Dispatchable demand: late bid revisions

Decision Paper

8 October 2015

Contents

1. The Authority has decided to amend the Code to ensure that dispatchable demand constrained on or off compensation is paid for valid reasons

1.1 Decision

1.1.1 The Electricity Authority (Authority) has decided to amend the Electricity Industry Participation Code 2010 (Code) in relation to dispatch-capable load stations (DCLS). The amendment provides that if a DCLS makes a revision to a nominated dispatch bid for a trading period during the 30 minutes prior to the start of the trading period:

(a) the revised bid must be a nominated non-dispatch bid

(b) the DCLS is not obliged to comply with a dispatch instruction issued for that trading period

(c) no constrained on or constrained off situation arises for that DCLS for that trading period.

1.1.2 The Code amendment is attached as Appendix A.

1.1.3 The Code amendment promotes the efficiency limb of the Authority's statutory objective because it ensures that constrained on or off payments made to dispatchable load purchasers are for valid reasons.

1.1.4 The Code amendment is consistent with the Authority's Code amendment principles because it:

(a) is lawful, and promotes the Authority's statutory objective, primarily the efficiency limb because it ensures that constrained on and constrained off payments made to dispatchable load purchasers are for the intended reasons, but also the competition and reliability limbs because it promotes confidence in the market arrangements for dispatchable demand

(b) addresses a regulatory failure, in this case unintended constrained on or off payments being made to dispatchable load purchasers when late bid revisions are made

(c) analysis indicates it will provide a net economic benefit.

1.2 Introduction

1.2.1 In May 2014, the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013 came into force.

1.2.2 As amended, the Code provides that an approved DCLS may elect to have its demand dispatched according to its bid (broadly similar to the way a generator is dispatched according to its offers). An approved DCLS may also receive constrained on or off payments. The economic purpose of the constrained on or off payments is to encourage an efficient effort from each DCLS to comply with dispatch instructions.

1.2.3 The Authority has since identified that constrained on and constrained off payments were being made to DCLSs in some situations that did not align with the intended economic purpose of such payments.

1.2.4 On 5 May 2015, the Authority published a consultation paper titled *Dispatchable demand – late bid revisions* (consultation paper).[1]

1.2.5 The consultation paper proposed to amend part 13 of the Code in relation to DCLSs. The amendment provides that if a DCLS makes a revision to a nominated dispatch bid for a trading period during the 30 minutes prior to the start of the trading period:

(a) the revised bid must be a nominated non-dispatch bid

(b) the DCLS is not obliged to comply with a dispatch instruction issued for that trading period.[2]

1.2.6 The consultation paper also evaluated four alternative options:

(a) **Alternative A:** Re-dispatching DCLSs in the current trading period that have made late bid revisions using their revised bids[3]

(b) **Alternative B:** Revising the calculation of constrained on and constrained off payments to use the bids that were used for dispatch[4]

(c) **Alternative C:** Providing that a DCLS will not receive any constrained on and constrained off payments in relation to a trading period where it has submitted a late bid revision[5]

(d) **Alternative D:** Running another NRS schedule towards the end of each trading period.[6]

---

1 Refer to http://www.ea.govt.nz/development/work-programme/wholesale/operational-enhancements-to-dispatchable-demand/consultations/#c15243.

2 Note that the amendment described in paragraph 1.1.1(c) was not included in the consultation. This amendment was suggested by NZX in its submission, as discussed in section 3.5.

3 Refer to paragraph 3.4.1(a) of the consultation paper.

4 Refer to paragraph 3.4.1(b) of the consultation paper.

5 Refer to paragraph 3.4.1(c) of the consultation paper.

6 Refer to paragraph 3.4.1(d) of the consultation paper.

2. The Authority considered submissions on the proposed Code amendment

2.1 Submissions received

2.1.1 Submissions closed on 16 June 2015. The following participants made submissions on the proposal:

(a) Genesis Energy Limited (Genesis)

(b) Meridian Energy Limited (Meridian)

(c) the Major Electricity Users' Group (MEUG)

(d) Norske Skog Tasman Limited (Norske)

(e) NZX Limited (NZX)

2.1.2 Genesis and Meridian both supported the proposal without comment.

2.1.3 NZX also supported the proposal but suggested an additional Code amendment to clarify that constrained on and constrained off situations do not occur when late bid revisions are made (discussed further in section 3.5).

2.1.4 MEUG and Norske expressed concerns with the proposal. MEUG noted they had seen Norske's submission and agreed with it.

2.1.5 Authority staff met with both Norske and MEUG to discuss their submissions, and to consider how to address their concerns about the proposal.

3. Issues raised in submissions

3.1 Concern about the cost benefit analysis

3.1.1 Both MEUG and Norske disagreed with the cost benefit analysis (CBA) of the proposal.

3.1.2 Norske considered that the proposal would not have positive net benefits compared with the status quo, and made the following criticisms of the CBA's net benefit calculations:

(a) The CBA does not make an allowance for the cost for existing DCLSs to modify their systems, or for training operators to conform to the proposal. These costs would easily exceed $42,800.

(b) The CBA evaluates the proposal as having significant benefits from avoiding costs associated with compliance when there have been no such costs observed by Norske.

(c) The figures used to represent the elasticity of supply and demand were arbitrary. MEUG added to this point by commenting that the CBA assumes future demand response will be more elastic than current responses.

(d) The CBA is completely deterministic which is a poor way to model an uncertain future.

3.1.3 MEUG added the following criticisms of the CBA:

(a) the discount rate of 6% used in the CBA is too low

(b) Alternative C should have been used as the counterfactual

(c) there should have been at least a qualitative description of the dynamic efficiency implications of the proposal.

Authority response

Allowance to be made for cost incurred by existing DCLSs in enhancing their bidding systems

3.1.4 The Authority agrees that an allowance should be made in the CBA for costs for existing DCLSs to enhance their bidding systems. The Authority understands that when Norske (which operates both existing DCLSs) submits a revised bid, it submits revised bids for a number of trading periods at the same time. Norske is able to flag all the bids as either dispatchable or non-dispatchable. However, it is not able to flag the first bid (the one for the next trading period beginning in less than 30 minutes) as non-dispatchable while flagging the bids for subsequent trading periods as dispatchable. There would be a cost to Norske associated with enhancing this system to allow different flags to be used for different trading periods.

3.1.5 Norske submitted that this cost would easily exceed $42,800. Authority staff have discussed the work that would be involved in enhancing Norske’s bidding system with Norske staff. Further to those discussions, the Authority considers Norske’s original estimate to be too high and that a cost of $10,000 is more realistic.

Costs arise for the Authority and/or participants because the Code requires compliance with a dispatch instruction that cannot realistically be complied with

3.1.6 The consultation paper notes (in paragraph 2.2.1(b)) that the current Code provisions require a DCLS to comply with its dispatch instruction. The dispatch instruction is based on the “old bid” and is normally issued to the DCLS around 25 minutes before the start of the trading period. The DCLS, by making a late bid revision, indicates that the circumstances have changed and it can no longer comply with that dispatch instruction. However, the Code still requires compliance with the "old bid" except where personnel or plant safety is at risk.[7] An incongruity exists between the general rule requiring compliance, and the DCLS' indication that circumstances have changed and it can no longer comply. This incongruity gives rise to the costs referred to in paragraphs 2.2.1(b) and 3.3.1(b) of the consultation paper.

3.1.7 The costs associated with this incongruity could take different forms:

(a) the DCLS could incur costs endeavouring to comply with the dispatch instruction despite having signalled that such compliance is not realistic

(b) the Authority could incur costs in pursuing an alleged breach of dispatch compliance against the DCLS, although this has not occurred to date[8]

(c) the DCLS could incur costs in obtaining legal advice as to whether its actions comply with the Code.

Estimates for elasticity of supply and demand to remain unchanged

3.1.8 The Authority does not agree that there is any compelling reason to alter the estimates of the elasticity of supply and demand that contribute to the calculation of the benefits of the proposal. No evidence in favour of alternative figures was put forward by the submitters. The Authority does not consider that it has, in determining the figure for the elasticity of demand, made an assumption that future demand response will be more elastic than current responses. The Authority considers the supply and demand elasticity figures of 2.7 and -0.26 respectively that were used in the CBA to be reasonable.

A deterministic CBA that is robust to sensitivity analysis is an adequate tool for evaluating the proposal

3.1.9 The Authority notes that the CBA requires a number of assumptions, each of which contains quite a high degree of uncertainty. Given this uncertainty, the Authority considers that more sophisticated CBA techniques are not likely to provide significant additional insight into the merits of the proposal and the alternatives. More sophisticated analysis techniques will also have a cost to the Authority. The existing CBA approach involves making "reasonable" or "believable" point estimates for key variables, and subjecting outcome to a sensitivity analysis. The

7 Refer to clause 13.82(2)(a) of the Code.

8 To date the Authority has not pursued any alleged breaches against a DCLS for not complying with its dispatch instruction after it has made a late bid revision. The dispatch exception relating to personnel or plant safety may well apply in a given individual situation.

Authority considers that this “deterministic” approach is an adequate tool for evaluating the proposal.

The discount rate of 6% is the standard discount rate used by the Authority for CBAs

3.1.10 The discount rate of 6% is the usual discount rate used by the Authority for CBAs. A sensitivity analysis of +/-2% was applied to this discount rate.

The status quo will continue to be used as the counterfactual

3.1.11 The Authority considers it is still appropriate to use the status quo (no changes to the Code) as the counterfactual. The Authority also evaluates the net benefit of the identified alternative options to determine whether any of them present a better option than the proposal.

Qualitative description of the dynamic benefits

3.1.12 As set out in the consultation paper, Authority staff consider that participants’ confidence in the dispatchable demand regime could be damaged if the status quo is retained. Over the longer term this could create risks for investment and pressure for larger scale market reviews.

3.1.13 The Authority notes that continuing over-payments of constrained on and constrained off amounts creates wealth transfers between participants. In the Authority’s view, these wealth transfers are not of themselves an inefficiency. [9] However, the status quo is unlikely to be acceptable to participants that fund these over-payments. The continuation of these over-payments may undermine stakeholder’s confidence in dispatchable demand. The Authority expects there would be continuing pressure to review the aspects of the market design that cause these over-payments. This explains the comments in the consultation paper about “participant confidence in the dispatchable demand regime” and “pressure for larger scale market reviews”.

3.1.14 Since purchasers fund the over-payments, there would be a reduction in the demand for electricity. This would lead to an inefficient disincentive for investment in activities that used electricity. There would also be an inefficiently high incentive to participate in the dispatchable demand regime and to make late bid revisions.

[9] See Appendix A, paragraphs A24 and A64 of *Interpretation of the Authority’s Statutory objective* at http://www.ea.govt.nz/about-us/strategic-planning-and-reporting/foundation-documents/

3.2 Concern about the cost estimate of Alternative B

3.2.1 Norske disputed the system operator's cost estimate of $315,000 to implement Alternative B as unrealistically high.

Authority response

3.2.2 The Authority invited the system operator to review the cost estimate for Alternative B. The system operator has advised that $315,000 remains its best cost estimate. The system operator's cost estimate was carried out in a similar way to other system operator cost estimates for the degree of accuracy required. It was an initial high level estimate provided for the purpose of comparing options. The system operator is not able to provide a more definitive estimate until a detailed investigation can be carried out.

3.2.3 The Authority's usual practice is to narrow the options down to one or two options before requesting a detailed investigation.

3.2.4 The Authority is confident that the system operator prepared its estimates as best as it could given the information available and the timeframe allowed.

3.3 Preference for Alternative B

3.3.1 Despite the cost estimate, both MEUG and Norske preferred Alternative B that was proposed in the consultation paper. Alternative B would revise the calculation of constrained on and constrained off payments to use the bids that were used for dispatch (rather than using final bids to determine the "scheduled quantity").

3.3.2 Norske noted that under the proposal, whenever a late bid revision is made (even a small one), the dispatchable load purchaser loses the opportunity to receive constrained on and constrained off payments. The dispatchable load purchaser would then receive no compensation if the price forecasts turn out to be incorrect to the extent that the load regrets its level of electricity usage.

Authority response

3.3.3 Authority staff discussed the proposal, Norske's concerns, and various possible options, including Alternative B, both during a visit to the Norske site at Kawarau and later via telephone.

3.3.4 The consultation paper identified three policy problems:

(a) constrained on and constrained off overpayments

(b) the cost of compliance with dispatch instructions

(c) the opportunity for dispatchable load purchasers to manipulate prices.

3.3.5 While Alternative B would solve the constrained on and constrained off overpayments, it would leave the other two policy problems unresolved.

3.3.6 During the Authority's discussions with Norske, the possibility of a "modified Alternative B" to potentially resolve the remaining two policy problems was raised.

3.3.7 The "modified Alternative B" proposed that:

(a) the second policy problem (the cost of compliance with dispatch) could be resolved by amending the Code to remove the compliance obligation on a DCLS when a late bid revision is made

(b) the third policy problem (the opportunity to manipulate prices) could be resolved by close monitoring of late bid revisions.

3.3.8 However, the Authority considers constrained on or constrained off payments should not be paid to a dispatchable load participant in relation to a trading period in which the participant was not obliged to comply with dispatch. Also, the potential for dispatchable load purchasers to manipulate prices would place a lot of pressure on the Authority's monitoring activity. It would be costly for the Authority to carry out this monitoring activity, and there are risks that some manipulative activity could occur despite the monitoring. The Authority considers that amending Alternative B in line with the above suggestions is not a viable solution.

3.4 Norske suggested a variation to the proposal

3.4.1 During the Authority's discussions with Norske following consultation, Norske suggested a variation to the Authority's proposal. It suggested that whenever a late bid revision is made, the purchaser who makes it must ensure that it is:

(a) either a non-dispatch bid,

(b) or a dispatch bid that is used to form a dispatch instruction.

3.4.2 To ensure the latter, the purchaser submitting the revised bid would need to advise the system operator that the revised bid had been submitted, and request that the short non-response schedule (NRSS) be re-run and a new dispatch instruction be issued.[10]

[10] Dispatch instructions for DCLSs are issued from the NRSS.

Authority response

3.4.3 The Authority discussed this option with the system operator. Essentially this option relies on the system operator re-running the NRSS upon request.

3.4.4 The system operator did not support this option because the NRSS is the basis on which the system operator ensures secure and economic dispatch. The system operator considers that re-running the NRSS could risk it not being fully security checked.

3.4.5 The system operator was also concerned that allowing a re-run of the NRSS could set a precedent and lead to participants requesting other schedules to be re-run in other situations.

3.4.6 The Authority has decided not to proceed with this option given the issues raised by the system operator.

3.5 NZX suggested an additional amendment

3.5.1 NZX suggested a relatively minor amendment to the proposed Code amendment to clarify that constrained on and constrained off situations do not occur when late bid revisions are made.

Authority response

3.5.2 The Authority agrees with NZX's suggestion and has revised clauses 13.192 and 13.202 accordingly, as shown in Appendix A.

4. The Authority has updated the CBA

The Authority has identified an error in one of the formulae used to estimate the benefits of the proposal

4.1.1 The Authority has identified that one of the formulae in the CBA that was used to estimate the benefits of the proposal had an error in it. The error has now been corrected. The benefits should have been $98,698, approximately $10,000 less than stated in the CBA.

The Authority is satisfied that the proposal has positive net benefits

4.1.2 The Authority has also amended the CBA to include the costs for existing DCLSs to enhance their bidding systems.

4.1.3 These two amendments to the CBA result in the following changes to the assessed present value (PV) of the benefits and costs of the proposal (excluding any assessment of dynamic efficiency benefits).

Table 1: Updated net present value (NPV) of the proposal excluding dynamic benefits

Item	As published in the consultation paper	Updated values
PV of benefits (assessed over 15 years with 6% discount rate)	$108,762	$98,698
less PV of costs	$42,800	$52,800
NPV of the proposal	$65,962	$45,898

4.1.4 A positive NPV remains under the following sensitivity scenarios:

Table 2: Sensitivity of the NPV of the proposal to different assumptions

Sensitivity scenario	NPV
Base case	$45,898
Discount rate is 8% rather than 6%	$35,824
Benefits from avoiding costs of dealing with Code compliance issues are evaluated using an estimate of 25 staff hours per year rather than 50 (that is, the hours are halved)	$20,160
Elasticity of demand is 0.13 rather than 0.26 (that is, the elasticity is halved)	$23,371
Elasticity of supply is 1.35 rather than 2.7 (that is, the elasticity is halved)	$42,085
Benefits flow for 10 years rather than 15 years	$19,105

4.1.5 The Authority is satisfied that assessed benefits of the proposal (not including any dynamic efficiency benefits) continue to outweigh the costs.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
CBA	Cost benefit analysis
Code	Electricity Industry Participation Code 2010
DCLS	Dispatch-capable load station. A load that has registered with the Authority to participate in the dispatchable demand regime.
Dispatched purchaser	A purchaser who purchases electricity at a DCLS that is dispatched
Late bid revision	Aa revised nominated dispatch bid relating to a trading period submitted after about 27 minutes before the beginning of the trading period (which is when the NRS is normally scheduled to commence its run)
NPV	Net present value
NRS	Non-Response Schedule prepared under clause 13.62 of the Code. In this paper, NRS refers to the schedule that covers 8 trading periods and is (at present) run once every half hour (clause 13.62(1)(b)). The NRS that runs during a trading period determines dispatch instructions to DCLSs for the following trading period.
NRSS	Non-Response Schedule (Short), the common term for the NRS defined in clause 13.62(1)(b) of the Code.
PV	Present value

Appendix A Draft Code amendment – strikethrough version

A.1 Tracked changes indicate the changes that will be made by the Code amendment, with changes made following the May 2015 consultation in red.

The following amendments are proposed to Part 13 of the Electricity Industry Participation Code 2010.

13.19A Bids may be revised or cancelled

(1) Each **purchaser** may—

(a) revise any of its **bid** prices or **bid** quantities for any **trading period** by submitting a new **bid** to the **system operator**; or

(aa) revise a **nominated bid**—

(i) from being a **nominated dispatch bid** to being a **nominated non-dispatch bid**; or

(ii) from being a **nominated non-dispatch bid** to being a **nominated dispatch bid**; or

(b) cancel any of its **bids** by notice in writing to the **system operator**.

(2) Despite subclause (1), a **purchaser** must not do any of the following within the 2 hours before the beginning of the **trading period** in respect of which a **bid** is made:

(a) revise the **bid** price:

(b) revise the **bid** quantity:

(ba) revise a **nominated bid**—

(i) from being a **nominated dispatch bid** to being a **nominated non-dispatch bid**; or

(ii) from being a **nominated non-dispatch bid** to being a **nominated dispatch bid**:

(c) cancel the **bid**.

(3) Despite subclause (2),—

(a) a **purchaser** may do any of the following within the 2 hours before the beginning of the **trading period** in respect of which a **bid** is made, if the **purchaser** has a **bona fide physical reason** necessitating the **purchaser** to do so:

(ia) revise a **nominated bid**—

(A) from being a **nominated dispatch bid** to being a **nominated non-dispatch bid**; or

(B) from being a **nominated non-dispatch bid** to being a **nominated dispatch bid**:

(i) revise its **bid** quantities:

(ii) cancel the **bid**:

(b) before the beginning of the **trading period** to which a **nominated bid** applies, the **purchaser** that submitted the **nominated bid** must immediately submit a revised **nominated bid** quantity to the **system operator** if the **purchaser** expects, or ought reasonably to expect, that the quantity of **electricity** likely to be purchased by the **purchaser** at the prices indicated in the **nominated bid** will,—

(i) if the **nominated bid** is a **nominated non-dispatch bid**, differ from the quantity in the **nominated bid** by more than the lesser of—
(A) 20**MW**; and
(B) 20% of the **nominated bid** quantity; or
(ii) if the **nominated bid** is a **nominated dispatch bid**, differ from the quantity in the **nominated bid** by more than the lesser of—
(A) 10**MW**; and
(B) 10% of the **nominated bid** quantity; or
(c) if the **system operator** declares a **grid emergency**, a **purchaser** must comply with clauses 13.99 to 13.100.
(3A) If a **purchaser** revises a **nominated bid** for a **dispatch-capable load station** in the **trading period** that is immediately before the **trading period** to which the **nominated bid** applies, the revised **nominated bid** is a **nominated non-dispatch bid**.
(4) Despite subclause (3)(b), a **purchaser** is not required to submit a revised **nominated bid** quantity, if the expected change in the quantity is less than 5 **MW**.
(5) Whether or not the cancellation or revision was in accordance with this clause must be determined in accordance with clause 13.21(2).

…

13.82 Dispatch instructions to be complied with

(1) This clause applies to—
(a) a **generator**; and
(b) an **ancillary service agent**; and
(c) a **dispatched purchaser**.
(2) Each **participant** to which this clause applies must comply with a **dispatch instruction** properly issued by the **system operator** under clause 13.72 unless,—
(a) in the **participant's** reasonable opinion,—
(i) personnel or plant safety is at risk; or
(ii) following the **dispatch instruction** will contravene a law; or
(b) the **generating plant** or **dispatch-capable load station** is already responding to an automated signal to activate—
(i) **capacity reserve**; or
(ii) **instantaneous reserve**; or
(iii) **automatic under-frequency load shedding**; or
(iv) **over frequency reserve**; or
(c) the **participant** is a **generator** or **ancillary service agent** acting in accordance with clause 13.86; or
(d) the **participant** is an **intermittent generator** that has complied with clause 13.17, and the **system operator** has not advised that there is—
(i) a **grid emergency**; or
(ii) a system constraint that directly affects the **intermittent generator**; or
(e) the **participant—**
(i) is a **generator**; and
(ii) deviates from a **dispatch instruction** for **active power** to comply with clause 8.17; or
(f) the **participant—**
(i) is a **dispatched purchaser**; and

(ii) deviates from the **dispatch instruction—**

(A) to comply with a request issued by the **system operator** under clause 5(4) of **Technical Code** B of Schedule 8.3; or

(B) to comply with clause 8.18; or

(g) the **participant—**

(i) is a **dispatched purchaser**; and

(ii) cannot comply with the **dispatch instruction** because of a disconnection of **demand** under clause 7A of **Technical Code** B of Schedule 8.3; or

<u>(ga) the **participant—**</u>

<u>(i) is a **dispatched purchaser**; and</u>

<u>(ii) the **dispatch instruction** is issued for a **trading period** for which the latest **nominated bid** for the relevant **dispatch-capable load station** is a **nominated non-dispatch** bid; or</u>

(h) the **participant—**

(i) is a **generator** or an **ancillary service agent**; and

(ii) deviates from a **dispatch instruction** to comply with clause 9 of **Technical Code** B of Schedule 8.3; or

(i) the **participant—**

(i) is a **generator** or an **ancillary service agent**; and

(ii) is acting in accordance with a commissioning or test plan that—

(A) is required under clause 2(6) of **Technical Code** A of Schedule 8.3; and

(B) expressly allows the **generator** or **ancillary service agent** to depart from the **dispatch instruction** for the purpose of the commissioning or test plan; and

(iii) has no reasonable means of complying with the **dispatch instruction** while acting in accordance with the commissioning or test plan.

…

13.141 Pricing manager to use certain input information

(1) The **pricing manager** must use the following **input information**:

(a) for existing generation configuration—

(i) data specifying the instantaneous **MW injection** at the **grid injection point** at the beginning of each **trading period** for each **generating plant** and each **generating unit** that was the subject of **offers** for that **trading period**; or

(ii) if no such data is available, a reasonable estimate of such data:

(b) for actual **demand** over the **trading period**,—

(i) the **demand half-hour metering information** described as LMA below must be calculated as follows:

LMA = GEA + LMX - LDCLS (for a **grid exit point**)

LMA = GEA - LMI - LDCLS (for a **grid injection point**)

LMA = LMX - LDCLS - UIGEA (for an **intermittent generating station** with a **point of connection** to the **grid** and/or **unoffered generation** from a **generating station** with a **point of connection** to the **grid**)

where

LMA is the adjusted quantity of **electricity** measured in **MWh** by a **metering installation** at a **grid exit point** or **grid injection point**
LMX is the unadjusted **half-hour metering information** for the quantity of **electricity** measured in **MWh** at a **grid exit point**
LMI is the unadjusted **half-hour metering information** for the quantity of **electricity** measured in **MWh** at a **grid injection point**
LDCLS is the adjusted **half-hour metering information** for the quantity of **electricity** measured in **MWh** used by a **dispatch-capable load station** for the **trading periods** that the **system operator** listed under clause 13.138B
GEA is the adjusted **half-hour metering information** given to the relevant **grid owner** under clause 13.136
UIGEA is the information given to the relevant **grid owner** under clause 13.137:

(ii) if any of the **half-hour metering information** is not available, an **initial estimate** for each **grid exit point** or **grid injection point**:

(iii) to avoid doubt, each **grid owner** must provide the **half-hour metering information** to the **pricing manager** required under this clause in accordance with Part 15 for the collection of that **grid owner's volume information**:

(c) the final **offers** for each **trading period** submitted by **generators** and provided to the **pricing manager** by the **system operator** in accordance with clause 13.63. The **pricing manager** must remove all **offers** from **intermittent generators** from this information before using it in the pricing process:

(ca) the final ~~submitted~~ **nominated dispatch bid** for each **dispatch-capable load station** (other than a **dispatch-capable load station** for which the final **nominated bid** for the **trading period** was a **nominated non-dispatch bid**) dispatched in each **trading period** that was provided to the **pricing manager** by the **system operator** in accordance with clause 13.63:

(d) the final **reserve offers** for each such **trading period** as given by **ancillary service agents** in accordance with clauses 13.37 to 13.54:

(e) the final information provided to the **system operator** by a **grid owner** under clauses 13.29 to 13.34 for each **trading period** that the **system operator** notifies in accordance with clause 13.63.

…

13.192 Constrained off situations may occur

A **constrained off situation** occurs when—

…

(c) in relation to a **dispatch-capable load station** ~~**dispatched purchaser**~~ (except when the final **nominated bid** for the **dispatch-capable load station** in a **trading period** is a **nominated non-dispatch bid**), the latest **dispatch instruction** issued by the **system operator** for the **dispatch-capable load station** for a **trading period** is for a **MW** amount that is less than the **MW** amount scheduled for the **dispatch-capable load station** in the schedule of **final prices** for the **trading period**.

…

13.202 Constrained on situations may occur

(1) Subject to subclause (2), a **constrained on situation** occurs when—

…

(d) in relation to a **dispatch-capable load station** ~~**dispatched purchaser**~~ (except when the final **nominated bid** for the **dispatch-capable load station** in a **trading period** is a **nominated non-dispatch bid**), the latest **dispatch instruction** issued by the **system operator** for the **dispatch-capable load station** for a **trading period** is for a **MW** amount that is more than the **MW** amount scheduled for the **dispatch-capable load station** in the schedule of **final prices** for the **trading period**.

…