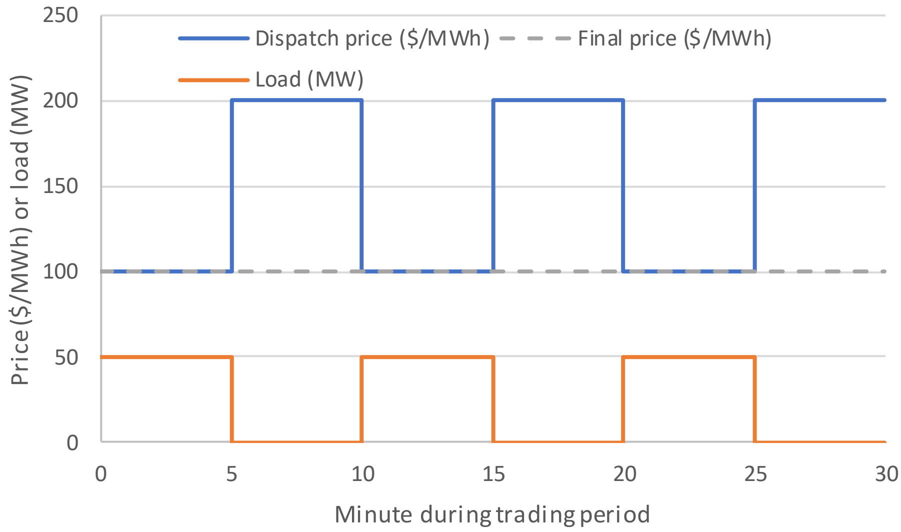
(b) *Arithmetic mean of dispatch prices at a node during a trading period*. This would capture the effect of low and high dispatch prices, but would not take account of how long each price applied. This is clearly undesirable, as dispatch prices which apply for longer time intervals should carry more influence, and vice versa.

(c) *Volume-weighted mean of dispatch prices at each node during a trading period*.

(i) Volume weighting would multiply each dispatch price by the load or generation at the node in each dispatch interval. These values would be summed for each trading period, and that sum divided by the total demand or generation over the trading period at that node.

(ii) For example, Figure 3 shows a highly responsive load (orange line). This illustration assumes uniform 5-minute dispatch intervals, but the same principles apply with variable length intervals. The single consumer at the node consumes 50 MW when the dispatch price is \$100/MWh, and no power when the price is \$200/MWh. With a volume-weighted mean, the consumer faces a spot price for the trading period of $100/MWh. In contrast, with a time-weighted mean the spot price would be $150/MWh.[10]

Figure 3: Illustrative example of volume-weighted prices (single responsive consumer node)

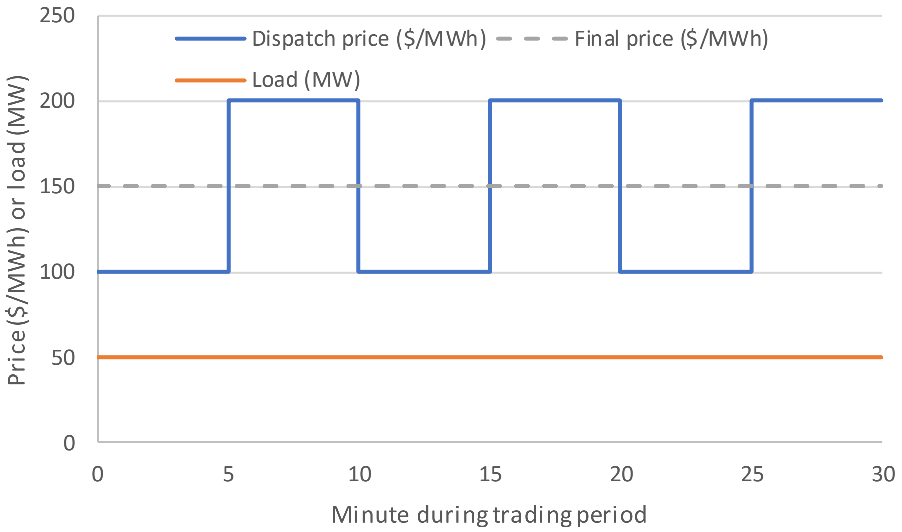


Source: Electricity Authority

(iii) This approach would provide a closer match between spot prices and the marginal value of electricity consumed/generated at each node because it would account for effects within trading periods. However, it would mean that spot prices across nodes would vary according to differences in load/generation profiles as well as locational effects. For example, the final price at the node in Figure 3 would be $100/MWh under volume-weighting. An adjacent node could see the same dispatch prices, but if it had a flat load profile would have a final price of $150/MWh as shown in Figure 4. In this example, the nodal price difference between nodes would be entirely due to differences in their load profiles, rather than differences in location factor.

10 This example is highly simplified for illustrative purposes. In reality, consumers are unlikely to react instantaneously to changes in price and be either on or off.

Figure 4: Illustrative example of volume-weighted prices (single flat load consumer node)

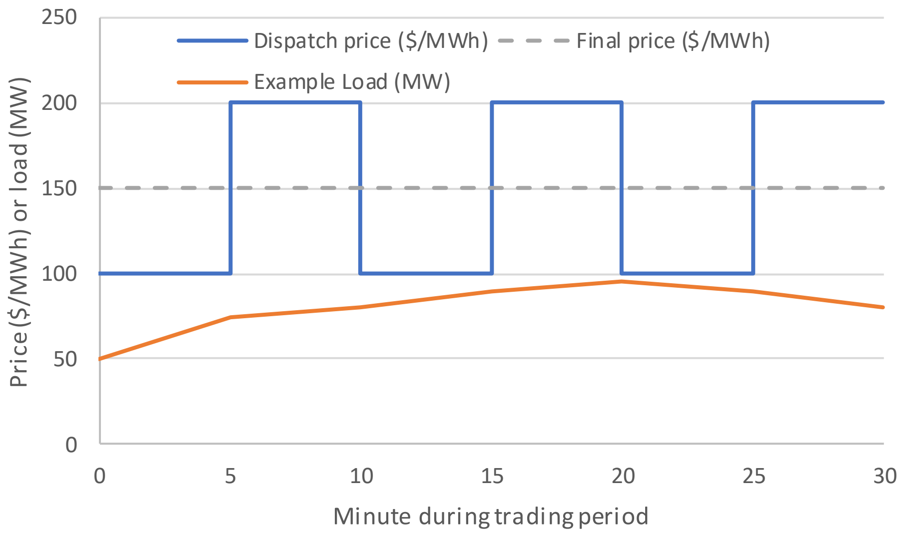


Source: Electricity Authority

(iv) While volume-weighted prices would arguably better reflect the value of electricity *at each individual node*, the final prices at some nodes can have significant wider implications. In particular, risk management contracts (such as futures, contracts for differences, and financial transmission rights) are generally priced relative to ‘reference nodes’, such as Benmore, Islington, and Otahuhu. At present, final prices at these nodes are generally representative of those applicable in the surrounding region. They are therefore suitable anchor points for pricing risk management contracts. That would not necessarily be the case with volume-weighting. The prices at these nodes would be directly influenced by the individual load and generation profiles. These could differ materially from the profiles at other nodes in the region, making the chosen nodes less suitable as reference points. This issue could be addressed by altering the reference points in risk management contracts, but that would require lead-time.

(d) *Time-weighted mean of dispatch prices at a node during a trading period*. This would capture the effect of all dispatch prices in a trading period, and their relative duration. It is also relatively straightforward to compute based on available data sources. Based on analysis to date, we do not expect time-weighting to require any material changes to other aspects of the electricity market, such as financial transmission rights or futures contracts. Figure 5 shows the final price calculated with time-weighted averaging. Note the load profile at the node has no effect on the final price.

Figure 5: Illustrative example of time-weighted prices



Source: Electricity Authority

3.11 After considering the options, we propose the spot price at each node will be the time-weighted average of dispatch prices at that node for the trading period.[11] This balances the desire to calculate spot prices in a way that reflects the value of electricity over each 30-minute period, while avoiding significant additional implementation costs or impacts (such as to hedges or financial transmission rights). Prices for reserve would be calculated the same way.

3.12 We recognise that a time-weighted average will not capture all of the within-period efficiency gains that are potentially available. However, we believe the gains of the time-weighted option will still be material relative to the status quo. It will also be possible to change the way spot prices are produced at a later point if desired; eg, by shortening the trading period or adopting volume-weighting of dispatch prices over 30-minute periods.

Q2. Do you agree with using the time-weighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.

The clearing manager would take over the residual functions of the pricing manager

3.13 The pricing manager currently undertakes the ex-post calculations for spot prices, and most of this function would cease with RTP. However, there are three residual functions of the pricing manager, which we propose to allocate as follows:

(a) Calculating interim prices—this would be an automated process, as described in paragraph 3.11. We propose the clearing manager undertake this function.

(b) Changing the status of prices from interim to final—this would be an automated process as described in the draft Code amendment (see clauses 13.182A and

11 More precisely, the term 'time-weighted average' refers to a time-weighted mean.

13.182B in Appendix C) unless a pricing error or undesirable trading situation is claimed. We propose the clearing manager undertake this function.

(c) Addressing material pricing errors—as discussed in paragraph 3.96, a safeguard mechanism would be retained to address any material pricing errors. We propose the system operator manage this process.

Q3.	**Do you agree with disestablishing the pricing manager and allocating residual functions to other parties? If not, please explain your reasoning.**

All demand that is not the subject of a bid would be assigned scarcity pricing values

3.14 We propose assigning default scarcity pricing values to all forecast demand not bid by purchasers. Under current arrangements, a shortage of generation will lead to emergency load shedding. This can trigger the scarcity pricing provisions, adjusting final prices if the system operator instructs widespread load shedding in one or both islands. In those events, spot prices are scaled (if needed) so that the generation-weighted average price is at least $10,000/MWh and no greater than $20,000/MWh, measured over the relevant island.

3.15 In combination, these boundaries for scarcity prices give improved revenue certainty for providers of last-resort resources (generation and demand response). It also gives more assurance to wholesale purchasers that spot prices during emergency load shedding will not settle well above the level expected in a workably competitive market. Scarcity pricing increases incentives for consumers and net-retailers to enter into hedge arrangements with providers of last-resort resources, increasing competition to provide those resources. It also provides an important incentive for purchasers to bid their demand directly into the spot market.

3.16 However, this ex-post adjustment mechanism means there is considerable uncertainty in real-time over whether scarcity pricing will be triggered. This uncertainty is undesirable when the system is under stress. In those situations, we want participants to have clear and actionable price signals to create strong incentives to maximise generation and reduce discretionary demand.

3.17 We propose to achieve this by assigning default scarcity values to all forecast demand that is not bid by a purchaser. Emergency load shedding of demand assigned scarcity values could manifest itself first in forecast schedules—the price-responsive schedule (PRS) and the non-response schedule (NRS)—and then, if not resolved by participants rebidding or reoffering, in dispatch prices in real-time.

3.18 At this stage, we propose default scarcity values for forecast load, applied in three blocks as shown in Table 1, and described in the text that follows. The values will be refined in light of submissions and further analysis if RTP is implemented.

Table 1: Proposed scarcity price blocks for forecast demand

Proportion of load	Value
5%	$10,000/MWh
15%	$15,000/MWh
80%	$20,000/MWh

Source: Electricity Authority

3.19 The lower and higher values in Table 1 are consistent with the parameters in the existing scarcity pricing arrangements.[12] We propose the volume in the first block would be equivalent to the first 5% of relevant load. This reflects an expectation that relatively modest load-shedding would have lower costs than more extensive demand curtailment. A second block of 15% of the relevant load would be assigned an intermediate value of $15,000/MWh, the mid-point between the current scarcity price values. The sum of these first two blocks (20%) is designed to approximate the level of demand curtailment at the comfortable limit of load management within distribution networks. The remaining load (80%) would have a default scarcity value of $20,000/MWh. Further information on these default scarcity values is given in Appendix D.

3.20 Purchasers at non-conforming nodes and other purchasers submitting demand bids could choose their own prices.[13] These bid prices could be lower or higher than the default scarcity values, although only purchasers willing to be dispatched can set dispatch prices.[14] Indeed, we want purchasers at conforming nodes to reveal the value they place on their load. This would reduce the proportion of load assigned default scarcity values—the three blocks are only assigned to load not bid by purchasers. The treatment of forecast load and purchaser bids at all nodes is detailed in Appendix G.

3.21 A dispatch schedule could indicate a shortage of generation at an affected node or nodes, resulting in demand curtailment at default scarcity values. That in turn would generate the associated scarcity price for that dispatch interval at the affected node(s). Applying default scarcity values in this way is the best translation of the current ex-post scarcity pricing arrangements into an RTP framework. But unlike the existing arrangements, parties would be certain of the dispatch price in real-time (assuming there is no pricing error or undesirable trading situation).

12 An explanation of scarcity pricing and the values assigned during scarcity events is available on the Authority's website at http://www.ea.govt.nz/operations/wholesale/spot-pricing/scarcity-pricing/.

13 The system operator forecasts the load at conforming nodes. Purchasers at non-conforming nodes must instead indicate their intended consumption by submitting nominated bids.

14 Such bids can be either dispatchable demand bids (see paragraph 3.73) or dispatch-lite bids (see paragraph 3.79).

3.22 Our proposal would also remove the current requirement that generation shortages must be (at least) island-wide before scarcity pricing is triggered.[15] This means load shedding could occur over a large area today (eg, across the upper North Island), yet not trigger scarcity pricing because it is not island-wide. In contrast, default scarcity values could occur for localised shortages under RTP. Of course, at present, a shortage of transmission and generation is normally signalled by infeasible prices in the forecast schedules hours ahead. This signal can induce local load management or an increase in local generation so that prices return to normal in dispatch. We do not expect this situation to be any different under RTP—only that the infeasible prices would be replaced by default scarcity prices.

Generation shortage with emergency load shedding: Illustrative example of existing and proposed approaches

Scenario: Demand is very high due to extremely cold weather on a winter evening. This coincides with some generation being out of service due to urgent planned maintenance. The system is tight, and at 5.30pm it is clear that demand will exceed generation. The system operator invokes emergency load shedding between 6pm and 9pm throughout the North Island.

Current: *Forecast prices* for the 6-9pm period are ~$480,000/MWh (ie, based on infeasibilities). *Real-time dispatch prices* in the 6–9pm period are $550/MWh (because demand has been cut). *Spot prices* are published two days later and are scaled up to $10,000/MWh (because the pricing manager has applied the scarcity price adjustment in the Code).

Proposed: *Forecast prices* for the 6-9pm period are around $10,000/MWh (ie, based on default scarcity values).[16] *Real-time dispatch prices* in the 6–9pm period are the same. *Spot prices* are published at the end of each trading period and are the same.

Comment: Participants and consumers face significant uncertainty under the current arrangements. Forecast, real-time, and spot prices can vary greatly even though they reflect the same physical conditions in the power system. Spot prices can be very sensitive to changes in some inputs, creating potential for large divergence with real-time prices. In the example, spot prices under current arrangements could easily have settled at much lower levels with very little change in the inputs (eg, if scarcity pricing did not apply due to one constrained circuit within an island). Similarly, spot prices could have been well over $20,000/MWh if a high priced offer or bid was the marginal resource, and scarcity pricing adjustments did not trigger due to a constrained circuit within an island.

Under the RTP proposal, forecast, real-time, and spot prices would be consistent for a given set of system conditions. Participants and consumers would have access to actionable real-time prices, enabling them to make better-informed decisions.

15 See clause 13.135A(3)(a) of the Code.

16 As described in paragraph 3.109, changes would apply to align the inputs used for forecast and real-time schedules.

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.

The system operator would issue a grid emergency notice if demand assigned scarcity pricing values is not fully scheduled

3.23 Under the proposed approach, default scarcity bids could be dispatched before generation or dispatchable demand offered or bid at higher prices. This is a change from the current approach where the system operator dispatches all generation, irrespective of offer prices, before invoking emergency load shedding. Under our proposal, emergency load shedding may be invoked even if there is some generation or dispatchable demand available at a higher price.

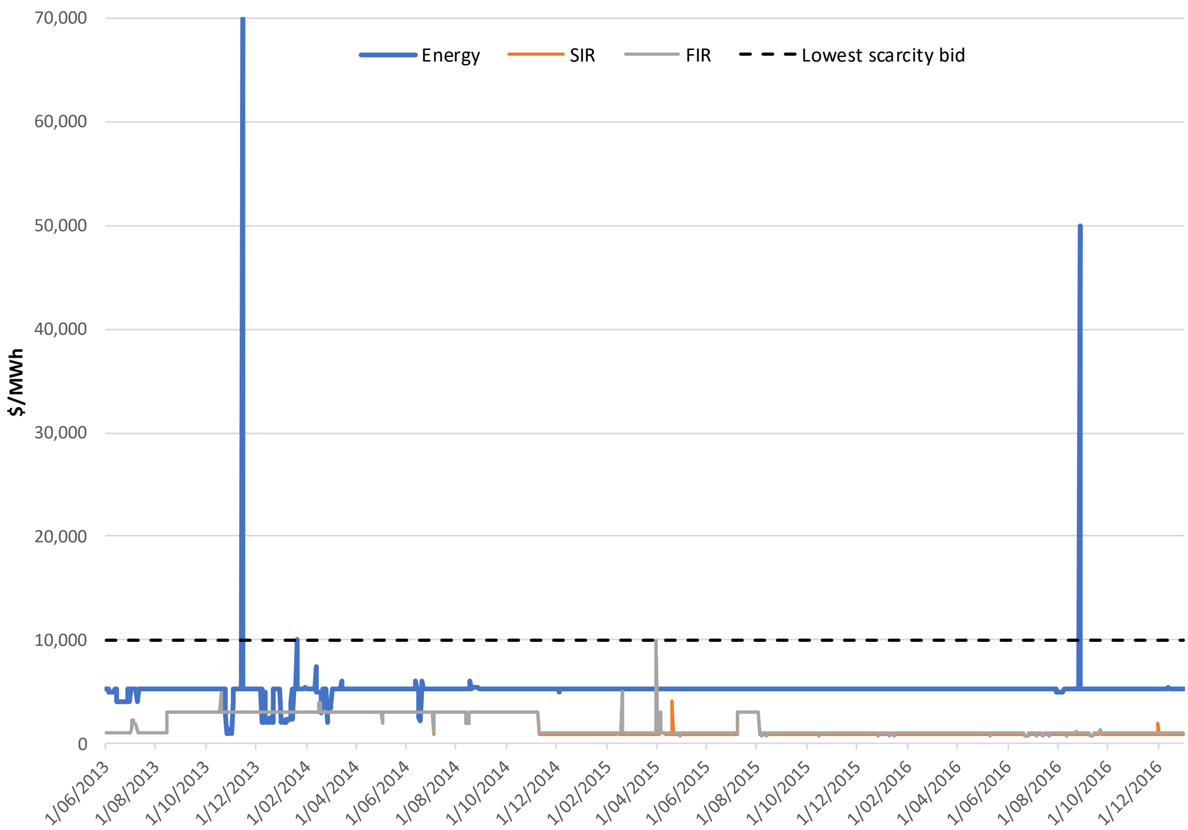
3.24 However, this does not mean generation offers are capped at the lowest default scarcity price. We propose a relatively modest proportion of demand would be assigned the lowest scarcity value (5%, as shown in Table 1); most of the volume would be bid at higher scarcity values. In addition, the absolute volume of load subject to default bids could reduce over time if purchasers choose to bid their demand.

3.25 If purchasers bid below default scarcity values, they would be expected to reduce demand if dispatch prices reach or exceed their bid price. If they bid above default scarcity values, then ideally electricity distribution business (EDBs) would take this preference into account in their load shedding decisions. While this might be impractical for smaller customer loads today, it should become more feasible over time with advances in technology.

3.26 Further, we do not expect many bids or offers above default scarcity values. This makes it unlikely that higher-priced last-resort resources would be discouraged from entering the market. Prices for generation offers and dispatchable demand bids are typically well below these scarcity pricing values. As shown in Figure 6, we identified only one trading period during 2015 and 2016 with a generator offer above $20,000/MWh, and it appears this offer may not have been deliberate.[17]

[17] One tranche of a generator's output was offered at $50,050/MWh for a single period. This offer price was roughly ten times the value of offers in preceding and following months, and may have been an input error with an extra zero. We note also that some dispatchable demand bids have been priced at over $100,000/MWh. However, these appear to be associated with the portion of load that is non-dispatchable at a dispatch-capable load station (ie, the bidder is signalling that it does *not* want this part of its load to be dispatched downwards).

Figure 6: Historic offers for energy and reserve



Source: Electricity Authority

3.27 Our proposed approach would therefore be efficient. It recognises shedding load at scarcity pricing values on rare occasions would be preferable to scheduling other resources that have an even higher cost.

3.28 Finally, the system operator would likely issue warning notices seeking additional resources in a situation where emergency load shedding was looming. This gives participants the opportunity to reoffer or rebid at a lower price within the gate closure period if they wished to be dispatched ahead of emergency load shedding at default scarcity prices.

Q5. Do you agree with using default scarcity bids before generation or dispatchable demand offered at a higher price in the dispatch schedule? If not, please explain your reasoning.

We do not propose to change the way the system operator handles emergency load shedding

3.29 Only load bid as dispatchable demand is subject to dispatch instructions. To date, no load at conforming nodes participates in the dispatchable demand scheme. Instead, the system operator can issue instructions to curtail this load under the grid emergency provisions in Technical Code B of Schedule 8.3 of the Code. The system operator uses dispatch schedules to inform these instructions, but can depart from a schedule if it believes this will better meet the dispatch objective in the Code.[18] Any such use of discretion can be scrutinised afterward.

3.30 In practice, the system operator instructs emergency load shedding pragmatically, rather than strictly following the dispatch schedule. For example, the system operator may limit the load of a specific EDB, rather than issue node-by-node instructions. EDBs also have a degree of discretion in how they implement load shedding across their networks.

3.31 Any exercise of discretion by the system operator or EDBs creates the potential for variations between the outcomes modelled in the dispatch schedule and those 'on the ground'. This includes the possibility that emergency load shedding has not occurred, even though the dispatch schedule indicated it was required.

3.32 However, it would only be possible to test for differences between load-shedding indicated by the dispatch schedule and the actions the system operator actually took after the fact. Including any such test in the pricing process would make it impossible to provide participants with actionable price information in real-time.

3.33 We therefore propose scarcity prices should apply if they occur in the dispatch schedule, even if no load shedding occurs in practice.

3.34 The opposite situation is also possible: the system operator instructs load shedding but scarcity prices do not occur in the dispatch schedule. We propose that scarcity prices will not apply in these situations, and note this is the same as current arrangements.

3.35 In general, we are not proposing any changes to the rights and responsibilities of the system operator and EDBs in relation to load shedding as part of RTP. However, the system operator has estimated the costs of providing an electronic facility to communicate with EDBs to manage emergency load shedding. This may reduce the scope for differences between scheduled and actual outcomes. The estimated rough order of magnitude (ROM) cost for this variation is $110k–$150k.

3.36 While this cost appears reasonable, it only covers providing the communication facility, not the time and costs involved in electronically connecting each EDB. EDBs could choose to take up the facility when it was ready. We think adding the option of an electronic communication facility to RTP implementation is unnecessary at this stage. Instead, we suggest it be considered after the Electronic Dispatch Facility (EDF) Phase 3 and RTP have both been implemented.[19]

Q6. Do you agree the system operator does not need to make changes to the existing process it uses to notify distributors of emergency load shedding?

18 See clause 13.70(a) of the Code.

19 See the system operator's website for details on its EDF programme: https://www.transpower.co.nz/system-operator/so-projects/electronic-dispatch-facility-edf-programme.

There would be a proxy price at disconnected nodes

3.37 Transpower schedules planned outages of transmission equipment to start or end at the beginning of trading periods. However, operational factors on the ground mean these outages will generally start or stop part-way through trading periods.

3.38 These differences may lead to inconsistencies between the actual configuration of the grid and the one the system operator has modelled. For example, an infeasibility will occur if load has been restored following an outage but the dispatch schedule shows the grid asset is still unavailable until the next trading period.[20] Under RTP, this would manifest as a price based on default scarcity values at the node. But this price would not be appropriate as there was no actual shortage of generation.

3.39 To address this issue, the system operator has proposed assigning a proxy price to nodes marked as dead or disconnected by the market system. This proxy would be set to the price at an appropriate adjacent node for the relevant trading period multiplied by the historic average of the affected node's location factor over some period.

3.40 This option would be relatively straightforward to implement but involves a level of approximation. We would like to explore whether there are other, more efficient options. We are interested in stakeholder views on this issue.

Q7.	**What is your view on the preferred treatment of disconnected nodes? Please explain your reasoning.**

There would be no cumulative limit to scarcity prices

3.41 The current scarcity pricing arrangements contain a provision that stops the further application of scarcity pricing adjustments if spot prices over the preceding week reach an average of $1,000/MWh.[21]

3.42 The practical effect of this mechanism is that 'normal' pricing provisions will apply if the average price limit is reached; ie, final prices will be determined by the interaction of offers, bids, and actual demand. While emergency load shedding would reduce actual demand, final prices may settle at low, moderate, or high levels—possibly even above the scarcity pricing range—depending upon participants' offer and bid behaviour. For this reason, the current mechanism to suspend scarcity pricing does not necessarily reduce prices.

3.43 While it may be technically feasible to adopt an average price limit with RTP, we think it would be challenging to implement. One option would be for the clearing manager to apply an adjustment after calculating the time-weighted average of dispatch prices. However, that could give rise to large constrained on/off payments to generators and

20 An infeasibility refers to a situation where there is insufficient offered supply to satisfy projected demand while also maintaining normal security levels. In this situation, there is no feasible solution, and the model 'solves' by breaching some constraint(s). As a result, the prices generated by the software will reflect so-called constraint violation penalties. These penalties are set at very high levels (over $100,000/MWh), acting as a flag that an infeasibility occurred.

21 See clause 13.135C of the Code.

dispatchable demand providers.[22] Such an approach would also reduce the certainty of real-time prices by adjusting them afterward.

3.44 Alternatively, dispatch prices could be 'constrained' by significantly reducing the scarcity pricing values and reserve shortage constraint violation penalties (CVPs) if the average price limit is triggered.[23] Resources with higher bid or offer prices would not be cleared in the dispatch schedule. However, this could lead to unstable dispatch outcomes, because of the cliff-face between normal conditions (when prices are not constrained by an average price limit) and the application of a limit.

3.45 Further, from a practical perspective, we expect the rolling outage provisions in the Code would apply if there was an ongoing need to curtail demand.[24] A supply shortage declaration requiring rolling outages does not trigger the existing scarcity price provisions and we expect this would also be the case with RTP.

3.46 Overall, we think it is preferable to not incorporate a cumulative limit in RTP, but instead to rely on existing provisions in the Code relating to rolling outages.

Q8. Do you agree that it is not desirable to apply a cumulative price limit under RTP? If not, please explain your reasoning.

Reserve shortages would be priced below the lowest scarcity pricing value

3.47 As part of the dispatch process, the system operator normally schedules sufficient resources to meet projected demand, and some additional resource to provide cover if there is a sudden failure of a large generator or transmission circuit. This additional resource is called instantaneous reserve (or simply reserve). The amount of reserve required will vary depending on the size of the largest generator or transmission circuit in operation. There are two types of reserve: fast instantaneous reserve (FIR), and sustained instantaneous reserve (SIR). Reserve can be provided by generators (reducing the quantity they produce for energy) or by interruptible load.

3.48 At present, if there are insufficient resources offered to meet demand and maintain normal reserve cover, the dispatch schedule may relax the requirement to procure reserve. This frees up resources from providing reserve to instead meet demand for energy. Of course, this relaxation means there may be insufficient reserve to cover sudden failure of a major generator or transmission circuit. That may in turn lead to automatic under-frequency load shedding (AUFLS).[25]

3.49 The existing pricing process applies an adjustment if this occurs. Prices caused by a shortage of reserve are limited to the greater of either:

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22 That issue does not arise with the existing scarcity pricing arrangements, because when the limit is triggered prices would be determined based on 'normal' processes.

23 The discussion from paragraph 3.47 details how we propose to treat shortages of reserve under RTP, including the use of CVPs.

24 See subparts 1 and 2 of Part 9 of the Code.

25 This form of load shedding occurs automatically and is different to the instructed emergency load shedding discussed elsewhere in this paper.

(a) three times the highest scheduled energy offer price

(b) or the highest-priced offer scheduled for the reserve product that cannot be fully supplied (ie, FIR or SIR).

3.50 This adjustment seeks to signal that reducing reserve cover—and lowering security—has an economic cost. In practice, the mechanism is an approximation because the cost associated with lowering reserve cover will depend on specific circumstances. Again, adjusting prices after the fact in this way is incompatible with a move to real-time pricing.

3.51 In our proposed approach, an inability to maintain normal reserve cover would trigger a CVP in the dispatch schedule. Dispatch prices would therefore reflect the CVP during the period that reserve cover is short.

3.52 We have not determined specific values for the SIR and FIR CVPs at this point. However, we propose relaxing reserve cover should be a contingency measure that is seldom used, but may be invoked ahead of emergency load shedding. This means the CVPs for reserve will need to be set at some value below the lowest scarcity pricing value (ie, $10,000/MWh).

3.53 However, we are also mindful of the effect on investment decisions in the long-term from a low CVP for shortages of reserve. Ideally, we want to provide incentives in the short-term that lead to investment in assets that are sufficient to meet the need for both energy demand and reserve. If some assets can be used to provide both energy and reserve, then valuing reserve below energy could compromise investment in reserve in the long term.

Reserve shortage: Illustrative example of existing and proposed approaches

Scenario: A large generator unexpectedly goes out of service at 6.55pm on a winter evening. The system operates with less than the normal reserve requirement between 7.00 and 8.30pm. After that, sufficient additional generation is running and reserve procurement returns to normal.

Current: *Forecast prices* for the three trading periods between 7.00 and 8.30pm are $100/MWh (ie, based on 'normal' winter peak conditions). *Real-time prices* in the 7.00–8.30pm period are in excess of $100,000/MWh (ie, CVP for IR). *Spot prices* are published two days later and are $8,000/MWh.

Proposed: *Forecast prices* for the 7.00–8.30pm period are $100/MWh (ie, based on 'normal' winter peak conditions). *Real-time dispatch prices* in the 7.00–8.30pm period are approximately $9,500/MWh because the CVP value is used. *Spot prices* are published at the end of each trading period and are $9,500/MWh.

Comment: Participants face a substantial uncertainty with current arrangements. Forecast, real-time, and spot prices can vary greatly for the same physical system conditions. Spot prices can be very sensitive to changes in some inputs, creating the potential for large divergence from real-time prices. In the example, spot prices could easily have settled at much lower or higher levels with little or no change in inputs.

Under the RTP proposal, forecast, real-time, and spot prices would be consistent for a given set of system conditions. Importantly, participants would have access to actionable real-time prices, enabling improved decisions.

Q9. Do you agree the current principle of partially relaxing reserve procurement before invoking emergency load shedding should continue under RTP? If not, please explain your reasoning.

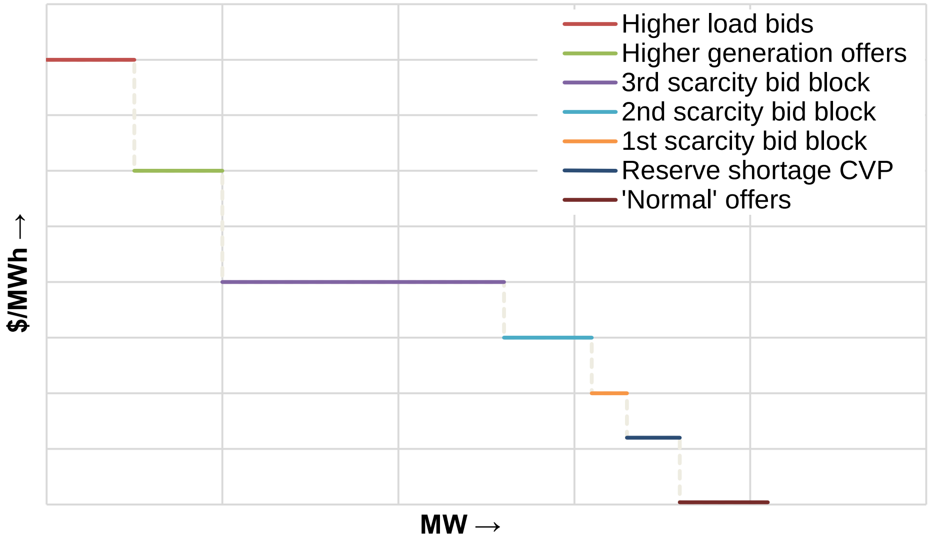
Load would be dispatched off before reserve and generation offered above the reserve shortage CVP value

3.54 Under our proposed approach, a CVP would be triggered in the dispatch schedule if there is a reserve shortage. It is technically possible the normal reserve requirement would be partially relaxed in the dispatch schedule, even though there is some offered reserve and/or generation available (if the offered reserve is priced above the CVP value). This is different to current arrangements, which provide for all reserve and generation to be used, irrespective of offer prices.

3.55 Figure 7 shows how we propose different system resources would operate. 'Normal' generation and reserve offers priced below the reserve shortage CVP would settle the market in most periods. As the requirement for system resources increases, the contingent event (CE) risk would be relaxed and prices would be determined by the reserve shortage CVP. When that no longer helps the situation, load would be dispatched off according to bid price (see Table 1). At least initially, most load at conforming nodes would be assigned default scarcity values.[26] Purchasers can choose to bid their load above or below these default values, as detailed in paragraph 3.20. Finally, higher-priced resources would be dispatched if the default scarcity bids do not provide enough resource.

[26] See the treatment of load and purchaser bids detailed in Appendix G.

Figure 7: Illustrative example of dispatch order for different system resources



Source: Electricity Authority

3.56 However, we do not expect the outcome under RTP to be significantly different than today in practice:

(a) Very few reserve resources are currently priced above $10,000/MWh.

(b) By way of example, participants have priced reserve offers above $6,000/MWh on only two occasions since mid-2013, and these may not have been deliberate.[27]

3.57 The proposed approach appears reasonable from an economic perspective. It recognises it may be preferable to relax security on rare occasions (applying the reserve shortage CVP), rather than use all offered resources regardless of their cost.

3.58 Further, the system operator can issue warning notices seeking additional resources in a situation where supply is becoming very tight. This would give reserve providers an opportunity to reoffer at a lower price within the gate closure period if they wish to ensure they are dispatched.

3.59 Finally, reserve provided by generators can often substitute for energy. The reserve CVP will not act as a cap on energy offers, because the reserve requirement can only be reduced by a finite amount. At this point the reserve CVP is no longer the price-setting value. Prices may instead be set by reserve or energy offers between the reserve CVP and the first scarcity pricing value of $10,000/MWh.

The current provisions for high spring washer pricing situations would be removed

3.60 Situations can arise where a loop flow on part of the transmission grid can lead to prices at some nodes being many times higher than prices at other nodes—a ‘high spring washer pricing situation’ (HSWPS). The Code provides for the pricing manager to adjust spot prices after real-time if a HSWPS arises.[28] This process limits the impact of small

27 Both occasions appeared to be input errors, given the preceding and subsequent offers (see paragraph 3.26).

28 See clause 13.134 of the Code.

potential errors in data inputs which can cause high prices in a HSWPS (such as line impedance ratings).

3.61 Introducing default scarcity values for forecast load will in effect limit prices in a HSWPS. Further, introducing RTP should facilitate greater voluntary demand bids and other actions in response to regular HSWPS to reduce their impact. We therefore propose to remove the current HSWPS provisions from the Code.

Q10. Do you agree with the proposed removal of the high spring washer pricing provisions in the Code? If not, please explain your reasoning.

Indicative effects of RTP on average spot prices and consumer charges

3.62 The Authority has undertaken a high-level analysis to estimate the potential effect of RTP on spot prices and delivered electricity charges for different types of consumer. We considered both the initial effect of RTP and the full effect after allowing for potential changes in participant behaviour.

3.63 Our analysis indicates:

(a) The RTP initial effect on delivered electricity charges varies between nil impact (for responsive residential consumers) and an increase of around 1.1% (for unresponsive industrial consumers).

(b) The RTP full effect on delivered electricity charges varies between an increase of around 0.1% (unresponsive residential consumers) and a reduction of around 1.1% (responsive industrial consumers).

3.64 These estimates are based on a 'hindcast' analysis using real-time dispatch schedules for April 2015 to May 2017, substituting values of $10,000/MWh when infeasibilities occurred due to deficits in instantaneous reserve.

3.65 The results are subject to a range of assumptions and should be treated as indicative. Most importantly, the RTP initial effect should be understood as an unrealistic 'worst-case scenario'—it is based on the unrealistic assumption that nobody changes their behaviour in response to RTP in any way.

3.66 Our analysis is detailed in Appendix F. This appendix also discusses other types of infeasibilities and how these may influence spot prices and consumer charges.

Demand metering would be used for load forecasts

3.67 Load at conforming nodes is currently represented in the dispatch schedule by a 'top-down' forecast. This is calculated from the current system generation, adjusted to account for losses and modified for the projected change over the next 5 minutes. The aggregate system load forecast is then assigned to individual nodes in proportion to their current actual load. The source of the actual load data is the system operator's SCADA Data Validation (SDV) process within the market system.

3.68 SDV assesses sampled SCADA data against quality and other criteria. Data that fails validation tests is replaced by the next-best-quality data following a predefined hierarchy.

The system operator judges this process to be fit for its current purpose (balancing generation and demand).

3.69 Under RTP, the system operator proposes to move from the current top-down real-time dispatch load forecast to a bottom-up load forecast. Both the Authority and the system operator expect this to make the real-time dispatch forecasts of load at each node more accurate.[29]

3.70 The system operator has recommended that demand inputs for non-dispatchable load at non-conforming nodes would be based on actual load values, derived in the same way as for conforming nodes.[30] The system operator expects this to be more accurate than using non-conforming load bids from the PRS. It is also consistent with the current treatment in final pricing where all bid information is discarded and metered values are used instead.

Q11.	**Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning.**

ION meters could be the primary data source for load metering

3.71 The system operator has separately costed a variation where the grid owner's ION meter data would be the preferred primary data source for demand inputs.[31] ION meters are more accurate than SCADA sources. SCADA data would then be the second highest priority within the SDV processing, with all other alternate sources moving one level down the quality hierarchy. This variation has a rough order of magnitude cost estimate of $120k to $180k to implement.

3.72 We believe the use of ION meter data would be worthwhile and propose that this variation be implemented as part of RTP, if it has not already been adopted by the time RTP is implemented.

Q12.	**Do you agree that ION meter data should be the primary data source for demand inputs? If not, please explain your reasoning.**

Dispatchable demand would be dispatched from the dispatch schedule

3.73 Current dispatchable demand arrangements allow demand-side participants to operate in a similar manner to generators. Dispatchable demand providers have certainty over the price consequences of their demand-response decisions, because they qualify for constrained on and off payments. They can also set spot prices if they are the marginal resource.

[29] See section 4.1.7 of the system operator's TAS060 report in Appendix B.

[30] See section 4.2.9 of the system operator's TAS060 report in Appendix B and Appendix G for details on the treatment of forecast load and purchaser bids under RTP.

[31] These revenue quality meters replaced the old MV90 meters.

3.74 Incorporating the existing dispatchable demand product within RTP is not straightforward. Unlike generation, dispatchable demand is currently dispatched every half hour from the non-response schedule (NRS) rather than the dispatch schedule. This approach was adopted to facilitate participation in the dispatchable demand scheme and reduce the cost to implement. It removed the need for dispatchable demand participants to have a GENCO connection (currently necessary to receive real-time dispatch instructions through the electronic dispatch facility). It also avoided the potential for dispatchable demand providers to receive 'yo-yo' dispatch instructions. These could occur if dispatchable demand load is the marginal resource, resulting in instructions that alternate between ‘on’ and ‘off’ within a trading period.

3.75 The GENCO requirement would be mitigated when Transpower's EDF Phase 3 project is implemented, which we expect to occur before RTP goes fully live. However, dispatchable demand providers might still be exposed to potential yo-yo dispatch instructions. The system operator has suggested that a possible mitigation would be to include ramp rates and minimum cycle times for dispatchable demand bids.[32]

3.76 Alternatively, the system operator has considered an option where dispatchable demand dispatch continues on a 30-minute basis from the NRS. To enable this, load in the dispatch schedule would need to be adjusted to account for any difference between the dispatched demand quantities (from the NRS) and cleared dispatchable demand quantities in the dispatch schedule. This is not straightforward. The difference between the two quantities would not be known until the dispatch schedule solves; yet the difference needs to be an input for the dispatch schedule—a degree of approximation would be required, with some resulting loss of efficiency.

3.77 We propose dispatchable demand should be dispatched from the dispatch schedule, the same as generators are today. We expect the yo-yo dispatch instructions for dispatchable demand providers to be relatively rare. However, a dispatchable demand provider subject to yo-yo dispatch could use the ability to rebid within the trading period (see paragraph 3.87) to avoid being on the margin and therefore subject to yo-yo dispatch. We propose that such rebidding within the trading period (except during a grid emergency) would make them ineligible for constrained on or off payments.

3.78 Adopting RTP would also mean that dispatchable demand purchasers no longer need to provide metering data to the pricing manager the next day. At present, this data is used as an input for calculating final prices. Under RTP, final prices would instead be calculated from dispatch prices.

Q13. What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning.

We propose a new ‘dispatch-lite’ category for small purchasers

3.79 We also propose introducing a new 'dispatch-lite' category of demand-response as part of the RTP design. We intend this to facilitate demand-side participation by providing an alternative to the existing dispatchable demand product for smaller consumers.

32 Minimum cycle times could for example specify how long a load will remain offline following a shutdown. See page 23 of the system operator’s TAS060 report in Appendix B.

‘Dispatch-lite’ would be available to participants at both conforming and non-conforming nodes.

3.80 'Dispatch-lite' participants would be able to bid their controllable load into market schedules. These bids would be able to set forecast and dispatch prices.[33] However, ‘dispatch-lite’ bids would receive dispatch ‘notifications’ from the system operator, rather than dispatch instructions as dispatchable demand does. Dispatch-lite participants would have less onerous compliance obligations than dispatchable demand, but as a result would not be eligible for constrained on and off payments.

3.81 Dispatch-lite participants need to have an incentive to comply with dispatch notifications, otherwise actual system demand could diverge significantly from expected demand. This could lead to unduly frequent re-dispatch by the system operator, with possible adverse security impacts.

3.82 However, we would like to facilitate smaller price-sensitive consumers participating directly in setting spot prices. For this reason, we propose that approved dispatch-lite participants would have the option not to comply with the notification, provided they communicate this swiftly to the system operator and do not make it a habit. This will ensure the system operator has the latest information about purchasers’ intentions. Note that we expect this option to be available only after the system operator has implemented Phase 3 of the electronic dispatch facility.

3.83 One option for parties to signal their intentions not to comply with a dispatch notification is immediately rebidding their revised intention. This approach would be feasible if revisions to offers and bids are enabled within trading periods. This potential variation to the core RTP proposal is discussed in paragraph 3.87.

3.84 Alternatively, dispatch-lite participants may be able to use the dispatch facility to acknowledge whether they will follow their scheduled quantities. If they say ‘no’, the system operator may exclude the associated bid from the dispatch schedule for the remainder of the trading period. The system operator has not been asked to provide a cost estimate for this approach.

3.85 In either case, dispatch-lite participants would be monitored to ensure they comply with their obligations. Parties that repeatedly did not comply could have their dispatch-lite status revoked by the system operator, removing them from the dispatch notification process.[34]

3.86 The treatment of dispatch-lite bids in the forecast and dispatch schedules is detailed in Appendix G.

Q14. Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning.

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33 We propose dispatch-lite will bid in the same way as dispatchable demand (using nominated bids). The TAS060 report in Appendix B indicates dispatch-lite would use difference bids at conforming nodes. Our proposal to instead use nominated bids is a further development in consultation with the system operator after TAS060 was finalised.

34 For a summary of the dispatchable demand proposals see Appendix 2 of the system operator’s TAS060 report in Appendix B.

Participants would be allowed to reoffer or rebid during a trading period

3.87 We propose to allow participants to revise their bids and offers once a trading period has begun. This is not possible under current arrangements.[35] Instead, the system operator manually manages any revision of bids or offers during a trading period, if required.

3.88 However, spot prices are calculated based on offers and bids at the start of the trading period, irrespective of any subsequent manual changes. The RTP proposal retains these provisions, and this is reflected in the rough order of magnitude costing.

3.89 We are considering an alternative where RTP would include functionality to allow participants to revise their bids and offers within a trading period. Such revisions would only be permitted in specific limited circumstances, the same as today: either in response to a grid emergency or for a bona fide physical reason.[36] Monitoring would occur to ensure compliance. This functionality would allow prices to be calculated in a way that accounts for bid and offer changes up to and within a trading period.

3.90 This change would also allow for better identification of costs attributable to any use of discretion by the system operator in the dispatch schedule. At present, the system operator manually adds constraints to the dispatch schedule if participants advise their capabilities have changed within the trading period. These revisions currently cannot be distinguished from any actual use of discretion by the system operator.

3.91 The change should better enable participants to revise their bids or offers if they wish in in response to a grid emergency or where reserve shortage CVPs are binding (as discussed in paragraphs 3.23 and 3.47). It is also required to enable the alternate solution for ‘opt-out’ of dispatch-lite bids (see paragraph 3.83). This variation has a rough order of magnitude cost estimate of $25k to $50k to implement.

3.92 We believe that this variation would be worthwhile, and propose to implement it as part of RTP.

3.93 Importantly, we do not believe reoffering or rebidding in this way risks manipulation of spot prices. The circumstances where revisions within the trading period would be allowed would be strictly specified, as they are today. Any such changes would be subject to market monitoring, which would include assessing any evidence of price manipulation. In fact, transparency would be increased relative to current arrangements, because these changes to bids and offers would be published and therefore open to scrutiny.

Q15. Do you agree with the proposal to allow revisions to offers and bids within trading periods in some circumstances? If not, please explain your reasoning.

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35 Nor can they typically revise offers or bids inside the gate closure period leading into real-time. This is now set one hour before the start of the trading period, as of 29 June 2017. Bids or offers can only be revised after gate closure (and before the start of the trading period) for bona fide reasons as per the Code.

36 Participants can only modify their offers or bids inside the gate closure period if there is a bona fide physical reason (clauses 13.19 and 13.19A of the Code), or if a grid emergency has been declared, allowing them to offer more supply or reduce their bids (clauses 13.98 and 13.99).

Constrained on and off payments would not be changed

3.94 Constrained on and off payments are calculated by the clearing manager. We are retaining this aspect of market design under an RTP regime because market settlement remains on 30-minute trading periods using an average price. Consequently, generators or dispatchable demand providers can be dispatched when the spot price is contrary to their intentions as stated in their offer or bid. Subject to their actual performance, they may be eligible to receive constrained on (generators and dispatchable demand) or constrained off (dispatchable demand only) payments.

3.95 Calculating constrained on and off payments would need to be adjusted if revisions to bids and offers are permitted during a trading period, as discussed in paragraph 3.87. Payments would be calculated using the last bid or offer received before the end of the trading period.

Q16.	**Do you agree with using the last bid or offer received in a trading period when calculating constrained on and off payments? If not, please explain your reasoning.**

We could retain an interim pricing period to guard against material errors

3.96 We propose a process for guarding against errors in prices for energy and reserve would continue to apply, although in a modified form.

3.97 Currently, a person must submit a claim of a pricing error to the pricing manager once interim prices have been published. A pricing error occurs when the interim price is incorrect because of an error in an input or an error in the calculation process. There is no minimum threshold that applies to the size of the error (in \$/MWh), but it must 'materially affect' the claimant if they are a participant.[37]

3.98 We propose a minimum materiality threshold should apply before the pricing error provisions are invoked. This is consistent with the approach used by other electricity markets with RTP.

3.99 We have considered two broad options to address pricing errors under RTP:

(a) **Manual claim:** A modified form of the current process for claiming pricing errors. This would involve setting a minimum threshold for the material impact of the error—say, in \$m per event—including how widespread it is. The threshold would consider the size of an error (in \$/MWh) and the amount of load or generation affected by the pricing error. This means a smaller pricing error (in \$/MWh) affecting the whole system would exceed the threshold, but would need to be larger if it only applies to a small part of the system.

(b) **Automated checking:** The approach used by the Australian National Electricity Market (NEM) where a set of filters is automatically applied to dispatch prices in real-time to flag for checking of input data. These filters screen for instances where manifestly incorrect inputs may have resulted in material differences in price

[37] See clauses 13.168 through 13.170 of the Code.

across successive dispatch intervals.[38] The market operator publishes and consults on the form of filters that will apply, and reports on the number of errors (and false positives) that are detected.

3.100 We are seeking stakeholder views on whether to adopt a pricing error process and, if so, which approach best achieves the balance between providing actionable real-time prices and safeguarding against material errors. We will consider the system implications of any process to correct pricing errors during the next detailed design phase of RTP with the system operator (neither approach is included in the current cost estimate).

3.101 For both options discussed above, we propose the dispatch price for an interval would be discarded for settlement purposes when a dispatch price is flagged and the subsequent checking process identifies an input error. The previous dispatch price would continue to stand instead.[39] This process is highly automated in the NEM, and prices can only be republished if an error is detected within 30 minutes of real-time.

3.102 The manual claim option is presented in the draft Code amendment in Appendix C, and illustrated in Figure 8. However, the service provider function for most of the current process (the pricing manager) would cease to exist after implementing RTP. We do not consider the cost of retaining the pricing manager service provider role purely for this function would be justified (we expect claims to continue to be uncommon). Further, the pricing manager would also likely lose its knowledge over time, given it would no longer be calculating daily final prices. The pricing error claim role would also not fit easily with the functions of the clearing manager.

3.103 We considered the Authority adopting this role directly, but on balance propose it would be undertaken by the system operator. The Authority would make the final determination of a pricing error based on the system operator's report—the same as for recommendations from the pricing manager under the current process.

3.104 We propose using either the system operator's standalone dispatch tool or the Authority's vSPD solver to evaluate dispatch prices.[40] This would closely replicate the dispatch schedules, but avoid the cost of altering the market system to rerun dispatch schedules on a very infrequent basis.

3.105 We recognise there may be concerns over a perceived conflict of interest for the system operator producing dispatch prices, as well as investigating claims of a pricing error. However, we believe this risk is low, because:

(a) the system operator's dispatch process ultimately determines prices in the first place

(b) a public notice will be produced automatically if any error is claimed, and the system operator's report will be publicly available

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38 The filters to trigger the NEM's error procedure are based on changes in prices and interconnector flows from one period to the next. When prices are more than $20/MWh, the threshold requires prices change by more than a factor of three. The change in interconnector flow threshold is different for each interconnector, but is set at a significant proportion of each interconnector's capacity. Both price and flow changes must exceed the thresholds to trigger a review.

39 See also the discussion of market system outages from paragraph 3.106.

40 The Authority's vectorised Scheduling, Pricing, and Dispatch (vSPD) tool is a precise mathematical replica of the system operator's SPD engine. vSPD is routinely used by the Authority to analyse the wholesale spot market. It is periodically externally audited by the same independent party that audits SPD for the system operator. For more information, see https://www.emi.ea.govt.nz/Tools/vSPD.

(c) the Authority retains the final decision over the claim and could critically assess the system operator’s report, including performing modelling using vSPD

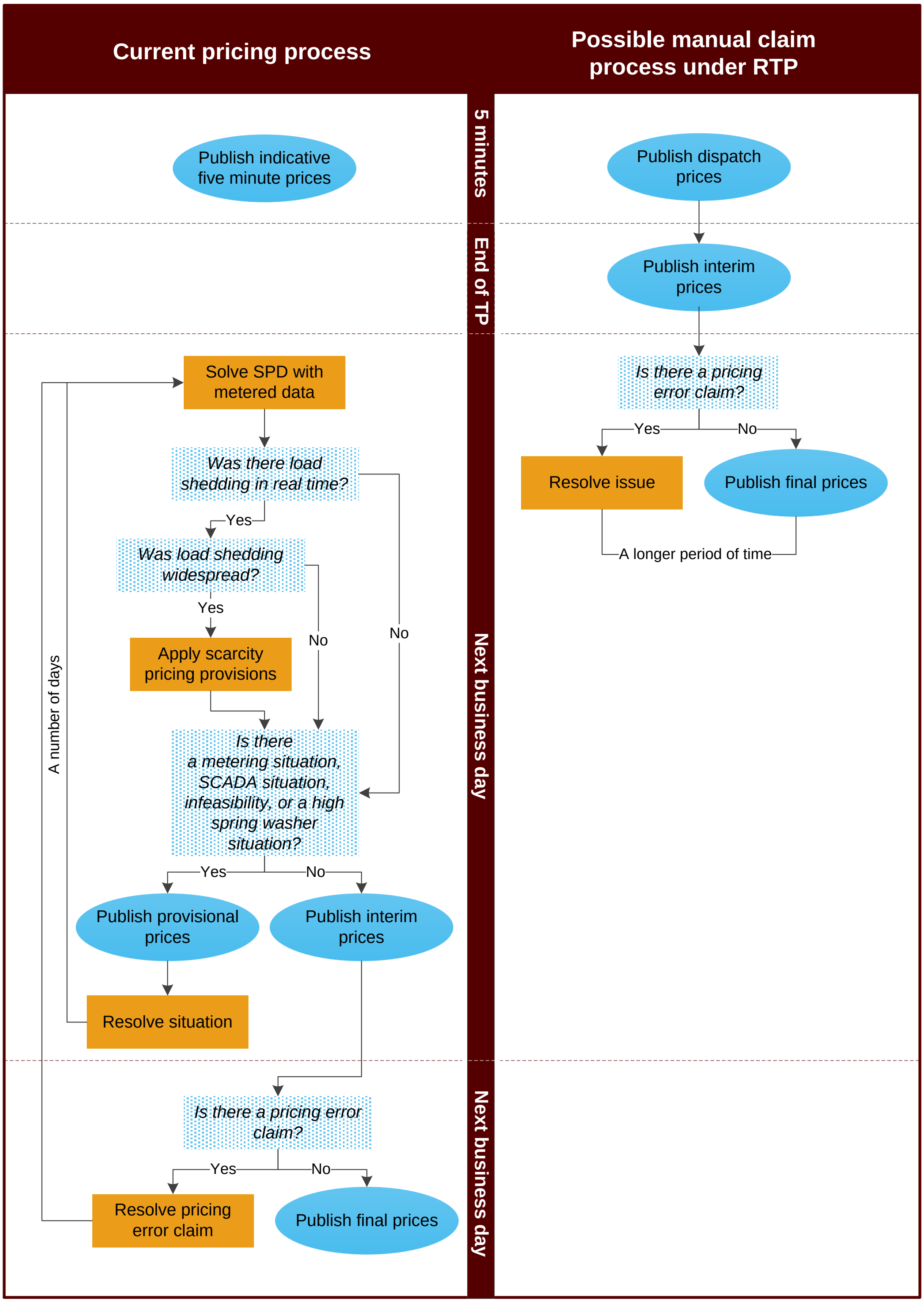
(d) any interested party can also assess dispatch prices using the relevant data and vSPD, which are both publicly available (this was not the case when the pricing manager role was introduced).

Q17. Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning.

Q18. Which approach do you prefer for managing pricing errors: a manual claim or automated checking? Please explain your reasoning (this could include suggestions for an automated filter).

Q19. If we retain a manual claim process for pricing errors under RTP, who should perform that role:
– the system operator?
– the Authority?
– the pricing manager, as their only function?
– some other party?
Please explain your reasoning, including regarding any possible conflict of interest.

Figure 8: A possible manual error claim process under RTP compared to the current process



Source: Electricity Authority

We propose the previous published dispatch price would prevail during market system outages

3.106 Prices are not always available for publication; eg, if there is a market system outage or similar problem. Participants must instead make their own judgements about the prices that will likely emerge in those situations.

3.107 We propose that:

(a) the last published dispatch price would stand until the end of the trading period on the rare occasions when there is a market system outage

(b) if a dispatch price is not published at the beginning of a trading period, the latest price from the PRS for the trading period would apply

(c) for the trading period in which a market system outage ended, the latest price from the PRS for the trading period would be included in the time weighted average, along with the published dispatch prices

(d) constrained on and off provisions would continue to apply in all cases.

3.108 This approach is consistent with the philosophy of providing certainty about real-time prices. It means prices would be formed from the best available information at the time a market system outage occurs.

Q20. Do you agree with the proposed treatment of spot prices during market system outages? If not, please explain your reasoning.

Forward schedules would be modified to align with RTP changes

3.109 The system operator prepares and publishes a number of forecast schedules in advance of real-time to help guide participants with their planning (week ahead, NRS, PRS). These schedules should provide prices which are 'like-for-like' with dispatch prices if forecast and actual conditions turn out to be the same.

3.110 For this reason, we propose these schedules would use the same treatment of energy and reserve shortfalls as dispatch schedules. This would not completely eliminate all sources of differences, because of the non-linear relationship between demand and price. Averaging the dispatch prices arising from multiple load values over 30 minutes (used in final prices) will probably give a slightly different outcome to calculating the price using the average forecast load over 30 minutes (used in forecast schedules).

3.111 The system operator has suggested an option to create a PRS-type forecast schedule that solves for 5-minute instead of 30-minute trading periods. However, producing six times as many forecast prices would be a significant development, so we view this option as a possible enhancement for future consideration.

3.112 Further, grid outages that affect a portion of the trading period could lead to very different prices from one dispatch period to the next. The forecast schedule can only use a single system configuration for the entire trading period and would be unable to account for any such changes.

Q21. Do you agree with the proposed changes to forecast schedules to align them with dispatch schedules? If not, please explain your reasoning.

The current five-minute and final pricing schedules would be discontinued

3.113 Both the ex-post five-minute schedule (the real-time price schedule as currently defined in the Code) and the final pricing schedule (produced separately by the pricing manager) would be discontinued under RTP. This is because there is no need to continue publishing either schedule once dispatch-based RTPs are used for settlement.

The loss and constraint excess would be divided using the dispatch schedules

3.114 The loss and constraint excess (LCE) is the settlement surplus that arises because the total amount paid by purchasers in the spot market typically exceeds the amount paid to suppliers.[41] Schedule 14.3 of the Code breaks LCE into two portions each month. The majority is used to fund financial transmission rights (FTRs), and the residual LCE (along with proceeds from auctions of FTRs) is rebated to transmission customers.

3.115 Introducing RTP would not materially alter these arrangements. However, Schedule 14.3 currently uses the final pricing schedules to apportion LCE each month—but final pricing schedules would no longer exist under RTP.

3.116 At this point it is not entirely clear whether an amendment to Schedule 14.3 will be required for RTP. This is because the portion of LCE allocated to fund FTRs has been growing over time as new FTRs nodes are added.[42] If the Authority decided in future to use all LCE to fund FTRs, Schedule 14.3 would cease to apply and would (presumably) be removed from the Code.

3.117 On the other hand, the references to final pricing schedules in Schedule 14.3 have to be replaced as long as the LCE needs to be divided. We propose using the dispatch schedules for each month instead, with time-weighting for the duration of each dispatch schedule. This approach is consistent with the underlying philosophy used to apportion LCE under current arrangements.

3.118 The draft Code amendment in Appendix C sets out the specific wording of our proposal to use the dispatch schedules to apportion LCE (if that is required).

Q22. Do you agree with the proposed use of dispatch schedules to apportion loss and constraint excess for financial transmission rights each month (if that is required)? If not, please explain your reasoning.

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41 The surplus is caused by transmission constraints, and differences between marginal and average transmission losses.

42 The Authority recently consulted on potential further developments for FTRs, including changing the number of locations where they can be used. See http://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/consultations/#c16389.

RTP would be implemented in stages over four years

3.119 The proposed RTP design is closely linked to some existing projects, and we assume these would be completed prior to RTP implementation. These projects are:

(a) Phase 3 of the electronic dispatch facility

(b) Shortened gate closure (reduced to one hour before the start of the trading period, as of 29 June 2017).[43]

3.120 Adopting RTP would involve significant changes to the current market systems. The system operator is recommending a staged delivery approach over four years, detailed in section 6 of the TAS060 report in Appendix B.

3.121 As part of the implementation process, we intend to publish the new real-time prices on a pilot basis before they go fully live. This would provide an opportunity for participants to gain knowledge and experience with the new arrangements before they are used for settlement.

3.122 Our aim is for these pilot prices to be closely aligned with the prices that will apply under RTP. However, it may not be possible to achieve full pricing alignment during the period when pilot prices are published. For example, dispatch-lite bids may not be applicable until RTP is fully implemented. In that case, the pilot real-time prices would not include the effect of dispatch-lite bids.

3.123 If the Board agrees to implement the RTP design, the Authority will work with the system operator to develop a detailed implementation plan, and seek stakeholder input on that plan.

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning.

43 See the shortened gate closure decision paper at http://www.ea.govt.nz/dmsdocument/20107, and the gazetted Code amendment at http://www.ea.govt.nz/dmsdocument/22185.

4 Regulatory statement

4.1 Sections 39(1)(b) and (c) of the Electricity Industry Act 2010 require the Authority to prepare and publish a regulatory statement on any proposed amendment to the Code and to consult on the proposed amendment and regulatory statement.[44]

4.2 Section 39(2) provides that the regulatory statement must include:

(a) a statement of the objectives of the proposed amendment

(b) an evaluation of the costs and benefits of the proposed amendment

(c) an evaluation of alternative means of achieving the objectives of the proposed amendment.

Objective of the proposed amendment

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

Spot prices would be more actionable

4.4 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

4.5 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.

4.6 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.

Consistency with statutory objective

4.7 We believe the Code amendment will promote all three limbs of the Authority's statutory objective[45] because it would result in:

(a) greater competition between generators and consumers (via voluntary demand response), 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 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.

4.8 In particular, we think making prices more actionable and more reliable would remove barriers and promote uptake of new technologies and new business models. New technologies like battery storage, smart appliances, or other forms of automated demand

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44 A regulatory statement is not required to make an urgent Code amendment. Other exceptions are set out in section 39(3) of the Act.

45 Refer to section 15 of the Electricity Industry Act 2010.

response make it easier for parties to react to prices—but they are unable to fully capture this benefit if prices are calculated after the fact as they are today.

4.9 Appendix E sets out more information on why RTP is expected to promote each of these limbs.

Q24. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning.

Consistency with demand response guiding regulatory principles

4.10 In August 2015, we published an information paper setting out our view on the guiding regulatory principles that should apply to demand response initiatives.[46] Although RTP is not a demand response initiative per se, we expect it to provide significant benefits in this area. Table 2 assesses the proposed RTP design against the demand response guiding regulatory principles.

Table 2: Demand response guiding regulatory principles and RTP design

Guiding principle	Assessment
Demand response should be driven by, and should contribute to, efficient prices	✓ RTP will promote more efficient pricing outcomes, and make it easier for demand-side bids to directly influence spot prices for the reasons set out in paragraphs 4.4 and 4.5.
The costs of demand response should be recovered efficiently	✓ Consumers will face the costs of their voluntary demand-response actions under RTP, which will promote efficient outcomes.
Arrangements should provide for efficient trade-offs between different uses of demand response resources	✓ Demand-response capability may be offered into the energy and reserve markets under RTP, and the most valuable use will be selected. The only potential exception is dispatchable demand. These bids are not currently co-optimised with reserves in real-time. This may (or may not) continue under RTP, depending on the detailed design.
Demand response arrangements should support an efficient level of reliability	✓ RTP will facilitate more efficient reliability for the reasons set out in the cost benefit analysis.
Demand response participants should follow good practice	✓ Under RTP, demand-side bids and actions will be subject to the standard transparency and monitoring provisions for the spot market.

46 The principles are available at https://www.ea.govt.nz/dmsdocument/19671. The Authority sought feedback on the principles, and may update them in future to reflect feedback or other developments in the electricity sector.

Guiding principle	Assessment
Barriers to the use of demand response should be avoided or removed where it is efficient to do so	✓ RTP will lower the barriers to demand response by providing more actionable price signals, and (subject to detailed design) allow for dispatchable demand and dispatch-lite bids.

Source: Electricity Authority

4.11 Overall, we conclude the proposed RTP design is consistent with the demand response guiding regulatory principles.

Benefits and costs of amendment

Broad approach

4.12 Our cost-benefit analysis (CBA) builds on the framework used in our April 2016 RTP information paper.[47] Our analysis retains the same overall framework, but we have updated it to:

(a) incorporate more recent or accurate information where it is available, especially in relation to expected implementation costs

(b) reflect comments and feedback raised in submissions on the earlier 2016 CBA of the dispatch-based RTP option.

4.13 The quantitative assessment adopts the following approach:

(a) the analysis is undertaken from an economy-wide perspective based on the expected incremental benefits and costs of adopting RTP

(b) effects are assessed over a 15-year period, starting from the date RTP is implemented

(c) values are estimated in 2017 dollars using a 6% real discount rate; sensitivity cases with discount rates of 4% and 8% are also considered

(d) the counterfactual to RTP assumes that existing arrangements remain in place, except that shortened gate closure (to one hour) applies and the EDF Phase 3 project has been implemented.

Categories of benefit

4.14 We have developed quantitative estimates for the following benefits:

(a) more efficient levels of demand-response (noting demand response can compete with other types of resource, such as generation or battery storage)

(b) more efficient levels of reliability.

4.15 We expect RTP will also provide other benefits. For example, spot prices should more accurately reflect actual conditions when the system is very tight; ie, prices are less likely to under- or over-shoot the true value of energy and reserve. This should improve confidence in the value of risk management products (such as caps in the hedge

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47 Our April 2016 *Assessment of real-time pricing options* information paper is available at http://www.ea.govt.nz/dmsdocument/20599.

market), and enable better risk management decisions. Similarly, RTP should facilitate more efficient scheduling and dispatch decisions by generators and owners of storage devices such as batteries. We have not compiled quantitative estimates for these types of benefits because there is not enough information to do so at this time. However, qualitative factors indicate these benefits may be material.

Categories of cost

4.16 Our cost analysis considers the effect on the system operator, the clearing manager, the pricing manager, and participants. We have also included allowances for the direct costs associated with more efficient levels of demand response.

4.17 We have set out the detailed analysis in Appendix E. Table 3 summarises the results of the assessment. Note that numbers in Table 3 may not add due to rounding (to whole millions).

Table 3: Estimated benefits and costs

Item $m (present value)	Lower case	Base case	Higher case
Benefits[1]			
Demand response benefit—industrial and commercial	28	48	85
Demand response benefit—residential	8	21	53
Reliability benefit	0	8	19
Total benefits	36	77	157
Demand response costs			
Industrial and commercial	-5	-9	-17
Residential	-2	-7	-21
Total demand response costs	-7	-16	-37
Implementation costs			
System operator function	-10	-8	-7
Pricing and clearing functions (net saving)	0	0	1
Participant implementation costs	0	0	0

Total implementation costs	-10	-8	-6
Net benefits	19	53	114

Source: Electricity Authority
Notes: 1. Excludes some benefits that are not quantified

4.18 The analysis shows significant net benefits of $53 million in the base case. The lower and upper cases also show positive net benefits. For completeness, we note these upper and lower cases are likely to exaggerate the likely range of outcomes. This is caused by the compounding effect of multiple ‘downside’ or ‘upside’ assumptions in each case.

4.19 We note that most of the quantified benefits come from more efficient demand response, based on the belief that this will improve if participants have access to more reliable real-time price signals.

4.20 We recognise that the improvement in demand response is uncertain. For this reason, we have considered what improvement in demand response would be required, in order for RTP just to break even.

4.21 This analysis indicates that if improved demand response is the sole benefit of RTP, it would need to increase by approximately 10 MW to breakeven under the base case cost estimates. This level of improvement in demand response appears relatively modest in overall terms, as it represents slightly more than 0.1% of total system demand in peak periods.

4.22 In light of the overall analysis, we think there are strong grounds to expect RTP to provide positive net benefits.

Q25. Do you agree with the cost benefit assessment? In particular:
– what (if any) other sources of benefit should be included in the assessment?
– what is your view on key assumptions, such as the level of improved demand response enabled by RTP?
– what (if any) other sources of costs should be included in the assessment?
Please explain your reasoning.

Alternative means of achieving the objectives of the proposed amendment

4.23 Our April 2016 information paper previously considered a range of alternative RTP designs (where Option B is the current proposal):

(a) Option A: single look-ahead 30-minute price

(b) Option C: average of look-behind 5-minute prices calculated in a trading period

(c) Option D: single look-behind 30-minute price.

4.24 Option A would provide a price based on expected conditions over the next 30 minutes. Setting prices in advance would allow both generation offers and demand bids to set prices. This includes bids for emergency load shedding at scarcity prices.

4.25 However, a lot can change in 30 minutes. Option A would require arrangements to prevent manipulation, such as a balancing market for differences. In effect, this would be an ahead-market option rather than RTP per se. We believe ex-ante mechanisms are better considered in their own right, and we have been considering them as a separate project.[48]

4.26 Options C and D would both produce prices on a look-behind basis. Neither of these options would produce prices that are closely aligned with dispatch outcomes. We expect them both to produce much lower net benefits than the proposed RTP changes. Further reasoning is set out in our earlier papers.[49]

Q26. Do you agree with our assessment of alternative RTP designs? If not, why not?

The Authority has given regard to the Code amendment principles

4.27 When considering amendments to the Code, the Authority is required by its Consultation Charter to have regard to the following Code amendment principles, to the extent the Authority considers they are applicable.[50] Table 4 describes the Authority's regard for the Code amendment principles in preparing our RTP proposal.

Table 4: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective (see paragraph 4.7) and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The efficiency gains are set out in the evaluation of the costs and benefits (see paragraphs 4.12 to 4.22).
3. Net benefits are quantified	The extent to which the Authority has been able to estimate the efficiency gains is set out in the evaluation of the costs and benefits (see paragraphs 4.12 to 4.22).

4.28 Principles 4 to 9 are not included in Table 4. They apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter). At this point, the Authority considers it is clear the proposed option is best.

48 See our consultation on making hours-ahead prices more accurate, http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/exploring-refinements-to-the-spot-market/consultations/#c16353.

49 See https://www.ea.govt.nz/dmsdocument/20599 and http://www.ea.govt.nz/dmsdocument/21128.

50 The consultation charter is one of the Authority's foundation documents, available at http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/.

Appendix A Format for submissions

Submitter	

Question		Comment
Q1.	Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.	
Q2.	Do you agree with using the time-weighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.	
Q3.	Do you agree with disestablishing the pricing manager and allocating residual functions to other parties? If not, please explain your reasoning.	
Q4.	Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
Q5.	Do you agree with using default scarcity bids before generation or dispatchable demand offered at a higher price in the dispatch schedule? If not, please explain your reasoning.	
Q6.	Do you agree the system operator does not need to make changes to the existing process it uses to notify distributors of emergency load shedding?	
Q7.	What is your view on the preferred treatment of disconnected nodes? Please explain your reasoning.	
Q8.	Do you agree that it is not desirable to apply a cumulative price limit under RTP? If not, please explain your reasoning.	
Q9.	Do you agree the current principle of partially relaxing reserve procurement before invoking emergency load shedding should continue under RTP? If not, please explain your reasoning.	

Q10.	Do you agree with the proposed removal of the high spring washer pricing provisions in the Code? If not, please explain your reasoning.	
Q11.	Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning.	
Q12.	Do you agree that ION meter data should be the primary data source for demand inputs? If not, please explain your reasoning.	
Q13.	What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning.	
Q14.	Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning.	
Q15.	Do you agree with the proposal to allow revisions to offers and bids within trading periods in some circumstances? If not, please explain your reasoning.	
Q16.	Do you agree with using the last bid or offer received in a trading period when calculating constrained on and off payments? If not, please explain your reasoning.	
Q17.	Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning.	
Q18.	Which approach do you prefer for managing pricing errors: a manual claim or automated checking? Please explain your reasoning (this could include suggestions for an automated filter).	
Q19.	If we retain a manual claim process for pricing errors under RTP, who should perform that role: – the system operator? – the Authority? – the pricing manager, as their only function? – some other party? Please explain	

your reasoning, including regarding any possible conflict of interest.	
Q20. Do you agree with the proposed treatment of spot prices during market system outages? If not, please explain your reasoning.	
Q21. Do you agree with the proposed changes to forecast schedules to align them with dispatch schedules? If not, please explain your reasoning.	
Q22. Do you agree with the proposed use of dispatch schedules to apportion loss and constraint excess for financial transmission rights each month (if that is required)? If not, please explain your reasoning.	
Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning.	
Q24. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning.	
Q25. Do you agree with the cost benefit assessment? In particular: – what (if any) other sources of benefit should be included in the assessment? – what is your view on key assumptions, such as the level of improved demand response enabled by RTP? – what (if any) other sources of costs should be included in the assessment? Please explain your reasoning.	
Q26. Do you agree with our assessment of alternative RTP designs? If not, why not?	

Appendix B TAS060 report from the system operator

Appendix C Form of Code amendment

Appendix D Information on default scarcity bid blocks

D.1 This appendix provides information on the proposed default scarcity bid blocks, as set out in Table 5. The initial discussion is given in section 3 from paragraph 3.14.

Table 5: Default scarcity bid blocks for forecast demand

Proportion of load	Value
5%	$10,000/MWh
15%	$15,000/MWh
80%	$20,000/MWh

Source: Electricity Authority

Scarcity bid values

D.2 The lower and higher values—$10,000/MWh and $20,000/MWh—reflect the existing parameters in the Code. If scarcity pricing is triggered, the Code provides for interim prices to first be calculated normally. Prices are then scaled up or down (if necessary), so that the generation-weighted average price over the affected island(s) is at least $10,000/MWh, and no more than $20,000/MWh.

D.3 These values were set in 2011 after extensive analysis and consultation. The Authority had detailed input from a technical group with representatives from consumer and supplier organisations. The Authority also developed two consultation papers that addressed scarcity pricing values. We considered feedback from a wide range of stakeholders before deciding on scarcity pricing values.

D.4 In summary, the Authority considered two alternative approaches to derive values:

(a) The assessed economic cost of curtailment to consumers. This approach indicated a range of values (around $10,000/MWh to $60,000/MWh for New Zealand), recognising that costs were expected to vary according to each situation. Important factors included the nature of affected load (eg, residential, commercial or industrial), duration of outages, and time of day and year. The analysis indicated a scarcity price of $10,000/MWh was reasonable, provided emergency load shedding could be targeted to avoid curtailing consumers with higher value load. To the extent this was not possible, a higher value would be justified.

(b) To achieve a target level of security; ie, sufficient to enable a last-resort diesel-fired peaking plant to breakeven at a given level of security. This approach indicated a value of approximately $10,000/MWh.

D.5 The Authority also considered a range of other information sources as cross-checks to derive scarcity pricing values. These included:

(a) scarcity price values used in other electricity market jurisdictions, including Australia and Singapore

(b) market indicators of the price at which demand-side participants would voluntarily reduce load (noting that emergency load shedding is not voluntary)

(c) the value of lost load used for assessing transmission investment proposals.

D.6 Further information on how the Authority derived these values is available in the 2011 scarcity pricing consultation documents.[51]

Scarcity bid block function: volume and value steps

D.7 The proposed volume structure for the blocks is based on the following considerations:

(a) Costs from involuntary curtailment would be expected to rise with the increasing levels of emergency load shedding at each node. For this reason, a stepped function should apply at each node.

(b) Given there is insufficient information to differentiate between nodes based on expected costs of emergency load shedding, a common bid structure based on percentage load blocks has been applied across nodes.

(c) The initial block has been set at 5% of load at each node at $10,000/MWh. This value is the bottom end of the scarcity value range. Although this block is a modest fraction of the load at each node, it is likely to be sufficient to address many emergency situations (bearing in mind that 5% of load across multiple nodes can represent a significant number of MW). Setting the block size at 5% also means that emergency load shedding would typically be shared across many nodes, rather than concentrated at single (or few) nodes simply based on transmission loss differences.[52]

(d) The second block has been set at 15% of load at each node at $15,000/MWh. Together with the initial 5% block, this is likely sufficient to address most emergency situations. This incremental tranche of load is expected to have a substantially higher cost of curtailment because it has a much larger impact on demand. In the absence of more specific data, the price has been set at the mid-point of the existing scarcity price range.

(e) The third block comprises the remaining load at each node (ie, 80%) at $20,000/MWh. Emergency load shedding of this depth should only be required in extreme situations, and affected consumers would be expected to incur significant costs from curtailment. This block has been priced at the higher scarcity pricing value in the Code ($20,000/MWh).

[51] See http://www.ea.govt.nz/dmsdocument/9784 and https://www.ea.govt.nz/dmsdocument/11096.

[52] Further detail is given in section 4.1 of the system operator's TAS060 report in Appendix B.

Appendix E Assessment of benefits and costs

E.1 This appendix sets out the estimated benefits and costs of adopting RTP.

Assessment framework

E.2 The Authority has adopted the following approach to this assessment:

(a) the analysis is undertaken from an economy-wide perspective, based on the expected incremental benefits and costs of adopting RTP

(a) effects are assessed over a 15-year period, starting from the date RTP is implemented

(b) values are estimated in 2017 dollars using a 6% real discount rate; sensitivity cases with discount rates of 4% and 8% are also considered

(c) the counterfactual to RTP assumes that existing arrangements remain in place, except that shortened gate closure (to one hour) applies and the EDF Phase 3 project has been implemented.

E.3 Our cost benefit analysis builds on the framework used in our April 2016 RTP information paper.[53] In summary, our earlier work developed quantitative estimates for demand response, retail competition and innovation, and reliability benefits. Given the inherent uncertainties involved, benefits were estimated for a base case, and lower and higher case scenarios. These estimates were compared to the expected costs of implementing and operating RTP, to calculate expected net benefits under the range of scenarios.

E.4 Our assessment retains the same overall framework, and we have updated it to:

(a) incorporate more recent or accurate information where it is available, especially in relation to expected implementation costs

(b) reflect comments and feedback raised in submissions on our April 2016 RTP information paper.

Categories of expected benefit

E.5 We expect RTP to have the following benefits:

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

(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.

E.6 Each of these benefits is discussed below.

53 Our April 2016 *Assessment of real-time pricing options* information paper is available at [http://www.ea.govt.nz/dmsdocument/20599.](http://www.ea.govt.nz/dmsdocument/20599)

Benefits from more efficient levels of demand-response from industrial and commercial consumers

E.7 We expect RTP to make it easier for consumers to react to spot prices in an efficient way; ie, reduce consumption if the price exceeds their willingness to pay, and vice versa. Market participants will have better pricing information in real-time, allowing them to calculate the financial consequences of prospective actions with more certainty.

E.8 We expect the increased demand response to come from existing parties who become even more active, and from parties who currently do not offer any demand response capability. In both cases, the demand response may involve a cut in energy usage, a shift in timing of consumption away from peak periods, or a reduction in system demand[54] enabled by using non-grid connected generation that is not subject to dispatch rules.[55] For simplicity, all of these are referred to as 'demand response' for the purpose of this analysis.

E.9 Unlocking this latent demand response capability should reduce the total volume of generation capacity required to meet peak demand, all other things being equal. That is, we could obtain the same overall level of reliability at lower cost through a more efficient mix of voluntary demand response and generation. We recognise that there is considerable uncertainty about the amount of demand-response that RTP will unlock. For this reason, we have adopted a bottom-up approach with significant variation in key inputs to cover the range of possible outcomes.

E.10 We estimate the benefit using the formula $B = (L + G)pXV / (1+DR)^{Y}$, where:

(a) B is the efficiency benefit (in $m present value)

(b) L and G are the amounts of load and embedded generation, respectively, that can potentially respond to short-term spot price forecasts (in MW)

(c) p is the incremental proportion of this capacity that chooses to respond as a result of improved spot price signals

(d) X is a ratio that reflects the reduction in peak generation capacity that is enabled by each additional unit of demand response capacity. A ratio of one means each additional MW of demand response reduces the generation capacity required by 1 MW

(e) V is the cost of installing new peak generation and associated network infrastructure (real $m/MW)

(f) DR is the discount rate

(g) Y is the number of years until new investment will be required to provide peak capacity.

E.11 We previously estimated L to be approximately 400 MW, based on information in distributor Asset Management Plans about the amount of commercial and industrial load in the 1-20 MVA range.[56] We estimated G to be approximately 50 MW. We have retained these figures from our previous assessment as the base case assumptions.

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54 In this context, system demand refers to energy used at the grid level.

55 In other words, the gate closure rules do not restrict changes in generation output.

56 This excludes residential load, which is separately identified in Asset Management Plans.

E.12 These estimates for L and G do not include any allowance for increased demand response from major grid-connected industrial consumers. In effect, this assumes these consumers already respond to spot prices, and adopting RTP will not increase that response. We note this assumption is likely to be conservative, as improved spot price information should also assist grid-connected consumers to make more efficient decisions. However, we have retained this assumption for the current analysis given the absence of firm new information to the contrary.

E.13 To develop projections for 15 years, we adjusted the estimates for L and G using the projected annual growth rates for peak demand in Transpower's most recent 'Transmission Planning Report', published in 2015 (ie, 0%, 1.1%, and 2.5% per annum for the lower, base, and higher cases, respectively).

E.14 We estimated V to be $1.2m/MW (real) in the base case. We have retained this estimate, and also adopted it for the higher and lower cases.

E.15 We assumed there is no lag between introducing RTP and the first year in which benefit begins to accrue (ie, Y=0).

E.16 We assumed demand response has an average variable operating cost of about $550/MWh. Demand response will displace the marginal generator at peak times, and this is normally an open-cycle gas turbine with a variable operating cost of about $300/MWh. Demand response therefore incurs an additional cost of $250/MWh for each unit of output.

E.17 The additional demand response is assumed to operate for 90 hours per year (~1% of hours). This figure should be consistent with the assumed MW level of demand response; as discussed below, this equates to around 75 MW across the combination of industrial, commercial, and residential load. There is limited information in this area, but one potential comparator is the number of hours of demand response that would be required to reduce peak demand by 75 MW, based on historical demand duration curve data. Between 2010 and 2016, the difference between peak annual grid demand and the 99th percentile of demand (ie, the difference across the highest 1% of hours) consistently exceeded 260 MW. If anything, that suggests demand response across fewer than 1% of hours would be required to lower peak demand by 75 MW. However, not all additional demand response is likely to occur during the absolute peak demand periods, so a 90 hour assumption has been adopted in the CBA.

E.18 We revised the base estimate of X from 0.7 to 1, because reducing demand by 1 MW should also reduce generation requirements by 1 MW. This is a conservative estimate because reducing the need for generation will also reduce losses, so we would expect X to be slightly greater than 1 in practice.

E.19 We have retained 10% as the base case estimate for the value of p, with lower and upper values of 8% and 12%.

E.20 As a reality check, the reduction in peak generation capacity required under the base case assumptions is 52 MW. This is equivalent to 1.4% of total non-residential peak demand. Thus, we assume RTP will enable a relatively modest increase in demand response.

E.21 As a point of comparison, a 2013 study from the United States estimated that active demand response resources varied between around 2.3% and 10.5% of peak system demand across seven regions, with varying market arrangements.[57] These estimates were based on prevailing demand response resources, rather than the total potentially available. The International Energy Agency stated in 2011 that 'recent studies have estimated demand response potential in the more competitive European and North American markets at 15% to 20% of peak demand'.[58] In light of these figures, an assumed increase in demand response of 1.4% does not appear unreasonable.

E.22 This analysis yields overall efficiency benefits from demand-response of industrial and commercial consumers of $48 million, less additional costs of $9 million (ie, $39 million in net terms).

Benefits from more efficient levels of demand-response from residential consumers

E.23 Our estimated benefit from increased demand response, calculated in the previous subsection, is based purely on more efficient demand response from larger commercial and industrial consumers (excluding grid-connected parties). It does not include any benefit from improved demand response by residential consumers, even though they account for the majority of peak demand on the system.

E.24 There is significant potential for residential consumers to participate in the wholesale electricity market as technology improves (especially through smart appliances and batteries). In fact, some consumers already do this; eg, by purchasing electricity from retailers on terms directly linked to spot prices. More actionable spot prices would make existing participation broader and more dynamic. In turn, we expect this to produce broader benefits through greater competition and more innovative retail offers to consumers.

E.25 We expect this response to be achieved primarily through automated demand response mechanisms. However, current residential consumer behaviour suggests some customers may wish to actively vary their usage in response to spot prices themselves.[59]

E.26 The peak demand requirement for residential consumers is approximately 3,740 MW from around 1.7 million residential connections, with an average use at peak of approximately 2.2 kW per connection.

E.27 There is little concrete information available on the level of demand response that RTP could enable. For the purposes of this assessment, we assumed a base case estimate of demand response equal to 0.6% of total residential demand, with upper and lower estimates of 0.9% and 0.4%. We apply varying lead-in periods after RTP is implemented to attain this benefit.

E.28 We assume the operating cost of demand response from residential consumers is $800/MWh.[60] Residential demand response therefore incurs an additional cost of $500/MWh for each unit of output, compared to an open-cycle gas turbine.

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57 See http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-03.RAP_.US-Demand-Response.12-080.pdf.

58 See http://www.iea.org/publications/freepublications/publication/Empower.pdf.

59 Note, this benefit was referred to as 'retail innovation and competition' in our April 2016 RTP information paper for this reason

60 This means we assume discretionary residential usage is more costly than the discretionary commercial and industrial usage described in paragraph E.16

E.29 This yields base case benefit estimates of $21 million, less additional demand response costs of $7 million (ie, $14 million in net terms).

Benefits from more efficient levels of reliability

E.30 The two estimates of benefit calculated so far—increased demand response and retail innovation and competition—considered the benefit from improving the mix of *voluntary* demand response (including embedded generation) and conventional peak generation. That analysis assumes the system is already achieving an efficient level of reliability. Put another way, it assumes the system is already delivering the optimal level of *involuntary* demand response.

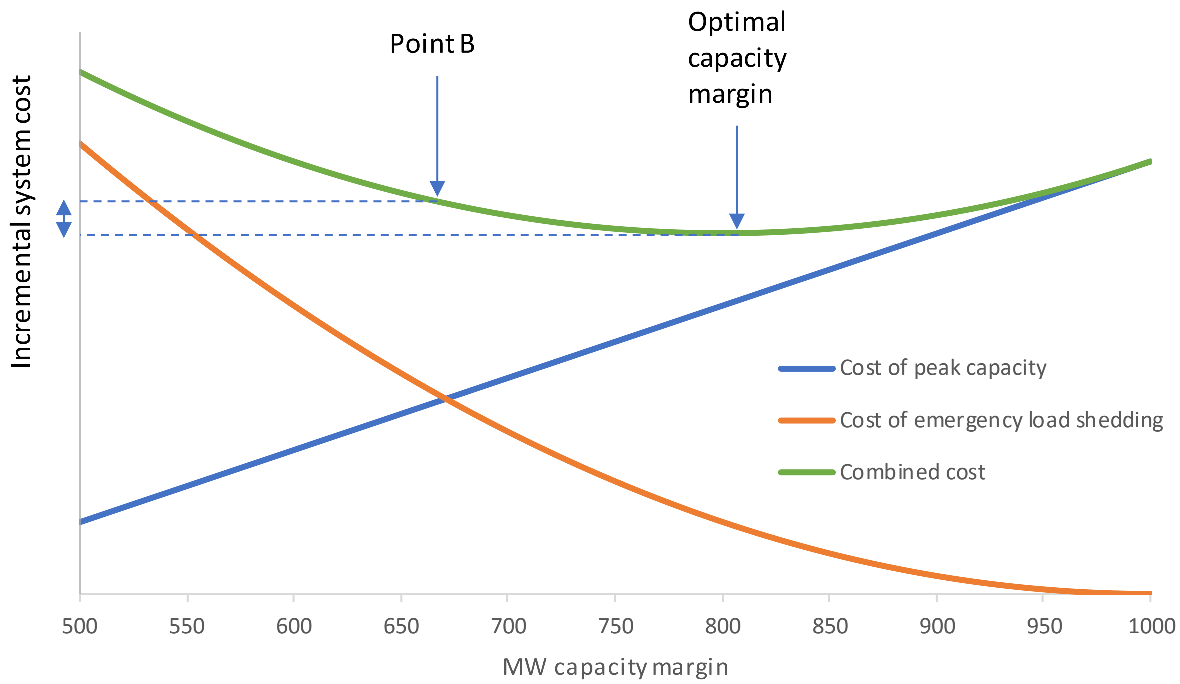
E.31 However, under current arrangements indicative spot prices can be unreliable predictors of final prices, especially during system stress. This undermines confidence in prices, and can reduce the incentives to provide last-resort resources. For example, resource providers may perceive an increased likelihood of high final prices being moderated in some way in situations where they have not been preceded by high indicative prices.

E.32 Similarly, any high prices under present arrangements are likely to be based on a generator offer, or be derived from an administrative process such as scarcity pricing. This may reduce the perceived integrity of prices, as compared to the proposed alternatives where high prices are more likely to reflect bids submitted by consumers.

E.33 Together, these effects can undermine confidence in prices during times of system stress, and in turn reduce the incentives for parties to provide last-resort resources. The overall impact is shown in Figure 9 below, which depicts the system capacity margin along the x-axis, and the incremental system cost on the y-axis (values are illustrative).

E.34 The blue line shows the incremental cost of adding more peaking generation capacity, assuming efficient voluntary demand response is already being used. The total cost of peaking capacity rises as the capacity margin increases. The red line depicts the cost of emergency load shedding. This falls as system margin increases. It is not linear because the cost of load shedding rises with how often and how much load is cut. The combined cost of load shedding and peak capacity is shown by the green line—the minimum point represents the efficient (optimal) level of system margin.

Figure 9: How spot price signals affect reliability



E.35 Departures from the minimum (such as Point B) mean the total system cost will rise, as shown on the y-axis. Because the combined cost is non-linear, the change in cost is not proportional to the change in capacity margin.

E.36 We have previously estimated the total cost of divergences from the optimal capacity margin.[61] That analysis indicated that a 50 MW difference would increase system costs by around $1 million per year, whereas a 100 MW difference would increase system costs by approximately $5 million per year.

E.37 Historically, there is no clear evidence to indicate that capacity margins have been below efficient levels. However, past investment and retention decisions in New Zealand have been driven mainly by a desire to ensure energy-adequacy; ie, the ability to get through sustained dry periods.

E.38 Resources provided to meet that need also contribute to meeting short-term capacity requirements. For this reason, capacity adequacy has not been the binding constraint in driving resource decisions.

E.39 Over time, the system has evolved toward a position where capacity or energy constraints could bind. Indeed, in recent years it appears more likely that capacity constraints could bind before energy constraints, because peak demand has been growing faster than energy demand. This means historical data does not necessarily provide a good guide to the future.

E.40 In light of these factors, our analysis assumes a divergence of 50 MW (0.6% of peak demand) from the optimal capacity margin in the base case. Given the range of uncertainty, we have assumed no reliability benefit for the lower case, and a divergence of 75 MW for the higher case.

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61 See our 2012 *Winter energy and capacity security of supply standards* decision paper, available at http://www.ea.govt.nz/dmsdocument/13936.

E.41 This yields base case benefit estimates of $8 million.

Benefits from more efficient generation scheduling and dispatch

E.42 Some generators have complex short-term planning and optimisation decisions, and prices are a key input to these decisions. The extended lag before final prices are published reduces the quality of information available to optimise these decisions.

E.43 Anecdotal evidence suggests this category of benefit may be important. For example, one generator has indicated informally that providing better forecasts of final prices close to real-time would improve its commitment decisions. Similarly, the widespread support for shortening gate closure amongst generation participants supports the view that optimising short-term generation is an important issue;[62] although it is not clear how much improvement depends on better information or providing more flexibility to generators.

E.44 Based on present information, we have not developed any quantitative estimate of benefits. However, the benefits in this area may be material.

Benefits from more effective risk management

E.45 Under RTP, spot prices should more accurately reflect actual conditions when the system is very tight; ie, prices are less likely to under- or over-shoot the true value of energy and reserve. This should improve confidence in the value of risk management products (such as caps), and enable better risk management decisions

E.46 Although this effect could be material, we do not have sufficient information to quantify it in this cost benefit assessment.

Benefits from increased overall market confidence

E.47 Current arrangements increase the risk of a major loss of market confidence. An unexpected large spike in final prices could cause widespread financial distress and associated loss of market confidence. RTP should reduce the risk of this occurring by increasing the response of smaller parties to consume less and generate more.

E.48 We have not quantified this benefit as there is insufficient information to derive an estimate. Nonetheless, the benefit may be material because a loss of confidence could lead to changes that ultimately affect the entire wholesale electricity market.

Categories of expected cost

E.49 RTP is expected to facilitate more efficient levels of demand response, though this gives rise to some ongoing direct costs.[63] These costs are summarised in paragraphs E.16 and E.28. In addition, we expect introducing RTP will lead to implementation costs in the following areas.

Costs for system operator

E.50 The system operator would need to change market systems. The system operator has developed rough order of magnitude (ROM) estimates of $7.6 million and $11.0 million, with an expected value of $8.9 million. In addition, we are proposing variations to enable revisions to bids and offers inside trading periods, and use of ION meter data (mid-point

62 For example, see Meridian Energy’s submission to the 2015 consultation on *Gate Closure and Bid Offer revisions* at https://ea.govt.nz/dmsdocument/20002.

63 In other words, the costs to consumers of voluntarily reducing electricity use at times.

estimates of $37.5k and $150k respectively). The system operator's TAS060 report sets out further detail in Appendix B.

E.51 For simplicity, we assume these costs are incurred halfway through the implementation period and discount accordingly. This gives a net present value of $8 million in the base case.

Costs for pricing and clearing manager functions

E.52 The pricing manager currently determines provisional, interim, and final prices after real-time. This is a separate service provider from the system operator. The role and most of its functions would cease with RTP, with some residual responsibilities being transferred to other parties (eg, the clearing manager for calculation of interim and final prices, and the system operator to address any pricing error claims).

Overall service provider costs

E.53 Implementing these changes will incur some up-front costs, including contract termination payments. Taking these costs into account, as well as the operational savings, we expect a saving in overall service provider costs. These have been estimated at a net present value of $0–$2 million.

Implementation costs for participants

E.54 We do not expect RTP to create any material ongoing implementation costs for wholesale market participants, because:

(a) participants already receive real-time pricing information, so we do not expect the proposals to trigger any material requirement for participants to change their systems or processes

(b) participants already lodge bids and offers and would continue to do so under the proposed changes

(c) the RTP design should not create any material new compliance obligations or costs for participants.

(d) although dispatchable demand processes would change, there is currently only one affected participant, and current information suggests they will not face significant costs.

E.55 In light of these factors, we do not expect a net change in participant costs.

Estimated benefits and costs

E.56 The results of the analysis are summarised in Table 6. Note that numbers in Table 6 may not add due to rounding (to whole millions).

Table 6: Estimated benefits and costs

Item $m (present value)	Lower case	Base case	Higher case
Benefits[1]			
Demand response benefit—industrial and commercial	28	48	85
Demand response benefit—residential	8	21	53
Reliability benefit	0	8	19
Total benefits	36	77	157
Demand response costs			
Industrial and commercial	-5	-9	-17
Residential	-2	-7	-21
Total demand response costs	-7	-16	-37
Implementation costs			
System operator function	-10	-8	-7
Pricing and clearing functions (net saving)	0	0	1
Participant implementation costs	0	0	0
Total implementation costs	-10	-8	-6
Net benefits	19	53	114

Source: Electricity Authority

Notes: 1. Excludes some benefits that are not quantified

E.57 The analysis shows net benefits of $53 million in the base case.

E.58 The lower and upper cases also show positive net benefits. For completeness, we note these upper and lower cases are likely to exaggerate the likely range of outcomes. This is caused by the compounding effect of multiple ‘downside’ or ‘upside’ assumptions in each case.

Break-even sensitivity test

E.59 We note that most of the quantified benefits come from more efficient demand response. This is based on the belief demand response will improve if participants have access to more reliable real-time price signals.

E.60 We recognise the level of improvement in demand response enabled by RTP is subject to uncertainty. For this reason, we have also asked what improvement in demand response would be required, in order for RTP to be breakeven in economic terms.

E.61 This analysis indicates that if improved demand response is the sole benefit of RTP, it would need to increase by approximately 10 MW to achieve a breakeven result under the base case cost estimates. This level of improvement in demand response appears relatively modest in overall terms, as it represents slightly more than 0.1% of total system demand in peak periods.

E.62 In light of the overall analysis, we think there are strong grounds to expect RTP to provide positive net benefits.

Appendix F Indicative effects of RTP on prices

F.1 This appendix discusses the indicative effect of adopting RTP on spot prices and electricity charges for consumers. In particular, it considers the effect on final prices of using dispatch prices where ‘infeasibilities’ occur in dispatch schedules.[64]

F.2 This analysis should be treated as a broad approximation because:

(a) it cannot take account of all factors that would apply in the real world

(b) the results are sensitive to the input assumptions.

We used a ‘hindcast’ analysis to assess indicative price effects

F.3 To assess indicative price effects, we prepared a ‘hindcast’ that seeks to simulate the pricing outcomes if RTP had been operating in the past.

The status quo case

F.4 Our status quo case uses historic data for 1 April 2015 to 7 May 2017. The time-weighted average of final spot prices at Otahuhu in the status quo was $61.76/MWh.

F.5 Over the period, more than 200,000 real-time dispatch (RTD) schedules were produced that resulted in dispatch instructions.[65] Around 1% of these RTD schedules contained an infeasibility. Table 3 summarises these infeasibilities by source.

Table 7: Analysis of dispatched RTD schedules April 2015 to May 2017

Infeasibility cause	Number of RTD schedules	Number of trading periods
Reserve deficit	27	13
Branch limit	26	9
Branch constraint[66]	71	23
Disconnected node	1,800	603
Disconnected region	2	1
Total schedules containing an infeasibility	1,926	649

Source: Electricity Authority

64 Strictly speaking, infeasibilities will not arise under RTP (see paragraph 3.6). However, dispatch prices may be influenced by default scarcity bids or the constraint violation penalty function that applies in an instantaneous reserves shortfall. We have use ‘infeasibility’ here because it describes what occurs under current real-time dispatch schedules.

65 We did not consider any RTD schedules that did not result in a dispatch instruction.

66 ‘Branch limit’ refers to situations where the flow in a line is limited by its rated capacity. ‘Branch constraint’ refers to situations where the flow across multiple lines exceeds their combined capacity.

F.6 Instantaneous reserve deficits affected 27 RTD schedules and 13 trading periods. Under RTP, these situations would be expected to trigger a constraint violation penalty, which would influence dispatch and final prices. Instantaneous reserve deficits would have a widespread geographic impact, because they affect the whole of one or both islands.

F.7 Infeasibilities caused by branch limits and branch constraints affected 97 RTD schedules and 32 trading periods. Most of these situations were localised in nature, affecting 20 or fewer nodes. There were three situations where 27 nodes were affected, and one which affected 59 nodes (the entire upper South Island). Under RTP, these situations would be expected to trigger default scarcity bids, affecting final prices in the relevant local area.

F.8 Most of the infeasibilities (>90%) were due to disconnected nodes or disconnected regions. As discussed in paragraph 3.37, in these situations we propose assigning a price based on the applicable reference node's final price for the relevant trading period, multiplied by a location factor. This is not expected to have any discernible effect on final prices, as compared to the status quo.

The RTP cases

F.9 We have assessed two different RTP cases:

(a) **RTP initial effect**: focuses on the 'year one' effect of RTP when it is first introduced. We assumed market participants do not change their behaviour after RTP is introduced in any way. In particular, we assumed participants that are currently price-responsive continue to react, and those that are currently unresponsive do not alter their behaviour when the system is under stress despite the introduction of sharper and clearer price signals.[67] This assumption is unrealistic, because some participants are likely to alter their behaviour—indeed that is one of the intended outcomes. The RTP initial case analysis is therefore likely to overstate the expected price effect, all other things being equal.

(b) **RTP full effect**: considers the potential effect once participants have adjusted to RTP. In this case, the time-weighted average spot price would be expected to be the same as if RTP is not introduced, because in both cases the time-weighted price will be capped by the cost of new generation.[68] However, even though the time-weighted average price is expected to be unchanged, RTP is expected to alter the structure of spot prices, with higher (and more certain) prices in tight supply periods, and slightly lower prices on average in other periods.[69] The change in the structure of prices would affect different types of consumer and supplier in different ways, depending on their pattern of usage or supply.

F.10 To estimate the size of the RTP initial effect, we replaced the final prices from the status quo case whenever the associated real-time dispatch schedule indicated an instantaneous reserve deficit. We assumed a value of $10,000/MWh applied for the proportion of time within any trading period that an instantaneous reserve deficit

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67 That is, during an instantaneous reserve shortfall or energy deficit.

68 In the medium term, we expect new generation would enter the market if the time-weighted average price exceeded the time-weighted average cost of new generation. This would put downward pressure on prices, which in turn would delay further new investment. The reverse position also holds. These observations refer to general tendencies over the medium term; oscillations around that trend are likely.

69 RTP is expected to more accurately reflect the cost of resources when the system is under stress, raising average prices in these times. To maintain the same overall time-weighted average price as without RTP (as discussed in footnote 68), prices in non-peak periods are expected to be slightly lower on average under RTP.

appeared in a dispatch schedule.[70] Otherwise, final prices were left unchanged. This adjustment produced a time-weighted average price at Otahuhu of $62.82/MWh.

F.11 We did not adjust for:

(a) branch constraints or branch limits because these did not affect prices at the Otahuhu node (see further comments at paragraph F.18)

(b) disconnected nodes or disconnected regions because Otahuhu was again unaffected, and we do not expect RTP to materially alter prices for these events in any case.

F.12 For the full RTP effect, we assumed spot prices in trading periods affected by instantaneous reserve shortfalls were the same as in the RTP initial effect. We slightly scaled down spot prices in other trading periods to achieve the same overall time-weighted average price as the status quo case. We did not make any other adjustments to prices.

We estimated effects for different types of consumer

F.13 We considered the effect of RTP on four illustrative consumer types:

(a) Residential consumer (unresponsive): most households consume more electricity during periods of higher-than-average system demand, when spot prices tend to be elevated. We assumed the illustrative residential consumer uses 34% more electricity in these demand periods than other periods, and that periods of higher-than-average demand accounted for 39% of the total time. These assumptions appear reasonable based on observed historic data. We also assumed they will not react to a change in price signals associated with RTP.

(b) Residential consumer (responsive): the assumptions were the same as (a), except we assumed this consumer reacts to price signals to the degree necessary to avoid the RTP initial effect. In practice, a highly responsive consumer may be able to respond even more aggressively and lower their charges. However, we simply assumed response sufficient to keep charges constant.

(c) Industrial consumer (unresponsive): industrial consumers tend to have consumption profiles that are less correlated with system demand. We assumed the illustrative industrial consumer pays the time-weighted average price.[71]

(d) Industrial consumer (responsive): the assumptions were the same as (c), except that we assumed this consumer will react to price signals to the degree necessary to avoid the RTP initial effect. Again, a highly responsive consumer may be able to respond even more aggressively and lower their charges.

F.14 For all consumer types, we estimate the effects of RTP on delivered charges, based on the observed proportions of total electricity charges that are due to wholesale energy costs.

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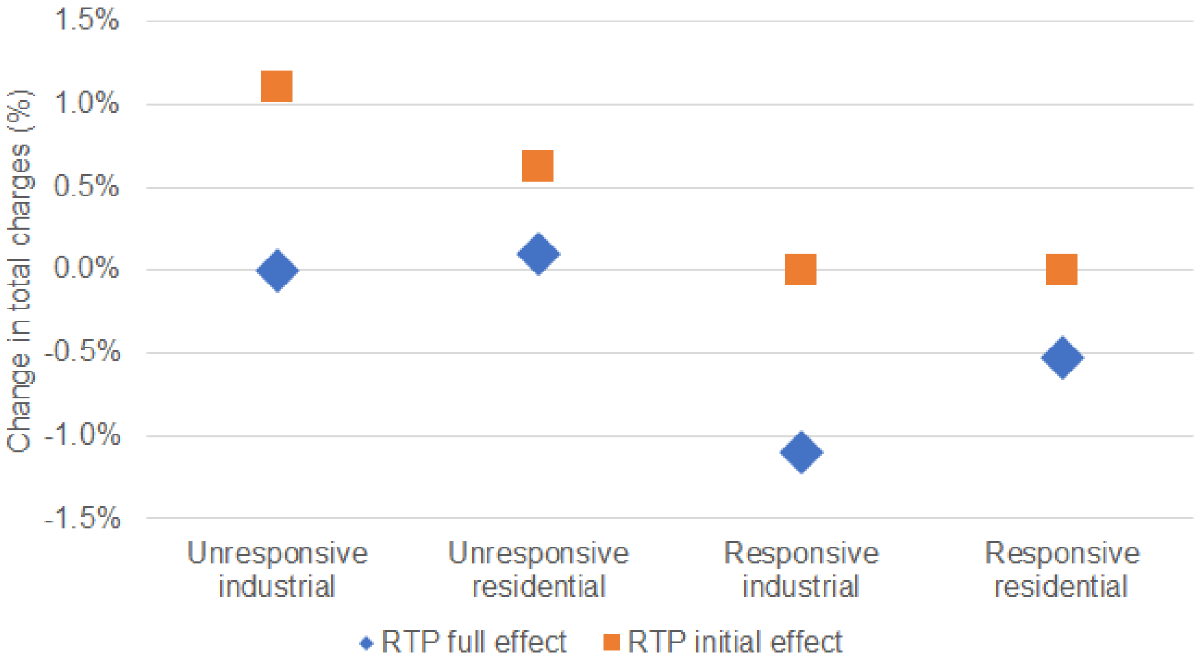
70 Strictly speaking, if the status quo Otahuhu price ("OTA price") was greater than $10,000/MWh, we set the final price to the minimum of $10,000/MWh, and $10,000/MWh × OTA price / (sustained instantaneous reserve price + fast instantaneous reserve price).

71 The consumer need not have a baseload consumption profile. Their usage may vary, but they would pay the time-weighted average spot price as long as their consumption is not correlated with spot prices.

RTP effect varies by timeframe and consumer type

F.15 The results of applying the analysis are summarised in Figure 10.

Figure 10: Indicative effect of RTP on delivered electricity charges



Source: Electricity Authority

F.16 Key observations from this analysis are:

(a) The RTP initial effect on delivered electricity charges varies between nil effect (responsive consumers) and an increase of around 1.1% (unresponsive industrial consumers).

(b) The RTP full effect on delivered electricity charges varies between an increase of around 0.1% (unresponsive residential consumers) and a reduction of around 1.1% (responsive industrial consumers).

(c) The RTP initial effect puts upward pressure on charges—but this effect is expected to be mitigated or offset where consumers are able to respond to the more certain price signals RTP provides.

(d) The RTP full effect results in no increase for most of the illustrative customer types. Unresponsive residential consumers are the exception, for whom a 0.1% increase in charges is projected. These consumers use more energy during periods with higher system demand, and they will not benefit from the more certain price signals RTP provides if they do not alter their usage patterns.

The results of the analysis are sensitive to input assumptions

F.17 The projected effects are based on data for the period April 2015 to May 2017. This period may or may not be representative of future conditions. In particular, it did not contain any RTD schedules where widespread energy shortages occurred (which would trigger default scarcity bids under RTP). On the other hand, we expect final prices would be similar under the status quo and RTP if such events occurred. This is because the default scarcity values proposed for RTP are based on the current scarcity price arrangements. In short, while differences could arise, we do not have any reliable information to estimate the likely magnitude or direction.

F.18 Our analysis also does not incorporate any price adjustments for infeasibilities that arose due to branch constraints or branch limits. These did not affect the Otahuhu node, as noted in paragraph F.11. However, 97 RTD schedules (approximately 0.05% of the total) did contain such infeasibilities, and these would affect pricing at relevant nodes under RTP. Looking at the historical data, some nodes were only affected by a few events, and we therefore expect little effect on prices. On the other hand, some nodes were affected more frequently.

F.19 To obtain a rough estimate of possible effects, we considered a scenario where 58% of all the branch constraint and branch limit events occurring in the historic period affect a single node.[72] We assumed prices in these events are $61.76/MWh under the status quo (ie, the same as the time-weighted average at Otahuhu), moving to $10,000/MWh under RTP.

F.20 In this scenario, the time-weighted average spot price at the affected node would increase by 3.1% for the RTP initial effect. For an unresponsive residential user, this equates to an increase in delivered charges around 0.9%. For an unresponsive industrial user, this equates to an increase in delivered charges around 2.0%.

F.21 However, these estimates assume participants at a node repeatedly affected by branch limits or constraints do not change their behaviour. That assumption seems implausible. We expect the clearer price signal RTP introduces would alter behaviour. In particular, the reward for demand response (or increased self-supply) at a node subject to frequent branch limits or constraints would increase substantially compared to the status quo. We expect that in turn would reduce the frequency of these types of events and the consequent effect on price. We have not explicitly modelled this effect, but expect it would substantially mitigate the impact of RTP at nodes frequently affected by branch limits or branch constraints.

Wealth effects versus efficiency effects

F.22 The analysis above focuses on RTP's indicative effect on electricity prices. Price effects will not necessarily be the same as efficiency effects (assessed in the cost benefit analysis in Appendix E).[73] Efficiency effects measure costs or benefits for society as a whole. For example, a price effect that simply results in one consumer paying slightly more and another paying slightly less is a wealth transfer. This is not a gain or a loss for society as a whole.

F.23 Conversely, price changes that reduce total costs for society are classified as efficiency gains. For example, introducing RTP should make it easier for consumers who value electricity at less than the spot price to voluntarily reduce their demand. That in turn should enable a saving in generation costs, compared to the status quo.

F.24 This a net gain to society as a whole, because the value of the foregone electricity consumption is lower than the incremental cost of generation.

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72 58% of branch constraints affected the upper South Island. This region was the most frequently affected.

73 However, the Authority would take wealth transfer effects into account in a cost benefit analysis, to the extent they are expected to affect efficiency.

Appendix G Treatment of load and bid types under RTP

A.1 Table 8 lists all load and purchaser bid types, where they apply, and how their price and quantity would be used across the forecast and dispatch schedules under RTP. The four-character identifiers in square brackets are market system bid codes listed by the system operator in Table 3 of the TAS060 report in Appendix B (p. 29). An entry of 'Scarcity' means the relevant load is assigned default scarcity pricing values.

Table 8: Treatment of load and purchaser bids by type under RTP

Bid or load type	**Node type**	**NRS**		**PRS**		**Dispatch**	
		Price	***Quantity***	***Price***	***Quantity***	***Price***	***Quantity***
Forecast load	Conforming	Scarcity	Load forecast	Scarcity	Load forecast	Scarcity	Load forecast
Non-dispatchable purchasers at conforming nodes <u>may</u> indicate their intentions, using relative volumes							
Difference bid [ENDF]	Conforming	N/A	N/A[74]	Bid	Bid	N/A	N/A
Non-dispatchable purchasers at non-conforming nodes <u>must</u> indicate their intentions, using absolute volumes							
Non-DCLS[75] nominated non-dispatch bid [ENCC]	Non-conforming	Scarcity	Bid	Bid	Bid	Scarcity	Load forecast (persistence[76])
DCLS bidding available for dispatch							
Dispatchable demand: nominated **dispatch** bid [ENDL]	Any	Bid	Bid	Bid	Bid	Bid	Bid

74 Difference bids are only indicative in the PRS; their quantity (and hence price) is simply part of the conforming load forecast for the NRS and dispatch.

75 Dispatch-capable load stations (DCLS) refer to the device(s) approved by the system operator for use as dispatchable demand.

76 As per the system operator's TAS060 report in Appendix B (p. 38 and Appendix 1, item 12): <u>all</u> load at non-conforming nodes (ie, node level, not purchaser-specific) is replaced by bottom-up persistence forecast (using ION meter data).

Bid or load type	**Node type**	**NRS**		**PRS**		**Dispatch**	
		Price	***Quantity***	***Price***	***Quantity***	***Price***	***Quantity***
Dispatch-lite:[77] nominated **dispatch** bid [ENXX]	Non-conforming	Bid	Bid	Bid	Bid	Bid	Bid
Dispatch-lite: nominated **dispatch** bid [ENZZ]	Conforming	Bid	Bid	Bid	Bid	Bid	Bid
DCLS bidding unavailable for dispatch (becomes an indication of intent)							
Dispatchable demand: nominated **non-dispatch** bid[78] [ENDL]	Any	Scarcity	Bid	Bid	Bid	Scarcity	Load forecast (persistence)
Dispatch-lite: nominated **non-dispatch** bid[79] [ENXX]	Non-conforming	Scarcity	Bid	Bid	Bid	Scarcity	Load forecast (persistence)
Dispatch-lite: nominated **non-dispatch** bid [ENZZ]	Conforming	Scarcity	Bid	Bid	Bid	Scarcity	Load forecast (persistence)

77 Dispatch-lite will be a form of DCLS using nominated bids, as for existing dispatchable demand.

78 Dispatchable demand does not need to bid dispatchable for all trading periods; ie, it can bid undispatchable. This discretion will be retained under RTP.

79 Bidding undispatchable is likely to be re-used as the mechanism to allow dispatch-lite to either rebid unavailable, or to reflect a ‘no’ acknowledgment to a dispatch notification.

Glossary of abbreviations and terms

Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
CVP	Constraint violation penalty
EDB	Electricity distribution business
FIR	Fast instantaneous reserve
FTRs	Financial transmission rights
HSWPS	High spring washer pricing situation
LCE	Loss and constraint excess
NEM	Australian National Electricity Market
NRS	Non-response schedule
PRS	Price-responsive schedule
ROM	Rough order of magnitude
RTD	Real-time dispatch
RTP	Real-time pricing
SCADA	Supervisory Control and Data Acquisition
SDV	SCADA Data Validation
SIR	Sustained instantaneous reserve
TAS	Technical Advisory Services provided by the system operator
vSPD	Vectorised scheduling, pricing, and dispatch model
WAG	Wholesale Advisory Group
WDS	Weekly dispatch schedule
WITS	Wholesale Information and Trading System