RULE CHANGE

AEMC

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Negative offers from scheduled network service providers) Rule 2012

Rule Proponents

International Power-GDF Suez Australia
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29 March 2012

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Reference: ERC0140

Citation

AEMC (2012), *Negative offers from scheduled network service providers*, Consultation Paper, 29 March 2012, Sydney.

About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the MCE.

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1 Introduction

1.1 Rule change request

On 5 December 2011, International Power-GDF Suez Australia (IPRA) and Loy Yang Marketing Management Company (LYMMCo) (the proponents) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) in relation to prices offered by scheduled network service providers (SNSPs). The proponents are concerned that negative offers from SNSPs can cause some generators to have an effective offer below the price floor, undercutting other generators. They are concerned this leads to inefficient outcomes. Consequently, IPRA and LYMMCo are proposing SNSPs be subject to a price floor of zero.

1.2 Rule change process

The proposed time frame for the AEMC's consideration of this rule change request is set out below.

Table 1.1 Key dates for this rule change process

Milestone	Date
Submissions to this consultation paper due	3 May 2012
AEMC to release draft determination	12 July 2012
Submissions to draft determination due	23 August 2012
AEMC to release final determination	4 October 2012

1.3 This consultation paper

This consultation paper has been prepared by staff of the AEMC to facilitate public consultation on the rule change proposal and does not necessarily represent the views of the AEMC or any individual Commissioner of the AEMC.

This paper:

- sets out a summary of, and background to, the *Negative offers from scheduled network service providers* rule change proposed by IPRA and LYMMCo;
- identifies a number of questions and issues to facilitate consultation on this rule change request; and
- outlines the process for making submissions.

2 Background

This section sets out relevant background to this rule change request. This includes:

- an explanation of how market network service providers (MNSPs)[1] earn revenue and make offers into the National Electricity Market (NEM) to transport energy; and

- a discussion of the specific circumstances relating to Basslink, which is currently the only MNSP operating in the NEM.

2.1 How MNSPs earn revenue and make offers

MNSPs are entitled to the inter-regional residues (IRR or residues) that accrue across the interconnector. These residues are essentially the difference between the spot prices in the importing and exporting regions, multiplied by the flow across the interconnector. MNSPs can therefore be considered to buy energy at the spot price in one region and sell it at the spot price in another region, subject to losses.[2]

Box 2.1: Example of how MNSPs earn revenue

Assume the spot price in region A is $20/MWh, the spot price in region B is $30/MWh, and the flow from region A to region B is 300 MW. Ignoring losses the IRRs that accrue, and so the revenues earned by the MNSP, are:

($30/MWh - $20/MWh) * 300 MW = $3,000/h

An MNSP is required to submit a schedule of offers that sets out how much energy it is willing to transport in up to ten different price bands, similar to generators.[3] However, MNSPs must submit two schedules: one for each direction of flow.

An MNSP's offer represents the price difference between the two regions. The offer reflects the minimum price difference that the MNSP is willing to accept to transport energy. For example, an offer of $10/MWh to transport 300 MW from region A to region B means that the interconnector will only be dispatched for those 300 MW if the spot price in region B is at least $10/MWh higher than the spot price in region A.

1 Note that the terms "MNSP" and "SNSP" are used interchangeably in this document. Strictly, MNSPs are a category of market participant that must register with the Australian Energy Market Operator (AEMO) to operate in the NEM. SNSPs make network dispatch offers so as to dispatch scheduled network services. An SNSP must be registered as an MNSP and, as such, are considered equivalent for the purpose of this document.

2 The net revenue that an MNSP earns is specified in National Electricity Rules (NER) clauses 3.8.6A(g)-(h).

3 NER clauses 3.8.6A(a)-(f) set out the requirements for MNSP offers.

MNSPs are generally dispatched where the difference between the spot prices in the two regions is greater than or equal to the MNSP's offer for the relevant direction of flow. There are some exceptions to this, which are discussed in section 5.1.2.

Like generators, MNSPs are subject to the market price cap,[4] currently set at $12,500/MWh.[5] However, while generators are also subject to a price floor, the NER do not impose a lower limit on MNSP offers. Despite this, the AEMC understands that the Australian Energy Market Operator (AEMO) currently uses a lower limit of -$1,000/MWh against which MNSPs' offers are validated.[6] While this price floor is consistent with that imposed on generators, it is not derived from the NER.

2.2 Overview of Basslink

Basslink connects Tasmania (at Tasmania's regional reference node (RRN) at George Town) with the rest of the NEM (at the Loy Yang 500 kV power station in Victoria). It has a continuous rating of approximately 480 MW in either direction, and up to 610 MW from Tasmania to Victoria for limited periods.

2.2.1 Structure of Basslink's ownership and operation

Basslink is currently the only interconnector that operates as an MNSP in the NEM.[7] It is owned by CitySpring Infrastructure Trust and operates under Basslink Pty Limited (BPL).

Hydro Tasmania and BPL entered into an agreement, prior to the commissioning of Basslink, called the *Basslink Services Agreement* (BSA). Under the BSA, Hydro Tasmania pays a fixed fee to BPL in exchange for the (variable) revenue stream that accrues on the interconnector. Of key relevance to this rule change request, the BSA also gives Hydro Tasmania the right to direct Basslink's offers, subject to the restrictions discussed below.

2.2.2 Bidding restrictions

The Treasurer for the State of Tasmania has issued two Ministerial Notices[8] that have placed various restrictions on the offers that Hydro Tasmania may instruct BPL to make, in addition to those set out in the NER. The first Ministerial Notice was issued in July 2005, the second in May 2008. The restrictions set out in each are described below.

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4 NER clause 3.8.6A(i).

5 The price cap will be increasing to $12,900/MWh on 1 July 2012. See AEMC, *Schedule of reliability settings*, 21 February 2012.

6 IPRA and LYMMCo, *Request for Rule Change: Scheduled Network Service Offers*, 5 December 2011, p. 4.

7 Murraylink and Directlink were commissioned as MNSPs but were subsequently converted to regulated interconnectors.

8 The Ministerial Notices were issued under section 96 of the Tasmanian *Electricity Supply Industry Act 1995*.

July 2005 to May 2008

On 31 July 2005 a Ministerial Notice was issued by the Treasurer for the State of Tasmania that prevented Hydro Tasmania from instructing BPL to offer:[9]

- negative transport bids in either direction; or
- positive transport bids for southward flows other than in limited circumstances for technical reasons.

These conditions were considered necessary as far back as 2001, when the Australian Competition and Consumer Commission (ACCC) was considering the entry of Tasmania into the NEM. The ACCC noted stakeholder concerns, as well as its own concerns, that the BSA may lead to anti-competitive outcomes as a result of Hydro Tasmania's dominant position in the Tasmanian market and its ability, through the BSA, to effectively control flows across Basslink. The ACCC considered in respect of scheduled network services offers:[10]

> "While a detailed analysis of the incentives and effects of non-zero pricing is complex and speculative, the [ACCC] believes there could be circumstances where non-zero bids give rise to significant anti-competitive detriments."

The ACCC noted the Tasmanian Government's undertaking to disallow negative bids in either direction or positive bids on southward flows as a response to these concerns. However it remained concerned about the potential anti-competitive detriments of the BSA, noting that the Tasmanian Government would need to commit on an ongoing basis to addressing any future issues that could affect the level of competition in the Tasmanian market.[11]

May 2008 to today

On 4 May 2008 a revised Ministerial Notice was issued that set out the following principles:[12]

> "(a) Hydro Tasmania must not instruct BPL to submit a negative bid which applies to power flows across Basslink in either direction or otherwise agree to BPL making a negative bid in either direction for the purpose of producing counter-priced flows.

9 Cited in Department of Treasury and Finance, *Tasmanian Electricity Market Arrangements*, June 2006, p.11.

10 ACCC, *Applications for Authorisation, Tasmanian Derogations and Vesting Contract: Tasmania's NEM entry*, 14 November 2001, p. 30.

11 Ibid, p. 32.

12 *Electricity Supply Industry Act 1995*, Ministerial Notice under Section 36, clause 3.1.

(b) In the event that Hydro Tasmania instructs BPL to submit a negative bid which applies to flows across Basslink, it must only be in appropriate circumstances, which include the following:

(i) where mainland transmission constraints are causing Basslink northerly flow to be reduced."

The Ministerial Notice contained a number of other provisions, including maintaining the earlier restrictions on positive bidding on southward flows,[13] requiring Hydro Tasmania to disclose the reasons for any instructions for negative offers[14] and requiring Hydro Tasmania to develop a compliance plan[15].

Under Hydro Tasmania's subsequent compliance plan, its Board prohibited any instructions for negative bids in a southward direction on Basslink.[16] However, Hydro Tasmania was permitted to instruct BPL to make negative offers in the northward direction when the following three conditions are met:[17]

"(i) the Victorian spot price is higher than the Tasmanian spot price;

(ii) the Tasmanian price is negative; and

(iii) transmission constraints that affect the Latrobe Valley connection point start to bind."

These are the conditions under which Hydro Tasmania may currently instruct BPL to offer negative prices in the northward direction.

13 Ibid, clause 3.2.

14 Ibid, clause 3.3.

15 Ibid, clause 5.1.

16 Hydro Tasmania, *Enhancements Compliance Plan*, December 2010, p. 3.

17 Ibid.

3 Details of the rule change request

The rule change request from the proponents proposes to:

- modify clause 3.8.6A(i) as follows (proposed change is underlined):

  (i) prices specified in the *network dispatch offer* must not exceed the *market price cap* <u>and must not be negative</u>; and

- delete clause 3.8.6A(e), which becomes irrelevant if offers may not be negative.

A number of key points raised by the proponents in the rule change request are summarised and discussed below. Note that while IPRA and LYMMCo expressed the identified problem generically in respect of SNSPs, the example of Basslink and Hydro Tasmania is used in this section for ease of discussion.

IPRA and LYMMCo are concerned that when Hydro Tasmania instructs BPL to bid at negative prices in the northward direction, Hydro Tasmania can effectively undercut the price floor and so the price offered by the Latrobe Valley generators. Consequently Hydro Tasmania can be dispatched in favour of the Latrobe Valley generators, creating an opportunity cost for them associated with lost revenue.

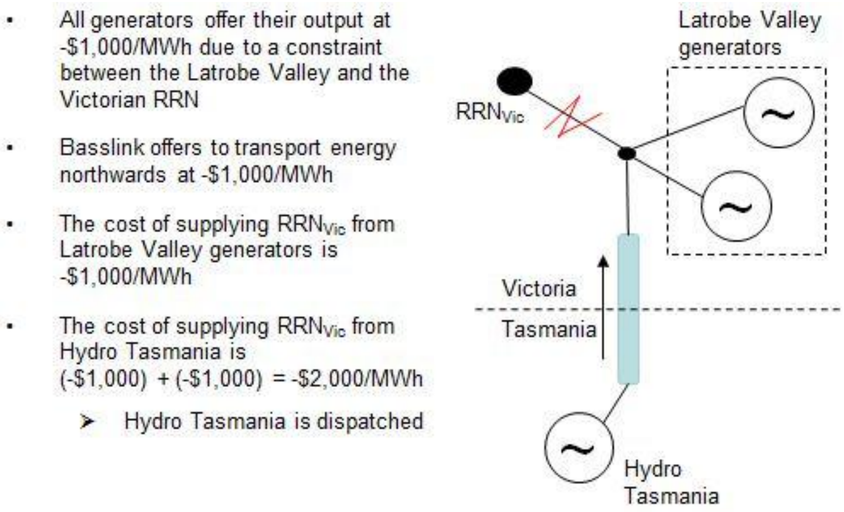
This situation occurs when there is a constraint affecting the Latrobe Valley, and so generators have an incentive to offer their energy at the price floor in order to maximise their dispatch.[18] If both Hydro Tasmania and Basslink are offered into the market at -\$1,000/MWh, then the effective offer price of Hydro Tasmania's energy at the Loy Yang connection point (ignoring losses) is -\$2,000/MWh. This is because Hydro Tasmania is effectively offering to pay the market -\$1,000 for each MWh of energy it produces, and Basslink is effectively offering to pay the market a further -\$1,000 for each MWh it transports. Therefore the apparent cost of importing energy from Tasmania is -\$2,000/MWh, as described in the figure below.

This behaviour can be profit maximising because the spot price in Victoria will be set by a generator on the other side of the constraint. Consequently, if dispatched, generators in the Latrobe Valley will receive the higher Victorian spot price. While Hydro Tasmania may risk setting the Tasmanian spot price at close to the price floor, any revenue losses[19] would be outweighed by the revenue that would accrue across Basslink. As discussed in the previous section, Hydro Tasmania receives the difference between the two spot prices for each MWh that flows across Basslink. This would be at its highest where the spot price in Victoria is at the price cap and the spot price in Tasmania is at the price floor.

18 The reason for non-cost reflective bidding is discussed further in section 5.2. Cost-reflective bidding requires generators to offer their energy at a price that reflects the cost of supplying one more unit of electricity from a generator's connection point to meet load requirements. In the absence of network constraints and generation scarcity this value is likely to equal operating and maintenance costs.

19 Note that these losses would be mitigated to some extent through Hydro Tasmania's contract position.

Figure 3.1



The proponents consider that the current bidding rules distort the market as some generation can be prioritised through "an artefact of the market rules".[20] They state that the proposed rule change will remove this distortion and so ensure that the most efficient generation is dispatched rather than generation which can effectively bid below the floor price.

Furthermore the proponents claim this would lead to an increase in certainty of dispatch outcomes for generators as they could no longer be underbid by a competitor effectively bidding below the market floor. This certainty in dispatch would lead to improved contract market outcomes.

The only potential cost the proponents identify is the possibility that AEMO may have to update their validation process. The proponents consider that this is only a minor cost and therefore is likely to be outweighed by the benefits of the rule change proposal. The proponents believe there will be no cost to MNSPs as they cannot determine any technical reason why MNSPs should need to bid negatively.

As part of the rule change request the proponents examined the proposal against the National Electricity Objective (NEO). They considered that the proposal meets the NEO on the basis that it would reduce distortions to effective competition. Removing the "unintended priority of some generators over others"[21] would lead to more efficient spot market outcomes and therefore a more efficient contract market. This, in turn, would lead to a more efficient operation of the NEM.

The rule change request from IPRA and LYMMCo includes a proposed rule, as set out above. The proponents noted that even if their proposed rule is not made, the current lack of a price floor appears to be an error that ought to be remedied.[22]

20 IPRA and LYMMCo, *Request for Rule Change: Scheduled Network Service Offers*, 5 December 2011, p. 5.

21 Ibid, p. 9.

22 Ibid, p. 4.

4 Assessment framework

The Commission's assessment of this rule change request must consider whether the proposed rule contributes to the achievement of the NEO as set out under section 7 of the National Electricity Law (NEL). The NEO states that:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

In the context of this rule change, the Commission will inform its decisions by considering, in particular, the likely impact of the proposal on the following elements:

- Efficient operation of electricity services:
  - MNSPs should have incentives to offer services at cost reflective prices; and
  - dispatch outcomes should maximise the value of trade to the market, optimised across both the energy and frequency control ancillary services (FCAS) markets.
- Efficient investment in electricity services:
  - generators and MNSPs should be able to recover their efficient fixed and variable costs over the long run.
- The reliability, safety and security of the supply of electricity and of the national electricity system should be maintained.

The Commission will also consider the materiality of the identified problem and the proportionality of any proposed solution.

As discussed above, Basslink is currently the only MNSP operating in the market. However, in assessing this rule change request the Commission will be mindful that any changes to the framework for MNSPs may have broader application. Therefore, in principle, the rules should continue to provide for the efficient construction and operation of any MNSP.

Despite this, the Commission will also need to consider the unique arrangements that currently apply to the operation of Basslink and whether changes are justified to address these particular circumstances.

In assessing this rule change request, the Commission will need to clearly identify a problem that requires resolution. As part of that process, the Commission will need to understand the cause of the problem and, in particular, whether it stems from the NER or another source. We will then be in a position to consider the appropriate response and whether this could be facilitated through amendments to the NER and is therefore in the Commission's power to implement.

5 Issues for consultation

Taking into consideration the assessment framework, we have identified a number of issues for consultation that appear to be relevant to this rule change request.

The issues outlined below are provided for guidance. Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this paper, including the proposed assessment framework.

Broadly, the AEMC seeks stakeholder views on whether the proposed rule will or is likely to contribute to the achievement of the NEO. The AEMC also seeks views on whether there is a more preferable rule that, having regard to the issues raised by the proponent, will or is likely to better contribute to the achievement of the NEO.

5.1 Unique arrangements applying to Basslink

As discussed in the previous section, the Commission will consider this rule change request in the broader context of whether the proposed rule will provide an efficient framework for MNSPs generally. However, there are some issues that the AEMC considers are unique to the only MNSP currently operating in the NEM, Basslink. Understanding these issues appears to be important in understanding the drivers behind the rule change request. These issues include:

- the market structure in Tasmania; and
- technical issues that we understand are unique to Basslink compared to the other (former) MNSPs.

5.1.1 Market structure in Tasmania

Hydro Tasmania is the dominant generator in Tasmania, owning 84 per cent of generation capacity. The majority of its plants are hydro generating units. Aurora Energy Tamar Valley (AETV) owns the remaining 16 per cent, which comprises the Tamar Valley and Bell Bay gas-fired plants.[23]

The proponents stated in the rule change request that Hydro Tasmania has the ability to control two of the three conditions under which it may instruct BPL to offer negative prices.[24] This included the conditions where the Victorian spot price is higher than the Tasmanian spot price and where the Tasmanian spot price is negative. They considered that the only condition that Hydro Tasmania cannot control is when the transmission constraints that affect the Latrobe Valley connection point start to bind.

Concerns about Hydro Tasmania's ability to control the Tasmanian spot price were also raised in a draft report by the Tasmanian Electricity Supply Industry Expert Panel

23 Australian Energy Regulator, State of the Energy Market 2011, p. 31.

24 IPRA and LYMMCo, *Request for Rule Change: Scheduled Network Service Offers*, 5 December 2011, p. 7.

(the Panel)[25]. The Panel analysed Hydro Tasmania's bidding behaviour in the context of assessing whether Hydro Tasmania has market power. The Panel concluded, among other things, that:[26]

"• Hydro Tasmania has a dominant position/market share in the Tasmanian region, controlling over 80 per cent of on-island capacity and holding a pivotal position;

- Hydro Tasmania can and does control Basslink flows through bidding in the energy and FCAS markets;

- Hydro Tasmania is almost always the marginal bidder in Tasmania and can choose to set the spot price; and..."

A number of generators raised concerns with the market structure in Tasmania in submissions to the Panel. Several have raised concerns specifically regarding the issues that this rule change is seeking to address and the role of the BSA in facilitating what they consider to be anti-competitive outcomes. For example LYMMCo, in their submission to the Panel's issues paper, noted their primary concerns were:[27]

"1. The structure of the Tasmanian electricity sector, primarily Hydro Tasmania's dominant position over the region which forms part of the integrated National Electricity Market.

2. Hydro Tasmania's operation of Basslink pursuant to the Basslink Services Agreement (BSA).

3. The legal validity of the BSA and the relationship between Hydro Tasmania and Basslink Pty Ltd (BPL) which arises as a consequence of this agreement.

4. The impacts on wholesale market competition in Victoria and Tasmania as a consequence of items 1 and 2 above, including the inability to enter into long-term contracts with commercial and industrial customers."

Similarly Alinta, in their response to the Panel's draft report, called for the Panel to investigate an end to the BSA and suggested that the Ministerial Notice in place prior to 4 May 2008 be reinstated as an interim solution to prevent Hydro Tasmania from effectively undercutting Victorian generators.[28]

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25 The Chair of the AEMC was a member of this Panel and will not participate in the determination of this rule.

26 Electricity Supply Industry Expert Panel, *An Independent Assessment of the Tasmanian Electricity Supply Industry: Draft Report*, December 2011, p. 157.

27 LYMMCo, Submission to the *Tasmanian Electricity Supply Industry Expert Panel Issues Paper*, 22 July 2011, p. 1.

28 Alinta Energy, Submission to the *Tasmanian Electricity Supply Expert Panel Draft Report*, 17 February 2012, p. 2.

These views suggest that some industry participants and commentators see the problem as a combination of:

- Hydro Tasmania's dominant market share in Tasmania; and
- the BSA, which allows Hydro Tasmania to coordinate its own offers with those of Basslink to maximise their overall revenues.

Maximising revenues from the energy market and the residues that accrue on Basslink requires a level of coordination that would be difficult to achieve if Hydro Tasmania and Basslink were operated independently.

However, Hydro Tasmania disagreed with a number of the Panel's observations and conclusions, particularly in respect of the wholesale supply arrangements. Hydro Tasmania considered the Panel's conclusions on market power were "incorrect, incomplete and unsupported by substantive evidence".[29]

Hydro Tasmania considered the use of negative offers by BPL represents one of a number of "innovative arrangements" that enables the performance of Basslink to be maximised. Hydro Tasmania also stated that the residues that accrue on Basslink:[30]

> "...have a cash value but they are much more valuable as risk management tools in an integrated portfolio operating across the Victorian and Tasmanian regions. This is how Hydro Tasmania uses them currently."

The Commission does not have the power to recommend or make structural changes in the Tasmanian market. However, the Commission seeks to understand the extent to which the problem identified by the proponents is dependent on, or independent of, the current market structure. Stakeholder views on these matters are welcome. Relevant considerations include both Hydro Tasmania's high market share of generation in Tasmania and the BSA.

If the source of the identified problem is the market structure in Tasmania, resolving the issue through a blanket restriction on the bidding behaviour of MNSPs could have unintended consequences. As discussed in section 4, while Basslink is currently the only MNSP operating in the NEM, this rule change would also impact any future MNSPs. For example, potential investors in MNSPs may find entry less profitable if their ability to operate is restricted. Irrespective of the likelihood of future entry by MNSPs, it may not be appropriate to introduce rules that would reduce the efficiency or effectiveness of existing frameworks.

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29 Hydro Tasmania, Submission to the *Tasmanian Electricity Supply Expert Panel Draft Report*, 17 February 2012, p. 4.

30 Ibid, p. 30.

Question 1 To what extent are the market outcomes identified by the proponents incentivised by the current market structure?

1.1 If Basslink was operated independently of Hydro Tasmania, would it have an incentive to offer negative prices (excluding for technical reasons which are discussed below)?

1.2 More generally, under what situations (excluding technical reasons) would an independently operated MNSP have an incentive to offer negative prices? Should the ability of such MNSPs to offer negative prices be viewed as anti-competitive or a legitimate business decision?

1.3 If Hydro Tasmania did not receive the revenue accruing across Basslink would it have an incentive to risk driving low spot prices in Tasmania?

5.1.2 Technical issues

The proponents of this rule change request consider that there are no technical reasons why MNSPs should need to offer negative prices, unlike generators and scheduled loads. This conclusion is based on the following:[31]

- there is no reason to expect any costs incurred through the operation of Basslink to increase with a reduction in dispatch;
- it is Hydro Tasmania that decides whether BPL should offer negative prices and therefore the decision is not driven by BPL's legitimate business interests;
- amongst the three MNSPs that have operated in the NEM, negative prices have only been offered where they "are evidently to gain dispatch priority"; and
- the Tasmanian Government did not provide any technical or cost reasons for the conditions under which BPL may offer negative prices.

However, through a combination of existing market arrangements and technical reasons, if BPL was operated independently it may have an incentive to offer negative prices. This occurs because of an interaction between:

- Basslink's "no go zone";
- the co-optimisation of the energy and frequency control ancillary services (FCAS) markets; and
- Basslink's ability to transfer FCAS.

The combination of these three factors can cause "counter-price flows"; that is, where energy flows from a high price region to a low price region. When this occurs, negative residues accrue and BPL must effectively pay the market operator, unless it can bid

31 IPRA and LYMMCo, *Request for Rule Change: Scheduled Network Service Offers*, 5 December 2011, p. 8.

unavailable. While counter-price flows can occur as a result of negative bidding, in Basslink's case they can occur even where BPL's offers are zero or positive.

These effects are described below.

The "no go zone"

Basslink is unable to operate at flows of less than approximately 50 MW in either direction.[32] The other high voltage direct current (HVDC) lines constructed in the NEM employed different technology and so are not subject to the same limitation.

This limitation is referred to as Basslink's "no go zone". Reversing flows on Basslink requires transitioning through this zone. This involves moving from a minimum 50 MW flow in one direction immediately to zero, staying at zero for a two minute period, then moving to at least 50 MW in the opposite direction. During this transition, Basslink cannot transfer energy or FCAS.

Co-optimising energy and FCAS markets

In finding a dispatch solution, the NEM dispatch engine (NEMDE) must balance not only generators' energy offers, but also their offers to provide FCAS. FCAS are required to manage unpredictable changes in frequency, which occur when supply and demand are not perfectly balanced. See Box 5.1 for further explanation of FCAS.

NEMDE must search for the overall least cost solution across the energy and FCAS markets to meet both demand and frequency requirements. This may mean, for example, that a more expensive generator is dispatched in favour of a cheaper generator because it is more cost effective for the cheaper generator to provide FCAS.

Counter-price flows arising from FCAS transfer

The AEMC understands that, of the three MNSPs that have operated in the NEM, Basslink is the only one that was designed with the capability to transfer FCAS. This was seen as an important feature of Basslink to allow FCAS to be transferred between Tasmania and the rest of the NEM.

It is this capability, in combination with Basslink's no go zone and the fact that NEMDE optimises across both the energy and FCAS markets, that can lead to counter-price flows. These flows can occur despite non-negative offers by BPL, which is typically when counter-price flows would occur across MNSPs. Further, BPL (and so Hydro Tasmania) is not remunerated for transferring FCAS.

32 AEMO, *Constraint Formulation Guideline*, 6 July 2010, p. 18.

Box 5.1: Frequency control ancillary services

The Australian Energy Market Operator (AEMO) is responsible for maintaining the frequency of the network within a narrow band around 50 hertz for reasons of security and reliability.[33] The frequency may alter unpredictably due to shifts in the demand/supply balance. For example, if a generator trips it may lead to a sudden drop in frequency. Conversely, if supply is greater than demand the frequency will increase. FCAS provide AEMO with the tools to return the frequency to within the required operating band.

There are eight separate markets for the supply of services to correct the frequency. Four of these are for services to raise the frequency and the other four markets are for services to lower the frequency. The eight markets are:

- regulation raise/lower (used for small corrections of the frequency required during normal operation);
- fast raise/lower (to be activated in six seconds to halt a sudden large change in frequency);
- slow raise/lower (to be activated within sixty seconds to stabilise the frequency after a sudden change); and
- delayed raise/lower (to be activated within five minutes to restore the frequency to normal operating levels).

The process for matching supply and demand in the FCAS markets is analogous to that used to dispatch generators. Any participant may bid to supply any of the above eight services. A generator may offer a lower FCAS by offering to reduce its output if required. Alternatively a customer may offer a raise FCAS service by being willing to shed load. AEMO will determine its FCAS requirements, either globally or for a region, and procure the needed amounts in each of the eight separate markets in merit order, as determined by NEMDE.

Basslink is unable to transfer either FCAS or energy through the no go zone. Therefore as Basslink's power transfer approaches its northward or southward limit or the no go zone (for example if it is trying to reverse its flows), its ability to transfer FCAS reduces. Consequently it may be cheaper for Basslink to continue to transfer FCAS and for more expensive generation to be dispatched (causing a counter-price flow) than to reverse the direction of the flow and lose Basslink's capability to transfer FCAS or energy for two minutes. Part of the reason this occurs is because NEMDE only solves

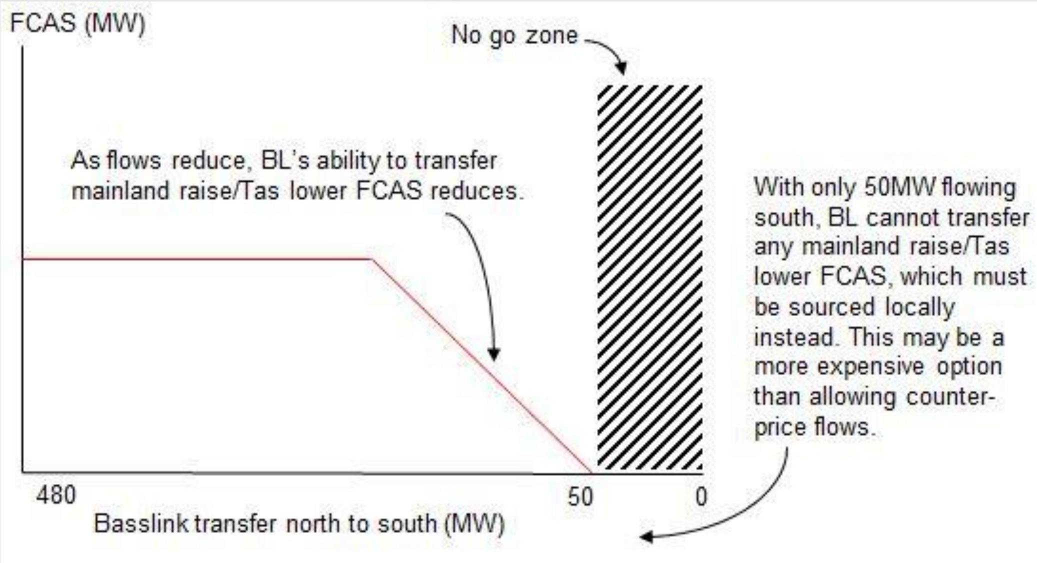
33 The Reliability Panel sets mainland and Tasmanian frequency and operating standards. See www.aemc.gov.au under Reliability Panel.

the market for the next five minute dispatch interval and so it cannot take into account any benefits that may materialise in later intervals from reversing the flow.[34]

Box 5.2: Counter-price flows on Basslink

As Basslink power transfer approaches its northward flow limit of 610 MW or the southward 50 MW no go zone (pictured below), the amount of FCAS lower services to Tasmania or FCAS raise services to the mainland that can be transferred reduces.

Figure 5.1



Conversely, as Basslink power transfer approaches its southward flow limit of 480 MW or the northward 50 MW no go zone, the amount of FCAS raise services to Tasmania or lower services to the mainland that can be transferred reduces.

When Basslink attempts to reverse its flow it approaches the no go zone where it cannot operate. Consequently the transfer of FCAS is restricted and the FCAS price increases. This causes two counteracting cost pressures:

- downward cost pressure from the FCAS market, which attempts to move the flow across Basslink *back away* from the no go zone; and
- the price difference in the energy market causes a cost pressure on the flow across Basslink to move *through* the no go zone.

These counteracting cost pressures can lead to an equilibrium with counter-price flows on Basslink, depending on the relative costs of balancing the FCAS and energy markets.

34 We note that AEMO introduced a "second solve" in dispatch that is intended to reduce (although not solve) the problem of negative residues accruing on Basslink. See NEMMCO, *Review of Intervention Pricing Methodology - Final Determination*, 6 December 2007.

Permitting Basslink to offer negative prices may assist in reducing the instances and/or duration of counter-price flows. This is because negative offers from BPL would effectively make it more expensive for Basslink to continue to transfer FCAS, relative to transferring lower-cost energy.

Question 2 Are there any technical reasons why BPL - or any other MNSP - should be able to offer negative prices?

2.1 Should BPL continue to be able to offer negative prices so as to (1) reverse flows more quickly; and/or (2) reduce the instances and/or duration of counter-price flows?

2.2 Is there a more efficient way to manage counter-price flows than through negative pricing?

2.3 Are there any other technical reasons why MNSPs should be able to offer negative prices?

5.2 Achieving productive efficiency

Whether this rule change will lead to efficiency gains, rather than simply wealth transfers between Hydro Tasmania and the Latrobe Valley generators, will depend on the relative costs of the plant competing for dispatch. To achieve productive efficiency requires that the lowest cost generators are dispatched before higher cost generators, subject to network constraints and FCAS requirements.

While it is possible to broadly approximate the short run marginal cost (SRMC) of the predominantly coal-fired generation in the Latrobe Valley, it is more difficult to establish the SRMC of hydro plant. This is because the SRMC of hydro is more variable as it depends on the opportunity cost of using water to generate electricity on a particular day. On some days this might be lower than the SRMC of coal-fired generation but on others, particularly in times of drought, it could be much higher.

Generally the existing regional market model for the NEM facilitates efficient outcomes. In the absence of network constraints, generators have an incentive to make broadly cost-reflective offers. This allows the dispatch engine to identify the optimal dispatch solution and so achieve productive efficiency without having to know the costs associated with each type of plant.

However, where congestion occurs and constraints start to bind this model begins to break down. Generators behind a constraint can offer non-cost reflective prices, knowing that the spot price in their region will be set by a generator on the other side of the constraint. Tied bids are pro-rated according to capacity made available. Therefore all generators have an incentive to offer energy at the price floor so as to maximise their dispatch. Where this occurs the dispatch engine cannot distinguish between higher and lower cost plant and inefficient dispatch can occur. It is under these circumstances that the problem identified by the proponents occurs.

If generators were exposed to the cost of congestion then they would have an incentive to make more cost reflective offers. This is because they would risk receiving a price closer to their offer.

Exposing generators to congestion costs may provide a more efficient, market based alternative to restricting MNSPs' offers. However, it is unlikely to be a proportional response to the identified problem. Implementing a congestion price would have market-wide impacts and broader implications than simply preventing some generators from being able to effectively offer less than the price floor. Further, the relative merits of introducing a congestion pricing mechanism are currently being considered as part of the AEMC's Transmission Frameworks Review.[35] Nevertheless, the AEMC is interested in stakeholder views on whether providing incentives for generators to make more cost-reflective offers when constraints bind would resolve the identified problem.

5.3 Impact of losses

There is a possibility that the proposed solution may not solve the problem identified by the proponents because of the way losses are treated.

The table below sets out three scenarios that vary the spot price in Tasmania (RRP_T)[36] and BPL's offer. It also shows the effective price of Hydro Tasmania's energy at the Victorian RRN (RRN_V), taking into account losses and assuming a flow across Basslink of 600 MW from Tasmania to Victoria (see Box 5.3 for an explanation of how these prices are calculated). This allows Hydro Tasmania's offer to be compared directly with those of the Latrobe Valley generators at the Victorian RRN.[37]

Scenario	1	2	3
RRP_T	$1,000	-$1,000	-$1,000
Basslink offer	$0	-$1,000	$0
Price of Tas energy at RRN_V	$1,158	-$2,190	-$1,158

Scenario 1 shows that with a positive spot price in Tasmania and a BPL offer of zero, Hydro Tasmania's energy will be more expensive in Victoria. This is because of energy losses that occur when Hydro Tasmania's energy is transported across Basslink into Victoria. Consequently Latrobe Valley generators will be dispatched in favour of Hydro Tasmania where all generators offer the same (positive) price.

35 See AEMC 2011, *Transmission Frameworks Review: First Interim Report*, November 2011, Sydney.

36 Note that these scenarios assume that Hydro Tasmania is the marginal generator in Tasmania and so sets the spot price.

37 Note that the Latrobe Valley generators' offers are also adjusted for intra-regional losses. It is in this adjusted form that they must meet the price floor.

Scenario 2 shows the problem that the rule change is intended to address, whereby Hydro Tasmania can effectively undercut Latrobe Valley generators where both Hydro Tasmania and BPL offer negative prices. This is because Hydro Tasmania and BPL's offers are essentially additive.

Scenario 3 shows why the proposed solution may not resolve the problem that was identified by the proponents. Where Hydro Tasmania offers a negative price it is essentially offering to pay the market for the energy it produces. Similarly, Hydro Tasmania would also effectively be offering to pay for the losses incurred in transporting energy to Victoria. Therefore although Hydro Tasmania's offers are limited by the price floor, generation from Tasmania actually appears to be cheaper since Hydro Tasmania - instead of the market - is paying for losses.

Box 5.3: How losses across Basslink are calculated

Applying loss factors to Basslink involves three stages.[38]

First, there is an intra-regional loss factor that applies to energy purchased at the Tasmanian RRN. However, since Basslink connects to the Tasmanian RRN, this loss factor is 1.

Second, a dynamic loss factor applies across Basslink. This loss factor depends on the technical characteristics of Basslink and the power flow (P), and is calculated as follows, where $P_{(receiving)}$ is the Basslink flow measured at the receiving end:

$$\text{Dynamic MLF} = 0.99608 + 2.0786 * 10^{-4} * P_{(receiving)}$$

Finally, for energy transported between the Loy Yang connection point and the Victorian RRN at Thomas Town, another intra-regional loss factor is applied. This is likely to be set at 0.9683 for Basslink for northward flows for the 2012/2013 financial year.[39] Note that a similar intra-regional loss factor applies to the Latrobe Valley generators.

As an example, if the spot price at the Tasmanian RRN is $1,000 and Basslink is transferring 600 MW of power north, the price of the energy at the Loy Yang connection point is $1,000 * (0.99608 + 2.0786 * 10^{-4} * 600) = $1,121. The price of Tasmanian energy at the Victorian RRN is $1,121 / 0.9682 = $1,158.

These results suggest that Hydro Tasmania may still be able to undercut Latrobe Valley generators even where BPL is restricted to offering non-negative prices. Therefore the proposed rule change may not have the desired effect.

We note that the proponents made the following comment in the rule change request:

38 See AEMO, *List of Regional Boundaries and Marginal Loss Factors for the 2011-12 Financial Year*, 7 July 2011, p. 55.

39 AEMO, *List of Regional Boundaries and Marginal Loss Factors for the 2012-13 Financial Year: Draft*, 14 March 2012, p. 36.

"Offers for scheduled network services differ from [offers from Scheduled Generators, Semi-Scheduled Generators, and Scheduled Loads] in that:

- they are not subject to a loss adjustment (instead there is an adjustment for losses in the supply/demand balances)"

Strictly the dispatch engine does factors losses across Basslink into the supply/demand balances rather than through the offer price. However, this would have the same practical effect as the discussion above.

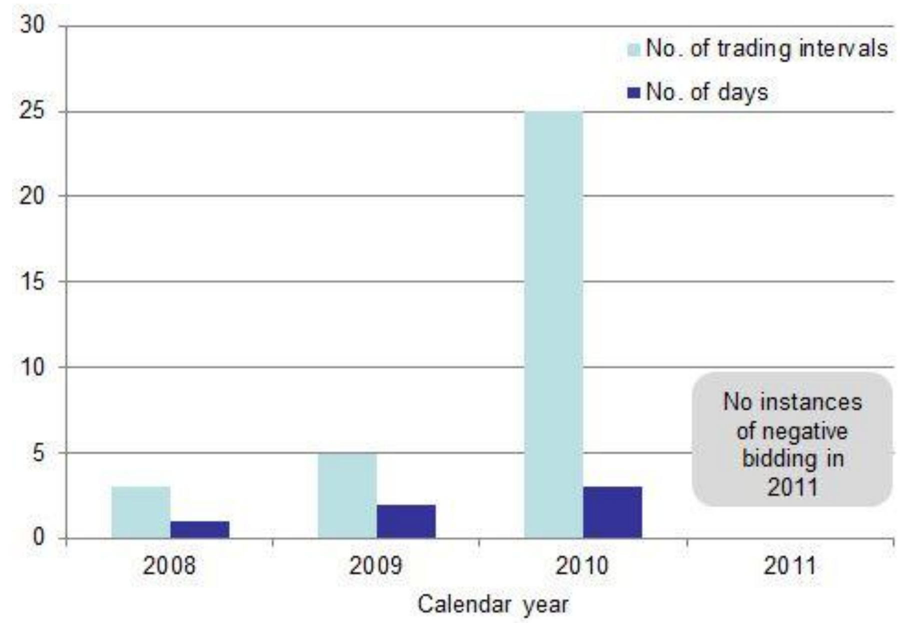
Question 3 Will the proposed solution resolve the identified problem?

3.1 Will the impact of losses mean that Hydro Tasmania would still be able to be dispatched before the Latrobe Valley generators even where BPL offers must not be negative?

5.4 Materiality

Hydro Tasmania is required to publish a report each time it instructs BPL to offer negative prices. The chart below shows the number of days and trading intervals over which negative offers have occurred since such offers were permitted in May 2008. Just considering the number of days, or even trading intervals, where negative prices are offered is unlikely to provide a good picture of the true cost of such incidents as they do not incorporate the market value to Victorian generators of not being dispatched.

Figure 5.2 Historical instances of negative bidding by BPL



In a submission to the Tasmanian Electricity Supply Industry Expert Panel, LYMMCo provided the following example to demonstrate the costs incurred by Latrobe Valley generators as a result of Hydro Tasmania's ability to undercut them:[40]

> "...during the incidents of 2 and 3 February 2010, Hydro Tasmania repriced all of its capacity to -$1,000/MWh and Basslink was rebid to -$968.20/MWh. The market operator's dispatch engine (NEMDE) commenced increasing the exports into Victoria reaching close to maximum export flow. The increased flow from Tasmania, resulted in further constraint of the output of Latrobe Valley based generators. We estimate the cost to the affected generators to be as much as $3 million over the two days."

As discussed in section 5.2 it is not clear to what extent this estimated $3 million represents a wealth transfer from Latrobe Valley generators to Hydro Tasmania as opposed to productive efficiency losses. As discussed further below, because the impacts on end-use consumers are unclear, it is difficult to determine at this stage whether the proposed rule change represents a proportional solution to the identified problem.

Question 4	**Is the proposed rule change a material response to the proposed problem?**
4.1	**How material is the identified problem?**
4.2	**Does the proposed solution represent a proportional response?**

5.5 Likely impact on market participants and end-use consumers

AEMC staff have undertaken a preliminary analysis of the likely impact of the proposed rule change on both market participants and end-use consumers. The purpose of this assessment is to help inform our consideration of whether the proposed rule is likely to contribute to the achievement of the NEO. The AEMC welcomes stakeholder views on this analysis and any further issues that the AEMC should take into account.

5.5.1 Generators in the Latrobe Valley

Generators in the Latrobe Valley are likely to benefit from this proposed rule change. As discussed, Hydro Tasmania currently has an advantage over these generators because it can effectively undercut their bids when constraints that affect the Latrobe Valley bind. Removing the ability for BPL to offer negative prices is therefore likely to improve Latrobe Valley generators' access to the Victorian RRN, particularly during periods of high prices.

40 LYMMCo, submission to the *Tasmanian Electricity Supply Industry Expert Panel Issues Paper*, 22 July 2011, p. 3.

However, as noted above, the effectiveness of the proposed rule change may be tempered by the treatment of losses. As such, Hydro Tasmania may still have an advantage compared to Latrobe Valley generators, although this may be lessened.

Question 5 What are the likely impacts on generators in the Latrobe Valley?

5.1 Are generators in the Latrobe Valley likely to benefit from this proposed rule change, taking into account the impact of losses?

5.2 Are there any other benefits or costs that are likely to affect the Latrobe Valley generators that have not been identified?

5.5.2 Generators in Tasmania

Hydro Tasmania would be likely to incur costs if this rule change was implemented. Preventing BPL from offering negative prices would reduce Hydro Tasmania's access to the Victorian market during times of constraints and so high prices. This would reduce Hydro Tasmania's ability to compete in the Victorian market and so impose an opportunity cost on Hydro Tasmania associated with lost revenue. Further, reduced flows across Basslink would result in lower revenues.

There is also a risk for Hydro Tasmania that the instances and duration of counter-price flows could increase. The reasons for this are twofold:

- First, counter-price flows resulting from the combination of Basslink's "no go zone" and its ability to transfer FCAS may be more difficult to reverse, increasing the duration of such flows.
- Second, the instances of counter-price flows could increase because generators in the Latrobe Valley may be dispatched in favour of Hydro Tasmania to meet Tasmanian load.

This second situation currently occurs across regulated interconnectors where generators in one region are constrained and so offer negative prices, while generators in a neighbouring region are unable to compete because they risk setting their own spot price at a negative amount. Consequently generators in the constrained region are dispatched in favour of their neighbours to meet load in the neighbouring region, causing counter-price flows.

AEMO currently limits counter-price flow across regulated interconnectors to restrict the negative inter-regional settlements residue that accrue. However, "clamping" is a market intervention that does not occur on MNSPs and so BPL would incur these costs. We note that BPL may be able to avoid these costs by bidding Basslink as unavailable.

The impact on AETV is less clear. Provided AETV has a high level of contract cover it should be insulated from any short term changes in the Tasmanian spot price (both negative and positive). In the longer term it is not clear what impact the proposed rule change would have on contract prices in Tasmania (discussed further below). Finally, as with Hydro Tasmania, AETV may risk not being dispatched to meet Tasmanian load when the Latrobe Valley generators are constrained off from their RRN and so are bidding at -$1,000/MWh.

Question 6	What are the likely impacts on generators in Tasmania?
6.1	**Is Hydro Tasmania likely to incur costs if this proposed rule change is implemented, taking into account the impact of losses? Are there any other costs or benefits that are likely to accrue to Hydro Tasmania that have not been identified?**
6.2	**On balance, what is the likely impact on AETV? Are there any other benefits or costs that are likely to affect AETV that have not been identified?**

5.5.3 Consumers in Victoria

In the short run end-use consumers in Victoria would probably not be affected if this rule change was implemented. Currently BPL is restricted to offering negative prices when constraints that affect the Latrobe Valley connection point start to bind. This implies that the marginal generator setting the Victorian spot price is on the other side of the constraint. This will not change irrespective of whether it is the Latrobe Valley generators or Hydro Tasmania that is being dispatched to meet load in Victoria. Consequently the spot price in Victoria is unlikely to change.

In the long run Victorian end-use consumers may face slightly lower prices. At the margin, generators in the Latrobe Valley would have greater certainty of access to the Victorian RRN. This may increase their ability and willingness to contract, improving liquidity in the contract market. In the long run this should result in lower contract prices.

Question 7	What are the likely impacts on Victorian end-use consumers?
7.1	**Are end-use consumers in Victoria likely to benefit from this proposed rule change?**
7.2	**Are there any other benefits or costs that are likely to affect Victorian consumers that have not been identified?**

5.5.4 Consumers in Tasmania

The effects on consumers in Tasmania are less clear. If Hydro Tasmania's access to the Victorian market is reduced there may be fewer instances of negative spot prices in Tasmania. In the short run, this could imply higher average spot prices in Tasmania to compensate for the loss in revenue associated with reduced access to Victoria. This would be consistent with expected outcomes in a competitive market where businesses earn a profit that is consistent with their risk adjusted rate of return. A loss in revenue would therefore imply a need to increase revenue elsewhere or else earn less than their risk adjusted rate of return.

Alternatively, if there were fewer instances of negative spot prices then generators in Tasmania would need fewer instances of higher prices to make up for lost revenue. If Hydro Tasmania was currently earning profits that exceeded a level that would be expected in a competitive market, it is unlikely that it would be profitable for it to seek to further increase average spot prices. Consequently average spot prices could remain unchanged.

In either case, in the short run changes in the spot price may have limited impact in practice due to existing contractual arrangements.

Similarly, in the long run, it is unclear whether contract prices will remain the same, or whether higher spot prices will translate into higher contract prices.

Question 8 What are the likely impacts on Tasmanian end-use consumers?

8.1 Are end-use consumers in Tasmania likely to benefit or incur costs from this proposed rule change?

8.2 Are there any other benefits or costs that are likely to affect Tasmanian consumers that have not been identified?

6 Lodging a submission

The Commission has published a notice under section 95 of the NEL for this rule change proposal inviting written submission. Submissions are to be lodged online or by mail by **3 May 2012** in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on rule change proposals.[41] The Commission publishes all submissions on its website subject to a claim of confidentiality.

All enquiries on this project should be addressed to Elisabeth Ross on (02) 8296 7800.

6.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ["ERC0140"]. The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

6.2 Lodging a submission by mail

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Or by Fax to (02) 8296 7899.

The envelope must be clearly marked with the project reference code: ERC0140.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

41 This guideline is available on the Commission's website.

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AETV	Aurora Energy Tamar Valley
BPL	Basslink Pty Limited
BSA	Basslink Services Agreement
Commission	See AEMC
FCAS	Frequency control ancillary services
HVDC	High voltage direct current
IPRA	International Power-GDF Suez Australia
IRR or residues	Inter-regional residues
LYMMCo	Loy Yang Marketing Management Company
MNSP	Market network service provider
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National Electricity Objective
NER	National Electricity Rules
RRN	Regional reference node
SNSP	Scheduled network service provider
SRMC	Short run marginal cost