Principles and Options for Managing Retailer Default Risk

Prepared for

Australian Energy Market Commission

22 October 2015

FINAL REPORT

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22 October 2015

Alan Rai
Director
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney, NSW 2000

Dear Alan,

Re: Principles and Options for Managing Retailer Default Risk

The Australian Energy Market Commission (AEMC) engaged Promontory Australasia (Sydney) Pty Ltd (Promontory) to provide advice and peer-review assistance on the design and modelling of options for managing the risk of retailer default in the national electricity and gas markets. This Report sets out our advice and recommendations on principles to support the regulatory framework for efficient allocation of retailer default risk and costs between market participants and, the options to address the risks associated with retailer default.

In providing our advice we have relied on information and reports made available to us by the AEMC and relevant energy market reports available in the public domain. In developing the principles and options we have taken the approach described in our contract dated 16 July 2015.

We note that Promontory is not a law firm, and no part of this Report should be viewed as constituting legal advice.

We thank the AEMC for the opportunity to provide this advice.

Sincerely,

Jeffrey Carmichael
Chief Executive
Promontory Australasia (Sydney) Pty Ltd

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Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	AGL Energy
BBSW	Bank Bill Swap Rate
CA	Retailer’s Credit Allowance
CA%	Retailer’s Credit Allowance Percentage
COAG	Council of Australian Governments’ Energy Council
D&B	Dun and Bradstreet
FRMP	Financially Responsible Market Participant
MCA	Maximum Credit Allowance
NCL	Network Charges Liability
NECF	National Energy Customer Framework
NEO	National Electricity Objective
NEM	National Electricity Market
NEL	National Electricity Law
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGO	National Gas Objective
NGL	National Gas Law
NGR	National Gas Rules
ROLR	Retailer Of Last Resort
S&P	Standard & Poor's
TARC	Total Annual Retailer Charges

Executive summary

The Australian Energy Market Commission (AEMC) engaged Promontory Australasia (Sydney) Pty Ltd (Promontory) to provide advice on effective mechanisms to address the risks to distributors, and ultimately customers, in the event of retailer default in electricity and gas markets in Australia. This Report assesses the potential impact of such defaults on distributors and customers, limitations of the current statutory arrangements to mitigate these risks and options to enhance or replace the current arrangements.

Risks arising from retailer default

Distributors rely on retailers to collect network charges for transporting electricity and gas to customers. Distributors are consequently exposed to the risk of non-payment (or untimely payment) of network charges in the event of retailer default. In the absence of any risk mitigation mechanisms the main risks to distributors from retailer default are:

- ***Revenue risk*** – the risk of being unable to recover revenue owing for power already supplied; and
- ***Liquidity risk*** – the risk of a cash flow shortage during the period of recovering lost revenue through the liquidation process.[1]

As a result of the revenue and liquidity risk faced by distributors, default by one or more large retailers could cause a distributor to face significant financial distress and, in extreme circumstances, may cause the distributor to fail. Given the central role that distributors play in facilitating the smooth supply of electricity and gas to homes and businesses, there is the potential for more widespread disruption given the interconnections that exist between participants. Sections 2.1 and 2.2 of this Report address these risks in further detail.

Current statutory mechanisms for mitigating retailer default risk

A number of statutory mechanisms have been introduced to mitigate the risk to distributors from retailer default in both the electricity and gas markets. Table 1 summarises these mechanisms, including some of their limitations.

Table 1: Assessment of current statutory mechanisms

Mechanism	Description	Key limitations
Credit support arrangements	A distributor may request credit support when a retailer's Network Charges Liability (NCL)[2] exceeds its Credit Allowance (CA).	The calculation of the CA and measures of credit worthiness mean that, in practice, credit support actually provided is minimal. This mechanism is ineffective in mitigating either revenue or liquidity risk.
Insurance	Distributors may enter into commercial insurance or self-insurance arrangements to mitigate the risks from retailer default.	Commercial insurance is expensive and may not be readily available. There is also a risk of claims being denied or delayed. Self-insurance may not provide for sufficient funds when needed.

[1] Although we discuss risks in the context of distributors, as part of our assessment and in making our recommendations, we also take into consideration the potential longer-term impact on customers.
[2] This represents an estimate of the distributor's exposure to a retailer at a point in time. It includes a retailer's billed but unpaid changes, as well as unbilled charges, over the outstanding period.

Overs and unders	Under a revenue cap model, the annual adjustment in prices includes the under- or over-recovery of allowable costs in the previous year.	Provides for recovery over time of forgone revenue from retailer default. Does not operate under the alternative weighted-average price cap regime. Unlikely to mitigate liquidity risk.
Cost pass-through	Certain costs (subject to a 1% materiality threshold and AER approval) can be passed through and recovered from distributor's customers.	Forgone revenue as a result of a retailer default is not explicitly included under this mechanism, therefore mitigation of revenue risk is uncertain. Unlikely to mitigate liquidity risk.

Some of these statutory mechanisms have been the subject of rule change requests, which the AEMC is currently assessing. The Council of Australian Governments' Energy Council (COAG) has proposed extending the pass-through to specifically include forgone revenue following a retailer default, and the removal of the 1% materiality threshold. AGL Energy (AGL) has proposed removing the CA under the credit support arrangements and requiring credit support to be based more directly on a retailer's NCL and credit rating.

Sections 2.3 and 2.4 of this Report provide further details about these mechanisms.

Options

This Report considers four broad options (including retaining the existing arrangements) for managing the risks associated with retailer default. Within the broad options, we also consider a number of sub-options that we model separately to determine relative costs, strengths and weaknesses. An outline of the options and sub-options is provided in Table 2 below (with further details set out in Section 4 of this Report).

Table 2: Description of options and sub-options

Option	Description	Sub-option
Option 1	***Retain existing arrangements*** Involves retaining existing arrangements for managing retailer default.	No separate sub-options are modelled, although we note that forgone revenue may be recovered under a revenue cap regime but not under a price cap regime.
Option 2	***Strengthen existing arrangements*** Includes the COAG proposal and strengthening the credit support arrangements (two variations).	***Option 2.1: COAG proposal with no credit support*** Removes credit support arrangements completely.
		Option 2.2: COAG and AGL proposals
		Option 2.3: COAG proposal with enhanced credit support Credit support based on alternative credit rating benchmarks, realigning ratings and restricting the use of D&B risk scores.
Option 3	***Retailer default fund*** Replaces credit support with an industry-wide retailer default fund. Includes the COAG proposal.	No separate sub-options are modelled.
Option 4	***Liquidity support scheme*** Replaces credit support with the requirement that each distributor obtain and maintain access to a committed liquidity facility from the banking sector. Includes the COAG proposal.	***Option 4.1: market-share-based allocation*** Ongoing cost of facility is allocated to retailers in proportion to their annual network charges.
		Option 4.2: risk-based allocation Ongoing cost of facility is allocated to retailers by a formula based on their NCL and credit worthiness.

The various options address revenue and liquidity risk to distributors in different ways and to different degrees. They also allocate costs differently.

We classify the first three sub-options (1, 2.1 and 2.2) as "aggressive", in that they only partially address revenue risk and are unlikely to address liquidity risk. Instead they largely rely on market or political forces to resolve potential market disruption after a default has occurred.[3] We classify the other four sub-options (2.3, 3, 4.1 and 4.2) as "defensive", in that they involve *ex ante* preventative measures to address revenue and liquidity risks in the event of retailer default.

For each of the sub-options we model the potential ongoing costs to distributors, retailers and customers from implementing the option (annual risk mitigation costs), as well as the likely costs in the event of retailer default (post-default impacts). We consider three default scenarios for each option:

- Scenario 1: Default of the retailer with largest market share within a distribution network.
- Scenario 2: Default of the retailer with largest market share across all electricity and gas networks.
- Scenario 3: Default of three retailers each with a market share of less than 5% across electricity and gas networks.

In terms of costs, default scenario 2 was, in our view, the most plausible severe-default event impacting multiple networks.[4] While the results in this Executive Summary refer exclusively to scenario 2, the relative strengths and weaknesses of the options are reasonably similar across the different scenarios.

An important factor in calculating the costs of the different options is the assumed level of coverage of the impact of the default scenarios on liquidity. While we tried in general to scale the options to provide a similar level of risk mitigation under each option, there are nonetheless some important differences. Sub-options 2.2 and 2.3, which involve strengthening the existing credit support arrangements, are scaled by the assumed structures of the credit benchmarks and, consequently, do not fully mitigate the liquidity impact of the default scenarios. Under the AGL proposal (sub-option 2.2), for example, credit support does not assist in recovering any of the immediate liquidity loss under default scenario 2, because the proposal results in no credit support being required from the more highly-rated (i.e., larger) retailers. Credit support under option 2.3 (the enhanced credit support arrangements) recovers 55% of the immediate liquidity loss. Both of these sub-options enable recovery of the balance of the loss over time through the COAG proposal, but leave some residual liquidity risk at the time of default. In contrast, options 3 and 4 are scaled to provide full coverage of the immediate liquidity impact of default scenario 2.

Modelling results

Ongoing costs

We assume that ongoing costs are passed on to the shared customers of retailers. We estimate the impact on shared customers as the percentage increase in annual energy costs.[5] We present the minimum, average and

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[3] In modeling the costs and impacts of option 1 (existing arrangements) we have assumed that energy pricing operates under a revenue cap regime, as it currently does. Where relevant, we note the changes in impact that would occur if regulators were to replace existing arrangements with a price cap regime.
[4] Scenario 1 effectively assumes an extreme event in which the largest retailer in each network simultaneously defaults. We consider this to be less plausible than scenario 2 in which a single retailer defaults (i.e., the largest retailer operating across multiple networks).
[5] We have not taken into account any potential offsetting impacts on customer energy prices through adjustments to a distributor's regulated rate of return (as a result of the revenue and pricing principles).

maximum impact on shared customers across the different networks under each of the options. We also estimate the proportion of shared customers affected, and the total ongoing annual costs in dollar terms under each of the options.[6] Tables 3 and 4 below present the results of our modelling.

Table 3: Ongoing costs to shared customers – gas

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual cost ($m)
Option 1	Nil	Nil	Nil	Nil	Nil
Option 2.1	Nil	Nil	Nil	Nil	Nil
Option 2.2	0.13%	0.17%	0.22%	1.7%	0.15
Option 2.3	0.07%	0.24%	0.84%	95.1%	8.12
Option 3	0.03%	0.24%	0.95%	100.0%	8.12
Option 4.1	0.01%	0.05%	0.18%	100.0%	1.86
Option 4.2	0.00%	0.06%	0.27%	100.0%	1.86

Table 4: Ongoing costs to shared customers – electricity

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual cost ($m)
Option 1	0.03%	0.10%	0.22%	1.0%	0.12
Option 2.1	Nil	Nil	Nil	Nil	Nil
Option 2.2	0.25%	0.52%	0.89%	3.0%	2.02
Option 2.3	0.15%	0.48%	1.02%	96.2%	62.96
Option 3	0.07%	0.53%	1.62%	100.0%	65.18
Option 4.1	0.03%	0.09%	0.19%	100.0%	15.12
Option 4.2	0.01%	0.11%	0.50%	100.0%	15.12

While customers of electricity retailers face generally higher ongoing costs than those of gas retailers for each option, the relative costs of the different options are quite similar for both gas and electricity.

For the aggressive options (1, 2.1 and 2.2), shared customers face little to no ongoing costs (with the exception of option 2.2, where the average ongoing costs to affected customers are comparable to those of the defensive options, although the percentage of customers affected is very small). The low ongoing costs are largely due to the low levels of credit support provided under these options.

In contrast, the defensive options (2.3, 3, 4.1 and 4.2) involve higher ongoing costs (as expected), although with considerable variations in average costs, maximum costs and total annual costs across the various sub-options. Option 4 (the liquidity facility) has the lowest average and total annual cost (at less than a quarter of the costs under options 2.3 and 3), while the retailer default fund (option 3) is the most costly.

[6] Affected customers are shared customers that are subject to increased ongoing costs as a result of the arrangement implemented under the relevant sub-option. The total annual cost is the sum of the costs to all affected customers in the gas and electricity markets respectively.

Post-default analysis

Tables 5 and 6 summarise post-default costs to gas and electricity customers (again measured as the percentage increase in annual gas or electricity bill), and the proportion of customers impacted under each of the options.[7] The tables also provide an estimate of total retailer default costs borne by customers (in dollar terms) under each of the options.[8]

Table 5: Post-default costs to customers (scenario 2) – gas

Option	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 1	1.14%	6.19%	16.98%	96.5%	165.6
Option 2.1	1.14%	6.19%	16.98%	96.5%	165.6
Option 2.2	1.14%	6.19%	16.98%	96.5%	165.6
Option 2.3	0.52%	2.74%	7.14%	96.5%	74.6
Option 3	0.33%	2.38%	9.53%	100.0%	81.2
Option 4.1	1.14%	6.15%	16.68%	96.5%	165.4
Option 4.2	1.14%	6.15%	16.68%	96.5%	165.4

Table 6: Post-default costs to customers (scenario 2) – electricity

Option	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 1	2.67%	7.45%	29.10%	100.0%	894.0
Option 2.1	2.67%	7.45%	29.10%	100.0%	894.0
Option 2.2	2.67%	7.45%	29.10%	100.0%	894.0
Option 2.3	1.22%	3.27%	12.30%	100.0%	398.3
Option 3	0.71%	5.33%	16.22%	100.0%	651.8
Option 4.1	2.67%	7.37%	28.25%	100.0%	891.8
Option 4.2	2.67%	7.37%	28.25%	100.0%	891.8

The aggressive options (1, 2.1 and 2.2) result in the highest post-default costs to customers of gas and electricity distributors. This is due to the low levels of credit support provided in these options, combined with the effect of passing costs to customers through the cost pass-through or overs and unders process.[9]

While all of the aggressive options involve high post-default costs to customers, the defensive options (with the exception of option 2.3) offer only modest reductions in these costs. The similarity in post-default costs

[7] Impacted customers are customers of distributors with exposure to the retailer that we have assumed to have defaulted.
[8] Default costs include forgone revenue and costs from retailer default.
[9] In the event that the energy-pricing regime changes from a revenue cap to a price cap regime, the post-default costs to customers would be minimal; distributors would absorb the majority of the retailer default costs since we assume they would have no mechanism through which to recover forgone revenue. The risk of distributor failure under such a regime would be correspondingly higher.

between the aggressive and defensive options arises because these options (other than option 2.3) allocate the cost of restoring forgone revenue to customers.

For option 2.3, the post-default cost to customers is roughly half that of the other options. This lower cost arises because the credit support received under scenario 2 (which is approximately 55% of the forgone revenue) is provided by the banking sector, and therefore does not have to be recovered from customers. This lower post-default cost is offset to some extent by the correspondingly higher ongoing costs of this option.

Sections 5 and 6.1 of this Report detail the modelling framework and the assessment of costs.

Alignment with regulatory principles

In assessing each of the options and forming a view as to which would be most suitable, Promontory was asked to consider not only the costs of the options, but also the extent to which they meet the principles that we consider most appropriate for supporting the regulatory framework. In narrowing our options into recommendations, we consider not only the costs of the options, but also the extent to which each option meets the regulatory principles.

Table 7 below provides a short description of the principles and a high-level summary of the extent to which each option aligns with them.

Table 7: Alignment with regulatory principles

	Stability To minimise potential financial contagion of a retailer default to its distributor	Efficiency To efficiently allocate the risks and costs to parties in order to minimise long-term costs to customers	Incentives To provide appropriate incentives to minimise the probability and impacts of retailer default	Revenue and pricing To take account of any change in network revenue resulting from the application of the scheme's revenue and pricing principles	Competition To consider any impacts on barriers to entry for retail businesses
Option 1	×	×	×	Partly	✓
Option 2.1	×	×	×	✓	✓
Option 2.2	×	×	Partly	✓	×
Option 2.3	✓	Partly	✓	✓	×
Option 3	✓	×	✓	✓	×
Option 4.1	✓	Partly	×	✓	✓
Option 4.2	✓	Partly	✓	✓	Partly

As shown in Table 7, when compared with the aggressive options, the defensive options generally align better with the principles of system stability, efficiency and incentives. On the other hand, the defensive options are generally more supportive of the principle of competition, in that they reduce potential barriers to entry for retail businesses in the gas and electricity markets.

Section 3, Section 6.2 and Appendix D of this Report provide further details on the principles and assessment of the options against them.

Recommendations

On the basis of the analysis and computations in this Report there is no single option that dominates all others in terms of balancing the costs and risks to distributors that may arise from retailer default. The options involve a trade-off between cost and certainty; in general, the greater the certainty of risk mitigation, the greater the cost of implementing the option.

There are nevertheless some options that we believe are clearly dominated by others that have similar combinations of risk and certainty. In particular, the current arrangements (option 1) involve some cost, while providing very little by way of effective or reliable risk mitigation for distributors. The COAG proposal by itself (option 2.1) provides much stronger revenue risk mitigation at no extra cost. Similarly, the AGL proposal does little to address the limitations of the existing credit support regime. Thus option 2.2 is dominated by option 2.1, which provides a similar risk mitigation outcome at lower cost. Finally, among the defensive options, the retailer default fund (option 3) appears to be more costly and inefficient than the other options.

That leaves options 2.1 (COAG proposal with no credit support), 2.3 (COAG proposal plus an enhanced credit support scheme), and 4 (COAG proposal plus liquidity support scheme) as the most promising options. Of these, Promontory's preferred option is option 4 as it:

- has a similar post-default cost structure to option 2.1, while providing considerably greater certainty that funds will be available if and when needed to mitigate liquidity risk, at a relatively small ongoing cost (roughly 0.1% of customers' power bills); and
- has a higher post-default cost than option 2.3 but a materially lower ongoing cost (roughly a quarter of the cost associated with option 2.3).

Recommendation:

- implement the COAG proposal on cost pass-through provisions by removing the materiality threshold and allowing forgone revenue to be passed through;
- remove the current requirements for credit support from retailers to distributors;
- introduce a requirement for distributors to establish a committed liquidity facility with a financial institution, with the size of the facility linked to the size of the largest retailer NCL within the network (subject to a cap); and
- allow the annual commitment fee and any utilisation costs associated with the liquidity facility to be recovered from retailers according to a formula based on both the NCL and risk rating of the retailer.

1 Introduction

1.1 Background

The AEMC has engaged Promontory to provide advice on effective mechanisms to address the risks arising from retailer default in electricity and gas markets in Australia.[10] This Report follows from two rule change requests submitted to the AEMC on regulatory mechanisms to manage the risks between energy distributors and retailers in the event of retailer default, namely:

- A rule change request from COAG[11] in March 2014 to remove the 1% materiality threshold[12] applied for cost pass-through in the event of a retailer default under the National Electricity Rules (NER). The COAG also requested enabling the pass-through of any forgone revenue following a retailer default. Throughout this Report these two recommendations will be referred to collectively as the COAG proposal.
- A rule change request from AGL Energy in January 2015 requesting amendments to the methodology for retailer-distributor credit support requirements under the NER and the National Gas Rules (NGR).

Promontory's Report aims to assist the AEMC with its analysis of the risks and costs associated with retailer default, and the development of appropriate options and responses to both rule change requests. The Report sets out:

- the various risks and costs that arise for distributors in relation to retailer default and how these risks and costs are currently allocated under the NER and NGR;[13]
- principles that we believe should be applied in determining the most effective mechanisms for managing the risk of retailer default for distributors;
- the design of three options for improvement of, or alternatives to, the present system;
- analysis of ongoing costs and post-default impact on customers under current arrangements and for the three design options considered;
- assessment of each option against the design principles; and
- recommendations on the best option that satisfies the principles developed.

The AEMC completed initial rounds of consultation in relation to both rule change requests in December 2014[14] and July 2015.[15] Given the inter-related nature of the retailer insolvency cost pass-through and credit support arrangements, the AEMC is assessing the rule change requests collectively, with a view to publishing an "options paper" in 2015. The options paper will consider the rule change requests in a holistic manner and

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[10] The jurisdictions which form part of the scope of this Report are those that have transitioned to the National Energy Customer Framework (NECF) – namely, Australian Capital Territory, New South Wales, Queensland, South Australia and Tasmania. Victoria is expected to transition by 31 December 2015.
[11] Throughout this Report we simply refer to "COAG" when referencing the COAG Energy Council.
[12] The materiality threshold is 1% of the relevant distributor's revenue requirement for that year.
[13] For the purposes of this Report, retailer default is an event in which a retailer is unable to pay its debts when they fall due.
[14] AEMC, *Consultation Paper: National Electricity Amendment (Retailer insolvency events - cost pass through provisions) Rule 2015*, 30 October 2014.
[15] AEMC, *Consultation Paper: National Electricity Amendment (Retailer-Distributor Credit Support Requirements) Rule 2015*, 28 May 2015.

set out options for the AEMC to consider as part of its policy formulation on managing retailer default risk. Promontory's Report will provide input and advice on the development of the AEMC's options paper.

Appendix A provides an overview of the market structure in Australia's electricity and gas markets.

1.2 Approach

In setting out our advice in this Report, Promontory has drawn on our experience in regulatory policy and similar arrangements in the financial sector. We have undertaken research on the various strengths and weaknesses of current regulatory arrangements for managing the risks to distributors, and ultimately customers, in the event of retailer default. In particular:

- In order to understand the risk and costs faced by distributors from retailer default, we have reviewed research and analyses completed as part of previous consultations conducted by the AEMC on cost pass-through and credit support arrangements. We have also examined studies and work carried out in the energy sector by both regulators and regulated entities to appreciate practical and indirect issues that warrant consideration.

- In identifying principles to improve current arrangements, we have considered the main objectives of the NER and NGR, and drawn on our experience and knowledge of regulatory regimes in other industries with similar competing objectives of stability, efficiency, competition, contestability and competitive neutrality.

- In designing the range of options, we worked collaboratively with the AEMC staff to discuss general design considerations and possible mechanisms for refining existing credit support and cost pass-through arrangements. Where relevant, we also drew on examples in other sectors or jurisdictions with similar retailer-distributor models (e.g., central banks and commercial banks) to identify options to effectively allocate risk and costs associated with retailer default.

1.3 Structure of this Report

This Report is structured as follows:

- Section 2 sets out an overview of the risks and costs of retailer default to distributors and other market participants in the electricity and gas markets, as well as how those risks are currently allocated under NER and NGR;

- Section 3 outlines the key regulatory principles that we consider as being most important in designing a regulatory framework that appropriately allocates risks and costs related to retailer default across market participants;

- Section 4 details options for improvement of, or alternatives to, the present system;

- Section 5 provides the results of our model in assessing the ongoing costs and post retailer default impacts for each of the options considered in Section 4; and

- Section 6 provides a summary of our findings, an assessment of the options against the design principles provided in Section 3 and our recommendations.

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2 Challenges arising from retailer default

2.1 The nature of the retailer-distributor relationship

The primary focus of Promontory's engagement is to assess the risks to distributors in the event of retailer default, and whether the current regulatory arrangements for managing these risks could be improved.[16] The focus on the risks to distributors from retailer default arises due to the nature of distributors' business models, and their reliance on retailers to collect revenues. In particular:

- Distributors rely on retailers to collect network charges for transporting electricity and gas to customers' premises, which exposes them to the risk of non-payment (or untimely payment) of network charges in the event of retailer default.

- Under the terms of rules governing their activities, the ability of distributors to manage the risk of retailer default is constrained by their limited ability to invoice customers directly and inability to price-discriminate against retailers according to their credit worthiness.

Box 1 below sets out further details of the mechanisms and regulatory obligations that define the retailer-distributor relationship in Australia's electricity and gas markets.

Box 1: Nature of the retailer-distributor relationship

In both electricity and gas markets, the distributor provides connection and supply of energy services to the customer directly.[17] However, distributors are prohibited from billing small customers directly and can only bill large customers directly with the consent of the customer.[18] For the vast majority of customers who are not billed directly, the billing and payment of services is governed by the concept of a "shared" customer. Section 2 of the National Energy Retail Rules (NERR) defines a shared customer as a person who is a customer of the retailer and whose premises are connected to the distributor's network.[19] A retailer provides retail services to customers (including customer service and an offer of different energy plans) and has a regulatory obligation to collect payments from shared customers and pay the distributor's network charges with respect to those shared customers.[20]

The regulatory obligation of retailers to collect and pay network charges varies slightly for electricity and gas. In the gas market, there is a direct relationship between the transmission network provider and the retailer. Thus, retailers are obligated to pay network charges separately to distributors and transmission network service providers. In the case of electricity, retailers pay network charges to distributors, who are then obligated to pass on the appropriate share to transmission network service providers. Nevertheless, in both the electricity and gas markets, distributors and transmission network service providers are reliant on retailers to collect network charges incurred by shared customers.

[16] As part of our assessment and in making our recommendations, we also take into consideration the potential longer term impact on customers.
[17] National Energy Retail Law (NERL) clause 66 provides that a distributor must provide customer connection services for the premises of a customer who requests those services, and whose premises are connected (or requested to be connected) to the distributor's network. This obligation is tempered slightly for gas distributors where the distributor may inform the prospective customer that it cannot provide the requested service and the reasons why the requested services cannot be provided.
[18] NERL Section 72(b); NER 6B.A2.2; and NGR clause 504.
[19] Throughout this Report we refer to "shared customers" as representing the customers of a retailer connected to a distribution network. We also refer to "distributor's customers" representing all customers from all retailers within a distribution network.
[20] NER 6B.A2.1 and 6B.A2.5; NGR clause 503.

The flow of payments across electricity and gas market participants exposes distributors to retailers defaulting on their obligations to pay network charges. That is, distributors are forced to accept a level of counterparty credit risk to retailers in providing direct services associated with the provision of power. We note that a retailer may default for a variety of reasons (e.g., inappropriate or ineffective hedging strategy in the wholesale electricity market).[21] Moreover, as regulated monopolies, distributors cannot factor in the credit worthiness of a retailer in setting the prices it charges shared customers. These structural features limit the ability of a distributor to manage its counterparty credit risk to retailers (including any concentration risk to larger retailers).[22]

2.2 Risks arising from retailer default

Based on the nature of the retailer-distributor relationship described above, there are various risks and costs to distributors as a result of the default of one or more retailers. In the absence of any risk mitigation mechanisms, distributors face material risks to their revenue and liquidity. These, in turn, generate a potential for contagion effects, insolvency and overall systemic instability. Ultimately any risk mitigation costs and retailer default impacts are largely borne by consumers of electricity or gas (i.e., customers). These costs and impacts may be allocated to customers through the use of one or more of the mechanisms described in section 2.3. Residual risks may also be taken into account through the application of the revenue and pricing principles in estimating a distributor's regulated rate of return (and subsequently in setting customer electricity and gas prices).[23]

Revenue risk

One of the main risks that distributors face in the event of retailer default is revenue risk. Distributors face revenue risk when a retailer does not pay for its network charges and hence the distributor faces a loss of revenue for direct services associated with the provision of power that it has already supplied. There is a risk that distributors will be unable to recover the lost revenue either in part or in full. The loss of revenue may also be sufficiently large to threaten a distributor's own solvency.

For distributors of electricity, revenue risk is amplified as distributors are obligated to pay transmission network service providers their share of the overall network charges received from retailers. In the event of a retailer default, a distributor is still liable to pay these transmission network charges, even though no associated revenue has been received from the defaulted retailer. As a result, distributors would have to absorb the transmission costs associated with retailer default.

Liquidity risk

The second main risk that distributors face in the event of retailer default is liquidity risk. As with revenue risk, liquidity risk arises when a retailer does not pay its network charges to a distributor. In the absence of any mitigating mechanisms (such as described below) a distributor would then proceed to recover the forgone revenue through the insolvency process. Even if the losses are fully recovered, the time period between a retailer's default and recovery of the forgone revenue by a distributor may create a material cash flow

[21] A discussion on the range of scenarios that could lead to a retailer default is beyond the scope of this report.
[22] Concentration risk is posed by retailers that have significant market share either directly or indirectly (i.e., multiple authorisations) within a network. Certain energy retailers operate under multiple financially responsible market participants (FRMP) and various legal entities – i.e., multiple authorisations within a same corporate group.
[23] It is our understanding that, in practice, such granular adjustments may not be made when estimating the regulated rate of return.

shortage for the distributor. A distributor may also face administrative costs (including legal and regulatory costs) for recovering network charges.

If the cash flow shortfall is sufficiently large, there may be other implications for the distributor, including an increase in the cost of temporary finance or even the inability to raise such external funding.[24] Again, the ultimate outcome could be the distributor's insolvency.

Systemic instability

In the absence of any risk mitigation mechanisms, the problem posed by potential retailer default is that it could, in turn, cause a distributor to face significant financial distress and consequently cease to operate. Given the central role that distributors play in facilitating the smooth supply of electricity and gas to homes and businesses, there is the potential for more widespread disruption when taking into account the interconnections that exist between participants. That is, if a distributor were to fail and cease operations, the generators and retailers within that network would no longer be able to supply energy, thereby reducing their revenue base. In an extreme scenario, this outage could impact on the ability of these other participants to continue operating. System stability in the National Electricity Market (NEM) may be compromised.

In considering the potential destabilising effects of a distributor ceasing operations, we acknowledge that regulatory intervention may play a role in preventing such a scenario. More specifically, as a distributor approaches insolvency with the potential to cease operations, there are existing mechanisms in place to ensure that supply is not compromised (e.g., the Australian Energy Market Operator (AEMO) direction powers and, in catastrophic cases, State emergency powers). We note, however, that there is no guarantee that such directions will be effective if a decision has already been made to cease operations and insolvency proceedings have begun. We also note that the application of these powers will involve costs, which may be material and are likely to be passed on to customers. The use of such powers, including their possible effectiveness and associated costs, is beyond the scope of this Report.

A key objective in considering options to strengthen the system's resilience to retailer default is to provide greater certainty to the way in which such a situation will be handled and to remove, or at least greatly diminish, the need for political decisions to be made under pressure.

Risk mitigation mechanisms

As a consequence of the reliance of distributors on retailers, a number of statutory mechanisms have been introduced to mitigate the risk of retailer default in both electricity and gas markets. Other mechanisms (which were introduced for other purposes) can also assist in managing the risks associated with retailer default. These mechanisms include the retailer of last resort (ROLR) mechanism and cost pass-through provisions.

The ROLR mechanism is not under review as part of this engagement. In essence, it provides a mechanism for replacing a failed retailer to ensure continuity in the market and that the exposure faced by the distributor to the defaulted retailer does not continue to increase. The replacement retailer, however, does not assume the failed retailer's liabilities for payments to a distributor for energy already provided. Thus, it does not address the risks that a failed retailer poses to a distributor. Other statutory mechanisms are discussed below.

[24] A government owned distributor may source additional funding from the relevant central borrowing authority in its jurisdiction. Any additional funding will form part of the distributor's overall borrowing capacity. If a distributor wanted to increase its borrowing capacity, it must apply to the Treasury for approval.

2.3 Current statutory mechanisms for managing retailer default risk

The National Energy Customer Framework (NECF) provides distributors with several statutory mechanisms under the NER or NGR that can assist in managing the risks and costs associated with a retailer default.[25] These statutory mechanisms include those in relation to:

- credit support arrangements;
- insurance arrangements;
- the "overs and unders" process; and
- cost pass-through provisions.

Statutory mechanisms may be used in combination. That is, a distributor has discretion to use a combination of mechanisms in order to minimise the impact of retailer default. Each statutory mechanism is described below.

Credit support arrangements

Under the current rules, credit support is designed to minimise a distributor's risks associated with retailer default by capping a retailer's unsecured network charges liability (NCL) to the distributor. This mechanism requires retailers to provide credit support for the amount by which their NCL exceeds a calculated credit allowance (CA). Retailers may pass on the cost of providing credit support to customers in the form of higher energy prices. The credit support requirements were introduced into the rules as part of the NECF in 2011[26] and are substantively the same for electricity and gas. Box 2 describes how credit support is currently calculated.

Box 2: Credit support calculation

A distributor may request credit support when a retailer's NCL (billed but unpaid as well as unbilled charges over the outstanding period) exceeds its CA.[27] The CA is determined by a formula based on the distributor's annual retailer charges and the retailer's credit rating,[28] with a higher credit rating leading to a higher CA.

For any given credit rating, as a retailer's market share increases, its NCL will grow and the amount of credit support that may be required (i.e., in excess of its CA) will increase.

The formula for calculating credit support is:

Credit Support = NCL – Retailer's CA

A retailer's CA represents the maximum level of exposure to a distributor for which no credit support is required. The calculation first requires determination of the maximum credit allowance (MCA) that each

[25] Where the NECF does not apply, gas distributors and gas retailers can negotiate under an access arrangement for other risk management arrangements (e.g., more frequent meter reading or billing, or payment in advance rather than in arrears). For electricity, distributors are allowed to bill retailers monthly but are not precluded from commercial negotiations (similar to gas) to manage retailer default risk.
[26] Where the NECF does not apply, credit support requirements are based on state-based regulatory arrangements.
[27] The access arrangement for gas prescribes the maximum amount of credit support a distributor may request from a retailer, although it provides the distributor and retailer some flexibility to negotiate different solutions to address the risks associated with retailer default. Some of the other mechanisms which may be available include more frequent billing, more frequent meter reading and payment in advance rather than in arrears. These mechanisms serve to decrease a retailer's NCL.
[28] The current rules allow retailers to use credit ratings from agencies such as Standard & Poor's (S&P) or a dynamic risk score provided by Dun & Bradstreet (D&B).

retailer in the network may be allowed. The MCA is the same for each retailer across a distributor's network and is calculated as follows:

MCA = 25% x Distributor's Total Annual Retailer Charges (TARC)

The MCA is then combined with a measure of the credit worthiness of each retailer to arrive at an individual retailer's CA. Credit worthiness is measured in the form of a credit allowance percentage (CA%). Retailers with a Standard & Poor's (S&P) rating of A- or better receive 100% of the MCA (i.e., a CA% of 100%). Retailers rated BBB+ or lower receive a CA% less than 100% with the CA% continuing to decline as a retailer's credit rating deteriorates. The calculation of each retailer's CA is as follows:

Retailer's CA = MCA x CA%

Although credit support is generally calculated as set out above, a distributor may also request credit support from a retailer for the full NCL irrespective of the credit rating of the retailer. A distributor may only do this if:

- within the previous 12 months the retailer has failed to pay its network charges in full;[29] or
- the AEMO makes a claim on any credit support from the retailer.[30]

Distributors are not mandated to request credit support from retailers but, if requested, the retailer must provide the support within 10 days of the request. Where a retailer accedes to a distributor's credit support request it must be in a form acceptable to the distributor (usually a bank guarantee).

The rules, which prescribe when a distributor may draw on the credit support, state that:

- the distributor must provide notice to the retailer at least three business days in advance of drawing on the credit support;
- there must be an amount of network charges due and payable which remains outstanding; and
- there is no unresolved dispute relating to the amount that must be paid by the retailer for its network charges.[31]

Insurance arrangements

Insurance arrangements are another means by which distributors can protect themselves against the financial impact of a defaulting retailer. The insurance arrangement can be either commercial insurance (where a premium is paid to a third-party insurance provider) or self-insurance (where a distributor sets aside funds until such time a retailer default event occurs, after which those funds are drawn to cover the costs related to the retailer default).

Distributors are subject to economic regulation under the NER for electricity and access arrangement for gas. Broadly, this involves the Australian Energy Regulator (AER) making a regulatory determination for "allowed" revenue over a defined regulatory control period, usually five years. It is the primary determinant of revenue recovery for distributors.

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[29] This may be failure to pay charges contained within two (consecutive) or three statements by the due date. Where retailer has failed to pay network charges contained in one statement, credit support for the full NCL can be requested after 25 business days has passed from the due date and the payment remains outstanding.
[30] NER, 6B.B3.5; NGR, Part 21, Section 522.
[31] If these three requirements are satisfied and the distributor holds credit support, it can then call on the credit support to satisfy the retailer's outstanding network charges.

Distributors can include certain expenses as a component of operating expenditure as part of the regulatory determination process; allowable expenses can be passed through into higher prices for customers in order to recover these expenses without an adverse impact on profitability. The cost or premium paid for insurance arrangements to manage retailer default risk may be incorporated into a distributor's operating expenditure forecast as an allowable cost, subject to AER determination. The AER's regulatory determination process generally allows recovery of commercial insurance costs.

If a distributor is unable to secure a commercial insurance arrangement, the regulatory framework also allows costs for self-insurance. Self-insurance only tends to be allowed as a component of operating expenditure to the extent such risks are not:

- able to be efficiently covered by commercial insurance arrangements;
- already remunerated through other elements of the regulatory regime, such as inclusion in the weighted average cost of capital; or
- recovered through the cost pass-through mechanism.[32]

Overs and unders process

The AER has two alternative operating models for pricing power. The first is the revenue cap model. Under this model there is an annual adjustment in prices for under- or over-recovery of allowable costs in the previous year. The alternative is a weighted-average price cap model (determined by the AER at the beginning of each regulatory period).[33] The AER sets the pricing regime for five years at a time. While the choice of regime is influenced by a range of factors, the two have very different implications for recovery of lost revenue from a retailer failure. In particular, under the weighted-average price cap model, distributors do not have the option of protecting themselves against the risk of retailer default through the overs and unders process.

In contrast, under the revenue cap model, the over- or under-recovery of costs is deducted from, or added to, the maximum allowable revenue in future years. Such adjustments are built into the price of energy charged to customers. If an over-recovery of revenue occurs, the distributor is required to return the excess to customers through a reduction in future prices. Conversely, if an under-recovery of revenue occurs (e.g., due to a retailer default), the distributor is entitled to recover it from customers through an increase of future prices. The adjustment to a distributor's maximum allowed revenue through the overs and unders process is subject to approval by the AER. The overs and unders process thus provides some protection against revenue risk arising from a retailer default.

Distributors currently operate under the revenue cap model. However, this may not always be the case.

Cost pass-through provisions

The cost pass-through provisions refer to yet another revenue-adjustment mechanism available to distributors. Actual revenue for a distributor may deviate from its expected regulated revenue due to the occurrence of exogenous events that are not within the reasonable control of the distributor. The regulatory framework makes provision for managing the cost impact of uncertain exogenous events on revenues through different adjustment mechanisms, depending on the nature of the event.

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[32] The AER has also considered it to be necessary for the particular risk to have been historically incurred, in order to be able to use the commonly accepted method of calculating self-insurance premiums.
[33] Under a weighted average price cap, prices for regulated services provided by distributors are based on the weighted average of prices for individual services, within a specified "basket" of services. This mechanism caps the average increase in prices for services in the basket from one year to the next.

When an exogenous cost pass-through event occurs, such as a retailer default, which materially increases a distributor's costs, the distributor may apply to the AER to approve a pass-through of the increase in costs to customers through higher energy prices. It is important to note that under current rules, the cost pass-through provisions may not allow for the recovery of forgone revenue as a result of the retailer default. Recovery of other associated costs, however, is permitted.[34] Distributors can seek recovery of cost increases from a retailer default, provided the costs exceed the materiality threshold of 1% of the relevant distributor's revenue requirement for that year. The materiality threshold is designed to provide consistency, transparency and predictability.[35]

Under the rules, cost pass-through is only permitted when it is the least inefficient option and when event avoidance, mitigation, commercial insurance and self-insurance are found to be inappropriate. The cost pass-through provisions treat each retailer insolvency event separately. Hence, each event must pass the relevant 1% materially threshold. If the distributor's application for a cost pass-through is approved by the AER, any increase in costs incurred by a distributor from a retailer's default are passed through, and recovered from, the distributor's customers in the form of increased prices.

2.4 Assessment of current mechanisms for managing retailer default

From the discussion in Sections 2.2 and 2.3, it is evident that there are material risks that a distributor is exposed to and that the current arrangements for managing the impact of a retailer default include a variety of risk mitigation elements of varying industry coverage, effectiveness and cost. In this section we provide an assessment of each mechanism in the context of the risks that a distributor is exposed to.

Credit support arrangements

The current credit support arrangements are designed to partially mitigate both revenue and liquidity risks for distributors in that they enable distributors to access funds in the event an outstanding amount has not been paid by a retailer. There are, however, a number of limitations that appear to weaken the effectiveness of credit support arrangements in managing a distributor's risks. These include:

- The amount of funds received from a defaulted retailer's credit support is limited to the excess of the retailer's NCL over the retailer's CA.
- The structure and features of the current credit support arrangements mean that many retailers are able to apply the maximum CA available (refer Box 3 below), thereby minimising the size of the credit support (refer to Section 5.3 for our estimate of the current levels of credit support provided).
- The current calibration of the MCA (i.e., 25% of the distributor's TARC) is quite large. Given that all retailers are given the same base MCA (before adjustment for credit ratings), those networks with many retailers are likely to have high MCAs relative to individual NCLs, and therefore very low levels of credit support.
- The current arrangements do not mandate that distributors request credit support and hence some distributors may be reluctant to make such requests unless the credit support amounts are material.
- For distributors to draw on any credit support provided, the current arrangements prescribe that there must be no unresolved disputes associated with the retailer's liability to pay for its network charges. A

[34] Other costs (to distributors) as a result of a retailer default may include funding, legal and administrative costs.
[35] It is also designed to limit the applications that can be made such that only substantive change in costs should be covered.

failing retailer may create a dispute as a way of avoiding worsening its solvency by having to provide the credit support, at the very time that it is needed by the distributor.

- A distributor is reliant on the third-party provider of the credit support to meet its obligation under the support agreement and within the timeframe agreed.

Box 3 – Structure and features of credit support arrangements

For a distributor to request credit support from a retailer, a retailer's NCL must exceed its CA. The structure and features of credit support arrangements combine to reduce the likelihood of a retailer's NCL exceeding its CA. This is a result of the following features of the current credit support rules:

- CAs are not currently apportioned across legal entities – Where a retailer has more than one authorisation within a distributor's jurisdiction, the CA is not calculated at the parent level or "looked-through" for related legal entities.[36] This suggests that the CA is currently not apportioned across legal entities associated with a retailer group.[37] As a consequence, some retailers' CAs may be overestimated.

- Inconsistency in credit ratings – The current rules allow retailers to use a Dun and Bradstreet (D&B) dynamic risk score as an alternative to a rating from S&P or other such agencies. It is not apparent that, in aligning the D&B dynamic risk score and S&P ratings, the rules account for differences in their calculations.[38] This raises the possibility that S&P and D&B ratings may be misaligned and hence retailers are allowed to choose the higher of the two ratings.[39] A consequence of this misalignment is that some retailers' CAs are potentially overestimated.[40]

- Selective use of D&B dynamic risk scores – Another issue that arises when using credit ratings is the selective use of D&B dynamic risk scores. For instance, an unrated subsidiary of an S&P-rated parent entity may prefer to use a D&B dynamic risk score in order to obtain a higher CA than otherwise would be the case (i.e., than if they had gained an explicit guarantee from their parent and hence used their parent's S&P credit rating).[41] In other instances, retailers without S&P credit ratings have responded to distributors' requests for credit support by simply applying for a D&B dynamic risk score. An indirect consequence of the selective use of D&B dynamic risk scores is that the retailers' CAs are being overestimated and the corresponding credit support under-provided.

In light of the limitations noted above, the current credit support arrangements appear to have limited capacity to mitigate either revenue or liquidity risk effectively. We explore the effectiveness of the current credit support arrangements further in Section 5.3.

[36] Under the current rules each retailer calculates its CA separately for each legal entity.
[37] Discussions with distributors confirmed this tends to be case, particularly with retailers who operate under multiple authorisations within their jurisdiction.
[38] Credit ratings from S&P and similar agencies are concerned with an entity's likelihood of default based on an entity's financials, future economic potential and other criteria. In contrast, the D&B dynamic risk score functions as a historical payment perspective, evaluating the probability that a business will experience financial distress using the payment history of the retailer.
[39] Submissions from certain distributors and subsequent discussions confirmed misalignment of credit ratings.
[40] The direct impact of misalignment is on the CA% which is derived from a retailer's credit rating or D&B dynamic risk score.
[41] This was confirmed by our discussions with retailers which have unrated subsidiaries that operate across multiple retailer authorisations.

Insurance arrangements

Insurance arrangements allow a distributor to protect itself against a retailer default either through a commercial insurance arrangement or self-insurance. Any premiums paid for the arrangement may potentially be included in the operating expenditure forecasts as part of the regulatory determination process.

For the purposes of protecting distributors from the risks of retailer default, we have considered the use of insurance as a risk protection technique. Ultimately we believe that that such a low-probability, high-impact event (such as retailer default) would be difficult to insure in conventional insurance markets given that the structure and composition of electricity and gas markets means that there are relatively few participants across which such high-impact risks can be diversified. Furthermore, prior to an insurance claim being paid, the claim must be assessed and approved. Hence, there is a risk that a claim may be delayed or denied due to an insurance company challenging the details or events associated with the claim. This raises the possibility that such an arrangement would lead to funds not being provided in a timely manner, thereby still leaving the distributor exposed to liquidity risk.

We have also considered the potential use of self-insurance by a distributor. This involves a distributor setting aside funds over a period of time until a retailer default event occurs. Fundamentally, the success of an insurance business is reliant on the pooling of risks across a portfolio of policies. Self-insurance on an individual distributor basis works against this principle in that funds accumulated over time (especially in the early years of self-insurance) may not be sufficient to protect against retailer default. In a small market, self-insurance is therefore of limited value in protecting against retailer default.

Overs and unders process

The overs and unders process is one of the main statutory mechanisms currently in place to mitigate revenue risk by allowing distributors to recover forgone revenue through future increases in customer prices. The ability to reduce revenue risk through the overs and unders process is, however, limited to periods in which the industry operates under a revenue cap regime.[42] That is, if the AER were, in some later period, to reintroduce a weighted-average price cap regime for distributors, the overs and unders process would no longer be available to mitigate against a distributor's revenue risk.

In relation to a distributor's liquidity risk, we note that recovery through the over and unders process is not a short-term exercise. There may be a significant time period between a retailer default and recovery of funds through increased prices. The application to AER for revenue adjustments would also be subject to an assessment process. On this basis, we are of the view that the over and unders process does little to protect a distributor from any cash flow shortfalls and hence liquidity risk. Uncertainty about approval by the AER also reduces the strength of this mechanism for mitigating revenue risk from a retailer default.

Cost pass-through provisions

Unlike the overs and unders process, cost pass-through provisions can be applied by a distributor regardless of whether distributors are subject to a revenue or price cap regime. However, a key limitation of cost pass-through is that, under the current rules, cost pass-through provisions may not accommodate the recovery of forgone revenue. The provisions only facilitate the recovery of other costs associated with a retailer's default. Without some modifications (see the COAG recommendations below in Section 4.3.1), the cost pass-through provisions currently do little to protect a distributor against the loss of revenue in the event of a retailer default.

[42] It is our understanding that all distributors subject to the NECF apply a revenue cap for the current regulatory control period.

In relation to a distributor's liquidity risk, there are similar limitations to the over and unders process. That is, even if the current cost pass-through rules were modified, the period of time between a retailer default and the recovery of funds through cost pass-through provisions is such that the mechanism does little to protect a distributor against liquidity risk.[43]

Overall assessment of existing mitigation mechanisms

We are of the view that there are limitations in all of the current mechanisms that protect distributors against revenue and liquidity risks in the event of retailer default. Some of the mechanisms may not work with certainty (e.g., the over and under process)[44] and some are simply ineffective given the way they are structured (e.g., the credit support arrangements and cost pass-through provisions). In particular, none of the current mechanisms adequately addresses liquidity risk. While the credit support arrangements could, in principle, provide some liquidity, in practice the support is limited because of the way the mechanism is structured. Distributors currently have little discretion and ability to appropriately protect themselves against the impacts of retailer default and hence are themselves exposed to failure or default. The risk of contagion may further intensify any systemic instability that a large retailer default may cause.

[43] The application to the AER for cost pass-through must be submitted within 90 days of the cost pass-through event. The AER is then provided with 40 days to assess the application. If the application is approved, the distributor's annual pricing proposal must be submitted by 31 March if the costs are to be passed through in the next regulatory year which starts on 1 July. We note that the AER has the power to allow costs to be passed through from the time of approval, rather than requiring a distributor to wait until the beginning of the next regulatory year. We understand that such power is only exercised in extreme circumstances.
[44] This is recognising the possibility that the AER may at some point reintroduce a weighted average price cap.

3 Regulatory principles

3.1 Background

Promontory has been asked to develop a set of design principles for assessing the options for addressing the weaknesses in the current retailer default risk management framework outlined above. These principles provide a foundation for challenging, evaluating and assessing the options set out in Section 4.

At a broad level, any revisions to the current retailer default risk management framework (i.e., a change in one or more rules) must work towards achieving the National Electricity Objective (NEO) and National Gas Objective (NGO).

- The NEO as set out in the National Electricity Law (NEL) is to:[45]

  "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"

- The NGO as set out in the National Gas Law (NGL) is to:[46]

  "promote efficient investment in, and efficient operation and use of natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas"

With focus placed on the risks faced by distributors as a result of retailer default, we consider the relevant aspects of the NEO and NGO to be "efficient operation"[47] as well as, the "reliability and security" of the national electricity system and supply of gas.

Separately, Section 88B of the NEL and Section 293 of the NGL require the AEMC to take into account the effect of the revenue and pricing principles[48] in revising the retailer default risk management framework. Further, any revisions should also be aligned with the objectives of NECF that aims to reduce regulatory red tape for the energy sector and foster increased competition in the retail market.[49]

Taking all of these relevant aspects into consideration, we consider the following principles to be of most importance in assessing the various options in Section 4:

- stability;
- efficiency;
- incentives;
- revenue and pricing principles; and
- competition.

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[45] Section 7 of NEL.
[46] Section 23 of NGL.
[47] This is consistent with the views of the AMEC in its consultation paper, *National Electricity Amendment (Retailer-Distributor Credit Support Requirements) Rule 2015*, 28 May 2015
[48] These relate to the AER's economic regulation of revenues, prices and investment by electricity (or gas) transmission and distribution.
[49] Queensland Government, Department of Energy and Water Supply, Discussion of the NECF (www.dews.qld.gov.au/policies-initiatives/customer-framework).

3.2 Principles to guide assessment of options

Stability

The rule should minimise potential financial contagion of a retailer default to its distributor

As discussed in Section 2.2, one of the greatest dangers of a retailer default is that it may lead, or substantially contribute, to the failure of a distributor. Such an outcome could ultimately lead to systemic instability if it results in the failure of other system participants and a consequent inability of the system to provide energy to homes and businesses as intended. That is, financial contagion from one institution to another could impair the safety and security of the national electricity (or gas) system. Any viable option to protect distributors against retailer default must address the potential for systemic instability that exists in the current arrangements.

Efficiency

The rule should efficiently allocate the risks and costs to parties in order to minimise long-term costs to customers

Any mechanism for managing the risk of retailer default for distributors should be designed to achieve its objectives in the most efficient manner and with the least long-term impact on customers. The efficient operation of the market is a key tenet of both the NEO and NGO. The assessment of options should take into consideration the efficient allocation of risks and costs across distributors, retailers and customers.

Incentives

The rule should provide appropriate incentives to minimise the probability and impacts of retailer default

Incentives are an important component of any rule-making exercise. Introducing incentives that work towards reducing the risk and impact of retailer default, will ultimately lead to a more efficient market that minimises the long-term impact on and costs to customers. Incentives may include retailer incentives to better manage risks and improve credit worthiness. Customers also have an incentive to choose a retailer based on energy prices. As the AEMC consultation paper noted, retailers already face incentives to manage payments and avoid default. These include meeting requirements to maintain their authority to operate as a retailer as well as having existing incentives to avoid default in the wholesale market. The options may nevertheless introduce new incentives. For each option we present, we consider the impact on the operational decisions that participants may make to reduce their costs and protect their longer-term interests.

Revenue and Pricing Principles

The rule should take account of any change in network revenue resulting from the application of the scheme's revenue and pricing principles

In its consultation paper, the AEMC highlighted that any rule change that affects the costs and risks faced by a distributor could affect the AER's determination of a distributor's revenue. Any such rule change requires the AEMC to take into account the revenue and pricing principles. Two principles have been called out as being relevant to any change for managing the risk of retailer default. These are:

- Networks should be provided with a reasonable opportunity to recover at least the efficient costs in providing services and complying with regulatory obligations.

- Any risks remaining after accounting for efficient operational decisions should be considered when estimating the regulated rate of return.

Consistent with these principles, any option recommended should allow a distributor to recover costs associated with managing the risks and impacts of a retailer default. These may include risk management costs involved in minimising the impact prior to default, as well as forgone revenue and increased funding costs that may be incurred after a retailer default. If any residual risks to a distributor remain, then the distributor should be allowed to consider these risks in the regulated rate of return and hence the prices charged for direct services associated with the provision of gas and electricity.

Competition

The rule should consider any impacts on barriers to entry for retail businesses

It is possible that some options may end up increasing the risk management costs of retailers. This may lead to smaller, less creditworthy retailers experiencing higher costs, which could lead to industry exits or deter such retailers from entering the market.

We do not suggest that an increase in barriers to entry should override other goals of any revised or new regime, but believe that the assessment of options should take into account their effects, if any, on increased costs for retailers, especially smaller retailers.

4 Options

4.1 Overview

As noted in Section 1, the AEMC intends to prepare and publish an options paper for stakeholder comment prior to the preparation of the draft determination. In preparation of its options paper, the AEMC has requested that Promontory design three to four options that provide an efficient allocation of the risks and costs to distributors and customers associated with retailer default.

In designing the various options, Promontory has discussed with the AEMC the general design considerations and range of possible mechanisms that may be used in designing a regime to address the risks and costs associated with retailer default. Subsequent to these discussions, and drawing on examples from similar retailer-distributor models in gas and electricity markets, we have identified the following four broad approaches to managing retailer default risk:[50]

1. Retain existing arrangements.
2. Strengthen existing arrangements.
3. Establish a retailer default fund.
4. Introduce a liquidity support scheme.

The design of each of these options is described below, along with the main advantages and possible disadvantages. We note that each of options 2, 3 and 4 include the COAG proposal.

4.2 Option 1: Retain existing arrangements

This option essentially involves retaining the existing arrangements and mechanisms for managing retailer default. The components and mechanisms of the current arrangements are described in Section 2. The main elements of these arrangements can be summarised as follows:

- Credit support requirements – Credit support is provided by retailers for any NCL above the retailer's CA (which represents the unsecured credit limit for each retailer). The CA is based on the TARC of the distributor and the credit worthiness of the retailer. A retailer is only required to provide credit support once a request is provided by the relevant distributor.
- Insurance – A distributor may purchase commercial insurance to cover the loss from a retailer default. We note that we do not regard this as a viable option in the current market context and, consequently, it has not been included as part of the modelling outlined in Section 5.
- Overs and unders process – For those distributors subject to the revenue cap regime as set by the AER, revenue and cost recovery is permitted through the overs and unders process. Any revenue and

[50] In addition to these options, we also considered an option involving credit derivatives and/or commercial insurance but, chose to exclude it for following reasons: 1) credit derivatives or commercial insurance would be available only for retailers with lower market share; and 2) even if credit derivatives or commercial insurance were available for retailers with higher market share, the cost or premium paid would make them uneconomic.

cost impact as a result of a retailer defaulting can be recovered through an increase in energy prices to account for the difference in actual versus expected revenue.[51]

- Cost pass-through mechanism – Exogenous events (e.g., retailer default) that materially increase a distributor's costs can be passed through as increased energy prices. A materially threshold of 1% of the relevant distributor's revenue requirement for that year applies for each cost pass-through application. Current arrangements may not allow forgone revenue to be passed through.

Main benefits

Benefits of the current arrangements include simplicity, facilitation of competition and the avoidance of other costs associated with change under the other options. The main beneficiaries of the current mechanisms are retailers, in that few (if any) are required to provide credit support. Ultimately, it could be argued that customers are the ultimate beneficiaries in that they are not required to pay for protection against an event that has a low chance of occurring (in much the same way as a driver might benefit from not paying motor vehicle insurance premia during a period in which he/she managed to avoid accidents).

The main benefit of the current arrangements for distributors is the scope they would have under the over and unders process to recover forgone revenue after a retailer's default, although even this is uncertain as its applicability changes depending on the form of the price setting regime.

Potential disadvantages

As discussed in Section 2.4, the current arrangements have some weaknesses. The main disadvantage with the current mechanisms is that none of the mechanisms effectively addresses liquidity risk. Reliance is placed on distributors to obtain external funding at a time when distributors' solvency could be in jeopardy. Further, as noted above, the current mechanisms do not provide certainty with respect to revenue risk. In particular:

- the credit support arrangements, in their current form, are too restricted to recover forgone revenue;
- the overs and unders process may not be able to be used in subsequent regulatory control periods (if the AER decides to re-introduce weighted-average price caps); and
- the cost pass-through provisions, in their current form, may not facilitate recovery of forgone revenue.

These disadvantages mean that the revenue risk faced by distributors is mitigated only as long as a revenue cap regime remains in place.

The modelling of this option (see Section 5.3 below) considers primarily the continuation of existing arrangements under a revenue cap regime. For comparison purposes some post-default costs are also calculated for a price cap regime (under which distributors are not able to rely on the overs and unders process to recover forgone revenue as a result of retailer default). This is not, however, considered as a separate option.

4.3 Option 2: Strengthen existing arrangements

This option strengthens existing arrangements by enhancing the cost pass-through and credit support mechanisms. The various enhancements proposed can be considered independently or combined. Our

[51] The modelling of this option will also consider the applicability of the weighted average price cap for distributors and hence the limitations in using the overs and unders process.

modelling of option 2 (see Section 5.4 below) combines the enhancements into three sub-options. All three sub-options assume the proposed COAG rule change (to explicitly allow cost pass-through to recover forgone revenue from a retailer default). In addition to the COAG change, option 2.1 removes the current credit support arrangements (with no replacement mechanism implemented), option 2.2 assumes the AGL credit support proposal and options 2.3 assumes a different (more comprehensive) approach to credit support enhancement (described below).

4.3.1 Enhance cost pass-through provisions (COAG proposal)

The main potential enhancements to the retailer insolvency cost pass-through provisions involve removing the materiality threshold (and hence increasing the amount of costs allowed to be passed through) and allowing forgone revenue to be passed through. These enhancements are in line with the COAG rule change request.[52] As noted by the AEMC in its consultation paper, the amendments to the cost pass-through provisions proposed by the COAG aim to correct the inadvertent omission of these features in the previous drafting of amendments to the NER. In particular:

- During the implementation of the National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 No.9, (Network Regulation Rule)[53] the proposed NECF amendment to remove the materiality threshold for retailer insolvency event was erroneously omitted.
- The definition of retailer insolvency costs including forgone revenue (or unpaid network charges) was erroneously omitted from the relevant amending rule, the National Electricity (National Energy Retail Law) Amendment Rule 2012.

On balance, we strongly support the COAG amendments. While they are not, on their own, a comprehensive solution to all risks faced by distributors in the event of a retailer default, we view them as an integral component of any solution to the underlying systemic risk that could arise from retailer default. We note that the COAG amendments have been included in the modelling we have performed for option 2 and its sub-options (see Section 5.4 below).

4.3.2 Strengthen the credit support mechanism

The existing credit support arrangements are inadequate in mitigating either revenue or liquidity risk. There are a number of ways in which the arrangements could be revised to strengthen them. These include allocating CAs where multiple licences are involved, removing CAs, limiting the credit rating options, and addressing credit concentration concerns.

Allocate CAs where multiple authorisations are involved

As discussed in Section 2.4, CAs are not currently apportioned across legal entities. Where a retailer has more than one authorisation within a distributor's jurisdiction the CA is not calculated at the parent level or looked-through for related legal entities.

If CAs are retained as a key component of any reforms, we recommend addressing the anomaly that arises from the current treatment of retailer groups, if only for logical consistency. In order to account for CAs across a retailer group, we propose an enhancement to clarify the application 6B.B3.4 of the NER and Part 21,

[52] Although the COAG rule change request only applies to the electricity market, we understand that a similar rule change request for the gas market will be submitted to the AEMC in the near term.
[53] AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

Section 521 of the NGR. More specifically, the rules require the allocation of a guarantor's CA amongst retailers to whom the guarantor provides a guarantee. We propose enhancements that clarify the application of these rules to a retailer group. The revised rules would clarify that:

- a licenced retailer is not allowed to use its parent's credit rating unless an explicit guarantee is provided by the parent; and
- if multiple guarantees are provided by the parent of a retailer group (i.e., where retailers utilise their parent's credit rating), the CA of the parent must be apportioned among those retailers being guaranteed.

Unlike the current rules, where each legal entity of a retailer receives a separate CA, the CA under this enhancement would be calculated for the retailer parent, and apportioned across the retailer entities in the group.

We note that none of the sub-options considered for modelling in this Report uses CAs. Hence the allocation of CAs (where multiple authorisations are involved) has not been incorporated in the modelling for option 2.

Remove CAs

Another potential enhancement to the current credit support arrangements would be to completely remove the CAs provided to retailers. As highlighted in Section 2.4, the use of large CAs has contributed to the ineffectiveness of the current credit support rules. The option of removing CAs is in line with AGL's proposal (see Box 4).

Box 4 – Credit support under AGL's rule change

AGL's rule change request proposes to change how credit support is determined under the NER and NGR. The proposal removes the concept of a CA and instead requires credit support to be directly based on the value at risk for the distributor (represented by NCL) and the credit rating of the retailer.

The AGL proposal first sets a benchmark credit rating for which credit support is not required to be provided by any retailers rated at the benchmark level or better, irrespective of their size and market share. The benchmark rating proposed by AGL is BBB-. The proposal then proceeds to calculate the required credit support for any retailers rated below the benchmark.

For retailers below the BBB- benchmark, the amount of credit support is calculated so that the value at risk to the distributor for the retailer below the BBB- benchmark is equivalent to the value at risk if that retailer was rated BBB-. For example, under the AGL proposal, a BBB- rated retailer has a historical default probability of 0.32%[54] and a BB+ rated retailer has a historical default probability of 0.43%. For a BB+ rated relater with a network charges liability of \$100, the following amount of credit support would be required:

$$\textit{Credit support required} = \$100 \times \left[1 - \frac{0.32}{0.43}\right] = \$100 \times 25.58\% = \$25.58$$

[54] Standard & Poor's Ratings Services, *Default, Transition, and Recovery: 2013 Annual Global Corporate Default Study and Rating Transitions, March 2014*, Table 26, p58.

As indicated by the AEMC in its consultation paper, the benchmark chosen by AGL is the level of risk a distributor, and by consequence, a customer, is assumed to be comfortable with bearing without requiring any form of credit support. Based on our discussions with distributors, and submissions received by the AEMC on its consultation paper, we note that distributors are not only concerned with the credit worthiness of retailers but also with the relative size of retailers in their network and, by implication, the impact of not being able to recover a large NCL for a period of time. Furthermore, large retailers are currently rated in the BBB range by credit rating agencies. Setting a benchmark rating of BBB- would mean that no credit support would be provided by the very retailers that generate the largest revenue and liquidity risks for distributors.

As noted above, all three sub-options considered under option 2 remove CAs. More specifically, option 2.1 removes all requirements for credit support, option 2.2 assumes credit support in line with AGL’s proposal (based on a BBB- benchmark) and option 2.3 uses a similar approach to AGL’s proposal but adjusts the benchmark to the higher rating of A-. The higher benchmark rating is consistent with the A- credit rating used as the threshold in the current credit support rules (i.e., a retailer rated A- or better is given access to the MCA).

Limiting the available measures of credit worthiness

As discussed in Section 2.4, the current structure and use of measures of credit worthiness are such that many retailers are able to obtain the MCA available and, as a consequence, very little credit support is actually provided. If CAs are retained as part of any reforms, it is essential that they do not undermine the effectiveness of credit support as a mitigant for revenue and liquidity risk. To prevent such an outcome, enhancements could be made to limit the use of D&B dynamic risk scores. We note that these enhancements would apply to any arrangement that relies on some form of credit worthiness assessment, including both an arrangement that includes a retailer CA (i.e., similar to the current approach) and to an arrangement that does not include CAs (i.e., similar to AGL’s proposal).

The proposed enhancements are as follows:

- Realignment of S&P credit ratings and D&B dynamic risk scores – There are fundamental differences in how D&B dynamic risk scores and S&P credit ratings are calculated. The former is a measure of credit worthiness using payment history, while the latter relies on a wider range of information, including analysis of financials and discussions with management. To account for the limitations associated with a D&B dynamic risk score, we propose re-aligning the D&B scores to match up with lower equivalent S&P ratings. Realignment of D&B dynamic risk scores and credit ratings has been implemented in our model for option 2.3. Table 5.7 in Section 5.4 provides the realigned scores. Under the realigned scores, the highest credit rating allocated to a D&B dynamic risk score is BBB-. Our starting premise is that a retailer should not be able to be classified as the equivalent of an investment grade institution simply by virtue of having a good payment history.

- Mandate use of an S&P credit rating where one is available – The current rules do not clarify whether a retailer’s selective use of a D&B dynamic risk score is permitted. Inconsistencies arise when retailers are able to override existing S&P ratings by using a D&B dynamic risk score. Those retailers with an S&P credit rating (or parent S&P rating) should be required to use the credit rating from S&P (or a similar agency), or alternatively be treated as unrated. This enhancement has also been incorporated in the modelling of option 2.3, such that the use of D&B dynamic risk scores have been restricted in instances where a retailer or its parent group has a credit rating.

Credit concentration

In Section 2.2, we discussed the potential for contagion from a retailer default to a distributor and the subsequent potential for systemic instability. We propose an enhancement to assist in protecting distributors against this contagion by requiring additional credit support as a result of retailer credit concentration. This additional support would need to be sufficient to enable a distributor to meet its committed liabilities from the total credit support provided. The NSW distributors' submission to the AEMC (in response to the AEMC consultation paper) proposed the application of a similar approach.

In order to calculate the amount of additional credit support needed to address concentration risk, we would first assess a distributor's threshold market share (%).

$$Threshold\ Market\ Share\ (\%) = 1 - \frac{Distributor's\ Committed\ Liabilities}{Distributor's\ Billing\ Revenue} = \frac{Cash\ Flow\ at\ Risk}{Distributor's\ Billing\ Revenue}$$

Under this enhancement, additional credit support would be required to account for a retailer's market share beyond the threshold level. The additional credit support "premium", required to account for retailer credit concentration, is calculated as follows:

$$Excess\ Market\ Share\ (\%) = Retailer's\ Market\ Share\ (\%) - Threshold\ Market\ Share\ (\%)$$

$$Concentration\ Credit\ Support\ Premium = \ Exccess\ Market\ Share\ (\%) \times \ Cash\ Flow\ at\ Risk$$

The credit concentration enhancement has not been included in our modelling of option 2. In Section 5, we present results that show that the modelled cash flow risk for distributors is largely mitigated under option 2.3. Given these results, and for the purposes of simplifying the calculations, we are of the view that any potential for contagion has largely been addressed sufficiently by other enhancements made under option 2.3.

Main benefits

The main benefits of these enhancements are that they would provide additional protection to distributors through increased levels of credit support. Any additional credit support would work to reduce both the revenue and liquidity risk faced by distributors in the event of a retailer default. The enhancements also provide a level of certainty in the recovery of any residual forgone revenue and costs (i.e., forgone revenue and costs, for those amounts above the level of credit support, are passed through to the distributor's customers).

Potential disadvantages

The main disadvantage associated with this option is that distributors would still be only partially protected against revenue and liquidity risk. Hence they would still be reliant on the COAG rule change being approved (in order to effectively use cost pass-through) or remaining on a revenue cap in subsequent regulatory controls periods (in order to use the over and unders process) to provide adequate protection against revenue risk.

4.4 Option 3: Retailer default fund

This option involves replacing the current credit support regime with a retailer default fund. The purpose of the fund is to mitigate the revenue, liquidity and systemic risks that distributors face and hence ensure that distributors have access to enough funds to account for any network charges outstanding in the event of a retailer default.

A retailer default fund is in effect a form of industry self-insurance (similar in many respects to a pre-funded deposit insurance scheme) where a pool of funds is accumulated over time which can be used by distributors as needed in the event of a retailer default. Although from a conceptual perspective, establishing a default fund may seem a simple task, there are many aspects to consider:

- Target fund size – The target fund size is typically set at a level sufficient to reduce the probability of the fund's insolvency to an acceptable level. Another simpler approach is to set the target size in order to cater for the largest retailer in the market, that is, the target size of the default fund should aim to be at least big enough to protect against the impact of the largest retailer defaulting.[55] This coverage level can be calculated by taking the largest retailer group (including all licenced retailers operating within that group and including all networks in which they operate) and aggregating the group's NCLs outstanding to all distributors. This would be the base target amount for the default fund. A buffer could also be added (e.g., 15-20%) to account for the potential increase in size of the largest retailer, other costs incurred as a result of a retailer default (other than forgone revenue) and to take into account a scenario in which multiple retailers default in a short period of time. As set out in Section 5.5, our modelling of option 3 assumes a target fund size of approximately $940 million based on the largest retailer's aggregate NCL across all networks.

- Contributions – Sound funding arrangements are critical to the effectiveness of such a retailer default fund. The funds collected for a retailer default fund must be built up over time. There is a need to establish the rules that will drive contributions to the fund. The allowed period of time to achieve the fund's target size will have a bearing on the amount of annual contributions needed. The allocation of the annual contribution requirement to market participants is dependent on the method of allocation.[56] As per AGL's proposal, it is reasonable to expect retailers with equal credit ratings to provide the same contributions in proportion to their own total outstanding network charges liability. Similarly, retailers with a lower credit rating would be expected to contribute proportionally more funds than a retailer with the same outstanding network charges, but a higher credit rating. For the purposes of modelling option 3, we assume an annual contribution of sufficient size to achieve the target fund size after 10 years. We further assume that retailers with equal credit ratings or risk scores provide similar contributions in proportion to their NCLs. A risk-weighted approach has also been implemented in our model to account for different levels of credit worthiness when allocating the annual contribution (see Section 5.5).

- Use and replenishment – Rules must also be developed to govern the use and replenishment of the fund. That is, a central authority (such as the AER) should have the responsibility of determining that a retailer has defaulted and that affected distributors can now make applications to the AER in order to be allowed access to the fund. Each distributor should be able to support its application showing the total outstanding exposure (or NCL) to the defaulted retailer. Replenishment of the fund could use the same retailer contribution rules that were used to build up the fund. Alternatively, once a distributor recovers its funds through the corporate insolvency process or through one of the other statutory mechanisms (such as cost pass-through or over and unders), the funds could be returned and the default fund would be replenished to its size prior to the retailer's default. This alternative approach to replenishment ensures that only those customers within distributors' networks that drew

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[55] For instance, in the banking sector in the event of a failure of an authorised deposit-taking institution, payouts to the failed bank's depositors covered under the Financial Claims Scheme are initially financed by the Australian Government through a standing appropriation of $20 billion per failed ADI (although it is possible that additional funds could be made available, if needed, subject to parliamentary approval).
[56] For example, under *ex ante* funded deposit insurance schemes, banks are either required to make contributions based on their risk profile or make contributions based on their asset base at a flat rate (e.g., 0.10%).

on the default fund are affected by increased prices. Our modelling of option 3 assumes that funds are accessible within 10 days following retailer default (subject to AER approval) and that replenishment occurs through the same retailer contribution rules that we use to build up the fund.

- Management – A governing body must be appointed to manage the fund over time. Typically with such a fund, it is important that the managing party is operationally independent, transparent and insulated from political and industry influence. Like any other managed fund, the governing body will need to be guided as to the most appropriate fund strategy (likely to be conservative in nature) and the level of liquidity needed (a large proportion of assets is likely to be held in liquid assets that can be converted into cash within a short period of time). There will also need to be a fee payable from the fund to the investment managers responsible for managing the fund. This is likely to be in the range of 35-50 bps per annum. For the purposes of modelling, we assume management costs of 50 bps per annum.

There are many similarities between a retailer default fund and a deposit insurance fund used in the banking sector. The Basel Committee on Banking Supervision and the International Association of Deposit Insurers collaborated and developed an internationally agreed set of Core Principles for Effective Deposit Insurance Systems. [57] The principles were released in June 2009, many of which would also apply to the formation of a retailer default fund.

Main benefits

The main benefit of this option is that, once sufficient funds have been accumulated, distributors may face little residual risks from a retailer default. In particular, the fund provides a guaranteed pool of funds available to mitigate against a distributor's revenue and liquidity risks in the event of a retailer default, even if it is one of the largest retailers by market share. Recovery of funds through the insolvency process and statutory mechanisms can be used to replenish the fund after a retailer default.

Potential disadvantages

The main disadvantage of this option is its potential cost:

- Administrative time and resources are needed to set up the governance structures and rules that will govern the operation of the fund. Based on our experience with deposit insurance funds, the setup costs can be considerable.

- Raising funds at the cost of capital and investing them in highly-liquid, low-yield assets involves a negative "carry". It is inefficient to build up a pool of funds that has a high carrying cost and a very low chance of being used (or at least a very low chance of being used in full, given that larger retailers tend to have stronger credit ratings).

- Replenishing the fund after a retailer default involves ongoing costs to customers. Using the same contribution mechanism adopted to build the fund imposes a cost on all customers until the fund has been replenished. Even if the proposed COAG rule change is adopted, replenishing the fund through cost pass-through still imposes the same cost on customers, albeit with a different distribution of costs among customers in different networks.

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[57] Basel Committee on Banking Supervision and International Association of Deposit Insurers, *Core Principles for Effective Deposit Insurance Systems*, June 2009.

- The retailer default fund has the potential to introduce moral hazard risk for distributors. This means that there is no incentive for distributors to reduce their exposure to retailers as distributors are the beneficiaries of the default fund protection.

4.5 Option 4: Liquidity support scheme

The motivation for this last option is recognition that the primary risk in the current arrangements is liquidity risk. Most of the existing mechanisms are designed to recover lost revenue from a retailer default, but to do so over time, thereby leaving distributors subject to potentially debilitating cash flow shortages. Provided (with some minor adjustments) one or more of the existing mechanisms can be relied on to recover lost revenue as well as the costs associated with a retailer default, the main focus for reform should shift to addressing liquidity risk.

In terms of mitigating revenue risk, our preference would be to amend the cost pass-through provisions along the lines of the COAG recommendation. The current credit support arrangements address neither revenue risk nor liquidity risk adequately, leaving this mechanism as both contentious and ineffective unless it is completely overhauled as in option 2.3. For reasons stated above, the overs and unders process, while potentially effective in addressing revenue risk, is complicated by the existence of the alternative weighted-average price cap regime for distributors. The COAG recommendation mitigates revenue risk with the least disruption.

In this section (and in the modelling of option 4 in Section 5.6) we assume that the COAG proposal is implemented and turn to the problem of mitigating liquidity risk through a liquidity support scheme.

Under this option, each distributor would be required to obtain and maintain access to a committed facility from the banking sector.[58] The purpose of the committed facility is to mitigate a distributor's liquidity risk in the event of a retailer default. More specifically, distributors would draw on the committed facility in order to cover any cash flow shortfall between the time of a retailer default and the time a distributor is able to recover its forgone revenue and associated costs through the cost pass-through provisions. Once a distributor recovers the funds, it repays the loan and reinstates the facility back to its full value.

In considering the implementation of this option, we make the following comments:

- There is no pooling of funds or cross subsidisation across networks. That is, a distributor would only be able to access funds from the committed facility that it has obtained for its segment of the market. While it may be possible to design a broader, system-wide liquidity support scheme, we have limited consideration at this stage to a narrow, commercial facility linked to each individual distributor.

- The administrative cost for distributors in obtaining a committed facility should be relatively small.

- A bank could refuse to provide or renew a committed facility due to concerns about the credit worthiness of the distributor. However, provided the COAG recommendation is implemented, the distributor should be able to offer the known recoveries under the NER or NGR, as collateral for any drawing on the facility. This should provide a level of comfort to the lender and reduce the cost of the facility.

[58] We note the design of this facility has some parallels to the committed liquidity facility provided to the commercial banks by the Reserve Bank of Australia in order to meet liquidity requirements under the Basel III framework.

- In the event of a retailer default, discretion would still be left with the distributor as to whether or not to draw on the facility to meet liquidity needs.

Two key design features that require consideration are the required size of each committed facility and the allocation of the commitment fees:

- Size – In establishing the appropriate size of the facility, a distributor's working capital[59] and exposure to retailers through NCL would need to be considered. A simple approach to determining the size of the facility would be to use the NCL of the largest retailer. Alternatively, the overall size of the facility for a distributor could be capped at say, 50% of all retailers' NCLs. While these rules are somewhat arbitrary, they have the advantage of being simple. Nonetheless, more sophisticated rules could be developed and calibrated to better reflect the liquidity needs of distributors following a retailer default.[60] For the purpose of modelling option 4 (see Section 5.6), we assume that the size of the facility is set to the distributor's exposure to the largest retailer in its network (i.e., the NCL of the largest retailer). We also cap the size of the facility at 50% of the distributor's exposure to all retailers in its network.

- Fees – Committed facilities typically carry an annual commitment fee (ongoing fee) and a utilisation fee (funding fee) in the event of drawdown. The commitment fee could be passed on to retailers operating within a distributor's network.[61] The allocation of commitment fees could be based on a simple proportion based on market share, or risk adjusted such that, for a given market share, retailers with lower credit worthiness would pay a higher proportion of the fees and vice-versa. This could be achieved by assigning a risk-weight to each retailer's NCL based on the retailer's credit rating.[62] Alternatively, the fees could be recovered under the cost pass-through provisions. Either way, the commitment and utilisation fees would ultimately be recovered from customers. As set out in Section 5.6, our modelling of option 4 considers two sub-options. Option 4.1 allocates the cost of the liquidity facility based on retailers' market share. Alternatively, option 4.2 allocates the cost using each retailer's NCL and a measure of the retailer's credit worthiness.

Main benefits

The main benefit of this option is that it would protect distributors from the impact of retailer default on the distributor's liquidity. In combination with the COAG recommendation, the committed facility would provide distributors with the ability to recover forgone revenue and the availability of sufficient funds to cover any cash flow shortfalls.

While retailers may be required to pay for the cost of maintaining the committed facility, our results show that the commitment fee is less than the total cost associated with each retailer obtaining sufficient credit support to meet the same level of risk mitigation (see Section 5.4 for our cost estimates under an enhancement credit support arrangement). Section 5.6 presents our estimates of the ongoing costs associated with establishing a liquidity facility.

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[59] Working capital can be in the form of cash, overdraft or a revolving line held by distributors at their respective commercial banks.
[60] For instance, some distributors may be able to survive five weeks after a large retailer default without drawing on the committed facility.
[61] We have not investigated the logistics or associated administration costs for which a fee paid by a distributor can be passed on to retailers operating within its network. This could possibly be implemented through existing network change billing arrangements.
[62] Risk-weight is the concept used in banking which takes into account probability of default and loss given default for a given counterparty/security exposure.

Potential disadvantages

Although we are of the view that this option does not have any significant disadvantages, we highlight the following aspects which may work against its implementation:

- The option is reliant on each distributor being able to secure a committed facility from the banking sector. Market confidence in the use of cost pass-through for revenue recovery will be an important factor in securing committed funds. An AER decision to refuse a distributor's application to pass-through forgone revenue would have a significant impact on the ongoing ability of distributors to establish committed lines of funds at reasonable cost.

- The option introduces an *ex ante* risk management cost (the ongoing facility fee) in managing the risk of retailer default. The cost would ultimately be borne by customers through higher energy prices (this is further explored in Section 5).

- The committed facility and associated risk management costs do not protect distributors (or customers) from the revenue risk impact of a retailer default. Hence, even though retailers (and their shared customers) would pay an *ex ante* risk management cost, those same customers would still also be required to pay for any lost revenue (in the event of retailer default) through the cost pass-through mechanism.

5 Modelling of options

5.1 Framework

Section 4 presents four options for managing retailer default. In this section, we model the revenue and cash flow implications of those options for distributors, as well as the ongoing and post-default costs that would flow through to customers. Our model attempts to provide a realistic representation of electricity and gas networks across jurisdictions where the NECF either currently applies or will apply by the end of 2015. As with any modelling exercise, a range of assumptions underlie our calculations. While we have based those assumptions on available information and discussions with industry, we acknowledge that our estimates and results may not be a fully accurate representation of practice.

Our modelling framework is based on representative electricity and gas networks. Our framework includes 11 electricity networks (i.e., E1 to E11) and eight gas networks (i.e., G1 to G8).[63] While broadly reflecting existing networks, our model excludes two electricity distribution networks due to their unique retailer and customer composition: one network has only a single participating retailer; while the other network has a customer base that is dominated by large customers. We also excluded two gas distribution networks due to lack of sufficient data.

The information and data we use to construct the networks and model the various impacts is based on publicly available sources, supplemented by data provided by the AEMC. The following is an overview of key model inputs and assumptions.

- Distributor revenue – The relevant component of revenue for each distributor (i.e., a distributor's TARC) was sourced from AER's Regulatory Information Notices (for electricity) and access arrangements (for gas). TARC is a key input in all of the options and is used to estimate items such as retailers' NCLs and distributors' current assets.

- Shared customers - The number of shared customers for each retailer within a network was provided by the AEMC. These data are used to estimate each retailer's market share within a network which, in turn, allows us to allocate each distributor's TARC to the relevant retailers that participate in that network. From this information we calculate the NCL for each retailer.

- Credit worthiness – Credit ratings and D&B risk scores for both retailers and distributors were either obtained from public sources or assigned based on information provided by the AEMC. Retailer credit ratings are used to determine the amount of credit support required for options 1 and 2, as well as the allocation of costs for options 3 and 4. Distributor credit ratings are used in option 4 to assist in estimating the cost for a distributor in establishing a liquidity facility.

Appendix B provides further detail on our assumptions and sources of data.

Ongoing costs

For each of the options described in Section 4, we estimate the annual ongoing risk mitigation costs for each retailer within a network. By assuming that these costs are passed onto the shared customers of the retailer, we can estimate the impact of the annual ongoing costs to a shared customer in dollar terms and as a percentage increase in energy costs. In order to estimate the dollar impact, we assume that the risk

[63] References in this section to E1 to E11, and G1 to G8, denote both the network and the distributor for that network.

management costs are applied equally across all shared customers of the retailer (with no distinction made between smaller or larger customers). In order to determine the percentage increase, we rely on annual gas and electricity consumption figures for a representative customer in each NECF jurisdiction. These consumption figures are then used to estimate the current annual costs of electricity and gas for shared customers of 23 different retailers.[64]

We note that we have not taken into account any offsetting impacts from potentially lower distribution charges. Where an option reallocates the impacts of retailer default from distributors to customers, this may affect the distributor's regulatory determination process and hence customer prices. In accordance with the revenue and pricing principles, the regulated return on capital for a distributor could be reduced to take into account the reallocation of risk to customers and hence the reduction in the residual risk for the distributor. A lower regulatory rate of return could flow through to lower prices for customers. Modelling the change in risk profile and its impact on the regulated rate of return would have added unnecessary complexity to our model. It is our understanding that, in practice, such granular adjustments may not be made when estimating the regulated rate of return.

Post-default analysis

In modelling the impact of retailer default, we consider three separate default scenarios as shown in Table 5.1 below. We note that these default scenarios are not relevant when estimating ongoing costs.

Table 5.1: Description of default scenarios

Scenario	Description
Scenario 1	Default of the retailer with largest market share within a distribution network.[65]
Scenario 2	Default of the retailer with largest market share across all electricity and gas networks.[66]
Scenario 3	Default of three retailers each with a market share of less than 5% across electricity and gas networks.[67]

For each of the options described in Section 4, we consider the impact of retailer default under each of the three default scenarios in terms of:

- Revenue impact – The revenue impact for each distributor across each of the scenarios above is measured in terms of forgone revenue plus related costs (as a result of the retailer default). Forgone revenue is calculated as 110% of the defaulted retailer's NCL, while related costs include administrative and funding costs that may be incurred by a distributor as a result of a retailer default.[68]

[64] The 23 retailers were selected as they provided automated calculators that allowed us to obtain the approximate annual costs for a shared customer.
[65] Even though larger retailers tend to operate in multiple distribution networks, the largest retailer in each network may be different from one network to another.
[66] In our model, the retailer with largest market share (across electricity and gas) operates in all of the electricity networks, and in all but one of the gas networks.
[67] We selected the largest retailers that met the specified criterion and participated in both gas and electricity markets. We note that we would expect our results to be similar to scenario 3 if we had chosen three retailers that exclusively operated in the electricity market and three from the gas market, all with similar market share to that in scenario 3.
[68] The reason forgone revenue is assumed to be greater than 100% of NCL is to account for the potential increase of unpaid network charges following a retailer default (i.e., the additional buffer of 10% is to account for the increase in unpaid network charges that distributors would face until such time that customers of the defaulted retailer are transferred or acquired by another retailer).

- Cash flow impact – The cash flow impact for each distributor across the three default scenarios is also analysed by estimating the distributor's working capital ratio three months after the retailer default. We define the working capital ratio as the distributor's current assets (minus the forgone revenue) divided by current liabilities (plus any costs associated with the retailer default).[69]

- Customer impact – As with ongoing costs, we also estimate the post-default cost impact on customers, in the options where the distributor is able to recover forgone revenue and/or costs from customers across the network. The dollar impact for each customer is estimated by applying the costs equally across all customers in the distribution network (including the customers of the defaulted retailer). To estimate the impact as a percentage increase, we use the average of the estimated annual energy costs for shared customers within the network.[70]

Sub-options

In order to explore possibilities within the broad options described in Section 4, we developed a number of sub-options, which we modelled separately. An outline of these sub-options is provided in Table 5.2.

Table 5.2: Description of sub-options

Options	Description
Option 1	Retain existing arrangements (revenue cap regime)
Option 2.1	Strengthen existing arrangements: COAG proposal without credit support
Option 2.2	Strengthen existing arrangements: COAG and AGL proposals
Option 2.3	Strengthen existing arrangements: COAG proposal with enhanced credit support
Option 3	Retailer default fund with COAG proposal
Option 4.1	Liquidity support scheme (market-share-based allocation of ongoing fees) with COAG proposal
Option 4.2	Liquidity support scheme (risk-based allocation of ongoing fees) with COAG proposal

5.2 Revenue and cash flow impacts post default

Revenue impact

Before we can consider the post-default impacts under each option, we first estimate the forgone revenue under each of the three default scenarios. This provides a foundation for our modelling of each option and assists in our analysis of cost implications, revenue recovery options and impacts of any risk mitigation undertaken.

Figures 5.1 (for gas) and 5.2 (for electricity) present our estimates of distributors' forgone revenue under each of the three retailer default scenarios described in Section 5.1.

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[69] Current assets include cash and receivables and current liabilities consist of maintenance, operating expenditure, planned capital expenditure, finance charges and transmission costs (for electricity).
[70] The estimated annual costs for a shared customer was determined in the same manner used for the ongoing costs to shared customers.

Figure 5.1: Forgone revenue under retailer default scenarios – gas distributors

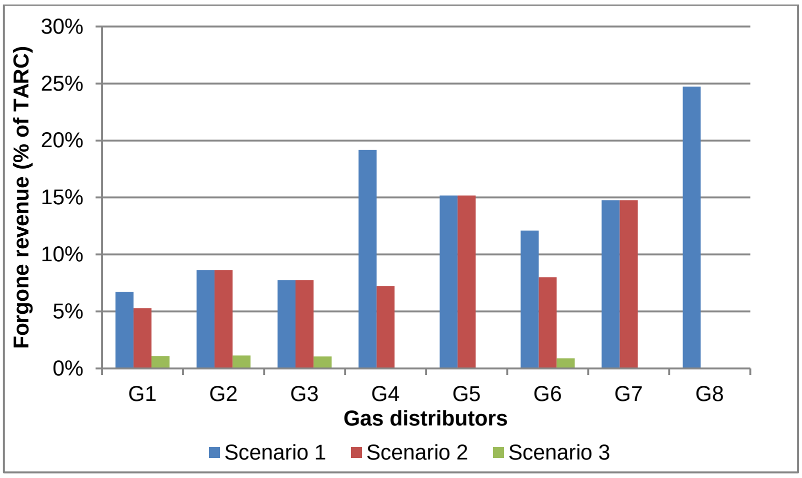
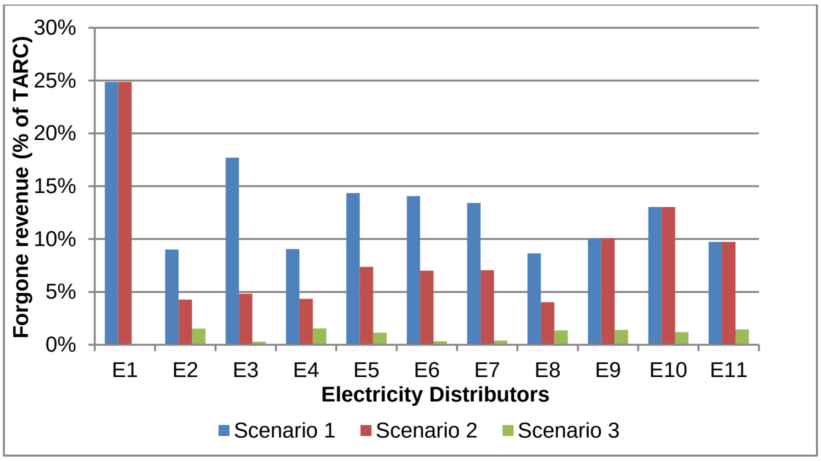


Figure 5.2: Forgone revenue under retailer default scenarios – electricity distributors



We note that, for both gas and electricity distributors, the maximum forgone revenue for scenario 1 is approximately 25% of TARC. For scenarios 2 and 3, distributors are impacted only if the defaulted retailer(s) selected for each scenario operates within their network. Accordingly, one gas distributor is not impacted by scenario 2. One electricity and four gas distributors are not impacted by scenario 3.

Cash flow impact

In addition to considering forgone revenue post retailer default, we also consider the short-term cash flow impact for each distributor across the three default scenarios. The cash flow impacts presented below are shown as an estimate of each distributor's working capital ratio three months after the retailer default (Figures 5.3 (for gas) and 5.4 (for electricity)). The results also include a base-case scenario to show the assumed level of distributors' working capital prior to default. If the working capital ratio is greater than 1.0, this means that there are sufficient current assets to meet committed liabilities, three months after the retailer default. In contrast, if working capital is below 1.0, this means that the distributor is experiencing a cash flow shortfall and will need to obtain enough external funding to bring its working capital ratio back to 1.0.

Figure 5.3: Cash flow impact under retailer default scenarios – gas distributors

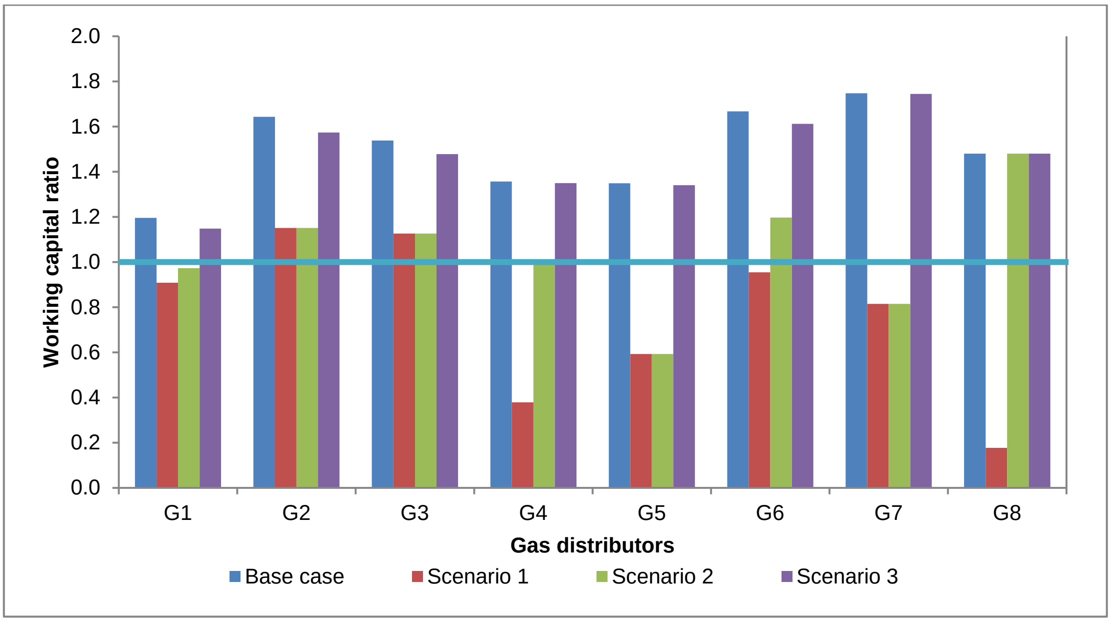
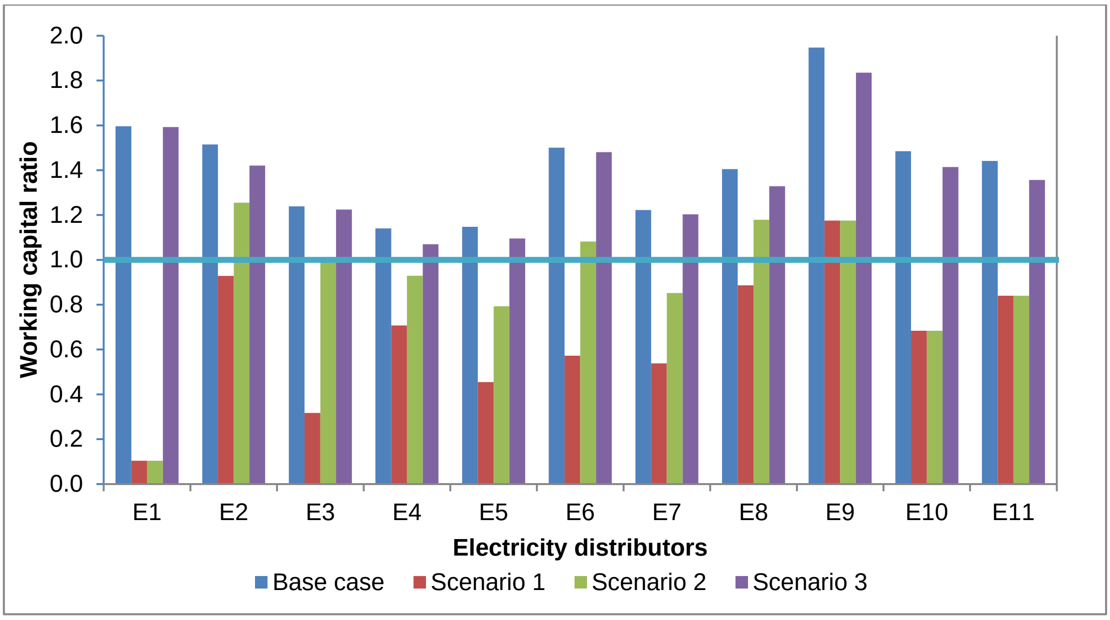


Figure 5.4: Cash flow impact under retailer default scenarios – electricity distributors



Our results show that the working capital ratio for a majority of distributors falls below 1.0 under scenarios 1 and 2. This suggests that these distributors face a cash flow shortfall under the relevant default scenarios that must be externally funded.

5.3 Option 1: Retain existing arrangements

This section reports the results of modelling the ongoing costs and post-default impact of existing arrangements, including current credit support requirements. As noted earlier, our modelling of option 1 assumes the current revenue cap regime continues to apply. For purposes of comparison, however, in calculating the cost implications of option 1 we also consider the operation of a price cap regime.

5.3.1 Ongoing costs

Under current arrangements, the ongoing costs for a retailer are driven by the amount of credit support required and hence the amount that a retailer's NCL exceeds its CA. Our results show that the majority of the retailers in both gas and electricity distribution networks operate at NCL levels well below their CAs. Tables 5.3 (for gas) and 5.4 (for electricity) show the percentage of retailers within each network that have a NCL (as a proportion of the retailer's CA) of less than 100% (these retailers, which are divided into in three bands, provide no credit support) and the proportion of retailers operating at a level greater than 100% (these retailers provide credit support for the amount of NCL that exceeds the retailer's CA).

Table 5.3: Gas distributors – retailer's NCL operating bands

NCL to CA (%)	G1	G2	G3	G4	G5	G6	G7	G8
< 5	50.0%	46.2%	46.2%	66.7%	60.0%	33.3%	75.0%	80.0%
5 to 50	50.0%	53.8%	53.8%	16.7%	20.0%	66.7%	18.8%	-
50 to 100	-	-	-	16.7%	20.0%	-	6.3%	20.0%
> 100	-	-	-	-	-	-	-	-

Table 5.4: Electricity distributors – retailer's NCL operating bands

NCL to CA (%)	E1	E2	E3	E4	E5	E6	E7	E8	E9	E10	E11
< 5	92.9%	71.4%	89.7%	75.0%	81.5%	87.9%	87.1%	75.0%	75.9%	76.9%	77.4%
5 to 50	-	25.0%	6.9%	21.4%	18.5%	9.1%	12.9%	21.4%	20.7%	23.1%	19.4%
50 to 100	7.1%	-	3.4%	3.6%	-	3.0%	-	-	-	-	-
> 100	-	3.6%	-	-	-	-	-	3.6%	3.4%	-	3.2%

Table 5.3 shows that four of the eight gas distributors have a significant proportion of their retailers with a NCL of either less than 5% of their CA, or between 5% and 50%. No gas retailer exceeds 100% of its CA and hence no credit support is provided to any gas distributors.

Table 5.4 shows that the majority of electricity retailers operate with a NCL less than 5% of their CAs, although, in contrast to the gas networks, electricity distributors have a small proportion of retailers whose NCLs exceed their CAs. We note that, of those retailers providing credit support in our model, the amount of credit support provided ranges from 4% to 32% of the relevant retailer's NCL. The total dollar amount of credit support received by distributors across all networks is approximately $3 million.

Given the minimal credit support actually provided under option 1, the ongoing costs of existing arrangements for both retailers and their shared customers is insignificant. Our results suggest that the maximum ongoing cost impact on a shared customer's annual electricity bill is approximately $2.40, or less than 0.22% of their current annual bill. Furthermore, only 1% of all electricity customers (across all networks) are affected, that is, there is no ongoing cost impact for 99% of electricity customers.

5.3.2 Post-default analysis

The allocation of post retailer default costs between distributors and their customers under option 1 is determined by whether the distributors are subject to a revenue cap or a price cap regime. Accordingly, we estimate post-default costs to distributors and/or their customers under the two possible pricing regimes.

In both cases we assume that the AER will only allow customer price increases (via a distributor's revenue adjustments) of up to 10% in any one year. Any adjustments beyond 10% are applied in later years.[71] The distributor's cost of debt is used to calculate the funding costs incurred by distributors from a delay in the recovery of forgone revenue.

Option 1 – (Revenue cap regime)

Where distributors are subject to a revenue cap regime, the forgone revenue and costs from retailer default are passed to the distributors' customers by way of higher distribution charges in future years. Before we consider the recovery of forgone revenue, we must model the additional costs (i.e., funding costs) that distributors face as a result of retailer default.[72] To estimate funding costs as a result of retailer default, we model cash flow impacts to determine the amount of external funding required as a result of any cash flow shortfall to distributors (refer to Section 5.2). The cash flow impact takes into account the delay faced by distributors in recovering forgone revenue and costs through the overs and unders process.

We note that even though a small amount of credit support is provided under option 1, none of those retailers providing credit support are impacted by the three default scenarios. In other words, the retailers that we assume to default do not overlap with those retailers providing credit support for option 1. Figures 5.3 (gas) and 5.4 (electricity) above provide the cash flow position for each distributor for option 1. We use these figures to estimate the amount of external funding the distributors would need to access in order to bring their working capital ratio back to 1.0.[73] The associated funding costs are then modelled using each distributor's cost of debt (obtained from their regulatory determination or access arrangements).

In applying the distributor's cost of debt we assume that distributors face a recovery period (i.e., the period of time between retailer default and recovery of forgone revenue through over and unders) of between 1.5 and 3.5 years. The length of the recovery period is based on the assumption that increases in customer energy prices of up to 10% per annum will be approved. Thus, if the increase in customer energy prices is greater than 10%, the period of recovery is extended accordingly (up to a maximum of 3.5 years).[74] For the purposes of comparing the total additional amounts payable by customers, we present the *total* dollar cost increase for a customer (irrespective of whether that increase applies over one, two or three years) as a percentage of the

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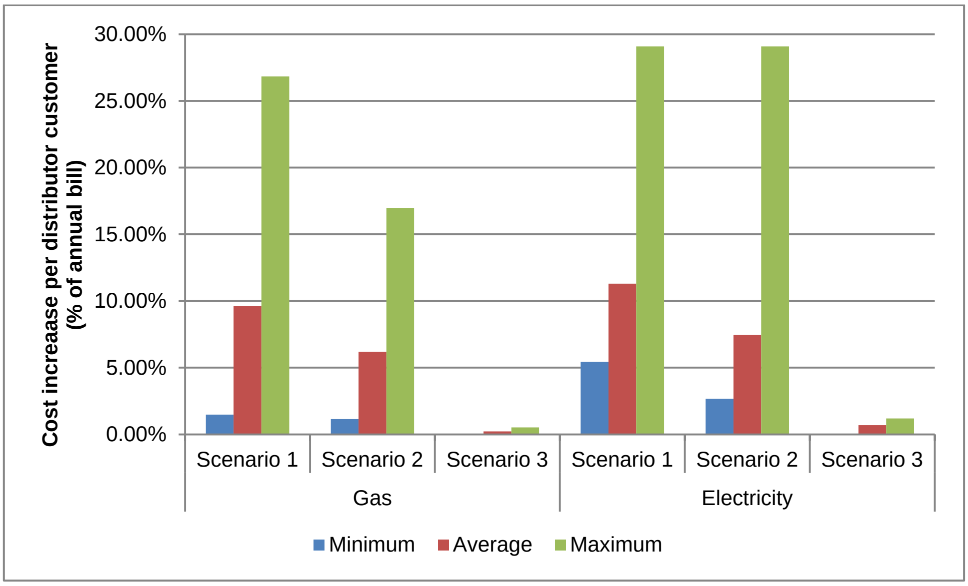
[71] The assumption that the AER will only allow customer price increases of up to 10% (as a result of a distributor recovering forgone revenue and costs through the use of over and unders or cost pass-through) is also applied for options 2 and 4.
[72] Administrative costs are also added to the costs for each distributor and are assumed to be $100,000 for each scenario. This is to account for legal and accounting expenses incurred by distributors following the retailer(s) default.
[73] The amount of external funding required is calculated as current liabilities minus current assets (after adjusting for the impact of forgone revenue and any credit support associated with the defaulted retailer). We assume that no additional funding is required once a distributor's working capital ratio reaches 1.0.
[74] We have assumed that the retailer default occurs on 1 January and the recovery period starts on 1 July and ends on 30 Jun the following year. This represents a minimum period of recovery of 1.5 years. The ability to extend this period to 3.5 years in our model recognises that the AER has the discretion to require a longer recovery period. We have assumed that this will occur when customer prices are expected to increase by more than 10% in a regulatory year as a result of the distributor's proposed recovery of forgone revenue and costs. We note that the maximum customer price increase we observe in our modelling across all options is less than 30% and hence we did not find the need to extend the period of recovery beyond 3.5 years.

customer's *annual* electricity or gas bill. We also apply the same approach when presenting the impacts on customers under option 2 (refer Section 5.4.2) and option 4 (refer Section 5.6.2).

Customer impact

As indicated above, the total post retailer default impacts include forgone revenue and additional costs (which we assume to include both funding and administrative costs). Applying these costs to a distributor's customers would result in some material impacts on customers, as illustrated in Figure 5.5. Figure 5.5 shows the minimum, average and maximum cost impact on (gas and electricity) customers across the different networks under each of the three scenarios.

Figure 5.5: Post-default costs to distributors' customers – revenue cap (overs and unders process)



The most striking feature of Figure 5.5 is the wide dispersion of impacts across different networks for any given scenario. For example, the average cost increase for a gas distributor's customers under scenario 1 is 9.6%, with a minimum of 1.5% and a maximum of 27%. Similarly, the average cost increase for an electricity customer under scenario 1 is 11.3%, with a minimum of 5.4% and a maximum of 29%. A second feature of Figure 5.5 is that the cost impact of scenario 3 is relatively minor, both for gas and electricity. The cost impacts on customers under both scenarios 1 and 2, however, have the potential to be material (particularly for electricity).

Option 1 - (Price cap regime)

When distributors operate under a price cap regime, we assume they cannot rely on the overs and unders process to recover forgone revenue as a result of retailer default. They can, however, recover costs (but not forgone revenue) provided these costs are more than 1% of their TARC. Thus, we first estimate whether the 1% materiality threshold is met for different networks under the three default scenarios (see Table 5.5).

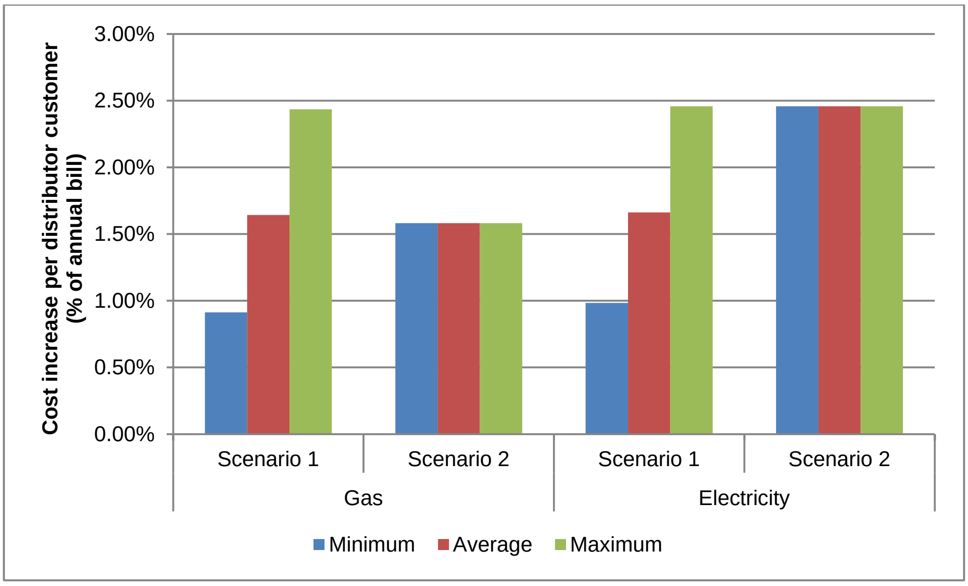
Table 5.5: Cost pass-through (materiality threshold by network)

	Gas		Electricity	
	Met	Not met	Met	Not met
Scenario 1	3	5	3	8
Scenario 2	1	7	1	10
Scenario 3	0	8	0	11

Customer impact

The results show that the cost pass-through materiality threshold is not met for the distributors in any of the modelled networks under scenario 3, but is exceeded for some distributors under scenarios 1 and 2. For those distributors that exceed the materially threshold, we estimate the post-default costs for distributors' customers under scenarios 1 and 2 (see Figure 5.6). Figure 5.6 shows the minimum, average and maximum cost impact on (gas and electricity) customers across the different networks under scenarios 1 and 2.

Figure 5.6: Post-default costs to distributors' customers – price cap (cost pass-through)



While the cost impact on customers (under a revenue cap regime) for scenarios 1 and 2 is potentially material, the effect of switching to a price cap regime and using a materiality threshold means that the impact on customers is diminished and limited to just a few of the networks. For example, the average price increase for those customers in networks that have exceeded the materially threshold (i.e., 3 out of 8 networks in gas and 3 out of 11 in electricity for scenario 1, and 1 out of 8 in gas and 1 out of 11 in electricity for scenario 2) are in the range of 1.6% to 2.5%. These increases all occur within one year.

Revenue impact absorbed by distributor

Next, we estimate the post-default costs absorbed by distributors (as a percentage of TARC). These costs fall to the distributors as a result of the distributors' inability to recover forgone revenue and costs below the 1% materiality threshold (in accordance with the current operation of the cost pass-through mechanism) (see Figures 5.7 (gas) and 5.8 (electricity)).

Figure 5.7: Post-default costs to gas distributors – price cap (cost pass-through)

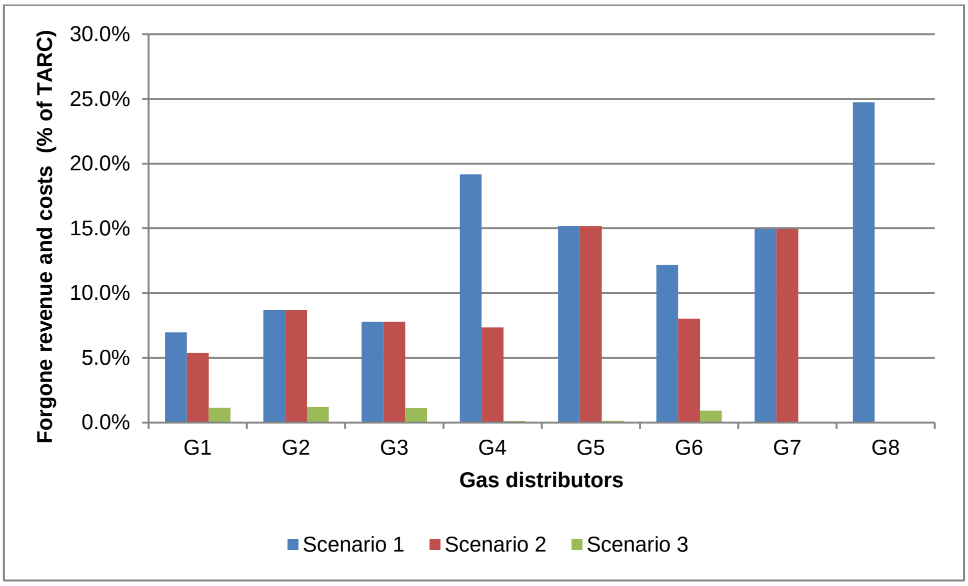
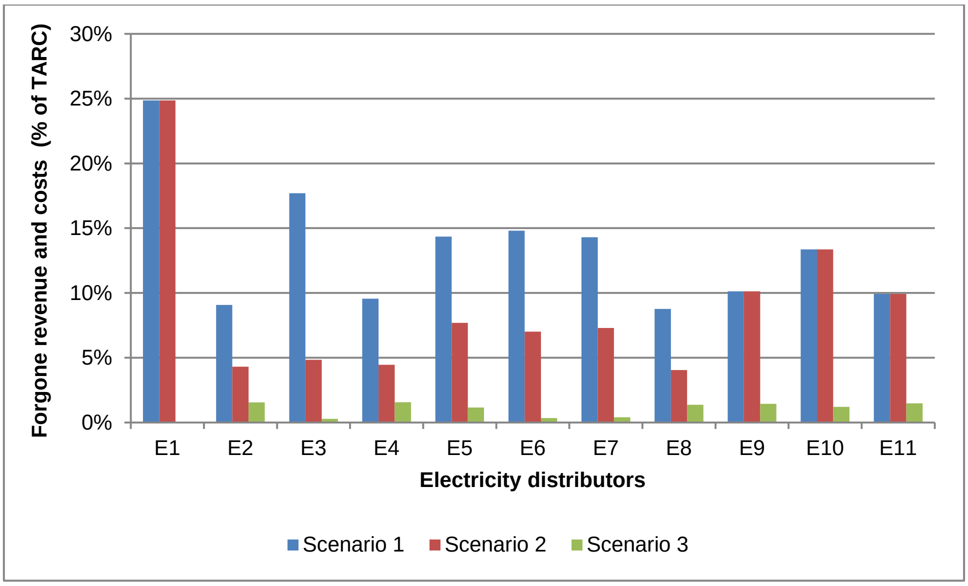


Figure 5.8: Post-default cost to electricity distributors – price cap (cost pass-through)



Figures 5.7 and 5.8 show the post-default impact to distributors under existing arrangements (i.e., forgone revenue and related costs below the 1% materiality threshold) if a price cap regime were to apply. Revenue impacts are significant for gas and electricity distributors under both scenarios 1 and 2. In particular, one gas and one electricity distributor under scenario 1 and one electricity distributor under scenario 2 would face a revenue impact of close to 25% of TARC, with around two-thirds facing a revenue impact of greater than 10%. For scenario 2, all affected gas distributors and more than half the electricity distributors would lose between 5 to 15% of their TARC. The impact under scenario 3 is considerably lower with distributors generally exposed to less than 3% of TARC.

5.4 Option 2: Strengthen existing arrangements

In this section, we model various enhancements to the cost pass-through mechanism and credit support requirements. The various combinations of these enhancements are grouped into three sub-options for the purposes of assessing ongoing costs and post-default impacts (see Table 5.6).

Table 5.6: Description of options 2.1, 2.2 and 2.3

Options	Description
Option 2.1	Strengthen existing arrangements: COAG proposal without credit support. The purpose of this option is to assess the impacts on distributors of removing the current credit support arrangements and introducing the COAG proposal. Under the COAG proposal the cost pass-through mechanism is enhanced by allowing the recovery of forgone revenue from retailer default and by removing the materiality threshold.
Option 2.2	Strengthen existing arrangements: COAG and AGL proposals. This option assumes that the COAG proposal is approved (as per option 2.1) and credit support requirements are amended as per AGL's proposal. Under the AGL proposal CAs are removed and only retailers rated below BBB- are required to provide credit support.
Option 2.3	Strengthen existing arrangements: COAG proposal with enhanced credit support. This option assumes that the COAG proposal is approved (as per option 2.1 and 2.2) and an alternative set of credit support requirements (different to those proposed by AGL) are introduced. Under the alternative credit support arrangements CAs are removed. Unlike the AGL proposal, however, this option retains the current benchmark credit rating of A-. That is, only retailers rated below A- are required to provide credit support. Other enhancements implemented for this option include: re-alignment of D&B dynamic risk scores and credit ratings to reflect differences in methodology (see Table 5.7); and restricting the use of D&B risk scores in instances where a retailer or its parent group have a credit rating.

Table 5.7 shows the proposed realignment of D&B dynamic risk scores under option 2.3. The intention is to better align the D&B risk scores with credit ratings.

Table 5.7: Re-alignment of D&B dynamic scores and credit ratings

S&P/ Fitch credit rating	Moody's credit rating	Current D&B dynamic risk score alignment	Re-aligned D&B dynamic risk score
AAA	Aaa		
AA+	Aa1	Minimal	
AA	Aa2	Minimal	
AA-	Aa3	Minimal	
A+	A1	Very Low	
A	A2	Very Low	
A-	A3	Very Low	
BBB+	Baa1	Low	
BBB	Baa2	Average	
BBB-	Baa3		Minimal
BB+	Ba1		Very Low
BB	Ba2	Moderate	Low
BB-	Ba3	High	Average
B+	B1	Very High	Moderate
B	B2		High
B-	B3	Severe	Very High
CCC	Caa		Severe
CC	Ca		
C	C		

Several other credit support enhancements were discussed in Section 4 but have not been incorporated into option 2.3 (or the other two options). These include:

- The allocation of CAs where multiple authorisations are involved – It is not necessary to model this enhancement as none of the sub-options in this section uses CAs.
- The addition of a credit concentration surcharge – As shown in our results below, the cash flow risk for distributors is largely mitigated under option 2.3. That is, under option 2.3, the majority of distributors do not experience a cash flow shortfall. Furthermore, for the majority of distributors that do experience a shortfall, the amount of the shortfall is minimal (see Figures 5.17 and 5.18).

Given these observations, and the computational advantages of simplifying the calculations in option 2.3, we chose to exclude these additional reforms on the grounds that the potential for contagion in our model has largely been addressed by other enhancements made under option 2.3.

5.4.1 *Ongoing costs*

As with option 1, the ongoing costs for a retailer are driven by the amount of credit support required. In the absence of the CAs the amount of credit support required is materially higher under option 2 than under option 1. The level of credit support required under each sub-option within option 2 is calculated as a proportion of each retailer's NCL. The proportion is calculated using relative default probabilities using each retailer's credit rating as demonstrated in Section 4.3. The default probabilities for various credit ratings and corresponding credit support required under each sub-option are shown in Table 5.8 below.

Table 5.8: Credit support under option 2

Standard & Poor's / Fitch credit rating	Moody's credit rating	S&P default probabilities (2013)[75]	Option 2.1: no credit support	Option 2.2: credit support as % of NCL	Option 2.3: credit support as % of NCL
AAA	Aaa	0%	Nil	Nil	Nil
AA+	Aa1	0%	Nil	Nil	Nil
AA	Aa2	0.02%	Nil	Nil	Nil
AA-	Aa3	0.03%	Nil	Nil	Nil
A+	A1	0.06%	Nil	Nil	Nil
A	A2	0.07%	Nil	Nil	Nil
A-	A3	0.08%	Nil	Nil	Nil
BBB+	Baa1	0.14%	Nil	Nil	42.86%
BBB	Baa2	0.20%	Nil	Nil	60.00%
BBB-	Baa3	0.32%	Nil	Nil	75.00%
BB+	Ba1	0.43%	Nil	25.58%	81.40%
BB	Ba2	0.68%	Nil	52.94%	88.24%
BB-	Ba3	1.13%	Nil	71.68%	92.92%
B+	B1	2.31%	Nil	86.15%	96.54%
B	B2	4.73%	Nil	93.23%	98.31%
B-	B3	7.92%	Nil	95.96%	98.99%
CCC	Caa	26.87%	Nil	98.81%	99.70%
CC	Ca	26.87%	Nil	98.81%	99.70%
C	C	26.87%	Nil	98.81%	99.70%

The difference in the benchmark ratings between options 2.2 and 2.3 (and absence of credit support under option 2.1), leads to different levels of credit support for a given retailer under each of these sub-options.

[75] Standard & Poor's Ratings Services, *Default, Transition, and Recovery: 2013 Annual Global Corporate Default Study and Rating Transitions*, March 2014, Table 26, p58.

Tables 5.9 and 5.10 show the aggregate levels of credit support for each distributor as a proportion of the relevant gas and electricity distributor's unpaid network charges.[76] We also provide the results under option 1 for comparative purposes.

Table 5.9: Credit support as a proportion of unpaid network charges – gas distributors

Option	G1	G2	G3	G4	G5	G6	G7	G8
Option 1	-	-	-	-	-	-	-	-
Option 2.1	-	-	-	-	-	-	-	-
Option 2.2	1.8%	2.0%	2.2%	0.0%	0.0%	2.4%	0.0%	0.0%
Option 2.3	57.7%	57.0%	56.2%	70.9%	66.4%	63.3%	62.3%	44.3%

Table 5.10: Credit support as a proportion of unpaid network charges – electricity distributors

Option	E1	E2	E3	E4	E5	E6	E7	E8	E9	E10	E11
Option 1	-	1.1%	-	-	-	-	-	0.7%	0.2%	-	0.7%
Option 2.1	-	-	-	-	-	-	-	-	-	-	-
Option 2.2	0.0%	5.8%	0.6%	4.4%	0.0%	0.5%	0.5%	6.0%	4.9%	4.3%	5.5%
Option 2.3	60.3%	61.0%	69.2%	56.8%	69.6%	61.9%	66.5%	60.0%	55.9%	58.8%	56.8%

The lowest level of credit support (i.e., zero) is provided under option 2.1. Option 1 (current arrangements) provides very minimal credit support (also zero in all gas networks as well as in the majority of electricity networks). From this low base, option 2.2 increases the overall level of credit support to each distributor only marginally. This result is driven by the fact that, under option 2.2, credit support is provided by small retailers that represent only a small fraction of each distributor's exposures[77] (i.e., retailers with a market share of less than 5%). In practice, retailers that represent more than 5% of a distributor's unpaid network charges do not provide credit support under option 2.2 because they have credit ratings (or equivalent D&B risk score) of BBB- or better.

In contrast to the other sub-options, there is a significant increase in the amount of credit support provided under option 2.3. This is driven by the inclusion of credit support requirements that apply to retailers that represent more than 5% of a distributor's exposure. The vast majority of these retailers have a credit rating (or equivalent D&B risk score) in the range of BBB- to BBB+ and hence are required to provide credit support under option 2.3 (in contrast to option 2.2).

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[76] A distributor's "unpaid network charges" represents the distributor's total exposure to all retailers within its network, that is, the sum of each retailer's NCL operating within the network. In our model we have assumed the distributor's unpaid network charges is the equivalent of a distributor's TARC over a 90-day period (i.e., 25% of TARC).
[77] The total exposure of a distributor to retailer default is equal to the sum of each retailer's NCL operating within the network. Given our approach to the calculation of a retailer's NCL, for the purposes of our model, the sum of all retailers' NCL within a distributor network is equal to 25% of the distributor's TARC.

The removal of credit support under option 2.1, and the differing levels of credit support provided under option 2.2 and 2.3, result in a range of annual ongoing costs to retailers and their shared customers under each of these sub-options.

Firstly, there are no ongoing costs to shared customers under option 2.1 due to the removal of the credit support regime in this sub-option. The annual ongoing costs to shared customers under options 2.2 and 2.3 are presented in Figures 5.9 and 5.10 for gas and Figures 5.11 and 5.12 for electricity.

Costs to shared customers are presented as a percentage change to a shared customer's annual energy bill. We note that the percentage change will vary both across and within networks. To assist in understanding the range of impacts, we present the minimum, average and maximum percentage impacts. We also separate the impacts into retailer credit rating and D&B dynamic risk score categories.

Figure 5.9: Ongoing costs to shared customers of gas retailers (option 2.2)

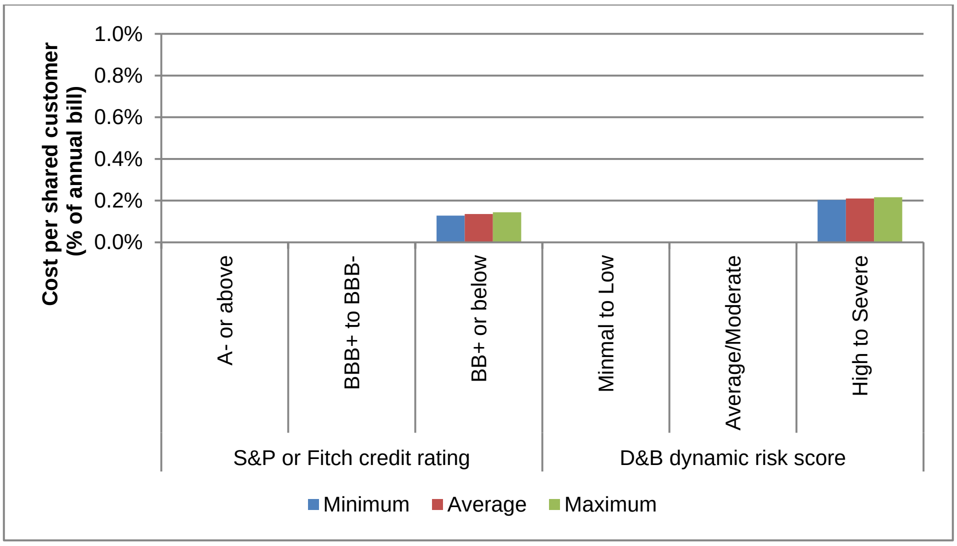
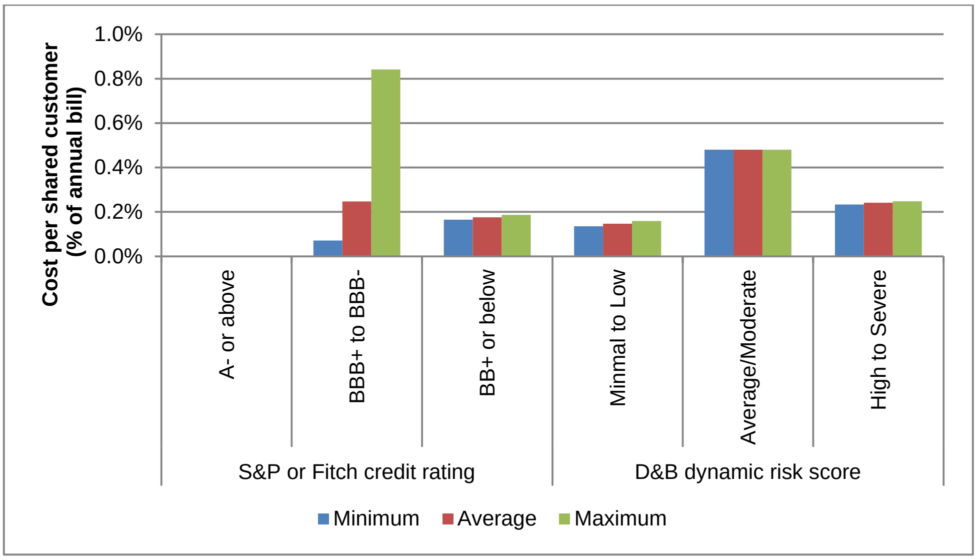


Figure 5.10: Ongoing costs to shared customers of gas retailers (option 2.3)



As expected, the annual ongoing costs to shared customers of gas retailers are higher under option 2.3 than option 2.2. For example, shared customers of gas retailers rated BB+ or below face cost increases in the range of 0.12% to 0.14% per annum under option 2.2, compared with 0.17% and 0.19% under option 2.3. Similarly, shared customers of gas retailers with D&B risk scores of High to Severe experience cost increases of between 0.20% and 0.22% under option 2.2, compared with 0.23% and 0.25% under option 2.3.

The cost increases under option 2.3 are more substantial for shared customers of retailers rated BBB+ to BBB- by S&P or Fitch and for those with a D&B score of Moderate or Average. For retailers rated BBB+ to BBB-, the increase is driven by the use of a benchmark credit rating of A- for option 2.3, as opposed to BBB- for option 2.2. For retailers with D&B risk score of Average or Moderate, the increase is largely an outcome of realigning D&B risk scores with S&P/Fitch credit ratings.

Figure 5.11: Ongoing costs to shared customers - electricity retailers (option 2.2)

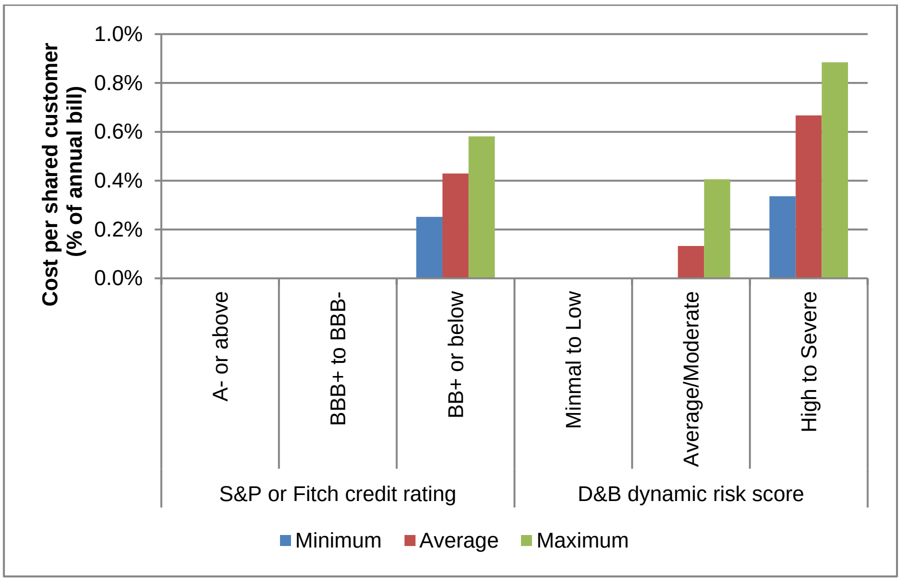
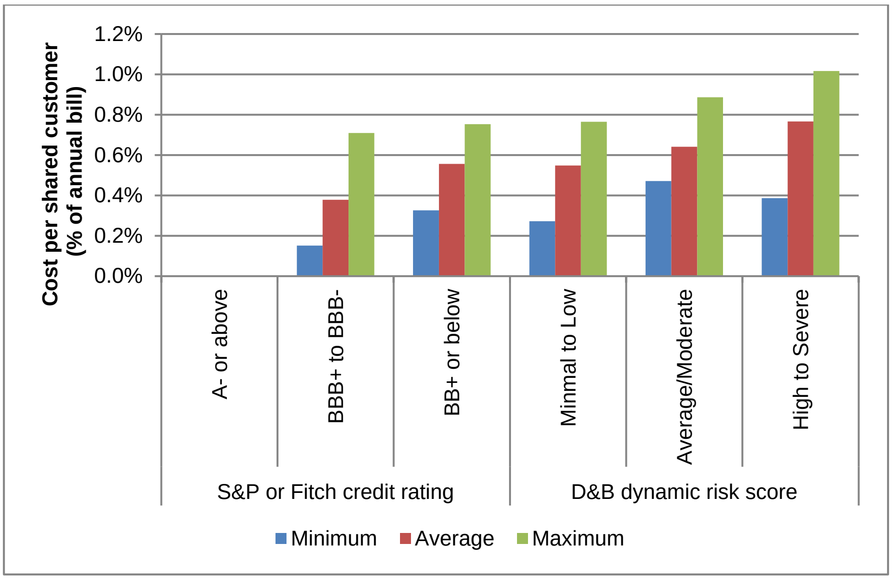


Figure 5.12: Ongoing costs to shared customers – electricity retailers (option 2.3)



As with the customers of gas retailers, the annual ongoing costs to shared customers of electricity retailers are higher under option 2.3 than under option 2.2. In the upper and lower risk ranges the differences are only minor. For example, under option 2.3, the shared customers of electricity retailers with credit rating BB+ or below would experience an increase in their annual power bills in the range of 0.33% and 0.75%, compared with 0.25% to 0.58% under option 2.2. Similarly, the shared customers of electricity retailers with D&B risk scores of High to Severe would experience cost increases of between 0.39% and 1.02% under option 2.3, compared with 0.34% and 0.90% under option 2.2. As in the gas market, however, the differences between the options are more marked in the middle risk rating ranges. In particular, retailers with S&P/Fitch ratings between BBB+ and BBB-, or D&B risk score of Average or Moderate, are not exempt from credit support requirements under option 2.3. For example, for retailers with credit rating between BBB+ and BBB, the cost per shared customer is between 0.15% and 0.71% under option 2.3, compared to none under option 2.2.

5.4.2 Post-default analysis

For the purposes of post-default analysis under option 2, we assume that the COAG proposal to remove the materiality threshold and to allow recovery of forgone revenue under cost pass-through are implemented. Moreover, as with the application of overs and unders under option 1, we have assumed that the recovery of forgone revenue and costs using enhanced cost pass-through extends beyond a one-year period.

As with option 1, we model the impacts of retailer default in terms of forgone revenue, cash flow impact (and implications in terms of funding costs) and customer impact (where the post-default cost to distributors' customers are a function of both forgone revenue and funding costs under retailer default scenarios). For option 1 we calculated the revenue impacts by estimating the forgone revenue under each retailer default scenario. Our focus for option 2 is to estimate how much of this forgone revenue is mitigated by credit support. The higher the level of credit support provided by a defaulted retailer, the lower the post-default forgone revenue. In relation to the cash flow impacts and funding costs, we model the amount of external funding required as a result of any cash flow shortfall following retailer default (which is also influenced by the amount of credit support provided by each defaulted retailer).

We first determine whether credit support is provided from any of the defaulted retailers under the three default scenarios. The results are summarised in Table 5.11 below.

Table 5.11: Provision of credit support by defaulted retailers under three scenarios

Option	Default scenario 1 (Largest retailer within a network)	Default scenario 2 (Largest retailer across networks)	Default scenario 3 (Three retailers (less than 5% market share))
Option 2.1 **No credit support**	×	×	×
Option 2.2 **AGL credit support**	×	×	✓
Option 2.3 **Enhanced credit support**	✓	✓	✓

Under option 2.1, no retailer provides credit support. Under option 2.2, the large retailers that are assumed to default under scenarios 1 and 2 have credit ratings of BBB- (the benchmark credit rating) or higher, and hence do not provide credit support. Only in scenario 3 (where smaller retailers are assumed to default) is credit support activated for option 2.2. In contrast, all of the retailers assumed to default under any scenario under option 2.3 for all the three default scenarios provide credit support. That is, all of the defaulted retailers under the scenarios have credit ratings of lower than A- (the benchmark rating for option 2.3).

Revenue impact

Figures 5.13 to 5.16 below show the amount of forgone revenue mitigated (or recovered from credit support) in instances where credit support is provided for each of the three default scenarios. Figures 5.13 and 5.14 show the proportion of forgone revenue mitigated under option 2.2 for retailer default scenario 3. Figures 5.15 and 5.16 show the proportion of forgone revenue mitigated under option 2.3 for all the three default scenarios. There are no figures needed for the five out of nine option/scenario combinations where no credit support is activated.

Figure 5.13: Forgone revenue mitigated by credit support – gas (scenario 3 for option 2.2)

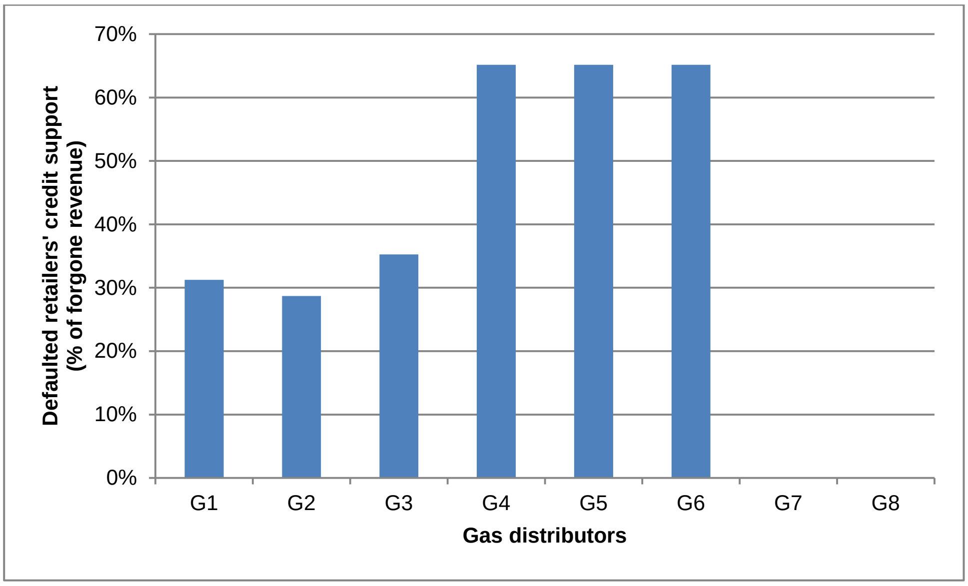


Figure 5.14: Forgone revenue mitigated by credit support – electricity (scenario 3 for option 2.2)

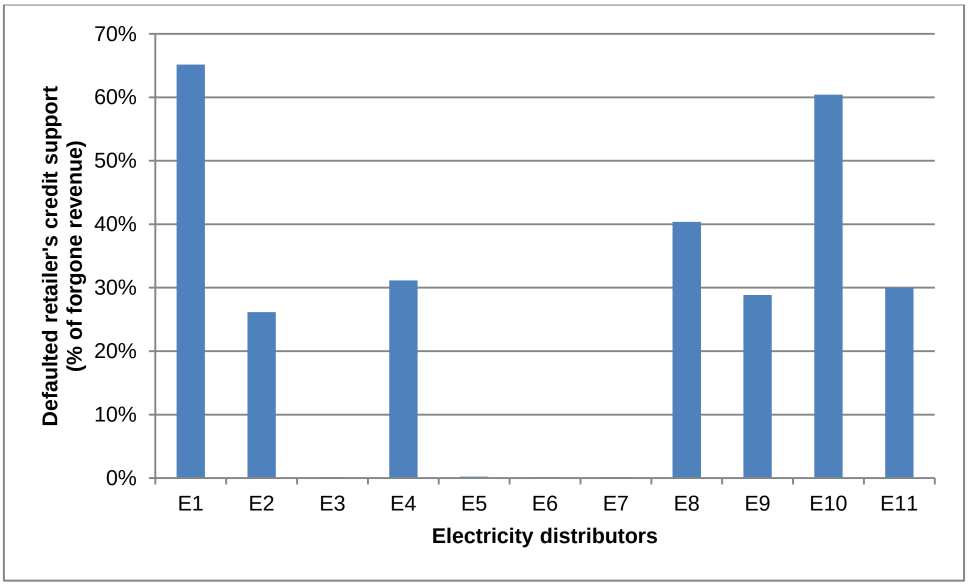


Figure 5.15: Forgone revenue mitigated by credit support – gas distributors (option 2.3)

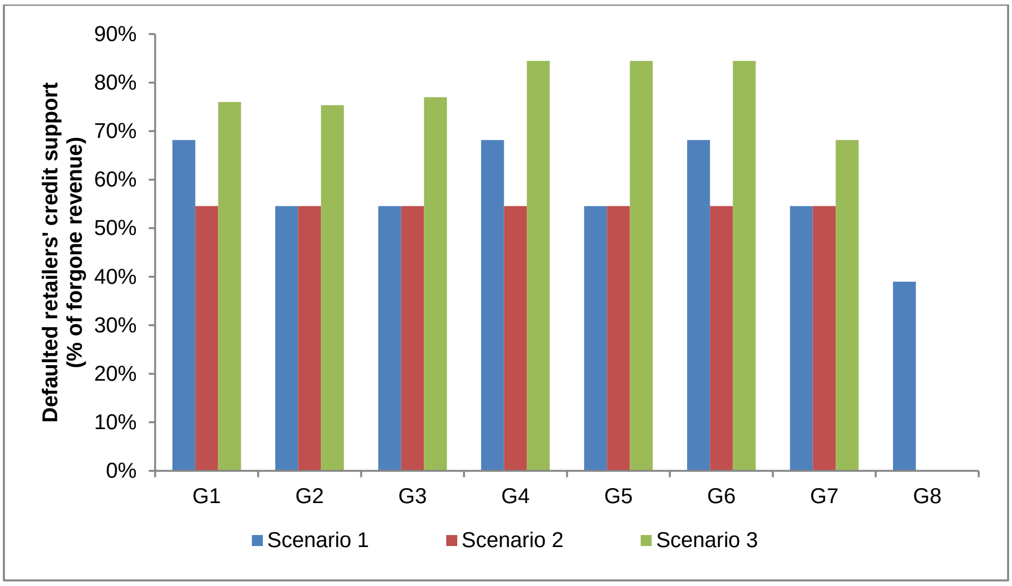
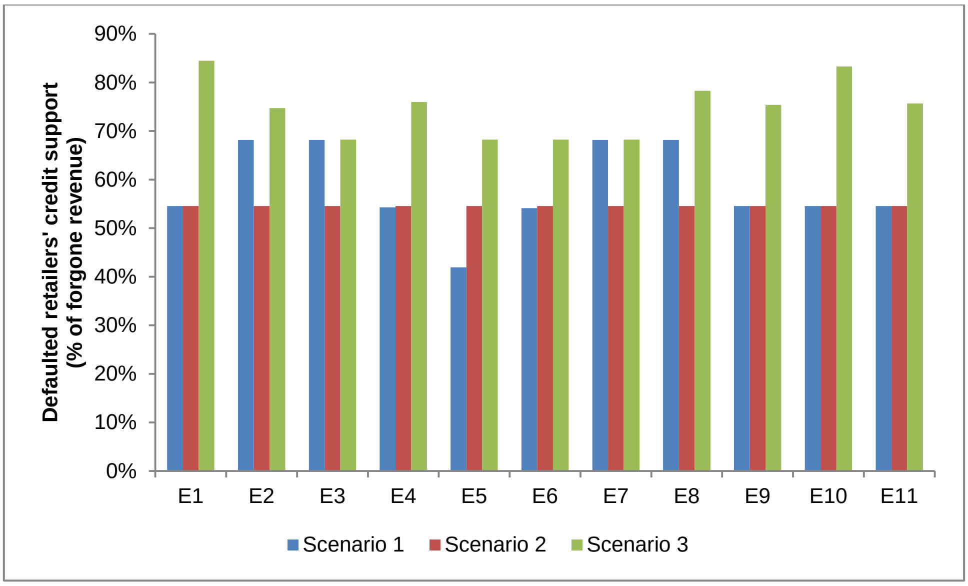


Figure 5.16: Forgone revenue mitigated by credit support – electricity distributors (option 2.3)



The proportion of forgone revenue mitigated under all retailer default scenarios for option 2.3 is material. For example, under option 2.3, gas and electricity distributors recover approximately 70% to 80% of forgone revenue under scenario 3 and approximately 55% of forgone revenue under each of scenarios 1 and 2.

Cash flow impact and funding costs

Given the amount of credit support provided under each of the scenarios it is possible to model the residual cash flow impact on distributors. Before presenting our results, we highlight that the cash flow impacts under options 2.1 and 2.2 are not materially different from those under option 1 (see Figures 5.3 and 5.4) and hence are not replicated here.[78] We further note that cash flow impacts under scenario 3 are insignificant, even without the provision of credit support. Hence any credit support provided under scenario 3 for option 2.2 will have an insignificant impact in improving a distributor's cash flow position. Accordingly, the cash flow impacts shown in Figures 5.17 and 5.18 below are limited to option 2.3.

Figure 5.17: Cash flow impact mitigated by credit support – gas distributors (option 2.3)

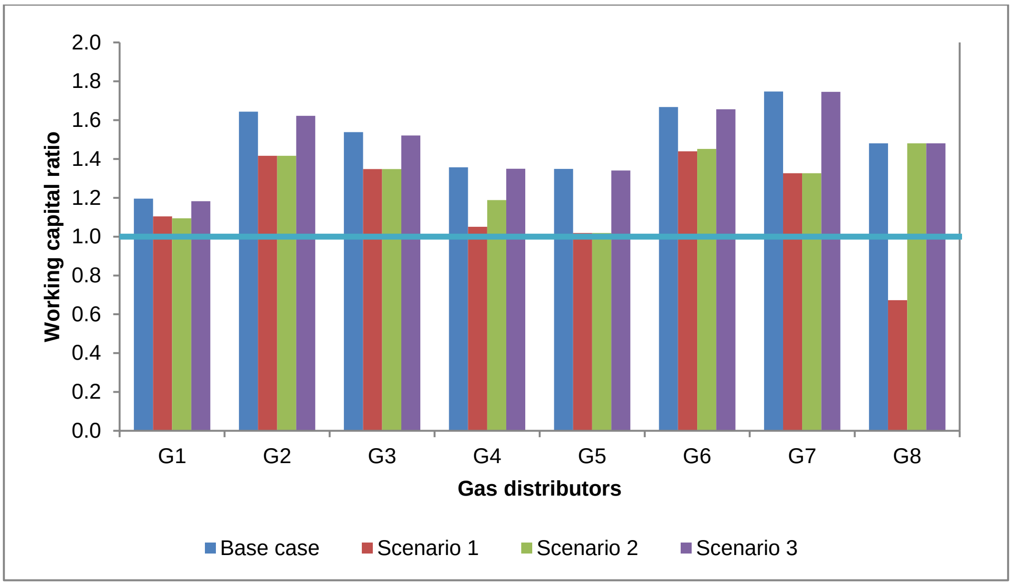
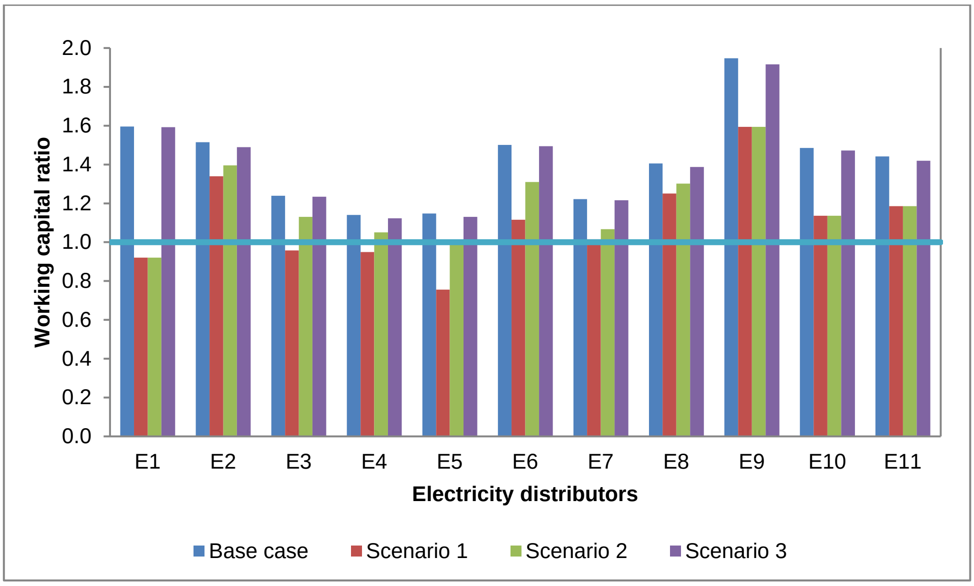


Figure 5.17 highlights that the ability to draw on credit support (following retailer default) allows gas distributors to maintain their cash flow position to meet current liabilities (i.e., maintain a working capital ratio above 1). It follows that the level of external funding required for option 2.3 is minimal.

Figure 5.18 shows the cash flow impact on electricity distributors under option 2.3. In general, the impact on electricity distributors, while not major, affects more networks than is the case with gas distribution. As with the impact on gas distributors, the level of credit support alleviates the bulk of any potential cash flow shortfall faced by electricity distributors following retailer default. This also has the effect of lowering the corresponding amount of external funding required.

[78] We note that under all the default scenarios for option 2.1, and most of the default scenarios for option 2.2, no credit support is provided from defaulted retailers (refer Table 5.11 above). Hence the cash flow impacts are materially the same as those from option 1 (where similarly, no credit support is provided by any of the retailers we assume to have defaulted).

Figure 5.18: Cash flow impact mitigated by credit support – electricity distributors (option 2.3)



Customer impact

We offer the following observations with respect to the flow-on effects to distributors' customers following retailer default, under each of the three default scenarios:

- Default scenarios 1 and 2 – Given the varying levels of credit support and cash flow impacts, the post-default impact on customers is lower for option 2.3 than for options 2.1 and 2.2. We note that the post-default impact for options 2.1 and 2.2 will be identical (given the lack of any credit support for the particular group assumed to default) and hence these are combined in the figures below.

- Default scenario 3 – The post-default impact on customers varies across options 2.1, 2.2 and 2.3 as a consequence of the different levels of credit support provided by the three retailers that are assumed to have defaulted.

The post-default impacts are presented below as a percentage change in the annual bill of gas and electricity customers. Figures 5.19, 5.20 and 5.21 show the cost impact on customers under the default scenarios 1, 2 and 3, respectively for options 2.1, 2.2 and 2.3. As with option 1, we present the minimum, average and maximum cost impact on customers.

We note that many of the assumptions from our post-default analysis for option 1 also apply to option 2. In particular, we have assumed that the AER will only allow customer price increases (via a distributor's price adjustments under cost pass-through) of up to 10% in any one year. Any adjustments beyond 10% are applied in later years. Funding costs incurred by distributors from a delay in the recovery of forgone revenue are calculated on the basis of the distributor's cost of debt.

Figure 5.19: Post-default costs to distributors' customers – scenario 1

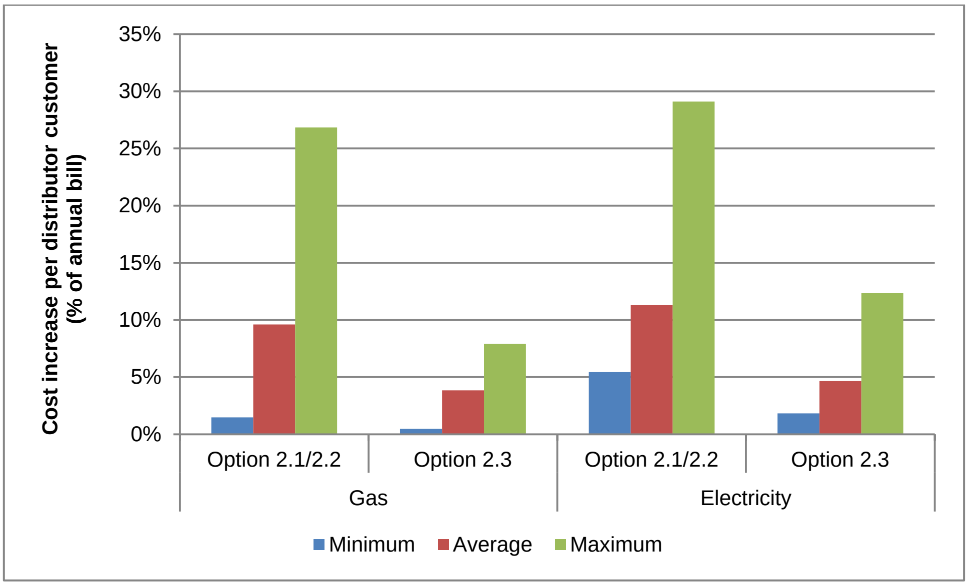
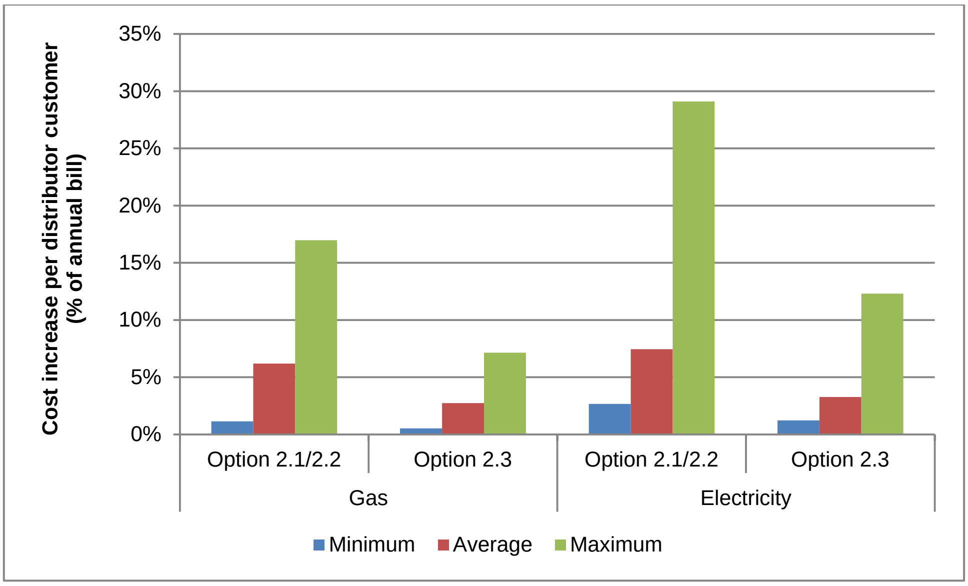
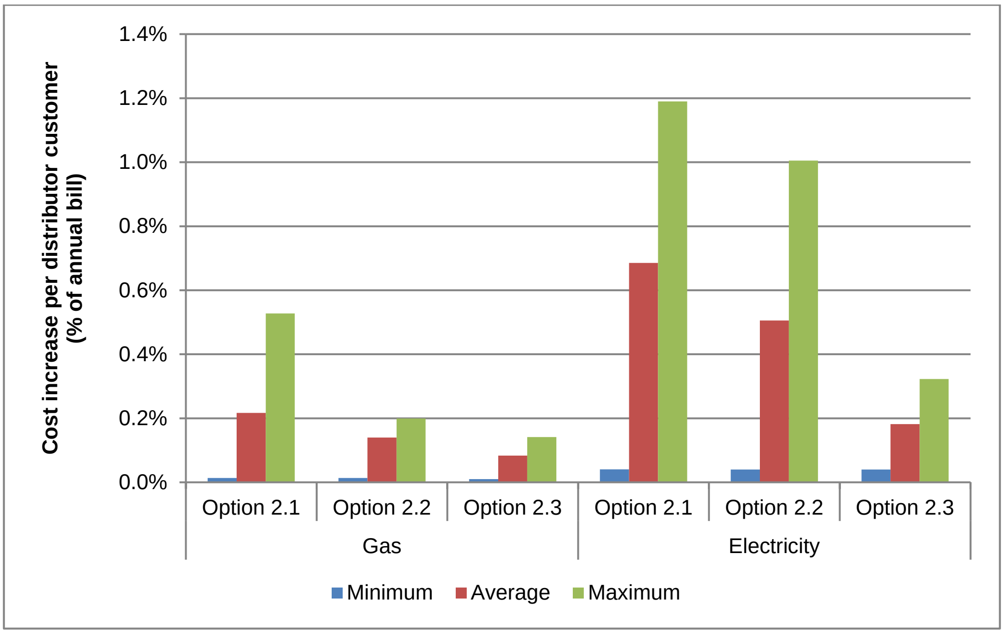


Figure 5.20: Post-default costs to distributors' customers – scenario 2



As shown in Figures 5.19 and 5.20, the unmitigated impact of a major retailer default on customer gas and electricity bills is potentially major under options 2.1 and 2.2 (e.g., a maximum impact under scenarios 1 and 2 of almost 30%). For scenarios 1 and 2, the mitigating effect of credit support provided under option 2.3 has the effect of materially reducing the impact on customers (when compared to options 2.1 and 2.2). In particular, the average cost increase to gas and electricity customers under option 2.3 is less than half of those under options 2.1 and 2.2. Similarly, the maximum cost increase to gas and electricity customers under option 2.3 is significantly lower than those under options 2.1 and 2.2.

Figure 5.21: Post-default costs to distributors' customers – scenario 3



For scenario 3, the average and maximum cost impact across the various options are much smaller than those under scenarios 1 and 2. This reflects the lower overall impact of defaults by small retailers. For option 2.3 it also reflects fact that credit support is provided by those retailers that are assumed to fail (option 2.3 has considerable credit support from retailers with market share below 5%).

5.5 Option 3: Retailer default fund

This section assesses the annual ongoing costs and provides a post-default analysis of establishing a retailer default fund. As noted in Section 4 a number of design aspects would need to be considered before establishing a retailer default fund; these include target fund size, basis of contributions, use and replenishment of the fund and fund management. These considerations ultimately impact on the ongoing costs and post-default implications. While there are many alternative designs of such a scheme, we based our analysis on a simple structure in which the fund size is determined by the largest retailer NCL (this aligns with the default assumption under scenario 2) and in which the fund is established over a period of time. Critically, we assume that the fund is operated and managed on a national basis. This enables the fund to benefit from risk pooling across the industry. Table 5.12 summarises the key assumptions used in analysing this option.

Table 5.12: Retailer default fund – key assumptions

Features	Description or nominal value
Target fund size	$941.25 million (largest retailer NCL aggregated across all networks for which the retailer operates)
Annual contribution	$73.32 million (target fund size reached after 10 years)

Use and replenishment	Funds accessible within 10 days following retailer default subject to AER approval. Replenishment occurs through annual retailer contributions.
Management costs	0.5% per annum

Below we provide a summary of issues considered in determining various aspects of the retailer default fund. Further details about our assumptions are provided in Appendix B.

- Target fund size – We assume a single retailer default fund across both gas and electricity markets as the three large retailers operate across most gas and electricity distribution networks. Further, our decision to have a single fund is also driven by efficiency aspects (i.e., lower management costs). The target fund size of $941.25 million is set to cater for the default of at least one large retailer across both gas and electricity markets. This is to recognise the high degree of concentration in the retailer segment of energy markets (with the three largest retailers accounting for a market share of over 70% in gas and over 80% in electricity).
- Contributions – In determining the annual contribution of $73.32 million a number of issues were considered including the acceptable amount of time required for the fund to reach its target size (10 years), investment return on the annual contributions collected (6% per annum), and the management costs of the fund (0.5% per annum). We have treated the annual contributions as if they were an annuity premium with costs passed on by retailers to their shared customers.
- Use and replenishment – We assume that the rules governing the use of the funds by distributors would be similar to cost pass-through arrangements, where distributors would have to make an application to the AER within 90 days of retailer default event.[79] We assume that distributors can draw on retailer default within 10 days of their application being approved by the AER. The 10 day period is to allow for the fund to convert investments into cash and hence enable distributors to draw on the fund. We assume that the full amount of a defaulted retailer's forgone revenue is drawn from the default fund. In the event distributors draw on the fund, it is assumed the replenishment of the fund would be governed by the same rules that applied for retailer contributions (i.e., there is no use of cost pass-through to replenish the fund).

5.5.1 Ongoing costs

As noted above, we assume that the annual ongoing costs of the retailer default fund will be allocated to retailers and ultimately paid by the retailers' shared customers. These ongoing costs depend importantly on how the annual contribution is collected from retailers participating in the gas and electricity market. In our view, contributions should be a function of size of exposure (as measured by NCL) and likelihood of default (as measured by credit ratings or D&B risk scores). Using size of exposure as one determinant of contributions ensures that retailers that represent larger risks to the system because of their size, will contribute proportionately more to the fund. It is reasonable to expect retailers with equal credit ratings or risk scores to provide similar contributions in proportion to their own NCL. However, a retailer with a lower credit

[79] Under the rules, each distributor should support its application showing the total unpaid network charges of defaulted retailer(s). Moreover, distributors should have access to funds without the extensive time delay that is observed under the cost pass-through mechanism.

rating or risk score should be expected to contribute proportionally more funds than a higher-rated retailer with the same NCL. Requiring a larger contribution from lower-rated participants also provides an incentive for retailers to improve their credit rating.

In order to achieve a risk-based allocation of costs we assign risk-weights to each retailer based on their credit rating or risk score.[80] The risk-weights are created using S&P default probabilities and are extended to D&B risk scores as per the realignment of risk scores under option 2.3 (see Table 5.7). The risk-weights for the various credit ratings and risk scores are provided in Table 5.13 below.

Table 5.13: Risk-weights for determining annual default fund contributions

Standard & Poor's / Fitch credit rating	Moody's credit rating	Dun and Bradstreet dynamic risk score	Risk-weight
AAA	Aaa		100%
AA+	Aa1		100%
AA	Aa2		100%
AA-	Aa3		100%
A+	A1		100%
A	A2		100%
A-	A3		100%
BBB+	Baa1		175%
BBB	Baa2		250%
BBB-	Baa3	Minimal	400%
BB+	Ba1	Very Low	538%
BB	Ba2	Low	850%
BB-	Ba3	Average	850%
B+	B1	Moderate	850%
B	B2	High	850%
B-	B3	Very High	850%
CCC	Caa	Severe	850%
CC	Ca		850%
C	C		850%

[80] The risk-weights in Table 5.14 are largely by way of illustration of how such weights may work. In practice, weights can be constructed in many different ways, and with varying degrees of sophistication.

These risk-weights are applied to each retailer's NCL in order to calculate a risk-weighted NCL for each retailer. For example, if retailer A has a NCL of $10 million and a D&B risk score of 'minimal', the risk-weighted NCL for that retailer is $40 million ($10 million x 400%). We use the risk-weighted NCL for a retailer to calculate the retailer's share of the annual default fund contribution. Assuming the risk-weighted NCL for retailer A of $40 million represents 0.5% of the total risk-weighted NCLs across all retailers, retailer A's annual contribution to the default fund would be $366,600 (0.5% x $73.32 million).

The total annual cost of maintaining and operating a retailer default fund at this level is approximately $73.32 million. Notwithstanding the fundamental differences between credit support and the retailer default fund, this compares with the total cost of credit support under option 2.3 of $71.08 million per annum. One key difference between the two approaches is that retailers continue to pay some variation of the ongoing costs of credit support in perpetuity, whereas annual contributions to a default fund would cease once the fund reaches its target size after 10 years (assuming there are no retailer defaults during the 10-year period – refer to Section 5.5.2 for our post-default analysis).

Figures 5.22 and 5.23 present the annual ongoing costs to shared customers from establishing a retailer default fund. The ongoing costs are presented as a percentage of shared customers' annual bills for gas and electricity. The results are categorised according to a retailer's credit rating or D&B risk score, in order to show the impact of the risk-weighting approach.

Figure 5.22: Ongoing costs to shared customers of gas retailers (retailer default fund)

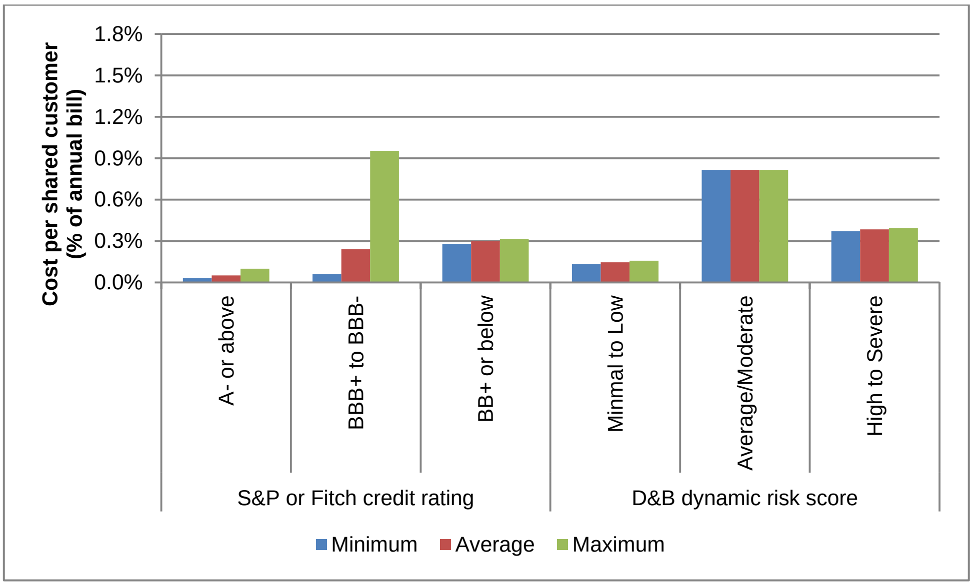
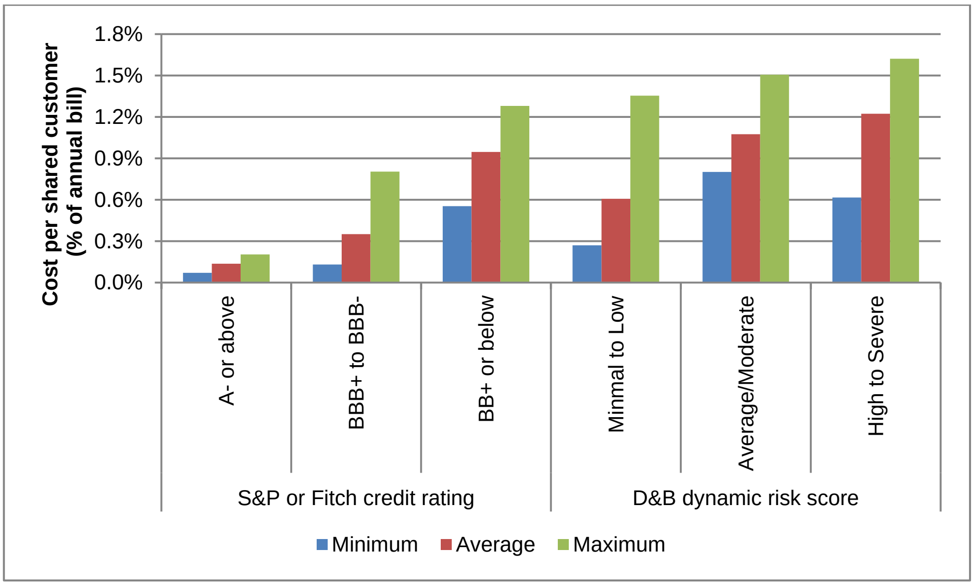


Figure 5.23: Ongoing costs to shared customers of electricity retailers (retailer default fund)



In general, the annual ongoing costs to the shared customers for gas networks are lower than those for electricity networks. The shared customers of electricity retailers with lower credit worthiness (S&P rating of BB+ or below and D&B risk score of Average or below) face an average ongoing cost impact of between 0.9% and 1.2% per annum until the default fund reaches its target size. This compares to average ongoing cost impact of between 0.3% and 0.8% for shared customers of gas retailers with the same level of credit worthiness.

The notable disparity between the ongoing costs to shared customers of gas and electricity retailers suggests that, on average, gas retailers have a better credit rating or risk score than electricity retailers. We further note that the maximum ongoing costs for shared customers when comparing gas and electricity retailers are also significantly different, particularly for retailers using a D&B risk score, as well as those retailers that have credit rating of between BB+ or below.

5.5.2 Post-default analysis

In our post-default analysis, we make the following assumptions with respect to the retailer default fund:

- the retailer default fund has reached its target size under all the retailer default scenarios;
- in the event of retailer default, distributors have access to funds within 10 days and draw the full amount of a defaulted retailer's forgone revenue; and
- the replenishment of the fund, following retailer default, occurs through the same annual retailer contributions (i.e., total of $73.32 million per annum) that were used to build the fund to its target size.

The implications of the above assumptions are as follows:

- Distributors do not face any forgone revenue or cash flow impact under any of the retailer default scenarios when there is a default fund in place.[81]
- The post-default costs are allocated to the shared customers of retailers in accordance with the methodology used to determine contributions to the fund (i.e., the replenishment of the fund would be governed by the same rules governing retailer contributions with a total annual contribution of $73.32 million). The annual impact on shared customers during the period of replenishment (presented as a percentage increase in shared customers' annual bills) is therefore consistent with Figures 5.22 and 5.23.
- The period of time needed to replenish the default fund to its original target size under each of the default scenarios is as follows:
    - Default scenario 1 - Approximately 10 years if we assume multiple retailer defaults occur so that the full target fund size is drawn;[82]
    - Default scenario 2 - Approximately 10 years given that scenario 2 was used to set the target size of the fund; and
    - Default scenario 3 - Between 1 and 2 years.

Given the assumptions we have used to characterise the default fund, there are no further post-default impacts under option 3.

5.6 Option 4: Introduce a liquidity support scheme

This section reports the results of modelling the annual ongoing costs and post-default impact of introducing a liquidity support scheme. Under this option, each distributor obtains a liquidity facility from the financial sector and passes on the cost of maintaining such a facility to retailers and ultimately to shared customers. Two sub-options are considered, based on different ways of allocating the cost of the facility to retailers. The first is a simple allocation model based on market share. The second uses a combination of a retailer's NCL (a scale factor) combined with a measure of credit worthiness (a risk factor). The characteristics of the two sub-options are described in Table 5.14 below.

Table 5.14: Description of options 4.1 and 4.2

Options	Description
Option 4.1	Liquidity support scheme (market-share-based allocation of ongoing fees) Each distributor calculates its exposure to each retailer operating in its network (i.e., each retailer's NCL). The size of the liquidity facility for a given distributor is set to the largest single exposure to a retailer within the distributor's network, subject to a cap equal to 50% of the distributor's unpaid network charges. Within each network, the cost of the liquidity facility is allocated to retailers in proportion to the retailer's annual network charges.

[81] We have assumed that the target fund size is set as the NCL of the largest retailer across all of the networks it operates in. The fund size is therefore sufficient to fully mitigate revenue and cash flow risks for scenario 2 and 3. For scenario 1, we note that it is unlikely that the largest retailers in each network will all default simultaneously. Hence we assume that the fund size is also sufficient to mitigate revenue and cash flow risks for scenario 1.
[82] Although the sum of each defaulting retailer's NCL under scenario 1 is greater than the target fund size, we note that it is highly unlikely that there will be a simultaneous default of the largest retailer in every network.

Option 4.2	Liquidity support scheme (risk-based allocation of ongoing fees) As with option 4.1, the size of the liquidity facility is set equal to the largest single exposure to a retailer within each distributor network, subject to a cap of 50% of the distributor's unpaid network charges. Within each network, the cost of the liquidity facility is allocated to retailers in accordance with a formula based on both their NCL and credit worthiness.

Both sub-options cap the size of the facility at 50% of the distributor's unpaid network charges in order to ensure the size of each liquidity facility does not become unreasonable. The use of a retailer's NCL in allocating costs under option 4.2 scales the cost allocation according to the distributor's credit exposure to the retailer. It also provides a retailer the opportunity to reduce that exposure in order to minimise its allocation of the facility cost. Similarly, the use of credit worthiness under option 4.2 modifies the basic scale approach by allocating a higher proportion of the cost to those retailers which are more likely to be the cause of a drawdown of the facility.

In estimating the drawn and undrawn components of the liquidity facility fee, we make a number of assumptions. These assumptions were developed through discussions with relevant financial institutions. Broadly, we assume that the fees associated with the facility fall into two categories – ongoing and funding. We note that such facilities may also attract upfront fees, although it is our understanding that such fees can often be waived (and hence were not included as part of our model).

Using the information provided, we assume that the ongoing facility fee consists of a commitment fee plus a 50% credit margin applied by the financial institution (based on a distributor's credit rating). We assume that the funding (i.e., drawdown) fee is a mix of the three-month bank bill swap rate (BBSW) plus a credit margin. We also assume that all distributors have at least an investment grade rating (i.e., have a credit rating of BBB- or better). Table 5.15 summarises our assumptions about ongoing and funding fees for the liquidity facility.

Table 5.15: Liquidity facility fees

Credit rating	Commitment fees	3-month BBSW	Credit margin	Ongoing fee	Funding fee
AAA	0.38%	2.18%	0.75%	**0.68%**	**2.93%**
AA+	0.38%	2.18%	0.75%	**0.68%**	**2.93%**
AA	0.38%	2.18%	0.75%	**0.68%**	**2.93%**
AA-	0.38%	2.18%	0.75%	**0.68%**	**2.93%**
A+	0.38%	2.18%	0.75%	**0.68%**	**2.93%**
A	0.38%	2.18%	0.75%	**0.68%**	**2.93%**
A-	0.38%	2.18%	0.75%	**0.68%**	**2.93%**
BBB+	0.75%	2.18%	1.50%	**1.35%**	**3.68%**
BBB	0.75%	2.18%	1.50%	**1.35%**	**3.68%**
BBB-	0.75%	2.18%	1.50%	**1.35%**	**3.68%**

5.6.1 Ongoing costs

The ongoing costs for option 4 include the annual ongoing facility fee, which is passed on to the retailers that operate within a distributor's network (and ultimately to the shared customers of those retailers). The allocation of the ongoing facility fee to retailers is performed separately for the two options.

- Option 4.1 – a distributor first determines the size of the facility, which is equal to the distributor's largest exposure to a retailer within its network; that is, the largest NCL for a retailer (capped at 50% of the distributor's unpaid network charges). For each network, the cost of the liquidity facility is then allocated to retailers in accordance with their market share, that is, in proportion to the retailer's network charges.[83]

- Option 4.2 – the size of the facility is determined in the same manner as in option 4.1. The distributor allocates the cost of the facility based on a risk-weighted NCL for each retailer (using the risk-weights specified in Table 5.13 for option 3).[84]

A risk-based approach used to calculate ongoing costs (for option 4.2) incentivises retailers to improve their credit worthiness and/or minimise the distributor's exposure to retailers (i.e., reduce their NCL). For example, retailers may decide to increase the billing frequency of shared customers. This has the effect of reducing the distributor's exposure to the retailer and hence reducing the retailer's share of the ongoing costs associated with the liquidity facility.

The ongoing cost of the liquidity facility for each distributor network is driven by the size of the facility and the distributor's credit rating. In Figures 5.24 and 5.25 we present the overall cost of the facility for each network as a percentage of the distributor's unpaid network charges (i.e., as a percentage the distributor's total exposure to all retailers within its network). We note that the size of the facility for each network is the same for options 4.1 and 4.2 and hence it is not necessary to separate these sub-options at this stage.

[83] For the purposes of our model, we allocate the cost of the liquidity facility in proportion to the number of customers for each retailer (as a proxy for market share).
[84] To illustrate, if a distributor's ongoing costs for the liquidity facility is $1 million per annum and a retailer's risk-weighted market share is 10%, the retailer's allocation of the overall costs of the facility would be $100,000 ($1 million x 10%).

Figure 5.24: Cost of facility – gas distributors

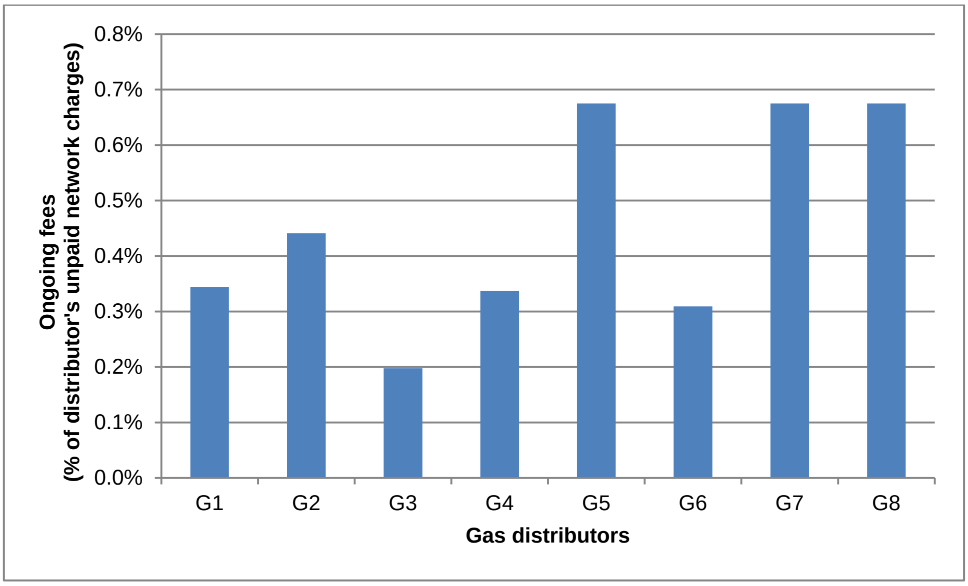
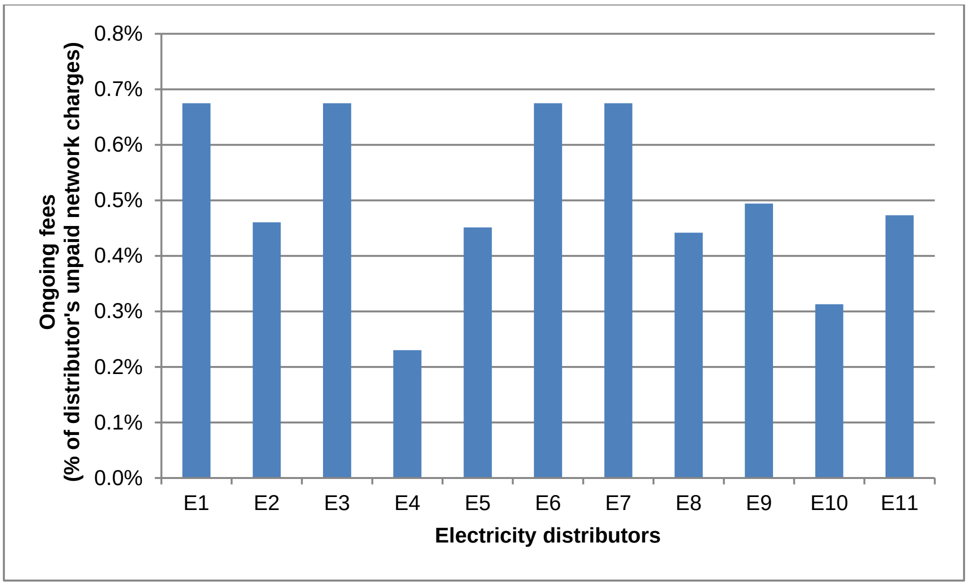


Figure 5.25: Cost of facility – electricity distributors



Figures 5.24 and 5.25 show that the ongoing cost of the liquidity facility varies considerably across networks. This is largely driven by the different retailer structures across the networks. Those networks dominated by a large retailer which manage to reach the facility size cap (i.e., 50% the distributor's unpaid network charges) tend to have the largest ongoing fees on a proportional basis. Such networks account for half of the gas networks and approximately a third of the electricity networks.

Once the ongoing cost is allocated to retailers within a network (and ultimately to shared customers), the results are sensitive to the allocation approach adopted (i.e., market-share-based or risk-based). Figures 5.26 and 5.27 present the ongoing costs to shared customers for gas networks for options 4.1 and 4.2 (as a percentage of a customers' annual energy bill).

Figure 5.26: Ongoing cost to shared customers of gas retailers (option 4.1)

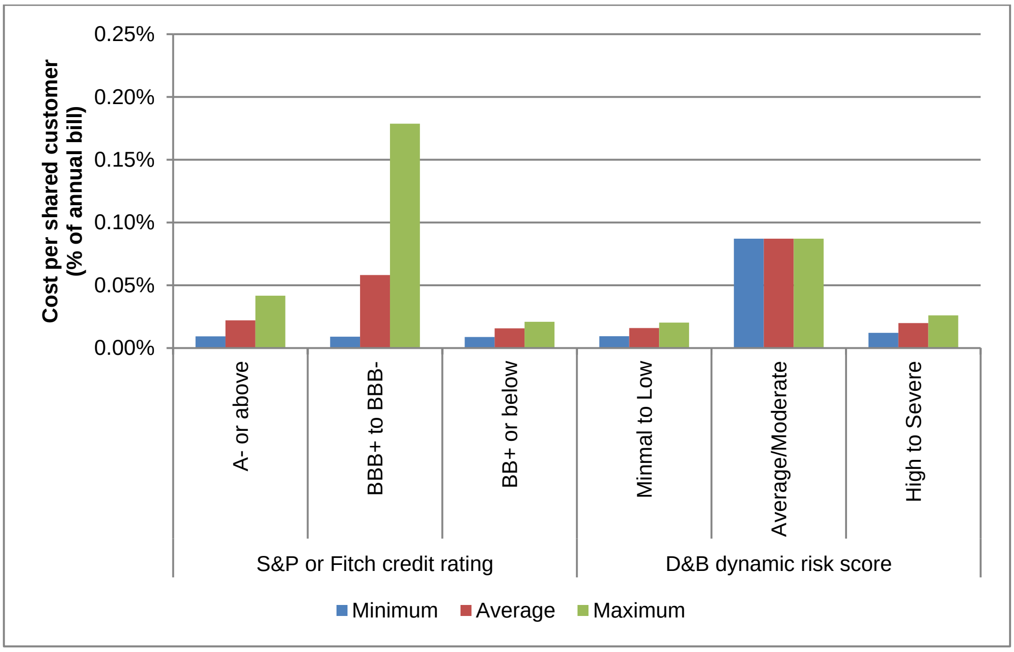
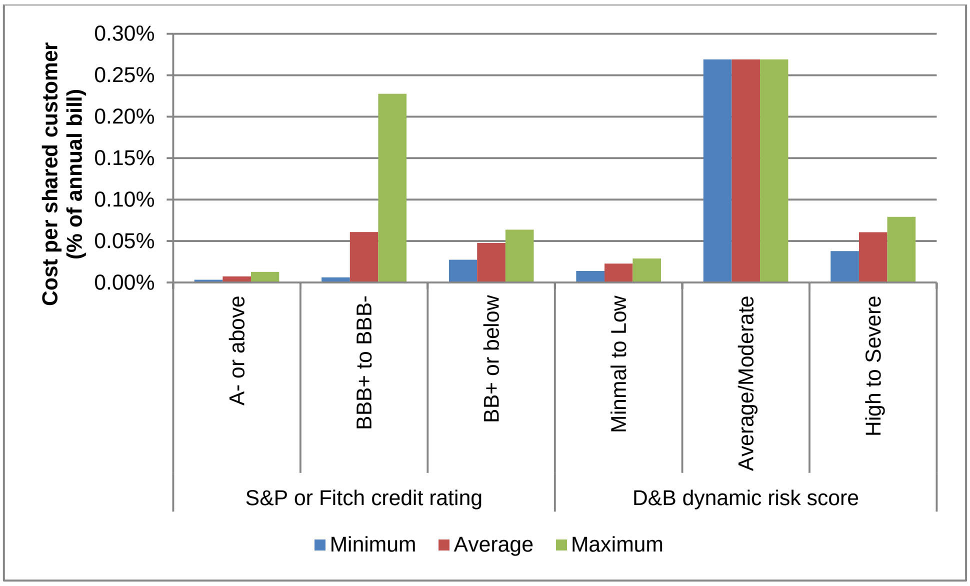


Figure 5.27: Ongoing cost to shared customers of gas retailers (option 4.2)



The cost impacts overall are small as a proportion of a customer's annual gas bill. The maximum cost impact to shared customers is 0.18% when using a market-share-based allocation approach (option 4.1) and 0.27% when using a risk-based allocation approach (option 4.2). We also observe that, when using a risk-based allocation approach (option 4.2), the credit worthiness of a retailer impacts on the ultimate costs to shared customers. For example, for retailers rated A- or above (the highest rated category), the average cost impact on shared customers reduces from 0.02% (under option 4.1) to 0.01% (under option 4.2). For retailers rated BB+ or below (the lowest rated category), the average cost impact increases from 0.02% (under option 4.1) to

0.05% (under option 4.2). Similar movements can also be observed for those retailers with a D&B risk score. For example, for retailers with a D&B score of High to Severe, the average cost impact increases from 0.02% (under option 4.1) to 0.06% (under option 4.2).

Figures 5.28 and 5.29 show the annual ongoing costs to shared customers for electricity networks (as a percentage of a customer's annual energy bill). These costs are shown separately for options 4.1 and 4.2.

Figure 5.28: Ongoing cost to shared customers of electricity retailers (option 4.1)

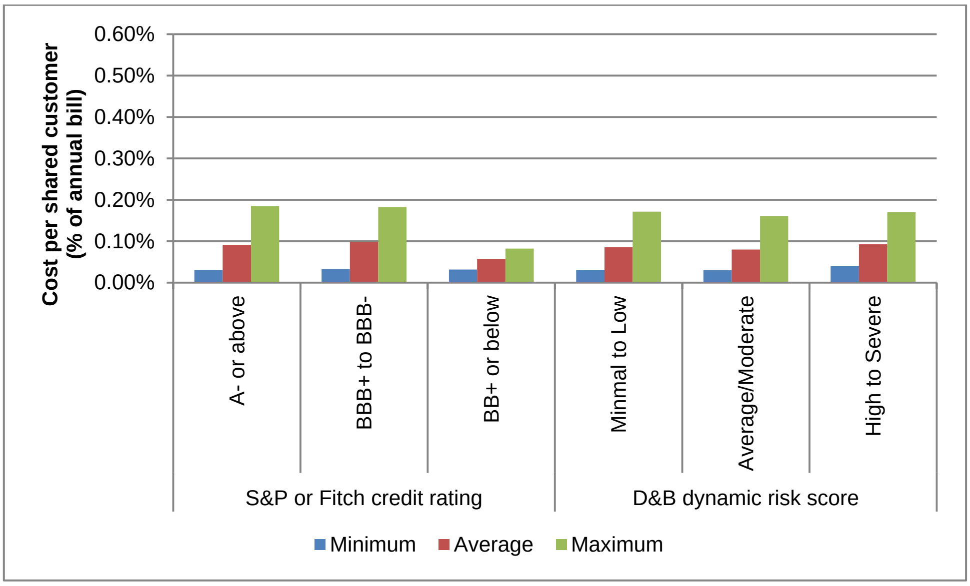
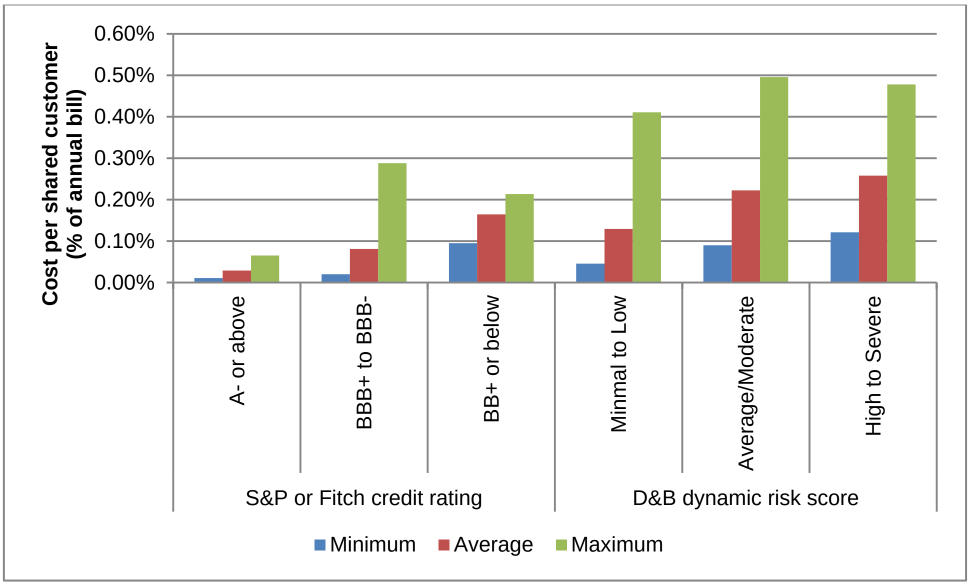


Figure 5.29: Ongoing cost to shared customers of electricity retailers (option 4.2)



The observations we made for gas also apply to electricity networks when comparing results from a market-share-based allocation (option 4.1) to a risk-based allocation (option 4.2). When using a risk-based allocation, we observe that the credit worthiness of a retailer impacts the costs for customers. For example, for retailers rated A- or above (the highest rated category), the average impact on shared customers reduces from 0.09% (under option 4.1) to 0.03% (under option 4.2). For retailers rated BB+ or below (the lowest rated category), the average impact increases from 0.05% (under option 4.1) to 0.16% (under option 4.2).

We also observe that, although the overall cost for electricity networks remains relatively low as a percentage of a customer's annual electricity bill, in all but one credit rating category, the average cost increase is noticeably higher for electricity than gas. For example, for shared customers of BBB+ to BBB- retailers, the average cost increase for gas customers (using a market-share-based allocation under option 4.1) is 0.06%. The same cost increase for electricity customers is 0.10%. A similar observation can be made when using results from a risk-based allocation (option 4.2). For example, for BB+ or below using a risk-based allocation, the average cost increase is 0.05% for gas customers and 0.16% for electricity customers.

5.6.2 Post-default analysis

As with option 2.3, the post-default recovery of forgone revenue and costs (including the funding cost associated with drawing on the liquidity facility) occurs via the enhanced cost pass-through to distributors' customers. Thus, the post-default analysis for option 4 assumes an allocation of post-default impact on a distributor's customers, irrespective of the approach adopted to allocate the cost of the liquidity facility.

Under this option, the post-default impacts are a function of forgone revenue and funding costs on the drawn component. The cost associated with funding will depend on the amount of the liquidity facility utilised by a distributor under each of the three retailer default scenarios, as well as the duration for which the facility remains drawn. With these considerations in mind, the following assumptions were made with respect to the liquidity facility:

- Distributors use the facility only if their working capital ratio falls below 1.0 under the default scenarios (i.e., a distributor only draws on the facility if the distributor experiences a cash flow shortage).
- The amount of the facility used is enough to increase a distributor's working capital ratio back to a level of 1.0.
- The duration for which the facility remains used ranges from 1.5 to 3.5 years, where the precise duration is determined by the need to contain customer price increases to less than 10% in any regulatory year.

Cash flow impact

In estimating the post-default impacts for option 4.1 and 4.2, we model the utilisation of the liquidity facility under the three default scenarios. There is no difference in the utilisation of the liquidity facility across options 4.1 and 4.2 and hence the cash flow results apply equally to the two sub-options. Our results are shown in Figures 5.30 (gas) and 5.31 (electricity). As with the post-default analysis for the other options, we use the working capital ratio to assess the cash flow impacts under the three retailer default scenarios.

Figure 5.30: Cash flow impact under default scenarios – gas distributors

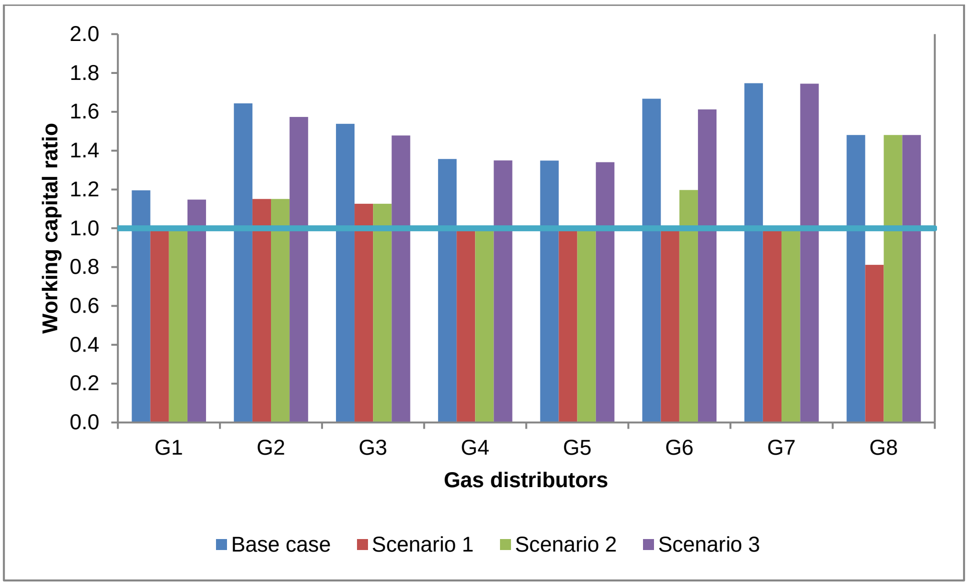
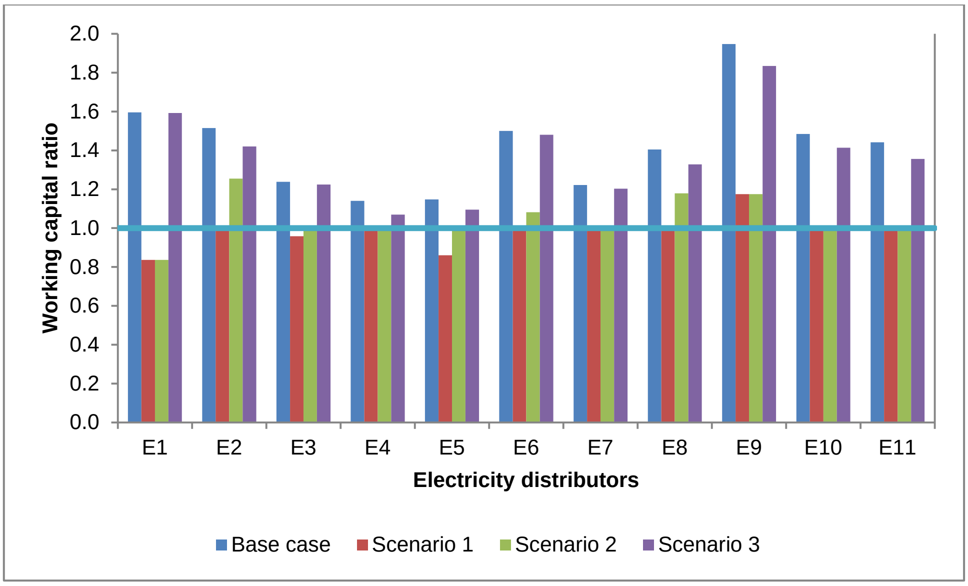


Figure 5.31: Cash flow impact under default scenarios – electricity distributors



We observe significant improvements in the cash flow position across all networks when compared to impacts that do not incorporate the availability of a liquidity facility or credit support (refer Figure 5.3 and 5.4). The results show that seven of the eight gas distributors and eight of the 11 electricity distributors require no additional external funding in any of the three retailer default scenarios.

Customer impact

The ability to mitigate post-default cash flow impacts on distributors is not without costs to energy customers. The post-default costs to customers include forgone revenue, funding costs associated with drawing on the facility to cover any residual cash flow shortfall and administrative costs. These costs are assumed to be shared equally by the customers of the affected distributors and hence the separate allocation approaches of options 4.1 and 4.2 are not relevant for the post-default analysis. Accordingly, we present combined results for options 4.1 and 4.2.

The cost increase to customers is assessed under the three retailer default scenarios and presented as a percentage of the customers' annual energy bill. Figure 5.32 shows the minimum, average and maximum change for both gas and electricity.

Figure 5.32: Post-default costs to distributors' customers (option 4)

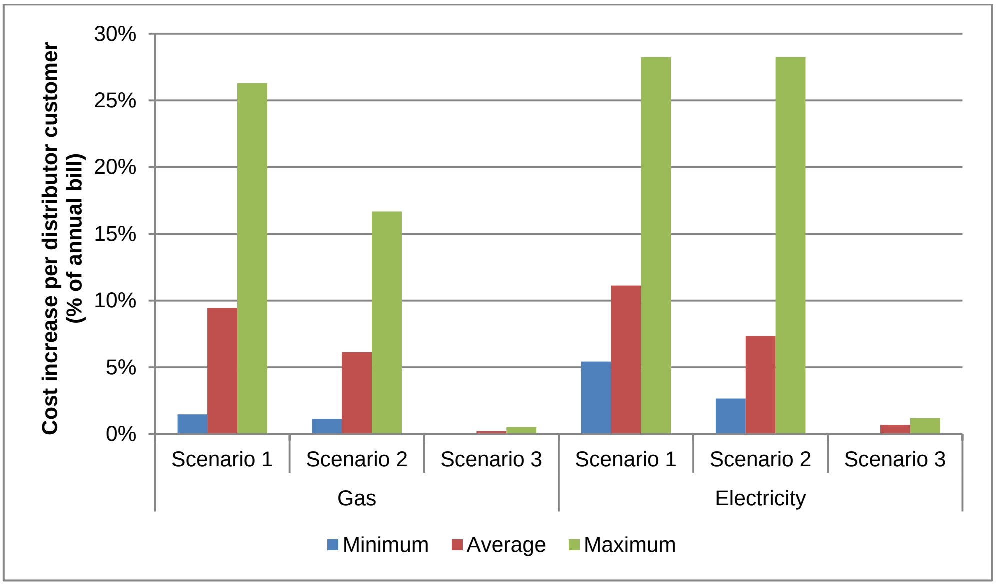


Figure 5.32 shows the average cost increase to customers to be substantial for both gas and electricity under scenarios 1 and 2 (although to a lesser extent for gas). In particular, the average cost increase for gas customers is 6.2% under default scenario 2, compared to 7.4% for electricity customers. The average cost increase to customers under scenarios 1 and 3 are also lower for gas. We also note the extreme maximum price increases across both scenarios 1 and 2 (greater than 25% increase for some customers).

6 Summary and recommendations

6.1 Summary of findings

In this section we summarise the results of our modelling in terms of the ongoing costs that flow through to customers and the post-default impacts for each of the sub-options described in Section 4 (and set out in Table 6.1 below). Although we considered three separate default scenarios in modelling the impact of retailer default, we present the results in this section for scenario 2 only (default of the retailer with largest market share across all electricity and gas networks), as this scenario represents the most plausible severe default event impacting multiple networks. Refer to Appendix C for a summary of our modelling results across all three default scenarios.

Table 6.1: Description of options

Option	Description
Option 1	Retain existing arrangements (revenue cap regime)
Option 2.1	Strengthen existing arrangements: COAG proposal without credit support
Option 2.2	Strengthen existing arrangements: COAG and AGL proposals
Option 2.3	Strengthen existing arrangements: COAG proposal with enhanced credit support
Option 3	Retailer default fund
Option 4.1	Liquidity support scheme (market-share-based allocation of ongoing fees)
Option 4.2	Liquidity support scheme (risk-based allocation of ongoing fees)

In this chapter we will refer to options 1, 2.1 and 2.2 as “aggressive” options, in that all address revenue risk but, do little or nothing to address liquidity risk (preferring to allow the market and/or political processes to resolve a liquidity crisis, should it arise). We will refer to options 2.3, 3 and 4 (both variations) as “defensive” options in that they address both liquidity and revenue risks (by putting preventative measures in place before a crisis arises). At a simplistic level, the aggressive options should be expected to involve lower *ex ante* costs (ongoing costs) but possibly high *ex post* costs (post retailer default) than the defensive options. Notwithstanding this classification into aggressive and defensive, the sub-options involve wide variations in terms of *ex ante* and *ex post* costs and how these are distributed across industry participants and customers.

6.1.1 Risk mitigating characteristics of the options

The various options can be characterised by the way in which they address revenue and liquidity risk and the mechanisms they use to address these risks. These characteristics not only influence the magnitude of the cost implications of the options, they also influence how they are allocated across different participants in the networks (essentially distributors, retailers, and customers, as well as the banking sector) and the balance between ongoing and post-default costs. As per our comments in Section 5.1, we have assumed that each distributor’s regulated rate of return remains unchanged when comparing the various options. More specifically, we have not modelled potential changes in regulated rates of return as a result of the revenue and pricing principles (and any potential impact in setting customer prices). It is our understanding that, in practice, such granular adjustments may not be made when estimating the regulated rate of return.

Table 6.2 summarises the allocation and mitigation of revenue and liquidity risk under default scenario 2 across the various options. The allocation of risk is shown in terms of who ultimately bears the costs of revenue and liquidity risk and whether the risk is mitigated (or partially mitigated).

Table 6.2: Revenue and liquidity risk

Option	Allocation of revenue risk*	Allocation of liquidity risk*	Mechanism applied	Revenue risk mitigated	Liquidity risk mitigated
Option 1	DC	D	Overs and unders	✓	×
Option 2.1	DC	D	COAG cost pass-through	✓	×
Option 2.2	DC	D	COAG cost pass-through; AGL credit support	✓	×
Option 2.3	BS, DC	BS, D	COAG cost pass-through; Enhanced credit support	✓	Partly
Option 3	SC	SC	Retailer default fund	✓	✓
Option 4.1	DC	BS	Liquidity facility; COAG cost pass-through	✓	✓
Option 4.2	DC	BS	Liquidity facility; COAG cost pass-through	✓	✓

* Where
D – Distributors (risk to distributor has not been mitigated), DC – Distributor customers (impacts transferred by the distributor to customers), SC – Shared customers (impacts transferred to retailers and ultimately to the retailers' shared customers), BS – Banking Sector (impacts transferred to the banking sector)

Table 6.2 shows that the allocation of revenue and liquidity risks under default scenario 2 varies considerably across the options. For example, revenue risk is either allocated to distributors, customers (either as a result of being connected to a distributor's network or, alternately, as a result of being a "shared customer" of a retailer), the banking sector, or a combination. Similarly, liquidity risk is allocated either to distributors, shared customers or the banking sector. The variations in the allocation of these risks under the different options arise from the mechanisms available under them and their effectiveness. For example, the absence or ineffectiveness of credit support under options 1, 2.1 and 2.2 results in risks being allocated to distributors or their customers.

The structure of these aggressive options is such that they only address revenue risk (or costs), while leaving liquidity risk completely unmitigated. Neither revenue nor liquidity risk is mitigated under option 1 when operating under a price cap regime; forgone revenue under these arrangements cannot be recovered through the cost pass-through mechanism and the credit support arrangements are too small to be effective in meeting liquidity needs. In contrast, both revenue and liquidity risks are mitigated under options 4.1 and 4.2. Under these options forgone revenue can be recovered under the COAG cost pass-through proposal, while liquidity needs are met from funding through the liquidity facility.

While options 2.3 and 3 also address both risks, the extent to which the risks are covered is not exactly the same as under option 4. In constructing the comparisons we attempted to scale the options to provide a similar level of risk mitigation. There are nevertheless some important differences. Coverage of potential lost revenue (measured as the overall level of support provided under each option as a percentage of retailers' NCLs across all networks) is relatively complex to measure. At a simplistic level, coverage levels decrease when moving from option 2.3 (approx. 60%) to option 4 (approx. 40%) to option 3 (approx. 30%). Although option 2.3 appears to provide greater coverage, these simple measures do not take into account the risk pooling characteristics of options 3 and 4. For example, even with a 60% overall coverage under option 2.3, if an A- rated retailer defaulted there would be no credit support available. This is a result of credit support being provided at the retailer level, that is, credit support that one retailer provides cannot be used to support the default of another retailer. In contrast, option 4 provides each liquidity facility at a network level. Under option 4, a single facility for a network can be used to support any retailer default(s) within the network. Option 3 further pools its support across all networks in both gas and electricity. Consequently, under option 3, a single default fund can support any retailer default(s), regardless of which network that retailer operates in.

When comparing the coverage under a particular default scenario, we calculate how much of the support is drawn to cover the forgone revenue of the defaulted retailer (e.g., the forgone revenue of the single retailer that defaults under scenario 2). For option 2.3, we assume the full amount of the credit support provided by the retailer is used to recover the forgone revenue. Our analysis shows that 55% of the forgone revenue is able to be recovered immediately under option 2.3 given the availability of credit support from this one retailer. For option 3, coverage is 100%, as we assume that the full amount of the retailer's forgone revenue is drawn from the default fund. For option 4, our results show that only 23% of the retailer's overall forgone revenue is drawn from the various liquidity facilities across the networks that the retailer operates in. This low utilisation rate is not surprising given our assumption under option 4 that each distributor only draws enough liquidity to bring its working capital ratio back to a level of 1.0. This behaviour is illustrated in Figures 5.30 and 5.31 of Section 5.6 above, which present the cash flow default impacts under option 4 (for many of the networks, the working capital ratio under scenario 2 equals 1.0).

6.1.2 Ongoing costs

Tables 6.3 (gas) and 6.4 (electricity) summarise the ongoing costs to the shared customers of gas and electricity retailers and the proportion of shared customers affected under each of the options.[85] The ongoing costs are presented as a percentage increase in shared customer's annual energy bills and are categorised into minimum, average and maximum impacts (for those customers who are affected). The tables also provide an estimate of total ongoing annual costs in dollar terms ($ million) under each of the options. The total annual dollar cost is the sum of costs to all customers in the gas and electricity markets respectively (i.e., aggregated across all networks).

Table 6.3: Ongoing costs to shared customers (scenario 2) – gas

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 1	Nil	Nil	Nil	Nil	Nil
Option 2.1	Nil	Nil	Nil	Nil	Nil
Option 2.2	0.13%	0.17%	0.22%	1.7%	0.15
Option 2.3	0.07%	0.24%	0.84%	95.1%	8.12
Option 3	0.03%	0.24%	0.95%	100.0%	8.12
Option 4.1	0.01%	0.05%	0.18%	100.0%	1.86
Option 4.2	0.00%	0.06%	0.27%	100.0%	1.86

[85] Affected customers are shared customers that are subject to increased ongoing costs as a result of the arrangement implemented under the relevant sub-option.

The results in Table 6.3 show that shared customers of gas retailers face little or no ongoing costs under the aggressive options. For example, there are no ongoing costs under options 1 and 2.1, since no gas retailer is required to provide credit support under option 2.1 and, in practice, no gas retailers provide credit support under current arrangements. Shared customers of gas retailers, however, face some ongoing costs under the defensive options, with considerable variation in average costs, maximum costs, rates of affected customers and total annual costs.

Of the defensive options, option 4 has the lowest average cost, at less than a quarter of the costs calculated under options 2.3 and 3. Options 2.3 and 3 also have significantly greater maximum costs. Since the defensive options affect virtually the entire customer base, the lower level of average costs under option 4 means that it also has considerably lower total annual dollar costs than options 2.3 and 3. In contrast, although aggressive option 2.2 has an average cost comparable to options 2.3 and 3, its total annual cost is significantly lower because only 1.7% of customers are affected.

Table 6.4 Ongoing costs to shared customers (scenario 2) – electricity

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 1	0.03%	0.10%	0.22%	1.0%	0.12
Option 2.1	Nil	Nil	Nil	Nil	Nil
Option 2.2	0.25%	0.52%	0.89%	3.0%	2.02
Option 2.3	0.15%	0.48%	1.02%	96.2%	62.96
Option 3	0.07%	0.53%	1.62%	100.0%	65.18
Option 4.1	0.03%	0.09%	0.19%	100.0%	15.12
Option 4.2	0.01%	0.11%	0.50%	100.0%	15.12

Broadly, shared customers of electricity retailers face higher ongoing costs (both average and total annual) than gas retailers under all options. For example, the average ongoing costs to shared customers of electricity retailers are almost twice as those of gas retailers. However, the results for electricity customers are broadly similar to those for gas customers in that, of the defensive options, option 4 has lower average costs and total annual costs than options 2.3 and 3. Again, the aggressive options (1, 2.1 and 2.2) have lower costs and lower participation rates than the defensive options.

Overall, the retailer default fund (option 3) is the most expensive option for the shared customers of electricity retailers with the highest average ongoing cost of 0.53%, the highest maximum ongoing costs of 1.62%, and the highest total dollar cost of the scheme of just over $65 million per annum (compared with $15 million for option 4 and negligible cost for the aggressive options).

6.1.3 Post-default analysis

Tables 6.5 and 6.6 summarise post-default costs to gas and electricity distributor customers and the proportion of distributor customers impacted under each of the options for scenario 2. Impacted customers are customers of distributors with exposure to the defaulted retailer under scenario 2. The post-default costs are presented as a percentage increase in the annual gas and electricity bill for a customer in the distributor's network and categorised into minimum, average and maximum. The tables also provide an estimate of retailer default costs under each of the options. Default costs include forgone revenue and related costs from retailer default.

Table 6.5: Post-default costs to customers (scenario 2) – gas

Option	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 1	1.14%	6.19%	16.98%	96.5%	165.6
Option 2.1	1.14%	6.19%	16.98%	96.5%	165.6
Option 2.2	1.14%	6.19%	16.98%	96.5%	165.6
Option 2.3	0.52%	2.74%	7.14%	96.5%	74.6
Option 3	0.33%	2.38%	9.53%	100.0%	81.2
Option 4.1	1.14%	6.15%	16.68%	96.5%	165.4
Option 4.2	1.14%	6.15%	16.68%	96.5%	165.4

Table 6.6: Post-default costs to customers (scenario 2) – electricity

Option	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 1	2.67%	7.45%	29.10%	100.0%	894.0
Option 2.1	2.67%	7.45%	29.10%	100.0%	894.0
Option 2.2	2.67%	7.45%	29.10%	100.0%	894.0
Option 2.3	1.22%	3.27%	12.30%	100.0%	398.3
Option 3	0.71%	5.33%	16.22%	100.0%	651.8
Option 4.1	2.67%	7.37%	28.25%	100.0%	891.8
Option 4.2	2.67%	7.37%	28.25%	100.0%	891.8

While not included in Table 6.6, option 1 results in the lowest post-default costs to customers of both gas and electricity distributors when it operates under a price cap regime (see Figure 5.6). It also has the lowest proportion of impacted customers. While such an outcome may appear attractive on the surface, the low cost to customers arises because distributors bear close to the full cost of the default. Under a price cap regime, we assume distributors have no mechanism through which to recover forgone revenue or related costs below the materiality threshold (in accordance with the current operation of the cost pass-through mechanism). The potential for such an outcome to lead to the failure of a distributor is what motivated this review of the credit support arrangements.

Conversely, the remaining aggressive options, 1 (under a revenue cap regime), 2.1 and 2.2, result in maximum post-default costs to customers of gas and electricity distributors. This is due to the low levels of credit support, combined with the effect of transferring costs to customers through the cost pass-through or overs and unders process. The weakness of these options is that they involve a high post-default cost for customers and do not adequately address the liquidity risk to which distributors are exposed.

While the aggressive options involve high post-default costs to customers, with the exception of option 2.3, the defensive options offer only modest reductions in these costs. The similarity in post-default cost burdens between the aggressive and defensive options arises because all these options (with the exception of option 2.3) allocate the cost of restoring forgone revenue to customers.

The main divergence in post-default costs comes between option 2.3 and the other options. Under option 2.3 the credit support provides liquidity in a form that does not carry with it a liability to repay. Under option 3, for example, the industry fund provides the immediate liquidity, but the fund must be replenished over a period of time, thereby imposing a cost on customers. Under option 4 the distributor may draw liquidity from the committed facility but, again, the drawdown must be repaid over time, thereby imposing a cost on customers. Under option 2.3 the liability against the credit support facility becomes a liability of the failed retailer, thereby separating the cost of repayment from customers. Consequently, option 2.3 has a post-default cost to customers that is roughly half that of the other options. The reason that there are still post-default costs under option 2.3 is that the extent of credit support calculated is roughly 55% of the assumed retailer default under scenario 2. Conversely, as noted earlier, it has a considerably higher ongoing cost to customers due to the high cost of maintaining effective credit support.

6.2 Alignment with principles

The AEMC has asked Promontory to provide a recommendation of the option that best satisfies the principles developed. Hence, in narrowing our options into recommendations, we consider not just the costs of the options, but also the extent to which each option meets the regulatory principles set out in Section 3. Table 6.7 below provides a high-level summary of the alignment of each option with these principles. The table uses ticks and crosses to provide our view as to whether an option is aligned with the regulatory principles. We use the label ‘partly’ where an option is only partially aligned with the principles.

Table 6.7: Alignment with regulatory principles

Option	Stability	Efficiency	Incentives	Revenue and Pricing	Competition
Option 1	×	×	×	Partly	✓
Option 2.1	×	×	×	✓	✓
Option 2.2	×	×	Partly	✓	×
Option 2.3	✓	Partly	✓	✓	×
Option 3	✓	×	✓	✓	×
Option 4.1	✓	Partly	×	✓	✓
Option 4.2	✓	Partly	✓	✓	Partly

The following is a brief summary of some of the key observations underlying our assessments in Table 6.7 (Appendix D provides a more detailed commentary on the alignment of each overall option with the principles):

- Option 1 – Existing arrangements do not consider the potential for contagion and hence instability. Distributors are exposed to risks which have the potential to lead to significant impacts on distributors and possibly the stability of the power system. Revenue risk is only partially mitigated and liquidity risk is assumed by distributors. We also consider option 1 to be inefficient. In addition, existing arrangements do not provide retailers with incentives to reduce exposure or improve their credit worthiness.

- Options 2.1 and 2.2 – There is no consideration given under these options to a distributor's liquidity risk and its impact on the distributor's ability to remain in operation in the event of a large retailer default. Without further adjustments, the credit support arrangements for option 2.2 (and their complete absence in option 2.1) are ineffective.

- Option 2.3 – This option minimises financial contagion and transfers both revenue risk and a significant proportion of liquidity risk to a combination of customers and the banking sector. We note option 2.3 has among the lowest post-default costs for customers. There are incentives in place under this option for retailers to minimise their NCLs and reduce their probability of default. A residual concern is that, even with the enhancements, distributors retain some residual liquidity risk unless the level of credit support is very high. Increasing the level of credit support would lead to an increase in the ongoing costs borne by shared customers and hence impact on the efficiency of the option.

- Option 3 – The retailer default fund minimises systemic instability concerns and provides positive incentives to retailers. Establishing a common fund across both gas and electricity networks means there is potential for customers of one network to subsidise customers in the other network. A key concern, however, is the cost inefficiency of establishing such a fund (from an administrative and resource perspective), which has the highest ongoing costs for customers (over the 10-year contribution period) when compared with other options.

- Options 4.1 and 4.2 – The committed facility, in conjunction with the enhanced cost pass-through, materially reduces any risk of financial contagion. However, the cost impact to customers under a default scenario has the potential to be significant given the full amount of the revenue risk is ultimately borne by customers. For option 4.2, the allocation of the ongoing fee uses a risk-based approach and hence provides positive incentives to retailers to reduce NCL and improve credit worthiness. Option 4.1 uses a market-share-based approach to cost allocation and hence provides no such incentives.

6.3 Recommendations

The AEMC has requested Promontory to provide a recommendation of the option that should be adopted with supporting rationale. In our view, there is no single option that clearly dominates all others. At the same time, there are some options that are clearly dominated by others. We start this section by eliminating the less attractive options.

Current arrangements (option 1) do not provide either effective or reliable mitigation of revenue or liquidity risk for distributors. If systemic risk is to be reduced, there is a need for some reform. Even if systemic risk were not regarded as relevant, some reforms are warranted to address inefficiencies in the current arrangements. Similarly, although aggressive option 2.2 (COAG and AGL proposal) goes some way to addressing potential issues with revenue risk via the COAG proposal, the credit support arrangements proposed by AGL would, in our view, do little to address liquidity risk and the limitations of the existing regime.

The aggressive option 2.1 (COAG proposal plus removal of credit support) has the advantage over other aggressive options of reducing the inefficiencies of current arrangements by removing the currently ineffective credit support arrangements. Not only would this remove cost and a source of contention within the industry, it could arguably increase competition by lowering the barrier to entry posed by credit support requirements.

Option 2.1 has the added advantage of providing certainty to distributors about their ability to recover forgone revenue following a retailer default (through the COAG reforms). While option 2.1 does not address liquidity risk directly, there is a plausible case that the COAG reforms could provide sufficient certainty around revenue recovery for distributors to raise liquidity from the financial system if and when it is needed. Such an assumption is not unrealistic, although it still leaves some uncertainty over the ability of distributors to deal with a liquidity problem. In the case of government-owned distributors it is possible that emergency liquidity support may be provided by government, although that would not provide certainty for private sector distributors. The attraction of option 2.1 is that it incurs no ongoing costs (since liquidity support is addressed only when a liquidity event occurs). The counterpart of that cost saving is less certainty that a liquidity problem will be addressed quickly enough if it should arise.

If ongoing costs were the over-riding consideration, option 2.1 would be attractive.

Of the defensive options, the retailer default fund (option 3) appears to be the least attractive, for the simple reason that it is more costly than the other options, with other options (such as 2.3 and 4.2) also able to address the same regulatory principles as option 3. The other two candidate options (2.3 and 4) address the residual uncertainty of option 2.1 in very different ways.

In many ways, option 4 (liquidity support facility) is the closer of the two defensive options to option 2.1. Like option 2.1, option 4 relies on the COAG proposal to recover forgone revenue. Thus, the two options have very similar post-default cost structures (an average post-default cost to customers of around 7% of their power bills under scenario 2 and a total dollar cost of recovery of around $900 million for electricity and $165 million for gas – see Tables 6.5 and 6.6). However, whereas option 2.1 simply recovers the forgone revenue over time from customers, option 4 draws down the liquidity facility and repays the drawdown from customers over time. The need to pay for the liquidity facility means that, unlike option 2.1, option 4 incurs ongoing costs (equal to roughly 0.1% of customers' energy bills – see Tables 6.3 and 6.4). In our opinion, this cost (estimated to total around $17 million per annum for both markets) is a relatively small price to pay for certainty that funds will be available if and when needed.

Option 2.3 (COAG proposal plus a restructured credit support scheme) relies on credit support to provide funds for both revenue and liquidity purposes when needed. The main difference between the credit arrangements under option 2.3 and current arrangements is that the arrangements are much more tightly structured and are designed to greatly increase the level (and therefore effectiveness) of such support. Option 2.3 has the advantage that it creates positive incentives for retailers to improve their credit ratings.

As with option 4, option 2.3 involves an ongoing cost that is passed to customers. As shown in Tables 6.3 and 6.4, this ongoing cost under option 2.3 is materially higher (roughly four times higher) than the equivalent ongoing cost of the liquidity facility under option 4. While the ongoing cost may appear to make option 2.3 unattractive, it has a feature that none of the other options has. Namely, the funds that are made available in the event of a retailer default are not a liability of the distributor or of energy customers. The credit support, when provided, becomes an asset of the providing financial institution and a claim against the liquidation of the retailer. Thus, the post-default costs involved with option 2.3 are considerably lower than under either option 2.1 or 4 (indeed, less than half of the cost of the other options – see Tables 6.5 and 6.6).

Thus, compared with option 2.1, option 2.3 provides certainty of funding (for both revenue and liquidity), but at an ongoing cost and a lower post-default cost. Compared with option 4, option 2.3 provides roughly half the amount of funding to meet a retailer default. It does so at a higher ongoing cost and a lower post-default cost.

In our view, option 2.3 would be the most attractive option if retailer defaults were a regular occurrence. It involves higher ongoing costs (approximately $70 million per annum for both markets, compared with $17 million per annum for both markets under option 4) but lower post-default costs (approximately $470 million for both markets, compared with $1,060 million for both markets under option 4), thereby smoothing the cost burden over time.

However, on the basis of our limited knowledge of the history of retailer failures, the likelihood of regular, large defaults appears to us to be low. Therefore, option 4 appears to us to be preferable on the grounds that the “premium” paid for certainty of funding (i.e., the ongoing cost) is more acceptable than in option 2.3 when taking into consideration the potential for a low-probability, high-impact retailer default. Promontory’s preferred option is sub-option 4.2, which establishes better incentives for retailers to manage their exposures and credit ratings.

Recommendation

That the AEMC consider introducing reforms to the credit support arrangements in the gas and electricity markets based on the following:

- Implementing the COAG proposal to enhance the cost pass-through provisions by removing the materiality threshold and allowing forgone revenue to be passed through;
- Removing the current requirements for credit support from retailers to distributors;
- Introducing a requirement for distributors to establish a committed liquidity facility with a financial institution, with the size of the facility linked to the size of the largest retailer NCL within the network, but subject to a cap to ensure that the facility is not unreasonably large; and
- Allowing the annual commitment fee and any utilisation costs associated with the liquidity facility to be recovered from retailers according to a formula based on both NCL and risk rating.

Appendix A: Energy market structure[86]

The National Electricity Market (NEM) is a wholesale market in which generators sell electricity in Eastern and Southern Australia (covering Queensland, NSW, Victoria, South Australia, Tasmania and the ACT). The NEM has approximately 200 large generators, five state-based transmission networks (linked by cross-border interconnectors) and 13 major distribution networks that supply electricity to end-use customers. The main customers are energy retailers, which bundle electricity with network services for sale to residential, commercial and industrial energy users.

Distribution networks are confined to particular geographic areas, with Queensland, NSW and Victoria each having multiple networks that are sole distributors in designated areas. The ACT, South Australia and Tasmania have one major network each. Some jurisdictions also have small regional networks with separate ownership. Ownership arrangements of distribution networks are mixed. Some are fully government owned (all networks in Queensland, NSW and Tasmania), some are privately owned (all networks in Victoria), while the others are a mixture of public and private ownership (in the ACT and South Australia). Reliability is a key service measure for a distribution network, with most electricity outages in the NEM originating in distribution networks.

Gas is used widely for industrial manufacturing and for generating electricity (around 31% of Australian gas consumption is for electricity generation). Household demand is relatively small, except in Victoria, where residential demand accounts for around one-third of total consumption. A network of distribution pipelines delivers gas from demand hubs to industrial and residential customers. All 11 gas distribution networks are privately owned and there are significant ownership links between gas and electricity networks.

The National Energy Customer Framework (NECF) is a suite of legal instruments that regulate the sale and supply of electricity and gas to retail customers. The NECF currently applies in the ACT, Tasmania, South Australia, NSW and Queensland, with Victoria expected to transition to the national framework by 31 December 2015.

All NEM jurisdictions have full retail contestability in electricity and gas markets which allows customers to contract with their retailer of choice. In the residential and small business market, there are currently 27 active retailers. Around 70% of retailers are active in more than one jurisdiction and 10 active retailers offer both electricity and gas in at least one jurisdiction in which they are active. Other retailers offer only electricity with one retailer specialising in gas.

Despite retail contestability, retail markets remain highly concentrated. Three private retailers (AGL Energy, Origin Energy and EnergyAustralia) jointly supply over 70% of small electricity customers and over 80% of small gas customers. The concentration is greater in some jurisdictions, with four jurisdictions having three or fewer retailers supplying more than 90% of small electricity customers. In terms of ownership, government retailers retain a strong presence in some jurisdictions, while others have stronger private ownership (Victoria has the highest penetration of small private retailers). The three largest retailers all have a Standard and Poor's (S&P) credit rating of BBB- or better.

Despite government-mandated separation in the 1990s, the trend has been for vertical re-integration of retailers and generators to form ‘gentailer’ structures. The vertical integration structure provides a means for generators and retailers to internally manage price risk in the spot market. Government-owned generators are

[86] AER, *State of the Energy Market*, 2014.

also in the process of vertically integrating. The three major retailers all have significant shares in both generation and retail markets, controlling 46% of generation capacity (up from 15% in 2009). Vertical integration also occurs between the retail sector and other segments of the supply chain (such as distribution, gas production and gas storage).

Appendix B: Assumptions

Table B.1: Model input assumptions

Variable	Assumptions	Data source
Forgone revenue	• Measured as 110% of defaulted retailer's NCL. • The additional 10% is to account for the fact that retailer's NCL would continue to grow following retailer default until its customers are transferred by the AEMO or acquired by another retailer. • The calculation of a defaulted retailer's NCL involved use of the retailer's market share and an assumption about the aggregate NCL across all retailers within a distribution network. • The market share is estimated using the number of shared customers of each retailer within a distribution network. The aggregate retailer's NCL is assumed to be 25% of each distributor's TARC (i.e., we assume that a distributor's TARC over a 90 day period represents the sum of each retailer's NCL across the network).[87] • We then allocate the total network NCL to the retailers in that network based on each retailer's market share (measured by number of shared customers divided by the total number of customers in the network). For example, if a distributor's TARC is $10 million and a retailer's market share based on its number of customers is 20%, the NCL for that retailer would be calculated as $10 million x 25% x 20% = $500,000.	Shared customer data was obtained from the AEMC. Information on TARC was obtained from the AER's access arrangements (for gas) and responses to regulatory information notices (for electricity).
Working capital ratio	• Estimated as at 3 months post a retailer default. • Measured as current assets (minus forgone revenue) as a percentage of current liabilities over a 3 month period (plus costs from retailer default). • Current assets = cash (1% of distributor revenue) and receivables (25% of TARC). • Current liabilities = Maintenance costs (for electricity), operating expenditure, transmission costs (for electricity), debt costs and capital expenditure.[88] In order to adjust for a 3 month timeframe, we divided current liabilities by four. • Costs from retailer default = administrative costs (capped at $0.1 million) and funding costs (varies according to the amount of external funding required by a distributor and debt costs).	Distributor's revenue, maintenance costs, operating expenditure, transmission costs, debt costs and capital expenditure was obtained from AER's access arrangements, regulatory determination, and/or annual reports.

[87] In practice, each retailer's NCL will be driven by the maximum days outstanding (MDO) which is dependent on how frequently the distributor invoices its retailers, the time it takes prepare invoices and the period allowed for payment. We make a simplifying assumption that the MDO is equivalent to a 90 day period.
[88] For electricity, data was obtained from distributor's responses to AER's Regulatory Information Notices (RIN). For gas, information was obtained from access arrangements.

<table>
<tr><th>Variable</th><th>Assumptions</th><th>Data source</th></tr>
<tr><td>Cost to shared customers</td><td>Measured as a dollar impact as a percentage of annual energy bills.
To estimate the cost increase, market offers from 23 retailers are used for a representative customer in a distribution network.
To obtain market offers we relied on electricity and gas consumption of a representative shared customer in each network at a jurisdiction level. These are provided below.
<table>
<tr><th>Annual usage</th><th>Gas (mj)</th><th>Electricity(kWh)</th></tr>
<tr><td>ACT</td><td>25,000</td><td>7,180</td></tr>
<tr><td>NSW</td><td>21,600</td><td>6,500</td></tr>
<tr><td>QLD</td><td>12,000</td><td>4,533</td></tr>
<tr><td>VIC</td><td>54,000</td><td>4,645</td></tr>
<tr><td>SA</td><td>18,000</td><td>5,000</td></tr>
</table>
Further, we assume retailers pass on any costs of managing default risk under each of the options to their shared customers. We also assume that retailers make no distinction between small and large customers in allocating the cost.</td><td>AER’s Energy Made Easy, My Power Planner and Yourchoice;

Electricity usage was obtained from the AEMC’s price trends report.[89]

Gas usage was obtained from a variety of documents.[90]</td></tr>
<tr><td>Cost to distributor customers</td><td>To estimate the post-default impact on customers for options 1, 2 and 4 (including relevant sub-options), we assume that costs are shared equally by customers in a distributor’s network.
The dollar post-default impact is measured as a percentage of the average of the estimated annual market offers to representative gas and electricity customers from retailers operating in each network.</td><td>As above</td></tr>
</table>

[89] AEMC, *2014 Residential Electricity Price Trends Report*, 5 December 2014.
[90] Sustainability Victoria and State Government of Victoria, *Victorian Households Energy Report*, 2014; IPART, *Typical household energy use* (http://www.ipart.nsw.gov.au/Home/For_Consumers/Compare_Energy_Offers/Typical_household_energy_use);
South Australian Council of Social Service, *The South Australian Gas Market Consumer Factsheet*, 2014.

Table B.2: Assumptions in applying various mechanisms

Mechanism	Assumptions	Option
Overs and unders and cost pass-through	Where overs and unders process or cost pass-through mechanism is applied the minimum duration of recovery of forgone revenue and/or costs from retailer default is 1.5 years. This is based on the assumption that: • It takes a maximum of 130 days for the cost pass-through application process to be approved. That is, maximum 90 days from the date of default to submit an application and maximum 40 days for approval. • Subsequent to approval, distributors face a time lag until the start of the next regulatory year before recovery begins (given AER's preference for no more than one annual price adjustment). • In total, we have assumed a period of 6 months between a retailer's default and when recovery commences. • The AER does not allow for cost increases of more than 10% per annum to distributors' customers under cost pass-through.	Option 1; Options 2.1, 2.2 and 2.3; Option 4

Credit support calculation	• Retailer's NCL is a product of 25% of the distributor's TARC and the retailer's market share (based on number of shared customers divided by total number of customers in the network).
	• The assumptions related to retailers' credit worthiness vary based on the option being modelled:
	  o Option 1 – Estimating a retailer's CA involves the use of the retailer's credit rating or D&B risk score. We have assumed that retailers with a credit rating who operate across multiple FRMPs will adopt a D&B risk score of either Minimal or Very Low if it benefits them in minimising the amount of credit support needed. We have also assigned the remaining unrated retailers with a D&B risk score ranging from Minimal to Very High. The process of assigning risk scores was aided by data provided by the AEMC.
	  o Option 2.2 and 2.3 – In estimating the credit support as a percentage of NCL it is assumed those retailers with multiple FRMPs and an S&P credit rating would cease using a D&B risk score, particularly if their credit rating is BBB- or better.
	• We assume that our re-alignment of S&P credit ratings and D&B risk scores for option 2.3 reflects the fundamental differences in these two measures of a retailer's credit worthiness. In particular, we have aligned D&B risk scores to no more than a BBB- rating from S&P.
	• We categorised various credit ratings into six counterparty grade buckets as specified below. We assumed a credit support cost of 3.5% for BBB+ to BBB- counterparty grade using figures from AGL's proposal. Using 3.5% as a base, we extrapolated credit support costs for other credit rating categories based on corporate bond credit spreads.
	• If a retailer does not have a credit rating, we have assumed the retailer is rated BB+ for the purposes of calculating credit support costs.
		Option 1;
		Options 2.2 and 2.3

<table>
<tr><th>Mechanism</th><th>Assumptions</th><th>Option</th></tr>
<tr><td></td><td>
<table>
<tr><th>Credit rating</th><th>Credit support cost</th></tr>
<tr><td>AAA to AA</td><td>1%</td></tr>
<tr><td>AA- to A-</td><td>1.50%</td></tr>
<tr><td>BBB+ to BBB-</td><td>3.50%</td></tr>
<tr><td>BB+ to BB-</td><td>4%</td></tr>
<tr><td>B+ to B-</td><td>7.50%</td></tr>
<tr><td>CCC/C</td><td>15%</td></tr>
</table>
It is assumed that retailers allocate credit support costs equally to their shared customers and make no distinction between small and large customers.
</td><td></td></tr>
<tr><td>Retailer default fund</td><td>

Target fund size – Both the electricity and gas market are highly concentrated with the market share of three largest retailers accounting for about 80%. Recognising the concentrated nature of the market, we have assumed the target fund size should cater for at least the default of the largest retailer's NCL across gas and electricity market. Using the largest retailer's NCL for both gas and electricity distributors from our credit support calculations above, we have estimated the target fund size to be $941.25 million.[91]
Contributions – It is assumed the target fund size would be built up over time through annual contributions from gas and electricity retailers. The two key determinants for the annual contributions are the acceptable time period for the fund to reach its target size and the investment return earned on the contributions. We have assumed the acceptable time period to be 10 years and investment return earned on the contributions to be 6% per annum. Based on these assumptions and after accounting for management fees of 0.5% per annum, we estimate the annual contributions for the fund to reach its size to be $73.32 million.
Management – We have assumed the fund will be managed independently. The AEMC would be required to set the investment mandate for the fund's strategy and the level of liquidity needed (proportion of assets that can be converted into cash within a short period of time). There will also be management fee and operating expenses. As noted above, we have assumed this to be 0.5% per annum broadly representing the management fee of running an investment fund with a relatively low risk profile.

</td><td>Option 3</td></tr>
</table>

[91] We note this is likely to be higher than would be the case if the actual NCL of largest retailer was used. However, in the absence of such data we have used this amount for the purposes of modelling the benefit and costs of this option. We also note that we considered the possibility of establishing separate retailer default funds for gas and electricity. Recognising that many retailers operate in both markets and the potential efficiency benefits of single fund, we assumed a single retailer default fund would be established that covers both gas and electricity.

Mechanism	Assumptions	Option
	• Use and replenishment – We assume that distributors can draw on retailer default within 10 days of their application being approved by the AER. The 10 day period is to allow for the fund to convert investments into cash and hence enable distributors to draw on the fund. We assume that the full amount of a defaulted retailer's forgone revenue is drawn from the default fund. In the event distributors draw on the fund, it is assumed the replenishment of the fund would be governed by the same rules that applied for retailer contributions (i.e., there is no use of cost pass-through to replenish the fund).	
Liquidity facility	• Size – Each distributor calculates its exposure to each retailer operating in its network (i.e., each retailer's NCL). The size of the liquidity facility is set to the largest NCL for a retailer within each distributor network (capped at 50% of the distributor's unpaid network charges). • Allocation – There are two approaches to allocating the cost to retailers. A market-share-based allocation and a risk-based allocation (which uses the retailer's NCL combined with a measure of credit worthiness). • Fees – Two types of fees are ongoing and funding fees. Ongoing fees are passed on by distributors to retailers and ultimately, to shared customers. Funding fees are passed on by distributors to their customers under cost pass-through. We assume no upfront fees. The fees (in accordance Table 5.15) were constructed based on discussions with financial institutions. • Ongoing fee = commitment fee plus 50% of the credit margin (based on a distributor's credit rating). • Funding fee (i.e., drawdown fee) = three-month bank bill swap rate (BBSW) plus a credit margin (based on a distributor's credit rating). • We assume that all distributors have at least an investment grade rating (i.e., have a credit rating of BBB- and better). • Access – The access to facility is subject to AER approval and use test (i.e., facility cannot be accessed unless distributors experience a cash flow shortfall). • In a post-default scenario, distributors use the facility only if their working capital ratio falls below 1.0 (i.e., a distributor only draws on the facility if the distributor experiences a cash flow shortage). • The amount of the facility used is enough to bring a distributor's working capital ratio back to a level of 1.0. • The duration for which the facility remains used ranges from 1.5 to 3.5 years, where the precise duration is determined by the need to contain customer price increases to less than 10% in any regulatory year.	Options 4.1 and 4.2

Appendix C: Summary of modelling results

Option 1: Retain existing arrangements

Table C.1: Ongoing costs to shared customers (option 1) – gas

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 1	Nil	Nil	Nil	Nil	Nil

Table C.2: Ongoing costs to shared customers (option 1) – electricity

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 1	0.03%	0.10%	0.22%	1.0%	0.12

Table C.3: Post-default costs to customers (option 1) – gas

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 1 (revenue cap)	Scenario 1	1.48%	9.61%	26.83%	100.0%	208.6
	Scenario 2	1.14%	6.19%	16.98%	96.5%	165.6
	Scenario 3	0.01%	0.22%	0.53%	96.5%	8.5
Option 1 (price cap)	Scenario 1	0.91%	1.64%	2.44%	8.2%	4.1
	Scenario 2	1.58%	1.58%	1.58%	2.4%	1.2
	Scenario 3	Nil	Nil	Nil	Nil	Nil

Table C.4: Post-default costs to customers (option 1) – electricity

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 1 (revenue cap)	Scenario 1	5.43%	11.30%	29.10%	100.0%	1683.2
	Scenario 2	2.67%	7.45%	29.10%	100.0%	894.0
	Scenario 3	0.04%	0.69%	1.19%	100.0%	92.3
Option 1 (price cap)	Scenario 1	0.98%	1.66%	2.46%	27.8%	56.8
	Scenario 2	2.46%	2.46%	2.46%	2.1%	6.2
	Scenario 3	Nil	Nil	Nil	Nil	Nil

Option 2: Strengthen existing arrangements

Table C.5: Description of sub-options 2.1, 2.3 and 2.3

Option	Description
Option 2.1	Strengthen existing arrangements: COAG proposal without credit support
Option 2.2	Strengthen existing arrangements: COAG and AGL proposals
Option 2.3	Strengthen existing arrangements: COAG proposal with enhanced credit support

Table C.6: Ongoing costs to shared customers (option 2) – gas

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 2.1	Nil	Nil	Nil	Nil	Nil
Option 2.2	0.13%	0.17%	0.22%	1.7%	0.15
Option 2.3	0.07%	0.24%	0.84%	95.1%	8.12

Table C.7: Ongoing costs to shared customers (option 2) – electricity

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 2.1	Nil	Nil	Nil	Nil	Nil
Option 2.2	0.25%	0.52%	0.89%	3.0%	2.02
Option 2.3	0.15%	0.48%	1.02%	96.2%	62.96

Table C.8: Post-default costs to customers (option 2) – gas

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 2.1	Scenario 1	1.48%	9.61%	26.83%	100.0%	208.6
	Scenario 2	1.14%	6.19%	16.98%	96.5%	165.6
	Scenario 3	0.01%	0.22%	0.53%	96.5%	8.5
Option 2.2	Scenario 1	1.48%	9.61%	26.83%	100.0%	208.6
	Scenario 2	1.14%	6.19%	16.98%	96.5%	165.6
	Scenario 3	0.01%	0.14%	0.20%	96.5%	5.3
Option 2.3	Scenario 1	0.47%	3.84%	7.90%	100.0%	87.9
	Scenario 2	0.52%	2.74%	7.14%	96.5%	74.6
	Scenario 3	0.01%	0.08%	0.14%	96.5%	2.4

Table C.9: Post-default costs to customers (option 2) – electricity

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 2.1	Scenario 1	5.43%	11.30%	29.10%	100.0%	1683.2
	Scenario 2	2.67%	7.45%	29.10%	100.0%	894.0
	Scenario 3	0.04%	0.69%	1.19%	100.0%	92.3
Option 2.2	Scenario 1	5.43%	11.30%	29.10%	100.0%	1683.2
	Scenario 2	2.67%	7.45%	29.10%	100.0%	894.0
	Scenario 3	0.04%	0.51%	1.01%	100.0%	72.5
Option 2.3	Scenario 1	1.83%	4.59%	12.30%	100.0%	695.4
	Scenario 2	1.22%	3.27%	12.30%	100.0%	398.3
	Scenario 3	0.04%	0.18%	0.32%	100.0%	25.2

Option 3: Retailer default fund

Table C.10: Ongoing costs to shared customers (option 3) – gas

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 3	0.03%	0.24%	0.95%	100.0%	8.12

Table C.11: Ongoing costs to shared customers (option 3) – electricity

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 3	0.07%	0.53%	1.62%	100.0%	65.18

Table C.12: Post-default costs to customers (option 3) – gas

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 3	Scenario 1	0.33%	2.38%	9.53%	100.0%	81.2
	Scenario 2	0.33%	2.38%	9.53%	100.0%	81.2
	Scenario 3	0.04%	0.32%	1.29%	100.0%	7.8

Table C.13: Post-default costs to customers (option 3) – electricity

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 3	Scenario 1	0.71%	5.33%	16.22%	100.0%	651.8
	Scenario 2	0.71%	5.33%	16.22%	100.0%	651.8
	Scenario 3	0.10%	0.72%	2.19%	100.0%	91.2

Option 4: Introduce a liquidity support scheme

Table C.14: Description of sub-options 4.1 and 4.2

Option	Description
Option 4.1	Liquidity support scheme (market-share-based allocation of ongoing fees)
Option 4.2	Liquidity support scheme (risk-based allocation of ongoing fees)

Table C.15: Ongoing costs to shared customers (option 4) – gas

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 4.1	0.01%	0.05%	0.18%	100.0%	1.86
Option 4.2	0.00%	0.06%	0.27%	100.0%	1.86

Table C.16: Ongoing costs to shared customers (option 4) – electricity

Option	Minimum	Average	Maximum	Affected customers (%)	Total annual Cost ($m)
Option 4.1	0.03%	0.09%	0.19%	100.0%	15.12
Option 4.2	0.01%	0.11%	0.50%	100.0%	15.12

Table C.17: Post-default costs to customers (option 4) – gas

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 4.1	Scenario 1	1.48%	9.46%	26.30%	100.0%	207.6
	Scenario 2	1.14%	6.15%	16.68%	96.5%	165.4
	Scenario 3	0.01%	0.22%	0.53%	96.5%	8.5
Option 4.2	Scenario 1	1.48%	9.46%	26.30%	100.0%	207.6
	Scenario 2	1.14%	6.15%	16.68%	96.5%	165.4
	Scenario 3	0.01%	0.22%	0.53%	96.5%	8.5

Table C.18: Post-default costs to customers (option 4) – electricity

Option	Default Scenario	Minimum	Average	Maximum	Impacted customers (%)	Total retailer default cost ($m)
Option 4.1	Scenario 1	5.43%	11.14%	28.25%	100.0%	1660.7
	Scenario 2	2.67%	7.37%	28.25%	100.0%	891.8
	Scenario 3	0.04%	0.69%	1.19%	100.0%	92.3
Option 4.2	Scenario 1	5.43%	11.14%	28.25%	100.0%	1660.7
	Scenario 2	2.67%	7.37%	28.25%	100.0%	891.8
	Scenario 3	0.04%	0.69%	1.19%	100.0%	92.3

Appendix D: Further detail about alignment with principles

In light of the modelling results and analysis in Section 5, this Appendix considers the extent to which each of the options considered meets the regulatory principles set out in Section 3. Table D.1 below provides a high-level summary of the alignment of each option with these principles and Table D.2 provides more detailed commentary.

Table D.1: Summary of alignment with principles for each option

Principle	Option 1: Retain existing arrangements	Option 2: Strengthen existing arrangements	Option 3: Retailer default fund	Option 4: Liquidity support scheme
Stability	✗	✓	✓	✓
Efficiency	✗	Partly	✗	Partly
Incentives	✗	✓	✓	✓
Revenue and Pricing	Partly	✓	✓	✓
Competition	✓	✗	✗	Partly

Table D.2: Comments on alignment of options with principles

Option	Principle	Comment
Option 1: Retain existing arrangements	**Principles met**	
	Competition	As highlighted in Section 5.3, the current limitations of the credit support arrangements mean that there are minimal ongoing costs for retailers and their shared customers, irrespective of whether a retailer has obtained a credit rating. The minimal risk management costs lower the barriers to entry and incentivise new retailers to enter the market.
	Principles partly met	
	Revenue and Pricing	Under a revenue cap regime the overs and unders process provides distributors with a reasonable opportunity to recover costs and forgone revenue following a retailer default. However, as shown in Section 5.3.2, the potential cost impact of retailer default on customers can be significant. Further, under a price cap regime, distributors are unable to recover forgone revenue or related costs from a retailer default, when these items are below the 1% materiality threshold. This increases the revenue impact on distributors. Critically, it does not allow distributors to fully recover their costs and hence does not align with the revenue and pricing principles.
	Principles not met	
	Stability	Existing arrangements and mechanisms do not consider the potential contagion arising from the liquidity risk associated with a large retailer default. Such a default has the potential to lead to systemic instability if the system is unable to provide energy to homes and businesses as intended. While practical imperatives provide some reassurance that decisions will be made at the time to keep the system working, the stability of the system rests on this assumption rather than on pre-arranged mechanisms designed to remove uncertainty. Section 5.3 highlights the cash flow impact stemming from existing arrangements. The working capital ratio for a large proportion of distributors falls below 1.0 under default scenarios 1 and 2. This represents a cash flow shortfall which we show to be significant for some networks (see Figures 5.3 and 5.4). We highlight that reliance is placed on distributors to obtain potentially significant external funding at a time when distributors' solvency may be in jeopardy.

		While the current mechanisms have not led to failure of a distributor or systemic instability in the past, there is no guarantee that the same will always apply. In our view there is potential for systemic impacts in persevering with the current arrangements.
	Efficiency	The ineffectiveness of the current credit support requirements results in liquidity risk being assumed by distributors. Likewise, the current inability to recover forgone revenue under a weighted-average price cap regime results in the potential for revenue risk to also be assumed by distributors. Distributors are therefore exposed to risks which have the potential to lead to significant impacts from which it could be difficult to recover. Where costs and forgone revenue are able to be recovered, those costs are ultimately paid by all of the relevant distributor's customers. Analysis of option 1 in Section 5.3 highlights the potentially significant impact on customers of cost and revenue recovery. Shared customers of the defaulted retailer effectively pay twice for services received, while other customers of the distributor pay additional amounts for services they have not received.
	Incentives	Existing arrangements and mechanisms do not provide retailers with any additional incentives to minimise their probability of default and hence reduce the risks and impact on distributors. Distributors on the other hand, have an incentive to protect themselves on an *ex ante* basis, although they lack a viable cost-effective mechanism through which to do so.
Option 2: Strengthen existing arrangements[92]	**Principles met**	
	Stability	We considered several sub-options under option 2. The overall assessment is based largely on option 2.3, which involves additional credit support, in conjunction with the enhanced cost pass-through provisions proposed by COAG. This option minimises financial contagion by transferring revenue risk to the banking sector and customers of the distributor (through the provision of credit support and the use of cost pass-through) and transferring a significant proportion of the liquidity risk to the banking sector (also through the credit support arrangements). We note there remains a risk that the amount of credit support provided will be insufficient to fully protect against contagion. This is especially the case for a distribution network in which there is a significantly large retailer. On balance, however, we are of the view that contagion is sufficiently contained under option 2.3 and hence classify this principle as being met. More specifically, Section 5.4 shows that a significant portion of forgone revenue (i.e.,

[92] In assessing option 2 against the principles, we focus on sub-option 2.3 as we believe it to be the most viable of the three sub-options considered.

		approximately 55% across all gas and electricity networks under default scenario 2) is immediately recovered through credit support. The analysis further shows that, given these levels of credit support, distributors have the ability to draw on the support for liquidity purposes in order to maintain their working capital ratios above 1.0[93]. To the extent credit rating adjustments are sufficiently timely (i.e., they are updated in a timely manner to reflect a deterioration in credit worthiness), this will also work to increase the level of credit support provided prior to any retailer default.
	Incentives	Option 2.3 includes some positive incentives. The strengthening of credit support arrangements under option 2.3 provides an incentive for retailers to minimise their NCLs (e.g., through more frequent billing) and reduce their probability of default (e.g., through financial and organisational improvements which may lead to better credit ratings). The realignment of S&P credit ratings and D&B dynamic risk scores also provides an incentive for a mid-sized retailer to invest in a formal S&P rating (or equivalent).
	Revenue and pricing	The strengthening of credit support requirements provides a reasonable opportunity for distributors to quickly recover unpaid network charges. This would occur through the additional credit support provided as a result of the enhancements under option 2.3. The ability for a distributor to recover costs is also consistent with this principle, given the enhanced cost pass-through provisions that allow the recovery of forgone revenue and costs without the use of a materially threshold.
	Principles partly met	
	Efficiency	Some aspects of the enhanced arrangements under option 2.3 would work to improve efficiency compared to the current arrangements. Credit support provided by retailers under option 2.3 would be higher than current levels. Our results show that the enhanced credit support levels are effective in reducing the revenue and liquidity impacts as a result of retailer default (and hence work to reduce the risk of higher prices for customers stemming from any recovery of forgone revenue and costs). Our post-default analysis in Section 5.4.2 shows that electricity customers face an average increase in prices of 3.3% under default scenario 2 (compared with 7.5% under current arrangements). The results are similar for gas, where customers face an average increase in prices of 2.7% under

[93] Our results show that only one distributor (out of the 19 in our model) has a residual working capital ratio below 1.0 under retailer default scenario 2. The working capital ratio for that distributor is 0.93 which is reasonably close to 1.0 and hence unlikely to create financial contagion.

		default scenario 2 (compared with a 6.2% under current arrangements). However, even with the enhancements, distributors continue to retain some risk, particularly where credit support is insufficient or lapsed.[94] We note that where a proportion of forgone revenue and costs are not recovered through credit support, we assume a distributor uses the cost pass-through mechanism. Those costs are ultimately paid by all of a distributor's customers. Shared customers of the defaulted retailer effectively pay twice for services received, while other customers of the distributor pay additional amounts for services they have not received. The reduction in risk has an associated cost; namely, the ongoing cost paid by retailers for the credit support (which is dependent on the retailer's NCL and credit rating). As highlighted in Section 6, the average ongoing cost to shared customers under option 2.3 is 0.24% for gas (with a maximum increase of 0.84%) and 0.48% for electricity (with a maximum increase of 1.02%). These costs need to be balanced against the longer-term protection benefits for distributors and system stability and the incentives they create.
	Principles not met	
	Competition	The removal of CAs and the implementation of the enhancements under option 2.3 work to increase the level of credit support required by retailers (especially for unrated retailers using a D&B dynamic risk score). This will increase the barriers to entry for new retailers.
Option 3: Retailer default fund	**Principles met**	
	Stability	The retailer default fund minimises systemic instability concerns as it would facilitate short-term access to funds when needed. This, in turn, would minimise the probability of financial contagion that might otherwise have occurred following retailer default. The ultimate target size of the default fund determines whether or not there is any residual instability risk.
	Incentives	The size of the retailer default fund and the allocation of contributions based on a retailer's NCL and credit worthiness incentivises retailers to minimise their NCL and to improve their credit worthiness.
	Revenue and pricing	The retailer default fund provides distributors with short-term access to funds and hence provides a mechanism for distributors to recover costs and forgone revenue. This aligns with the requirements of the revenue and pricing principles.

[94] Any credit support is subject to renewal and failure to do so would result in credit support having lapsed.

	Principles not met	
	Efficiency	The suggested requirement for all retailers to contribute to the fund based on their exposure and credit worthiness ensures that costs are allocated to those retailers which have high NCLs (i.e., large retailers) and those that are most likely to lead to a drawdown of the fund (i.e., retailers with a lower credit rating). As detailed in Section 5.5, the contribution amount is dependent on each retailer's NCL and the retailer's risk-weight. Even though the allocation may create positive incentives for a retailer to improve its debt management, option 3 has the highest annual dollar cost to customers ($8.12 million for gas and $65.18 million for electricity) of all the options (although for gas, $8.12 million is equal highest with option 2.3). These costs translate into the highest (or equal highest for gas) average ongoing increases to energy prices for customers (0.24% for gas and 0.53% for electricity). We note that, under our model, we assume that the ongoing cost will cease after 10 years (whereas for other options, they are assumed to be perpetual in nature). Under retailer default scenario 2 the fund is fully depleted and contributions would need to rebuild the fund. Hence customers initially pay to mitigate the impact of a retailer default to a distributor (i.e., customer contributions for the initial 10-year period), but have to pay again in the event of retailer default in order to replenish the fund. We further note that option 3 requires administrative time and resources to set up the governance structures and rules that will govern the operation of the fund. Based on our experience with deposit insurance funds, the setup costs can be considerable.
	Competition	In relation to competition and barriers to entry, we note that the costs to retailers (and ultimately customers) are greater under option 3 than under the other options. These impacts may be amplified for a new entrant with a lower credit rating.

<table>
<tr><td rowspan="3">Option 4: Liquidity support scheme[95]</td><td colspan="2">Principles met</td></tr>
<tr><td>Stability</td><td>The committed facility under option 4, in conjunction with the enhanced cost pass-through provisions (under the COAG proposal), materially reduces any risk of financial contagion from a retailer default by transferring revenue risk to the customers of the distributor (through the use of cost pass-through provisions) and transferring a significant component of the liquidity risk to the banking sector (through the use of the liquidity facility).

We note that there remains a risk that the size of a facility (relative to the defaulted retailer) is insufficient to fully protect against contagion. In our model we assume a committed facility (for each network) equal to the largest NCL in the network, subject to a cap at 50% of the distributor’s unpaid network charges. The analysis in Section 5.6 shows that the residual liquidity risk from a facility of that size is minimal. We assume that the distributors have the ability to draw on their facilities for liquidity purposes in order to increase their working capital ratio back to a level of 1.0. Our results show that only one distributor (out of the 19 in our model) has a residual working capital ratio below 1.0 under retailer default scenario 2. The working capital ratio for that distributor is 0.8. We are of the view that the gap for this one distributor is not major and hence unlikely to lead to financial contagion and instability.</td></tr>
<tr><td>Incentives</td><td>Under option 4.2, the allocation of the ongoing fee for the liquidity facility uses a risk-based approach, where the fee is based on a combination of a retailer’s NCL and credit worthiness. This incentivises retailers to minimise their NCLs and improve their credit worthiness. Minimising NCL (especially with respect to the larger retailers) would have the additional benefit of improving the overall efficiency of the facility over the longer term. More specially, if a distributor’s exposure to large retailers is reduced, the size of the facility should also be able to be reduced, which would have the benefit of reducing the commitment fee across the network.

We note that the other sub-option considered (i.e., option 4.1) uses a simple allocation approach by taking the market share (i.e., annual retailer charges) and applying this to allocate the ongoing facility fee to the retailers within the network. We highlight that, although option 4.1 has the benefit of simplicity, it does not incorporate the same positive incentives as option 4.2.</td></tr>
</table>

[95] As discussed in Section 4.5, option 4 relies the implementation of the COAG proposal to remove the materiality threshold and include forgone revenue under cost pass-through provisions. In the absence of these revisions, the option would be materially impaired to the extent that there would be greater uncertainty about recovering lost revenue. Not only would that reduce the mitigation of revenue risk, there would also likely be an increase in the cost of the liquidity facility.

	Revenue and pricing	The committed facility provides distributors with immediate access to funds equivalent to the NCL of the largest retailer in the network. Distributors will also have access to cost pass-through provisions allowing them to fully recover forgone revenue over the longer term. These characteristics are consistent with the revenue and pricing principle of the scheme.
	Principles partly met	
	Efficiency	As stated above, the committed facility, in conjunction with the enhanced cost pass-through provisions, effectively transfers revenue risk to the customers of the distributor (through the use of cost pass-through) and a significant component of the liquidity risk to the banking sector (through the use of the liquidity facility). Any residual liquidity risk that remains with the distributor is a result of the assumed cap applied to the size of the facility (i.e., 50% of the distributor's unpaid network charges). The cap ensures that the size of each liquidity facility does not become unreasonable and assists in containing ongoing fees. In terms of ongoing fees, the average cost increase for an electricity customer under option 4.2 is 0.11% (maximum of 0.5%) with the equivalent for gas being 0.06% (maximum of 0.27%). Although these costs are lower than option 2.3, they need to be balanced against the stronger protection benefits to distributors and customers. In contrast to option 2.3 (where a large proportion of the revenue and liquidity risk is transferred to the banking sector), the full amount of the revenue risk under option 4 is transferred to customers. This key difference is evident when comparing the post-default impacts between option 2.3 and option 4. More specifically, under option 2.3, the total dollar impact for electricity customers under default scenario 2 is $398 million. This translates to an average price impact of 3.27% (maximum of 12.30%). For option 4, the equivalent dollar impact increases to $892 million, translating to an average price impact of 7.37% (maximum of 28.25%). The comparisons for gas are comparable. Hence, although this option protects distributors from retailer default (focusing on both liquidity and revenue risk), the impact on customers under a default scenario has the potential to be significant, and is materially greater than under option 2.3 (where a credit support arrangement is used).
	Competition	The risk-based allocation of the ongoing facility fee under option 4.2 is not as onerous as providing credit support on an individual retailer basis. For electricity, the ongoing average cost increase for option 4.2 is 0.11% compared with 0.48% for option 2.3 (enhanced credit support). Hence, although there is an additional barrier to entry in the form of the facility fee, it is kept to a minimum under this option. We note, however, that this impact is slightly

		amplified for a new entrant once we consider that a new entrant may have a lower credit rating. Customers of an electricity retailer with a D&B dynamic risk score of Average or Moderate would experience an average increase of 0.22% (maximum of 0.5%) under option 4.2. Overall, we are of the view that these costs, although not significant, may be taken into account by a potential new entrant in its decision making process.

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