15 Distribution reliability

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| Key points |
| * Reliability in distribution is usually measured by the frequency and duration of power interruptions in the network. * Most power interruptions that customers experience reflect faults or failures in distribution networks. * Distribution reliability varies significantly between jurisdictions and network businesses in the National Electricity Market (NEM) because it is affected by the specific characteristics of each network and the standards imposed. * In order to influence the reliability of distribution networks, state and territory governments and regulators apply reliability standards to distribution businesses, and the Australian Energy Regulator (AER) applies the Service Target Performance Incentive Scheme (STPIS). * This causes duplication and inconsistencies in the standards for some businesses, increasing their costs and making benchmarking of distribution businesses difficult. * Inappropriate reliability standards can also introduce inefficiencies, such as: * standards that are too high or too low impose (net) costs on customers. * standards that restrict the choice of combinations of inputs that distribution businesses can use to achieve improved reliability (such as planning, maintenance and responding quickly to outages) increase costs to businesses and consumers. * requiring distribution businesses to adhere to, and report on, different standards, administered by different regulators, increases costs to businesses and consumers. * A national reliability framework for distribution businesses could overcome these inefficiencies and facilitate benchmarking. It should: * remove jurisdiction-specific reliability standards * reflect customers’ preferences through estimated values of customer reliability * apply all components and parameters of the STPIS to all businesses * streamline reporting requirements * set efficient standards * ensure incentives are efficient and reflect customer preferences. |
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## 15.1 Introduction

Distribution businesses seek to deliver reliable electricity supply to customers by planning, building, and maintaining networks to avoid outages, and by responding to outages promptly when they occur.

For distribution businesses in the National Electricity Market (NEM), delivering reliable supply to customers can be challenging, due to:

* the characteristics of distribution networks. Distribution networks are made up of many physical components varying in age and condition and often spanning large distances
* the environments in which they operate. Some distribution networks deliver electricity to customers in difficult environments with inclement or extreme weather. Wind, lightning, birds, possums, cars and trees, for example, can affect overhead lines. Density of customers in different areas also affects reliability, with rural areas more likely, on average, to experience longer interruptions due to slowly repair response times by businesses given they have a greater geographic coverage (per customer).

Reliability standards are applied to distribution networks to encourage the network businesses to maintain high levels of reliability even though there are factors that affect reliability that are beyond the control of businesses. Standards are commonly (but not always) directly linked to customers’ experience of reliability.

There are several reasons why this customer-focused interpretation of reliability is appropriate for distribution networks.

* The majority (around 80–90 per cent) of power interruptions that customers experience are a result of faults or failures in distribution networks.
* Distribution networks are typically radial, rather than meshed, which limits the effects of an outage. Cascading failures between such radial networks are much less likely to occur. Therefore, the measures a distribution business takes to increase reliability usually only affect customers of that business. Similarly, changes to reliability in distribution networks do not cause the network effects that occur in transmission networks. Reliability outcomes in distribution networks can therefore differ markedly between businesses, without creating significant adverse effects on other networks in the NEM.
* Because distribution networks generally have more line length than transmission networks, reducing interruptions by building redundancy into the majority of distribution networks would have a prohibitively high cost.

These characteristics are reflected in the metrics that are used to measure distribution reliability outcomes (box 15.1). The ‘system average interruption duration index’ (SAIDI) and the ‘system average interruption frequency index’ (SAIFI) are the two most common measures of reliability performance in distribution networks. They describe for how long and how often a customer could expect to be without power over a given period of time (usually a year).

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| Box 15.1 Common metrics of reliability in distribution networks |
| * **SAIDI** — system average interruption duration index — is the total minutes on average that a customer could expect to be without power over a given period, usually a year. SAIDI is calculated by adding the total duration of each customer interruption and dividing that by the total number of customers. Separate indices can be calculated for planned and unplanned interruptions. * **SAIFI** — system average interruption frequency index — is the number of times in a year that a customer could expect to experience an interruption. SAIFI is calculated by dividing the total number of interruptions across customers by the total number of customers. Separate indexes can be calculated for planned and unplanned interruptions. SAIFI does not usually include ‘momentary’ interruptions lasting for less than one minute. * **CAIDI** — customer average interruption duration index — is the average time a customer could expect to wait to have supply restored after an interruption. CAIDI is calculated by adding the duration of each customer interruption and dividing that by the total number of interruptions (that is, SAIDI divided by SAIFI). * **MAIFI** — momentary average interruption frequency index — is the number of momentary interruptions lasting less than a minute that a customer could expect to experience in a year. MAIFI is calculated as the total number of momentary interruptions across all customers divided by the total number of customers. |
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## 15.2 Reliability performance of distribution businesses in the National Electricity Market

Over the last 10 years, state and territory average reliability performance data reflect reasonably consistent performance. International comparisons similarly show that the relative performance of Australia’s distribution businesses overall has been quite stable, and the NEM has consistently recorded significantly higher average SAIDI results than networks in many other countries.[[1]](#footnote-1)

Aggregate SAIDI results for jurisdictions and for the NEM as a whole, however, mask the variation in performance between distribution businesses, and even reliability performance data for a single distribution business may mask significant variations in the experience of customers in different parts of that business’s network.

Participants in this inquiry have suggested that many factors contribute to variation in reliability performance between and within distribution businesses over time:

Reliability is ultimately the key measure of the performance of a network and a [distribution business]… major events such as storms, the network design (planning standards/network type CBD/Rural/Urban) and the condition of the network have a major influence on this measure. (Ausgrid, sub. 19, p. 2)

… comparisons between jurisdictions can be difficult, as factors such as the level of customer density, the size of the network and the terrain it covers, and environmental factors (e.g. exposure to extreme weather) can have a significant impact on the reliability performance which is achieved and the costs of augmenting and maintaining each network. (AEMC, sub. 16, p. 2)

Some factors affecting reliability, such as the condition of the network and the level of redundancy (subject to planning and reliability standards), are controlled by the business. Others, such as severe weather events and customer density, are not. For example, some networks — and especially those in rural areas of the NEM — are ‘stringier’ than others with long lines, low customer densities and, on average, lower ‘redundancy’.[[2]](#footnote-2) These characteristics increase the likelihood of interruptions, and longer outage durations (for example, if maintenance crews must travel long distances).

In 2010, distribution businesses in Victoria attributed around 32 per cent of customer interruptions to equipment failure (AER 2012h, p. 38). Other common causes were vegetation falling on lines and weather events (figure 15.1). The significance of these causal factors varies across businesses. For example, SP AusNet’s distribution business recorded a high proportion of interruptions caused by vegetation, which it attributed to ‘the nature of the environment of the network’ (AER 2012h, p. 39), whereas Powercor had proportionately more interruptions from the weather.

Figure 15.1 Causes of supply interruptions in Victorian distribution networks, 2010

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| Figure 15.1 Causes of supply interruptions in Victorian distribution networks, 2010. This figure shows the percentage of total supply interruptions of other interruptions, inter-distributor connection failure, load shedding, transmission failure, third party impacts, animals, vegetation, operational error, equipment failure and weather in selected Victorian distribution networks. |

*Data source*: AER (2012h, p. 39).

Distribution businesses can address common causes of faults in various ways, including by building more redundancy into their networks to address some equipment failures, clearing vegetation away from overhead lines, installing animal shields on poles and building new lines away from roads. The mix of planning, operational and maintenance actions that distribution businesses take to deliver reliability to their customers is in turn a function of the:

* characteristics of each network, including the environments in which each operates, and the densities and types of customer
* regulatory frameworks (in each jurisdiction and NEM-wide) including reliability standards and incentive schemes.

An efficient distribution business will deliver reliability outcomes by meeting customer preferences, given the characteristics of the network. It will do so for a low cost and by using instruments within its control to mitigate the effects of factors outside its control. Benchmarking could be used to identify these businesses.

As discussed in chapter 14, efficient reliability levels for distribution networks have two dimensions.

* The framework for setting reliability should seek to achieve overall economic efficiency, so that costs of improving reliability are broadly equivalent to the benefits for customers from that improvement (that is, the marginal costs are equivalent to the marginal benefits). Regulatory benchmarking can help in the development of such a framework by highlighting instances where this benefit cost tradeoff is integral to the process of determining reliability standards.
* Businesses should meet reliability standards efficiently, with their capacity for doing this tested through traditional benchmarking tools (chapter 4).

## 15.3 Reliability settings for distribution networks in the National Electricity Market

As discussed in chapter 14, under incentive regulation, network businesses have an incentive to reduce costs by reducing reliability. Governments and regulators therefore apply reliability specific planning and performance requirements to complement incentive regulation in the NEM (box 15.2). (Governments also apply safety standards to distribution businesses, some of which operate under approaches consistent with incentive regulation (chapter 5), others under prescriptive regulatory approaches — chapter 7.) The frameworks in which these standards are applied to distribution businesses differ between jurisdictions (table 15.1).

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| Box 15.2 Reliability specific planning and performance requirements |
| Throughout this chapter, the reliability settings imposed on distribution businesses are termed reliability specific planning and performance requirements. These comprise:   * standards — generally these are planning requirements placed on businesses that require a certain level of redundancy in specific parts of the network. These are usually expressed as ‘N-x’ requirements (appendix F) * probabilistic planning requirements — represent a ‘performance standard’ or criterion imposed on the distribution businesses, such as a requirement that reliability improving investments take place if the benefits from doing so exceed the costs * targets — represent maximum outage levels that a distribution business should seek not to exceed * guaranteed service levels — minimum levels of service requirements that should be provided to individual customers within a distribution network. |
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Distribution businesses in the NEM are required to plan and build their networks to meet the security requirements to ensure stability of the network (these are contained in schedules 5.1a and 5.1 of the National Electricity Rules, hereafter the ‘Rules’). Apart from this requirement, ‘service reliability standards’ are state and territory functions (SCER 2011b, annexure 2, p. 2).

Table 15.1 Jurisdictional reliability planning and performance requirements

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Jurisdiction | Planning criteria | Performance measuresa | Performance measures applied to | STPIS - current or due to commence | Jurisdictional performance measures consistent with or additional to STPIS |
| NSW | Deterministic, set out in licence conditions | SAIDI, SAIFI are expressed as standards and set out in licence conditions | Feeder type | 2014 | Unknown until STPIS introduced |
| Vic | Probabilistic | SAIDI (planned and unplanned), SAIFI (exc. momentary interruptions), MAIFI, CAIDI set by distribution businesses in line with STPIS targets set by AER | Feeder type | Currently in operation | Consistent |
| Qld | Deterministic, set by distribution businesses in network management plans | SAIDI, SAIFI set out in Codeb | Feeder type | Currently in operation | Additional |
| SA | Deterministic, set by distribution businesses | SAIDI, SAIFI set out in Codec | Region | Currently in operation | Additional |
| Tas | None | SAIDI, SAIFI set out in Coded | Customer category | Currently in operation | Additional |
| ACT | None | SAIDI, SAIFI, CAIDI minimum targets set out in Codee | n/a | 2014 | Unknown until STPIS introduced |

a In some jurisdictions, SAIDI and SAIFI performance standards apply only to unplanned outages. b Queensland Electricity Industry Code Electricity Distribution (Supply Standards) Code. c South Australian Electricity Distribution Code. d Tasmanian Electricity Code. e Electricity Distribution (Supply Standards) Code.

*Source*: AEMC (2012k).

Reliability specific planning and performance requirements applied to distribution businesses in the NEM can include:

* design planning criteria, such as deterministic planning standards, or probabilistic requirements that customer benefits of network augmentations outweigh the costs
* reliability performance targets, which are usually measured using SAIDI and SAIFI, that are applied through state and territory regulatory instruments (for example, codes and licence conditions) as well as under the AER’s Service Target Performance Incentive Scheme
* ‘worst served’ (guaranteed service level) requirements protecting customers who experience significantly poorer reliability outcomes than the average. In some jurisdictions, distribution businesses are required to make guaranteed service level payments to compensate customers when reliability standards are not met (such as in Victoria).

The types of reliability planning and performance requirements imposed varies significantly between jurisdictions, but also between businesses within a jurisdiction. This variation can affect how easy it is to benchmark distribution businesses as different reliability planning and performance requirements can have a large effect on the costs of a business.

Inefficiencies in the type, level, and combination of reliability planning and performance requirements applied to each distribution business can lead to inefficient reliability investments across distribution networks. For example, deterministic standards might not be set in a way that allows (and encourages) the business to provide reliability for a low cost, and at a level that reflects their customers’ preferences.

There are also limited controls placed on distribution businesses to ensure reliability investments are efficient. While reliability investments by distribution businesses are now subject to some scrutiny through the Regulatory Investment Test for Distribution, a preferred option identified in the Test may have a net economic cost (fail a cost–benefit test) if the investment is required to meet a reliability standard (Rules s. 5.17.1(c)(9)(v)). The Commission has recommended that this feature of the Regulatory Investment Test for Distribution be removed — chapter 10.

There are three main dimensions of cost and inefficiency in reliability planning and performance requirements for distribution networks in the NEM:

* levels of reliability that are too high or too low will not equate benefits and costs — imposing unnecessary price imposts on customers if too stringent, or resulting in excessive outage related costs if too low (chapter 14)
* restrictions on the way that businesses deliver improved reliability can needlessly increase the costs of providing distribution services to customers
* it is costly to meet and report on reliability performance. Hence, duplicative, overlapping or different reporting requirements inflate compliance costs to businesses. These costs increase further if applicable sets of planning and performance requirements are inconsistent with each other.

These three types of inefficiency provide a framework to assess whether reliability settings for distribution businesses in the NEM are contributing unnecessarily to costs for customers. This framework is used below to assess the consequences on costs to customers of different reliability planning and performance requirements applied in the NEM, keeping in mind the role that such requirements play under incentive regulation — an exercise of regulatory benchmarking. An assessment is also made of how current reliability planning and performance requirements might hinder, or facilitate, benchmarking of the managerial efficiency of distribution businesses.

### Planning standards

In New South Wales, distribution businesses must comply with deterministic planning standards, which are set out in the business’s licence conditions (a description of deterministic standards in the context of transmission networks is contained in appendix F). The New South Wales Minster for Energy introduced the standards in 2005. Before then, businesses were responsible for determining the appropriate level of reliability (AEMC 2012i). These deterministic planning standards that have required higher levels of redundancy have been one of the main drivers of increases in capital expenditure by New South Wales distribution businesses and in customer bills (Brattle Group 2012a, p. 157 and Rollinson 2013, p. 23).

Although businesses in other states and territories use deterministic standards to some extent, they have more discretion in the way they are used and the levels at which they are set. In Queensland, Energex and Ergon Energy use explicit deterministic standards to plan their networks. SA Power Networks sets deterministic standards to help it meet the performance targets set by the Essential Services Commission of South Australia and the reliability requirements set out in the South Australian Electricity Distribution Code. The deterministic standards, however, are not strict, and investments are deferred when the risk of contingencies can be dealt with using other operational actions (ETSA Utilities 2012b, p. 7).[[3]](#footnote-3)

In Victoria, CitiPower and Powercor Australia use deterministic standards for small, localised upgrades (CitiPower and Powercor 2012, p. 2). The Victorian Electricity Distribution Code specifies that businesses must develop plans to ensure they deliver reliability with consideration of high cost, low probability events. Mostly, distribution businesses in Victoria conduct their own probabilistic planning when making their planning decisions (the probabilistic process they use is similar to that used by the Australian Energy Market Operator (AEMO) for transmission in Victoria and is described in appendix F).

#### Consequences for efficiency

There are also costs in setting prescriptive regulations that specify how a distribution business should plan its network to meet reliability standards. The additional costs arise because, for a given level of reliability, the lowest cost combination of inputs (redundancy, maintenance, operational flexibility, portable energy generators and others) is different from one business to the next and even within a business over time. According to Jamasb et al. (2010):

Due to the presence of possible trade-offs between Opex [operating expenditure] and Capex [capital expenditure] … utilities might adopt different strategies to combine operating and capital inputs to improve service quality. (p. 5)

Deterministic planning standards therefore reduce the flexibility of a business to find the most efficient input mix to ensure a given level of reliability.

There are, however, some benefits of setting deterministic planning standards for distribution businesses. Requiring a distribution business to maintain a level of redundancy ensures that the business does not defer augmentations needed to maintain reliability in order to reduce costs under incentive regulation. These benefits largely drove the recommendation for the use of deterministic standards in Queensland, as described in the Somerville report (2004), which included the recommendation that distribution businesses in Queensland adopt deterministic standards of the form N‑1 (see appendix F).[[4]](#footnote-4) These standards, however, have imposed high costs on Energex and Ergon Energy customers and it is not clear that the resulting increased levels of reliability are adequately valued by them. Both distribution businesses have recently suggested that the deterministic standards be scaled back, with ensuing cost savings of $505 million in the current regulatory period (Somerville 2011, p. 74 and IRPNC 2012, p. 13).

Customers would only be willing to pay for augmentations to a distribution network to meet deterministic standards if they value the increases in reliability more than the price increases arising from the cost of the required investments (chapter 14). There is little evidence to suggest that the deterministic standards applied in New South Wales and Queensland are the result of an analysis of customer value of reliability. Consequently, it is likely that the level of reliability set by the deterministic standards is inefficient.

While this type of inefficiency is less likely to exist for distribution businesses that use probabilistic planning (as this uses a cost–benefit framework informed by the customer values of reliability), there are costs attached to undertaking a full probabilistic assessment every time a constraint emerges on a distribution network.

### Jurisdiction-specific performance targets

Distribution businesses are required to meet performance targets set at the jurisdictional level, and at the national level through the AER’s STPIS. Distribution businesses in Queensland, Tasmania, South Australia, and Victoria are currently operating under the STPIS. In Queensland, Tasmania and South Australia, state governments and regulators also apply different and additional performance targets to distribution businesses. In Victoria, distribution businesses are required under the Victorian Electricity Distribution Code to set their own SAIDI and SAIFI targets, but all the businesses have currently chosen to adopt the STPIS targets set by the AER. In this way, distribution businesses in Victoria are not subject to additional jurisdiction-based reliability targets. (The exception is incentive-based safety targets, in particular, the ‘F-Factor’ scheme introduced in the wake of the 2009 bushfires with the aim of reducing the number of fires started by electricity assets (box 15.3).) Whether the jurisdictional targets in New South Wales and the ACT will continue to apply in addition to the STPIS will be determined when the STPIS comes into force in 2014 and 2015, respectively.

Performance targets are set most commonly using SAIDI and SAIFI performance indicators (for example, table 15.2) although in some jurisdictions, there are also targets for MAIFI and CAIDI. In most jurisdictions, performance targets are determined according to feeder type — whether they are CBD, urban, or short or long rural feeders.[[5]](#footnote-5) Categorising performance targets by feeder type recognises that those feeders that are longer, have less redundancy and are further away from maintenance crews, generally have lower reliability and that these feeders generally service areas with lower customer density. South Australia, however, does not use feeder types, but rather sets targets for seven regional areas, and Tasmania classifies each community into one of five customer categories (critical infrastructure, high-density commercial, urban and regional centres, high-density rural, and low-density rural) with corresponding performance targets.

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| Box 15.3 The F-Factor scheme |
| In response to the 2009 Victorian bushfires, the Victorian Department of Primary Industries introduced a financial incentive scheme to encourage the management of electricity distribution assets with the aim of reducing the number of fires started by those assets. The scheme became operational in January 2012.  The scheme was specifically designed to operate in a similar way to the STPIS. It recognises that while the five year expenditure allowances include an allowance for bushfire mitigation, actual mitigation activities delivered by distribution businesses may be below levels for which customers are willing to pay as there are not strong market signals to encourage efficient mitigation levels. Therefore, bushfire mitigation activities may be inefficiently low. Incentive payments (and penalties) are used to encourage distribution businesses to increase mitigation activities to efficient levels.  The scheme was specifically designed to complement the STPIS regime, meaning any costs related to inconsistencies between it and the STPIS are likely to be minimised — unlike the additional reliability standards imposed by other jurisdictions in the NEM. |
| *Source*: DPI (2013a). |
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Sometimes, as is the case in Tasmania and South Australia, the target levels are informed by averaging past performance. Other times, they are set at a more demanding level than past performance to encourage businesses to improve reliability. Targets can be static or become more demanding over time, as was the case in New South Wales between 2005‑06 to 2010‑11, and is currently occurring in Queensland. While ActewAGL and the Office of the Tasmanian Economic Regulator have considered the use of customer values of reliability, neither have explicitly incorporated value of customer reliability estimates into the setting of their targets.

Jurisdiction-specific performance targets are set by the state regulator in South Australia, Tasmania and the ACT.[[6]](#footnote-6) In Queensland, the Minister can amend the Code and the regulator can propose amendments subject to stakeholder consultation. In New South Wales, the Minister sets the targets.

Businesses in Queensland, South Australia, Tasmania, and Victoria are required to use ‘best’ or ‘reasonable’ endeavours to meet targets. ActewAGL faces penalties for missing targets unless they can provide a ‘reasonable excuse’ and businesses in New South Wales must be as compliant as ‘reasonably practicable’ by 2014 and fully compliant by 2019. Penalties apply in all jurisdictions if businesses contravene their reliability targets and can range from fines of around $100 000 to revocation of a business’s licence (although this has never occurred in the NEM).

Table 15.2 Queensland distribution network performance targets, 2010‑11

|  |  |  |  |
| --- | --- | --- | --- |
| Distribution business | Feeder type | SAIDI (minutes)  per year | SAIFI per year |
| Energex | CBD | 15 | 0.15 |
| Urban | 106 | 1.26 |
| Short-rural | 218 | 2.46 |
| Ergon Energy | Urban | 149 | 1.98 |
| Short-rural | 424 | 3.95 |
| Long-rural | 964 | 7.40 |

*Source*: AEMC (2012k, p. 64).

Distribution businesses are required to report their performance against their targets, with (potentially) additional reporting in the event of a failure to reach their targets. For example, in New South Wales, distribution businesses are required to report their performance against the targets to the Minister quarterly and include reasons for failing to reach their target. Distribution businesses in New South Wales are also required to provide an independently audited report annually to the Independent Pricing and Regulatory Tribunal (AEMC 2011g, p. 18).

#### Consequences for efficiency

The discussion above highlights that no two jurisdiction-specific reliability performance frameworks are the same. The Australian Energy Market Commission (AEMC) (2009b) agreed:

There is a lack of consistency and transparency in how the different jurisdictional standards are determined and described. Also how the distribution businesses interpret and comply with these standards can vary significantly across the NEM. (p. xii)

In this type of regulatory environment, benchmarking distribution businesses is difficult. Reliability settings that vary considerably from one jurisdiction to the next create another factor that is external to the business that may need to be controlled for in benchmarking.

Benchmarking the targets themselves, and the frameworks in which they sit, however, is more straightforward, and a number of costs and benefits can be identified.

The benefits of imposing jurisdiction-specific performance targets in addition to the STPIS are not immediately obvious. However, it is possible that jurisdictional authorities value retaining an ability to remove the licence of a grossly underperforming distribution business. However, this power aside, it is not clear why jurisdictions do not align their targets with those in the STPIS, as is the case in Victoria. Requiring distribution businesses to adhere to and report their performance against two sets of targets (and could be viewed as three when reporting against planning standards is considered) is costly to consumers and does not seem to produce obvious benefits. According to Endeavour Energy (2012a):

We do however see benefits in aligning national and jurisdictional reporting requirements where duplicate reporting regimes are to be maintained (for example the AER’s STPIS and jurisdictional requirements). (p. 3)

Another possible benefit of jurisdictional control of targets is that customers may feel that a local target-setting body would take account of their preferences and be more responsive to local needs. However, no jurisdiction‑specific targets incorporate customer values in setting targets (as distinct from the AER’s STPIS and Victoria’s probabilistic planning requirements). Rather, significant changes to targets by jurisdictional authorities appear to occur in response to political pressure or intervention and publicly-expressed customer discontent, which are, at best, delayed and reactive responses to customer demands, and take no account of the costs of meeting the targets. These ‘reactive’ responses could also be disproportionate to the actual overall value the customers place on rectifying the issues in question, and may not be targeted appropriately in any case.

Using the historical performance of a business to set targets can also be inefficient since the resultant targets — and the costs of meeting them — may be divorced from the customers’ values of reliability (chapter 14).

### The AER’s service target performance incentive scheme

The STPIS provides incentives for distribution businesses to deliver reliability outcomes to customers. Its purpose is to:

… balance the incentive to reduce expenditure with the need to maintain and improve service quality for customers through establishing a direct financial link (reward or penalty) between revenue and service standards. (AER 2007a, p. 7)

The Rules set out requirements for the AER to establish and publish the STPIS (clause 6.6.2(b)). In carrying out this role, the AER was required to meet a number of criteria including taking into account the willingness of customers to pay for improved performance in the delivery of services, and the need to ensure that incentives are sufficient to offset any incentive the business might have to reduce costs at the expense of service levels.

The STPIS has five components:

1. reliability of supply
2. quality of supply
3. customer service
4. guaranteed service levels
5. information and reporting.

All components of the STPIS, except the guaranteed service level component, operate in addition to existing jurisdiction-specific requirements. The guaranteed service level component only applies where no corresponding jurisdiction‑specific requirement exists. As a result, it is not currently applied to any distribution business in the NEM. However, at the time the STPIS was introduced into Victoria in 2011 it was anticipated that the guaranteed service levels component would commence at the beginning of the next regulatory period (AER 2009d, p. 99).

#### Reliability of supply

The STPIS sets performance targets according to feeder type for distribution businesses using unplanned SAIDI, unplanned SAIFI, and MAIFI indicators.[[7]](#footnote-7)

The AER sets performance targets for these indicators at the beginning of each regulatory control period during the revenue determination process (table 15.3). The targets are calculated as the average of the available performance data for the five most recent years. The AER then makes adjustments, such as for:

* impacts on past performance from events that are considered to be outside of the control of a distribution business, for example, load shedding due to generation shortfall or failures in transmission networks, or interruptions during extreme weather events (box 15.4)
* any improvements in reliability that are anticipated to result from expenditure that the AER has or will approve in past or current revenue determinations.

Distribution businesses report their performance against their targets annually, and differentiate outages that they believe should be excluded from the calculation of their reward or penalty.

Table 15.3 Example targets for STPIS reliability of supply component and corresponding state-based targets

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Parameter | Unit | Ergon Energy’s Targets | | | | |
|  |  | 2010‑11 | 2011‑12 | 2012‑13 | 2013‑14 | 2014‑15 |
| **STPIS targets** | | | | | | |
| SAIDI | Minutes |  |  |  |  |  |
| Urban |  | 129 | 128 | 127 | 127 | 126 |
| Short rural |  | 296 | 291 | 287 | 283 | 279 |
| Long rural |  | 699 | 687 | 675 | 664 | 652 |
| SAIFI | Interruptions |  |  |  |  |  |
| Urban |  | 1.69 | 1.68 | 1.66 | 1.64 | 1.63 |
| Short rural |  | 3.06 | 3.02 | 2.98 | 2.94 | 2.91 |
| Long rural |  | 5.59 | 5.52 | 5.44 | 5.37 | 5.29 |
| **State targets (minimum service standards)** | | | | | | |
| SAIDI | Minutes |  |  |  |  |  |
| Urban |  | 149 | 148 | 147 | 146 | 145 |
| Short rural |  | 424 | 418 | 412 | 406 | 400 |
| Long rural |  | 964 | 948 | 932 | 916 | 900 |
| SAIFI | Interruptions |  |  |  |  |  |
| Urban |  | 1.98 | 1.96 | 1.94 | 1.92 | 1.90 |
| Short rural |  | 3.95 | 3.90 | 3.85 | 3.80 | 3.75 |
| Long rural |  | 7.40 | 7.30 | 7.20 | 7.10 | 7.00 |

*Sources*: AER (2009c, p. 304); QCA (2009, p. 20).

Some events are excluded from the measurement of performance against targets because, in theory, distribution businesses should not be penalised for interruptions that were not their fault. Excluding certain types of event, however, also weakens the incentives that businesses have to prevent such events. The AEMC gives the example of an interruption caused by a car accident. While the business is not ‘directly responsible’ for the accident, there are measures that it could take to avoid accidents, such as positioning poles further from roads (albeit at a cost) (AEMC 2012k, p. 32).

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| Box 15.4 Major event days — an exclusion from STPIS performance measures |
| A major event is defined as a catastrophic event that exceeds the capacity of the electricity network to avoid significant power interruptions. Major event days (MED) are days on which a major event occurs — even if the power interruption lasts for several days, only one day is recorded as an MED.  A day with a large unplanned SAIDI can be classified as an MED if the total unplanned SAIDI for that day is unusually high (that is where unplanned SAIDI is more than 2.5 standard deviations from the mean of the log normal distribution of five regulatory years’ SAIDI data).  The unplanned SAIDI from MEDs are not included in the calculation of how far a business’s performance is from its target in a regulatory year. Therefore, there has been some debate about the best way to define a MED, with less stringent definitions leading to more events being excluded (and therefore the appearance of an improved performance by the business against its target).  Similarly, as discussed by SP AusNet (2010, p. 37), setting the definition of a MED too leniently might create perverse incentives for businesses to allow an event with negative consequences for unplanned SAIDI to escalate into a major event (by failing to reconnect power as quickly as possible), such that it ‘creates’ an MED.  Setting the definition of an MED too stringently might put businesses’ revenue at risk from events that are outside their control. For example, there have been suggestions that raising the threshold would be more appropriate (from the current minimum 2.5 standard deviations to 3.5 standard deviations). Businesses, however, were concerned that many events that were caused by extreme weather events (and therefore outside of the control of businesses) would cause unplanned SAIDI results of less than the MED threshold and consequently put business revenue at risk from not meeting STPIS targets. |
| *Sources*: AER (2009d); SP AusNet (2010). |
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These matters illustrate a problem common with many incentive schemes — that they can potentially motivate as much ‘internal’ focus on debating and defining the ‘rules and exceptions’ as they do on businesses genuinely looking outwards and trying to achieve the intended objective — in this case improved satisfaction in the eyes of end customers. Apart from the issues around the accuracy of the value of customer reliability (VCR) used to determine incentive payments in the STPIS, customers may also have not been adequately consulted for some of the other components and targets. For example, do customers care much about the exact reasons for an outage? It is likely that many customers only care about having their power supply restored quickly, rather than whether the outage was planned, unplanned or due to an event defined as ‘controllable or uncontrollable’. It is important that distribution businesses and the AER spend adequate time gathering feedback from end customers about their views in regard to supply interruptions, and that over time the STPIS targets are adjusted to reflect this feedback.

#### Quality of supply component

While the STPIS allows for the quality of supply to be measured (for example, the absence of voltage spikes), no targets are currently specified for distribution businesses to meet.

#### Customer service component

The STPIS includes parameters for customer service that distribution businesses are required to meet, including times for making streetlight repairs, new connections, answering telephone enquiries and responding to written queries.

Distribution businesses that exceed (do not meet) the targets that the AER sets for these parameters can gain (or lose) in total a maximum of 1 per cent of their allowed revenue. The targets are usually an average of the performance of the previous five years and are also adjusted for anticipated improvements from customer service related expenditure allowed under past or current revenue determinations.

#### Guaranteed service levels

The guaranteed service level component of the STPIS is intended to provide an incentive for distribution businesses to acknowledge and address the sub-standard reliability and service outcomes that some customers experience. The parameters covered under this component and the target levels of performance for businesses are contained in table 15.4, along with the payments that businesses would be required to pay, for each instance of performance shortfall.

These payments are not linked to the cost that poor service imposes on customers, but are intended to be an acknowledgment of poor service. Payments must be made directly to consumers as soon as a distribution business becomes aware of having missed a target and where it is responsible for that failure.[[8]](#footnote-8) This is not the case in some of the guaranteed-service level schemes applying at the jurisdictional level, where customers must request payments.

The guaranteed service levels component of the STPIS is not currently applied in any jurisdiction in the NEM (although it was anticipated to begin in the next regulatory control period for Victoria (AER 2009g, p. 99)). Instead, jurisdiction-specific schemes containing a wide range of parameters, targets and levels of payments are applied.

Table 15.4 Guaranteed service level parameters, thresholds and payments in STPIS

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| Parameter | Thresholda | Penalty per occurrence above the threshold ($) |
| Frequency of interruptions – CBD and urban feeders | 9 interruptions | 80 |
| Frequency of interruptions – rural short and long feeders | 15 interruptions | 80 |
| Duration of interruptions – CBD and urban | 12 hours | 80 |
| Duration of interruptions – rural short and long feeders | 18 hours | 80 |
| Total duration of interruptions – level 1 | 20 hours | 100 |
| Total duration of interruptions – level 2 | 30 hours | 150 |
| Total duration of interruptions – level 3 | 60 hours | 300 |
| Streetlight repair | 5 days | 25 |
| New connections | Connection on or before the agreed day | 50 per day  (maximum 300) |
| Notice of planned interruptions | 4 days excluding weekend and public holidays | 50 |
| Frequency of interruptions – CBD and urban feeders | 9 interruptions | 80 |

a Thresholds are per regulatory control period where applicable.

*Source*: AER (2009h, p. 18).

#### Information and reporting requirements

The STPIS requires distribution businesses to report annually against the parameters under the scheme, and stipulate any exclusions that the business believes should be applied. The AER can review the reports to ensure they account for exclusions accurately, calculate the consequences for allowed revenue correctly, and that the data collected match the parameters under the scheme.

Aspects of the reporting requirements, and related information gathering processes appear to lack transparency. For example, the AER issues each business with a request for information outlining the business specific data that it wants to collect. Any public reporting of this data needs to be approved by the business before it is released.Currently, there is no public reporting that is specific to the STPIS.

Nevertheless, STPIS reporting and information requirements mostly exceed, and are in addition to, jurisdiction‑specific reporting requirements, with the exception of Victoria. In the latter case, the AER’s Annual Performance Report (2012h) for the Victorian distribution businesses details reliability performance at the zone substation level and identifies the main causes of faults in the networks. This reporting structure and detail was inherited by the AER in the transition of responsibilities from the Essential Services Commission of Victoria and now forms the basis of the reporting requirement for Victoria under the STPIS. This report provides a useful benchmark for establishing consistent, transparent and detailed reporting of reliability performance NEM-wide.

#### Incentives under the STPIS

The first three components of the STPIS have incentives attached to them to encourage the distribution businesses to meet their specific targets. The incentives are based on a VCR (noting some issue surrounding the accuracy of the VCR estimates — chapter 14) and the gap between the performance of the business and the target. The AER calculates the incentive rates using a VCR that is specific for each feeder type. The VCR for a CBD-feeder is $96 per kWh (indexed to the CPI from September 2008). For all other feeder types, the VCR is $48 per kWh (AER 2009h, p. 10). In this way, the incentives for businesses to meet their targets are related to an assessment of the costs (benefits) that customers experience when businesses fall short of (exceed) their targets.[[9]](#footnote-9)

The incentives are converted into a share of the annual maximum allowable revenue for a business, termed the ‘s-factor’. The maximum that a business can be rewarded or penalised is termed the ‘revenue at risk’. The default level for each year in a regulatory control period is 5 per cent, though actual levels range from 3 per cent for Ergon Energy in Queensland (which primarily services rural and remote customers) to 7 per cent for SP AusNet in Victoria (which primarily services urban customers). Distributors can apply to postpone the incorporation of the revenue increments or decrements for a year to avoid excessive price fluctuations for customers.

Under the STPIS, a business that meets all its targets receives additional revenue because the AER allows it to increase its prices to customers — they effectively pay an additional price for the improved quality of the service they receive. Likewise, if a network business fails to meet its targets it is penalised and has to reduce its prices to customers, who receive some compensation for the poorer performance. The fact that customers ultimately pay for the performance encouraged by the STPIS emphasises the importance of aligning the STPIS targets with customers’ value of reliability. Further, the two-sided nature of payments (penalties and rewards) avoids a ‘cliff edge’ effect. The Brattle Group (2012a) contended that without this feature:

… distributors will be reluctant to invest to improve reliability when they are close to their target if this could lead to higher than target reliability for which they will not be rewarded. (pp. 14‑5)

#### Consequences for efficiency

The reporting requirements under the STPIS are likely to facilitate benchmarking of businesses if the information currently collected by the AER is consistent and reasonably detailed. However, there is room for significant strengthening and streamlining of reporting requirements in the STPIS, especially outside Victoria. Furthermore, the Commission considers all non-commercially confidential information should be released publicly. Where confidentiality concerns exist, the onus of proof should lie with the business to show why any of this information is commercially confidential. After all these are regulated monopolies.

The STPIS currently operates alongside existing jurisdiction‑specific reliability planning and performance requirements, and therefore, not every business is subject to the same parameters of the scheme. This inconsistency adds to the factors that any benchmarking exercises must consider — and therefore the complexity and difficulty of such exercises.

The STPIS has many valuable features, including the consistency between the incentives offered and the reliability related revenue approved by the AER. Nonetheless, several concerns remain.

* The targets are based on the historical performance of the business. As discussed in the context of jurisdiction‑specific targets, as a basis for a reliability target, historical performance does not have regard to customers’ willingness to pay.
* The rewards and penalties received under the scheme are unlikely to be providing the right incentives to distribution businesses to encourage them to meet customer preferences efficiently, due to problems in using a single VCR (box 15.5) and the implications of errors (box 15.6). A single VCR applied to all distribution businesses ignores the likely differences in customer preferences between distribution networks, and indeed those of customers within individual distribution networks.

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| Box 15.5 The problem with incentive payments based on a constant VCR during a regulatory period |
| As discussed in chapter 14, the efficient level of reliability occurs where the marginal benefit to customers of extra reliability is equal to the marginal cost to the business of supplying it.  Assuming that the targets in the STPIS are set at the efficient level, the optimal incentive to apply to businesses that perform above or below their target is a function of the VCR and the gap between the target and the performance. Theoretically, however, the VCR is not constant at differing levels of reliability, and the incentives should be higher when a business under-performs than when it over-performs.  In the figure below, when a business performs at R’, below its efficient (and target) level of R\*, the optimal penalty should recognise that the cost to customers, VCR’, is higher than the cost to the business of improving reliability. Penalising the business using VCR\* will not be equivalent to the loss that consumers experience for this level of underperformance.  Box 15.5 Figure 1. This figure adds to the figure shown in Box 14.2, by showing the relationship between varying levels of reliability and corresponding VCR along the marginal benefit to customers of reliability improvement curve.  Similarly, if a business exceeds the target at R’’, it will be rewarded using VCR\* when customers only value the increased reliability at VCR’’. This means that businesses are being rewarded by more than the marginal benefit accruing to customers.  In reality, however, applying variable VCRs that correspond to a marginal benefits curve like that in the figure is challenging, especially considering the difficulties associated with identifying accurate VCRs as discussed in chapter 14. Despite this, given greater challenges and costs in adopting other approaches, such as attempting to set optimal targets which also requires the regulator to accurately determine the marginal cost curve of reliability improvements (discussed below), use of a single but regularly updated VCR for incentives payments is likely to generate efficient outcomes in the longer-term. |
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| Box 15.6 What happens if the value of customer reliability and the targets are wrong? |
| Using the figure below it is possible to examine how incentive schemes can produce inefficient levels of reliability when the VCR and/or the targets are not at their optimal points.  Assume first that the target is set optimally at R\*, but the VCR is set at VCR’. As the business will receive a payment greater than its marginal costs at the point R\*, it will have an incentive to supply reliability up to the point R’’. This point is not optimal for customers, and inefficiencies are generated.  Assume instead, that that target is set incorrectly at point R’’, but the VCR for the incentives is the correct VCR\*. Businesses will have the incentive to supply reliability only up to point R\* but not beyond. Beyond R\*, the costs to the business are larger than the penalties they will incur for failing to meet the targets.  Box 15.6 Figure 1. This figure adds to the figure shown in Box 14.2, to show how different levels of incentives encourage network businesses to increase or decrease reliability above or below the efficient level.  These examples suggest that, in theory, as long as the VCR is set at an appropriate level, businesses will tend towards supplying a level of reliability that reflects customer preferences, regardless of the target set. |
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* The default revenue at risk is 5 per cent to avoid ‘imposing undue risk’ on businesses by making businesses ‘accountable for events caused by factors over which [they have] little or no control’ (AER 2008b, p. 16; AER 2007a, p. 23). It is not clear, however, from the discussion contained in the documents establishing the STPIS, that 5 per cent revenue at risk provides the right incentive for businesses to adjust their reliability performance sufficiently. On the other hand, uncapped revenue at risk also exposes consumers to the risk of excessive price fluctuations from year to year, although the s-bank[[10]](#footnote-10) mechanism in the STPIS helps to smooth volatility in prices over time (AER 2009d, p. 10).

## 15.4 An efficient and effective distribution reliability framework — a bolstered STPIS

Remedying the above limitations would improve the efficiency of reliability planning and performance requirements and the frameworks in which they operate. It could also improve managerial performance if it improved the prospect for more accurate benchmarking of the kind described in chapter 8.

### Removing input standards

An efficient reliability framework would set reliability targets at levels that reflect customer preferences, and encourage distribution businesses to pursue those targets through the best combination of building, maintaining and managing their networks and responding to outages. To some extent, these inputs can be substituted. Imposing restrictions on the way that businesses choose the mix of inputs, such as through imposing deterministic standards, increases costs. According to the Brattle Group (2012a):

… rigid planning standards could be counter-productive because they can prevent distributors implementing innovative approaches to improving reliability. (p. 160)

Costs can also be imposed on a network business by requiring that they plan using a probabilistic process. While probabilistic planning is likely to lead to efficient augmentation decisions, it may not be the most appropriate planning tool for all businesses, for all investments, all the time. Distribution businesses should therefore be free to choose the way that they plan.[[11]](#footnote-11) Jemena (2012) submitted that:

… the adoption of probabilistic planning for our network has improved reliability and cost outcomes and in our case has provided a superior alternative approach to deterministic planning. That said, we believe the [distribution businesses] should be allowed to decide the most suitable approach to network reliability planning having regard to local network characteristics or geographic conditions. (p. 3)

Energex (2012) agreed:

… planning standards (e.g. utilisation) should be the responsibility of [distribution businesses]. Regulators and/or governments should not be involved in determining the design planning criteria as [distribution businesses] are the parties that are best placed to perform this function. (p. 2)

#### How much is this change worth?

The possible benefits of removing planning standards for distribution businesses could be substantial. As an example, AEMO calculated the cost savings of removing the deterministic standards that apply to Ausgrid. Using a probabilistic process, AEMO found that one proposed substation could be safely deferred for up to 10 years. In total, AEMO identified $1.1 billion in augmentation capex that could be deferred until the next regulatory period. For the average customer, this would equate to a saving of around $50 per year from their electricity bill from 2014 onwards.

Smaller gains were identified by the AEMC (2012l) in their recent review of distribution reliability outcomes in New South Wales. The ‘extreme’ reduction in reliability outcomes scenario in New South Wales identified a possible saving of $15 a year for residential customers from 2028. Several points might help explain these smaller results.

* The reliability reductions modelled by the AEMC might not have been very ‘extreme’.[[12]](#footnote-12) For example, Public Interest Advocacy Centre was ‘surprised by the very modest reductions in customer reliability … that occur under the three scenarios modelled by the AEMC’ (PIAC 2012, p. 4).
* The capital assets to meet existing deterministic standards into the future have already been built, leaving few investments to be deferred, and resulting in lower expected benefits (AEMC 2012l, p. 129).
* The distribution businesses might have been unable to identify all the areas in which efficiencies could be realised given the ‘simplifying assumptions’ they made to prepare the data for the report in a ‘relatively short timeframe’ (AEMC 2012l, p. 26).

The total change in capital expenditure in the ‘extreme’ scenario was projected to be $1.1 billion over the next 15 years (net present value), which would equate to an annual saving of around 4 per cent of the forecast capital expenditure in New South Wales in 2012‑13.

In reality, the effect of removing planning standards for distribution businesses is likely to result in larger benefits than those that those estimated above. Combining the flexibility of choosing exactly how to meet target levels of reliability (by removing any bias towards capital expenditure) with incentives to meet standards efficiently (and removing the incentive to over‑invest — chapter 5) should result in larger savings for customers NEM‑wide. Further, as demand increases, and the current redundancy built into the network diminishes, the value of deferring new investments efficiently will produce higher savings to customers in the long-run.

### Bolstering the STPIS

Removing *planning* standards altogether would increase the need for *performance* targets (the output measure) to be set efficiently, as well as the need for strong incentives to encourage businesses to provide levels of reliability to the point where customers’ willingness to pay for additional incremental improvements is equal to the cost of its provision.

#### Establishing a national framework

Requiring distribution businesses to adhere to more than one set of performance targets increases the risk that businesses would inefficiently deliver reliability outcomes below (or above) the level for which customers are willing to pay. The AEMC (2012k) also points to potentially unclear or inconsistent incentives from ‘duplication between jurisdictional requirements and the requirements of the STPIS’ (p. 41).

In the Commission’s view, removing jurisdiction‑specific performance targets and relying on the STPIS is likely to be the most efficient option for the NEM.

The Commission notes that the third option for a national framework for distribution reliability outcomes identified by the AEMC (2012k) recommends removing ‘some of the existing jurisdictional requirements that may no longer be needed once the STPIS is in place’ (p. 41). This option is (notionally) widely supported by participants in the review, including CitiPower and Powercor, SP AusNet, Essential Energy, Major Energy Users Inc. and Jemena (Energex supports a national framework, and Endeavour Energy proposes a larger role for the AER). This option was put forward as part of the AEMC’s suggested approach in its draft report of that review (AEMC 2012v).

However, retaining even some reliability requirements in jurisdictional codes and licence conditions inefficiently adds to costs for distribution businesses, which are passed on to customers, including:

* the costs of ‘unclear or inconsistent incentives’ discussed above are maintained
* new costs are introduced from the uncertainty for distribution businesses from state and territory governments and regulators having the authority to introduce or change reliability requirements at will
* for example, as a result of the politicisation of reliability outcomes, the potential for which was identified by the Brattle Group (2012a, p. 28).

Therefore, all reliability requirements should be removed from distribution businesses’ jurisdictional licence conditions, codes and regulations. (Safety related requirements should ultimately be encompassed in the national licence conditions, but with independent jurisdictional or national safety regulators ensuring compliance — chapter 11.) This would require the Standing Council on Energy and Resources to transfer the responsibility of setting a reliability performance framework to the national level, through an amendment of the Australian Energy Market Agreement, as well as introduce legislative amendments, and agree that the STPIS becomes the only vehicle for delivering distribution reliability outcomes to customers. Under this framework, the AER would set reliability targets using business-specific average past performance, and would set rewards and penalties using customer preferences specific to the region in which the business operates (these factors are discussed in detail below).

#### Harmonising parameters

Removing duplicated jurisdiction‑specific reliability requirements, while at the same time ensuring that an incentive scheme is as effective as possible, requires that all parameters of the components in the STPIS be applied to all network businesses.

The Commission recognises that some businesses might not currently be able to record and report on all parameters, such as MAIFI performance. In these instances, the AER should approve the revenue required for the businesses to install the additional equipment needed, subject to the business showing that it has not had the revenue or opportunity to do so previously, and the AER is satisfied that the long‑term benefits of applying the parameter outweigh the costs of the required investment.

#### Addressing worst served customers

Participants in the AEMC’s review commonly identified the lack of provisions in the STPIS to address the experience of worst served customers. According to Essential Energy (2012):

[T]he STPIS, as currently structured, will encourage [distribution businesses] to focus reliability improvements on parts of the network in urban areas that may already be performing quite well at the expense of poorly performing parts of the network in rural areas. (p. 2)

Essential Energy recommended that the AER establish minimum service standards, such as those that already exist in New South Wales. The Brattle Group (2012a), however, while recommending supplementary mechanisms relating to worst served customers, believed a requirement to publish annual distribution planning statements was more appropriate than establishing financial incentives attached to targets specifically designed for worst performing feeders.

Public reporting of performance (and possibly planning) would be likely to help to encourage an improvement in the performance of worst performing feeders, provided distribution businesses are responsive to public pressure and reputational consequences. Licence conditions that require businesses to supply connected customers, and develop contingency plans for how to deal with outages are also likely to help ensure that at least minimum acceptable levels of service are met.

For individual customers, poor service is recognised by distribution businesses through the payments for guaranteed service levels as specified within the STPIS. While these payments are not intended to be compensation for poor reliability, their reporting, especially at a disaggregated level, is likely to increase awareness of areas where distribution businesses are failing to provide reliable supply. While the public reporting, licence and guaranteed service level provisions are likely to help encourage distribution businesses to address the concerns of worst served customers, the AER should continue to monitor this area and investigate adjustments to the STPIS if these arrangements were found to be ineffective.

To support more disaggregated reporting of reliability for worst served customers, the relevant reporting requirements under the STPIS should be amended to reflect the level of detail and consistency currently contained in the Victorian Annual Performance Reports. Where distribution businesses are unable to collect the information required to report to the AER in that detail, the AER should approve efficient expenditure required to upgrade recording and reporting equipment.

Importantly, it should be recognised that an efficient reliability framework would not give rise to uniformly high reliability across all parts of Australia. As discussed in chapter 14, the much higher cost of improving reliability in parts of the NEM — and especially in more remote areas — means that differences in reliability levels are both inevitable and efficient. Further, as noted in chapter 14, for certain groups (such as those in rural or remote areas) reliability levels delivered commensurate with VCR may be viewed by society more broadly as unacceptably low (box 15.7). In these instances it is generally better for state governments to directly fund improved (above VCR) reliability levels directly through the use of Community Service Obligations rather than the alteration of particular standards or targets as has been proposed by the AEMC in its recent draft report of its review of distribution reliability outcomes and standards (AEMC 2012v). Using Community Service Obligations in this manner is both transparent and efficient (chapter 14).

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| Box 15.7 The difficulty with the Back o’ Bourke |
| A correctly estimated VCR will indicate the costs that customers experience due to power interruptions in different locations, and the price they are willing to pay for reliability to be improved. But the costs to increase (or even maintain) levels of reliability to some places, especially in rural or remote locations, are likely to far outweigh the willingness (or ability) to pay of the customers who reside there.  Through an economic lens, prices should be cost reflective, and it can be difficult to justify maintaining network infrastructure to deliver relatively reliable supply to some locations at a price at reasonable parity with urban areas. A VCR framework would be likely to deliver significantly less reliability in more remote areas.  In most areas of essential service provision, society and governments have a desire to ensure some level of parity between rural and urban residents and thereby maintain a reasonable level of reliability for all. Responses to ensure that customers in rural and remote locations receive reasonable levels of reliability of electricity supplied through networks connected into the NEM have included specific reliability standards (including Guaranteed Service Levels) and requirements to connect new customers.  However, in these instances it is preferable for governments to directly fund improved (above VCR) reliability levels through the use of Community Service Obligations. The level of reliability that customers actually receive in these locations is therefore largely a question that should be determined by governments. In some cases it may be more efficient to improve reliability by means other than augmenting the network, such as through the installation of remote generation capacity. |
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#### Setting efficient targets

The reliability performance targets in the STPIS, based on historical performance, are unlikely to be efficient. However, given the demanding informational requirements and uncertainties, it is not trivial to set reliability targets at a level where the incremental costs and benefits of further improvements are aligned.

One issue is that businesses are likely to know their marginal cost functions but regulators are not, at least not without significant increases in information and data from businesses. While methodologies exist for estimating the marginal cost curves for distribution businesses in the NEM,[[13]](#footnote-13) robust estimates are unlikely to be available for use in setting reliability targets in the near future, especially at a disaggregated level.

So how should efficient targets be set? The key lies not in the targets themselves, but in the incentives (or penalties) that apply for divergence from target levels, which are based on an appropriate VCR.

Applying the right incentives (in terms of rewards and penalties to businesses) over time can encourage businesses to adjust their reliability levels to reflect the levels that customers prefer even if only one value of VCR is used (box 15.5) and the initial targets are incorrect (box 15.6). To motivate this adjustment, the AER should issue the performance targets for businesses annually using a moving five-year average of past performance.[[14]](#footnote-14) Box 15.8 sets out how the STPIS would iterate towards an efficient level of reliability using historical performance based target.

It should be noted that while using past performance avoids the complexity of determining a distribution business’s marginal costs of improving reliability, difficulties in accurately measuring VCR remain.

Were the Australian Bureau of Statistics to conduct regular surveys of customers as recommended by the Commission (recommendation 14.2), it would be able to identify a VCR corresponding to the level of reliability that customers have recently experienced. If the incentives for distribution businesses are then based on this VCR, it should (in theory) be possible to tell if the business has been performing below (or above) the efficient level through its response to the incentive payments. If the business responds by improving performance, previous levels of reliability would have been inefficiently low. The change in reliability would eventually shift the targets up. Customers would then value further incremental improvements to reliability less, meaning the VCR estimated from subsequent surveys would fall. This process should iterate until the costs of an incremental increase in reliability were equal to the value customers place on that increase.

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| Box 15.8 Adjusting to efficient targets and incentives |
| Basing incentive payments under the STPIS on an accurate VCR should encourage distribution businesses to supply the efficient level of reliability across their networks. Under the proposed arrangements, the VCR (estimated at the feeder level) would be used to set the incentive payments/penalties, with caps on the aggregate reward or penalty imposed on a distribution business. Ex ante, the efficient target is not known, so that a moving average of historical performance would be used as the estimate of the efficient target.  The efficiency of the targets at the start would depend on the efficiency of the current reliability requirements. However, given distribution businesses are only rewarded or penalised by the amount customers value changes to reliability, they would start to move to more efficient reliability levels (and with it the target). For example, in a network where reliability standards were inefficiently high, the distribution business would chose to pay the penalty and reduce reliability levels, as the costs of maintaining the status quo would be higher than the penalty. On the other hand, if reliability levels were currently inefficiently low, then the costs of improving levels would be less than the reward payments, inducing improvements.  In response to these changes in reliability, however, customers would also adjust the value they place on further incremental changes in reliability. By taking regular surveys to identify these values and incorporating the updated values into the incentives, changes in how customers value incremental increases in reliability would also be captured in the incentive scheme. Together, these factors would mean the reliability performance of distribution business should iterate towards the efficient level. |
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These changes are not a significant shift for the AER or distribution businesses already operating under the Scheme and ensure that reliability targets and the incentives to meet them are firmly planted within a cost–benefit framework. In short, the Commission proposes that:

* performance targets be set using a rolling five year average of past performance
* the incentives be business specific by feeder type and based on the VCRs estimated by the Australian Bureau of Statistics as recommended in recommendation 14.2.

The Commission notes that its proposed approach differs from the proposals made by the AEMC in the draft report of its *Review of Distribution Reliability Outcomes and Standards* (AEMC 2012v). The AEMC proposed that distribution businesses be involved in setting targets based on disclosures of various options and their costs to the standard setter. While such an approach could, in theory, motivate an instantaneous shift to efficient reliability levels (the Commission’s approach requires this to be revealed over a number of periods), it is likely that revelations of efficient reliability costs would be difficult and costly to obtain. Therefore, some iteration between periods would still be required. Given this, if the VCR used to determine incentive payments (and penalties) is correct, under the Commission’s proposed approach distribution businesses would reveal the efficient level of reliability over time without the additional cost of a negotiation process between distribution businesses and the standard setting agency as proposed by the AEMC.

#### Ensuring incentives are strong

The transition path to efficient reliability targets will be slower under capped incentives penalties and payments. The Brattle Group (2012a) noted that:

We also found that … distributors with the most to lose (i.e. facing the highest potential penalties) tend to comply more closely with reliability standards than those facing less punitive sanctions, at least as regards the average duration of interruptions. (p. 11)

Some businesses, for example SP AusNet, preferred such uncapped two-sided incentives. However, the Energy Users Coalition of Victoria (EUCV 2010) noted that there is already an implicit floor in the penalty that the AER can apply, because removing too much revenue from a business would ultimately result in a loss of supply of electricity to SP AusNet customers. This would make the incentives ‘asymmetric’ (p. 45).

There is also a concern that because rewards and penalties affect the prices that customers pay, large incentives can lead to excessive fluctuations in price for customers (AER 2010b, p. 674).

Similarly, point targets for businesses can introduce uncertainty if small changes in performance can tip a business over the line from receiving a reward to having to pay a penalty and vice versa. To address this, some commentators discuss the possibility of using ‘dead bands’, which comprise a target range for businesses rather than a point (for example Yahav et al. 2008 and Ramanathan et al. 2006). However, as small variations from performance targets should result in small rewards and penalties, it seems reasonable to suggest that across a five year regulatory period, small deviations from targets year to year should even out, avoiding the need for ‘dead bands’.

An advantage of ensuring sufficiently strong incentives is that it encourages businesses to use their choice of inputs more efficiently to achieve reliability over time. This means that while operational inputs can be used to meet performance targets in a given year (such as responding quickly when faults occur), longer-term investments in network capacity should also be made when they are needed, and when it is cost effective to do so. The likelihood of large future penalties for poor performance from inefficiently deferring investment should create the incentive for businesses to make efficient decisions about their choice of inputs over both the short term and the long term.

While the default incentive of 5 per cent under the STPIS should therefore remain, the revenue at risk facing each business should be negotiated with the AER during the revenue determination process, leaving room for the AER and the business to negotiate away from the default where this would be appropriate. In this way, the AER can use all the information available to it more effectively. This includes the past responsiveness of the business to incentives, the revenue granted for improvements to reliability and the specific characteristics of a network that might make fluctuations in performance more common (for example, inclement weather that results in more events that are close to being classified as ‘major events’).

Recommendation 15.1

All jurisdictions should adopt the Australian Energy Regulator’s Service Target Performance Incentive Scheme as the basis for setting efficient reliability requirements for distribution businesses. The Scheme should replace all existing jurisdiction-specific distribution reliability requirements.

Recommendation 15.2

The Australian Energy Regulator should make the following amendments to the Service Target Performance Incentive Scheme:

* reliability performance targets for the system average interruption duration index, system average interruption frequency index and momentary average interruption frequency index should be adjusted annually, according to a rolling five‑year average of annual performance
* incentive payments for deviations from the reliability performance targets should reflect the preferences of customers by using the estimated values of customer reliability, as spelt out in recommendation 14.2, and should be specific to the distribution business
* revenue at risk should be negotiated as part of the Australian Energy Regulator’s revenue determination process
* the reporting and information component of this scheme should require distribution businesses to report their reliability performance at the zone substation level. Worst performing feeders should be identified as part of this process
* reporting by all distribution businesses of performance against the parameters in the scheme should be published annually and be at least as detailed and comprehensive as current reporting mechanisms for distribution businesses in Victoria.

1. For example, the Brattle Group (2012a) compared average SAIDI results for the NEM with Italy, New Zealand, the Netherlands, New York, the United Kingdom and California to find that performance had shown no trend anywhere except in Italy where reliability appears to be improving. [↑](#footnote-ref-1)
2. Redundancy involves the duplication of critical components to reduce the likelihood that a fault or failure will cause an outage to occur. [↑](#footnote-ref-2)
3. Operational actions might include diverting supply through another route or temporarily running equipment at a higher rate of utilisation until the fault can be rectified. [↑](#footnote-ref-3)
4. For example, the report recommended, ‘that for assets as important as bulk supply sub-stations, “N-1” should be the standard used’ (2004, p. 15). [↑](#footnote-ref-4)
5. Feeders represent the lines that emanate from a substation. [↑](#footnote-ref-5)
6. In the ACT, these are minimum performance targets and the business can set higher targets. [↑](#footnote-ref-6)
7. Some distribution businesses are excluded from meeting MAIFI targets if they can show that they do not have the capabilities to measure and report on momentary interruptions and the costs of installing the required equipment are expected to outweigh the benefits. [↑](#footnote-ref-7)
8. Distribution businesses do not have to make payments when they are not responsible for missing a target (for example, due to transmission failure). [↑](#footnote-ref-8)
9. These values are taken from estimates of Victorian VCRs and so do not accurately reflect the true VCR for most distribution businesses. In line with recommendation 14.2, the AER should replace these with actual VCR estimates by feeder type for individual distribution businesses (section 15.4). [↑](#footnote-ref-9)
10. The s-bank mechanism allows a revenue increment or decrement (or portion thereof) to be delayed by one regulatory year for the purpose of reducing price variations to customers. [↑](#footnote-ref-10)
11. While this arm’s length approach is appropriate for distribution businesses, which can be encouraged to deliver reliability using incentive regulation, it is not appropriate for transmission networks, where transmission-specific characteristics (chapter 16) require a more ‘hands on’ approach to NEM-wide transmission planning. [↑](#footnote-ref-11)
12. The ‘extreme’ scenario was expected to result in 15 more minutes of outage a year. the Independent Pricing and Review Tribunal suggested the AEMC use more objective descriptors for the scenarios (IPART 2012d, p. 3). [↑](#footnote-ref-12)
13. For example, Jamasb et al. 2010 estimate marginal cost curves for UK electricity distribution companies at an aggregate level. [↑](#footnote-ref-13)
14. The Energy Networks Association (sub. DR71) disputed the use of a five-year moving average target as they believed it would not be practical due to the lags involved in correcting reliability issues and the time taken for the results to be revealed. They argued that as a result of this, the ability for a distribution business to recoup the costs of an investment within the five-year regulatory control period was uncertain. However, even in the presence of such lags, actions by distribution businesses will be rewarded under a five-year moving average when the improvement in reliability is observed. Despite this, the improvement will not accrue reward payments for as long as under a fixed period system. The Commission does not see a justification for ‘locking in’ rewards within a set period if the VCR used to calculate rewards and penalties is set at the right level. [↑](#footnote-ref-14)