Removing constrained on payments for generation ramping down

Consultation paper

Submissions close: 5 pm, Tuesday, 30 April 2019

26 March 2019

Executive summary

Purpose of the paper

The purpose of this paper is to consult with interested parties on the Authority's proposal to remove constrained on payments for generation that is dispatched down at its maximum ramp rate.

Background

Constrained on payments are intended to be paid to generators and dispatchable demand that is required to meet demand and maintain security, but whose offer prices are too high to be dispatched in normal circumstances (ie, they are "out of merit"). For generators, constrained on payments are, for the generation volume dispatched from the higher priced tranche(s) of the generator's offer, the difference between:

- the generator's offer price; and
- the final nodal price.

Constrained on payments ensure high cost generation is available when within-merit generation is insufficient to maintain security and meet demand. Constrained on payments are intended to enable high cost generation to recover its costs when it is dispatched out of merit.

Generators with slow ramp-down rates can take several trading periods to be dispatched down to a level that puts them within merit (ramp-constrained generation). As a result, ramp-constrained generation that is dispatched down may receive constrained on payments for a significant period.

Issues with the existing arrangements

The Authority considers that the existing arrangements of paying constrained on payments to ramp-constrained generation when it is dispatched down do not promote the Authority's statutory objective. This is because the current arrangements:

(a) promote scheduling and dispatch of, and investment in, ramp-constrained generation, even when it is higher cost than other generation

(b) undermine allocative efficiency, risk management, and market confidence because constrained on costs are not reflected in nodal prices, which makes hedging for the costs of ramp-constrained generation more difficult.

Recently, a ramp-constrained generator's offers have resulted in monthly constrained on payments exceeding $1.0m, which are excessive, compared to the monthly average of $76,000 for the 12 months ending 30 June 2018. While the generator has since altered its offering behaviour, this is the latest instance of a repeated problem that is not limited to a single party's generating plant.

The costs of constrained on payments are shared by purchase volume among all wholesale electricity market purchasers — electricity retailers and consumers that purchase electricity directly from the wholesale market — but are not reflected in nodal prices.

Proposal

This paper proposes amending the Code by inserting a new clause in Part 13 of the Code to stop constrained on payments to ramp-constrained generators (see Appendix A). This would mean ramp-constrained generators would not be paid constrained on payments when they are dispatched down at their maximum ramp rate but would just be paid the nodal price. In all other respects constrained on payments would not change.

The benefits of the proposal are expected to exceed the costs

The benefits expected from the proposal are:

(a) more efficient scheduling, dispatch, and investment, as the costs of ramp-constrained generation would be more transparent

(b) increased allocative efficiency, as the costs of ramp-constrained generation would be better reflected in nodal prices, which would improve market confidence, as hedging would be more straightforward.

The costs from the proposal are:

(a) implementation costs because of system changes required by the system operator and clearing manager

(b) implementation costs for ramp-constrained generators

(c) risk of lower reliability, if ramp-constrained generation is not able to compete with unconstrained generation (expected to be minimal)

(d) risk of regulatory uncertainty if some investments in ramp-constrained generation had been made on the basis of these constrained on payments (expected to be minimal).

To the extent the costs and benefits can be quantified, the proposal is expected to provide net benefits of $9.1 million over 15 years under a base case using a discount rate of 6 percent (see Appendix C). Estimated net benefits under a lower case are $4.5 million while under a higher case the estimated net benefits are $12.2 million.

The proposed amendment is preferred to other options

The Authority has identified six other options for addressing the objectives (see paragraphs 4.16 - 4.34). The Authority has evaluated these other options and prefers the proposal.

Maintaining the status quo would not address the problems with the existing arrangements, as constrained on payments would continue to be paid to out-of-merit ramp-constrained generation when it is not required.

The proposal complies with s.32(1) of the Act and is consistent with the Code amendment principles

The proposed amendment promotes the Authority's statutory objective and complies with s.32(1) of the Act. In particular, the proposal would:

(a) promote competition by better ensuring ramp-constrained and unconstrained generation compete on an equivalent basis

(b) promote reliability by ensuring that ramp-constrained generators continue to be available when they are both within and out of merit, to the extent they are competitive

(c) promote the efficient operation of the electricity industry by better ensuring the costs of ramp-constrained generation are reflected through nodal prices, which in turn promotes more efficient operation, investment and use of electricity

(d) will not materially affect the performance of the Authority's functions or any other matter specifically referred to in the Act for inclusion in the Code.

The proposal is also consistent with the Code amendment principles.

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What this consultation paper is about

2.1 The purpose of this paper is to consult with interested parties on the Authority's proposal to amend the Code, to remove constrained on payments for generation that is dispatched down at its maximum ramp rate.

2.2 Constrained on payments are made to generators that are out of merit (ie the generators' offer prices are too high to be dispatched in normal circumstances) but are required to meet demand and/or maintain security (meet demand). When a generator is no longer required it receives a dispatch instruction to reduce its generation. Constrained on payments continue to be paid until the generator reaches the level of generation specified by a dispatch instruction that puts it back in merit.

2.3 However, some generators are unable to reduce generation to this level within the timeframe required by a single 5-minute dispatch instruction (ramp-constrained generation). If this generation is out of merit it is paid constrained on payments. The proposed Code amendment would remove constrained on payments in this circumstance. Under the proposed Code amendment constrained on payments would continue for generators dispatched out of merit to meet demand.

2.4 The proposal would allow nodal prices to better reflect the full cost of generation and so better align with the Authority's statutory objective.

2.5 The proposal would mean ramp-constrained generation would need to seek to recover costs through offers that reflect the full costs of being dispatched, rather than through constrained on payments when ramping down. As a result, the costs of operating ramp-constrained generation would be reflected in nodal prices. This would improve efficiency as nodal prices would better reflect the costs of the generation required to meet demand. In turn, this would promote more efficient use of electricity and more efficient investment in generation and demand response.

2.6 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

2.7 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "Consultation Paper— Removal of constrained on payments for ramp-constrained generation" in the subject line.

2.8 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

2.9 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).

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

2.11 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

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

2.13 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.

Possible workshop/webinar

2.14 Given the technical nature of the proposal, we would like to hear from interested parties on whether they see value in a workshop or webinar to explain the proposal. Please let us know if you would like the Authority to hold a workshop or webinar by emailing the Authority at submissions@ea.govt.nz with "Removal of constrained on payments for ramp-constrained generation – Possible workshop" in the subject line. The deadline for indicating your interest in a workshop or webinar is **5pm** on **Tuesday 2 April 2019**.

3 Issue the Authority would like to address

The existing arrangements

3.1 Under clauses 13.202 to 13.212 of the Code, generators, ancillary service agents and dispatchable demand are paid constrained on payments when they are dispatched out of merit. For generators, this occurs:

(a) when their offer price exceeds the price at which generation clears in the wholesale market but their generation is needed to meet demand and/or maintain security. The system operator will use discretion to dispatch a generator on. This usually occurs when a generator is required for the following period but start-up time limitations mean that it must be dispatched ahead of time to ensure it is available when needed

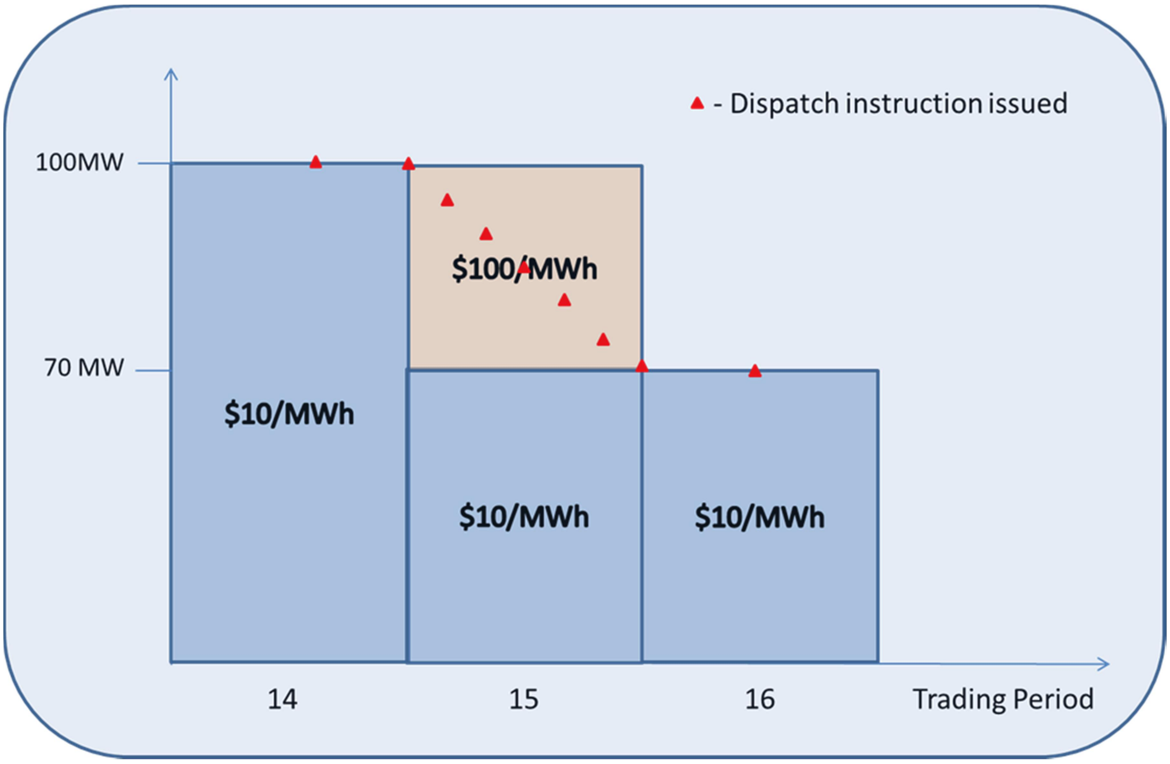
(b) when a generator has been dispatched down due to the clearing price dropping below the generator's current offer price but their physical ramp-down rate prevents them from reaching their lower price band in a single 5 minute dispatch period (ramp-rate constrained dispatch).

3.2 Constrained on payments are, for the generation volume dispatched from the higher priced tranche(s) of the generator's offer, the difference between:

- the generator’s offer price; and
- the final price for the node at which the generator operates (nodal price).

3.3 Constrained on payments to a ramp-constrained generator that has been dispatched down at its maximum ramp rate are illustrated in Figure 1.

Figure 1: Illustration of constrained on payments for a ramp-constrained generator dispatched down at its maximum ramp rate



3.4 Figure 1 shows a generator that has offered 100 MW in trading period 14 at $10/MWh. The marginal price is $20/MWh for trading period 14 so the generator is fully dispatched.

3.5 Resource constraints require the generator to ramp down to 70 MW over trading period 15. The expected marginal price is still $20/MWh so the generator offers the 30 MW it must ramp down at $100/MWh to ensure that it is out of merit order and dispatched down. This higher offer is meant to reflect that the generator needs to ramp down and that continuing to generate will involve substantial costs.[1] The marginal price remains at $20/MWh in real time so the generator is dispatched down accordingly.

3.6 However, the generator offer has an associated ramp-down rate of 60 MW per hour, or 5 MW per 5 minute dispatch period. This results in the generator being progressively dispatched down 5 MW at a time through trading period 15 until it reaches 70 MW and is once again dispatched in merit order.

3.7 For settlement, the average dispatch level for trading period 15 is calculated and compared to the offered generation level at the marginal price. In this case, the average generation dispatch would be 85 MW and the offered generation at or below the marginal price of $20 would be 70 MW, and so the generator was constrained on by 15 MW. Assuming the generator followed its dispatch instructions, it would be paid:

- the marginal price for its total generation for the half hour: (85 MW x $20/MWh)/2 = $850

  plus

- for the constrained on portion of its output, the difference between the marginal price and the offer tranche price of the constrained on generation: (15 MW x ($100/MWh-$20/MWh))/2 = $600.

3.8 That is, for trading period 15, the generator would be paid a total of $1,450.

3.9 The generation quantity in MWh used to calculate a generator's constrained on payment is the lesser of:

(a) the generator's dispatched quantity from the price band in the generator's offer that was constrained on, or

(b) the positive difference between the generator's actual (reconciled) generation output and the quantity it was scheduled to generate.[2]

3.10 Any actual generation above a generator's dispatch level is paid for at the nodal price. In our example, if the generator actually generated 90 MW they would only be paid the spot price for the 5 MW difference between their dispatched volume and their actual volume.

3.11 Constrained on payments are usually paid to high cost generation that has signalled its high costs through an offer that, in normal circumstances, would mean they are only dispatched when nodal prices are sufficiently high to recover their costs. Generators may also need to signal that a physical or a resource constraint applies to generation for one or more trading periods. The appropriate way to signal such a constraint is through an offer above the expected marginal price. This allows the model used to operate the

1 Some generators signal they are unable to generate by removing volume from their offer. However, this has broader dispatch efficiency implications. In particular, SPD will seek to replace the lost volume from other sources but the generator may be continuing to generate as it is ramping down, implying excessive generation.

2 See the definition of Q_{con} in clause 13.204 of the Code.

electricity spot market (the scheduling, pricing and dispatch or SPD model) to ramp a generator through its generation level while maintaining grid security through complementary dispatch of other plant.

3.12 As a result, the amount of constrained on payments generators receive will depend on how much higher their offer is relative to the relevant nodal price.

3.13 The costs of constrained on payments are paid for by all wholesale electricity market purchasers – electricity retailers and consumers that purchase electricity directly from the wholesale market. Since retailers pass these costs on to their customers, the costs of constrained on payments are borne by all end-consumers, even if the out-of-merit generation is only required to meet demand at a single node.

3.14 The costs of constrained on payments are not reflected in nodal prices so the costs are not transparent.

Issues with the existing arrangements

3.15 The Authority has formed the view that the existing arrangements do not promote the Authority's statutory objective. This is because making constrained on payments to ramp-constrained generation dispatched down at its maximum ramp rate results in:

(a) inefficient scheduling and dispatch

(b) inefficient investment

(c) allocative inefficiency

(d) inefficient risk management, undermining market confidence.

3.16 Each of these issues is discussed below.

Inefficient scheduling and dispatch

3.17 As SPD only takes into account the generation costs for the current trading period in determining scheduling and dispatch, generation with higher costs in subsequent trading periods may be dispatched in preference to generation with lower costs overall. This means slow down-ramping generation may be scheduled and dispatched in preference to faster ramping generation, even though it would be paid constrained on payments for longer after it is no longer required to meet demand. As a consequence, scheduling and dispatch is less efficient than if the full costs of dispatching a particular generator were taken into account in a dispatch decision.

3.18 Further, the current arrangements give out-of-merit generators incentives to prolong the time to ramp down as they receive constrained on payments for the total time they are dispatched out of merit. This further undermines efficient scheduling and dispatch as the generation from ramp-constrained generators prevents dispatch of potentially lower cost generation to meet demand. Moreover, in normal circumstances lower cost generation would be within merit so would not receive constrained on payments, implying further foregone cost savings.

3.19 The only mechanism in the Code that might provide a disincentive against this behaviour is the requirement under clause 13.5A that "Each generator … must ensure that its conduct in relation to offers …is consistent with a high standard of trading conduct." However, clause 13.5B provides a 'safe harbour'. The safe harbour sets out behaviours generators must follow in order to be sheltered from non-compliance with clause 13.5A.[3]

[3] The requirements of the safe harbour under clause 13.5B of the Code are that:

As a consequence, generators could be acting to maximise constrained on payments but the safe harbour provided by clause 13.5B prevents compliance action by the Authority against such behaviour.

3.20 The Market Development Advisory Group (MDAG) is reviewing the Code's trading conduct provisions, including the safe harbour.

Inefficient investment

3.21 Payment of constrained on payments for the full period generators are out of merit, rather than just when the generation is needed, undermines incentives for investors to invest in generation that is responsive to the market's needs. This is because, at best, it makes investors indifferent between investing in slow-ramping and fast-ramping generation, and it may actually make investment less responsive by encouraging investment in generation that will accrue constrained on payments when ramping down.

3.22 As constrained on payments are not reflected in nodal prices, this too undermines efficient investment, as neither generators nor consumers receive the full nodal price signal of the cost of meeting demand during a trading period at each node. This is an issue with constrained on payments in general, but is heightened with payments to ramp-constrained generation who receive the payments including when they are not required. The effect is that neither other generators nor consumers receive an efficient price signal of the cost of ramp-constrained generation, which would provide them with a signal to invest in lower cost alternatives.

Allocative inefficiency

3.23 Because nodal prices do not incorporate the costs of constrained on payments, nodal prices do not accurately signal the cost of consuming electricity at each node in each trading period. As a result, consumers exposed to nodal prices may choose to consume electricity even though they would not if nodal prices reflected the full cost. This is inefficient. The inefficiency is greater with ramp-constrained generation as the inaccurate signalling of the cost of consuming electricity when constrained on payments are incurred takes place over more trading periods. However, because the cost of constrained on payments is spread across all consumers, the size of this problem is likely to be small.

3.24 At the same time, this cost spreading creates its own efficiency problem. This is because consumers whose demand would be met without the out-of-merit generation have to share in the cost of the constrained on payments. For these consumers, the overall cost of consuming electricity is higher than is efficient because of the additional cost of constrained on payments.[4] At the margin, this higher overall cost means these consumers will consume less electricity than is efficient. The size of this problem is also likely to be small because the cost of constrained on payments is spread across all consumers.

(a) the generator offers all capacity it is able to operate

(b) if the generator decides to make or change its offer it does so as soon as it can

(c) if it is pivotal (so that demand would not be met without its generation) its offers do not result in higher prices at the node at which it operates (its node), its offers are consistent with its offers when it is not pivotal or it does not benefit from an increase in the final price at its node.

4 Note, however, that nodal prices for these consumers accurately reflect the cost of supplying them since they do not include the cost of constrained on payments.

Inefficient risk management, undermining market confidence

3.25 Because the costs to purchasers from constrained on payments are not transparent until settlement it can be difficult for purchasers to determine at what level they should hedge for the costs of these payments. To the extent that this prevents purchasers obtaining the level of hedging that they would prefer, this is inefficient, as it means that purchasers are not able to obtain the level of hedging that reflects their risk preferences. The consequence is that purchasers are likely to use less efficient alternatives to manage their purchasing risk, such as not using as much electricity. Compared with other generation receiving constrained on payments, this is likely to be a bigger issue in relation to ramp-constrained generation because of the additional constrained on costs it incurs when it is ramping down.

3.26 The other main issue with hedging constrained on payments is that the costs to purchasers are incurred at all nodes but the generator receiving the constrained on payments operates at a single node. This means the generator best placed to offer hedges against the costs of the constrained on payments the generator receives does not operate at most of the nodes used by the purchasers who pay those costs. The consequence is constructing a hedge against those costs is likely to involve high transactions costs, implying less hedging than would be efficient. Again, relative to other generation receiving constrained on payments, this problem is likely to be greater for ramp-constrained generation because of the additional constrained on costs when it is ramping down.

3.27 The consequence of inefficient risk management is reduced market confidence. The reduction in market confidence is exacerbated by the fact that the cost of constrained on payments is uncapped and not exposed to competition – further increasing risk and uncertainty.

3.28 Because the costs of constrained on payments are spread across all purchasers, the actual amount each purchaser will incur will be relatively small. Accordingly the problem of inefficient risk management is also likely to be correspondingly small.

Why the Authority is addressing these issues now

3.29 The Authority has decided to address this issue now because recent offering by a ramp-constrained generator has resulted in monthly constrained on payments exceeding \$1.0m,[5] compared to a monthly average of \$76,000 for the 12 months ending 30 June 2018. While the generator has altered its offering behaviour since the Authority highlighted the issue, this is the latest instance of a problem that has occurred several times in recent years when other generators engaged in similar behaviour. In each instance, the generators have moderated their behaviour after the Authority raised the issue with them. While the Authority could continue to manage the issue in this way, the inefficiencies arising from constrained on payments for ramp-constrained plant would remain. Accordingly, the Authority considers it should address the issue now.

Q1. Do you agree the issues identified by the Authority are worthy of attention?

5 Part of the reason for high constrained on payments since 30 June 2018 was constrained on payments for security reasons, particularly during October 2018. However constrained on payments have been substantially higher overall because of the offering by a ramp-constrained generator.

4 Regulatory Statement for the proposed amendment

Objectives of the proposed amendment

4.1 The objectives of the proposed amendment are to remove constrained on payments to ramp-constrained and out-of-merit generation that is not required to meet demand and/or maintain security.

Q2. Do you agree with the objectives of the proposed amendment? If not, why not?

The proposed amendment

4.2 The proposed amendment involves inserting a new clause 13.212B after clause 13.212A. This clause would provide that constrained on payments would not be paid in relation to a generating unit:

(a) that was reducing generation in response to a dispatch instruction from the system operator

(b) where the dispatch instruction requires the unit to reduce generation at its maximum ramp-down rate.

4.3 The clause would apply to dispatch instructions relating to part of or a whole trading period.

4.4 Under the proposal, generation would still receive constrained on payments if it is dispatched out of merit in other circumstances. The payments would continue until the generation is required by a dispatch instruction to reduce generation at its maximum ramp-down rate. Like within-merit generation, out-of-merit generation would just be paid the nodal price when it is dispatched down at its maximum ramp-down rate.

4.5 The proposal limits removing constrained on payments to situations where a dispatch instruction requires a generator to reduce at the unit’s maximum ramp-down rate because:

(a) this is the rate specified in a generator’s offers

(b) a dispatch instruction requiring a generator reduce its generation at its maximum ramp-down rate reflects that the generation is no longer required to meet demand.

4.6 The proposal would mean that generators that have relied in part on constrained on payments when ramping down to recover their costs would need to recover these costs through their offers. Under the proposal, this implies that when these generators are dispatched:

(a) if they are within merit and the marginal generator, nodal prices for the nodes at which they operate would be higher

(b) if they are out of merit, constrained on payments would be higher for the period for which their generation is required to meet demand

(c) where they are out of merit and dispatched down at their maximum ramp-down rate, they would be paid the nodal price and receive no constrained on payments.

4.7 Competition would determine whether these generators can sustain higher offers.

4.8 Accordingly, the option that the Authority proposes would address concerns about ramp-constrained generators making offers so as to maximise constrained on payments. It also ensures reliability is not compromised because constrained on payments would continue for out-of-merit generation when it is needed.

4.9 The drafting of the proposed amendment is contained in Appendix A.

The proposed amendment's benefits are expected to outweigh the costs

4.10 The benefits from the proposed amendment are expected to outweigh the costs. Appendix C also sets out quantitative estimates of the benefits and costs, to the extent it has been possible to do this. The proposal is expected to provide net benefits of at least $9.1 million (base case) with a lower case estimate of $4.5 million and an upper case estimate of $12.2 million.

4.11 The benefits expected from the proposal are:

(a) more efficient scheduling and dispatch

(b) more efficient investment

(c) increased allocative efficiency

(d) increased market confidence.

4.12 The costs from the proposal are:

(a) implementation costs because of system changes required by the system operator and clearing manager

(b) implementation costs for ramp-constrained generators

(c) risk of lower reliability, if ramp-constrained generation is not able to compete with unconstrained generation.

4.13 The benefits and costs of the proposal are discussed in more detail in Appendix C.

Q3. Do you agree the benefits of the proposed amendment outweigh its costs?

The Authority has identified six other means for addressing the objectives

4.14 The Authority has identified six other means for addressing the objectives:

a) remove constrained on payments entirely

b) limit payment of constrained on payments to specified situations only

c) introduce a requirement that generators should remove volume from offers when they wish to ramp down

d) allow generators to make complex offers, which would allow generators to incorporate ramping costs into their offers

e) restrict access to the trading conduct safe harbours

f) remove the trading conduct safe harbours.

4.15 Maintaining the status quo would not achieve the objectives of the proposal as constrained on payments would continue to be paid to ramp-constrained generation when it is generating out of merit but is no longer required to meet demand and/or maintain security.

The proposed amendment is preferred to other options

4.16 The Authority has evaluated the other means for addressing the objectives and prefers the proposal. An evaluation of these options and an assessment against the proposal follows.

Remove constrained on payments entirely

4.17 While constrained on payments do raise some efficiency issues through not being reflected in nodal prices, removal of all constrained on payments would likely mean that out-of-merit generation would not be available when required to meet demand. This is because out-of-merit generation would not be able to recover its costs since nodal prices would be, by definition, less than their offers. As a result, removing constrained on payments would likely reduce reliability, which is inconsistent with the Authority's statutory objective.

4.18 The problems with constrained on payments could potentially be addressed through removing them and reflecting the actual costs of out-of-merit generation through nodal prices. However, this has broader implications for the operation of the electricity market than limiting removal of constrained on payments to ramp-constrained generation when it is no longer required, so is a matter that should be considered in a wider review.

Limit constrained on payments to specified situations

4.19 Rather than taking the approach under the proposal of specifying when constrained on payments must not be paid, this option would involve specifying the circumstances when constrained on payments would be paid. This option would potentially allow restricting constrained on payments to a very limited set of circumstances – eg, only when out-of-merit generation is required to provide security.

4.20 This option would allow continued access to the main benefit from constrained on payments: ensuring that out-of-merit generation was available when required. It would also allow the efficiency problems with constrained on payments - of nodal prices under-signalling the cost of meeting demand - to be confined to fewer trading periods.

4.21 The main disadvantage with this option relative to the proposal is that there is a greater risk of unintended consequences. This is because too narrow a specification carries a risk that out-of-merit generation is not available when it is required, and the costs in terms of reduced reliability are likely to be greater than the costs of making unnecessary constrained on payments.

Introduce a requirement that generators should remove volume from offers when they wish to ramp down

4.22 This option would involve introducing a Code requirement that generators should ensure that offered energy volume represents the level of generation achievable by the offered plant at the end of the offered trading period.

4.23 This would mean that, while the offered volume would reflect the generator's expected output at the end of the trading period, the generator would still physically ramp down through the trading period. As the SPD modelling would assume an instantaneous step change in the generator's output, in line with the generator's offer, it would schedule more generation to meet demand. However, this would lead to increased nodal prices and inefficient dispatch, as the system seeks to manage the excess generation and maintain system security.

4.24 This option would be effective in removing constrained on payments for ramp-constrained generation as it was ramping down. However, this would be at a cost to system security and economic dispatch. Accordingly, this option is inferior to the proposal.

Allow generators to make complex offers

4.25 Under the status quo, generators that are not intermittent generators or type A or type B co-generators are limited to making offers that identify:[6]

(a) the trading periods for which the offer is made

(b) their maximum output

(c) their maximum ramp-up and ramp-down rates

(d) up to five price bands at which they offer to sell a quantity (MW) of electricity at a particular price ($/MWh).

4.26 This offer structure prevents generators from making separate but simultaneous offers for when they are ramping up, operating at the relevant capacity, and ramping down. Complex offers would allow generators to do this. This would allow ramp-constrained generation to offer so as to recover their costs through nodal prices when ramping down rather than relying on constrained on payments to do this.

4.27 Like the option of removing all constrained on payments, this option would have broader implications for the operation of the electricity market than the proposal. Accordingly, it is an option that would be better considered in a wider review.

4.28 This option is likely to be higher cost to develop and implement than the proposal. The implications of this option for the wholesale electricity market would need to be carefully considered, so it is likely to take considerably longer than the proposal to develop and implement.

Restrict access to the trading conduct safe harbours

4.29 Rather than addressing the problem directly with amendments to the Code provisions that deal with constrained on payments or offers, an alternative would be to address behaviour that seeks to maximise constrained on payments. One such approach would be to prevent generators engaging in such behaviour from accessing the trading conduct safe harbours provided by clause 13.5B of the Code.[7]

4.30 For example, clause 13.5B(1)(a) and (b) provide access to the safe harbour provide a generator offers all of its capacity that it is able to generate and, if it decides to change its offer it does so as soon as its can. One approach to preventing behaviour to maximise constrained on payments would be to provide that access to the safe harbour provided by these clauses is not available for parties taking actions that are unlikely to be consistent with a high standard of trading conduct, such as market manipulation. This would mean that parties engaging in such behaviour would be exposed to compliance action for breaching clause 13.5A of the Code, which requires offers to be consistent with a high standard of trading conduct.

6 Refer to Form 1, Schedule 13.1.

7 See paragraph 3.19.

4.31 While this option would allow compliance action to address inefficient behaviour, unlike the proposal this option would not address the inefficiency arising from payment of constrained on costs to ramp-constrained generation when it is no longer required to meet demand. Further, the issue of trading conduct is a matter affecting the entire market. Given this, altering the safe harbour should be considered as part of a wider review of the trading conduct provisions. This is already happening through the MDAG's trading conduct review.

Remove the trading conduct safe harbours

4.32 This option would involve removing the trading conduct safe harbours entirely. This would potentially expose parties acting to maximise their constrained on payments to compliance action for breaching clause 13.5A of the Code if their behaviour was inconsistent with a high standard of trading conduct.

4.33 However, this option has the same problems of the previous option:

(a) it would not address the efficiency problems relating to constrained on payments to ramp-constrained generation when it is no longer required

(b) it is an option that should be considered as part of a wider review of trading conduct, which the MDAG is already working on.

4.34 Because of these problems, this option is therefore inferior to the proposal.

Q4. Are there any other options the Authority should consider?

Q5. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

The proposed amendment complies with section 32(1) of the Act

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

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

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

Section 32(1) of the Act	How proposal complies
(a) competition in the electricity industry;	The proposal promotes competition by better ensuring ramp-constrained and unconstrained generation compete on an equivalent basis. In particular, by removing constrained on payments for ramp-constrained generation when it is no longer required, the plant would have to compete with unconstrained plant according to how competitive its offers are.
(b) the reliable supply of electricity to consumers;	The proposal promotes reliability by ensuring that ramp-constrained generators would continue to be available when they are out of merit, as the

Section 32(1) of the Act	How proposal complies
	proposal would not prevent such generation from recovering its cost through its offers; to the extent it continues to be competitive.
(c) the efficient operation of the electricity industry;	The proposal promotes the efficient operation of the electricity industry because it would better ensure that the costs of ramp-constrained generation are reflected through nodal prices. In turn, this would better promote more efficient operation and investment, increased allocative efficiency and improved market confidence, as discussed in paragraphs 4.10-4.34 above.
(d) the performance by the Authority of its functions;	The proposed amendment would not materially affect the performance of the Authority's functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment would not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

Q6. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act? If not, why not?

The Authority has had regard to the Code amendment principles

4.37 When considering amendments to the Code, the Authority's Consultation Charter[8] requires the Authority to have regard to the following Code amendment principles, to the extent the Authority considers they are applicable. Table 2 (below) describes the Authority's regard for the Code amendment principles in preparing the proposal.

Table 2: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective (see paragraphs 4.35-4.36) 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 in Appendix C. The proposal addresses a regulatory failure: constrained on payments to ramp-constrained plant when they are no longer required, which causes inefficient operation, investment and use of electricity.
3. Net benefits are quantified	To the extent to which the Authority has been able to estimate the benefits and costs of the proposal, this is set out in the

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

Principle	Comment
	evaluation of the costs and benefits in Appendix C.
4. Preference for small-scale ‘trial and error’ options	Principles 4 to 9 apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter), which is not the case in relation to this matter. However, the proposal is consistent with principle 4, because it limits removing constrained on payments to just payments for ramp-constrained generation when it is no longer required, rather than removing constrained on payments entirely.
5. Preference for greater competition	Consistent with principle 5, the proposal promotes competition – see Table 1, point (a).
6. Preference for market solutions	Consistent with principle 6, the proposal promotes a market solution by promoting use of nodal prices to determine dispatch of ramp-constrained generation.
7. Preference for flexibility to allow innovation	Consistent with principle 7, the proposal does not preclude the development of the other options, should any of them have merit.
8. Preference for non-prescriptive options	Consistent with principle 8, the proposal does not prescribe particular behaviour by ramp-constrained generators but would allow them to determine how best to construct their offers if they no longer received constrained on payments when no longer required.
9. Risk reporting	Consistent with principle 9, the Authority would monitor the extent to which the proposal affected access to generation to meet demand when out-of-merit generation was required for this.

Appendix A Proposed amendment

After clause 13.212A, insert:

No payment of constrained on compensation for generators at maximum ramp down rate

13.212B No payment of constrained on compensation for generators at maximum ramp down rate

(1) Despite clause 13.202 to clause 13.212, **generators** do not receive **constrained on compensation** in respect of any **constrained on situation**.

(2) Subclause (1) applies in respect of any **reconciled quantity** of **electricity** the **generator's generating unit** produces in a **trading period**, if:

(a) the **generating unit** is reducing generation as a result of the **generator** having received a **dispatch instruction** for the **trading period** or part of the **trading period**; and

(b) the **dispatch instruction** requires the **generating unit** to reduce generation at the **generating unit's** maximum ramp down rate.

Q7. Do you have any comments on the drafting of the proposed amendment?

Appendix B Format for submissions

Submitter	

Question		Comment
Q1.	Do you agree the issues identified by the Authority are worthy of attention?	
Q2.	Do you agree with the objectives of the proposed amendment? If not, why not?	
Q3.	Do you agree the benefits of the proposed amendment outweigh its costs?	
Q4.	Are there any other options the Authority should consider?	
Q5.	Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q6.	Do you agree the Authority's proposed amendment complies with section 32(1) of the Act? If not, why not?	
Q7.	Do you have any comments on the drafting of the proposed amendment?	

Appendix C Assessment of benefits and costs

C.1 This appendix sets out the estimated benefits and costs of removing constrained on payments for ramp-constrained generation when it is dispatched down at its maximum ramp rate (restricting eligibility for constrained on payments).

Assessment framework

C.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 restricting eligibility for constrained on payments

(b) effects are assessed over a 15-year period, starting from the date constrained on payments are altered

(c) values are estimated in 2019 dollars using a 6 percent real discount rate; sensitivity cases with discount rates of 4 percent and 8 percent are also considered

(d) the counterfactual to this proposal assumes that existing arrangements remain in place.

C.3 Our quantitative cost benefit analysis considers how generators might change their behaviour if they no longer receive constrained on payments while ramping and how this might affect system dispatch. We have used vSPD[9] to estimate any changes in system costs and benefits.

Categories of expected benefit

C.4 We expect restricting constrained on payments to have the following potential benefits:

(a) more efficient generation scheduling and dispatch

(b) more efficient investment

(c) increased allocative efficiency

(d) increased overall market confidence.

C.5 Each of these benefits is discussed below.

Benefit (a) – more efficient generation scheduling and dispatch

C.6 Providing constrained on payments can lead to an inefficient dispatch order.

C.7 To see how this can occur, consider a simple electricity system with 19 MW of demand for three trading periods. The system is supplied by three generators, each with 10 MW capacity, and each with only a single price tranche during each trading period. The generators offer as follows, and each offer reflects their cost to generate in each trading period:

(a) Generator A offers its generation for $1/MWh during the first trading period, and $50/MWh for the next two. It can only ramp down by 2 MW per period.

(b) Generator B always offers its generation at $9/MWh

9 vSPD stands for vectorised Scheduling, Pricing and Dispatch. The vSPD model is a precise replica of SPD. It is written and solved using the GAMS software and is based on the published SPD formulation.

(c) Generator C always offers its generation at $10/MWh

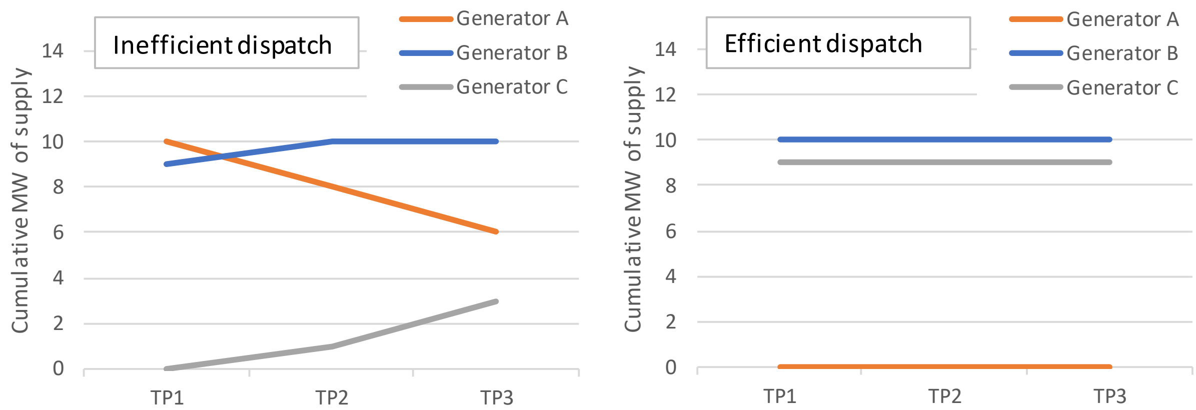
C.8 The dispatch process optimises each period individually, so generator A will be fully dispatched in the first trading period (because it is the cheapest) and will remain on at partial load in subsequent trading periods (due to its ramping constraint).

C.9 However, this leads to higher system costs over the three trading periods than if it is not dispatched at all, because it is more expensive to run in trading periods two and three than the other generators. The most efficient dispatch when considering all three trading periods uses generators B and C to meet demand, and generator A does not generate at all.

C.10 Restricting eligibility for constrained on payments will not change how the dispatch process operates within a trading period. However, if generator A is only paid the spot price in trading periods two and three[10] then it will lose money if it is dispatched in period one. To prevent this happening, generator A will need to increase its offer in trading period one to ensure it covers its potential ramping costs. An offer price in trading period one of approximately $60/MWh would be required to achieve this.

C.11 In this alternative scenario, generator A's fully cost reflective offer in trading period one is higher than the other generators, so it is not dispatched. This is a more efficient outcome because it takes account of the higher costs of generating in later trading periods for generator A when it is constrained on.

Figure 2 - Inefficient and efficient dispatch schedules



C.12 The quantitative assessment uses vSPD to investigate whether inefficient scheduling and dispatch is occurring in practice.

C.13 It considers the following scenarios:

(a) A base scenario using the historical dispatch schedule.

(b) A series of alternative scenarios in which individual inflexible generators are assumed to completely withdraw the discretionary portion of their generation, and the generation need is instead fulfilled by some other source. This is equivalent to the alternative scenario in the simple example discussed above, except the generator does not offer the inflexible portion of its generation volume at all. In effect, it assumes the cost of operating the inflexible generation is extremely high. In this respect, it is the most extreme response that might occur if generators

10 Generator C's offer price, because this is the marginal cost of generation.

increase their offer prices in response to no longer receiving constrained on payments.

C.14 vSPD is a linear program that minimizes system costs and maximizes system benefits by optimally dispatching generation and dispatchable load for each individual trading period. It reproduces the actual dispatch schedule produced by SPD, and can also produce a different dispatch schedule using modified inputs. vSPD produces an "objective function variable" (OFV), which represents the economic cost of generating electricity to meet demand.[11] The difference between the OFV from the base scenario and an alternative scenario provides an estimate of the economic cost or benefit from not utilising the inflexible generator in each alternative scenario.

C.15 Generators often alter their output to respond to changes in demand. Typically, output is highest in the morning and evening to meet demand peaks, with minimum output overnight. Generators may also reduce output during the middle of the day. Each large increase in generation followed by a large decrease in generation was considered a "ramping action" for that generator. A ramping action can last for a small number of trading periods or persist over many days.

C.16 We examined historical data to identify the effect on system costs if generators that received constrained on payments during ramping actions did not generate. For most ramping actions, removing the inflexible generation resulted in an increase in system costs because more expensive generation was used to meet demand instead. However, sometimes withdrawing the generator resulted in a *reduction* in system costs because constrained on costs during the ramp-down period outweighed any benefits. We refer to ramping actions that perversely resulted in an increase to system costs as "uneconomic ramping actions", and to their beneficial counterparts as "economic ramping actions".

C.17 If explicit payments are no longer given for constrained on costs while ramping, we expect generators to account for these costs in their energy offers, which may lead to a change in dispatch order. We expect that economic ramping actions and uneconomic ramping actions will be affected in different ways:

(a) we do not expect dispatch order during economic ramping actions to change significantly. This is because the ramping action provides a net benefit to the system, which means that the generator would have been dispatched, even if it increased its offers to account for its subsequent constrained on costs. Because dispatch order is not changed significantly, there would be little effect on system costs.

(b) we expect the dispatch order during uneconomic ramping actions to change. Dispatching the inflexible generator resulted in higher system costs, which means that it would not have been dispatched if its offers had reflected its constrained on costs. Instead, an alternative source of generation would have been dispatched. This would be a more efficient outcome for the system, leading to lower total system costs.

C.18 Note that vSPD does not calculate all constrained on costs, because vSPD produces a dispatch solution that matches generation to demand for a single point in time. There

[11] Strictly both the cost and benefit. The electrical system is a net benefit to the country overall, but the benefit of serving demand is not explicitly calculated in vSPD, because demand is a "hard limit". "Cost and benefit" is simply referred to as "cost" henceforth.

can be constrained on costs *within* a period that don't show up in the vSPD solve. However, we have not considered within-period constrained on costs further because:

(a) including within-period constrained on costs does not result in more generators performing uneconomic ramping actions

(b) for generators that *do* perform uneconomic ramping actions, the within-period constrained on costs are much smaller than the vSPD constrained on costs. [12] They are also estimated with less accuracy than the vSPD constrained on costs.

Caveat 1

C.19 A generator removing its generation completely is considered an unlikely outcome. Completely removing its generation is one way that a generator could avoid constrained on costs, but by doing so it would also forgo any revenue from the spot market. We consider a more likely outcome is that a generator might alter its offer prices and increase its output by a smaller amount during peak periods, or it might begin ramping down earlier than it currently does. Use of more realistic assumptions would be expected to increase the expected benefits significantly.

Caveat 2

C.20 This analysis assumes energy offers reflect the short run marginal cost (SRMC) for each generator in each trading period. While competition is expected to generally drive offer prices towards SRMC, in practice offer prices for individual generators could depart from SRMC at times. This factor could increase or reduce the estimated benefits, depending on the specific pattern of offer prices. Based on the information currently available, it is not possible to determine to size or direction of this effect. We do not expect this effect to bias results in either direction.

Results of quantitative analysis

C.21 The details of the quantitative analysis are:

(a) The analysis considered the 12 months from January 2018 to December 2018, inclusive.

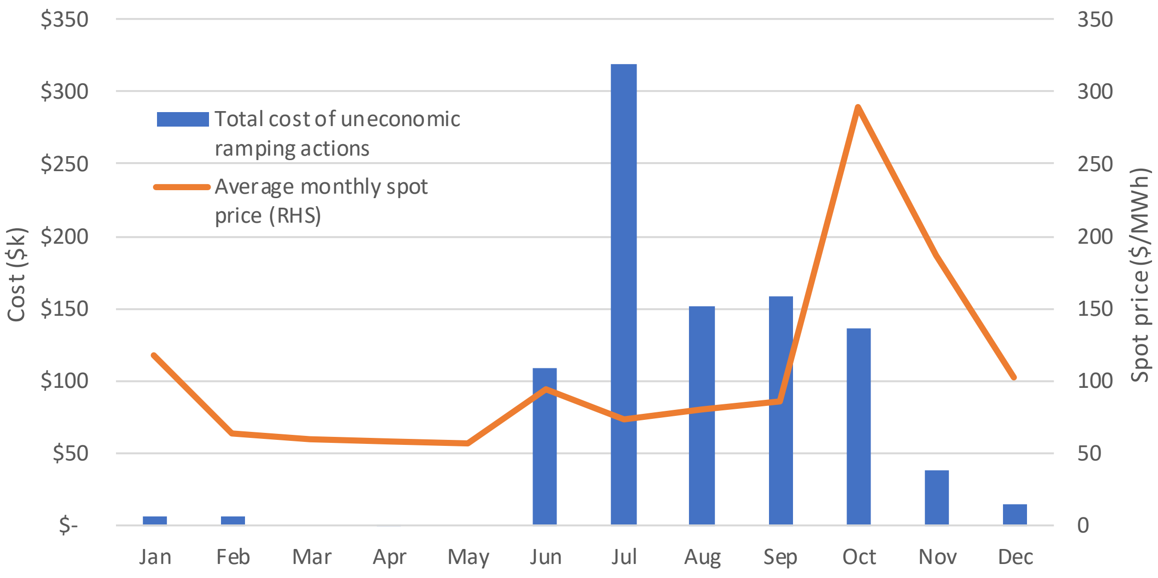
(b) The analysis considered the five generators with the lowest ramp-down rate, relative to their maximum generation output.[13]

C.22 The analysis identified 80 "uneconomic ramping actions", all of which were caused by one generator. The total cost over the year was $0.94 million but varied greatly from month to month.

12 Estimated within period constrained on costs were about 10 percent of those calculated by the vSPD method.

13 The six next most inflexible generators according to this metric were geothermal generators, which do not typically perform many ramping actions.

Figure 3 - Uneconomic ramping action costs



Benefit (b) – more efficient generation investment

C.23 Current arrangements incentivise less flexible sources of generation. There is no offer cap in the New Zealand electricity market, so theoretically there is no limit to the constrained on payment a generator could receive. And a generator with a theoretical ramp-down rate of zero could maintain this payment indefinitely once it was dispatched.

C.24 In practice, such offer behaviour would attract regulatory attention. However, even if a generator offers “reasonably”, it would receive more constrained on payments the less flexible it is. This may be an accurate reflection of the costs to the generator, but in an efficient market it would bear those costs, rather than be reimbursed for them.

C.25 Flexibility is an important consideration when designing and investing in sources of generation. An obvious example is when considering different types of gas turbines. One of the main differences between an “open-cycle gas turbine” (OCGT) and a “closed-cycle gas turbine” (CCGT) is the rate at which each can vary its output. OCGTs can start and stop much more quickly than CCGTs. As a trade-off, OCGTs have much lower heat-rate efficiency. If flexibility is not properly incentivized (or even dis-incentivized), this may lead to inefficient investment decisions. Similar considerations apply to other forms of generation.

C.26 We have not quantified the effect of this benefit but expect it to be significant.

Benefit (c) – Increased allocative efficiency

C.27 Nodal prices do not incorporate the costs of constrained on payments, so they do not accurately signal the cost of consuming electricity at each node in each trading period. As a result, consumers may choose to consume electricity even though they would not if they knew the full cost. This is inefficient.

C.28 The effect is expected to be relatively modest in size because the price uplift is small[14], and electricity demand is not particularly price responsive.

Benefit (d) – Increased overall market confidence

C.29 Current arrangements undermine market confidence because constrained on payments are not subject to competition and participants cannot limit their exposure to them. Total constrained on payments in July 2018 were $1.5 million, but in theory they are uncapped.[15] Restricting constrained on payments would remove this risk.

C.30 We have not quantified this benefit as there is insufficient information to derive an estimate.

Categories of expected cost

Costs for market services

C.31 Restricting constrained on payments is expected to give rise to costs in the following areas:

(a) Costs for the system operator. We estimate the cost to the system operator of changing market systems would be $0.05 million in net present value terms.

(b) Costs for the clearing manager. We estimate the changes to the clearing manager's system would be $0.14 million in present value terms.

Costs for participants

C.32 We have included a one-off cost of $15,000 per affected participant. Six participants received constrained on payments for generation in the previous five years,[16] resulting in a total cost of $90,000. This cost is to account for any changes to how they construct their offers in response to a restriction of constrained on payments.

C.33 We do not expect restricting constrained on payments to create significant ongoing costs for wholesale market participants. The generator likely to be most affected by the proposed change already frequently adjusts its offer,[17] indicating that it closely monitors the system to account for many factors and can therefore adjust its offer price to account for a restriction of constrained on payments.

C.34 We have assumed that participants who do not receive significant constrained on payments would not be affected because constrained on costs are small relative to their other revenue from the energy market.[18] It would be inefficient to significantly adjust their offers to avoid constrained on costs if this reduced their other market revenue.

Reduced system reliability

C.35 Restriction constrained on payments to generators could in theory result in less generation being available and reduce system reliability. In practice, we think this

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14 Averaged across all demand and all trading periods July's constrained on payments would increase prices by 0.50 $/MWh

15 Excessive constrained on payments could potentially be addressed through the trading conduct provisions and an extreme situation could potentially be resolved by a UTS claim.

16 Not all payments were necessarily due to ramping constraints, so this represents an upper limit.

17 In July 2018, energy offers during peak periods were revised an average of 5.5 times for each period.

18 In 2018 the highest monthly constrained on payments to Huntly were $0.4 million in October (and only some of these were due to ramping constraints). Genesis received $116 million revenue from the spot market for its generation at Huntly in October.

outcome would be unlikely because generators have the ability to adjust their offers to compensate for tighter eligibility for constrained on payments. Accordingly, if a given generator is the most efficient option to meet demand, we expect it would continue to be offered and dispatched following the proposed Code change.

C.36 For this reason, we do not expect there to be any effect on system reliability.

Regulatory uncertainty

C.37 Changing the Code and tightening constrained on payments to generators could increase regulatory uncertainty, hindering investment in generation. We consider this risk to be minimal because ramp-constrained generators would still be able to recover their costs through their offers. Additionally, the Authority has been consistent in addressing inefficiencies when they are identified. For these reasons, we have not included this cost.

Estimated benefits and costs

C.38 The results of the analysis are summarised in Table 3.

Table 3: Summary of estimated costs and benefits

Item	Lower case $m (present value)	Base case $m (present value)	Higher case $m (present value)
Benefits			
Improved dispatch	$4.81	$9.42	$12.45
Investment efficiency	Not quantified	Not quantified	Not quantified
Allocative efficiency	Not quantified	Not quantified	Not quantified
Increased market confidence	Not quantified	Not quantified	Not quantified
Implementation costs			
System operator	-$0.05	-$0.05	-$0.05
Clearing manager	-$0.14	-$0.14	-$0.14
Participants	-$0.09	-$0.09	-$0.09
Net Benefits	$4.5	$9.1	$12.2

C.39 The lower case includes both the lower estimate of benefits and the higher estimate of costs, and vice versa. This may overestimate the possible range of outcomes.

C.40 The higher and lower cases use 4 percent and 8 percent discount rates respectively. They also use different methods for assessing when ramping actions start and end. The lower case uses more stringent criteria for when ramping actions end. This leads to fewer, longer ramping actions, which reduces the calculated benefits because there are more generation periods to compensate for costs incurred during ramp down periods. The higher case assesses each morning and afternoon separately, treating each morning and afternoon as a distinct ramping period.

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
CCGT	Closed cycle gas turbine
Code	Electricity Industry Participation Code 2010
Constrained on payments	Payments to generators or dispatchable demand providers that are out of merit order but required to meet demand and/or maintain security
Dispatch	As defined in clause 1.1(1) of the Code, dispatch means the process of: (a) pre-dispatch scheduling, to match expected supply with expected demand, and to allocate ancillary service offers and transmission offers to match expected grid conditions; and (b) rescheduling to meet forecast demand; and (c) issuing instructions based on the dispatch schedule and the real-time conditions to manage resources to meet the actual demand
Dispatchable demand	Demand bidding into the electricity market that offers to curtail its demand by the amount and price specified in its bid in response to dispatch instructions from the system operator
Merit order	The order in which generation and dispatchable demand would be dispatched for a trading period as determined by its offer or bid
Node	Defined in clause 1.1(1) of the Code. In general, it refers to a location on the transmission network at which a wholesale electricity market price is calculated
Nodal price	The wholesale electricity market price applying at a particular node
OCGT	Open cycle gas turbine
Out of merit	Generation or dispatchable demand with a bid or offer above the marginal price
Ramp-constrained generator	A generator dispatched to reduce its generation level at its maximum offered ramp-down rate in one or more dispatch instructions
Ramp down rate	The rate at which generation is able to decrease its generation output, expressed in MW/h in the generation offer
SPD	Scheduling, pricing and dispatch. Refers to the model used for scheduling, pricing and dispatch in the wholesale electricity

	market
SRMC	Short-run marginal cost
vSPD	Vectorised SPD. An analogue of the SPD model used for modelling the wholesale electricity market
Within merit	Generation or dispatchable demand with a bid or offer below the marginal price.