Remaining elements of real-time pricing

Consultation paper

Submissions close: **5pm 30 April 2019**

19 March 2019

Executive summary

We are seeking views on three remaining design elements of our proposal to determine and publish final prices for the wholesale spot market in real-time. We call this real-time pricing (RTP). This second consultation follows our August 2017 consultation, which set out the major elements of our proposed RTP design.

The three remaining design elements are:

a. full details of our proposal for ‘dispatch-lite’, now expanded to include smaller-scale generation

b. the pricing that should apply during shortfalls in instantaneous reserve

c. a process for reviewing the dollar amounts assigned to the default scarcity pricing values.

A quick reminder on why the Authority is looking at RTP

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

At present, the spot prices published in real-time are only indicative. The final spot prices actually used to settle the wholesale spot market are not available until at least two days after real-time. Significant differences can sometimes arise between indicative and final spot prices, and neither may fully reflect prevailing real-time conditions. These factors increase the likelihood that consumers and participants will make decisions they later regret.

To address these issues, the Authority is proposing to:

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

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

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

We propose introducing an expanded form of ‘dispatch-lite’ to include smaller-scale generation

Our 2017 consultation paper included a proposed ‘dispatch-lite’ facility to allow qualifying consumers to bid their controllable demand into the spot market. Those bids would be able to directly influence spot prices. We have further developed our ‘dispatch-lite’ proposal based on submissions to our 2017 consultation. Most importantly, we have expanded dispatch-lite to now include smaller-scale generation.

Dispatch-lite participants would be able to say ‘no’ to dispatch notifications from the system operator, so long as they don’t do so too often. They would also be able to withdraw from the dispatch process at other times. Smaller purchasers and smaller generators would therefore retain a substantial degree of control over their operational processes. Dispatch-lite participants also wouldn’t generally need to provide SCADA telemetry to the system operator. In combination, these features reduce the compliance burden compared to current full offered generation or dispatchable demand, making dispatch-lite a lower-cost way to participate. As a trade-off, dispatch-lite participants would not be eligible for constrained on or off payments.

Dispatch-lite would make it easier and more attractive for smaller-scale purchasers and generators to participate in dispatch and hence the price-setting process. Dispatch-lite participants would then have greater certainty about the price they would pay or receive. We consider dispatch-lite would strengthen the expected benefits of RTP. We also consider dispatch-lite provides important qualitative benefits by making the power system more flexible, helping accommodate unknowable future shifts in technology.

We propose to implement dispatch-lite in this expanded form as part of RTP.

We propose modifying the way spot prices are calculated during reserve shortfalls

The power system is normally run so there is sufficient resource available to both meet energy demand and provide a buffer to protect against any unexpected loss of supply. This buffer is called instantaneous reserve, or simply reserve. The amount of reserve needed by the system varies and is normally set to cover the largest power generator or transmission circuit operating at the time.

Occasionally, there are not enough offered resources to both meet the demand for energy and provide full reserve cover. The power system may then be run with less than full reserve cover as an alternative to forcibly cutting off some consumers. However, operating with reduced reserve raises the risk of triggering widespread automatic power cuts if a supply source failed. The benefits and costs of reserve shortfalls must therefore be balanced carefully.

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

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

We propose the Authority should review the scarcity pricing values every five years

As set out in our 2017 consultation paper, the RTP design includes so-called scarcity pricing arrangements that would be triggered if there is insufficient resource offered to meet demand. In essence, the arrangements would set spot prices to pre-defined levels based on the extent of any shortage. Scarcity pricing is designed to increase revenue certainty for providers of last-resort resources (generation and demand response). It also gives more assurance to wholesale purchasers that spot prices will not settle well above the level expected in a workably competitive market.

We intend to review the dollar amounts assigned to the scarcity pricing values before RTP goes live. To date, we have used the current scarcity pricing values in the Code in developing our RTP proposal (the range $10,000–$20,000/MWh). Our review would also determine the related dollar amounts used in the risk-violation curve approach for reserve shortfalls. We have set out the methodology to determine these dollar values in detail in Appendix F, based on the methodology we used to set the current scarcity pricing values in 2011.

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

We have updated our estimate of benefits and costs

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

Further work on the detailed system design since our August 2017 consultation has improved the information on the expected costs to implement RTP. We have therefore updated our 2017 quantitative assessment based on this new information, including revised estimates of the benefits we expect RTP would provide. We estimate implementing RTP would produce operational benefits with a present value of $62 million over 15 years in the base case. Those benefits are from avoided generation costs of $79 million, less additional demand response costs of $17 million. 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. Some of the associated cost will be offset by savings to the pricing manager function. Participants may also incur some implementation costs. The present value of these combined costs is estimated to be $12 million.

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

Next steps and timetable

We will consider submissions on this consultation alongside submissions on our August 2017 consultation. We intend to publish a decision paper on RTP's final design incorporating both sets of submissions, likely in June 2019.

If we decide to implement RTP, we expect it would go live in 2022.

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1 What you need to know to make a submission

What this consultation paper is about

1.1 The purpose of this paper is to consult with interested parties on three elements of the Authority's proposed design for real-time pricing in the wholesale spot market:

(a) full details of our proposal for 'dispatch-lite', now expanded to include smaller-scale generation

(b) the pricing that should apply during shortfalls in instantaneous reserve

(c) a process for reviewing the dollar amounts assigned to the default scarcity pricing values.

1.2 The Code amendment would promote all three limbs of the Authority's statutory objective by making wholesale market spot prices more actionable and more resource efficient.

1.3 Section 39(1)(c) of the Act requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. Section 39(2) provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statement is set out in part 3 of this paper.

How to make a submission

1.4 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "Consultation Paper—Remaining elements of real-time pricing" in the subject line.

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

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

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

(a) Indicate which part should not be published

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

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

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

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

When to make a submission

1.9 Please deliver your submissions by **5pm** on Tuesday **30 April 2019**.

1.10 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 are consulting further on three elements of our proposed design for real-time pricing

2.1 In August 2017, the Electricity Authority (Authority) published a consultation paper detailing our proposed overall design for real-time pricing (RTP) in the wholesale spot market.[1] However, we have not yet published a decision on that 2017 consultation (**our 2017 paper**), because of uncertainty about funding during the 2018/19 year.

2.2 We determined the best option was instead to complete any remaining elements of RTP's design during 2018/19.[2] We are therefore seeking the views of interested parties on three elements of RTP's design through the present consultation paper:

(a) full details of our proposal for 'dispatch-lite', now expanded to include smaller-scale generation

(b) the pricing that should apply during shortfalls in instantaneous reserve

(c) a process for reviewing the dollar amounts assigned to the default scarcity pricing values.

2.3 We will then publish a decision paper on RTP's complete design, incorporating submissions on both consultations — most likely in June 2019.

A quick reminder on why the Authority is looking at RTP

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

2.5 At present, the spot prices published in real-time are only indicative. The final spot prices actually used to settle the wholesale spot market are not available until at least two days later. Significant differences can sometimes arise between indicative and final spot prices, and neither may fully reflect prevailing real-time conditions. These factors increase the likelihood that consumers and participants will make decisions they later regret.

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

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

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

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

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1 Our August 2017 *Real-time pricing proposal* consultation paper, all submissions on that paper, and a summary of those submissions are available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/.

2 We characterised these remaining design elements as 'non-core' at our 8 May 2018 public briefing. This was to distinguish these aspects from the 'core' elements that define the specifications the system operator and other service providers need to design their IT system changes. Essentially, these system specifications would have been sufficient to enable the system operator and other service providers to begin implementing RTP. Slides and video from our 8 May 2018 briefing are available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/events/.

Recapping the key design elements of our 2017 paper

2.8 Our 2017 paper proposed the following key design elements:

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

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

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

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

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

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

2.9 Our 2017 paper also noted RTP would require significant changes to the current systems, and that the system operator recommended a staged delivery approach over four years.

3 We propose expanding 'dispatch-lite' to encourage broader participation

3.1 We propose making it easier for smaller-scale purchasers and generators to participate in dispatch and the price setting process, as part of implementing RTP. We consider encouraging greater participation would strengthen the net benefits we expect RTP would deliver. To do this, we propose introducing a new form of dispatchable demand for smaller purchasers, coupled with a new form of dispatch for smaller generators.

Submitters on our 2017 paper were split in their views on 'dispatch-lite'

3.2 Our 2017 paper proposed introducing a new form of dispatchable demand for smaller purchasers (pp. 31–2). We called this 'dispatch-lite'. Dispatch-lite would make it easier for smaller purchasers to be dispatched by reducing the cost and compliance burden of the existing requirements for full dispatchable demand.

3.3 As dispatch-lite participants, we proposed smaller purchasers would:

(a) have to be approved by the system operator

(b) not need to provide the system operator with telemetry (ie, not need to install SCADA equipment and its associated communication link)[3]

(c) be able to say 'no' when dispatched by the system operator in real-time

(d) still be able to set dispatch prices.

3.4 As a trade-off for reduced compliance with dispatch instructions, dispatch-lite participants would not be eligible for constrained on or off payments. The system operator would also be able to revoke their approval if they say no too often.

3.5 Submitters on our 2017 paper were split roughly evenly between those supporting (with qualifications) and those opposing our dispatch-lite proposal. Two particular concerns raised were:

(a) a lack of detail around how dispatch-lite would work or what incentives there would be to use it

(b) scepticism there would be any real appetite for dispatch-lite, given the poor take up of the current dispatchable demand product.[4]

Some submitters suggested smaller generators should also be eligible for dispatch-lite

3.6 In their written submissions, EnerNOC and particularly the Independent Electricity Generators' Association (IEGA) argued a mechanism equivalent to dispatch-lite is required on the supply side. This would allow distributed energy resources more broadly to become part of the dispatch process.

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3 Supervisory control and data acquisition (SCADA) is an industry standard for remotely controlling and monitoring physical equipment. In this context, SCADA provides real-time telemetry showing the electricity output of a generator or the consumption of loads.

4 We published our post-implementation review of dispatchable demand in July 2018, available at https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2017/post-implementation-review-of-dispatchable-demand/.

3.7 During the consultation period, Contact Energy Ltd (Contact) also asked if dispatch-lite could be used with batteries, including when installed 'in front' of a consumer's meter. Our published response to Contact's question explained batteries could only be used for dispatch-lite if they were installed *behind* the meter.[5]

3.8 This is because our original proposal for dispatch-lite was a form of dispatchable demand, which means controlling how much electricity the consumer uses. That is, controlling the quantity of electricity consumed, or the total load.

3.9 Controlling the charge and discharge cycle of a battery installed behind the meter would allow the consumer to manage their total load. Charging the battery increases the total load; discharging the battery decreases it. The total metered load would always be zero or a positive quantity of electricity consumption.[6]

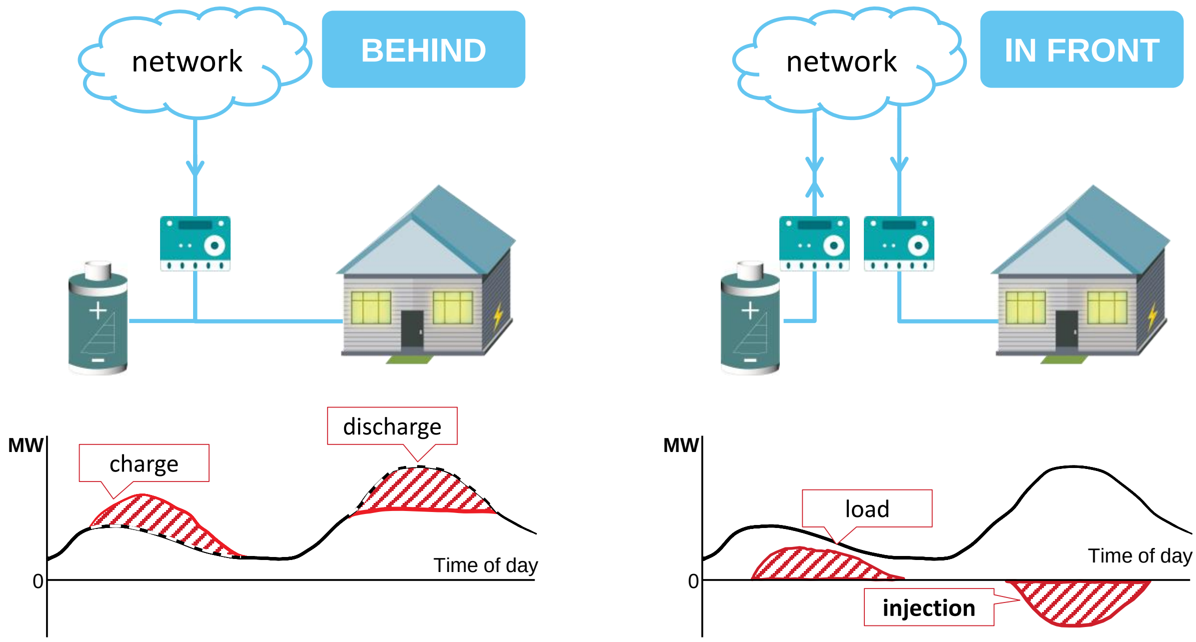
3.10 However, a battery installed in front of the meter — or in a configuration allowing net export — would instead inject electricity into the network. By injecting into the network when discharging, the battery would be generation and therefore not a form of dispatchable demand. A battery would then be excluded from dispatch-lite even if the consumer's *net* load was identical; ie, their total load (including charging the battery) minus the quantity injected by the battery.

3.11 Figure 1 illustrates the conceptual difference between batteries installed in front of versus behind the meter.

5 See the *Response to Contact queries regarding our proposal for real-time pricing*, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/correspondence/.

6 This description is simplified to illustrate the point. We note 'behind the meter' can include configurations where the consumer's meter allows both injections and consumption. This 'net export' configuration is covered in paragraph 3.10.

Figure 1: Batteries can be configured behind or in front of the consumer's meter



Source: Electricity Authority

Notes:

1. Behind: metered load rises when charging and falls when discharging, shown by the red hatched area; red line is modified metered load. In front: the battery is metered separately, and discharging is injection.
2. This is a conceptual illustration. We have not shown additional factors like the role of distribution network access charges. Batteries behind the single meter may also be configured for net export.

We have refined our proposal to now include distributed generation

3.12 We agree with Contact, EnerNOC, and the IEGA that encouraging smaller-scale generation to participate in dispatch would provide benefits. The example of batteries is compelling: why should the same device be eligible for dispatch-lite in one configuration, but excluded in another for the exact same net effect on load?

Box 1: We will use the term 'distributed generation' in its broader sense

> For simplicity, this consultation paper refers to smaller-scale generation resources not required to participate in dispatch as 'distributed generation'. In this broader sense, distributed generation could be connected to the grid, not only distribution networks.
>
> Note that the Code defined terms 'embedded generation' (used throughout the Code) and 'distributed generation' (used in Part 6) are both restricted to generation connected to distribution networks.[7] We have noted any instances where these terms are used in their formal Code sense.

3.13 We have therefore further developed our dispatch-lite proposal to:

(a) now include distributed generation

(b) give more detail on how it would work

(c) elaborate on the benefits it could provide.

3.14 Our refined dispatch-lite proposal comprises a 'mirrored' pair of new dispatch products, delivering the same outcome for both types of distributed resource. Dispatch-lite would use new **dispatch notifications** rather than dispatch instructions, reflecting the reduced compliance requirements.

3.15 The features of our updated dispatch-lite proposal are summarised in Table 1, then elaborated in the sections below. The system operator also provides supporting technical detail in its TAS078 report, attached as Appendix C.

Table 1: Features of dispatch-lite for distributed resources

Feature	Distributed generation	Demand
Eligibility	Up to 30 MW capacity, approved by system operator	No maximum capacity limit, but must be approved by system operator
Need for telemetry (SCADA)	Not generally required, though the system operator may require it in some circumstances[1]	
Method of dispatch	Dispatch notifications (likely using web services over public internet)	
Method to say 'no' to dispatch[2]	Reoffering immediately with quantity of 0 MW until end of next gate closure period[3]	Rebidding immediately as nominated non-dispatch bid until end of next gate closure period
Compliance	Assessed monthly retrospectively, comparing metered volume against dispatch notifications (except where saying 'no')	

[7] Some physically grid-connected generation may also be classed as 'notionally embedded'. These generators are covered by either a Prudent Discount Agreement (PDA) under Part 12 of the Code, or a Notional Embedding Agreement (the form of agreement preceding PDAs).

Feature	Distributed generation	Demand
Constrained on (or off) payments	Not eligible	
When bids/offers are required	Must submit offers for all trading periods	Must submit bids for all trading periods
Ability to withdraw from the dispatch process (outside gate closure)	Submit offer with quantity set to 0 MW for relevant trading periods[4]	Submit nominated non-dispatch bids for relevant trading periods

Source: Electricity Authority

Notes:

1. The system operator may determine larger load sources or, unrelated to dispatch, certain 'excluded generating stations' must provide SCADA indications. See paragraphs 3.22 and 3.26.
2. Participants must comply with any dispatch notification if they don't correctly say no. See paragraph 3.36.
3. End of next gate closure period is the rest of the current trading period to the end of the following trading period. See paragraph 3.32.
4. The market system does not allow 'cancelling' an existing offer or bid, and previous offers or bids would be rolled over (deemed) if none are submitted for coming trading periods.

Eligibility would be at the system operators discretion, with a maximum capacity limit for distributed generation

3.16 As we proposed in our 2017 paper, participation in dispatch-lite would require the system operator's approval. The system operator would consider individual dispatch-lite applications against the following general criteria.

Distributed generation-lite

3.17 To be eligible, a distributed generator must export less than 30 MW, connected to either a distribution network or the grid.[8] The 30 MW limit is based on the current threshold for 'excluded generating stations' under clause 8.21(1) of the Code. Excluded generating stations are not generally required to meet asset owner performance obligations, and other criteria stipulated in Part 8. Excluded generating stations can be either embedded (as defined by the Code) or grid-connected. In practice, an embedded generator with capacity of 30 MW or more would participate as full offered generation. The Code also currently requires a grid-connected generator with capacity greater than 10 MW to offer.

3.18 We considered tying eligibility for distributed generation-lite to the excluded generating station defined term. However, clause 8.38 of the Code allows the system operator to apply to the Authority to direct an excluded generator to comply with certain Part 8 obligations. Eligibility for distributed generation-lite may therefore be ambiguous and possibly somewhat confusing. For that reason, we propose setting the maximum capacity limit directly, using the same 30 MW threshold set in clause 8.21(1).

3.19 A distributed generator may also be able to use dispatch-lite to meet an obligation imposed under clause 8.25(5) of the Code. Clause 8.25(5) allows the system operator to require an embedded generator (as defined by the Code) of greater than 10 MW to

[8] They would be a **dispatch notification generator** in our proposed Code amendment (Appendix B).

indicate its intended output. The system operator may require the generator to submit offers for this purpose — these offers could be as a distributed generation-lite. Similarly, grid-connected generators with capacity between 10 MW and 30 MW may also be able to use distributed generation-lite to meet their obligation to offer under clause 13.6.

3.20 We do not propose a specific form for applying to use distributed generation-lite. Instead, clause 13.3E of our proposed Code amendment (Appendix B) requires a distributed generator to apply to the system operator in writing. This process is similar to the existing clause 8.21(2), requiring a generator of at least 1 MW capacity to advise the system operator in writing if it intends to connect to the grid or a distribution network.[9]

Q1.	**Do you agree with our proposed criteria for distributed generation to be eligible for dispatch-lite? If not, please explain your reasoning.**

Dispatchable demand-lite

3.21 To be eligible, a purchaser must apply to be approved as a ‘dispatch-capable load station’ (DCLS) using the process currently in place for full dispatchable demand in Schedule 13.8.[10] Applicants would state they wish to participate using dispatch-lite.

3.22 We do not propose setting a fixed maximum capacity limit for participating as a dispatch notification purchaser. However, when evaluating applications from larger load sources, the system operator will consider factors such as:

(a) the potential effect on system security from the DCLS saying no to dispatch notifications

(b) whether the DCLS would provide SCADA (see paragraph 3.25).

3.23 The system operator may then decline an application (suggesting the applicant must use full dispatchable demand), or require SCADA to participate in dispatch-lite. We may subsequently determine a maximum capacity limit for dispatchable demand-lite is warranted, after gaining operational experience.

3.24 A dispatchable demand-lite participant would need to be a purchaser, the same as under current arrangements for full dispatchable demand. In practice, this means aggregating multiple individual controllable load sources is possible, but subject to some restrictions.[11] Aggregation would require all load sources to be:

(a) connected within a single GXP (either conforming or non-conforming)

(b) bid by the same purchaser, such as the responsible retailer. However, the purchaser could decide to enter into a commercial relationship with a third-party to manage its participation in dispatch-lite.

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9 For clarity, our proposed clause 13.3E would apply even though the distributed generator may have a capacity less than 1 MW, and so would not be captured by clause 8.21(2).

10 They would be a **dispatch notification purchaser** under our proposed Code amendment. Dispatch-lite would use the current DCLS definition under the existing dispatchable demand regime.

11 The Authority has completed preliminary analysis of aggregating controllable load, as part of evaluating a proposal to introduce a load aggregator participant type and block dispatch for dispatchable demand. See project A8, *Enabling dispatchable demand at conforming nodes*, on our 2017/18 work programme, available at https://www.ea.govt.nz/dmsdocument/23899-report-against-the-201718-work-programme-1-july-2017-30-june-2018. This project is not currently active in our 2018/19 work programme. We may further progress this project in future work programmes, but this is outside the scope of RTP.

Q2.	**Do you agree with our proposed criteria for purchasers to be eligible for dispatch-lite? If not, please explain your reasoning.**

SCADA would not generally be required

3.25 SCADA telemetry would not be a standard requirement to participate in dispatch-lite. However, the lack of SCADA could compromise the accuracy of load forecasts at the GXP where dispatch-lite participants are located. This is because the dispatched load or generation would effectively be double-counted in the GXP forecast — this issue is explained in detail in the system operator's report (Appendix C). To avoid this problem, the market system would be modified to account for dispatch-lite bids and offers in determining the load at each GXP.

3.26 Note the system operator may determine SCADA is needed for larger load sources applying to participate as dispatch demand-lite (see paragraph 3.22). The system operator may also separately determine SCADA is required for an excluded generating station (as defined by the Code), even if it does not wish to be dispatchable.[12] In total, around 60 MW of currently unoffered, undispatched distributed generation already provides SCADA telemetry for this reason.

3.27 We considered but discounted using the requirement to provide SCADA as a 'bright line' to determine eligibility for dispatch-lite. That is, if the system operator determined a participant had to provide SCADA, they would only be eligible to use full dispatchable demand or offered generation. However, this approach would actively exclude those currently unoffered distributed generators already providing SCADA, for no valid reason.

Q3.	**Do you agree participants providing SCADA telemetry should be eligible for dispatch-lite? If not, please explain your reasoning.**

Participants would say no to a dispatch notification by sending a dispatch response and immediately rebidding or reoffering

3.28 We outlined two options for saying no to dispatch instructions in our 2017 paper (pg. 32):

(a) Option 1: Signalling their intention by immediately rebidding or reoffering after receiving the notification. We proposed allowing electronic rebidding and reoffering within a trading period in our 2017 paper (pg. 33). Submitters unanimously supported electronic rebidding and reoffering within the trading period, and we propose including this in RTP's final design.

(b) Option 2: Sending a 'rejection' acknowledgement response through the dispatch system — the system operator would then need to exclude the relevant bid or offer from the dispatch schedule for the remainder of the trading period. A specific rejection response could be introduced using the improved functions being implemented through the system operator's Dispatch Service Enhancement (DSE) project.[13]

12 Technical Code C of Schedule 8.3 covers SCADA, and clause 2 of that Technical Code allows the system operator to require an excluded generating station comply with the Technical Code in certain circumstances. Clause 8.38 also allows the system operator to request the Authority direct an excluded generating station to comply with certain clauses, including the Technical Codes.

13 Further information on the system operator's DSE project is available on its website at https://www.transpower.co.nz/system-operator/so-projects/dispatch-service-enhancement-project, and on

3.29 We now propose combining aspects of both options to say no to dispatch notifications. The dispatch-lite participant would:

(a) send a specific type of acknowledgement to the dispatch notification through the dispatch system

(b) then immediately rebid or reoffer as non-dispatchable (using the method set out from paragraph 3.44) for the remainder of the current trading period until the end of the next gate closure period.[14]

3.30 We consider this revised design is superior because it would:

(a) ensure the most recent active bid or offer applying within the trading period accurately reflects the dispatch-lite participant's behaviour

(b) impose a reasonable consequence for saying no to a dispatch notification (the participant must withdraw from the dispatch and price-setting process for a minimum time)

(c) give a readily identifiable record of these instances

(d) ensure the system operator has immediate information on the participant's intentions through both the acknowledgement response to the dispatch notification and the revised bid or offer

(e) avoid the additional cost and complexity needed to implement a facility for the system operator to exclude the relevant bid or offer from the dispatch schedule.

3.31 We recognise the need to quickly rebid or reoffer may appear challenging for dispatch-lite participants to implement, raising perceptions of a compliance burden. However, we consider this process would be straightforward and largely automated with modern technology, especially by the time dispatch-lite becomes available as part of RTP (see Box 2). For clarity, we do not propose building such an automated interface. However, we note third-party software providers are currently actively working with participants to develop web services client software for dispatch (as a result of the system operator's DSE project).

Q4. Do you agree combining an acknowledgement response via the dispatch system with an obligation to immediately rebid or reoffer is the best design option? If not, please explain your reasoning.

the Authority's website at https://www.ea.govt.nz/development/work-programme/operational-efficiencies/dispatch-service-enhancement/.

14 We expect WITS would provide a specific function for saying no to dispatch notifications to make this straightforward.

Box 2 Web services technology offers a low-cost and flexible mechanism to participate in dispatch-lite

The system operator is currently implementing a new web services interface for the dispatch service through its DSE project. This interface will allow dispatch instructions to be delivered over the public internet (subject to appropriate security protections). WITS also recently implemented a web services interface for submitting bid and offer orders. If we implement dispatch-lite, we expect participants would choose to use these same web services interfaces.

Web services over the public internet would provide a low-cost, flexible way to participate in dispatch-lite. It would leverage recent technology developments actively being deployed today (DSE and WITS). Most importantly, participants — or third-party providers — could build systems integrating these web services interfaces to manage the steps required to use dispatch-lite. For example, a mobile device app could handle sending the rejection acknowledgement to the system operator and submitting the revised bid or offer to WITS.

In its ideal form, sophisticated third-party software leveraging web services over the internet for dispatch could be indistinguishable from those built to control *response* to prices. Both would let owners of controllable resources specify their preferences about time of use, price, and amount of resource to make available. Both would 'plug in' to the various devices' control systems to manage their use. But the dispatch-lite version would be driven by the centrally-coordinated dispatch process itself.

We note that existing distributed generators providing SCADA do so using an ICCP interface. For this reason, they may prefer to also use ICCP for dispatch notifications, rather than web services. Even so, we think integrating a response to dispatch notifications via ICCP with reoffering via web services would be a practical solution.

Gate closure would be 30 minutes

3.32 We propose dispatch-lite would have a gate closure period of 30 minutes (one trading period). This would harmonise gate closure for all dispatch-lite participants with the current requirement for embedded generators (as defined in the Code).

3.33 Under current Code provisions, gate closure periods are:

(a) 30 minutes for embedded generators

(b) 1 hour for full dispatchable demand

(c) 1 hour for full offered generation.

3.34 Using these existing provisions would therefore mean dispatch-lite participants would have different gate closure periods. Gate closure would be 1 hour for dispatchable demand-lite and for distributed generation-lite if the generator was grid-connected. However, gate closure would be 30 minutes for distributed generation-lite if the generator was embedded. There is no valid reason for these different timeframes between types of dispatch-lite — otherwise equivalent participants would have different rights and obligations.

3.35 For this reason, our proposed Code amendment (Appendix B) sets the gate closure period to 30 minutes for all dispatch-lite participants explicitly. We do not consider it would be efficient to instead increase gate closure for embedded generators to 1 hour.

Q5.	**Do you agree gate closure for all dispatch-lite participants should be set at 30 minutes (one trading period), the same as for current embedded generators?**

Participants could say no to dispatch notifications if they do so rarely, but cannot ignore them

3.36 Dispatch-lite participants would have the right to say no to dispatch notifications, but cannot simply ignore them. Failing to follow a dispatch notification — without following the correct process to say no — would be a breach of the Code.

3.37 The system operator would have the right to suspend or revoke a dispatch-lite participant's approval if they repeatedly said no to dispatch notifications. We do not propose setting hard limits in the Code determining how often or over what time period this would be assessed. However, the system operator would develop and publish criteria in its policy statement for this purpose. The system operator would then review and may amend those criteria after gaining operational experience with dispatch-lite.

3.38 The system operator wouldn't necessarily know in real-time if a dispatch-lite participant failed to follow its dispatch notifications — because SCADA is not mandated. Failing to follow dispatch notifications could result in larger than expected changes in net load. The system operator and the Authority consider the potential for these changes is acceptable, because:

(a) the system operator would otherwise have no information about dispatch-lite participants' intentions anyway (if they reacted to prices outside the dispatch process) — unexpected changes in net load would not be worse than no information

(b) this is not a new issue, as a number of distributed generators already operate outside the dispatch process

(c) to reiterate, failing to follow dispatch notifications (without correctly saying no) would be a breach of the Code.

3.39 We consider dispatch-lite would likely reduce the scope for unexpected changes in net load by increasing participation in the dispatch process. At the very least, dispatch-lite would not make this potential for unexpected changes worse than it is today.

3.40 Because SCADA is not required, compliance with dispatch notifications would instead be assessed retrospectively using monthly reconciliation data (metered volumes). These volumes would be compared against the behaviour required by the relevant dispatch notifications, excluding those notifications the participant correctly declined.

3.41 Dispatch-lite participants could say no to dispatch notifications in the event their bid or offer was marginal; ie, it determines the dispatch price. In this scenario, the dispatch price based on that bid or offer would remain until the system operator produced a new dispatch schedule and hence a new dispatch price. We expect this would be reasonably quick, given the system operator would know the dispatch-lite participant said no to their notification. Because their bid or offer would now be non-dispatchable, the dispatch-lite participant could not set the price in the new dispatch schedule.

3.42 We recognise there may be some concern about the potential for gaming or price manipulation in this scenario. However, we think this risk is small, because:

(a) saying no must be rare, as discussed in paragraph 3.37

(b) any price effects are likely to be short-lived, as the affected dispatch price is replaced by a new one

(c) any repeated instances of suspicious behaviour could be flagged for investigation, as there would be a clear record the dispatch-lite participant said no to the notification.

3.43 The Authority is also currently reviewing the trading conduct provisions in the Code.[15] We expect dispatch-lite participants would be subject to these provisions, because we have not proposed any Code amendments that would exclude them.[16] We may also further revise the Code amendment for dispatch-lite in light of the review's conclusions, if we decide to proceed with the proposal.

Q6.	**Do you agree with the proposed compliance arrangements for dispatch-lite? If not, please explain your reasoning.**

Participants could elect to be non-dispatchable

3.44 Dispatch-lite participants would be required to submit bids or offers for every trading period. Participants could choose to let their previous bids or offers be rolled over for future trading periods.[17] However, this means they cannot become non-dispatchable by not submitting new bids or offers. The market system also does not allow 'cancelling' any existing bid or offer.

3.45 Instead, dispatch-lite participants would become non-dispatchable for any trading period (subject to gate closure) by:

(a) demand participants submitting a 'nominated non-dispatch bid'. This bid type is already in place for the existing full dispatchable demand, and ensures the participant is removed from the dispatch process

(b) distributed generators submitting an offer with a quantity of 0 MW. Note the market system would subsequently dispatch a new output target of 0 MW.[18] A generator becoming non-dispatchable would therefore be distinguished from other instances of 0 MW dispatch when they were priced out of merit; ie, they offered a non-zero quantity at a higher price. We consider introducing a new 'non-dispatch offer' purely to match arrangements for dispatchable demand would increase cost and complexity for no practical benefit.

3.46 Bidding or offering non-dispatchable in this way would be required when a dispatch-lite participant says no to a dispatch notification, as set out in paragraph 3.29.

3.47 This ability to become non-dispatchable means dispatch-lite participants would not need to operate a '24/7 trading desk' or facilities. For example, they could choose to be

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15 See the *Review of spot market trading conduct provisions* project on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/.

16 Distributed generation-lite participants would be covered today, because they are generators submitting offers, as defined by the Code. Dispatchable demand-lite participants would be covered if the review determines the trading conduct provisions should be extended to (dispatchable) bids.

17 If there are no bids or offers submitted for future trading periods, previous bids or offers are 'deemed' to have been submitted under clauses 13.8 and 13.8A of the Code.

18 The distributed generator would 'know' this new 0 MW dispatch notification was caused by reoffering with quantity set to 0 MW.

dispatchable only during business hours; at other times, they would simply be price takers, operating entirely at their own discretion.

3.48 Combined with the right to say no to dispatch notifications — if they don't do so too often — the ability to withdraw from dispatch gives dispatch-lite participants a substantial degree of flexibility. We consider this helps address concerns that becoming dispatchable imposes unacceptable compliance costs and a loss of operational control.[19]

Q7.	**Do you agree with the proposed method to allow dispatch-lite participants to withdraw from dispatch? If not, please explain your reasoning.**

3.49 Table 2 gives a summary of the dispatch processes set out above, in comparison to existing arrangements for generation and dispatchable demand.

[19] This concern has been raised by distributed generators (such as in the IEGA's submission to our 2017 paper), and cited by consumers as a factor in their decision not to adopt full dispatchable demand.

Table 2: Summary of dispatch processes for dispatch-lite participants

	Type	Capacity limit	Gate closure	SCADA	Can say no	Constrained on payment	Constrained off payment	Can withdraw from dispatch
Generation	Grid-connected generation	**Must** offer if > 10 MW	1 hour	**Mandatory**	✗	✓	✗	✗
		May offer if ≤ 10 MW		If directed	✗	✓	✗	✗
	Embedded generation	**Must** offer if ≥ 30 MW	30 min	**Mandatory**	✗	✓	✗	✗
		May offer if < 30 MW		If directed	✗	✓	✗	✗
	Distributed generation-lite	< 30 MW	30 min	Not generally required	✓	✗	✗	✓
Demand	Dispatchable demand	No set limit	1 hour	If directed[1]	✗	✓	✓	✓
	Dispatchable demand-lite	No set limit	30 min	Not generally required	✓	✗	✗	✓

Source: Electricity Authority

Notes: 1. By modifying the market system to account for dispatch-lite bids and offers, the need for providing SCADA telemetry when using full dispatchable demand may be reduced.

We consider dispatch-lite would provide important benefits by increasing participation, making the power system more flexible

3.50 We consider the overarching benefit of dispatch-lite is encouraging greater and more diverse participation in the dispatch process. Smaller purchasers and distributed generators could now use dispatch-lite where they otherwise don't want to become dispatchable, given the current perceptions of compliance burden and loss of control. This increased competition could in turn improve efficiency and reliability.

3.51 Turning to the question of incentives to use dispatch-lite (see paragraph 3.5): the main commercial driver would be the benefit of participating in the price-setting process. By participating through dispatch-lite, both purchasers and distributed generators would have greater certainty about the price they would pay or receive.[20] Further, in contrast to only responding to dispatch prices, dispatch-lite participants' bids and offers would be able to set those prices directly.

3.52 Setting the price can lead to markedly different results if the bid or offer is marginal:

(a) Reacting to dispatch prices in real-time outside the dispatch process changes net load, and this can lead dispatch prices to shift in consequence.[21] This is inherent in demand response to prices in a general sense: depending on the shape of underlying supply offers, demand response may 'chase' prices up and down (in opposite directions). Note this is not simply that the change in net load is 'large enough' — even small changes during tight market conditions can change prices.[22]

(b) In contrast, dispatch-lite participants would be dispatched to consume or produce a specific quantity determined by their bid and offer prices. Those prices should reflect the willingness to pay to consume (bids), and the variable costs to supply (offers). The core distinction is that where their response would otherwise cause dispatch prices to change (set by some different non-dispatch-lite bid or offer), their dispatch-lite bid or offer now sets the price instead. As the marginal tranche, the dispatch-lite bid or offer may be dispatched for some or all of their quantity.

(c) For purchasers, setting the dispatch price helps ensure they don't pay more for electricity than they're willing. Purchasers would be less likely to forego consumption they were willing to pay for, and more likely to avoid consuming electricity priced above what they are willing to pay.

(d) For distributed generators, setting the dispatch price helps avoid foregone revenue if their response would otherwise reduce the price. Distributed generators would be less likely to withdraw supply because dispatch prices were less than their costs.

3.53 By bidding and offering, dispatch-lite participants reveal the value of their resources to the system operator's scheduling and pricing processes. That information improves the granularity and accuracy of the demand and supply curves the system operator optimises in finding the least-cost dispatch solution (see paragraph 4.6). Dispatch prices are therefore more efficient. Appendix D gives further detail using simple examples.

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20 All generators and purchasers would be paid or would pay the final spot price for each trading period, determined by the time-weighted average of all dispatch prices published on WITS during that period.

21 In general, consumers use less electricity while distributed generators increase their output in response to higher dispatch prices. Both responses work to reduce net load at the GXP (total load minus total embedded generation). The opposite response to lower prices increases net load.

22 Prices would shift if the change in net load makes a different bid or offer tranche marginal, so the MW size of each tranche is an important factor.

3.54 Importantly, if scarcity conditions are looming, even small quantities of dispatchable demand or distributed generation could avoid triggering emergency load shedding. Again, this underscores the difference between responding to prices and participating in price-setting. In this scenario, dispatch-lite participants' bids or offers could set dispatch prices rather than default scarcity pricing blocks; ie, if their bid or offer quantity was enough to avoid energy deficit.[23] In contrast, if those same resources instead reacted to real-time scarcity prices — after load shedding has been triggered — they reduce net load at their GXP and prices fall back to 'normal'. Reacting to scarcity prices might mean load shedding is then short-lived, but it would still occur. Dispatch-lite participants' bids or offers instead setting dispatch prices below default scarcity prices and avoiding load shedding would be the efficient outcome.

Box 3: Dispatch-lite participants would have better price certainty even though they don't receive constrained payments

Dispatch-lite participants would not receive constrained on or off payments. They would therefore not be made whole for any difference between final spot prices and their bid or offer price when dispatched. However, dispatch-lite participants would be at least no worse off than simply responding to dispatch prices, and likely better off:

(a) If their response to dispatch prices would not have changed those prices, their purchase costs or revenue would be equivalent.

(b) If they are marginal, their purchase costs or revenue would more closely reflect their willingness to pay or their costs to supply. This is true even though final spot prices are the time-weighted average of dispatch prices. Again, the benefit of being able to set prices may be substantial in tight market conditions — foregone consumption or revenue could be significant.

3.55 Reliability would be improved for the same reasons set out above: the system operator would have better information about participants' intentions. Coordinating dispatch-lite resources through the dispatch process would reduce the scope for unexpected changes in demand and supply. That greater coordination of resources increases the flexibility of the power system. As noted in paragraph 3.54, more flexibility could in turn mean emergency load shedding is avoided during tight supply conditions.

3.56 In the longer term, we consider dispatch-lite would help 'future-proof' the wholesale market by making it easier to accommodate substantial shifts in the technologies used to generate, store, and use electricity. In particular, dispatch-lite could help mitigate the effects of highly-controllable technologies leading to rapid changes in real-time net load.

23 The role of the default scarcity pricing blocks under RTP is explained in section 4, from paragraph 4.21.

3.57 Consider a surge in the amount of controllable resources automatically responding to dispatch prices, as sketched in the paragraphs above. Most prominently, using battery storage, smart appliances, and new infrastructure like electric vehicle charging systems. As well as causing dispatch prices to oscillate, rapid automated-but-uncoordinated demand response at significant scale could result in step-changes in net load ('vertical' changes in the demand curve).[24] These step-changes could have adverse effects on power system security and power quality:

(a) Frequency keepers could struggle to maintain frequency in the normal band. Marginal generators may be subject to repeated on-off dispatch instructions. Both effects would likely result in greater supply costs.

(b) Such demand response would be extremely difficult to forecast, if not inherently impossible, degrading price certainty.

(c) Spot prices may become inefficiently volatile, negatively affecting the role of price signals for operational and investment decisions.

3.58 Dispatch-lite could help mitigate these effects by coordinating these controllable, rapid-response resources through the dispatch process. Critically, extending dispatch-lite to include distributed generation allows technologies like battery storage to participate in any configuration.

Implementing dispatch-lite would require changes to the market system, WITS, and the clearing and settlement processes

3.59 Implementing dispatch-lite would include:

(a) creating new bid and offer types in the market system and in WITS. Note dispatchable demand-lite would leverage the changes already required to move dispatchable demand to the dispatch schedule under RTP.

(b) modifying the market system to account for dispatch-lite bids and offers that don't provide SCADA telemetry

(c) implementing dispatch notifications in the dispatch service (currently being updated by the system operator's DSE project)

(d) adapting the WITS interfaces to identify dispatch-lite bids and offers

(e) accounting for dispatch-lite in the clearing and settlement processes (excluding constrained on and off payments).

3.60 For participants, dispatch-lite would require:

(a) approval from the system operator

(b) establishing the necessary interface to the dispatch service

(c) establishing access to WITS, and managing their bids and offers.

We are evaluating options for integrating battery storage in a separate project

3.61 Under current Code arrangements, a battery injecting into the network is a generator when discharging, but a purchaser when charging (consuming from the network). The

[24] The examples in Appendix D also show such step changes, but they are simplified illustrations mainly intended to show the benefit of participating in the price-setting process.

battery could then use both forms of dispatch-lite: as dispatchable demand-lite when charging, and as distributed generation-lite when discharging.

3.62 However, this means a battery provider using dispatch-lite has to manage simultaneous sets of bids (as demand) and offers (as generation). This complexity could increase costs and discourage participation in dispatch. Two options would make this task somewhat easier:

(a) A software platform using web services for both dispatch and submitting to WITS could handle these simultaneous requirements automatically. However, that platform would have to be developed and paid for.

(b) A participant may choose to use dispatch-lite for only one phase of the battery's charge cycle; eg, only offer as a distributed generator for the discharge phase.

3.63 This complexity may therefore hinder making the most effective use of batteries. The power system may then fail to take full advantage of the efficiency and reliability benefits available. But this question of how to optimally integrate batteries exists today and is not related to dispatch-lite itself; a full solution is outside the scope of RTP.

3.64 However, we are evaluating options to better incorporate battery storage and other forms of new technology in the wholesale spot market in a separate project.[25] If we decide to proceed with dispatch-lite, we would therefore leverage any new arrangements for batteries when RTP goes live.

We propose implementing dispatch-lite as part of RTP

3.65 We consider implementing the expanded form of dispatch-lite detailed above as part of RTP would promote all three limbs of our statutory objective. Dispatch-lite would add more options for accommodating new technologies and business models, helping to maximise their benefits for all consumers.

3.66 Implementing dispatch-lite as part of RTP would also be cheaper than doing it separately later, with a minor effect on the total time required to build RTP.[26] Providing certainty about dispatch-lite's design now may also help third-parties develop sound business cases for developing new software platforms. Implementing dispatch-lite later would substantially defer the potential benefits it could provide, likely on the order of years past RTP's projected go-live date in 2022. We consider this would be a lost opportunity.

3.67 On balance, we consider our proposed dispatch-lite improves the overall RTP design, strengthening the net benefits we expect RTP would deliver. We also consider greater flexibility to accommodate unknowable future shifts in technology is an important qualitative benefit. We therefore propose to implement dispatch-lite, if we decide to proceed with RTP.

Q8. Do you agree we should implement dispatch-lite as part of RTP, should we decide to proceed? If not, please explain your reasoning.

[25] See the *Participation of new generating technologies in the wholesale market* project on our website at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/participation-of-new-generating-technologies-in-the-wholesale-market/.

[26] The system operator indicates the cost for delivering dispatch-lite separately after RTP would increase to the high cost case in their Rough Order of Magnitude (ROM) estimate — an increase of almost 50% relative to the expected cost to deliver as part of RTP.

4 We propose a new ‘risk-violation curve’ to handle reserve shortfalls under RTP

4.1 This section explains how we propose to handle reserve shortfalls under RTP. This topic is inherently technical — perhaps the most complex aspect of RTP’s design. We suggest readers who want an overview in relatively non-technical terms read Box 4 below. Readers who want a fuller description can skip the Box and read the balance of this section.

Box 4: A brief explanation of reserve shortfalls and how we intend to price them under RTP for the non-technical reader

The power system is normally run so there is sufficient resource available to both meet energy demand and provide a buffer to protect against any unexpected loss of supply. This buffer is called ‘instantaneous reserve’, or simply ‘reserve’. The amount of reserve needed by the system varies and is normally set to cover the largest power generator or transmission circuit operating at the time. Reserve can be provided by generators operating at less than full energy output, or consumers who can cut their demand very quickly (called ‘interruptible load’).

Occasionally, the generation and controllable load resources offered by suppliers are not enough to both meet the demand for energy and provide full reserve cover. In that situation, the power system may be run with a shortfall in reserve cover as an alternative to forcibly cutting off some consumers.

However, operating with a reserve shortfall has a downside. One or more supply sources (large generators or transmission circuits) will not be covered by the available reserve. If one of these sources failed unexpectedly, that could trigger widespread automatic power cuts as a last line of defence to protect the power system. In general, the larger the reserve shortfall the more supply risks are not covered and the higher the chance of automatic power cuts. For these reasons, any reserve shortfall requires careful balancing of the benefits (avoiding certain power cuts of modest size) and costs (the potential for power cuts of significant size and duration).

Turning to pricing, the spot market determines prices for energy and reserve. If a shortfall occurs, the current practise is to set indicative real-time spot prices to extremely high ‘placeholder’ values. These prices are not intended to reflect the true value of energy and reserve and are not used for settlement — they simply signal a shortfall is occurring. A more complex procedure is then followed when calculating final spot prices the next day. This procedure seeks to estimate the true value of reserve and energy, albeit with some important shortcomings. Extensive investigation has shown replacing those placeholder values with ‘real’ prices under RTP leads to unacceptable and inconsistent outcomes. We consider the current pricing approach for reserve shortfalls is clearly not suitable for RTP.

We propose adopting an improved version of the current procedure under RTP. The key modification is to determine prices for reserve using a ‘risk-violation curve’ to more accurately determine spot prices during reserve shortfalls. A risk-violation curve sets a rising price for reserve as the quantity of reserve shortfall grows, representing the increasing economic cost from leaving sources of risk uncovered. In essence, this approach recognises:

(a) reserve prices should typically be higher for larger shortfalls
(b) reserve prices should typically be higher when there are multiple sources of risk
(c) at times it can be preferable to reduce demand to maintain some reserve, lowering the risk of widespread load shedding.

We also recognise setting the values for the risk-violation curves requires judgments and trade-offs. In the body of this section, we describe our current proposed values and reasoning. We also intend to review these values before the 'go live' date, if we decide to proceed with RTP.

4.2 As noted above, the discussion in this section is necessarily technical, covering an array of concepts and operational practises that may be unfamiliar to many readers in detail. To make our proposal accessible to as wide an audience as possible, we:

(a) have structured this discussion to first explain important aspects of the current system, then set out our proposed new model and the reasons why it's needed

(b) will provide extra material separately during the consultation period, as well as holding a stakeholder briefing session.

The system operator schedules additional resources on stand-by to keep the power system secure

4.3 Through the dispatch process, the system operator normally schedules sufficient resources to supply the expected demand for energy on the power system in real-time. However, the system operator also schedules additional resources to quickly respond to any sudden failure of a large generator or transmission circuit. These potential failures are known as 'contingencies'. The resources used to protect against contingencies are called instantaneous reserve, or simply **reserve**.

4.4 Resources assigned to provide reserve do not supply energy — they are not meeting system demand — but are instead on stand-by, ready to react to any failure. Resources providing reserve are a form of physical insurance, helping keep the power system secure.

4.5 There are two reserve products: fast instantaneous reserve (FIR), and sustained instantaneous reserve (SIR).[27] Both are provided by either generators agreeing to hold back some of their capacity (reducing the amount of energy they can supply at the same time); or by consumers agreeing to automatically cut their demand very quickly if system frequency falls past a certain point, providing 'interruptible load' (IL). The amount of reserve required in each trading period is modelled dynamically, varying with the size of the largest generator or transmission circuit 'risk' in operation.

Energy and reserve are co-optimised to determine the least-cost use of resources

4.6 The system operator's scheduling, pricing, and dispatch system (SPD) is tasked with finding a dispatch solution to meet the need for energy and reserve at least total cost. SPD does this by determining the optimal combination of energy and reserve costs, as expressed by supplier offers, dispatchable demand bids, and reserve offers.[28] Through this co-optimisation, SPD schedules (or 'clears') adequate quantities of energy and reserve for dispatch in each trading period as the least-cost solution.

27 The roles of FIR and SIR are discussed further in paragraph 4.42.

28 Generators offer to supply specific MW quantities of energy at the price they are willing to accept, while dispatchable demand bids specify the MW quantities purchasers wish to consume, up to a maximum price. Reserve offers are provided by both generators and interruptible loads (ie, there is no 'reserve bid').

4.7 Co-optimisation means SPD may schedule a higher-cost generator offer despite capacity being available from a cheaper supply source. This would occur if the cost of additional reserve to cover increased supply from that cheaper source would result in a greater total cost.

4.8 A range of 'constraints' sets mathematical boundaries or requirements SPD should usually honour. Some are hard limits that cannot be broken; eg, generators cannot be scheduled for more than their total offered capacity. Other constraints can be violated if SPD finds the cost of doing so — set by the price of the constraint violation penalty (CVP) — is the least-cost solution. For example, in rare conditions SPD will break the energy deficit constraint at a node or nodes, meaning expected demand for energy cannot be fully supplied. The system operator must then instruct emergency load shedding to keep the power system secure.

On rare occasions, reserve is sacrificed to meet the need for energy

4.9 SPD determines the target required MW quantity for reserve in each trading period dynamically (for FIR and SIR).[29] That target is usually the size of the maximum scheduled MW quantity from supply sources — these sources are the **'risk-setters'**. We will call this target maximum scheduled MW quantity the **actual maximum risk**. In turn, the MW quantity of reserve SPD schedules is the **maximum covered risk**. In normal conditions, the maximum covered risk is therefore equal to the actual maximum risk.

4.10 However, resources offered into the market may not be enough to meet the demand for both energy and reserve in real-time during tight market conditions. The long-standing practise in these times of resource scarcity is to partially relax reserve cover, prioritising meeting the demand for energy. Sacrificing reserve in this way frees generation resources from providing reserve to supply energy instead (where generators offer into both energy and reserve markets). If we did not sacrifice reserve, the system operator would have to instruct emergency load shedding to forcibly reduce the real-time demand for energy.

4.11 Sacrificing reserve at these times means there is a shortfall in reserve cover, relative to the target quantity required. The maximum covered risk will be less than the actual maximum risk by the MW size of that shortfall. The power system is therefore temporarily operating at a higher security risk: the reserve shortfall raises the likelihood of triggering widespread automatic under-frequency load shedding (AUFLS) if a contingent event were to occur, but avoids *certain* instructed load shedding now.[30]

Reserve shortfall is driven by SPD as the least-cost solution

4.12 The system operator does not manually decide or otherwise intervene to sacrifice reserve to meet the need for energy. Any reserve shortfall is instead an inherent and automatic outcome of SPD's co-optimisation process. SPD does this because of the

[29] For simplicity this paper does not discuss the role of 'net free reserve' in determining the required FIR quantity.

[30] AUFLS is the last line of defence before cascade failure of the power system, if the combination of FIR and SIR were not sufficient to handle a contingency. Load shedding through AUFLS occurs when protection relays automatically trigger at specific system frequencies, without any intervention or control from the system operator. AUFLS is therefore distinct from the *instructed* emergency load shedding discussed elsewhere in this paper.

relative prices assigned to any violation of the constraints representing a deficit in the scheduled quantities of reserve and energy:

(a) The CVP for a deficit in reserve in either FIR or SIR is set to $100,000/MW/h.

(b) The CVP for a deficit in energy — which would require emergency load shedding — is set much higher at $500,000/MWh.

4.13 These CVP values are far higher than any realistic market bid or offer price. This makes SPD highly likely to use all offered market resources first in meeting the demand for energy and reserve. It also ensures reserve deficit is preferred to energy deficit.

4.14 In times of resource scarcity, SPD is then highly likely to violate the reserve deficit constraint(s) in finding the least-cost dispatch solution. A reserve shortfall would result if physically possible, avoiding emergency load shedding. The real-time price(s) for FIR or SIR (or both) would be determined by the $100,000/MW/h CVP, indicating SPD could not find a 'feasible' dispatch solution — it had to break a constraint to solve. This situation is then known as a reserve 'infeasibility'.

4.15 But that outcome is not guaranteed. Under certain conditions, SPD will determine energy deficit (requiring emergency load shedding) is the least-cost dispatch solution, with little or no reserve shortfall beforehand. To reiterate the point above, reserve shortfalls are an outcome of co-optimisation, not an external intervention.

Box 5: What do dispatch prices for energy and reserve mean?

It's useful to consider the information conveyed in the prices for energy and reserve produced by SPD in finding the least-cost dispatch solution in tight supply conditions:

- The **energy price** is readily understood as the marginal cost to supply the next MW of demand. Importantly however, that marginal cost can itself be affected by prices for reserve if the marginal energy supply resource affects the quantity of reserve needed.
- The **reserve price**, perhaps less intuitively, is not simply the cost of the next MW of offered reserve. Rather it is best understood as the benefit to the system (ie, to the total cost) from one more MW of 'free' reserve. The reserve price represents the cost the market should be willing to pay to obtain additional resources when reserve is scarce — or equivalently, the price to charge to release resources from providing reserve to instead supply the demand for energy.[31]

The current final pricing process may not reflect instances of reserve shortfall in real-time

4.16 All infeasibilities must be removed in the final pricing schedule — the CVPs described in paragraph 4.12 above are not used to calculate the final spot prices used for settlement. As discussed in our 2017 paper (pp. 9–13), a range of manual interventions are required currently for this purpose.

4.17 Today, any reserve deficit infeasibility in a final pricing schedule is resolved using the virtual reserve provider (VRP) process described in clause 13.166A of the Code. The VRP is a manually-created 'dummy' source of reserve, providing the missing MW

31 See the excellent discussion of energy and reserve scarcity pricing in Hogan, Michael. 2017. 'Follow the Missing Money: Ensuring Reliability at Least Cost to Consumers in the Transition to a Low-Carbon Power System'. *The Electricity Journal* 30 (1): 55–61. https://doi.org/10.1016/j.tej.2016.12.006.

quantity needed to remove the reserve deficit infeasibility. The price for the VRP is configured as the greater of either:

(a) three times the highest scheduled energy offer

(b) the highest scheduled reserve offer, for the reserve class in deficit.

4.18 The VRP has been used very rarely. This is mainly because the final pricing schedule uses 30-minute averages, so reserve shortfalls in dispatch may not flow through to final pricing. This means some instances of reserve scarcity in real-time today are not being reflected in the final prices for energy and reserve. Prices when the VRP process is used are also not readily predictable in advance, given the need to first determine which offers clear in order to set the VRP offer price. For this reason, prices for reserve can be markedly different for otherwise very similar shortage conditions.

To deliver RTP, infeasibilities in real-time must no longer be possible

4.19 The fundamental principle of RTP is to determine the spot prices used for settlement in real-time from the dispatch process the system operator uses to run the power system. This makes spot prices more accurate and more certain — spot price signals would be more ‘actionable’ for participants and consumers.

4.20 It follows that the dispatch process must always produce a ‘real’ price in real-time, no matter the circumstances. Interventions and manual processing after the fact, such as using the VRP, break this fundamental principle. To deliver RTP, infeasibilities in the dispatch schedule must therefore no longer be possible.

4.21 Two core elements of RTP’s design serve this objective. First, our 2017 paper proposed assigning forecast load at every node to three default scarcity pricing blocks.[32] The three blocks are shown in Table 3 and illustrated conceptually in Figure 2. These values are based on the current scarcity pricing provisions in the Code. As set out in section 5, we also intend to review these values before RTP goes live, if we decide to proceed.

Table 3: Default scarcity pricing blocks for forecast load under RTP

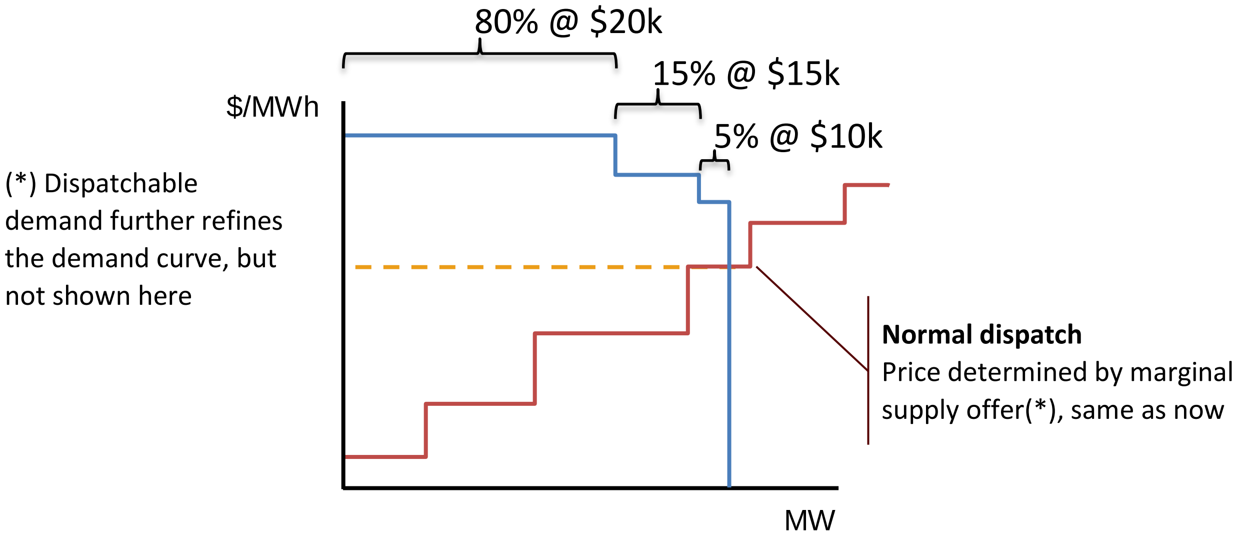
Proportion of load	Assigned price
First 5%	$10,000/MWh
Next 15%	$15,000/MWh
Last 80%	$20,000/MWh

4.22 Combined with explicit dispatchable demand (and dispatch-lite) bids, the default scarcity pricing blocks means all load would have a price assigned. The demand curve input to SPD would now be ‘closed’, so energy deficit infeasibilities would no longer be possible. A default scarcity pricing block would instead be the marginal tranche in the dispatch schedule if forecast load cannot be fully supplied. The system operator would then have

32 Forecast load means all load not subject to nominated dispatch bids (from existing dispatchable demand, and dispatch-lite). The load at non-conforming GXPs, and for any nominated non-dispatch bids for dispatchable demand purchasers, would be determined by persistence forecasts from ION meter data.

to instruct emergency load shedding. Full details of this scarcity pricing design element are set out in pages 18–22 and Appendix D of our 2017 paper.

Figure 2: RTP builds a closed demand curve by assigning default scarcity prices to all forecast demand



Source: Electricity Authority

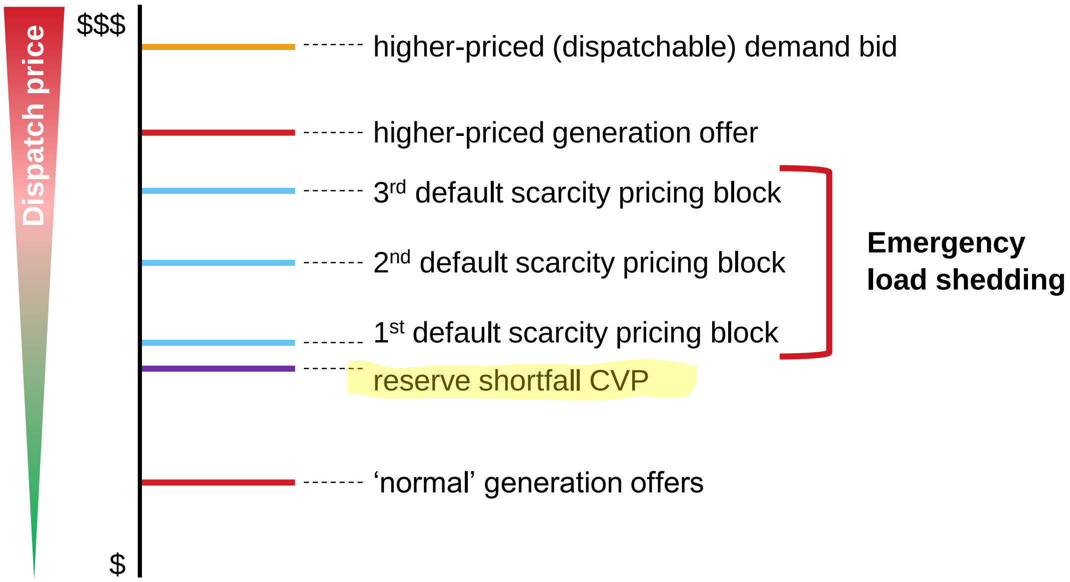
Notes: Generator offers form the supply curve (red line). Forecast load defines the demand curve (blue line), shown here as a vertical line at total expected MW quantity for simplicity.

4.23 Second, our 2017 paper proposed reserve shortfalls would trigger a penalty price set in SPD, and that price would directly determine reserve spot prices (pp. 25–27). These penalty prices for FIR and SIR would be 'real', unlike the current reserve deficit CVPs described in paragraph 4.12 above. The VRP process described in paragraph 4.17 would therefore no longer be needed.

4.24 Figure 3 conceptually illustrates the resulting intended dispatch order for system resources, as proposed in our 2017 paper. The main point is reserve shortfalls (yellow highlight) would generally occur before emergency load shedding is triggered by the first default scarcity pricing block.[33]

[33] Figure 3 is a slightly modified version of slide 30 from our August 2017 public RTP briefing, available at https://www.ea.govt.nz/dmsdocument/22492-real-time-pricing-briefing-presentation-pdf-version. We developed this graphic to better explain the design than Fig. 7 of our 2017 paper (on p. 28).

Figure 3: Illustrating the dispatch order of system resources under RTP (as proposed in our 2017 consultation)



Source: Electricity Authority

4.25 Our 2017 paper only outlined how reserve shortfalls would be handled at a high level, and did not propose specific penalty prices. Our intent at that time was to adapt the existing approach using SPD constraints on reserve deficit described from paragraph 4.12. To do so, we would replace the existing $100,000/MW/h CVP values with 'real' penalty prices. We stated those penalty prices would need to be below the first default scarcity pricing block (as suggested in Figure 3). That would allow some quantity of reserve shortfall, while leaving room to clear energy offers priced below $10,000/MWh.

Reserve prices during real-time shortages must signal that resources are scarce

4.26 There is an inherent tension in determining penalty prices to drive reserve shortfalls under RTP. In general, the lower that penalty price the more likely SPD would schedule reserve shortfall as the least-cost dispatch solution. Yet reserve prices during scarcity also need to be high enough to serve their vital role in promoting an efficient security of supply.

4.27 Reserve prices during scarcity send important signals in two time horizons: operationally, and for long-term investment.

4.28 Operationally, in the forward schedules and in real-time we want reserve prices to signal when resources are scarce, and the relative value of energy and reserve. We want reserve and energy prices to encourage participants and end-consumers to respond by:

(a) offering more reserve to free up generation to supply energy, including more reserve from interruptible load providers (replacing reserve otherwise being supplied by generation)

(b) offering more generation to supply energy directly (if this alleviates reserve scarcity, given the resources setting the reserve risk)[34]

(c) consumers reducing expected system load through voluntary demand response to elevated energy prices (in the event reserve scarcity affects the energy price).

4.29 By reacting to these signals, participants and consumers therefore help allocate resources to their most valuable use given the real-time conditions on the power system.

4.30 The frequency and duration of reserve prices during scarcity also sends an important long-term investment signal to deliver resource adequacy. If resources are inadequate to meet the demand for reserves, we would expect the average of reserve prices to rise accordingly. Higher average reserve prices then signal that more investment in resources to provide reserve would be valuable.[35] Reserve prices that are too low during scarcity may therefore perversely lead to underinvestment in reserve resources over time, undermining security of supply.

4.31 Prices during scarcity should therefore be based on the economic costs for shortfalls in reserve and in energy. SPD would then trade off these costs in real-time based on actual system conditions and hence send the right price signals.

The potential for multiple risk-setters means we need a new approach to handling reserve shortfalls under RTP

4.32 Extensive technical investigation since we published our 2017 paper has shown the current approach using SPD constraints on reserve deficit is not viable under RTP. The primary reason is the potential for multiple simultaneous sources of risk, a feature of the way reserve is dynamically modelled in each trading period.

4.33 For example, SPD may jointly schedule energy supply northward over the HVDC link and from two larger North Island generators, all at the maximum scheduled MW quantity. With all three risk sources setting the actual maximum risk (as defined in paragraph 4.9) there are then **multiple risk-setters**.

4.34 Inherent characteristics of the current approach using reserve deficit constraints (or the 'reserve deficit model') suppress energy prices in the presence of multiple risk-setters. Because of this price suppression effect, using the current model under RTP would result in price and dispatch outcomes that are inconsistent, unreasonable, and uneconomic. The details are complex, but in summary:

(a) The number of risk-setters would in effect dictate whether SPD can schedule any reserve shortfall before emergency load shedding. The current reserve deficit CVPs cannot be replaced by any 'real' penalty prices that allow reserve shortfalls both when there are multiple risk-setters and when there is only one.

(b) Suppressed energy prices in the presence of multiple risk-setters in and of itself sends a perverse signal counter to the increased risk of triggering AUFLS.

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34 Dispatchable demand purchasers could also respond by reducing their bid consumption quantities. But this seems unlikely, given purchasers should logically already have bid the price they are willing to pay for energy. That is, they would be willing to keep consuming so long as energy prices are no more than their bid price; if prices were higher, the system operator would already have dispatched them off. In contrast, generators may not have offered their full capacity for a range of reasons, but could now revise their offers to bring on more capacity in response to higher than anticipated prices.

35 Reserve scarcity prices help address the 'missing money problem' for efficient investment in an energy-only market, where participants must cover their fixed capital costs through the spot and contracting markets.

4.35 Appendix E provides more detail using simplified numerical examples. We will also release further information and modelling results during the consultation period.

We propose implementing a new 'risk-violation curve' to handle reserve scarcity under RTP

4.36 We propose introducing a new model for handling reserve shortfalls under RTP. We would change SPD's mathematical formulation by:[36]

(a) adding variables for the 'risk violation' of each *individual risk*, representing the MW quantity of that risk not being covered by scheduled reserve

(b) removing the existing constraints on reserve deficit itself (the MW quantity of reserve shortfall).

4.37 The cost for violating a risk would be the associated penalty price, representing the economic cost of violating a contingent event risk. Reserve prices during scarcity would therefore reflect the quantity of risk we're not covering when reserve is in shortfall.

4.38 We also propose setting a quantity limit on the risk-violation variables. But rather than a single MW limit, we propose using a set of price-quantity tranches, progressively raising the cost as the extent of risk-violation grows. That is, as the gap between the dispatched MW quantity and the maximum covered risk increases. The rising cost therefore reflects the economic cost of leaving an increasing quantity of risk uncovered.[37]

4.39 We call this model a **risk-violation curve**. We have developed the risk-violation curve with the close collaboration of the system operator and an independent SPD modelling expert. Our proposed approach extends RTP's overarching principle of embedding scarcity pricing within a demand curve — in this context, the system demand for reserve. The prices assigned to each risk-violation tranche would signal the growing risk to the power system (of triggering AUFLS) for that increasing reserve shortfall.

4.40 Our proposed risk-violation curve is illustrated conceptually in the following figures:

(a) Figure 4 first shows the reserve deficit model used today, where SPD sets constraints on the quantity of scheduled reserve (brown dashed line). SPD produces a dispatch solution to supply the expected load, based on available offers (suggested by the blue arrow). For two simplified dispatch solutions representing one risk-setter (A) versus three (B), a reserve shortfall (orange cross) breaches that constraint.

(b) Figure 5 shows the same dispatch outcomes using our proposed risk-violation model, where the risk-violation variables apply to the risk sources themselves. A reserve shortfall then breaches the risk-violation variable for each risk source — the MW quantity of the risk not being covered (red cross). Importantly, for dispatch solution B, this means the risk-violation variables are breached for all three risk-setters.

36 The SPD model formulation is published on the system operator's website at https://www.transpower.co.nz/system-operator/key-documents/software-specifications.

37 Note there is no limit on the size of reserve shortfall SPD can incur under the current reserve deficit model. In practice IL acts as a quantity restraint, because IL cannot be freed from providing reserve to instead supply demand for energy. Nonetheless, there is no inherent quantity limit, and the restraint from IL is purely an artefact of the current offered resources. As a specific example, a dispatch schedule during the 07:30 trading period on 26 July 2016 had a North Island SIR deficit of 144 MW.

Figure 4: Currently, SPD sets constraints on the quantity of reserve

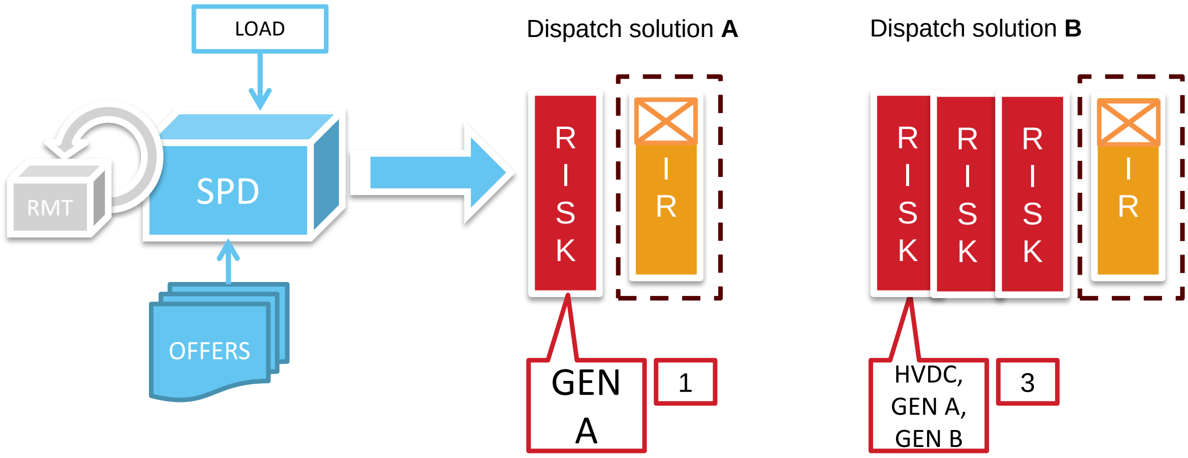
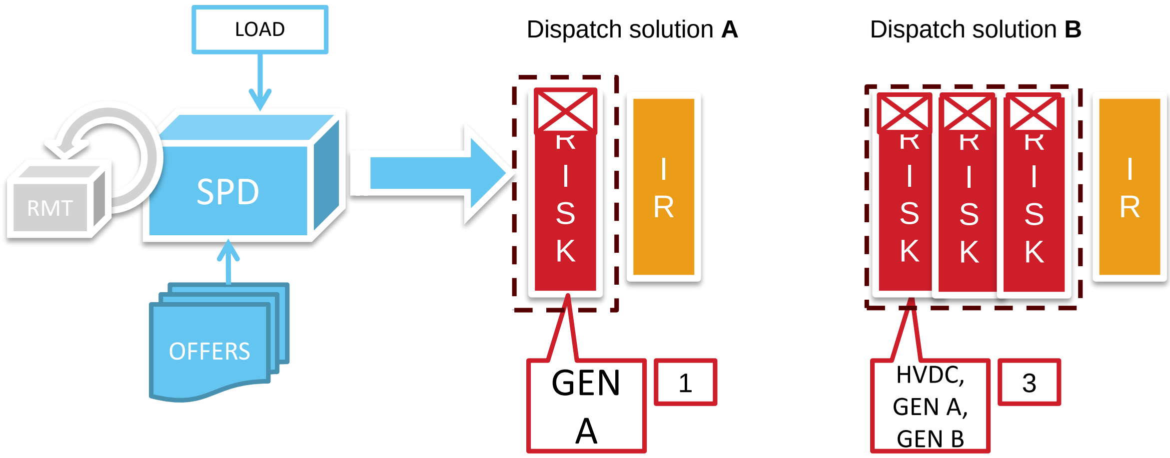


Figure 5: We propose to instead set constraints on the risk sources



Source: Electricity Authority

Notes: RMT = reserve management tool; IR (orange box) = the target instantaneous reserve quantity to cover the actual maximum risk, reduced by reserve shortfall to the maximum covered risk; red outline boxes show risk-setters (and total number).

The price for reserve scarcity should be slightly greater for FIR than SIR

4.41 We consider the risk-violation tranches should put a slightly greater price on a shortfall in FIR than a shortfall in SIR. This reflects the relative change in the risk of triggering AUFLS during a contingent event if either reserve class is short:[38]

(a) Inadequate FIR may result in failure to arrest the frequency excursion during the first seconds of an event, leading frequency to fall to 47.8 Hz and trigger AUFLS.

(b) In contrast, the system operator has more time to manage the impact of inadequate SIR by redispatching the system, restoring frequency to the normal band.

38 This view is also supported by the distribution of historical prices for FIR and SIR during tight supply conditions. See Appendix F for details.

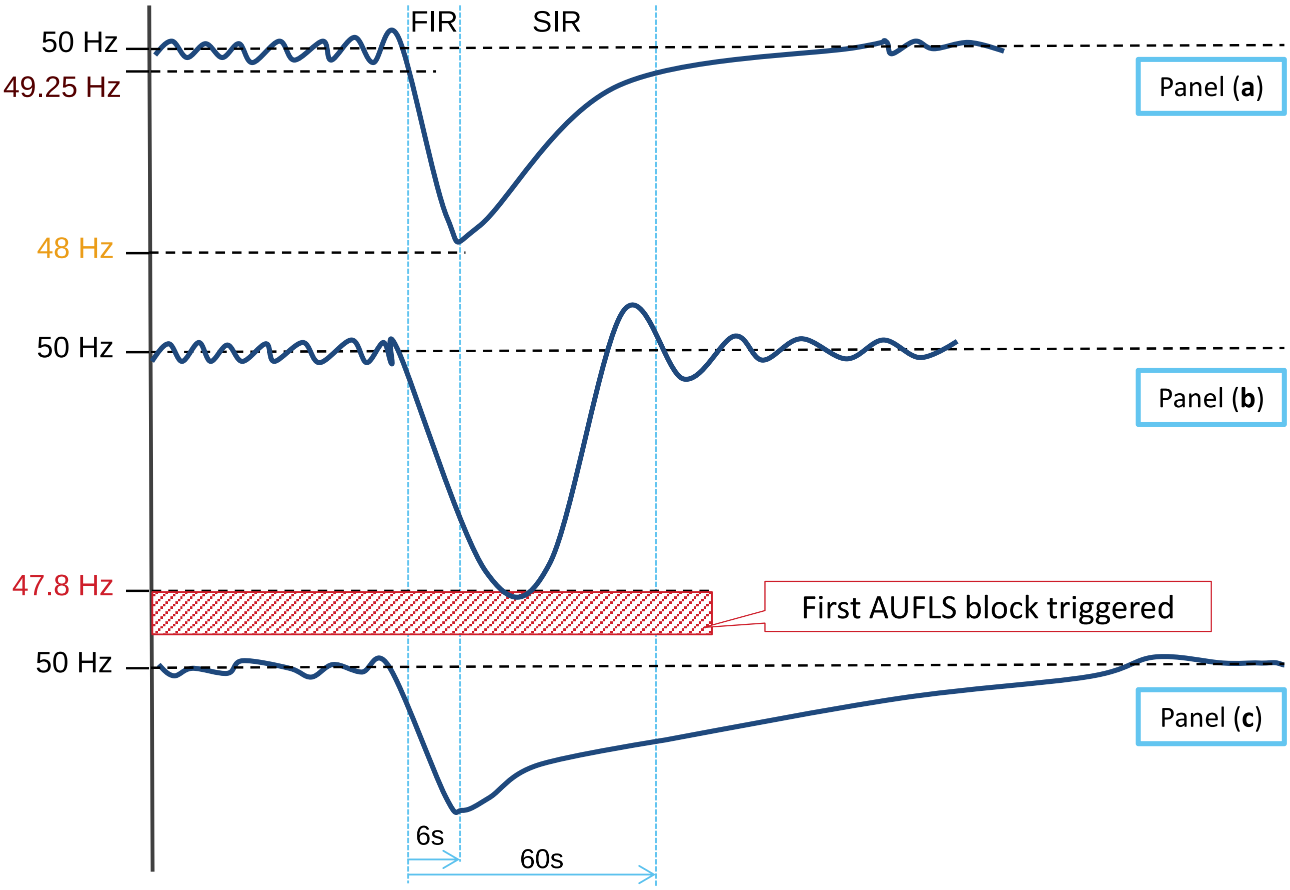
4.42 Figure 6 illustrates these factors using stylised examples of under-frequency excursions during a contingent event:

(a) Panel (a) shows FIR resources quickly reacting to the excursion (within 6 seconds), arresting the frequency deviation above the 48 Hz threshold (IL triggers at 49.2 Hz). SIR resources then provide additional power (within 60 seconds) to return frequency to the normal band, allowing time for the system operator to redispatch the system.

(b) Panel (b) shows inadequate FIR failing to arrest the frequency deviation above 48 Hz, triggering the first AUFLS block at 47.8 Hz.

(c) Panel (c) shows inadequate SIR unable to restore frequency to the normal band, but the system operator has enough time to redispatch the system to compensate.

Figure 6: Illustrating the roles of FIR and SIR during a contingent event



Source: Electricity Authority

4.43 Scarcity of FIR is therefore a higher security risk than scarcity of SIR. In general, a higher risk-violation price for a shortfall in FIR relative to SIR:

(a) favours a SIR shortfall ahead of FIR shortfall, all other things being equal. In the risk-violation model, technically this means favouring a single SIR risk violation ahead of a single FIR risk violation

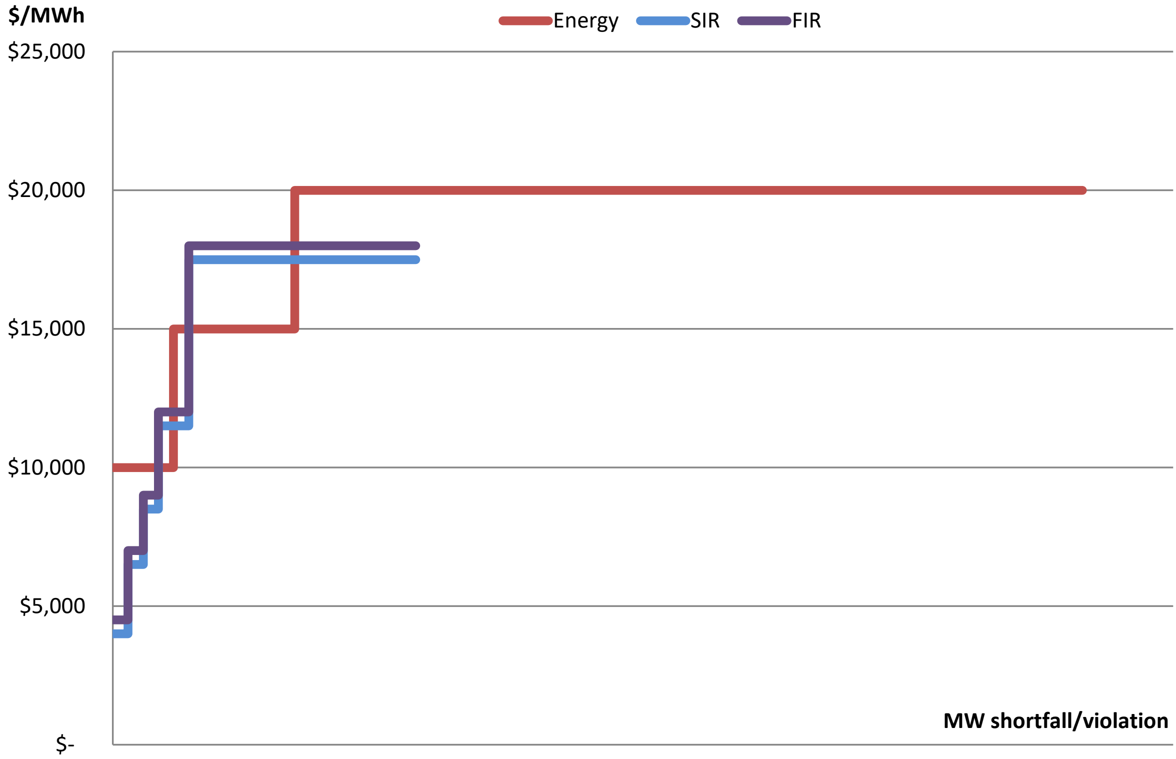
(b) sends a price signal during reserve scarcity — a period of risk violation — reflecting the greater risk of triggering AUFLS for a FIR risk-violation relative to a SIR risk-violation.

Q9.	**Do you agree reserve pricing under RTP should place a higher cost on scarcity of FIR than scarcity of SIR? If not, please explain your reasoning.**

4.44 Higher prices for violating FIR than for SIR results in a pair of risk-violation curves. These are illustrated in Figure 7. The default energy scarcity pricing blocks are also shown as stepped quantities of rising energy deficit.

4.45 This approach means the risk-violation curves for FIR and SIR shortfalls would be based on the economic costs of declining reserve cover. SPD would then trade these costs off in determining the least-cost dispatch solution.

Figure 7: Illustrative proposed curves for energy deficit and risk-violation under RTP



Source: Electricity Authority

Notes: The default energy scarcity pricing blocks (red) are shown as a progressive quantity of energy shortfall.

The risk-violation model more accurately reflects the extent of the risk not being covered during reserve shortfalls

4.46 The risk-violation model is robust to multiple risk-setters, largely resolving the problems outlined from paragraph 4.32. Dispatch outcomes would be consistent, reasonable, and economically justified, regardless of the number of risk-setters. Energy prices would not be suppressed if there are multiple risk-setters during reserve shortfalls. Reserve prices would scale in line with the risk not being covered; ie, reserve prices grow with the number of risks that are ‘binding’.

4.47 The resultant prices for reserve and for energy would then send the correct signals, operationally and for longer-term investment.

4.48 Further, the risk-violation model reveals an important dynamic obscured today. Using the terms defined in paragraph 4.9:

(a) The target quantity for each reserve class is usually the **actual maximum risk**, but reserve shortfalls reduce the MW size of the **maximum covered risk**.

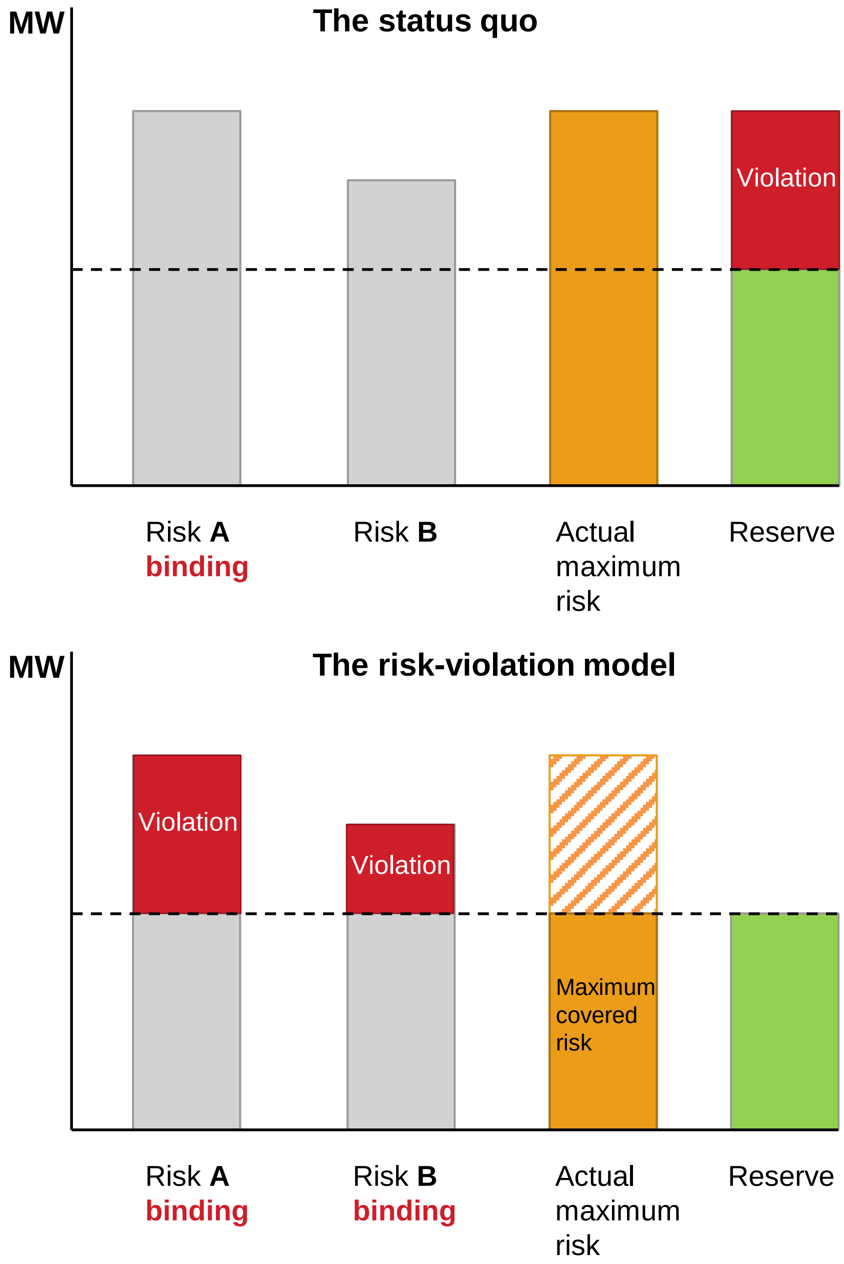
(b) Additional risk sources may not be fully covered as a result, even if they were dispatched for MW quantities less than the **actual maximum risk**.

4.49 The current reserve deficit model does not account for this effect, because the binding risks are only those dispatched *at* the actual maximum risk quantity. The number of binding risks therefore does not change if SPD schedules a reserve shortfall.

4.50 In contrast, binding risks under the risk-violation model are those dispatched *at or exceeding* the maximum covered risk quantity. As the maximum covered risk is by definition reduced by the size of any reserve shortfall, the number of binding risks can therefore change in consequence.

4.51 This effect is illustrated conceptually in Figure 8. Under the status quo, there is only 1 binding risk: Risk A alone determines the actual maximum risk. A reserve shortfall (red shaded box) does not change that. However, the scheduled quantity of reserve (green shaded box) — defining the maximum covered risk — is also less than Risk B’s dispatched quantity. Under the risk-violation model there are now two binding risks during this reserve shortfall.

Figure 8: The number of risks not fully covered can change during reserve shortfalls



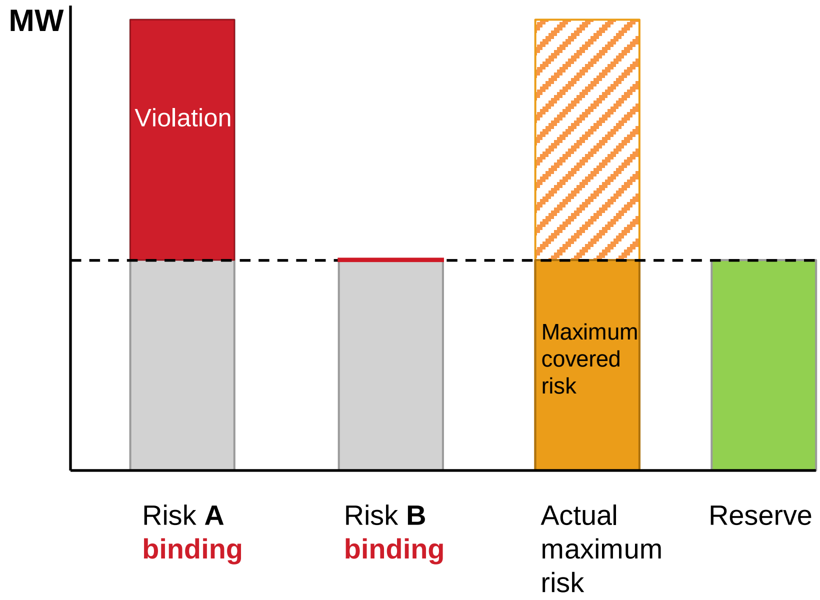
Source: Electricity Authority

Notes: Risk A determined the actual maximum risk in both cases.
Under the status quo, only Risk A is binding. Under the risk-violation model, both risks are binding because both are dispatched for MW quantities greater than the maximum covered risk.

4.52 SPD would apply the risk-violation curve to each binding risk. There would therefore be a higher violation price for Risk A in Figure 8, if we assume the larger quantity of violation reached a higher tranche in the curve. The reserve price includes both prices; ie, both the violation price from Risk B and the relatively-higher violation price from Risk A. The reserve price then more accurately reflects the economic cost of the total risk not being covered during a reserve shortfall, for the same dispatch outcome.

4.53 Finally, this understanding of binding risk underscores the critical role of the individual risk-violation tranches, both their MW quantity and their violation price. SPD may produce different dispatch outcomes in determining the least-cost solution. For example, Figure 9 illustrates the same scenario as Figure 8, but with different risk-violation quantities on binding risks A and B. In this outcome, the cheapest solution is to violate a larger quantity on Risk A to take advantage of its lower-cost energy.[39] Note Risk B is also a binding risk using the definition in paragraph 4.50.

Figure 9: Violating more of one risk source may be the least-cost solution



Source: Electricity Authority

Notes: Risk A determined the actual maximum risk. Both risks are binding, because both are dispatched for MW quantities greater than *or equal to* the maximum covered risk.

4.54 There is one drawback to the risk-violation approach, as detailed in Box 6: while reserve prices would increase with (be multiplied by) the number of binding risks, the underlying probability of a contingent event rises at a smaller rate. Reserve prices may then 'over signal' the cost of reserve shortfall. However, we consider this is an acceptable trade-off, because the smaller the probability of an individual failure in reality, the closer the rise in the probability of a contingent event comes to linear.

[39] Risk A is violated first because it has a lower marginal energy cost. Risk violation of Risk A will rise until the total of its marginal energy cost and risk-violation cost is greater than the total for Risk B.

Box 6: Reserve prices would scale linearly with the number of binding risks not being covered

If we assume all sources of risk are independent, with the same probability of failure, then the probability of a contingent event increases with the number of binding risks. However, the probability of an event does not increase linearly. Mathematically, the cumulative probability of any one risk failing in a set of *n* independent risk sources of equal probability *f* is

$$1 - (1 - f)^n$$

To illustrate, if we imagine *f* is an unrealistically large 10%, the probability of a contingent event is 27.1% for 3 risk-setters; for a hypothetical 11 risk-setters, the probability rises to 68.6%. However, for a much smaller (and closer to realistic) *f* of 1%, the probability for 3 risk-setters would be 3.0%, and for 11 risk-setters 10.5%.

However, SPD is a linear optimisation model, and the market system makes no attempt to assess the probability that any risk will fail (nor do we propose to do so). This means the economic cost of multiple binding risks under the risk-violation model would scale linearly — there would be a '**multiplier effect**'. For *n* binding risks, the reserve price during reserve shortfall would be *n* times the relevant risk-violation price.

Configuring the risk-violation curves requires trade-offs

4.55 Constructing risk-violation curves for FIR and SIR requires trading-off an array of factors in determining each price-quantity tranche, represented in Table 4. Visually, price sets the height of each step in Figure 7, and quantity sets the width.

Table 4: Factors to trade-off in constructing the risk-violation curves

High $	Factor affected by price	Low $
stronger	strength of scarcity price signal	weaker
weaker	restraint on higher-priced offers[1]	stronger
less likely	chance of reserve shortfall before energy deficit	more likely
less likely (only one)	chance of both FIR and SIR violation	more likely (both)
less likely	chance of multiple risks binding	more likely

High Q	Factor affected by quantity	Low Q
larger	size of reserve shortfall	smaller
stronger	restraint on higher-priced offers[2]	weaker
more likely	chance of triggering AUFLS	less likely

Source: Electricity Authority

Notes:
1. A higher risk-violation tranche price means it is more likely SPD would clear energy or reserve offers; ie, those priced below that tranche's price.
2. A larger risk-violation tranche quantity means more reserve shortfall (MW quantity) would be scheduled before clearing energy or reserve offers priced above that tranche's price.

4.56 The major considerations in trading-off these factors include:

(a) The total quantity in all risk-violation tranches priced below each default scarcity pricing block determines the maximum possible reserve shortfall before load shedding.

(b) The tranche prices determine:

(i) whether both FIR and SIR risk-violation can bind before triggering load shedding (if risk-violation prices plus cleared energy offers are less than the relevant default energy scarcity price). More generally, this is the likelihood of going into reserve shortfall before energy deficit

(ii) the strength of the operational and investment signal of the resultant reserve scarcity prices

(iii) the magnitude of reserve scarcity prices resulting from the 'multiplier effect' when multiple risk-violations bind (see paragraph 4.50 and Box 6).

(c) In combination, each price-quantity tranche determines the extent to which reserve and energy offer prices may be restrained if risk-violation binds:

(i) A smaller tranche quantity reduces any restraint by only allowing a relatively small reserve shortfall at that tranche's price. Reserve or generation offers initially restrained would then clear once that tranche quantity was exhausted.

(ii) A higher tranche price reduces any restraint by allowing more 'headroom' to clear higher-priced reserve and energy offers before that tranche price binds. But a higher price also limits the ability for both FIR and SIR shortfalls to occur.

4.57 Modelling the risk-violation curves to explore these trade-offs shows the first tranche plays a crucial role. In particular:

(a) A larger quantity for the first tranche means more reserve shortfall before load shedding.

(b) Conversely, a higher price for the first tranche makes it less likely reserve shortfall would occur before load shedding. This is because the higher price makes violating the first default energy scarcity pricing block ($10,000/MWh) lower cost than violating multiple risk sources, or violating both FIR and SIR cover.[40] Transmission losses and the marginal cost of energy also play a role.[41]

(c) The presence of multiple binding risks and/or violations of both FIR and SIR can mean load shedding at lower levels of risk-violation than might be expected by looking at the curves alone.

4.58 However, these outcomes are the lowest-cost solution determined by SPD, reflecting the economic costs assigned to these curves; ie, the relative costs of energy deficit versus risk-violation.[42] Again, it could be more efficient to incur energy deficit (load shedding) than further violating risk cover — for example, when supplying the next MW of energy requires reducing a MW of reserve, increasing the uncovered risk across multiple risk sources.

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40 Generally, the larger the ratio of the first default energy scarcity price at $10,000/MWh to the first risk-violation tranche price, the more likely reserve shortfall would occur before load shedding.

41 The effect of losses in the presence of multiple binding risks or both FIR and SIR violation can result in load shedding before reserve shortfall.

42 See Appendix F for related discussion.

We modelled two configurations of the risk-violation curve

4.59 We created illustrative risk-violation curves in two configurations to test the trade-offs discussed above: a 'lower price' version shown in Table 5 and a 'higher price' version in Table 6.

Table 5: Lower price risk-violation curve

Tranche	FIR price ($/MW/h)	SIR price ($/MW/h)	Quantity (MW)
1	4,500	4,000	10*
2	7,000	6,500	10
3	9,000	8,500	10
4	12,000	11,500	20
5	18,000	17,500	100

Table 6: Higher price risk-violation curve

Tranche	FIR price ($/MW/h)	SIR price ($/MW/h)	Quantity (MW)
1	7,500	7,000	10*
2	12,000	11,500	20
3	18,000	17,500	100

Source: Electricity Authority

Notes: * We modelled varying quantities for the initial tranche for both versions; see paragraph 4.61.

4.60 The main difference is the lower price version has three tranches priced below the first default energy scarcity pricing block at $10,000/MWh; the higher price version has only one. The multiple initial tranches allows both FIR and SIR violation to occur in the lower price version.[43] Both versions have the same single tranche below the second and third energy scarcity blocks ($15,000/MWh and $20,000/MWh). Both versions assign a slightly higher cost to FIR risk violation than SIR.

4.61 We modelled these curves against historical dispatch cases.[44] We also tested the effect of varying the quantity of the first risk-violation tranche (in the range 10, 20, 30, 40, 50 MW). The results are illustrative scenarios to help inform our choice of the best risk-violation curve to implement under RTP. They help understand how the risk-violation model behaves when changing these core parameters.

4.62 However, we stress these results *cannot be taken as expected outcomes under RTP* for any curve — they are based on offers from current market conditions.

43 The costs of violating both FIR and SIR in the first tranche are $4,500 + $4,000 = $8,500 < $10,000.

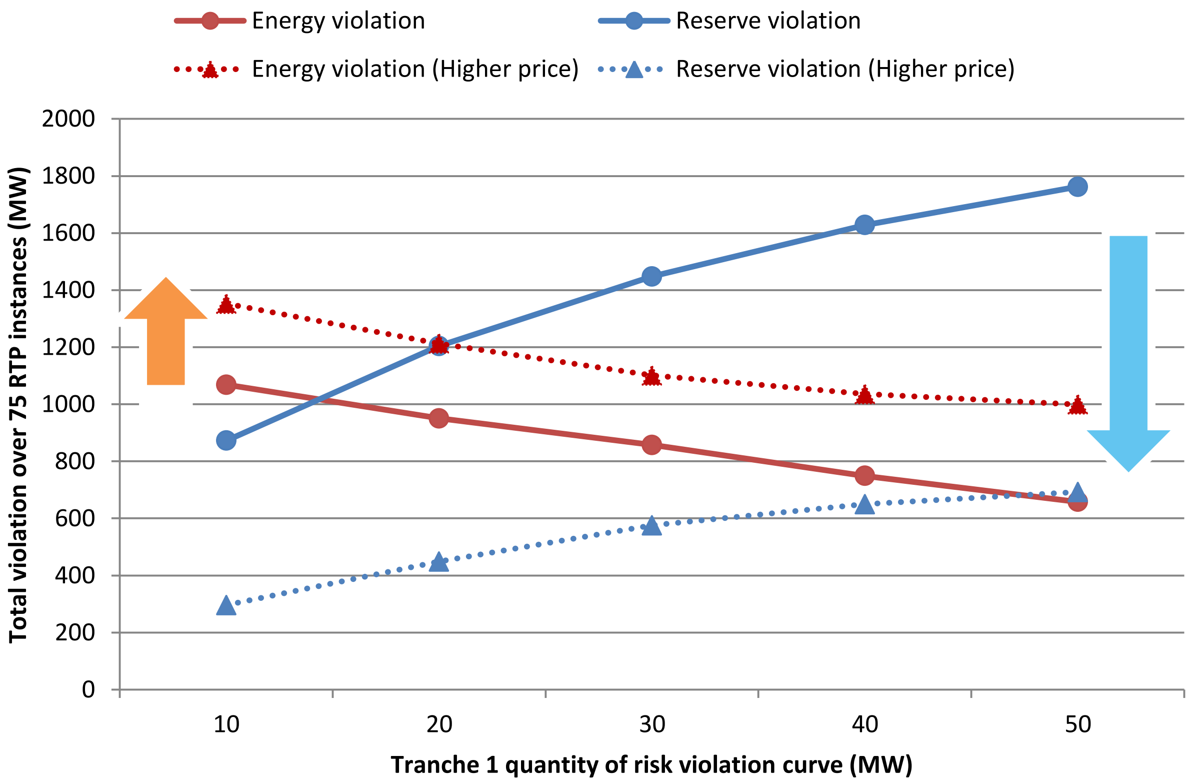
44 We used the 75 RTD cases where reserve prices were at least $3000/MW/h (reflecting scarcity and near-scarcity conditions), over the period 2015–2017.

4.63 Figure 10 shows a summary of the distribution between energy deficit (load shedding) and reserve shortfall (as risk-violation) in these modelling results. Figure 10 shows two major outcomes, consistent with the factors in Table 4:

(a) increasing the price of the first tranche increases the aggregate quantity of energy deficit (orange arrow) and reduces the aggregate quantity of reserve shortfall (blue arrow)

(b) the aggregate quantity of reserve shortfall rises in line with an increasing quantity for the first tranche in both lower and higher price versions.

Figure 10: Risk-violation curve modelling: energy deficit vs. reserve shortfall



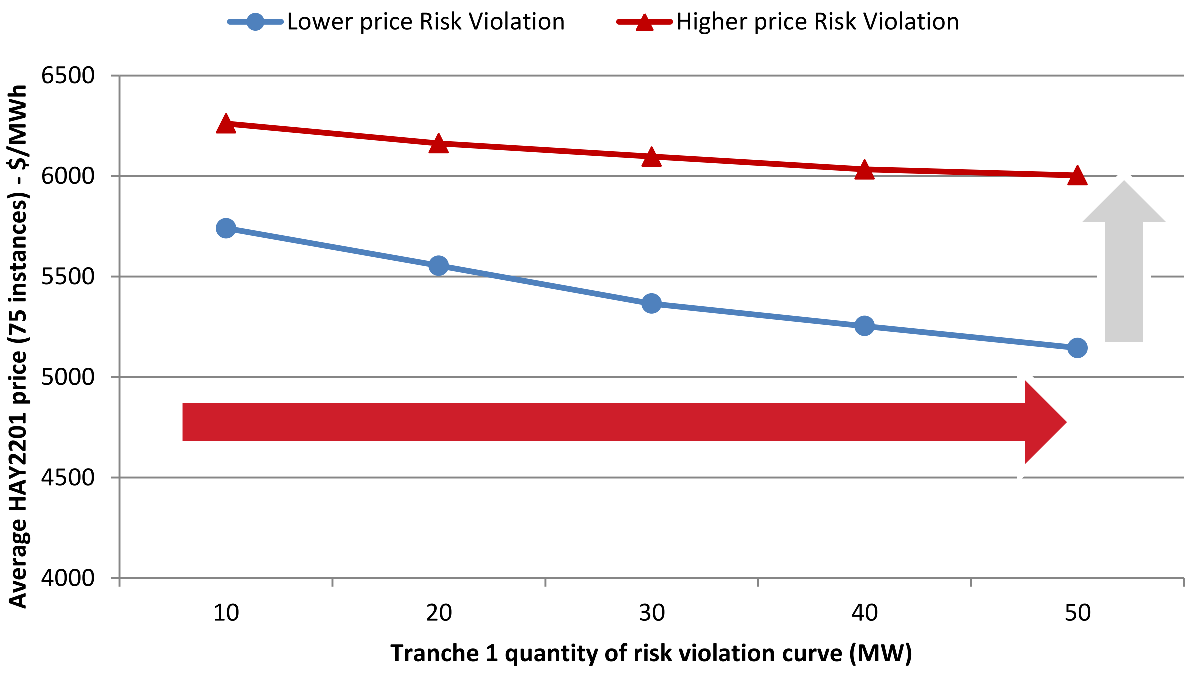
Source: Electricity Authority

4.64 Figure 11 shows a summary of these effects on energy prices (at the reference Haywards GXP). Here energy prices:

(a) are consistently higher in the higher price risk-violation curve (grey arrow)

(b) fall in line with an increasing quantity for the first risk-violation tranche in both lower and higher price versions (red arrow), reducing the scarcity price signal.

Figure 11: Risk-violation curve modelling: energy price outcomes



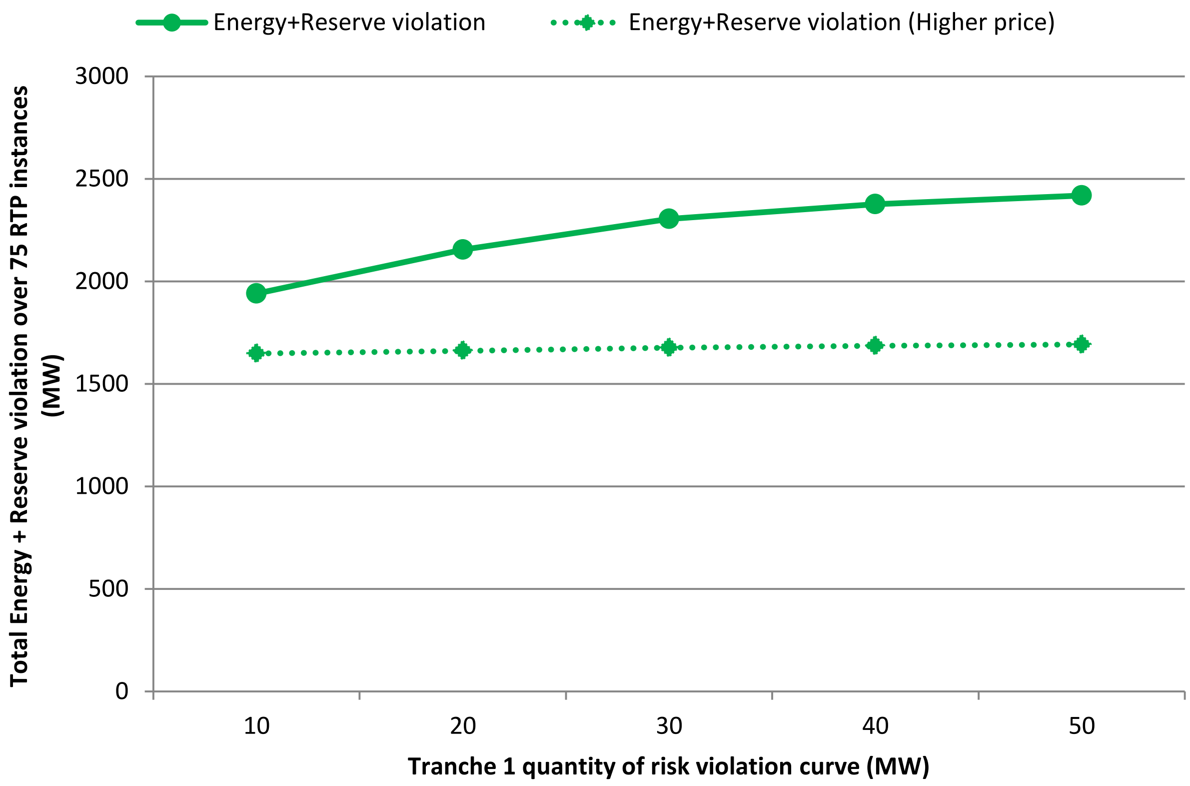
Source: Electricity Authority

4.65 Finally, Figure 12 shows the total MW quantity of reserve shortfall and energy deficit (load shedding) — or the total violation quantity. Figure 12 shows:

(a) the total violation quantity rises in line with an increasing quantity for the first tranche in the lower price version. This reflects the two 'restraint on higher-priced offers' factors in Table 4, consistent with paragraph 4.56(c). Higher-price offers are not being dispatched, as SPD determines the combination of reserve shortfall and energy deficit is the lower-cost solution. That is, the lower price risk-violation tranche is cheaper than physical market offers (for the MW size of that tranche).

(b) this effect also exists for the higher price version, but the rise in total violation is very minor.

Figure 12: Risk-violation curve modelling: total quantity of energy and reserve violation



Source: Electricity Authority

4.66 These modelling results underscore there is no perfectly 'right' answer. The choice of risk-violation curve depends on the weightings given to the factors described above in determining economic costs. The choice requires trade-offs. We also want the spot market to be as easy to understand as possible — participants need to be able to trade around these economic costs in building their offer structures.

4.67 Reducing the results to two broad scenarios makes the choice clearer:

(a) **Higher price, highest quantity (50 MW):** Reserve prices go to full scarcity levels immediately for any risk-violation (allowing a gap to clear energy offers), sending a strong price signal. This substantially limits any restraint on reserve or energy offer prices. But there would be relatively little reserve shortfall ahead of load shedding, and only FIR or SIR violation could occur, not both.

(b) **Lower price, lowest quantity (10 MW):** Reserve prices move through an intermediate step — elevated for a limited initial reserve shortfall, but not yet at full scarcity levels. This allows a degree of risk-violation before the price rises to signal 'emergency' conditions; the three intermediate tranches define the pace of that rise. Reserve shortfall is more likely ahead of load shedding, and both FIR and SIR violation can occur (at intermediate prices). While any restraint on reserve and energy offer prices would be stronger, it persists only for the relatively smaller MW quantity of the initial tranches.

We do not consider the risk-violation curve approach increases incentives or opportunities for gaming

4.68 We recognise some stakeholders may be concerned the risk-violation curve approach could raise questions of gaming or price manipulation. For example, could participants construct their offers to induce reserve scarcity, or the multiple binding risk effects described from paragraph 4.46, purely in order to capitalise on higher prices?

4.69 On balance, we do not consider incentives or opportunities for gaming would be increased. We also note instances of reserve scarcity are likely to be highly scrutinised, and monitoring should be able to detect evidence of strategic withholding of capacity.

4.70 Reserve offers are also subject to the good trading conduct provisions in the Code. Our current project reviewing these provisions may then further limit participants' ability to manipulate reserve scarcity.

Q10. Do you consider the risk-violation curve approach would increase incentives or opportunities for gaming? Please explain your reasoning.

We propose implementing the lower price, lower quantity risk-violation curve under RTP

We propose implementing the lower price version of risk-violation curve under RTP, as shown in Table 7. The initial tranche quantity would be set to 10 MW, the lowest quantity modelled above. We consider this design gives the best balance across the factors set out in Table 4, with the outcome described in paragraph 4.67(b).

Table 7: Proposed risk-violation curves under RTP

Tranche	FIR price ($/MW/h)	SIR price ($/MW/h)	Quantity (MW)
1	4,500	4,000	10
2	7,000	6,500	10
3	9,000	8,500	10
4	12,000	11,500	20
5	18,000	17,500	100

Q11. Do you agree we should implement the risk-violation curve we have described to handle reserve shortfalls under RTP? If not, please explain your reasoning.

Q12. Which configuration of the risk-violation curve do you consider we should adopt? Please explain your reasoning.

4.71 The final tranches for the risk-violation curves modelled above and proposed in Table 7 use a finite quantity of 100 MW. The total possible quantity of reserve shortfall for each reserve class in each island would therefore be strictly capped as the sum of all tranche quantities (150 MW for the lower price version, 130 MW for the higher price). An alternative approach is to remove any limit on total shortfall by making the final tranche unbounded; ie, removing the quantity limit.

Q13.	**Should we set a total reserve shortfall quantity limit if we implement the risk-violation curve under RTP? Please explain you reasoning.**

4.72 We also considered but discarded the option of introducing a new type of formal notice to cover periods of looming reserve shortfall inside the gate closure period. For example, a 'lack of reserve' notice would readily identify the particular conditions expected or currently occurring on the power system. Using a specific notice may give participants clearer information on how they could best respond to the reserve shortfall.

4.73 However, implementing a new notice would require additional market system changes, increasing the cost to implement RTP. In practice, would do not consider any benefit is likely to materially outweigh those costs. The existing Code arrangements for grid emergency notices (GEN) — as generally amended for RTP — already provide for these situations. Further, the system operator could give additional detail to clearly state the GEN applied to a reserve shortfall, if that were required.

Q14.	**Do you agree a new type of formal notice to cover periods of reserve shortfall under RTP is not warranted? If not, please explain your reasoning.**

5 We propose the Authority should review the scarcity pricing values every five years

5.1 Some submitters on our 2017 paper were concerned using the current scarcity pricing values in the Code may not be appropriate for RTP; ie, the range \$10,000–\$20,000/MWh. These values have not been changed since they were first set in 2011. They may then be too high — or too low — by the time RTP goes live in 2022. Submitters therefore suggested:

(a) the Authority review these values before RTP goes live

(b) there should be some process to review them periodically.

5.2 We agree the default scarcity pricing values should be reviewed before RTP goes live. We intend to conduct that review as part of implementing RTP, likely as part of any final update to RTP's Code amendment in the year before it comes into force. That ensures the dollar amounts assigned to those values reflect current assessments of key inputs, like the expected cost of peaking generation and the value of lost load.

5.3 Importantly, we also intend to assess the values assigned to the risk-violation curves proposed in section 4 as part of the same review process. The dollar amounts assigned to each risk-violation tranche implement 'reserve scarcity pricing' under RTP. The two forms of scarcity pricing are closely related, as detailed in Appendix F.

5.4 We therefore refer to this process as reviewing the scarcity pricing values, in a general sense.

5.5 We also agree it would be prudent to review the scarcity pricing values periodically. This would ensure the values are updated to reflect important developments as the electricity sector evolves.

We have revised and confirmed the methodology we will use to calculate the scarcity pricing values

5.6 We propose to adopt the methodology set out in Appendix F to determine the scarcity pricing values. As explained in Appendix F, that methodology continues the original approach we used when setting the current scarcity pricing values in the Code in 2011.

Q15. Do you agree with the proposed methodology to calculate the scarcity pricing values? If not, please explain your reasoning.

We propose setting an obligation in the Code to review the scarcity pricing values every five years

5.7 We consider an obligation for the Authority to review the scarcity pricing values periodically should be set in the Code. The time period for such a review is a balance between:

(a) the time and administrative cost needed to conduct a review

(b) how often the cost inputs detailed in Appendix F are likely to change

(c) providing confidence the values reflect those costs with reasonable accuracy.

5.8 We also consider the Authority should be able to review the values at any other time, if circumstances justified it. For example, if major and rapid shifts in technology or Government policy leads to material changes to inputs in the middle of a review period.

5.9 We consider five years is an appropriate time period. Any longer could risk failing to capture changes in cost inputs, reducing confidence in the scarcity pricing values. But shorter periods risk imposing unreasonable administrative costs (diverting Authority resources) without significant benefit.

5.10 We therefore propose an obligation to review the scarcity pricing values every five years, as set out in clause 13.58AB of the proposed RTP Code amendment (Appendix B).

Q16. Do you agree the Authority should have an obligation to review the scarcity pricing values at least once every five years? If not, please explain your reasoning.

6 Regulatory statement

6.1 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.[45]

6.2 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

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

Spot prices would be more actionable

6.4 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

6.5 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.

6.6 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.

Q17. Do you agree with the objectives of the proposed amendment? If not, why not?

Consistency with statutory objective

6.7 We believe the Code amendment will promote all three limbs of the Authority's statutory objective[46] 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.

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

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

6.8 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 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.

6.9 Appendix G sets out more information on why we expect RTP to promote each of these limbs.

Q18. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning.

Consistency with demand response guiding regulatory principles

6.10 In June 2018, we published an updated version of the guiding regulatory principles that should apply to demand response initiatives.[47] Although RTP is not a demand response initiative per se, we expect it to provide significant benefits in this area. Table 8 assesses the proposed RTP design against the demand response guiding regulatory principles.

Table 8: Testing RTP's design against the demand response guiding regulatory principles

Guiding principle	Assessment
Best-possible incentives: incentives to undertake demand response should reflect the marginal benefit of that response to the electricity system. Any payment for providing demand response should be funded by those benefiting from that response.	✓ RTP will promote more efficient pricing outcomes for the reasons set out in paragraphs 6.4 and 6.5. Dispatch-lite will make it easier for demand-side bids and non-dispatched generation to directly influence spot prices. Purchasers participating in the spot market would not receive a payment for providing demand response but would avoid paying spot prices that exceed their willingness-to-pay by reducing consumption.
Openness: demand response should be able to participate in market arrangements, wherever practical. Anybody should be allowed to provide demand response services, including consumers and their agents. Demand response initiatives should not unreasonably restrict the technologies used to provide that response.	✓ More actionable spot prices under RTP will make it easier for consumers to participate in the spot market and react to spot prices in an efficient way. RTP does not restrict the technologies consumers can use to provide demand response. Our proposed dispatch-lite product should facilitate greater participation in the spot market.

47 The updated principles are available at on our website at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/demand-response/development/demand-response-principles-2018-update/.

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

Source: Electricity Authority

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

Benefits and costs of amendment

Broad approach

6.12 The cost-benefit analysis (CBA) builds on the framework used in our 2017 paper. 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 our 2017 CBA of RTP.

6.13 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[48]

(c) values are estimated in 2018 dollars using a 6% real discount rate; sensitivity cases with discount rates of 4% and 8% are also considered

48 Now expected to be calendar year 2022.

(d) the counterfactual to RTP assumes that existing arrangements remain in place, except that the system operator's DSE project has been implemented.

Categories of benefit

6.14 We have developed quantitative estimates for the following benefits:

(a) Benefit 1: avoided generation investment by substituting more efficient demand-response from industrial and commercial users[49]

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

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

6.15 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.[50] This should improve confidence in the value of risk management products 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.[51]

Categories of cost

6.16 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.

6.17 We have set out the detailed analysis in Appendix G. Table 9 summarises the results of the assessment. Note that numbers in Table 9 may not add due to rounding (to whole millions).

Table 9: Estimated benefits and costs[52]

Item $m (present value)	Lower case	Base case	Higher case
Benefits[1]			
Demand response benefit – industrial and commercial	30	48	70
Demand response benefit – residential	9	23	46

[49] In this appendix, we use the term 'demand response' to describe the full range of ways demand for dispatched generation may be reduced. This includes load shifting, load cutting, and increased use of local generation or battery storage.

[50] However, this may manifest itself in undesirable price oscillations due to an increase in the amount of controllable resources automatically responding to dispatch prices. See the discussion from paragraph 3.57.

[51] We note RTP focuses on improving information available in real-time, and the benefits it can bring. We do not count benefits from improving *forecast* information, which is a distinct issue in its own right.

[52] These numbers have been updated, with more detail set out in Appendix G.

Item $m (present value)	Lower case	Base case	Higher case
Reliability benefit	0	8	19
Total benefits	38	79	135
Demand response costs			
Industrial and commercial	-5	-9	-14
Residential	-2	-8	-19
Total demand response costs	-8	-17	-33
Implementation costs			
System operator function	-11	-10	-9
Pricing and clearing functions (positive indicates a net saving)	-1	1	2
Participant implementation costs	-5	-2	0
Total implementation costs	-16	-12	-8
Net benefits	15	50	95

Source: Electricity Authority

Notes: 1. Excludes some benefits that are not quantified

6.18 The analysis shows significant net benefits of $50 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.

6.19 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.

6.20 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.

6.21 This analysis indicates that if improved industrial demand response is the sole benefit of RTP, it would need to increase by approximately 16 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 about 0.2% of total system demand in peak periods.

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

Q19.	**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

6.23 Our April 2016 information paper previously considered a range of alternative RTP designs (where Option B is the current proposal):[53]

(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.

6.24 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.

6.25 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 considered them as a separate issue.[54]

6.26 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.[55]

Q20.	**Do you agree with our assessment of alternatives? If not, why not?**

The Authority has given regard to the Code amendment principles

6.27 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

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

54 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.

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

Authority considers they are applicable.[56] Table 10 describes the Authority's regard for the Code amendment principles in preparing our RTP proposal.

Table 10: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective (see paragraph 6.7) 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 paragraph 6.12 to 6.22.
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 paragraph 6.12 to 6.22.

6.28 Principles 4 to 9 are not included in Table 10. 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.

56 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 our proposed criteria for distributed generation to be eligible for dispatch-lite? If not, please explain your reasoning.	
Q2.	Do you agree with our proposed criteria for purchasers to be eligible for dispatch-lite? If not, please explain your reasoning.	
Q3.	Do you agree participants providing SCADA telemetry should be eligible for dispatch-lite? If not, please explain your reasoning.	
Q4.	Do you agree combining an acknowledgement response via the dispatch system with an obligation to immediately rebid or reoffer is the best design option? If not, please explain your reasoning.	
Q5.	Do you agree gate closure for all dispatch-lite participants should be set at 30 minutes (one trading period), the same as for current embedded generators?	
Q6.	Do you agree with the proposed compliance arrangements for dispatch-lite? If not, please explain your reasoning.	
Q7.	Do you agree with the proposed method to allow dispatch-lite participants to withdraw from dispatch? If not, please explain your reasoning.	
Q8.	Do you agree we should implement dispatch-lite as part of RTP, should we decide to proceed? If not, please explain your	

Question		Comment
	reasoning.	
Q9.	Do you agree reserve pricing under RTP should place a higher cost on scarcity of FIR than scarcity of SIR? If not, please explain your reasoning.	
Q10.	Do you consider the risk-violation curve approach would increase incentives or opportunities for gaming? Please explain your reasoning.	
Q11.	Do you agree we should implement the risk-violation curve we have described to handle reserve shortfalls under RTP? If not, please explain your reasoning.	
Q12.	Which configuration of the risk-violation curve do you consider we should adopt? Please explain your reasoning.	
Q13.	Should we set a total reserve shortfall quantity limit if we implement the risk-violation curve under RTP? Please explain you reasoning.	
Q14.	Do you agree a new type of formal notice to cover periods of reserve shortfall under RTP is not warranted? If not, please explain your reasoning.	
Q15.	Do you agree with the proposed methodology to calculate the scarcity pricing values? If not, please explain your reasoning.	
Q16.	Do you agree the Authority should have an obligation to review the scarcity pricing values at least once every five years? If not, please explain your reasoning.	
Q17.	Do you agree with the objectives of the proposed amendment? If not, why not?	

Question	Comment
Q18. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning. Q19. 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. Q20. Do you agree with our assessment of alternatives? If not, why not? Q21. Do you have any comments on the drafting of the proposed Code amendment?	

Appendix B Proposed Code amendment

Q21. Do you have any comments on the drafting of the proposed Code amendment?

Appendix C TAS078 report from the system operator

Appendix D Illustrating the benefit of participating in dispatch when bids or offers are marginal

D.1 Two stylised, simplified examples illustrate the benefit of participating in dispatch-lite when bids or offers would be marginal (see the discussion in paragraph 3.52).

Dispatch-lite for a purchaser

D.2 Suppose a purchaser has a highly controllable load source of 10 MW, and they are willing to pay up to $250/MWh to consume. 6 MW of this load can be supplied by generation offered at $200/MWh, but the full 10 MW requires additional generation offered at $500/MWh.

D.3 Figure 13 shows the difference between responding to dispatch prices versus participating as dispatchable demand-lite:

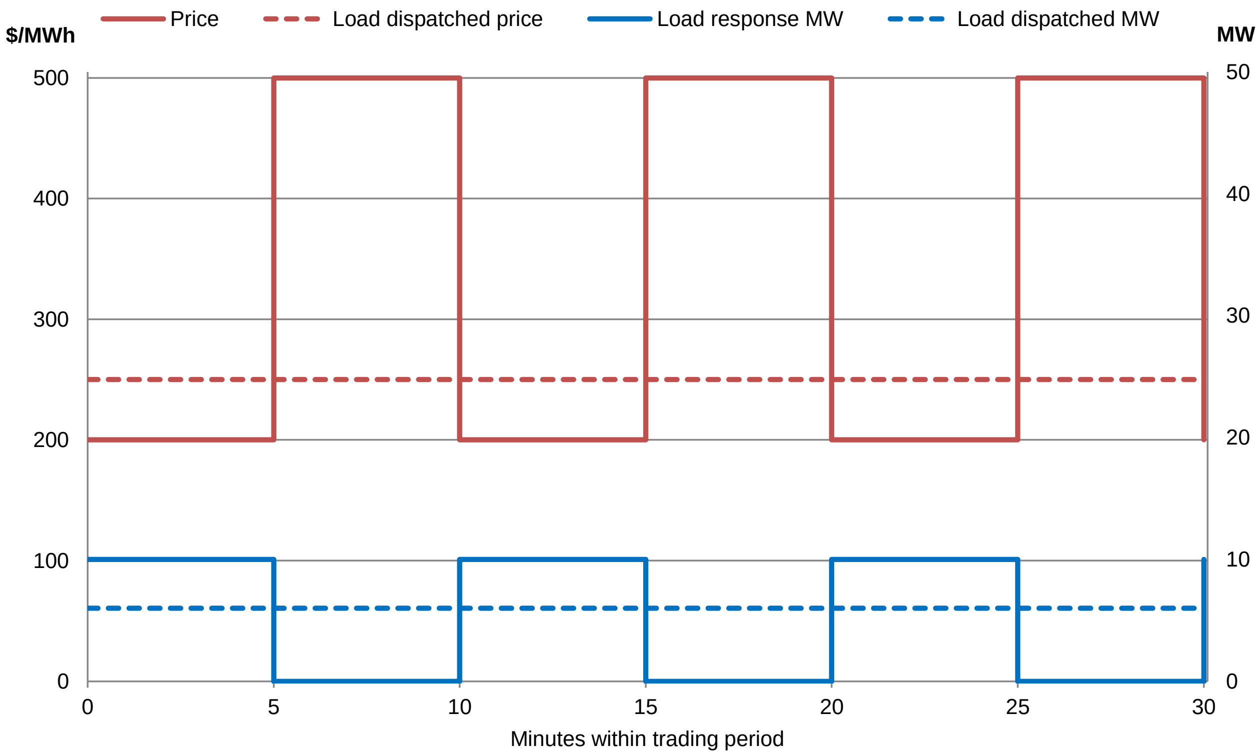
(a) The trading period begins (at minute 0) with a dispatch price of $200/MWh. This is less than the purchaser is willing to pay, so they consume the full 10 MW. But this additional load then pushes the dispatch price to $500/MWh, as the next generator is scheduled to provide the extra 4 MW. The new dispatch price is now more than the purchaser is willing to pay, so they drop their load to 0 MW. The $500 generator is then no longer needed, so the dispatch price falls back to $200/MWh. The purchaser then responds by again consuming their full 10 MW, and the cycle repeats.[57] The outcome is the price pattern shown as a solid red line, and the load pattern in solid blue. The final price for the trading period is $350/MWh.

(b) If the purchaser instead participated in dispatch-lite with a bid of 10 MW at $250/MWh, the outcome is shown by the dashed lines. They would be dispatched to consume 6 MW, the maximum quantity the cheaper generator can supply. But as the purchaser is now the marginal tranche — not all of their load can be supplied at or below their bid price — they set the dispatch price at $250/MWh. The single dispatch price is maintained for the full trading period, so the final price is also $250/MWh.

[57] The purchaser has no way of knowing (with any certainty) they can only consume 6 MW before the dispatch price rises to $500/MWh.

Figure 13: A purchaser responding to dispatch prices versus participating in dispatch

Dispatch prices for a 30-minute trading period are shown in red on the left axis ($/MWh), the purchaser's load is shown in blue on the right axis (MW).



Source: Electricity Authority

Notes:
1. Dispatch prices for a 30-minute trading period are shown in red on the left axis ($/MWh), struck every 5 minutes for simplicity.
2. The purchaser's load is shown in blue on the right axis (MW).
3. Generation offers can supply the load's full 10 MW for $500/MWh, or 6 MW for $200/MWh.

D.4 If they responded to dispatch prices, the purchaser would use an average of 5 MW for the trading period at a total cost of $875. However, if they participated in dispatch-lite they would use a higher average of 6 MW but at a lower total cost of $750.[58] The final price would also be lower for all consumers, compared to consuming their full 10 MW.

D.5 In this example, participating in the price-setting process therefore avoids foregone consumption and reduces costs for the purchaser, while setting an efficient spot price.

58 When responding, purchase cost is 2.5 MWh at $350/MWh. When dispatched as the marginal bid, purchase cost is 3 MWh at $250/MWh.

Dispatch-lite for a distributed generator

D.6 Suppose a distributed generator has a highly controllable supply source with a capacity of 10 MW, and their variable costs to supply are $250/MWh. Also assume their 10 MW would be enough to supply the underlying load at their GXP, on top of generation offered at $200/MWh. Without them, additional generation offered at $500/MWh has to be scheduled instead.

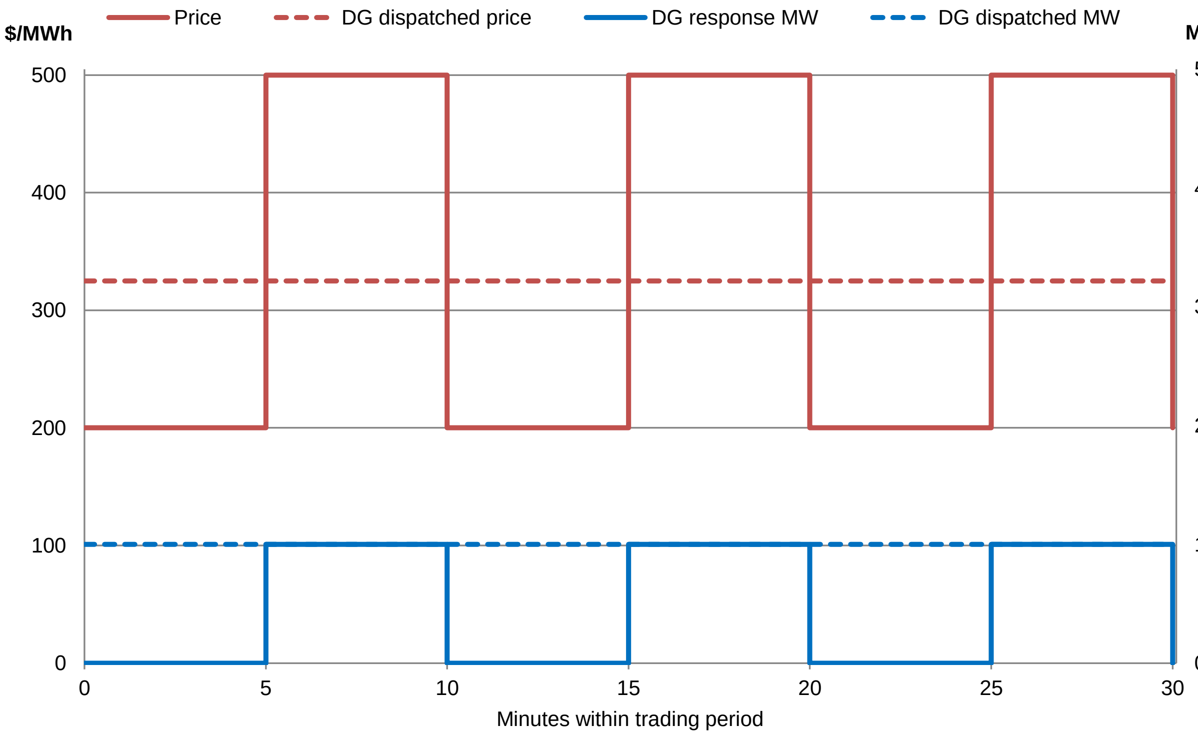
D.7 Figure 14 shows the difference between responding to dispatch prices versus participating as distributed generation-lite:

(a) The trading period begins (at minute 0) with a dispatch price of $200/MWh. This is less than the distributed generator's cost to supply, so they withdraw their generation. Without their generation, net load at the GXP rises and the next offered generator is scheduled to provide the extra 10 MW. The dispatch price increases to $500/MWh. The distributed generator then comes back on, producing at their full 10 MW. But this additional supply reduces net load at their GXP again, and the dispatch price drops back to $200/MWh. The cycle repeats. The outcome is the price pattern shown as a solid red line, and the distributed generation output in solid blue. The final price for the trading period is $350/MWh.

(b) The distributed generator could instead participate in dispatch-lite, offering to supply 10 MW. However, if they offer at $250/MWh and were dispatched to 10 MW for the trading period, the final price would be $250/MWh. Their revenue would then equal their costs. Following prices may therefore have resulted in more profit (a smaller quantity but at a higher price). Assume they offer at $325/MWh instead, to avoid this — above their cost, but less than the spot price would be otherwise.[59] The outcome is shown by the dashed lines. They would be dispatched to produce 10 MW, displacing the more expensive generator to supply the load at their GXP. The final price is $325/MWh.

59 We stress this is purely illustrative and do not suggest the distributed generator would be certain the spot price would otherwise have been $350/MWh.

Figure 14: A distributed generator responding to dispatch prices versus participating in dispatch



Source: Electricity Authority

Notes:
1. Dispatch prices for a 30-minute trading period are shown in red on the left axis ($/MWh), struck every 5 minutes for simplicity.
2. The distributed generator's output is shown in blue on the right axis (MW).
3. Generation offered at $500/MWh would otherwise be needed to supply the GXP load.

D.8 If they responded to dispatch prices, the distributed generator would produce an average of 5 MW for the trading period. Their profit would be $250, from total revenue of $875 at a cost of $625. However, if they participated in dispatch-lite they would produce at their full 10 MW for a profit of $375 (revenue of $1625 minus cost of $1250).[60] The final price would also be lower for all consumers.

D.9 In this example, participating in the price-setting process therefore avoids foregone profit for the distributed generator, while setting an efficient spot price.

60 When responding, revenue is 2.5 MWh at $350/MWh, and cost is 2.5 MWh at $250/MWh (their variable cost to supply, stated above). When dispatched as the marginal offer, revenue is 5 MWh at $325/MWh, and cost is 5 MWh at $250/MWh.

Appendix E SPD's existing reserve deficit model cannot be used under RTP

E.1 Detailed modelling analysis shows the current reserve deficit model configured in SPD is fundamentally not viable under RTP, as explained below.

Energy price suppression with multiple risk-setters is an inherent outcome of the reserve deficit model

E.2 An inherent outcome of co-optimisation under SPD's current reserve deficit model is the suppression of energy prices when multiple risk-setters are jointly marginal. Because the next MW of energy would be supplied by *n* risk sources (each supplying 1/*n* MW), the marginal increment of reserve (FIR and/or SIR) is also 1/*n* MW. The marginal cost of the relevant reserve class(es) reflected in the energy price is then 1/*n* of the marginal reserve offer's price. If that reserve class is in deficit, its CVP is the marginal cost of that class.

E.3 Table 11 illustrates the energy price suppression effect using highly simplified examples. For a given set of offers (note 2), the representative energy price falls as the number of risk-setters rises. A reserve deficit CVP of $100,000/MW/h represents current arrangements, for indicative 5-minute 'real-time prices'. Any deficit in final pricing is then subject to the VRP described in paragraph 4.17. A reserve deficit CVP of $10,000/MW/h represents dispatch reserve prices set by a penalty price using the reserve deficit model under RTP.

Table 11: Simplified numerical example of energy price suppression with multiple risk-setters under the existing reserve deficit model

# binding CE risks (*n*)	Energy price ($/MWh)		
	No reserve deficit	CVP = $100,000/MW/h	CVP = $10,000/MW/h
1	3,500	101,500	11,500
2	2,500	51,500	6,500
3	2,167	34,833	4,833

Source: Electricity Authority

Notes:
1. Single hypothetical reference energy price, with no accounting for transmission losses.
2. Assumes all risks are jointly marginal energy source with offer price $1,500; SIR is unlimited with reserve offer price $0; FIR is either unlimited with reserve offer price $2,000, or in deficit at stated CVP value.
3. In these examples, the energy price is:
$n \times (1/n \times 1500) + 0 + (1/n \times \$\mathrm{FIR}) = n \times (1/n \times 1500) + 0 + (1/n \times \$\mathrm{FIR})$

Using ‘real’ penalty prices during reserve shortfalls causes inconsistent, unreasonable, and uneconomic outcomes

E.4 The illustrative results in Table 11 show three important characteristics of the reserve deficit model when market conditions are tight:

(a) Under current arrangements (CVP = $100,000/MW/h), it is highly likely all realistic market offers for energy and reserve would be scheduled before reserve deficit. That is, scheduling those offers would be cheaper than incurring reserve shortfall. This is only possible by using non-economic CVP values in real-time, then replacing them with the VRP if a reserve deficit infeasibility manifests in the final pricing schedule.

(b) But in attempting to use a ‘real’ penalty price under RTP (CVP = $10,000/MW/h) — directly affecting energy and reserve prices — outcomes vary substantially with the number of risk-setters:

(i) A single risk-setter could result in load shedding, with no reserve shortfall at all. Energy deficit at the first default scarcity pricing block at $10,000/MWh would be cheaper than supplying energy from the marginal risk-setter and incurring a reserve shortfall at a combined cost of $11,500/MWh.

(ii) Yet conversely, reserve shortfall before load shedding would be likely if there were three risk-setters. However, the relatively suppressed energy price ($4,833/MWh) would in turn mean energy offered by last-resort providers (eg, $5,000/MWh) would not be scheduled.

E.5 These outcomes are inconsistent, unreasonable, and uneconomic. Changing the penalty price in an effort to ‘fix’ one scenario only shifts the flaw to other scenarios. For example, a reserve penalty price of $4,500/MWh would increase the likelihood of reserve shortfall before load shedding for a single risk-setter (for the Table 11 assumptions), but even further reduce the ability to clear higher-priced energy offers under multiple risk-setters.

E.6 The inherent effect of the current reserve deficit model means energy prices fall precisely because the number of risk sources not being fully covered is rising. If the model is used under RTP, resulting energy prices during periods of scarcity would be an inefficiently weak signal for voluntary demand response, if not perverse.

E.7 Introducing a quantity limit to the current reserve deficit CVP constraint did not resolve these problems. There is no possible configuration of CVP price or quantity limit that provides consistent, reasonable, or economic outcomes. We have therefore concluded the current reserve deficit model cannot be used under RTP.

E.8 We will publish the modelling and a detailed explanation of the results summarised above on the RTP project’s website.

Appendix F Our proposed approach to setting RTP's 'reliability parameters'

F.1 This appendix explains how the Authority intends to set and review the values and quantities for default scarcity pricing and instantaneous reserve risk-violation curves. For brevity, we refer to these collectively as the **reliability parameters**. These parameters will directly influence spot prices when the system is under stress — when offered resources are not sufficient to satisfy demand and/or maintain full instantaneous reserve cover. The process for setting and reviewing these parameters is therefore an important aspect of introducing real-time pricing.

We will review these parameters before RTP goes live

F.2 As noted in paragraph 5.2, the Authority intends to review and update the values we have used for the reliability parameters to date before RTP goes live in 2022. We intend to use the approach described in this appendix for that purpose.

F.3 The approach detailed here is similar to that used in 2011 to set the current scarcity pricing values in the Code.[61] In essence, that will entail:

(a) Using two different analytical methodologies to determine draft values for the reliability parameters.

(b) Cross checking the draft values with other relevant information sources.

(c) Consulting with stakeholders on the analysis and draft parameters and then making final decisions.

F.4 It is important to recognise that while analytical techniques help to establish the parameter values, a degree of judgement will be required. The Authority will be guided by our statutory objective in making this judgement.

We will use two different analytical approaches

F.5 The Authority intends to use the broad approaches adopted in 2011 as the primary basis for setting reliability parameters.

F.6 In brief, the two approaches are:

(a) Set parameters to reflect the estimated economic cost to consumers of forced demand curtailments and instantaneous reserve shortfalls.

(b) Set parameters to be consistent with the security of supply standard in Part 7 of the Code (ie, enabling a last-resort capacity provider to just achieve revenue adequacy).

F.7 The Authority will supplement these approaches by drawing on other relevant sources, such as international data for scarcity prices and observed demand-side bids and offers in New Zealand.

Approach 1: economic cost to consumers

F.8 Under this approach, default scarcity pricing values will be set to reflect the estimated economic costs to consumers of forced demand curtailment (emergency load shedding).

[61] These current values are set out in Schedule 13.3A.

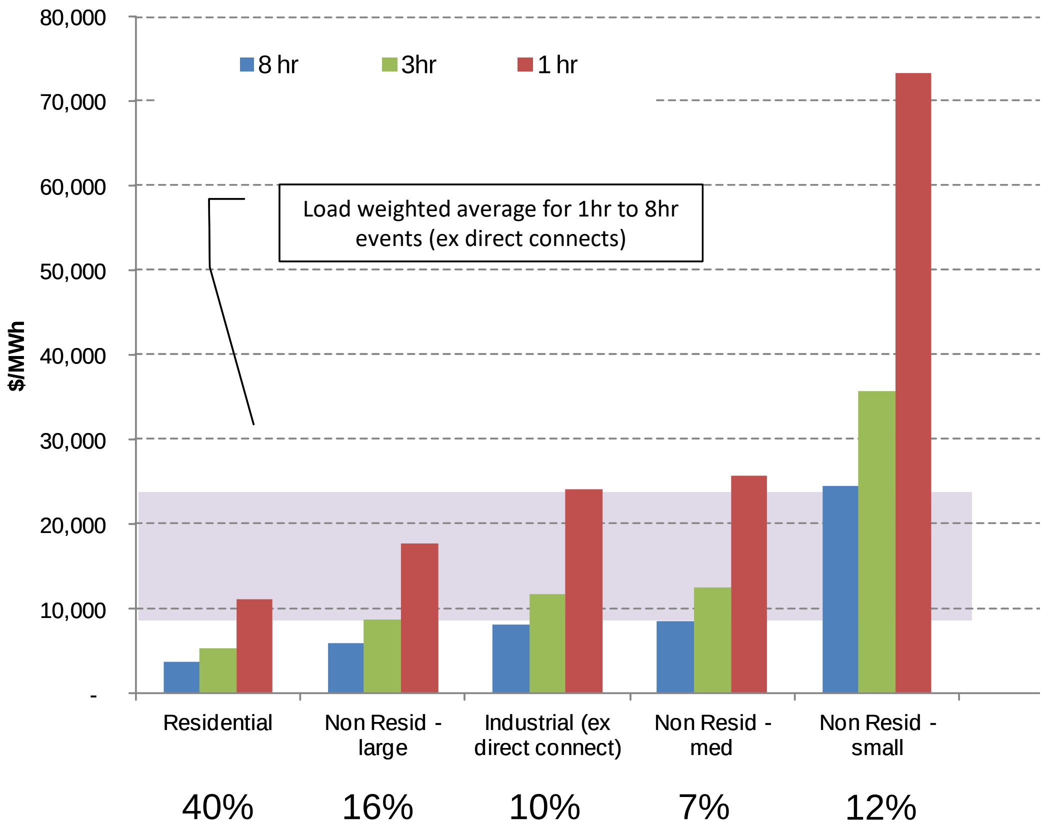
The underlying estimates will be drawn from pre-existing studies that assess consumers' willingness to accept outages, and/or willingness to pay to reduce outages.

Economic cost to consumers: forced demand curtailment

F.9 In 2011, the Authority drew on such a study undertaken by Strata Energy Consulting, New Zealand Institute of Economic Research, and UMR Research Limited. As with other similar studies, that report showed generally higher costs in $/MWh terms for outages of shorter duration, and higher costs for business than residential consumers. In general, the cost per MWh of shorter duration outages is expected to be higher than for longer outages because many of the disruption costs are fixed (eg, spoiled product in continuous manufacturing processes, tripping of security alarms).

F.10 Figure 15 summarises the estimates from the study used in 2011. The numbers below the bars indicate the estimated share of national demand for each consumer category.

Figure 15: Estimates of curtailment cost by user group and durations

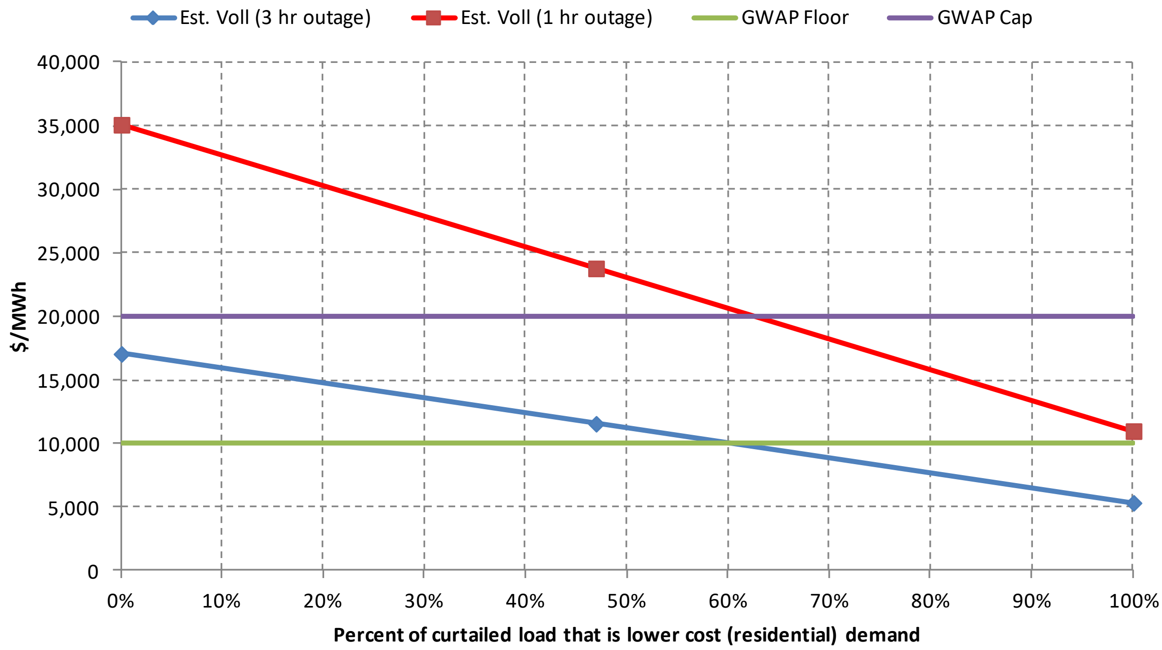


Source: Electricity Authority

Notes:
1. The Tiwai smelter owned by New Zealand Aluminium Smelters (NZAS) was covered by the study but is not shown in the chart.
2. Where available, this is based on specific data in the VOLL study (eg, for larger users). Where specific information was not available, the 1 hour outage is assumed to cost 300% of the 8 hour outage in $/MWh terms. The 300% ratio was an average figure which is comparable with the results of other studies.

F.11 If demand curtailment is instructed by the system operator, this is likely to focus most heavily on distribution networks because of their relatively greater ability to target curtailment towards less sensitive load. Figure 16 uses the data from Figure 15 to calculate average costs to consumers on a distribution network depending on the percentage of residential load.

Figure 16: Estimates of curtailment cost (for 1 hour and 3 hour outages)



Source: Electricity Authority

Notes: GWAP = generation-weighted average price.

F.12 The x-axis shows the degree to which demand curtailment is targeted towards lower cost (ie, predominantly residential) consumers. The markers in the central part of the chart indicate the result if demand curtailment were not targeted and reflect a load-weighted average cost. In practice, some degree of targeting is likely, especially for modest cuts of shorter duration. Where larger volumes of demand curtailment are required for longer periods, targeting is expected to be less practical. These considerations were key factors in the Authority selecting scarcity pricing values of $10,000/MWh and $20,000/MWh in 2011.

F.13 That information in turn was used by the Authority in 2017 to set the indicative default scarcity pricing blocks for RTP, as shown in Table 12 (and illustrated in Figure 2).

Table 12: Default scarcity bid blocks for forecast demand

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

F.14 As discussed in Appendix D of our 2017 paper, the proposed volume structure for the default scarcity pricing blocks was based on the following considerations:

(a) Costs from involuntary demand curtailment would be expected to rise with increasing volumes of load shedding as progressively less targeting is achievable. For this reason, a stepped default scarcity pricing function should apply.

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

(c) The initial block was set at the first 5% of load at each node at $10,000/MWh. This was 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 meant emergency load shedding would typically be shared across many nodes, rather than concentrated at single (or few) nodes simply based on transmission loss differences.

(d) The second block was set at 15% of load at each node at $15,000/MWh. Together with the initial 5% block, this is likely to be 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 was set at the mid-point of the scarcity pricing range.

(e) The third block comprises the remaining load at each node (the last 80%). Load shedding of this depth should only be required in extreme situations and it would be difficult to target curtailment to minimise its costs. This block was priced at the higher scarcity value ($20,000/MWh) in the Code.

F.15 The Authority plans to adopt a similar overall framework to that used in 2011 to derive updated default scarcity pricing values. While the framework itself is expected to remain largely unchanged, the Authority is aware of a number of more recent New Zealand studies on curtailment costs. The Authority will draw on these (and any further studies) to update the curtailment cost estimates and default scarcity pricing values.

Economic cost to consumers: reserve shortfalls

F.16 The preceding section discussed how economic costs to consumers can be estimated for forced demand curtailment events. A similar approach can be used to estimate the cost of shortfalls in instantaneous reserve.

F.17 It is important to recognise that reserve shortfalls increase the *likelihood* of triggering automatic under-frequency load shedding (AUFLS) by reducing safety margins, rather than making it a certainty. Hence, the expected cost to consumers of a reserve shortfall will be the cost of an AUFLS event if one is triggered, multiplied by the likelihood of such an event.

F.18 An AUFLS event would impose costs on consumers as follows:

(a) Consumers directly affected by tripping AUFLS relays will lose power and incur costs. The volume of affected demand will depend on the size of the relevant AUFLS block. There are currently two AUFLS blocks per island, each notionally set to be 16% of island demand. Hence, the volume of lost load could be quite large (over 700MW during peak demand periods for the North Island). The Authority is considering changes to AUFLS, and it is possible these will apply before RTP goes live. That would likely reduce the volume of demand affected by AUFLS relays being triggered, but it would still be relatively large. We estimate the average lost load cost for an AUFLS event at $13,000/MWh to $24,000/MWh, with an average restoration time of approximately 2 hours.[62]

(b) There is an inherent uncertainty about whether triggering AUFLS relays will stabilise the system following a contingent event. Relays may not operate as intended. Alternatively, they may shed too much load which can cause over-frequency and further generation tripping, which in turn triggers more load shedding. For this reason, there is a residual risk of system collapse during an AUFLS event. This probability is estimated at 1.7% to 4.6%. If system collapse occurred, such an event would be very costly for consumers because of the large volume of load lost and lengthy restoration time. The cost is estimated at $2.3 billion.

F.19 The analysis is very sensitive to some assumptions, especially the probability of contingent events (ie, risk of an initial plant or circuit trip) and system collapse. The latter is especially difficult to estimate because AUFLS is a protective system, and latent weaknesses can remain hidden until the system is required. This creates additional uncertainty about the probability of failure. A prudent response to these uncertainties is to attach a significant probability to hidden failure of the AUFLS system, leading to cascade failure.

F.20 Turning to the likelihood of a contingent event occurring,[63] this may be estimated from simulation studies and/or historic event data:

(a) Transpower's Under Frequency Event Reports show an average of 2.5 events a year between 2012 and 2017. This period included the commissioning of the HVDC, so may not be indicative of future failure rates. Excluding events caused by the HVDC results in an average of one event a year.[64]

(b) Transpower's Credible Event Review[65] reports the historical failure rate of generators, grouped by generation type. This grouping makes it difficult to find the failure rate for a single unit, except for those types of generation that have only a small number of generation stations. The reported failure rate for a CCGT or geothermal unit was 1.75 and 7 failures per unit per year respectively. This period included the commissioning of three geothermal generators, so may overstate the failure rate of geothermal units.

(c) Additionally, we should consider whether 'average' historical failure rates are representative for periods when reserves cover is reduced. To the extent the probability of failure is higher during periods of reserve shortfalls, an adjustment factor should be applied.

62 All numbers in this section are based on analysis by the Authority on proposed changes to extended reserves.

63 This is the average chance of a single event.

64 UFE reports may understate the real number of system interruptions because the actual reserve available to the system is often significantly higher than the amount procured. This means that many events that 'should' have caused an UFE with the procured amount of reserve did not.

65 See https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/2014_Credible_Event_Review.pdf.

F.21 In light of these factors, we have assumed a range of 1.5 to 5 contingent events a year.[66]

F.22 Multiplying the probability of a single contingent event occurring with the cost of an AUFLS event yields the expected cost to consumers of a single uncovered risk. No separate allowance is required for scenarios involving multiple risk-setters and classes of reserve shortfall. This is because those issues are dealt with directly by the SPD software when calculating spot prices for energy and reserve.

F.23 The result is expressed in dollars of expected cost per hour of reserve shortfall. Dividing this figure by the assumed size of the reserve shortfall yields the equivalent cost expressed in $/MWh terms. Perhaps counter-intuitively, a larger tranche leads to a lower cost per MWh. This is because, as modelled, the risk is assumed to be unchanged whether there is a 10 MW shortfall or a 50 MW shortfall (the upper and lower values considered in paragraph 4.61).[67] However, the cost of a shortfall expressed in $/MWh will decline, as there are more MW of reserve shortfall over which to distribute the fixed cost.

F.24 An illustration of the calculations using indicative values is set out in Table 13.

Table 13: Estimated costs to consumers of single contingent risk (indicative range)

Size of Band	Cost per hour of operation with single contingent risk ($)	Cost per MWh of operation with single contingent risk ($/MWh)
10 MW	8,000 - 85,000	800 - 8,500
25 MW	8,000 - 85,000	300 - 3,400
50 MW	8,000 - 85,000	200 - 1,700

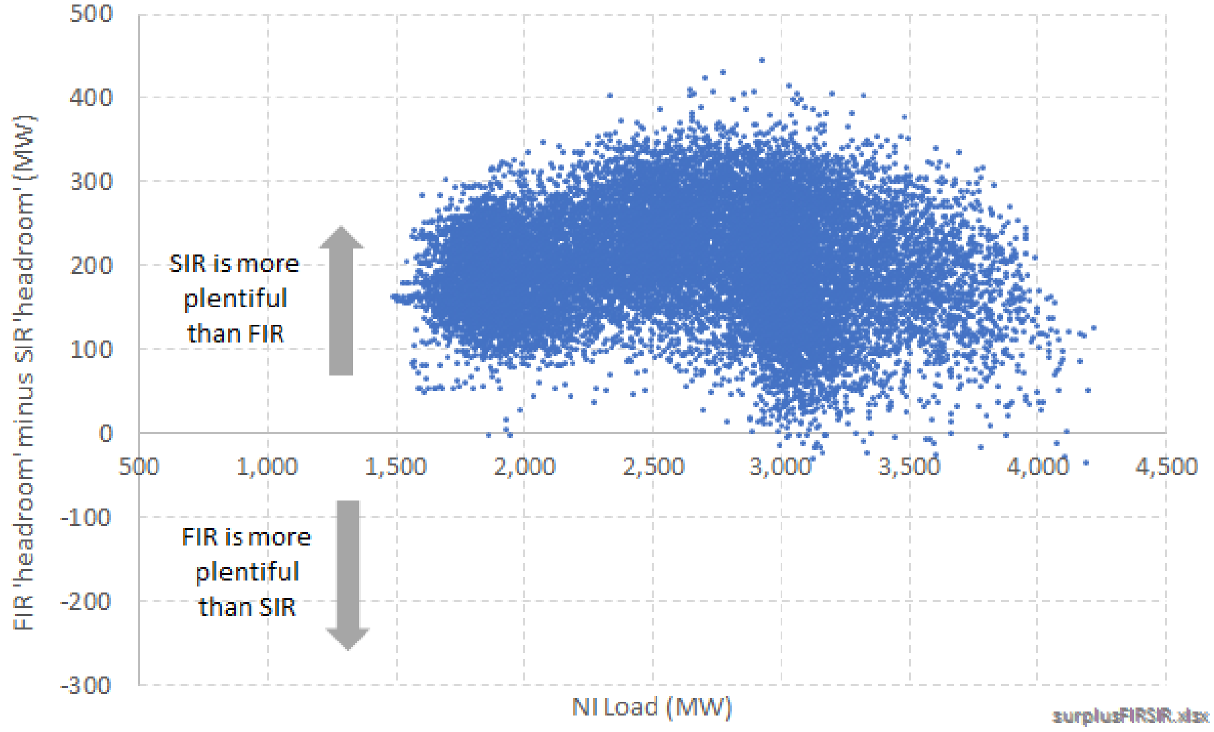
Source: Electricity Authority

F.25 These estimates reflect the expected cost to consumers of a shortfall of FIR or SIR. As noted in paragraph 4.41, there appears to be a slightly higher risk of triggering AUFLS during a FIR shortfall than a SIR shortfall. In addition, as shown in Figure 17, analysis of historic data indicates FIR tends to be in shorter supply than SIR during periods of higher demand (and other times). Hence, we propose that a slightly greater value be placed on the FIR CVP than the SIR CVP.

66 This encompasses a large range, reflecting the large uncertainty in this value.

67 This assumes the probability of triggering AUFLS is constant for small and large shortfalls — that may not be the case if larger shortfalls increase the number of contingent risks that can trigger an AUFLS event.

Figure 17: Relative scarcity of SIR and FIR



Source:	Electricity Authority
Notes:	Based on analysis of 2012 and 2013 data.

Approach 2: revenue adequacy for last resort capacity provider

F.26 An alternative approach to determining reliability parameters seeks to 'back-calculate' the scarcity pricing values required to incentivise the provision of last-resort capacity. That is, a resource provider that mainly operates in periods of reserve shortfall and forced demand curtailment.

F.27 This approach uses a nominated security standard as its anchor point. It recognises 'last resort' resource providers will operate for fewer hours as the security standard increases, all other things being equal. Put another way, if forced load shedding was a frequent event, the last resort resource provider would have greater operating hours than if forced load shedding were extremely rare.

F.28 The expected operating time of the last resort provider is important: operating for fewer hours means that provider must earn more per hour to cover its total costs. Those total costs include fixed costs such as fixed operating and maintenance costs, and a return on capital invested. In simple terms, the scarcity values are 'back calculated' by looking at the number of hours that the last resort provider is expected to operate during reserve shortfalls or demand curtailment events, and dividing this into its annual revenue requirement.

F.29 The winter capacity security of supply standard in Part 7 of the Code would be used as the anchor point for this analysis.[68] That standard is intended to reflect an economically

68 Clause 7.3(2)(a) specifies a winter capacity margin of 630-780 MW for the North Island.

optimum level of capacity: the level where the sum of expected demand curtailment and supply costs are minimised.

Revenue requirement for last resort capacity provider depends on technology

F.30 By nature, a last resort capacity provider will only be called into operation very infrequently; eg, to cover the 'super-peak' demand periods and/or breakdowns of other plant. For this duty, the conventional plant choice has been an open cycle combustion turbines (OCGT).[69] Looking ahead, it is possible that other technologies may become economic for this type of duty — especially large-scale batteries.

F.31 An analysis would be undertaken to determine the most likely source of last-resort response for the future when we next assess the reliability parameters. For now, the indicative calculations set out below use the values from 2011 based on OCGT costs.[70] These were estimated at $145/kW/year in annualised terms.

Revenue contributions for last resort capacity provider

F.32 A last resort capacity provider may earn revenues at times other than actual shortages of reserve or capacity. Such revenues would reduce the amount that must be earned during shortages, and in turn directly reduce implied scarcity price values.

F.33 During periods of 'normal' market conditions (no shortage of capacity or reserve), a last resort provider is unlikely to expect to operate or provide reserve. For this reason, in the 2011 analysis providers were assumed to earn zero revenue in these periods. This assumption will be reviewed for the updated analysis. However, it is likely to be maintained unless new information suggests a provider could earn revenue in normal conditions from services other than providing energy or reserve.

F.34 Another important issue to consider in the New Zealand context is the extent to which a last resort *capacity* provider will earn revenue in *energy* constraint periods. These are commonly referred to as 'dry years', but cover any period of energy shortage.

F.35 In these periods, a provider will earn revenue whenever spot prices exceed its short run marginal cost. The approach taken to address this issue in 2011 recognised that the system needs to satisfy both capacity and energy standards to provide adequate security.

F.36 This observation was used to assess the degree to which each constraint is likely to bind — taking account of projected system characteristics (eg, rates of change of energy and peak demand, plant mix, or operating attributes). When this assessment was carried out in 2011, the analysis indicated:

(a) under most scenarios, it appeared likely there would be more 'headroom' on the energy standard than the capacity standard; and

(b) if the system were to be just meeting the capacity standard, it would imply an actual winter energy margin that was appreciably above the energy standard.

F.37 Based on these observations, the revenue contribution during energy constraint periods was estimated at approximately $20/kW/year. The same framework would be used to

69 Demand response also provides 'last resort' coverage, and this is incorporated in the assumptions made about the costs of voluntary and involuntary load shedding.

70 These values may have changed over time.

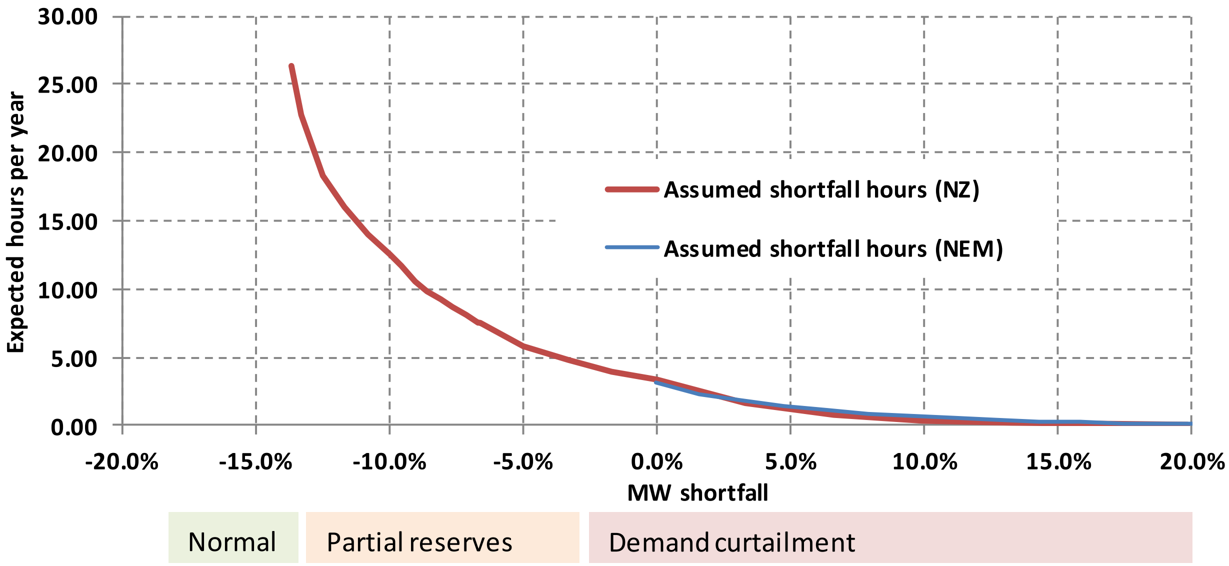
update this value. As with the 2011 analysis, sensitivity cases would be considered to recognise the uncertainties with this estimate.

Revenue contributions during reserve shortfall and capacity shortage periods

F.38 The residual revenue requirement for a last resort capacity provider ($125/kW/year in the 2011 example) needs to be generated during reserve shortfall and demand curtailment periods.[71] Key inputs for this calculation are the expected number of shortfall hours per year and expected level of prices for different amounts of reserve shortfall and demand curtailment.

F.39 In the 2011 analysis, the shortfall hours were estimated based on the observed shape of demand in peak periods, and assuming the system was just meeting the capacity standard.[72] This information indicated approximately 20 shortfall hours (curtailment and reserve) would be expected each year. On a percentage basis, those expected shortfall hours were very similar to the level expected at the time for the Australian national electricity market (NEM) at its optimal capacity standard.[73]

Figure 18: Assumed shortfall hours and comparison with NEM equivalent



F.40 There is no unique set of scarcity price values to achieve revenue adequacy for a provider of last resort resources. Rather, the aim is to identify an internally-consistent set of scarcity price values for load shedding and reserve shortfall that achieves revenue adequacy while recognising the following factors:

(a) Prices are expected to be higher in actual demand curtailment events than during modest reserve shortfalls. This is because the former will certainly result in lost load, whereas the latter increases the risk of losing load by triggering AUFLS.

71 Collectively referred to as 'shortfall hours'.

72 Noting it has been well above standard in recent years.

73 The NEM analysis is restricted to demand curtailment and does not consider periods of reserve shortfall.

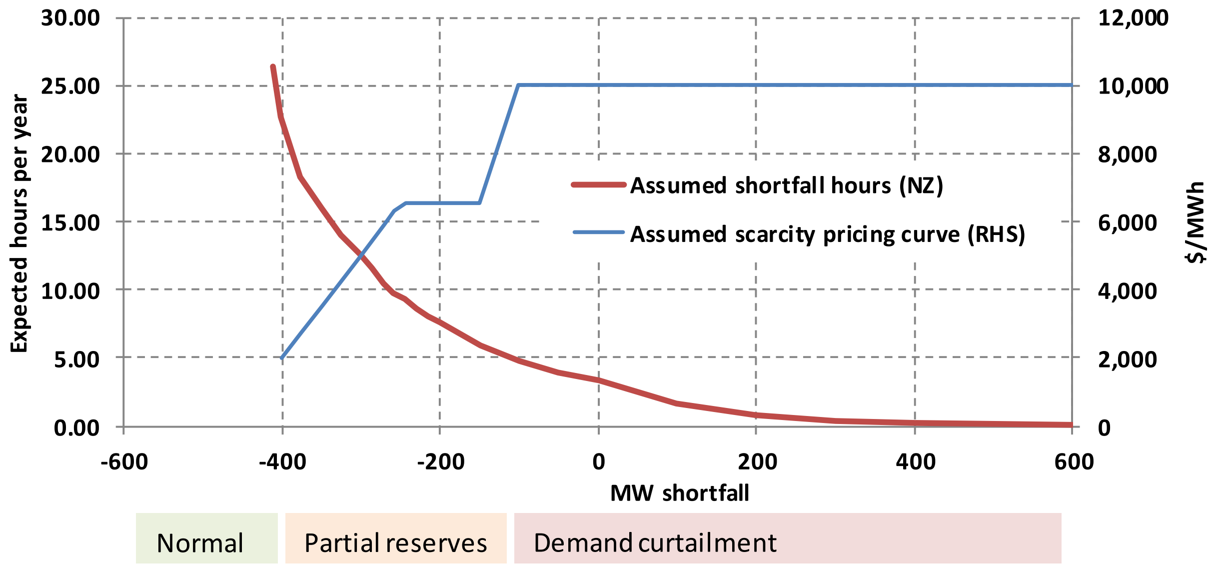
(b) Prices are expected to be higher for larger reserve shortfalls than smaller reserve shortfalls because there is vulnerability to an increased range of contingent risks.[74]

(c) Prices in reserve shortfalls should be above ‘normal’ offers/bids for supply and voluntary demand response.

(d) Total reserve shortfall should not be tolerated because they greatly increase the chance of AUFLS occurring and targeted demand curtailment is more desirable.

F.41 These factors were used to develop internally-consistent estimates for scarcity price values during reserve shortfalls and demand curtailment events. The values derived in 2011 are shown in Figure 19.

Figure 19: Shortfall hours and scarcity price curve



F.42 Under those assumptions, an OCGT recovered $20/kW from dry year operation, $107/kW during periods of reserve shortfall and $18/kW during periods of demand curtailment. The OCGT provider therefore achieved revenue adequacy. Recognising there was significant uncertainty around some assumptions in this analysis, the Authority undertook sensitivity testing to assess the robustness of the values. Extensive sensitivity would also be used to update the values.

Cross checks with other sources

F.43 The Authority will also consider other information sources as cross-checks. These are expected to include:

(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.

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74 For example, a small shortfall may expose the system to one contingent risk, while a large shortfall may make the system vulnerable to many contingent risks.

Appendix G Assessment of benefits and costs

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

Assessment framework

G.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 2018 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 the system operator's DSE project has been implemented.

G.3 Our cost benefit analysis uses the framework adopted in our 2017 paper. 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.

G.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 the August 2017 consultation paper.

Categories of expected benefit

G.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.

G.6 Each of these benefits is discussed below.

Benefit 1: reduced generation investment enabled by more efficient demand-response from industrial and commercial consumers

G.7 The main benefit from RTP is avoided capital cost for generation. This benefit arises because RTP is expected to make it easier for consumers to react to spot prices in an efficient way, substituting voluntary demand response for generation at times. This increased demand response is enabled by better pricing information provided in real-time.

G.8 We expect the increased demand response to come from existing parties who become even more active, and from parties who currently do not respond to spot prices. In both cases, the demand response may involve a cut in energy use, a shift in timing of consumption away from peak periods, or a reduction in system demand enabled by greater use of distributed generation.[75] For simplicity, all of these are referred to as 'demand response' for the purpose of this analysis.

G.9 Unlocking the latent demand response capability should reduce the total volume of generation capacity required to meet peak demand, all other things being equal. While RTP is expected to reduce the capital required for generation investment, there will be some offsetting costs associated with increased level of demand response. Our analysis incorporates both items.

G.10 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.

G.11 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 non-dispatched generation, respectively, that can potentially respond to spot prices (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.

G.12 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.[76] We estimated G to be approximately 50 MW.[77] We have retained these figures from our previous assessment as the base case assumptions.[78]

G.13 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

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

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

77 The Authority's embedded generation survey indicates there is about 400 MW of embedded generation that does not currently offer. Using 400 MW for G instead of 50 MW increases the net benefit in the base case substantially: from $53m to $77m.

78 However, we have scaled these numbers with projected future demand growth to retain a constant proportion of responsive load.

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.

G.14 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 2017.[79] This gives rates of 0.5%, 1.4%, and 1.5% per annum for the lower, base, and higher cases, respectively.[80]

G.15 We retained an estimate of $1.2m/MW (real) for V, the same as our 2017 paper.

G.16 We assumed there is no lag between introducing RTP and the first year in which benefit begins to accrue (ie, Y=0).

G.17 We assumed demand response for industrial and commercial consumers has an average variable operating cost of about $550/MWh. Demand response will displace the marginal dispatched 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.

G.18 The additional demand response is assumed to operate for 90 hours per year (~1% of hours). This figure should be internally 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).

G.19 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. In the five years between 2013 and 2017, 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. That suggests demand response across substantially 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 we have adopted a conservative 90 hour assumption in the CBA. Note that overestimating the number of hours here will understate system benefits.

G.20 We retained an estimate of 1 for X, the same as our 2017 paper. This is arguably conservative because reducing the need for generation will also reduce losses, so we would expect X to be slightly greater than 1 in practice.

G.21 We have retained 10% as the base case estimate for the value of p, with lower and upper values of 8% and 12%.

G.22 As a reality check, the reduction in peak generation capacity implied under the base case assumptions is 52 MW. This is equivalent to 1.5% of total non-residential peak demand. Thus, we assume RTP will enable a relatively modest increase in demand response from industrial and commercial users.

G.23 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.[81] These estimates

[79] Our 2017 paper used estimated growth from the 2015 Transmission Planning Report.

[80] Compound growth rates were inferred from Figure 3-2 in the Transpower report.

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

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'.[82] In light of these figures, an assumed increase in demand response of 1.5% does not appear unreasonable.

G.24 This analysis yields overall efficiency benefits from avoided generation investment of $48 million, less additional demand response costs of $9 million. This produces an estimate of $39 million in net terms (excluding implementation costs).

Benefit 2: reduced generation investment enabled by more efficient demand-response from residential consumers

G.25 The estimated benefit 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 reduction in generation investment enabled by improved demand response by residential consumers, even though they account for the majority of peak demand on the system. Benefit 2 applies the same methodology as Benefit 1, but to residential customers.

G.26 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.

G.27 We expect this response to be achieved primarily through automated demand response mechanisms.[83] However, current residential consumer behaviour suggests some customers may wish to actively vary their usage in response to spot prices themselves.

G.28 The 2018 peak demand requirement for residential consumers is approximately 3,960 MW from about 1.8 million residential connections, with an average use at peak of approximately 2.2 kW per connection.

G.29 There is little concrete information available on the level of demand response that RTP could enable for these consumers. To estimate this, we consider two parameters that combine to give the total reduction in peak demand. These are 'the percentage of residential load that could respond to price' and 'reduction in residential peak load enabled by improved price information'.

G.30 The first parameter is estimated at 12% in the base case. A 2013 review of various recent opt-in trials of time-of-use pricing in the United States found uptake varied from 5% to 28%, with a mean of 14%.[84]

G.31 The second parameter is estimated at 5% in the base case. Frontier Economics' 'Peak-Use Charging' report provides a summary of various studies into residential peak

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

83 That demand response may use our proposed dispatch-lite (see section 3).

84 See *Residential customer enrolment in time-based rate and enabling technology programs*, Todd et al., 2013, available at https://emp.lbl.gov/sites/all/files/lbnl-6247e.pdf.

response to time-of-use price signals.[85] The median reduction in demand is about 8%, suggesting 5% may be a conservative value.

G.32 The combination of these two parameters provides a base case assumption 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 this benefit.

G.33 We assume the operating cost of demand response from residential consumers is \$800/MWh.[86] Residential demand response therefore incurs an additional cost of \$500/MWh for each unit of output, compared to an open-cycle gas turbine.

G.34 This yields base case benefit estimates of \$23 million, less additional demand response costs of \$8 million (ie, \$15 million in net terms excluding implementation costs).

Benefit 3: more efficient levels of reliability

G.35 The two estimates of benefit calculated so far considered the benefits from substituting *voluntary* demand response for 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.

G.36 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.

G.37 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.

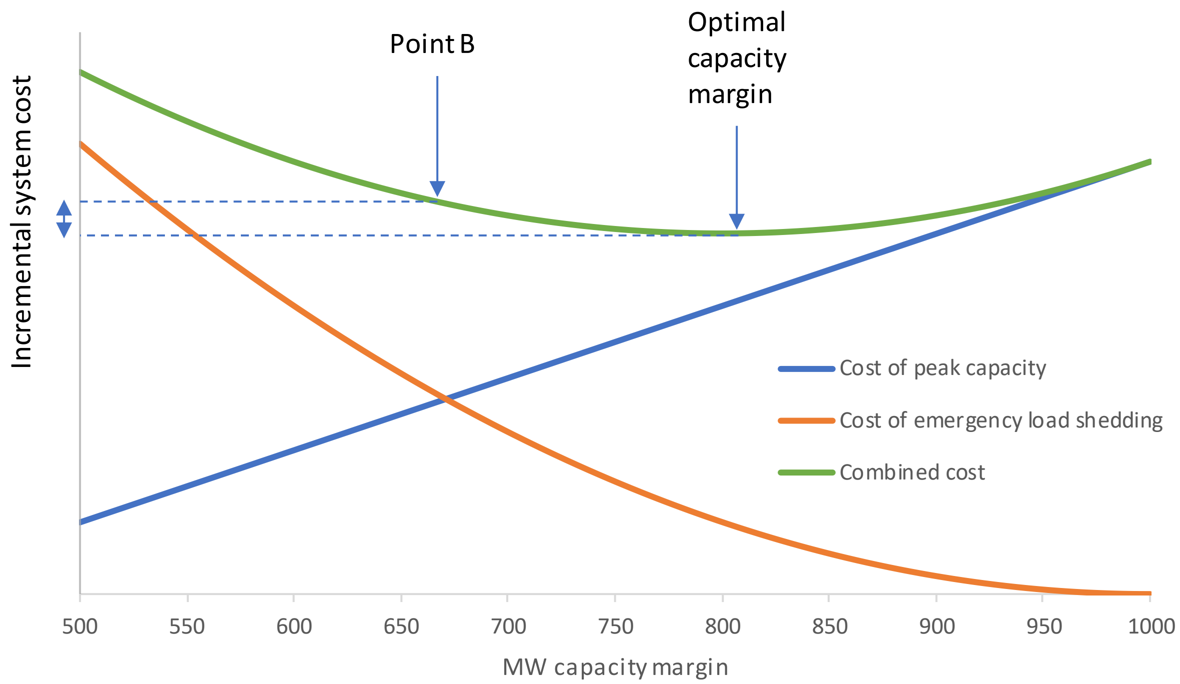
G.38 Together, these effects can undermine confidence in prices during times of system stress, and in turn reduce the incentives for parties to provide last-resort resources. The overall impact is shown in Figure 20 below, which depicts the system capacity margin along the x-axis, and the incremental system cost on the y-axis (values are illustrative).

G.39 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.

[85] Appendix B of Transpower's '*The role of peak pricing for transmission*' (2018), available at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission.

[86] This means we assume discretionary residential usage is more costly than the discretionary commercial and industrial usage described in paragraph G.17

Figure 20: How spot price signals affect reliability



G.40 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.

G.41 We have previously estimated the total cost of divergences from the optimal capacity margin.[87] 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.

G.42 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.

G.43 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.

G.44 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.

G.45 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.

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

G.46 This yields base case benefit estimates of $8 million.

Benefits from more efficient generation scheduling and dispatch

G.47 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.

G.48 Anecdotal evidence suggests this category of benefit may be important. For example, one generator has indicated informally that providing 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;[88] although it is not clear how much improvement depends on better information or providing more flexibility to generators.

G.49 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

G.50 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

G.51 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

G.52 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.

G.53 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

G.54 RTP is expected to give rise to costs in the following areas.

Costs for system operator

G.55 The system operator would need to change market systems. The system operator estimates the cost to be $10.3 million to $12.6 million, with an expected value of $11.4 million (undiscounted). This is above but relatively close to the rough order of magnitude range estimated in 2017 ($7.8 million to $11.2 million). The increases are primarily due to more detailed information being available on implementation requirements,[89] cost inflation due to a delay in the project start date, and incorporating dispatch-lite costs. The final item is estimated at $0.6 million (± $0.2 million).

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

89 This estimate also includes the costs for ION meter and revision of bids and offers within a trading period that were previously presented separately.

G.56 While we have not undertaken an analysis of dispatch-lite's stand-alone benefits, we note it would need to reduce peaking requirements by 0.7 MW to breakeven. This equates to around 0.01% of peak system demand, and a change of at least this magnitude appears quite plausible. For comparison, the Authority's embedded generation survey indicates there is about 400 MW of embedded generation that does not currently offer.

G.57 For simplicity, we assume market system costs are incurred halfway through the implementation period and discount accordingly. This gives a cost of $10 million in the base case in net present value terms.

Costs for pricing and clearing manager functions

G.58 The pricing manager currently determines provisional, interim, and final prices after real-time. The role and most of its functions would cease with RTP, with some residual responsibilities being transferred to other parties.

Overall service provider costs

G.59 Implementing these changes will incur some up-front costs, including contract termination payments. Taking these costs into account, as well as the operational savings, in net present value terms we expect a saving of $2 million in the higher case, and a cost of $1 million in the lower case.

Costs for participants

G.60 We do not expect RTP to create any material ongoing 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.

G.61 However, spot market participants receiving dispatch instructions may incur some one-off costs to adjust to RTP. In submissions on the August 2017 paper, one participant estimated these costs at $390k. However, participants making such investments will presumably derive some commercial benefit, reducing the net cost from a national economic perspective. To address the uncertainty on this issue, we have assumed an upper case of $5 million (14 dispatch participants @ 390k each), no costs for the lower case and the mid-point of $2.5 million for the base case.

Estimated benefits and costs

G.62 The results of the analysis are summarised in Table 14. Note that numbers in Table 14 may not add due to rounding (to whole millions).

Table 14: Estimated benefits and costs

Item $m (present value)	Lower case	Base case	Higher case
Benefits[1]			
Demand response benefit – industrial and commercial	30	48	70
Demand response benefit – residential	9	23	46
Reliability benefit	0	8	19
Total benefits	38	79	135
Demand response costs			
Industrial and commercial	-5	-9	-14
Residential	-2	-8	-19
Total demand response costs	-8	-17	-33
Implementation costs			
System operator function	-11	-10	-9
Pricing and clearing functions	-1	1	2
Participant implementation costs	-5	-2	0
Total implementation costs	-16	-12	-8
Net benefits	15	50	95

Source: Electricity Authority

Notes: 1. Excludes some benefits that are not quantified

G.63 The analysis shows net benefits of $50 million in the base case. This is slightly lower than the previous estimate of $53 million in our 2017 paper. The main reason for this change is an increase to system operator costs.[90]

G.64 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,

90 The system operator's Rough Order of Magnitude (ROM) cost estimate to deliver RTP was revised from a midpoint of $9.05m to $10.8m. Dispatch-lite costs are excluded from the ROM but have been provided separately. Quantified system operator costs have increased by $2.4m.

because of the compounding effect of multiple ‘downside’ or ‘upside’ assumptions in each case.

Break-even sensitivity test

G.65 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.

G.66 We recognise that the level of improvement in demand response enabled by RTP is subject to significant 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.

G.67 This analysis indicates that if improved industrial demand response is the sole benefit of RTP, it would need to increase by approximately 16 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 about 0.2% of total system demand in peak periods.

G.68 In light of the overall analysis, we think there are strong grounds to expect RTP to provide positive net benefits.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
AUFLS	Automated under-frequency load shedding is the last line of defence before cascade failure of the power system
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
CVP	Constraint violation penalty
DCLS	Dispatch-capable load station, used to participate as dispatchable demand
Dispatch price	Under RTP, the prices for energy and reserve struck in real-time from the dispatch schedule would be known as 'dispatch prices' and 'dispatch reserve prices'
DSE	The system operator's Dispatch Service Enhancement project
FIR	Fast instantaneous reserve
ICCP	Inter-control center protocol
IL	Interruptible load, a type of instantaneous reserve
Net load	Net load at a point of connection (eg, a GXP, a consumer's meter) is the total of actual load minus any injection from embedded generation.
SCADA	Supervisory control and data acquisition
SIR	Sustained instantaneous reserve
SPD	The system operator’s scheduling, pricing, and dispatch system
VRP	Virtual reserve provider, used to resolve reserve infeasibilities in a final pricing schedule
WITS	Wholesale information and trading system