APPLICATION FOR AMENDMENTS TO THE RETAIL SUPPLY CODE

OPTIONS PAPER

September 2012

38 Cavenagh Street DARWIN NT 0800
Postal Address GPO Box 915 DARWIN NT 0801

Email: utilities.commission@nt.gov.au

Website: www.utilicom.nt.gov.au

Table of Contents

Confidentiality ii
Public access to submissions ii
Amending the Retail Supply Code 3
Introduction 3
Timeframe for consultation 4
Proposed Options to amend the Retail Supply Code 6
Credit support arrangements between a retailer and a generator 7
Credit support arrangements between a retailer and a network provider 21
Access to metering data 22
Response time to a data request 22
Minimum timeframes for processing data requests 23
Data arrangements 24
Timeframes for customer transfers 25
Timeframe to reject a customer transfer request 25
Timeframe to advise of a customer transfer date 26
Cooling off period 27
Appendix A 29

Call for submissions

Submissions are invited from interested parties concerning the issues raised in this Options Paper and any related matters.

Submissions should be directed in the first instance to:

Executive Officer
Utilities Commission
GPO Box 915
DARWIN NT 0801

Telephone: 08 8999 5480
Fax: 08 8999 6262
Email: utilities.commission@nt.gov.au

The closing date for submissions is **17 October 2012**.

Confidentiality

In the interest of transparency and to promote informed discussion, the Commission will make submissions publicly available.

Persons wishing to submit confidential information should:

- clearly identify the relevant sections of the submission that are confidential, so that the remainder of the document can be made publicly available; and
- provide a copy of the submission suitable for publication with any confidential material removed.

Confidential information is defined in section 26 of the *Utilities Commission Act* as information that could affect the competitive position of a licensed entity or other person or information that is commercially sensitive for some other reason.

Public access to submissions

Subject to the above, submissions will be made available for public inspection at the office of the Commission and on its website (www.utilicom.nt.gov.au).

To facilitate publication on the Commission's website, submissions should be provided electronically in Adobe Acrobat or Microsoft Word format by CD, DVD, or email. However, if this is not possible, submissions can be made in writing.

CHAPTER 1

Amending the Retail Supply Code

Introduction

1.1 The Utilities Commission of the Northern Territory (the Commission) is an independent statutory authority responsible for the economic regulation of the electricity supply industry, which is governed by the *Utilities Commission Act* (the Act), the *Electricity Reform Act*, the *Electricity Networks (Third Party Access) Act*, and associated legislation.

1.2 Under the Act, the Commission has the power to make codes and rules if authorised to do so under a relevant industry regulation Act or by regulations under the Act[1]. These relevant industry regulation Acts include the *Electricity Reform Act,* and the *Electricity Networks (Third Party Access) Act* among others.

1.3 On 3 August 2011, the Commission made an Electricity Retail Supply Code (the Code) in accordance with the Act.[2] The Code prescribes matters relating to arrangements:

- between electricity businesses for the transfer of customers between retailers;
- between generators and retailers including credit support and billing;
- between electricity businesses for business-to-business interaction;
- for a retailer of last resort; and
- for dispute resolution between electricity businesses.[3]

1.4 On 15 May 2012, QEnergy Limited (QEnergy) made an application to the Commission to amend parts of the Code.[4] QEnergy expressed a number of concerns relating to credit support requirements between generators and retailers, access to metering data, and customer transfers arrangements governed by the Code.

1.5 On 10 July 2012, the Commission released a Consultation Paper on QEnergy's proposed amendments. The Consultation Paper invited submissions from interested parties and industry participants by 17 August 2012.

1.6 The Commission received submissions from QEnergy, Power and Water Corporation (PWC) and the Northern Territory Major Energy Users Group (NTMEU). Public versions of these submissions are available on the Commission's website: (www.utilicom.nt.gov.au).

---

1 Section 24, *Utilities Commission Act*.
2 Ibid.
3 Utilities Commission, Electricity Retail Supply Code Consultation Paper, July 2011, page 1.
4 An electricity entity may make a request for the Commission to vary or revoke parts of the Code under clause 2.2.1 of the Retail Supply Code.

Timeframe for consultation

1.7 In the Consultation Paper, the Commission outlined a proposed timeframe for considering QEnergy’s amendment application. The timeline included:

- consultation on the Commission’s Draft Decision on whether or not to amend the Code by 2 October 2012; and
- release of the Commission’s Final Decision to amend the Code (including the issuing of an amended Code) by 30 November 2012.

1.8 The Commission notes that further amendments were proposed by QEnergy in a supplementary application. It is also noted that PWC has proposed additional amendments to the Code in its submission to the Consultation Paper.

1.9 Given the importance of the arrangements in the Code and the potential impact on industry participants and consumers, the Commission considers that good regulatory practice requires the Commission to consult on a range of potential options prior to formulating its Draft Decision on whether or not to proceed to amend the Code (and if so, in what form). These potential options (outlined in this paper) were not initially proposed by QEnergy in its amendment application.

1.10 Despite adding a supplementary step in considering QEnergy’s amendment application, the Commission will endeavour to finalise its Draft Decision and Final Decision on whether or not to amend the Code, as much as possible by the timeframes set out in the Consultation Paper.

1.11 The Commission invites submissions on this Options Paper by close of business 17 October 2012.

1.12 The Commission intends to release its Draft Decision on whether or not to amend the Code by 15 November 2012. The Commission will endeavour to release its Final Decision to amend the Code by 14 December 2012. The timeframe for consultation is outlined in Table 1.1.

Table 1.1: Timeframe for consultation

Action	Timeframe
Release of Consultation Paper on QEnergy’s application to amend the Code	6 July 2012
Submissions due	17 August 2012
Commission releases Options Paper on proposed options for amendments to the Code	28 September 2012
Comments due on Options Paper	17 October 2012
Commission issues Draft Decision on whether or not to amend the Code	15 November 2012
Comments due on Draft Decision	30 November 2012
Final Decision to amend the Retail Supply Code, including the issuing of a varied Retail Supply Code (if required).	14 December 2012

Purpose of this paper

1.13 The purpose of this Options Paper is to invite submissions and seek comments from industry participants and stakeholders on the potential options identified by the Commission and whether or not these options adequately address the concerns raised by interested parties and industry participants in the Territory's electricity supply industry.

1.14 In considering the potential options, the Commission has had regard to the need to:

- promote competitive and fair market conduct;
- prevent misuse of monopoly or market power;
- facilitate entry into relevant markets;
- promote economic efficiency;
- ensure consumers benefit from competition and efficiency;
- protect the interests of consumers with respect to reliability and quality of services and supply in regulated industries;
- facilitate maintenance of the financial viability of regulated industries; and
- ensure an appropriate rate of return on regulated infrastructure assets.[5]

1.15 The Commission has also considered regulatory arrangements in the National Electricity Market (NEM) and sought advice from the Australian Energy Market Operator (AEMO) on the operation of these arrangements.

1.16 It should be noted that the Commission has not made a formal decision on QEnergy's proposed amendments in its application. Consultation on this Options Paper will assist the Commission in making its Draft Decision on whether or not to amend the Code (and if so, in what form).

1.17 Where possible, the Commission has provided an indication of the options that it considers to be more viable in the Territory's electricity supply industry. These views should not to be taken as the Commission's Draft Decision on whether or not to amend the Code. The Commission intends to consider all matters raised in the submissions.

1.18 Chapter 2 outlines potential options as well as accompanying information to assist interested parties in being informed of the reasoning behind these potential options.

1.19 This Options Paper should be read in conjunction with the Consultation Paper (released 10 July 2012), any submissions made in response to that Consultation Paper and the Code (released 3 August 2011). These documents are available on the Commission's website (www.utilicom.nt.gov.au) or by contacting the Commission's Office by telephone on 08 8999 5480, fax on 08 8999 6262, or email at utilities.commission@nt.gov.au.

5 Section 5 (2), *Utilities Commission Act*.

CHAPTER 2

Proposed Options to amend the Retail Supply Code

Summary

2.1 The Code provides an overall framework, together with appropriate mechanisms, to facilitate retail competition in the Territory's electricity supply industry. This is achieved through prescribing a coordinated package of processes and procedures for retail supply activities. In doing so, the Code aims to strike an appropriate balance between the needs of consumers and electricity entities and the protection of the Territory electricity market. Matters prescribed in the Code include arrangements:

- between electricity businesses for the transfer of customers between retailers;
- between generators and retailers including credit support and billing;
- between electricity businesses for business to business interaction;
- for a retailer of last resort; and
- for dispute resolution between electricity businesses.

2.2 The development of the Code was influenced by similar regulatory arrangements in other Australian jurisdictions.

2.3 The Territory market is dominated by one vertically integrated government-owned corporation, PWC. PWC business units (PWC Generation, PWC Network and PWC Retail) have substantial market power in each respective supply chain of the electricity supply industry.

2.4 PWC's vertical integration is seen as a major concern to some interested parties, such as QEnergy and the NTMEU. Despite the removal of legal barriers to full retail contestability[6], interested parties continue to express doubts over whether consumers will see the full benefits of retail contestability as demonstrated in the NEM.

2.5 Regulatory arrangements in the Code may assist in promoting a level playing field among competitors, while lifting barriers of entry to facilitate full retail contestability. However, the Commission is mindful of providing inappropriate market signals that encourage activities that are detrimental to the market and its continued stability.

2.6 For example, a credit support regime should encourage retailers' to appropriately manage risk as well as factoring in all of the potential costs in making business decisions, including any impact on third-party market participants. A credit support regime should be robust enough to actively discourage retailers from adopting inferior

6 The Territory adopted a staged approach to contestability. All large customers (depending on their consumption level) were able to choose their retailer from between 1 April 2000 to April 2002. Small businesses and household customers (that is consuming less than 750 megawatt hours of electricity each year) became contestable from 1 April 2010.

and inefficient business strategies, which are detrimental to generators and the market as a whole.[7]

2.7 This needs to be balanced with the need to promote appropriate risk management on behalf of generators. This is important in the Territory context, given PWC Generation's dominance in the generation market and PWC Retail's dominance in the retail electricity market.

2.8 An overly stringent credit support regime may not provide any incentives on PWC Generation to appropriately manage risk in a commercially sound manner, but instead provide a mechanism for PWC Generation to request credit support from a competitive retailer, to the commercial advantage (or perceived commercial advantage) of its related party, PWC Retail.

2.9 The Act requires the Commission to ensure that the Code remains relevant and effective.[8] To ensure that the Commission responds appropriately to the issues, the Commission has considered a number of options, which could address the concerns raised by QEnergy.

2.10 This chapter is structured as follows:

- the Code's existing arrangements are outlined;
- views in submissions are outlined, including QEnergy's initial and supplementary application for amendments to the Code and PWC's proposed amendments; and
- various options considered by the Commission are outlined in response to the views in submissions.

Credit support arrangements between a retailer and a generator

Existing arrangements

2.11 Credit support requirements between a generator and a retailer are contained in clause 3.2 of the Code. The Code:

- prevents a generator from requiring credit support from a retailer that either has an 'acceptable credit rating' (or its parent company has an acceptable credit rating) or is a fully owned subsidiary of the Australian Federal Government, or an Australian state or territory government;[9] and
- allows a generator to require credit support from a retailer up to the 'required generation credit support amount' calculated under the Code but only in instances where the retailer does not have an 'acceptable credit rating' or is not a fully owned subsidiary of the Australian Federal Government, or an Australian state or territory government.[10]

2.12 The Code defines 'acceptable credit rating' as a credit rating of BBB+ (or its equivalent) or higher from Standard and Poor's, Fitch Ratings or Moody's Investor Services.[11]

7 Competition Economists Group, 'Assessing efficiency in settlement and prudential arrangements for energy markets; A report for AEMO', January 2010.
8 Section 24 (9), *Utilities Commission Act*.
9 Clause 3.2.2 (a), Retail Supply Code.
10 Ibid, Clause 3.2.2 (b).
11 Ibid, Schedule 1.

2.13 If a generator requires credit support from a retailer, the 'required generation credit support amount' is the greater of:

- two times the retailer's reasonable forecast of its highest generation services bill (ie the billing period) over the following 12 months (of which the forecast must be updated half yearly); or
- two times the generator's record of the highest generation services bill issued to the retailers by the generator over the previous 12 months (which will be updated half yearly).[12]

2.14 The time period covered by the highest generation services bill must not exceed one month for the purpose of calculating the 'required generation credit support amount'.[13]

2.15 Therefore, the maximum time period covered by the credit support amount (the credit support duration) is 56 days (assuming the maximum monthly (or 28-day) billing period, multiplied by two).

2.16 The required generation credit support mechanism defined in the Code enables a generator to calculate the maximum amount it may require from a retailer.[14] Retailers and generators can negotiate and agree on alternative credit support arrangements.

2.17 The Code prescribes a form of credit support that may be any combination of:

- a bank guarantee that is unconditional and callable on demand and is issued by a financial institution supervised by the Australian Prudential Regulation Authority;
- an unconditional guarantee or other form of irrevocable credit support that is in a form that is acceptable to the generator (or network provider) at its sole discretion and is issued by an entity with an acceptable credit rating; or
- such other forms of credit that the parties consider to be acceptable.[15]

Views in submissions

QEnergy's proposed amendment

2.18 QEnergy's proposed amendment is to reduce the maximum 'required generation credit support amount' payable by a retailer to a generator from two months (ie two times) to two weeks (ie 0.5 times) of generation charges (or the retailer's reasonable forecasts of generation charges).

2.19 QEnergy claims that it is unable to compete on a level playing field, given PWC's dominant market position as a provider of generation services. QEnergy claims that PWC Generation will always require the maximum 'required generation credit support amount' and has been unwilling to negotiate terms below this upper limit. QEnergy also suggests that, as PWC Retail is not required to provide credit support to generators, the arrangements in the Code impose additional financial cost on QEnergy's business (which are not imposed on PWC Retail), and place it at a competitive disadvantage in the retail electricity market.

12 Ibid, Clause 3.2.2 (b).
13 Ibid.
14 Ibid, Clause 3.2.1.
15 Ibid, Clause 3.4.1.

2.20 QEnergy also claims that PWC has not been willing to consider any other way of mitigating risk to its business, including:

- more flexible forms of credit support from a retailer, such as a trust account; and
- shorter settlement periods (such as billing periods shorter than one month), which will reduce the 'required generation credit support amount' calculated under the Code.

QEnergy's proposed amendment in its supplementary application

2.21 As noted above, the Code currently states that the form of irrevocable credit support is to be determined at the sole discretion of the generator (or network provider).

2.22 QEnergy claims that this provides PWC with substantial power to determine the form of irrevocable credit support and proposes that the form of irrevocable credit support should be acceptable to the Commission at its sole discretion.

PWC's submission

2.23 PWC opposes QEnergy's proposed amendments to reduce the maximum 'required generation credit support amount', stating that its credit processes and systems are structured around monthly billing cycles. PWC considers that the maximum 'required generation credit support amount' payable by a retailer to a generator should remain at two months (two times) of generation charges or the retailer's reasonable forecasts of generation charges given that:

- six weeks of trading would have passed on the occurrence of a retailer of last resort (RoLR) event;
- two weeks of credit support would not cover the payments outstanding on the occurrence of a RoLR event; and
- QEnergy's proposed amendment would transfer considerable risk to PWC.

2.24 PWC opposes QEnergy's proposed amendments regarding the form of irrevocable credit support and considers that it is industry practice for management of commercial risk to lie with the business rather than the regulator.

NTMEU's submissions

2.25 The NTMEU consider PWC to have a unique position to limit entry of competitive retailers into the market by applying credit support requirements on new retailers. This results in increased costs to competitive retailers, which are not incurred by PWC Retail.

Option A: Proposed options regarding credit support amounts

2.26 From the submissions, there appears to be concerns around:

- credit support arrangements failing to facilitate negotiation between the parties and respond to the difficulties of negotiating in the Territory market;
- credit support arrangements being used (or perceived to be used) as an instrument to maintain barriers of entry and limit retail competition; and
- the need to maintain the financial integrity of the Territory market and prevent the transfer of undue risk to generators.

2.27 The Commission has also identified that the credit support duration for calculating the maximum 'required generation credit support amount' may lack clarity.

2.28 The following options have been identified by the Commission as potential approaches to addressing the concerns raised by industry participants. The Commission invites comments on all of the proposed options.

Option A1: Reducing the credit support amount to 0.5 times of generation services charge

2.29 QEnergy proposes a reduction of the maximum 'required generation credit support amount' payable by a retailer to a generator from two months (two times) to two weeks (0.5 times) of generation charges (or the retailer's reasonable forecasts of generation charges).

2.30 PWC advises that the Code should remain at two times the generation services charge to account for six weeks of trading that would have passed on the occurrence of a RoLR event.

2.31 As noted above, the maximum credit support duration is up to 56 days. It is noted that a 56-day credit support duration accounts for a 28-day billing period, 14-day payment period, and a 14-day allowance for the activation of RoLR procedures (reactive period). This results in credit support that covers the payments outstanding up to the transfer of customer load from a defaulted retailer to the RoLR, assuming the maximum billing period of one month or 28 days. The Commission considers this to be the worst-case scenario of a non-payment event by a retailer.

2.32 The Commission is inclined to consider that QEnergy's proposed amendment to two weeks (0.5 times) credit support payable is insufficient to cover for the transfer of customer load from the defaulted retailer to the RoLR and will always result in a shortfall of credit support to the generator to cover a RoLR event (assuming a monthly or 28-day billing period). The Commission's view is that this will adversely impact on the market and its continued stability and may transfer undue risk from retailers to the generators (example provided in Example 1).

Example 1

PWC Generation bills on a monthly or 28-day billing period. If QEnergy's amendment is accepted, the Code would specify that the maximum 'required generation credit support amount' be 0.5 times the generation services charge or the retailer's reasonable forecasts of generation charges. In this case, the credit support duration is 14 days (the generation services bill based on a 28-day billing period multiplied by 0.5).

Assuming that it takes 14 days for a retailer to pay PWC Generation (the payment period) and 14 days for the reactive period, the credit support duration should be 56 days (28-day billing period, 14-day payment period, and a 14-day allowance for the reactive period).

QEnergy's proposed amendment will result in a shortfall of credit support to a generator of up to 42 days worth of trading.

2.33 QEnergy's proposed amendment may also result in such a shortfall of credit support to generators that there may be no incentive for retailers to engage in effective negotiation with the generator.

2.34 Given bilateral contractual relationships in the Territory market, the Code could focus on improving the negotiation framework and providing additional incentives on the parties to engage in effective negotiation and manage risk in a commercially sound manner.

2.35 Option A2 intends to clarify the credit support duration by ensuring that the maximum 'required generation credit support amount' covers payments outstanding up until the transfer of customer load from the defaulted retailer to the RoLR in response to changes in the billing or payment period, as agreed between the parties. Option A3 intends to ensure that there is a fixed allowance for the reactive period, regardless of any changes to the billing or payment period. These options, together with Options A4 to A7, intend to facilitate negotiation of the billing period, payment period and alternative forms of credit support, as agreed through honest, fair and good faith negotiations between the parties. This may promote a level playing field among industry participants in the Territory's electricity supply industry.

2.36 The Commission is inclined to consider a combination of the options below, as they may serve as an appropriate alternative to QEnergy's proposed amendment.

Option A2: Defining the credit support duration

2.37 As noted above, the maximum credit support duration is up to 56 days. It is noted that a 56-day credit support duration accounts for a 28-day billing period, 14-day payment period, and a 14-day allowance for the reactive period. This results in credit support that covers the payments outstanding up to the transfer of customer load from a defaulted retailer to the RoLR, assuming the maximum billing period of one month (or 28 days). The Commission considers this to be the worst-case scenario of a non-payment event by a retailer.

2.38 At the time of developing the Code, the Commission considered that a maximum 'required generation credit support amount' calculated on a 56-day credit support duration (combined with the potential to negotiate alternative credit support arrangements), would protect the credit worthiness of the market while striking an appropriate balance between safeguarding the interests of generators and the need to support retail competition.

2.39 However, it is noted that the credit support duration is not specifically defined in the Code. It is also noted that the maximum 'required generation credit support amount' is calculated using a formula that does not specify the billing or payment period and does not contain a specific allowance for the reactive period.

2.40 This can result in instances where the maximum amount of credit support falls short of covering the payments outstanding up to the transfer of customer load to the RoLR (example provided in Example 2).

Example 2

A retailer and a generator may wish to negotiate a 14-day billing period with a 14-day payment period. Because of the formula in the Code, the maximum 'required generation credit support amount' would be calculated on a 28-day credit support duration (the generation services bill based on a 14-day billing period, multiplied by two).

However, in this case, the maximum 'required generation credit support amount' should be calculated on a 42-day credit support duration, which would account for a 14-day billing period, 14-day payment period, and a 14-day allowance for the reactive period.

2.41 The above example highlights the potential risk of shortfall that arises out of negotiating shorter billing or payment periods while using the current formula for calculating the maximum 'required generation credit support amount' in the Code. This risk of shortfall may be a key consideration for generators in deciding whether to accept shorter billing or payment periods and may actually hinder effective negotiation of shorter billing or payment periods between the parties.

2.42 It is noted that AEMO defines a credit support duration of either 42 days or 28 days (for calculating the 'maximum credit amount' or the 'reduced maximum credit amount'), which consists of:

- seven-day billing period[16];
- 28-day or 14-day payment period[17]; and
- seven-day reactive period (an allowance for the enforcement of RoLR procedures).[18]

2.43 By defining the credit support duration in the Code, consistent with AEMO guidelines, the maximum 'required generation credit support amount' could be calculated by multiplying the amount charged in the generation services bill (or the retailer's reasonable forecast thereof) by the quotient of the credit support duration divided by billing period of that generation services bill. Examples of the application of this methodology are provided in Example 3 and 4.

Example 3:

ABC Generation will issue a generation services bill with a billing period of 14 days to XYZ Retail with payment to be made 14 days after the bill is issued (and as agreed with the retailer). Regulatory arrangements specify a 14-day timeframe for the transfer of customer load to the RoLR. This results in a credit support duration of 42 days, which consists of the negotiated 14-day billing period, 14-day payment period as well as a 14-day allowance for the transfer of customer load to the RoLR.

The credit support duration of 42 days is divided by the billing period of 14 days, which is three. Therefore, the Required Generation Credit Support Amount is three times the highest generation services bill (based on a 14-day billing period) or the retailer's reasonable forecast thereof.

Example 4:

ABC Generation will issue a generation services bill with a billing period of 28 days to XYZ Retail with payment to be made 7 days after the bill is issued (and as agreed with the retailer). Regulatory arrangements specify a 14-day timeframe for the transfer of customer load to the RoLR. This results in a credit support duration of 49 days, which consists of the negotiated 28-day billing period, 7-day payment period as well as a 14-day allowance for the transfer of customer load to the RoLR.

The credit support duration of 49 days is divided by the billing period of 28 days, which is 1.75. Therefore, the Required Generation Credit Support Amount is 1.75 times the highest generation services bill or the retailer's reasonable forecast thereof.

16 The billing period is the period in the generation services bill, which represents the period in which electricity is consumed by the retailer.

17 The payment period is the period in which payment is due for a generation services bill.

18 AEMO Credit Limit Methodology, May 2012, page 11.

2.44 The Commission is inclined to consider this approach as it would ensure that the maximum ‘required generation credit support amount’ covers the payments outstanding up to the transfer of customer load to the RoLR, regardless of the billing or payment period (as negotiated between the parties). This removes any disincentives on generators to completely disregard shorter billing or payment periods on account of the regulatory arrangements in the Code. This approach would also provide greater clarity in the calculation of credit support and would facilitate flexible negotiation of billing and payment periods between the parties.

2.45 Appendix A contains potential changes to the Code.

Option A3: Defining the reactive period

2.46 The above option (Option A2) proposes to define the credit support duration in reference to various time periods, including a 14-day allowance for the reactive period, which may be set ‘as otherwise determined by the Commission’. In comparison, AEMO provides a 7-day allowance for the reactive period, which generally aligns with the timeframes set out in AEMO RoLR procedures.

2.47 A 14-day allowance for the reactive period is due to RoLR arrangements in the Code not being fully developed or tested to the same extent of similar arrangements in the NEM. In particular, the Code does not specify a clear timeframe for the transfer of customer load to the RoLR. However, there may be potential to further develop RoLR arrangements in the Code.

2.48 The Commission recognises that RoLR arrangements require specific, well-defined and achievable timeframes for the effective transfer of customer load to the RoLR. Fully formed RoLR arrangements may be set out in a number of ways, including guidelines under the Code.

2.49 As RoLR arrangements become more developed, there may be potential for a reduction of the 14-day allowance for the reactive period, which would reduce the maximum ‘required generation credit support amount’. To account for this, the Code could empower the Commission to determine an allowance for the reactive period that is other than 14 days. It is recognised that a 14-day allowance for the reactive period may be appropriate in the circumstances, at least until such time as the RoLR procedures in the Code are fully developed and tested.

Option A4: Framework for negotiation of retailer-generator credit support arrangements

2.50 As previously noted, the Code allows parties to negotiate alternative credit support arrangements below the maximum ‘required generation credit support amount’. Alternative arrangements may also include other forms of credit support as a replacement (or a partial replacement) to a bank guarantee.

2.51 The default level of credit support is set in the event that negotiations below this maximum have failed. In developing the Code, the Commission was influenced by bilateral contractual arrangements (reallocation agreements) between retailers and generators that seek to reduce exposure to NEM pooling arrangements.

2.52 There are particular characteristics in the Territory electricity supply industry that may make proper negotiation difficult to achieve. This is attributable to the absence of competitive forces in the market and the dominance of a government-owned corporation with a vertically integrated monopoly. In contrast, the NEM is a more contestable marketplace, with lower barriers to entry and a variety of market participants.

2.53 Some industry participants have expressed the view that the Code merely allows negotiation between parties with unequal (actual or perceived) bargaining positions. To address this, the Code's negotiation framework may need to be improved in order to provide a level playing field for all parties in the negotiation process (at least until such time as the market achieves the same level of contestability as demonstrated in the NEM).

2.54 The Code could be amended to incorporate a more robust negotiation framework, which would set high-level principles that govern the conduct of negotiation between the parties, to reflect honest, fair, and good faith negotiations. This would address the unequal (actual or perceived) bargaining positions between emerging retailers and the incumbent. This can be achieved without imposing a particular outcome on the parties. The parties would still be permitted to negotiate below the maximum 'required generation credit support amount' (including alternative forms of credit support).

2.55 The Code's negotiation framework could be improved by codifying the following negotiation principles in relation to credit support arrangements for the provision of generation services[19]:

- the generator and retailer must negotiate honestly, fairly and in good faith, terms and conditions relating to credit support;
- the generator must provide all information as the retailer may reasonable require to enable the retailer to engage in effective negotiation with the generator in relation to credit support;
- the generator must identify and inform the retailer of the reasonable costs and/or increase or decrease in costs (as appropriate) of considering alternative credit support arrangements including:
    - lowering or increasing the billing period or payment period (whichever is applicable); and
    - (on request of the retailer) alternative forms of credit support other than a bank guarantee, including but not limited to:
        - shareholder or parent guarantee (conditional or unconditional);
        - third party guarantee (conditional or unconditional);
        - cash deposit;
        - security bond;
        - security interest;
        - an insurance-related product (eg trade credit insurance); or
        - a hybrid product, which may include a bank guarantee and a combination of any of the above (whichever is applicable);
- the generator must commence, progress and finalise (whichever is applicable) negotiation of credit support arrangements on a best endeavours basis.

2.56 Considering the negotiation principles outlined above, the generator could be required to submit to the Commission for approval, a negotiating framework detailing the

19 For an example of a negotiation framework, see ElectraNet Negotiation Framework < http://www.electranet.com.au/assets/Uploads/negotiatingframework.pdf>

generator's approach to negotiation of credit support arrangements and demonstrating its compliance with the negotiation principles.

2.57 This proposed option is similar to the negotiation framework for access of transmission network services in the NEM.[20] A similar negotiation framework for access to network services also exists under the *Electricity Networks (Third Party Access) Act*.[21]

Option A5: Scaling down the required generation credit support amount

2.58 As previously mentioned, retailer-generator credit support arrangements in the Code were originally based on bilateral contractual arrangements in the NEM. However, it is noted that the Code permits bilateral contracting in a market that lacks competition. Given PWC's dominance in the market, the Commission notes that:

- there is less incentive for PWC Generation, with its substantial market power, to consider a competitive retailer's true risk of default as there is no commercial incentive on PWC Generation to contract with an alternative retailer);
- if PWC Generation does not (or if there is a perception that PWC Generation will not) appropriately consider a competitive retailer's true risk of default, there may be a perception of bias towards PWC Retail; and
- without appropriate regulatory responses, the Code may be perceived to ingrain PWC's dominance in the Territory market at the expense of competition. This may send market signals that regulatory arrangements in the Code are not conducive to competition.

2.59 The Commission also notes that there is a need to protect the credit worthiness of the market to ensure its continued stability (for example by ensuring that the credit support regime improves retailers' incentives to appropriately manage risk as well as to factor in all of the potential costs and impacts of its business decisions on third-party market participants).

2.60 In light of PWC Generation's dominant market position as a monopoly service provider and the need for access to generation services to facilitate full retail contestability, the Code could be amended to encourage generators to further consider a retailer's individual risk of default.

2.61 Credit ratings provide a standardised form of risk assessment. Entities with a higher credit rating are more unlikely to default on payments, while entities with a lower credit rating are more likely to default. Credit support arrangements that (in part) outsource risk assessment to rating agencies, such as Standard & Poor's, Fitch Ratings, Moody's Investor Services, and Dun & Bradstreet, are common in the NEM and other jurisdictions.[22]

2.62 Currently, the Code permits a generator to request credit support from a retailer if that retailer does not have an acceptable credit rating.[23] However, there is a risk that all retailers (other than PWC Retail) without an acceptable credit rating will be treated in

20 Clause 6A.9.5, National Electricity Rules.

21 See the Network Access Code, which is a Schedule to the *Electricity Networks (Third Party Access) Act (NT).*

22 For example, the application of the acceptable credit rating for AEMO generator-retailer credit support requirements and the scaling down of the retailer's credit allowance under NECF retailer-distributor credit support arrangements.

23 Acceptable credit rating means a credit rating of BBB+ (or its equivalent) or higher from Standard & Poors, Fitch Ratings or Moody's Investor Services.

the same way by a monopoly generation services provider. To address this, credit ratings could be used as a mechanism to scale the maximum 'required generation credit support amount', in accordance with the retailer's specific credit rating.

2.63 An example would be to scale down the maximum 'required generation credit support amount' if a retailer has a credit rating that is, for example, below the acceptable credit rating (currently set at BBB+[24]). For instance, a retailer with a BBB credit rating could have its maximum required generation credit support amount reduced by, for example, 30 per cent, while a retailer with a BBB- credit rating could receive a 15 per cent reduction.[25]

2.64 This approach would reinforce the notion that not all retailers have the same level of risk of default. It should also be noted that credit support arrangements should only cover the likelihood of default for a given level of financial risk (through commercial considerations) and should not be applied to the extent that the generator is taking advantage of its position as a monopoly service provider.

2.65 The National Electricity Customer Framework (NECF) [26] credit allowance percentage table may be used as a template (Table 2.1). The first three columns outline the credit ratings from Standard & Poor's, Fitch Ratings, Moody's Investor Services and Dun and Bradstreet. The fourth column lists the percentage of credit support reduction for each credit rating.

Table 2.1: Credit support allowance percentages

Standard & Poor's/Fitch rating	**Moody's rating**	**Dun and Bradstreet dynamic risk score**	**Credit support reduction (% reduction in the credit support)**
AAA	Aaa	N/A	100.0%
AA+, AA, AA-	Aa1, Aa2, Aa3	Minimal	100.0%
A+, A, A-	A1, A2, A3	Very Low	100.0%
BBB+	Baa1	Low	52.9%
BBB	Baa2	Average	37.5%
BBB-	Baa3	N/A	22.0%
BB+	Ba1	N/A	17.0 %
BB	Ba2	Moderate	11.0 %
BB-	Ba3	High	6.7 %
B+	B1	Very High	3.3 %
B	B2	N/A	1.4 %
B-	B3	Severe	0.9 %

24 This is the Standard & Poors and Fitch acceptable credit rating.

25 A similar proposal has been suggested to the New Zealand Electricity Authority. For more information see Settlement and Prudential Security Review Wholesale Advisory Group, 14 May 2012 < http://www.ea.govt.nz/our-work/consultations/advisory-group/settlement-prudential-security-review/>

26 National Electricity (Retail Supply) Amendment Rules 2010, Schedule 6B.1.

CCC/CC	Caa, Ca, C	N/A	0.3 %

2.66 The percentage of credit reduction in the fourth column is indicative only and is only included in this Options Paper as an example. The Commission has not formed a view as to the relevance of these figures for retailer-generator credit support arrangements. If the scaling down approach is adopted in the Code, the Commission may undertake further work and engage in further consultation with industry participants and stakeholders to determine the appropriate percentage reduction of credit for each credit rating. It is envisaged that the table may be included in guidelines made under the Code.

2.67 If generators wish to offset the risk (or perceived risk) that arises through the reduction of the maximum ‘required generation credit support amount’, they could negotiate alternative credit support arrangements, which may include shorter billing or payment periods or alternative forms of credit support, through honest, fair and good faith negotiations.

Option A6: NECF arrangements for retailer-generator credit support arrangements

2.68 The NECF is a national customer framework that harmonises consumer protection for the retail sale of electricity and gas into a single set of national laws, regulations and rules for the NEM.[27] In doing so, the NECF harmonises distributor-retailer credit support arrangements across NEM jurisdictions.

2.69 It is noted that an alternative approach to scaling down the maximum ‘required generation credit support amount’ (as discussed in Option A5 above) is to apply the NECF distributor-retailer arrangements to retailer-generation credit support arrangement in the Code.

2.70 The NECF arrangements for retailer-generation credit support would require retailers without an acceptable credit rating to provide credit support at the request of a generator, but only up to the maximum ‘required generation credit support amount’, which is determined through the following steps:

- A retailer’s initial ‘required generation credit support amount’ is calculated to cover payments outstanding up until the transfer of customer load to the RoLR.
- The retailer’s credit allowance is then calculated in two steps:
  - The maximum loss that a generator should be exposed due to a RoLR event is calculated. This can be 25 per cent of the generator’s annual generation charges, less than 25 per cent, or set through another methodology to suit generator-retailer business interactions, the nature of generation businesses, and the Territory market. [28]
  - The maximum loss is scaled down depending on the retailer’s credit rating.
- The maximum ‘required generation credit support amount’ is the amount of the initial ‘required generation credit support amount’ that exceeds the credit allowance for that retailer.

27 For more information ,see <http://www.mce.gov.au/emr/rpwg/default.html>

28 The NECF arrangements set the maximum loss that a network service provider is exposed to in the event of a RoLR at 25 per cent of the network service provider’s annual network charges. It is understood this was a policy decision set by Governments in NEM jurisdictions.

2.71 The credit allowance percentage under NECF arrangements for each credit rating is shown at Table 2.2.[29]

Table 2.2: Credit support allowance percentages

Standard & Poor's/Fitch rating	Moody's rating	Dun and Bradstreet dynamic risk score	Credit allowance (% of Maximum)
AAA	Aaa	N/A	100.0%
AA+, AA, AA-	Aa1, Aa2, Aa3	Minimal	100.0%
A+, A, A-	A1, A2, A3	Very Low	100.0%
BBB+	Baa1	Low	52.9%
BBB	Baa2	Average	37.5%
BBB-	Baa3	N/A	22.0%
BB+	Ba1	N/A	17.0%
BB	Ba2	Moderate	11.0%
BB-	Ba3	High	6.7%
B+	B1	Very High	3.3%
B	B2	N/A	1.4%
B-	B3	Severe	0.9%
CCC/CC	Caa, Ca, C	N/A	0.3

Forms of credit support

Existing arrangements:

2.72 As previously noted, clause 3.4.1 of the Code prescribes a form of credit support that may be any combination of:

- a (unconditional) bank guarantee;
- a form of unconditional guarantee (other than a bank guarantee) that is considered acceptable to the generator (or network provider) at its sole discretion; or
- such other form of credit support that is considered acceptable to the parties.

2.73 These arrangements intend to facilitate negotiation of alternative forms of credit support other than bank guarantees (as agreed between the parties through good faith negotiation).

QEnergy proposed amendment and PWC's response

2.74 As noted above, the Code currently states that the form of irrevocable credit support is to be determined at the sole discretion of the generator (or network provider).

2.75 QEnergy claims that this provides PWC with substantial power to determine the form of irrevocable credit support.

29 National Electricity (Retail Supply) Amendment Rules 2010, Schedule 6B.1.

2.76 To address this, QEnergy proposes that the form of irrevocable credit support should be acceptable to the Commission at its sole discretion.

2.77 In response, PWC states that it is industry practice for management of commercial risk to lie with the business rather than the regulator.

Commission's comments

2.78 The Commission considers that it may not be the most appropriate body to mandate forms of irrevocable credit support (other than bank guarantees). The Commission notes that the difference between an irrevocable form of credit support provided by a third party and a bank guarantee is that a bank guarantee is generally provided by an entity that is subject to Australian Prudential Regulatory Authority supervision.

2.79 The Commission is more inclined to consider the option below (Option A6). Together with Option A4 (improvements to the negotiation framework), these options intend to facilitate honest, fair and good faith negotiation regarding alternative forms of credit support as acceptable between the parties.

Option A6: Alternative forms of credit support

2.80 A common argument by monopoly service providers is that there are no alternatives to bank guarantees that would provide the same level of assurance and protection. However, the Commission notes that the costs associated with this form of credit support can be substantial, especially for small and emerging retailers. Such costs may be passed on to consumers.

2.81 Other alternatives to a bank guarantee may include, but are not limited to:

- shareholders or parent guarantee (including conditional guarantees);
- third-party guarantee (including conditional guarantees);
- cash deposit;
- security bond;
- security interest;
- an insurance-related product (for example trade credit insurance); or
- a hybrid product, which may include a bank guarantee and a combination of any of the above.

2.82 In line with Option A4 on improving the negotiation framework, the Code could be amended to ensure that the form of unconditional guarantee is determined as agreed between the parties through honest, fair and good faith negotiations and not at the sole discretion of the network provider or generator (whichever is applicable).

2.83 It is noted that cash is generally considered to be one of the safest forms of credit support. It is also noted that AEMO will accept a security deposit to secure payment of any amount which may become payable in respect to a billing period (eg so that market participants can maintain the trading margin).[30] There is also commentary to suggest that cash, as an alternative to bank guarantees, would not have an adverse impact on market stability.[31] However, relevant parties would have to be comfortable with any potential risk of clawback.[32]

---

30 Clause 3.3.8A National Electricity Rules.

31 Energy Prudential Readiness Report, Australian Energy Market Operator, April 2011, page 25.

32 Clawback involves reversing transactions in accordance with relevant bankruptcy or insolvency law. For example, payments made by a bankrupt or insolvent entity to a related party under section 139A-139H of the

2.84 The Code could be amended to permit payments by way of cash in lieu of bank guarantees and stipulate that such payments are to be “deposited into an official bank account as instructed by the network provider or generator (whichever is applicable)”.

2.85 Appendix A contains potential changes to the Code.

Treatment of government-owned corporations regarding application of the acceptable credit rating

Existing arrangements

2.86 The Code exempts both retailers with an acceptable credit rating and retailers that are a fully owned subsidiary of the Australian Federal Government, or an Australian state or territory government, from the credit support requirements under the Code.[33]

2.87 In comparison, credit support arrangements in the NEM (including the application of credit ratings) are applied equally across all market participants, regardless of the type of ownership. In cases where a market participant is required to provide an unconditional guarantee to discharge credit support obligations, the entity that provides the guarantee must have an acceptable credit rating and must be either (among other things):

- any entity under the prudential supervision of the Australian Prudential Regulatory Authority; or
- a central borrowing authority of an Australian state or territory, which has been established by an Act of Parliament of that state or territory.[34]

2.88 It is noted that government-owned corporations are exempt from the application of credit support requirements in the Code, even if they do not have an acceptable credit rating. In effect, this removes the right of competitive generators (or competitive network service providers) to request credit support from a government-owned retailer. In contrast, a privately-owned retailer may be called upon to provide credit support under the same conditions.

Option A7: Alignment of government-owned corporations with private enterprises

2.89 The Code could be amended so credit support requirements (including the application of the acceptable credit rating) are applied consistently across private and public enterprises. This would ensure that government-owned corporations are not provided with a competitive advantage in procuring services from other electricity entities.

2.90 The Commission is inclined to adopt the above option, as it understands that it is regulatory best practice to adopt regulatory arrangements that apply equally across all industry participants, regardless of Government ownership. However, the Commission recognises that the application of credit support arrangements between related parties or business units within a vertically-integrated corporation may be difficult irrespective of the ownership of the corporation (and in the absence of structural reform).

Bankruptcy Act 1966 and within a certain timeframe before the declaration of bankruptcy or insolvency may be ‘clawed back’ for the benefit of creditors.

33 Clause 3.2.2(a) of the Code.

34 Clause 3.2.2, National Electricity Rules.

Credit support arrangements between a retailer and a network provider

Existing arrangements

2.91 Credit support requirements between a network provider and a retailer are contained in clause 3.1 of the Code. The Code states that a network provider may require a retailer to provide credit support up to the 'required network credit support amount', which is calculated in accordance with the Credit Support Guidelines and Methodology in Appendix A of the Code.[35] The Credit Support Guidelines and Methodology is based on the NECF distributor-retailer credit support arrangements.

2.92 The 'required network credit support amount' is calculated in the following way:

- a credit allowance is established for each retailer;
- the average credit outstanding for that retailer is calculated; and
- the 'required network credit support amount' is the amount of the average credit outstanding that exceeds the credit allowance.

2.93 The Code details the methodology for calculating the credit allowance for a retailer.

2.94 Table 1 of Schedule 1 of the Code contains a table that lists equivalent credit ratings from Standard & Poor, Fitch Ratings, Moody's Investor Services, and Dun and Bradstreet against a credit support allowance percentage, which is used to scale down a retailer's maximum credit allowance. The Commission adopted the credit support allowance percentages table as it existed in the NECF legislation at the time the Code was developed in 2011.

Views in submissions

2.95 QEnergy has noted that the Code's credit support allowance percentages table reflects the previous version of the table under the *National Electricity (Retail Support) Amendment Rules*.

2.96 QEnergy has proposed that the Commission amend the Code to adopt the most recent version of the table.

Option B: Reference to the latest NECF credit support allowance table

2.97 The retailer-network provider credit support arrangements in the Code intend to reflect NECF arrangements. This reflects the Commission's position to adopt NEM practices wherever possible.

2.98 Given that the NECF credit support allowance percentage table may change from time to time, the Commission is inclined to amend the Code to define Table 1 of Schedule 1 of the Code in reference to guidelines issued by the Commission, or in reference to national legislation (or a combination of both).

35 Clause 3.1.1, Clause 3.1.2 of the Code

Access to metering data

Response time to a data request

Existing arrangements

2.99 Clause 6.2.9 of the Code requires a network provider to respond to a data request from a retailer within five business days. In comparison, clause 6.3.9 requires a network provider to respond to a data request from a customer within 20 business days.

QEnergy concerns and amendment proposal

2.100 QEnergy claims that PWC will not provide data to a customer or a retailer as soon as possible, leading to unnecessary time constraints on a competitive retailer. QEnergy believes that PWC Retail can access this data almost immediately and that this will enable PWC Retail to meet deadlines more aggressively. Furthermore, QEnergy believes that this data can be provided to retailers or customers within minutes.

2.101 QEnergy proposes that the timeframe within which a network provider must respond to a data request form should be one business day in all cases.

PWC's submission

2.102 PWC opposes QEnergy's proposal and considers that its existing systems are such that data requests cannot be accommodated within such a short period of time. The process includes:

- A request for data is sent to a full retail contestability (FRC) officer in the Regulation, Pricing and Economic Analysis team.
- This officer liaises with the Metering section in PWC Networks to confirm meter details.
- The FRC officer confirms receipt of the request and informs the retailer on costs to provide the data.
- Once the Metering section has prepared the data, the FRC officer forwards the data to the retailer.

2.103 PWC states that arrangements in the NEM are significantly different to PWC's manual processes for the provision of data to retailers and customers. For example, standing data in the NEM is populated and stored in MSATS (Market Settlement and Transfer System), a centralised system managed by AEMO. In comparison, PWC collects and stores the metering data itself and supplies it on request. Therefore, there is no automated process to enable access to data instantaneously.

2.104 In terms of provision of data to customers, PWC considers that customers may require markedly different data, depending on the customer's individual needs (for example for energy saving measures and energy consultants). In comparison, retailers have more knowledge and experience in the market (for example to request the correct type of data required). PWC considers that 20 business days is fair and reasonable considering the volume and nature of customer data requests.

Option C: Reducing the timeframe for provision of metering data to retailers and customers

Option C1: Align timeframes to respond to data requests

2.105 As noted above, a network provider is required to respond to a data request from a customer within 20 business days. In comparison, a network provider is required to respond to a data request from a retailer within five business days.

2.106 The Commission notes that timing is important for the provision of data to retailers, as this data may be used for negotiation and to sign on additional customers. However, this data could be used by customers in a similar way. For instance, a customer might want to obtain historical consumption data for the purpose of negotiating a new electricity supply contract with a retailer. In this case, timing can be very important, as default tariffs may apply in the absence of a supply contract.[36] The Commission is inclined to consider that 20 business days for the provision of historical consumption data may unnecessarily draw out negotiations or potentially skew the outcome of negotiations.

2.107 It is understood that a customer data request is processed and finalised through the same process as a retailer data request, with the same information required to process the request as well as the same business units involved in finalising the request.

2.108 The Commission is inclined to consider aligning the timeframe within which a network provider is required to respond to a customer's data request, with the same timeframe for responding to a retailer's data request.

Option C2: Reduce the timeframe to respond to a data requests

2.109 The Commission understands that PWC employs a manual process for the provision of metering data to retailers and customers. However, it is noted that PWC's role of storing, accessing and providing metering data is not dissimilar to the role of certain market participants in the NEM. Different types of market participants are required to provide metering services, which may include storing the data, accessing the data and delivering the data in accordance with regulatory requirements.[37] The way in which market participants comply with these regulatory requirements depends on their internal business practices and efficiencies.

2.110 It is also noted that MSATS stores standing data, which may be accessed by other market participants under certain conditions. However, MSATS merely facilitates requests for historical consumption data. The Commission understands that historical consumption data cannot be accessed automatically through MSATS in response to a request for historical consumption data.

2.111 The Commission's expectation is that PWC should have become more efficient in the provision of data to customers and retailers since the introduction of the Code and should continue to become more efficient in the future, irrespective of whether manual or automated processes are adopted.

2.112 The Commission is inclined to consider that one day is not sufficient for the provision of data, but it may consider reducing the timeframes for the provision of data to retailers and customers to three or four days.

Minimum timeframes for processing data requests

Existing arrangements

2.113 Clause 6.2.8 (b) of the Code states that, unless otherwise agreed with a network provider, the network provider will process a minimum of:

---

36 In this example, it is assumed that the customer was on an electricity supply contract that recently expired and is therefore classified as an out of contract contestable customer in accordance with PWC's retail licence.

37 For example see role of the responsible person; clause 7.2.5 National Electricity Rules.

- two requests for standing data per day; and
- two requests for historical consumption data per day.

PWC's proposed amendment

2.114 In its submission, PWC states that the inclusion of 'minimum' instead of 'maximum' in clause 6.8.2 (b) of the Code is a typographical error. PWC proposes that the Code be amended to place an obligation on the network provider to process a maximum of two requests for standing data (or historical consumption data) per day.

Commission's comments

2.115 It is noted that the intention of this clause is to ensure that data requests are processed constantly on a day-by-day basis. Setting a maximum, as proposed by PWC, will result in instances where the network provider would be exempt from processing more than the defined maximum per day as well as being potentially exempt from providing data to retailers within the timeframes set out in the Code.

Data arrangements

Existing arrangements

2.116 Currently, a retailer is required to make a request for standing data and/or historical consumption data to the network provider. A retailer may then provide this data to a generator for a wholesale generation quote after which it could provide a quote to a potential customer to supply electricity to that customer.

QEnergy's concerns and amendment proposal

2.117 QEnergy believes that this process is unnecessary and allows PWC to extend data requests and customer transfers for a prolonged period of time, resulting in unnecessary time constraints on a competitive retailer.

2.118 QEnergy also states that, given the vertically integrated nature of PWC, the Code should contain provisions that allow any data to be provided directly from PWC Networks to PWC Generation at the request of the retailer.

PWC's submission

2.119 PWC considers that the current situation is a reflection of PWC's compliance with the Commission's Ring-fencing Code, which requires operational separation of PWC's monopoly and contestable electricity businesses. PWC considers that the current arrangements demonstrate an arm's-length relationship between PWC's business units.

2.120 PWC also considers that the current process is as streamlined as possible, given the requirements of the Ring-fencing Code:

- An FRC officer at the Regulation, Pricing and Economic Analysis Team processes customer and retail data requests. The data request is forwarded to the metering section within PWC Networks. Once the FRC officer receives the data from the metering section, the officer will forward the data to the retailer or customer as requested.
- If the retailer wishes to obtain a wholesale generation quote, that retailer must liaise with PWC Generation and complete a wholesale pricing request form, which is provided by PWC Generation. The information in this form will constitute a wholesale pricing request. The form is checked by an officer in PWC Generation before a legally binding commitment is finalised.

Option D: Provision of historical data directly to a generator

2.121 It is noted that the Ring-fencing Code does not necessarily prevent relevant parties from cooperating or negotiating with one another. An arrangement (similar to a tripartite agreement) with the consent of all parties (for example a competitive retailer, network provider and generator) could facilitate a more efficient and effective process for the provision of data requests and wholesale generation quotes.

2.122 The Code could be amended to permit a tripartite agreement between relevant parties for the provision of data requests and wholesale generation quote, that is negotiated honestly, fairly and in good faith.

Timeframes for customer transfers

Timeframe to reject a customer transfer request

2.123 Under clause 8.2.6 of the Code, if a network provider rejects a customer transfer request form, it must electronically notify the retailer within five business days. The notification must set out all of the reasons for rejection. Clause 8.2.5 states that a network provider must use its best endeavors to resolve any potential grounds for rejection prior to rejecting a customer transfer request form.

2.124 The Code provides limited grounds for rejecting a customer transfer request form. These include instances where:

- the retailer does not have a network access agreement with the network provider;
- information provided by the retailer is materially inconsistent with the network provider's records on the customer;
- the meter type at the exit point is inconsistent with the meter type required under the Network Connection Technical Code before the customer may transfer, and the customer transfer request form does not include a request for a new meter; or
- the nominated transfer date does not comply with clause 8.2.9 of the Code.

2.125 Clause 8.2.9 defines the transfer date for all customer transfers. In most cases, the transfer will be at the end of the month, provided that the customer transfer request form is submitted no later than ten business days prior to the end of the month for an urban area, or 15 business days prior to the end of the month for a non-urban area.

QEnergy's concerns and amendment proposal

2.126 QEnergy claims that five business days for a network provider to inform a retailer of its rejection of a customer transfer request form is longer than the timeframe in the NEM. QEnergy believes that this timeframe increases the length of time for customer transfers, which it deems to be burdensome and inefficient.

2.127 QEnergy proposes that the timeframe within which a network provider may reject a customer transfer request should be one business day instead of five.

PWC's submission

2.128 PWC opposes QEnergy's proposal and considers five business days to notify a rejection of a customer transfer request is appropriate given the manual process involved in enabling customer transfers between retailers:

- Once a customer transfer request is received, PWC checks the request to ensure that the details are correct.
- Arrangements are made with other business units to ensure that the transfer can take place.

- PWC considers that these arrangements require cooperation between staff at the Regulatory Pricing and Economics Area, Metering, Networks, Generation and System Control (which may include a potential site visit) in addition to the current and prospective retailer.

Option E: Reducing the timeframe to notify the rejection of a customer transfer request

2.129 It is noted that there may be financial implications in having a timeframe that is too lengthy. The new retailer may not be able to supply electricity to the customer as initially agreed and the currently retailer will be forced to continue to supply electricity to the customer, against the wishes of that customer.

2.130 It is also noted that cooperation between various business units within PWC is not dissimilar to the cooperation required between various market participants in the NEM. In the NEM, different types of market participants have different roles in order to facilitate customer transfer requests, in line with regulatory requirements. The way in which market participants' comply with these regulatory requirements depends on their internal business practices and efficiencies.

2.131 The Commission is inclined to consider a reduction in the timeframe to notify the rejection of a customer transfer request.

Additional comments regarding administrative provisions

2.132 The Commission has noted ambiguity in clause 8.2.6 of the Code. Clause 8.2.6 does not specify whether the five-day timeframe commences after the receipt of the customer transfer request form or after the network provider rejects the customer transfer request form.

2.133 The Commission is inclined to amend clause 8.2.6 to clarify the commencement of the five–business-day timeframe, which is intended to commence after the receipt of a customer transfer request form and not after the network provider rejects the customer transfer request form. This would be consistent with clause 8.2.10 of the Code, which outlines a five-business-day timeframe (after receipt of the customer transfer request form) to notify the retailer of the customer transfer date.

Timeframe to advise of a customer transfer date

Existing arrangements

2.134 Clause 8.2.10 (a) of the Code states that, following the receipt of a valid customer transfer request form, the network provider must electronically notify the current retailer of the transfer date within five business days after receipt of the customer transfer request form.

2.135 In the event that a network provider is unable to transfer a customer within the nominated transfer date, the network provider must electronically notify the retailer of the reasons why it cannot initiate the transfer and provide a proposed timetable for the transfer within five business days after receipt of the customer transfer request form.[38]

38 Clause 8.2.12, Retail Supply Code.

QEnergy's concerns

2.136 QEnergy claims that five business days is longer than the timeframe in the NEM. Taken together with the other timeframes in the Code, QEnergy believes that it allows PWC Networks to extend customer transfer requests for a prolonged period of time, which QEnergy deems to be burdensome and inefficient.

2.137 QEnergy proposes that the timeframe within which a network provider must advise of a customer transfer date should be one business day after the receipt of a valid customer transfer request form.

PWC's submission

2.138 PWC opposes QEnergy's proposal and considers that five business days is an appropriate timeframe to determine whether a transfer can take place at the allotted time. This is because PWC employs a manual process to enable customer transfers between retailers, including cooperation with various business units and assessment of the information in the request.

Option F: Reducing the timeframe to advise of a customer transfer date

2.139 As noted above, the customer transfer date is strictly defined and, in most cases, this date will be set at the end of the month. Given that the customer transfer date is predictable, it may be reasonable to assume that the network provider would allocate staff for this particular activity at the end of each month.

2.140 It is also noted that cooperation between various business units within PWC is not dissimilar to the cooperation required between various market participants in the NEM.

2.141 The Commission is inclined to consider a potential reduction in the timeframe to advise a retailer of a customer transfer date.

Cooling-off period

Current arrangements

2.142 Clause 8.2.20 of the Code states that a customer transfer is not permitted prior to the completion of any cooling-off period. As a result, the incoming retailer will need to take this into account when nominating the customer transfer date.

2.143 Cooling off period is defined in Schedule 1 of the Code as the ten-business-day period following the date on which the customer enters into an electricity sales contract with a retailer for the supply of electricity to that customer at an exit point.

PWC proposed amendment

2.144 In its submission, PWC considers that a customer should be able to waive the cooling-off period and notes that the cooling-off period may delay the customer's ability to transfer between retailers.

Commission's comments

2.145 It is noted that the cooling-off period serves as a consumer protection mechanism for Territory electricity consumers. Given that the Territory market is dominated by one vertically integrated government owned corporation, the Commission is not inclined to consider waiving the ten-business-day cooling-off period for small to medium sized customers but may consider a provision for waiving the cooling-off-period for larger businesses on the basis that larger commercial customers should be in stronger negotiation position and able to appropriately assess their business risks.

Other proposed amendments and additional comments

2.146 PWC's has made a number of other proposed amendments and miscellaneous comments on various aspects of the Code.

2.147 The Commission invites comments on any of PWC's proposed amendments and comments as listed below (Table 2.3).

Table 2.3: Summary of PWC's proposed amendments and Commission's comments

PWC comments	**Commission comments**
Clause 9.4.2 of the Code states that following a RoLR event, the network provider must, as soon as practicable, transfer existing customers from the failed retailer to PWC Retail (as the RoLR). PWC seeks clarification on whether a separate customer transfer request form is required for each of the failed retailer's customers and, if so, PWC notes that this may delay the transfer of customers to PWC Retail.	The Commission notes PWC's concerns on the lack of clarity of RoLR procedures in the Code. The Commission will consider developing robust RoLR guidelines under the Code as a separate project to the issues raised in this paper.
Clause 9.4.3 of the Code states that PWC Retail, as the RoLR, must sell electricity to existing customers of the failed retailer in accordance with the RoLR tariffs approved by the Commission. The Commission proposes the following: • PWC considers that RoLR tariffs should be sufficiently high so as to encourage affected customers to negotiate more favourable terms with PWC Retail or another competitive retailer. • As such, the RoLR tariff for each customer should consist of existing generation, networks and retail costs plus a 7 per cent retail margin. PWC states that this is consistent with similar arrangements in the Victorian electricity market.	
Clause 9.4.4 and 9.4.5 (c) of the Code states that the Commission will gazette the RoLR tariffs for use by PWC Retail. PWC considers this unnecessary, as customers enter into contracts with PWC Retail through bilateral agreements.	
Clause 9.4.5 (d) of the Code allows customers to remain on the RoLR tariff indefinitely. PWC proposes that a maximum of three months for customers to remain on the RoLR tariff be set in order to encourage customers to renegotiate after a RoLR event.	
Clause 9.4.5 of the Code does not specify the terms and conditions of contracts associated with a RoLR event. PWC has flagged that it does not intend to apply the failed retailer's terms and conditions. PWC seeks confirmation on whether this is permissible under the Code.	
Clause 9.5.1 and 9.5.2 of the Code provides that PWC may apply to the Commission to recover costs associated with a RoLR event. However, PWC states that the Code does not outline a specific framework for costs recovery. As such, PWC proposes that a cost recovery scheme be developed prior to an application being made, including guidelines on the types of costs that may be recovered.	

APPENDIX A

Option A2: Defining the credit support duration

Clause 3.2.2 (b) could be amended as follows (amendments are in red):

(b) If the retailer is unable to satisfactorily demonstrate to the generator that it meets the credit rating requirements set out in clause 3.2.2 (a), the Required Generation Credit Support Amount shall be the greater of:

(ii) a multiple of the retailer's reasonable forecasts of its highest generation services bill over the following 12 months (which forecast must be updated half yearly); or

(iii) a multiple of the generator's record of the highest generation services bill issued to the retailer by the generator over the previous 12 months.

(ba) The multiple in clause 3.2.2 (b) must be calculated in accordance with the following formula:

CSD/BP, where:

CSD is the credit support duration calculated in accordance with the following formula:

BP + PP + RP, where:

- BP is the billing period for the generation services bill of up to 28 days;
- PP is the payment period of up to 14 days;
- RP is the reactive period, which is 14 days or as otherwise determined by the Commission; and

BP is the billing period of the generation services bill of up to 28 days.

Option A6: Alternative forms of credit support

Clauses 3.4.1 could be amendment as follows (amendments are in red):

The form of the credit support shall be any combination of:

a) a bank guarantee that is:

(i) in favour of the network provider or the generator (whichever is applicable) and is unconditional and callable on demand; and

(ii) issued by a financial institution supervised by the Australian Prudential Regulation Authority;

(ab) a payment by way of cash that is:

(ii) made by the retailer; and

(iii) deposited into an official bank account as instructed by the network provider or generator (whichever is applicable);

b) an unconditional guarantee or other form of irrevocable credit support that is:

(i) in a form that is acceptable to the network provider or the generator (whichever is applicable) and the retailer ~~at its sole discretion~~; and

(ii) issued by an entity with an acceptable credit rating; or

c) such other forms of credit support that the network provider or the generator (whichever is applicable) agrees with the retailer as being acceptable through honest, fair and good faith negotiation.