Fair approaches to distribution pricing

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Executive summary

Distribution pricing in New Zealand is under reform to support the large energy transition required for a net-zero carbon future. As New Zealand looks to electricity as one way to further reduce carbon emissions and transition away from fossil fuels, distribution pricing and the integration of distributed energy resources (DER) takes on increased importance and will play a critical role in facilitating this transition.

Effective, coordinated, and appropriate reform of distribution pricing has the potential to alleviate and defer a significant amount of the economy-wide long-term costs and infrastructure pressures required in this transition for distributors, the electricity network, and consumers. To fully leverage this potential, reform must consider all consumer groups, including vulnerable households and small businesses, to ensure that they have the opportunity and ability to participate in this future. Not taking vulnerable low-income groups and small businesses into consideration will diminish the overall effectiveness of New Zealand's energy transition.

This report explores alternative international electricity distribution sectors, examining the regulatory and structural setup involved in setting electricity prices for consumers, and examines the current integration of DER and the potential for cost-reducing effects.

International approaches to distribution pricing

Across the international markets that were investigated (Australia, Northern Ireland, Europe (Norway and Sweden), Great Britain, and North America (Ontario, New York, Washington, and Texas)), there are broadly three common approaches. On the **east coast of Australia**, **Northern Ireland**, and the **European Union** electricity distribution businesses are required to submit pricing proposals that are either approved by the regulator or agreed with the regulator. In **Western Australia** prices are set by the state government. In **Great Britain** distributors use a common pricing methodology designed and agreed between industry participants and the regulator. In the selected **North America** markets prices are set by the regulator, usually involving judges and public hearings.

The underlying basis and intent from the identified international markets has been on achieving economic efficiency and maintaining grid stability and reliability. These markets do not explicitly consider the impact on different consumer groups, specifically those potentially in energy hardship or vulnerable households and small businesses. It can be inferred that the majority of markets operate on the premise that electricity distribution is a natural monopoly and that a key desired outcome is efficient and "fair" prices – those which allow electricity distributors to make a "fair return" on their network investments and management, while ensuring that consumers face prices that are "subsidy-free".

Applicability in New Zealand

If New Zealand wanted to increase the Electricity Authority's role in pricing distribution it could consider the models in Europe and Great Britain which have greater direct involvement of the regulatory agency in approving the methodology used and/or the prices charged to consumers. In

Australia (excluding Western Australia and the Northern Territory) and many European markets the regulator is required to review the methodology used and approve proposed prices.

An alternative for New Zealand could be to adopt a common distribution pricing methodology similar to Great Britain. This would ensure a common methodology was applied across distribution networks. If New Zealand wanted to include principles that address energy hardship the use of a common methodology with a supporting model, provided by the regulator or industry would be an effective alternative.

Although it provides the opportunity for review and public input before prices are set, the time and resources required means it is unlikely New Zealand would adopt the North American model.

If New Zealand were to pursue an approach that incorporates energy hardship into distribution pricing it would be an outlier amongst markets with retail competition for residential and small business consumers. However, New Zealand could strengthen the principle that "development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives." Australia's pricing principles take this further and require that distributors must consider the impact of changes in tariffs on retail customers, including the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services.

Integration of DER and the potential for cost-reducing effects

Distributed energy resources (DER) are small-scale power generation, consumption, and storage technologies that are implemented closer to, and by, end-users of the electricity sector. They include, for example, electric vehicles (EVs), solar panels, batteries, and smart appliances. The ability for consumers to generate and consume their own electricity, shift and reduce consumption, and inject electricity back into the grid enables them to lower their electricity bills, decrease their overall reliance on the electricity network, facilitates the hosting of greater amounts of intermittent renewable generation, and improve environmental outcomes.

DER will play a critical role in New Zealand's energy transition

As New Zealand looks to decarbonise the economy and phase out use of fossil fuels, the role of electricity takes priority. To achieve climate change goals set by New Zealand, electricity generation capacity must increase, and average load factor should increase, in order to accommodate the widespread electrification of the economy. Climate and weather events also pose a growing risk to electricity distribution and infrastructure. New Zealand's first Emissions Reduction Plan (ERP) stated that "increasing demand flexibility and distributed energy resources will help to manage electricity infrastructure risk". This means that the role of distribution and retailer pricing takes on increased importance. Similarly, the implementation and management of DER grows in importance as another supporting measure, particularly to intermittent generation[1].

[1] Intermittent generation is generation that is not continuously available due to fuel availability that cannot be controlled and can change over a fairly short time scale

For distributors, the integration and adoption of DER (specifically flexible services) has the potential to defer investment in network infrastructure that would be required to meet the expected increases in electricity demand in the future. Such technologies, for example, can optimise energy consumption patterns, reduce consumer reliance on the network, and reduce consumer demand during peak times. These characteristics of DER can reduce the need to upgrade and expand network and generation infrastructure in order to handle the further electrification of the economy.

As they serve a critical role in New Zealand's energy transition, the growing investment in and integration of DER and flexibility services raises concerns about the ability for vulnerable consumers to participate in this future. The underlying challenge in this transition is ensuring opportunity for and participation from all consumer groups, specifically vulnerable consumers such as low-income households, households in rental premises, and small businesses.

To realise the most potential gains for all of New Zealand in the energy transition, without any adverse impact on vulnerable consumer groups, all consumer groups must be involved.

Distribution pricing and DER

New Zealand's energy transition is already underway, and both distribution pricing and DER (including flexible services) will play a critical role in facilitating and supporting a net-zero carbon future and wider electrification of the economy. An underlying concern in this transition is whether all consumer groups, particularly vulnerable households (including low-income and renters) and small businesses, will be able to participate in this future or be perversely impacted.

Internationally it is evident that the focus of distribution pricing remains on ensuring economic efficiency, grid stability and reliability, and security of supply. This will help facilitate the transition, but to support it, distribution pricing needs to strike a balance between these focuses and helping to incentivise the investment in DER. Governments across the world have taken extensive steps to facilitate and incentivise the widespread adoption of DER. They have also recognised that the approach to this must consider diversity in consumers including the factors that influence motivation, ability, and importantly, opportunity to participate in the electricity sector.

Distribution costs are expected to increase, and this will have an adverse impact on vulnerable consumers, specifically those who are unable to change consumption behaviours in response or afford the capital cost of DER generation and flexible response enabled appliances. At the same time, DER can be costly, unreliable, and unable to be fully leveraged by all consumer groups, and yet it is what will place downwards pressure on network and generation costs. These factors compound the impact on vulnerable consumer groups. Not recognising and considering this implication will significantly limit the potential for cost-reductions in New Zealand's energy transition.

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1 Introduction

Business and Economic Research Limited (BERL) was commissioned by the Consumer Advocacy Council (the Council) to investigate fair approaches to electricity network distribution pricing. The Council, established following the 2019 Electricity Pricing Review, is New Zealand's independent advocate for residential and small business electricity consumers.

The Electricity Authority has been consulting on changes to distribution pricing and transmission pricing has already been reformed. The Council requires this research to inform submissions it intends to make in 2024.

Proposals under consideration by the Electricity Authority and the Commerce Commission include raising peak tariffs. Such a move would be likely to adversely affect consumer groups that have no, or limited, ability to move the times when they use electricity. The Council's behaviour survey research has found few households would find it "very easy" to change when they use large appliances or heating. This report seeks to identify fair approaches to distribution pricing that acknowledge:

- Electricity is an essential service
- Many households are not able to easily switch power use to off-peak times
- Raising tariffs will be likely to increase hardship for those consumers who cannot load switch, or are in rental premises, and lack financial resources to invest in energy efficient/flexible enabled appliances
- Small business unable to load shift may also face cost increases as distribution charges rise.

To identify these approaches this report considers:

- International approaches to fair distribution pricing that could be applied in New Zealand
- Potential effects of sunrise technology (such as microgrids) that may reduce costs for lines companies
- Principles that should underpin a fair approach to distribution pricing.

1.1 New Zealand electricity market

In New Zealand most electricity is generated through renewable energy sources, such as hydropower, geothermal power, and wind energy. In 2022, 87 percent of electricity was generated from renewable sources, making New Zealand one of the countries with the lowest carbon dioxide emissions from electricity generation.[2]

The New Zealand electricity market is decentralised, regulated by the Electricity Industry Participation Code 2010, and administered by the Electricity Authority. Broadly speaking, New Zealand's electricity industry can be broken down into four main components – generation, transmission, distribution, and retail.

Generation - Electricity generation is dominated by four major electricity generating companies, but there are many smaller generators that contribute to the generation pool. Genesis Energy, Mercury, and Meridian Energy operate under a mixed ownership model in which the government holds a majority stake, while Contact is a private sector company. Generation companies own and operate power stations across the country. More than 200 generation plants are able to supply electricity to the national grid and 2,957 embedded generation plants >10kW (total of 1,637 MW) supply are embedded in local and secondary networks.[3]

Transmission - State-owned enterprise Transpower owns and operates the national electricity transmission system, which supplies electricity to distribution (lines) companies using high capacity, high voltage transmission lines.

Distribution - Twenty-nine lines companies and many secondary networks distribute electricity to consumers or from generators throughout New Zealand.

Retail - Electricity retailers are the companies that sell/buy electricity to/from consumers. Retailers buy electricity from the electricity market to sell to customers for the electricity they consume/generate, and act as the generator where consumers sell electricity to the retailer. Retailers mostly on charge all associated costs of delivery to customers, including generation, transmission, network, metering, and management costs.

1.2 Electricity distribution

There are 29 local network companies in New Zealand that provide and maintain the local power networks (poles and lines) that carry electricity from the national transmission grid to homes and businesses. There are also a large number of secondary networks (such as embedded networks and

[2] Ministry of Business Innovation and Employment. Energy in New Zealand 2023. https://www.mbie.govt.nz/dmsdocument/27344-energy-in-new-zealand-2023-pdf

[3] A local network is a network supplying more than one consumer, and directly connected to the grid. A secondary network is a network supplying more than one consumer and is indirectly connected to the grid through other networks. There are three configurations: customer network, network extension, and embedded network.

customer networks) to which the obligations in the Act and the code also apply.[4] On average, distribution accounts for around 27 percent of the total electricity bill.[5]

Distribution networks are highly capital intensive, costs are determined primarily by capacity and voltage, not necessarily by the quantity of electricity conveyed. For legacy reasons, invoices to mass market consumers have been based on the quantity of energy delivered through a variable volume fixed price (VVFP) set of contracts. This has created distortions in costs to consumers as it creates a cross subsidy from large consumers to small consumers and was in place only because capacity historically was impossible to measure economically. This is no longer the case and some networks such as Orion and the Lines Company use capacity elements in their pricing as this is the best indication of cost reflective network costs, but it may disadvantage smaller consumers and benefit larger consumers.

Local networks are monopoly businesses, so they are regulated by the Commerce Commission. Secondary networks are also monopolies but are not price regulated by the Commerce Commission. The Commerce Commission has information disclosure powers, which apply to all 29 network companies and Transpower, and sets price and quality controls for 17 local lines companies. These price controls involve capping the total revenue the companies can earn from their consumers and requiring them to maintain their average quality to certain levels. The other 12 are exempt as they meet community-ownership criteria. The Electricity Authority has distribution pricing principles on its website, while it oversees alignment through scorecards with distributors, ensuring there is no outcome where a distributor does not align.[6]

1.2.1 Distribution pricing

Efficient distribution pricing helps provide a reliable and affordable electricity supply for consumers. Distribution pricing is intended to send signals to consumers about the cost of electricity and encourage better use of the electricity network. Electricity networks are like roads in that they can become congested at peak times of the day. Cost reflective pricing uses price signals to demonstrate when there is capacity in a network (through lower prices), and when the network is more congested (through higher prices). Consuming more electricity at peak demand times may mean that distributors might need to incur costs to increase the capacity of the network in the future or invest in non-network alternatives.

Local networks are recommended to follow the 2019 Distribution pricing principles, but secondary networks are not. With the development of microgrids, this is a gap that the Electricity Authority could look to close by including secondary networks in distribution pricing principles. Local networks are required to publish their pricing methodology and discuss their pricing plans and

[4] Section 131A of the Electricity Industry Act 2010.

[5] Electricity Authority. Updating the Regulatory Settings for Distribution Networks. https://www.ea.govt.nz/documents/1741/Updating-the-regulatory-settings-for-distribution-networks.pdf

[6] Electricity Authority. Distribution Pricing. https://www.ea.govt.nz/industry/distribution/distribution-pricing/

progress with the Electricity Authority each year. These principles set out expectations for efficient distribution prices that the Electricity Authority uses for its monitoring and assessments. The purpose of the pricing principles is to ensure that prices are based on a well-defined, clearly explained, and economically rational methodology.

However, while local networks may create appropriate price signals to consumers, it is only one of a number of components that are on charged by retailers to customers. Retailer pricing may distort or remove the pricing signal that local networks provide, by not passing on a pricing plan, or smearing the price signals the distributor is attempting to provide.

2019 Distribution pricing principles

- Prices are to signal the economic costs of service provision, including by:
    - Being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);
    - Reflecting the impacts of network use on economic costs;
    - Reflecting differences in network service provided to (or by) consumers; and
    - Encouraging efficient network alternatives.
- Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.
- Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:
    - reflect the economic value of services; and
    - enable price/quality trade-offs.
- Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

The Electricity Authority has developed a scorecard approach to monitor and comment on local networks' pricing structures and pricing reform, with the intention that this will encourage improvements in local network distribution pricing. The scorecards are the basis for the Electricity Authority's regular and constructive engagement with local network distributors on their price reform aspirations, efforts, and roadblocks. The aim is to highlight good practice, identify weaknesses and gaps, and to suggest opportunities for improvement. The Electricity Authority reviews local network distributors' assessments of the:

- Current circumstances
- Efficiency of price structures
- Strategies and implementation of distribution pricing reform
- Management of consumer impacts arising from changes to pricing.[7]

[7] Electricity Authority. Distribution pricing, https://www.ea.govt.nz/industry/distribution/distribution-pricing/

2 International approaches to distribution pricing

To understand alternative approaches to electricity distribution pricing, that could be applied in New Zealand, we looked at examples from Australia, Northern Ireland, the European Union, Great Britain, and North America (Canada's Ontario, and New York, Washington, and Texas in the United States).

There are three common approaches across these markets. On the east coast of Australia, Northern Ireland, and the European Union electricity distribution businesses are required to submit pricing proposals that are either approved by the regulator or agreed with the regulator. In Western Australia, prices are set by the state government. In Great Britain, distributors use a common pricing methodology designed and agreed between industry participants and the regulator. In the selected North America markets we looked at how prices are set by the regulator, usually involving judges and public hearings.

2.1 Recognising energy hardship

Over the course of this literature review we also investigated what has been said about approaches to local network distribution pricing that could support those in energy hardship. The following sub-section presents this review.

Electricity is an essential service

The closest any of the markets we looked at came to acknowledging, in its distribution pricing, that electricity is an essential service is Western Australia. Regardless of whether a consumer is located centrally in Perth, or somewhere more remote, all residential and small business consumers pay the same price for electricity distribution regardless of where they live. There has been criticism of this approach. A 2015 report by the Grattan Institute noted that the current pricing structure gives consumers no reason to use less power at peak times. As a result, the amount of total electricity used at peak times continues to grow, and so do the costs of providing it."[8] Consequently, consumers whose electricity use does not peak at the same time as the peak in the network are effectively subsidising other consumers, such as air-conditioner users, who use a lot of power at peak times.

The Grattan Institute notes that "it would be better to target subsidies so that the intended social benefit is delivered with minimal unintended consequences. Our analysis of customer-level data from Horizon Power, which covers many of Western Australia's remote regions, shows that better targeted subsidies combined with demand tariffs could reduce annual electricity bills for more than 75 per cent of vulnerable consumers in remote areas by an average of $275."

[8] Wood T., Blowers D. Fair Pricing for Western Australia's electricity. https://grattan.edu.au/wp-content/uploads/2015/11/831-Fair-pricing-for-Western-Australia-electricity.pdf

Switching power use at peak times

The Council of European Energy Regulators' (CEER) Electricity Distribution Network Tariffs Guidelines of Good Practice, published in 2017, identifies that "in the context of wider system aspects, cost-reflective price signals, sent through distribution network tariffs, may not be material enough to trigger manual behavioural responses from consumers."

CEER also notes that from a consumer perspective, and especially for residential consumers, the value and potential for flexibility use is complex and can be hard to comprehend. It identifies that end-user energy usage decisions are influenced by a broad range of both behavioural and situational factors.

A 'one-size-fits-all' approach, like distribution pricing, usually focuses on providing financial incentives, assuming that people are mainly economically motivated to participate. However, there is plenty of evidence that people are not predominantly motivated by financial gains but can also have other motivations that are related to their individual circumstances, for example environmental goals, health, and comfort. Research in 2013 for Netbeheer Nederland, the association of all electricity and gas network operators in the Netherlands, found that often a small percentage of participants are responsible for the total response. It remains unclear why, and how, they responded, and why the rest did not. On average 30 percent of households were responsible for 80 percent of the load shifting.[9]

2.2 Australia

Australia's electricity markets are overseen by government, and operated and regulated by independent bodies funded from a mix of government and industry investment. Independent regulators oversee the operation of the wholesale market, generators, network businesses, and retailers.

The overarching responsibility for energy policy in Australia rests with the Standing Council for Energy and Resources (SCER). SCER is responsible to the Council of Australian Governments (COAG) and sets the general principles relating to national energy regulation. Under the Australian Energy Market Agreement (AEMA), signed by the Commonwealth, state, and territory governments in 2004, SCER also has general policy oversight of some relevant national energy legislative arrangements, including the national electricity laws and rules.

Australia's electricity system operates within a legislative and regulatory framework that seeks to promote the efficient investment, operation, and use of energy services for the long-term interests of consumers in relation to price, quality, safety, reliability, and security. As energy policy is the domain of the states, national laws, regulations, and rules (as well as any guidelines, standards, and procedures), must be applied at state and territory level.

[9] Breukers S.C., Mourik R.M. The end-users as starting point for designing dynamic pricing approaches to change household energy consumption behaviours. https://www.netbeheernederland.nl/_upload/Files/Dynamic_pricing_and_behaviour_change_99.pdf

2.2.1 Australia's National Energy Market

The electricity system and market in most Australian states and territories (excluding Western Australia and the Northern Territory) is governed by the National Electricity Law (NEL) and the National Electricity Rules (NER). Australia's National Energy Market (which excludes Western Australia and the Northern Territory) has 13 major electricity distribution networks. Queensland, New South Wales (NSW), and Victoria have multiple networks that are monopoly providers within designated areas. The Australian Capital Territory (ACT), South Australia, and Tasmania each have one major network.[10]

Australia's national energy market began operating in 1998. The governance structure is designed to deliver effective competition, to provide clear accountabilities, and to support investment certainty in the energy sector. The structure separates decisions on government policy, energy regulation, and energy system operation. Additionally, as Figure 2.1 shows, it includes three market bodies to oversee the nation's energy market:

- The Australian Energy Market Operator (AEMO) was created in 2009 and it takes responsibility for gas and electricity market operation roles.[11]

- The Australian Energy Market Commission (AEMC) is the rule maker for Australian electricity markets. It makes and amends the National Electricity Rules by which the markets must operate. As well as making and amending the rules, the AEMC undertakes reviews of the national energy frameworks and provides advice to energy ministers.[12]

- The Australian Energy Regulator (AER) forms part of the Australian Competition and Consumer Commission (ACCC) and enforces and monitors performance and compliance of the rules established by the AEMC.[13]

Each market body is an independent decision-maker with clear powers, functions, and accountabilities that support the efficient operation of the market in the long-term interests of consumers.

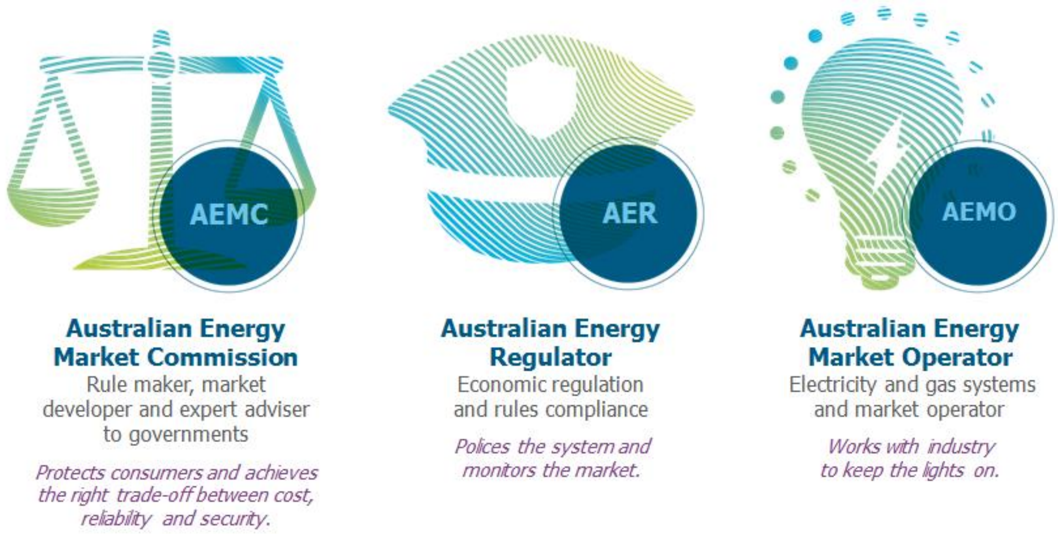
[10] Australian Energy Regulator. State of the energy market 2023. https://www.aer.gov.au/system/files/2023-10/State%20of%20the%20energy%20market%202023%20-%20Full%20report_1.pdf

[11] Australian Energy Market Operator. https://aemo.com.au/

[12] Australian Energy Market Commission. https://aemc.gov.au/

[13] Australian Energy Regulator. https://www.aer.gov.au/

Figure 2.1 Australian Electricity Industry Market body roles



Source: Australian Energy Market Commission.

National Electricity Law

The National Electricity Law (NEL) is the foundation for the National Electricity Market and establishes that all significant electricity industry participants in each relevant jurisdiction are required to participate in the single electricity market. The NEL also sets out the National Electricity Objective (NEO) and revenue and pricing principles.

The NEL is contained in a Schedule to the National Electricity (South Australia) Act 1996, and establishes the governance framework and key obligations for the Australian National Electricity Market. The NEL is applied as law in New South Wales, Queensland, Victoria, South Australia, Tasmania, and the Australian Capital Territory by application statutes. The Northern Territory has also applied the NEL with variations that cater to local requirements.

National Electricity Objective

The National Electricity Objective (NEO) governs and guides the AEMC in all of its activities under the relevant national energy legislation. The AEMC can only make and amend the rules, or recommend changes to the national energy framework in reviews, if doing so will contribute to the relevant energy objective. The energy objectives refer to several components of the long-term interests of consumers.

Section 7 of the NEL states that the current NEO is “to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

a. price, quality, safety, reliability, and security of supply of electricity; and

b. the reliability, safety, and security of the national electricity system; and

c. the achievement of targets set by a participating jurisdiction—

i. for reducing Australia's greenhouse gas emissions; or

ii. that are likely to contribute to reducing Australia's greenhouse gas emissions."[14]

Revenue and pricing principles

Section 7A follows the NEO and establishes the revenue and pricing principles that apply to the operation of the National Electricity Market. The revenue and pricing principles are:

- A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
  a. providing direct control network services; and
  b. complying with a regulatory obligation or requirement or making a regulatory payment.
- A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
  a. efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
  b. the efficient provision of electricity network services; and
  c. the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
- Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
  a. in any previous—
     i. as the case requires, distribution determination or transmission determination; or
     ii. determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
  b. in the Rules.
- A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

[14] Australasian Legal Information Institute. National Electricity (South Australia) Act 1996. https://www8.austlii.edu.au/cgi-bin/download.cgi/cgi-bin/download.cgi/download/au/legis/sa/consol_act/neaa1996388.txt

- Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
- Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

National Electricity Rules

The National Electricity Rules (NER) are made under the National Electricity Law and govern the operation of the Australian National Electricity Market. The NERs exist so that market participants understand their rights and responsibilities, and there is appropriate regulation so that consumers do not pay more than necessary for their electricity. In relation to distribution pricing, the rules govern the economic regulation of the services provided by monopoly transmission and distribution networks.

Chapter 6 of the NER sets the rules for economic regulation of distribution services and provides the AER with responsibility for the economic regulation of distribution services provided by means of, or in connection with, distribution systems that form part of the national grid.[15]

The AER regulates electricity networks by setting the maximum amount of revenue they can earn from consumers. Decisions generally apply for five years, and network businesses adjust their prices annually during the five-year period. Network businesses submit proposals to the AER on their required revenues and the AER makes decisions based on factors including:

- Projected demand for electricity
- Age of infrastructure
- Operating and financial costs
- Network reliability and safety standards.

Pricing proposals

Distributors set network tariffs every year setting out the charges that all users of the network must pay. The tariffs do not determine the overall amount of revenue that the distributor can collect, since this has already been decided. Rather, the tariff influences what proportion of the total revenue is collected from each network user, and how each user's charge depends on the way in which they use the network.

[15] Australian Energy Market Commission. National Electricity Rules. https://energy-rules.aemc.gov.au/ner/502

Every year, electricity distributors are required to submit a pricing proposal to the AER that contains the network tariffs (tariff structure statement) they propose to charge their customers to recover their revenues, transmission network charges, and costs of jurisdictional schemes.

A tariff structure statement must include the tariff classes into which retail customers will be divided during the relevant regulatory control period, the policies and procedures the distributor will apply for assigning retail customers to tariffs and reassigning retail customers to another tariff, the structures for each proposed tariff, and the charging parameters for each proposed tariff.

Pricing principles

The network pricing objective of the NER is that the tariffs that a distributor charges, in respect of its provision of direct control services to a retail customer, should reflect the distributor's efficient costs of providing those services to the retail customer. The NER includes the following principles a distributor must comply with in a manner that will contribute to the achievement of the network pricing objective. A distributor's tariffs must comply with the pricing principles set out in paragraphs (e) to (j). A distributor's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only to the extent permitted under paragraph (h), and to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).

(e) For each tariff class, the revenue expected to be recovered must lie on or between:

> (1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and
>
> (2) a lower bound representing the avoidable cost of not serving those retail customers.

(f) Each tariff must be based on the long-run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff, with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

> (1) the costs and benefits associated with calculating, implementing, and applying that method as proposed;
>
> (2) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant service; and
>
> (3) the location of retail customers that are assigned to that tariff, and the extent to which costs vary between different locations in the distribution network.

(g) The revenue expected to be recovered from each tariff must:

> (1) reflect the distributor's total efficient costs of serving the retail customers that are assigned to that tariff;

(2) when summed with the revenue expected to be received from all other tariffs, permit the distributor to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the distributor; and

(3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage of the relevant service that would result from tariffs that comply with the pricing principle set out in paragraph (f).

(h) A distributor must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the distributor considers reasonably necessary having regard to:

(1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period);

(2) the extent to which retail customers can choose the tariff to which they are assigned; and

(3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services.

(i) The structure of each tariff must be reasonably capable of:

(1) being understood by retail customers that are or may be assigned to that tariff (including in relation to how decisions about usage of services or controls may affect the amounts paid by those customers) or

(2) being directly or indirectly incorporated by retailers or Market Small Generation Aggregators in contract terms offered to those customers,

having regard to information available to the distributor, which may include:

(3) the type and nature of those retail customers;

(4) the information provided to, and the consultation undertaken with, those retail customers; and

(5) the information provided by, and consultation undertaken with, retailers and Market Small Generation Aggregators.

(j) A tariff must comply with the Rules and all applicable regulatory instruments.

Approval of pricing proposal

The AER must approve a pricing proposal if they are satisfied that a pricing proposal complies with Chapter 6, each proposed tariff set out in the proposal is broadly consistent with the corresponding indicative pricing levels for that tariff for the relevant regulatory year, and all forecasts associated with the proposal are reasonable.

The distributor must then maintain on its website its current tariff structure statement, its current indicative pricing schedule, and a statement of the provider's tariff classes and the tariffs applicable to each class.

When tariffs are changed, the AER publishes a Statement of Reasons for each electricity distributor, which further explains the annual pricing changes.

2.2.2 Western Australia

Western Australia's transmission and distribution networks are not connected to other networks in Australia and are wholly owned by the state government. There are two main electricity grids in Western Australia; the South-West Interconnected System (SWIS), which is the main grid and covers the south-western part of Western Australia, and the North-West Interconnected System (NWIS), which covers the north-western part of Western Australia. Western Power owns and operates the transmission and distribution infrastructure within the SWIS, and Horizon Power oversees the operation of the NWIS.[16] Consumers who use less than 50 megawatt hours (MWh) of electricity annually, which includes the majority of residential and small business consumers, cannot choose their retailer but are supplied by state owned corporation Synergy.

The State Government has a Uniform Tariff Policy (UTP) that applies to small use customers who consume less than 160MWh per year (most households and small businesses). The Western Australian Government reviews tariffs, fees, and charges, and sets the prices customers pay for electricity, on 1 July. Under the UTP, as part of the State Budget process, the state sets the maximum price retailers can charge small-use electricity customers. All Western Australian customers pay the same price for electricity regardless of where they live.

Residential electricity tariffs can be broken down into two types of fixed costs and a variable cost component. The first fixed cost reflects the cost per day of being connected to the network, including costs of accounting, management, network maintenance, and other factors independent of the amount of electricity supplied. The second type of fixed cost is the cost of maintaining sufficient generating and transmission capacity to ensure reliable, high-quality supply. The variable cost component reflects mainly fuels used to generate electricity and losses on the transmission and distribution network, both of which depend on the amount of electricity supplied.

The costs of supplying electricity to customers in regional and remote areas is usually higher than when compared to the SWIS. This means that regulated retail prices are usually lower than the expenses incurred for servicing remote and regional communities. The shortfall is recouped in two ways:

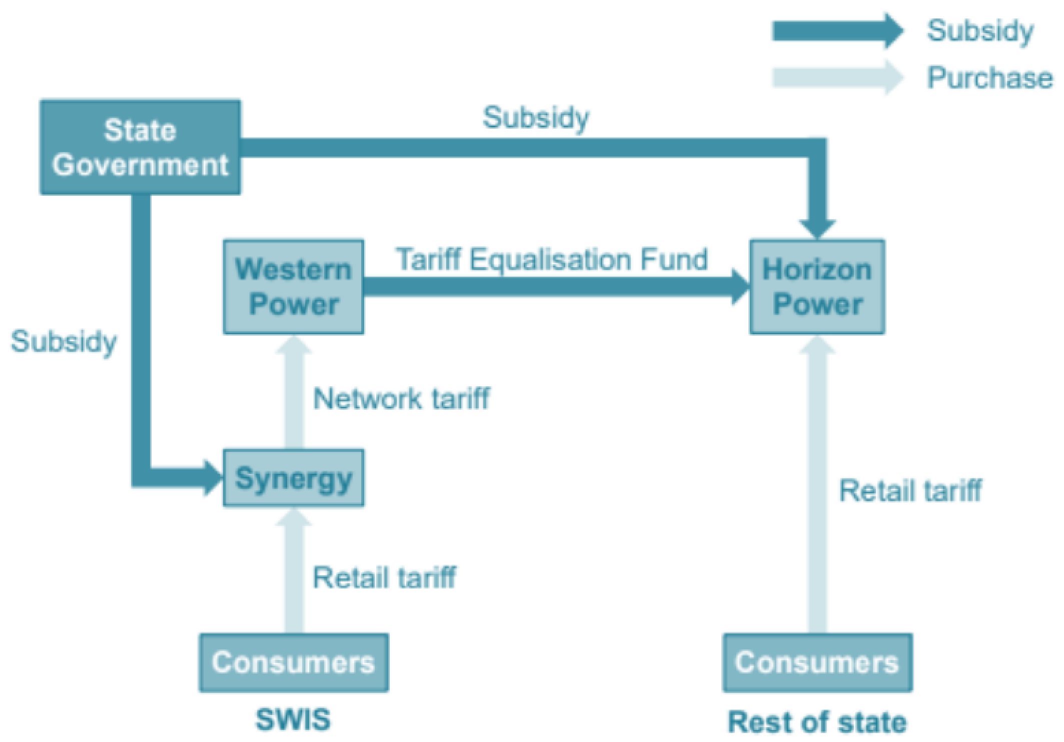
[16] Australian Energy Council. Western Australia: Electricity networks https://www.energycouncil.com.au/media/12991/western-australia-electricity-networks.pdf

- The Tariff Equalisation Contribution funds the difference between cost and supply by adding an amount to electricity network charges for customers in the SWIS.
- The Tariff Adjustment Payment is a subsidy from the State Government to fund the difference between regulated retail tariffs and the cost of supply.

Figure 2.2 shows the flow of electricity payments in Western Australia. This includes the subsidy paid to Horizon Power by the State Government, and the tariff equalisation fund payment from Western Power to Horizon Power to cover the higher costs to provide electricity to consumers in the NWIS. Synergy is the electricity retailer for all residential and small business consumers.

In the NWIS, and rural parts of the SWIS, most customers pay less than the actual cost of purchasing or generating, distributing, and selling electricity. The difference between the actual cost of electricity and the price NWIS customers pay is subsidised by the State Government. In 2022-23 this subsidy was $175 million for regional Western Australia, or $3,593 per customer connection.[17]

Figure 2.2 Western Australia electricity market pricing structure



Source: Horizon Power

[17] Horizon Power. 5 things to know about the cost of electricity in WA. https://www.horizonpower.com.au/about-us/news-announcements/5-things-to-know-about-the-cost-of-electricity-in-wa/

Regulation of distribution

As Western Australia's independent economic regulator, the Economic Regulation Authority (ERA) licenses electricity generators, distributors, and retailers, and also monitors the performance of licensees and the behaviour of generators and participants in the wholesale energy market. This includes approving the terms and conditions for accessing the electricity networks, including the prices Western Power, owner and operator of the transmission and distribution infrastructure within the SWIS, can charge for access.

The terms and conditions for accessing networks is done through access arrangements. An access arrangement defines the services the distributor must provide, and the revenue and policies under which it operates. The ERA reviews the access arrangement every five years. Distributors must comply with the tariff structure statement approved by the ERA.

A distributor's price list sets the prices that apply to access the network. These services are provided to all customers connected to the distribution network, but are generally charged to retailers and generators who have a contractual relationship with the distributor.

Pricing objective and principles

Although prices are fixed for residential and small businesses, there is retail competition for large consumers. The Electricity Networks Access Code (The Code) 2004 establishes a framework for third party access to electricity transmission and distribution networks. The framework's objective is to promote economically efficient investment in the operation and use of networks and services in Western Australia, to help facilitate competition in markets upstream and downstream of the networks. The Code includes a "pricing objective", and "pricing principles".[18]

Section 7.3 of the code requires that the pricing methods used must have the objective (the "pricing objective") that the reference tariffs that a service provider charges in respect of its provision of reference services should reflect the service provider's efficient costs of providing those reference services.

A service provider's reference tariffs must then comply with the code's pricing principles which are:

- For each reference tariff, the revenue expected to be recovered must lie on or between:

(a) an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom that reference tariff applies; and

(b) a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom that reference tariff applies.

[18] Western Australia Government. Electricity Networks Access Code 2004 (30 July 2021). https://www.wa.gov.au/system/files/2021-07/ENAC-consolidated-version-30July2021.pdf

- The charges paid by, or in respect of, different customers of a reference service may differ only to the extent necessary to reflect differences in the average cost of service provision to the customers.

- The structure of reference tariffs must, so far as is consistent with the Code objective, accommodate the reasonable requirements of users collectively and end-use customers collectively.

- Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

(a) the additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network; and

(b) the location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network.

- The revenue expected to be recovered from each reference tariff must:

(a) reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff;

(b) when summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement; and

(c) comply with sections 7.3H(a) and 7.3H(b) in a way that minimises distortions to the price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G.

- The structure of each reference tariff must be reasonably capable of being understood by customers that are currently on that reference tariff, including enabling a customer to predict the likely annual changes in reference tariffs during the access arrangement period, having regard to:

(a) the type and nature of those customers;

(b) the information provided to, and the consultation undertaken with, those customers.

- A reference tariff must comply with this Code and all relevant written laws and statutory instruments.

2.3 Europe

In Europe network pricing, referred to as network tariffs, has the core objective to recover the costs incurred by transmission and distribution system operators. In European Union Member States, National Regulatory Authorities (NRAs) have the duty of fixing or approving transmission or distribution tariffs or their methodologies.[19] Although, how this is done varies across member states depending on the relevant principles in each national context.

Based on current legal frameworks, in 24 EU Member States and Norway (part of the European Economic Area), the NRA sets or approves distribution tariff methodologies. In Finland and Sweden, each system operator individually defines the tariff methodology based on the legal framework, but it is not subject to the NRA's approval. In Germany, the relevant ministry defines the tariff methodologies, while the NRA supervises the compliance with the tariff methodology.[20]

Tariffs can be designed in multiple ways to achieve various tariff-setting principles including cost recovery, cost reflectivity, efficiency, non-discrimination, transparency, non-distortion, simplicity, stability, predictability, and sustainability.

The Tariff setting process across most of Europe often consists of three steps:

- The allowed revenues (including the remuneration method for distribution costs) and other relevant costs are determined
- The tariff structure is defined
- The costs are allocated to each of the tariff structure's items (i.e. charges paid by network users).[21]

2.3.1 Norway

The Norwegian Energy Act is based on the principle that electricity production and trading should be market-based, while grid operations are strictly regulated. On behalf of the Norwegian government, the Norwegian Water Resources and Energy Directorate (NVE) determines how much electricity network operators can earn in a particular year. Since there is only one network operator in each geographic area, the NVE audits the company's accounts every year to make sure they are

[19] Official Journal of the European Union. Directive (EU) 2019/944 of the European Parliament and of the council of 5 June 2019 on Common rules for the internal market for electricity and amending Directive 2012/27/EU https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019L0944

[20] European Union Agency for the Cooperation of Energy Regulators. Report on Electricity Transmission and Distribution Tariff Methodologies in Europe (January 2023). https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_electricity_network_tariff_report.pdf

[21] European Union Agency for the Cooperation of Energy Regulators. Network tariffs. https://www.acer.europa.eu/electricity/infrastructure/network-tariffs

not exploiting their monopoly position. Network operators set the price that individual customers must pay for electricity to be delivered to their homes, but the operators' overall income must not exceed the cap that the NVE has determined for each company.[22]

Under the Energy Act, a licence is required in order to construct, own, and operate grid assets. Licences specify obligations and requirements for grid companies, irrespective of commercial viability. As well as the specific requirements and obligations in licences, there is incentive-based regulation in the form of a revenue cap. The overall purpose is to ensure that operation, utilisation, and development of the grid is rational and in the best interests of society.[23]

Grid companies are responsible for setting their own tariffs, but the national authorities set the general principles for tariff design. Over time, the grid companies' total tariff revenues must be within the permitted level set by NVE. Grid tariffs must be objective and non-discriminatory, and they must be designed and differentiated on the basis of relevant grid conditions. To the extent possible, tariffs should also be designed to provide long-term signals, encouraging efficient utilisation and development of the grid.

The current regulation gives distributors a large degree of freedom regarding how to design tariffs based on their allowed revenue. Tariffs for households, vacation homes, and small commercial customers mainly consist of a fixed charge and an energy charge. On average, the fixed charge constitutes about 30 percent of the network tariff.

The Norwegian Energy Act Regulation provides guiding principles, which state that tariffs shall be designed so that they contribute to effective utilisation and development of the network. Furthermore, tariffs shall ensure customers' non-discriminating access to the energy market, cover grid owners' costs within allowed revenue, as well as provide a fair allocation of costs between network users.

2.3.2 Sweden

The electricity market in Sweden was deregulated in 1996 and, as in New Zealand, the transmission and distribution of electricity is considered a natural monopoly and is therefore subject to regulation. The national regulatory authority for energy, the Swedish Energy Markets Inspectorate (EI), determines a revenue cap for each distributor and the transmission system operator for a regulatory period of four years. According to the Swedish Electricity Act, electricity distribution

[22] Energifakta Norge. Energy Facts Norway. The power market. https://energifaktanorge.no/en/norsk-energiforsyning/kraftmarkedet/#:~:text=The%20Norwegian%20Energy%20Act%20is,and%20reasonable%20prices%20on%20electricity

[23] Climate Change Laws of the world. The Energy Act, No. 50 of 1990 https://climate-laws.org/documents/energy-act_1360?id=the-energy-act-no-50-of-1990_f8a0

tariffs shall be reasonable, objective, and non-discriminatory.[24] The fact that the tariffs must be objective means that they must reflect the costs in the network that each customer group causes. Non-discrimination means that no special treatment in tariffs between network users may take place.[25]

The EI determines a revenue cap for each distributor for a period of four years at a time. The revenue cap indicates the total amount that the distributor may charge their customers. The purpose of the revenue cap is to ensure that distributors shall obtain reasonable coverage for their costs and reasonable return on the invested capital. When calculating the revenue cap the EI is required to consider the reliability of supply, and also to what extent the operations are conducted in a manner consistent with, or contributing to, an efficient utilisation of the power grid. Each distributor individually defines the tariff methodology based on the legal framework, but it is not subject to EI approval.[26]

In 2018, the EI received authorisation to prescribe how the tariffs should be structured. Since then, a project has been under way at the authority to design network tariffs that promote efficient network usage. The new regulations were decided on in March 2022, and enter into force in 2027. The new regulations state that the network tariffs must contain four appropriately priced components, in order for them to be considered as promoting efficient network usage. The first component, the energy charge, must be imposed as a charge per kilowatt (kW) hour and be based on the marginal costs of electricity transmission. It may also vary over time depending on how the costs in the network vary. The second component is the charge for power output, which must be based on the forward-looking costs, and imposed as a charge on measured power output. In accordance with the regulation charge for power output must be time differentiated, that is it must vary in some way over the 24-hour day and/or the year. The third component is the customer-specific charge, and it must equate to the costs that the network operator incurs for a specific customer or customer group, for example metering, reporting, and customer service. This charge is imposed as a fixed charge. The fourth and final component is a tariff charge that must equate to the other costs of the activity that are not already covered by other components (so-called residual costs). Consumers should perceive this cost as also being fixed.[27]

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[24] Wallnerström C. J., et al. The regulation of electricity network tariffs in Sweden from 2016. https://ei.se/download/18.4ed2158a18722d7df785b6b/1680684552490/CIRED-2016-The-regulation-of-electricity-network-tariffs-in-Sweden-from-2016.pdf

[25] Nordic Energy Regulators. Electricity distribution tariffs. https://www.nordicenergyregulators.org/wp-content/uploads/2021/05/20210216-NR-WG-Tariff-report.pdf

[26] Supra n 14.

[27] Swedish Energy Markets Inspectorate. Sweden's electricity and natural gas market, 2021. https://ei.se/download/18.31b721ca18388fe22ad2d3f/1664799315977/Sweden's-electricity-and-natural-gas-market-2021-Ei-R2022-07.pdf

2.4 Northern Ireland

Northern Ireland Electricity (NIE) is the owner and operator of the electricity transmission and distribution networks in Northern Ireland, serving all customers connected to the Northern Ireland electricity network. NIE Networks is a regulated company and day to day business activities are overseen by the Northern Ireland Authority for Utility Regulation (the Utility Regulator).

The Electricity (Northern Ireland) Order 1992 established the legal framework for the privatisation of the electricity industry in Northern Ireland. The 1992 Order requires that NIE Networks operates under an Electricity Distribution Licence granted by the Department for the Economy.[28]

Condition 32 of the Electricity Distribution Licence sets the basis of charges for the use of, and connection to, the distribution system. NIE Networks is required to prepare a statement, approved by the Utility Regulator, setting out the basis upon which charges will be made.[29]

The Utility Regulator approves NIE Networks charges on an annual basis. In approving the charges, the Utility Regulator ensures that they are in line with the associated price control which sets the amount of revenue NIE Networks earns.[30]

The statement is required to include, amongst other things, a schedule of charges for transport of electricity, the methods by which, and the principles on which, charges (if any) will be made, and a schedule of charges in respect of meter reading, accounting and administrative charges, and such other matters as shall be specified in directions issued by the Utilities Regulator.

Statement of Charges for use of the NIE Networks Electricity Distribution System

The current statement of charges in place for NIE Networks is effective from 1 October 2023 to 30 September 2024. This statement of charges has been set to recover Income of £314.7m and includes principles for charging for use of the system.[31]

Principles for charging for use of the system

The statement of charges includes the following principles relevant to distribution pricing for residential and small business consumers.

- Where a supply of electricity is provided over electric lines or electrical plant comprising a part of the system, a charge for use of the System will be levied on the supplier. These charges may

[28] The Electricity (Northern Ireland) Order 1992 https://www.legislation.gov.uk/nisi/1992/231/contents

[29] Northern Ireland Electricity Ltd. Electricity Distribution Licence https://www.uregni.gov.uk/files/uregni/documents/2023-05/NIE%20Networks%20Distribution%20Licence%20-%20effective%2024%2005%202023.pdf

[30] Utility Regulator. Tariffs. https://www.uregni.gov.uk/tariffs

[31] NIE Networks. Statement of Charges for use of the Northern Ireland Electricity Networks Ltd Electricity Distribution System by Authorised Persons https://www.nienetworks.co.uk/documents/regulatory-documents/2023-06-16-duos-statement-of-charges_2023-24.aspx

then be passed through to their customers by the suppliers under the relevant supply agreements between such parties, and may be incorporated into the charges payable by customers to suppliers under such agreements.

- The charges for use of the system reflect the costs of providing, operating, and maintaining the system to the standards prescribed by the Licence Document, other than those costs which are recovered through charges paid to NIE Networks in respect of connection to the system. The charges for use of the system include a reasonable return on the relevant assets, and the revenues arising from the charges are subject to regulation in accordance with the terms of the Licence Document.

- The charges for each category of supply depend upon the criteria which determine eligibility for that category as described in the pricing schedules. Such criteria include the voltage of connection to the system, the power factor and other characteristics of the load, and installation of the metering necessary to establish those characteristics.

- In general, no separate distribution use of system charge will be levied on an embedded generator, or electricity storage customer, for the use of the system in respect of the electricity which is exported on to the system. However, if the generator, or electricity storage customer, is also importing electricity from the system, or supplying electricity to exit points from the system, charges will be levied for use of the system in respect of such use of the system. (An embedded generator is a generator whose generating equipment is directly connected to the system)

- In accordance with pricing schedules, and depending on the criteria stated, the charges for use of the system to suppliers may include some or all of the following elements:

- A standing charge to cover the costs that do not vary with the extent to which the supply is taken up. This charge is designed to reflect the cost of basic metering, meter reading, billing, and the cost of service cables and terminations not recoverable as part of the connection charge and maintenance of those aspects of the supply. The cost of the customer record, associated on-costs, and other indirect costs are also reflected.

- A charge per kVA of Maximum Import Capacity (MIC), meaning the maximum amount of electricity (expressed in kVA) that has been agreed can be supplied to the connection point.

- An excess capacity charge per kVA, if a customer exceeds their MIC (MIC Exception Charge).

- A charge per kWh for each unit delivered through the system, designed to reflect costs of the system that are not recovered through the connection charge, or capacity charge, the costs of maintaining and reinforcing the system, where connection charges are not applicable, and associated on-costs.

Charges to suppliers for use of the System - Supply to Domestic Premises

NIE Networks offers five different rate types to domestic premises based on different uses of the system. These different rates are then passed on to consumers in the power bills from their electricity supplier. As Table 2.1 shows, the standard rate includes a standing charge per quarter and a unit charge per kWh. There are three rates called economy 7 that have charges that vary depending on the time and type of use.

Table 2.1 NIE Networks domestic electricity distribution tariffs

DUoS Tariff Code	Tariff Description	Standing Charge	Unit Charge 1 (p / kWh)	Unit Charge 2 (p / kWh)	Unit Charge 3 (p / kWh)
T011	Standard Rate	11.57	4.450	N/A	N/A
T012	Economy 7 Rate	11.57	5.335	0.859	N/A
T014	Economy 7 Rate	11.57	5.335	0.859	0.859
T015	Economy 7 Automatic (Preserved Tariff)	11.57	5.335	0.859	0.859

Source: NIE Networks

- Unit Charge 1 - All units delivered per Quarter (Excluding hours of availability for Unit Charge 2 & 3 where applicable).
- Unit Charge 2 - Reduced price per unit delivered for seven hours within the period 2300 hrs and 0800hrs GMT.
- Unit Charge 3 - All units delivered for storage heating for seven hours in 24 hours plus 4 hours during the night for water heating with an additional one-hour boost in the afternoon.
- T015 (Preserved Tariff) - All units delivered for storage heating up to nine hours charge, depending on the weather conditions plus 4 hours during the night for water heating with an additional one-hour boost in the afternoon.

The fifth rate for domestic premises includes the same standing charges, but as Table 2.2 shows, includes four variable rates that decline based on the time when electricity is used to incentivise electricity use outside of peak times.

- Unit charge 1 - All units delivered between 1600hrs to 1900hrs GMT Monday to Friday inclusive.
- Unit charge 2 - All units delivered between 0800hrs to 1600hrs GMT Monday to Friday inclusive.
- Unit charge 3 - All units delivered between 1900hrs and 2400hrs GMT Monday to Friday inclusive and 0800hrs to 1900hrs GMT Saturday and Sunday.
- Unit charge 4 - All units delivered between 0000hrs and 0800hrs GMT Monday to Friday inclusive and 1900hrs to 0800hrs GMT Saturday and Sunday.

Table 2.2 NIE Networks time banded domestic electricity distribution tariffs

DUoS Tariff Code	Tariff Description	Standing Charge	Unit Charge 1 (p / kWh)	Unit Charge 2 (p / kWh)	Unit Charge 3 (p / kWh)	Unit Charge 4 (p / kWh)
T016	4 Rate Time-banded	11.57	13.064	6.662	2.505	0.964

Source: NIE Networks

2.5 Great Britain

Since gas and electricity networks in Great Britain are monopolies, the Office of Gas and Electricity Markets (Ofgem) sets price controls for the gas and electricity network companies. Ofgem regulates the monopoly companies that run gas and electricity networks in England, Scotland, and Wales. It makes decisions on price controls and enforcement, acting in the interests of consumers and helping the industries to achieve environmental improvements.

Ofgem's price controls are intended to balance the relationship between investment in the network, company returns, and the amount that they charge for operating their respective networks. This is done through the price controls implemented under Ofgem's Revenue using Incentives to deliver Innovation and Outputs (RIIO) model. RIIO is an investment programme intended to transform the energy networks, and the electricity system operator, to enable the delivery of emissions-free green energy in Great Britain, along with world-class service and reliability.[32] RIIO-2 is the second set of price controls implemented under the RIIO model and runs for five years, from 2023-2028.

Ofgem's regulation is primarily accomplished by granting licences to companies and ensuring that those companies comply with the requirements and conditions of their licence, one of which is the methodology distributors must use to calculate prices.

Ofgem have responsibility for ensuring that the distributors charge customers in an appropriate way for connecting to, and using, the electricity distribution networks. It does not approve the charges themselves, but the methodologies used to calculate them.

2.5.1 Charging requirements imposed by licenses

The Electricity Act 1989 requires that anyone operating a distribution network is licensed.[33] Distributors as licensees are obliged to comply with the licence conditions. Condition 13A of the licence requires that a distributor must take all steps within its power to ensure that the Common Distribution Charging Methodology ('the CDCM') is used for the determination of the distributor's Use of System Charges on the basis that it achieves the following objectives:

[32] Ofgem. Network price controls 2021-2028 (RIIO-2). https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2021-2028-riio-2

[33] Electricity Act 1989. https://www.legislation.gov.uk/ukpga/1989/29/contents

- Compliance with the Regulation[34] and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators
- Compliance with the CDCM facilitates the discharge by the distributor of the obligations imposed on it under the Electricity Act 1989 and by its licence
- Compliance with the CDCM facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector.
- Compliance with the CDCM results in charges that, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the distributor.
- So far as is consistent with the first four objectives, the CDCM, so far as is reasonably practicable, should properly take account of developments in the distributor's business.[35]
- The distributor must, for the purpose of ensuring that the CDCM continues to achieve the relevant objectives, review the methodology at least once every year, and make such modifications (if any) of the methodology as are necessary for the purpose of better achieving the objectives.

2.5.2 Common Distribution Charging Methodology

Schedule 16 of the Distribution Connection And Use Of System Agreement (DCUSA) sets out the CDCM.[36] The CDCM gives the methods, principles, and assumptions underpinning the calculation of Use of System Charges by each distributor. The CDCM comprises two parts. Part one sets the cost allocation rules, and Part two sets the tariff structures and their application.[37]

[34] Regulation means regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.

[35] Ofgem. Standard conditions of the Electricity Distribution Licence https://www.ofgem.gov.uk/sites/default/files/2023-03/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20-%20Current.pdf

[36] The DCUSA was established as a multi-party contract between the licensed electricity distributors, suppliers and generators of Great Britain. It is concerned with the use of the electricity distribution systems to transport electricity to or from connections to them. It is a requirement that all licensed electricity Distribution Businesses, Suppliers and CVA Registrants become Parties to the DCUSA.

[37] Wragge & Co. Distribution Connection And Use Of System Agreement. https://dcusa-cdn-1.s3.eu-west-2.amazonaws.com/wp-content/uploads/2023/11/02134556/DCUSA-v15.4.pdf

In order to comply with the CDCM methodology the distributor populates a CDCM model that is made available by Distribution Connection and Use of System Agreement (DCUSA) Limited.[38]

Part one — Cost allocation

As shown in Figure 2.3, there are four steps in how the CDCM allocates costs.

1. Determine costs or revenue allowances for various parts of the network, and collect information about the relevant characteristics of network users.

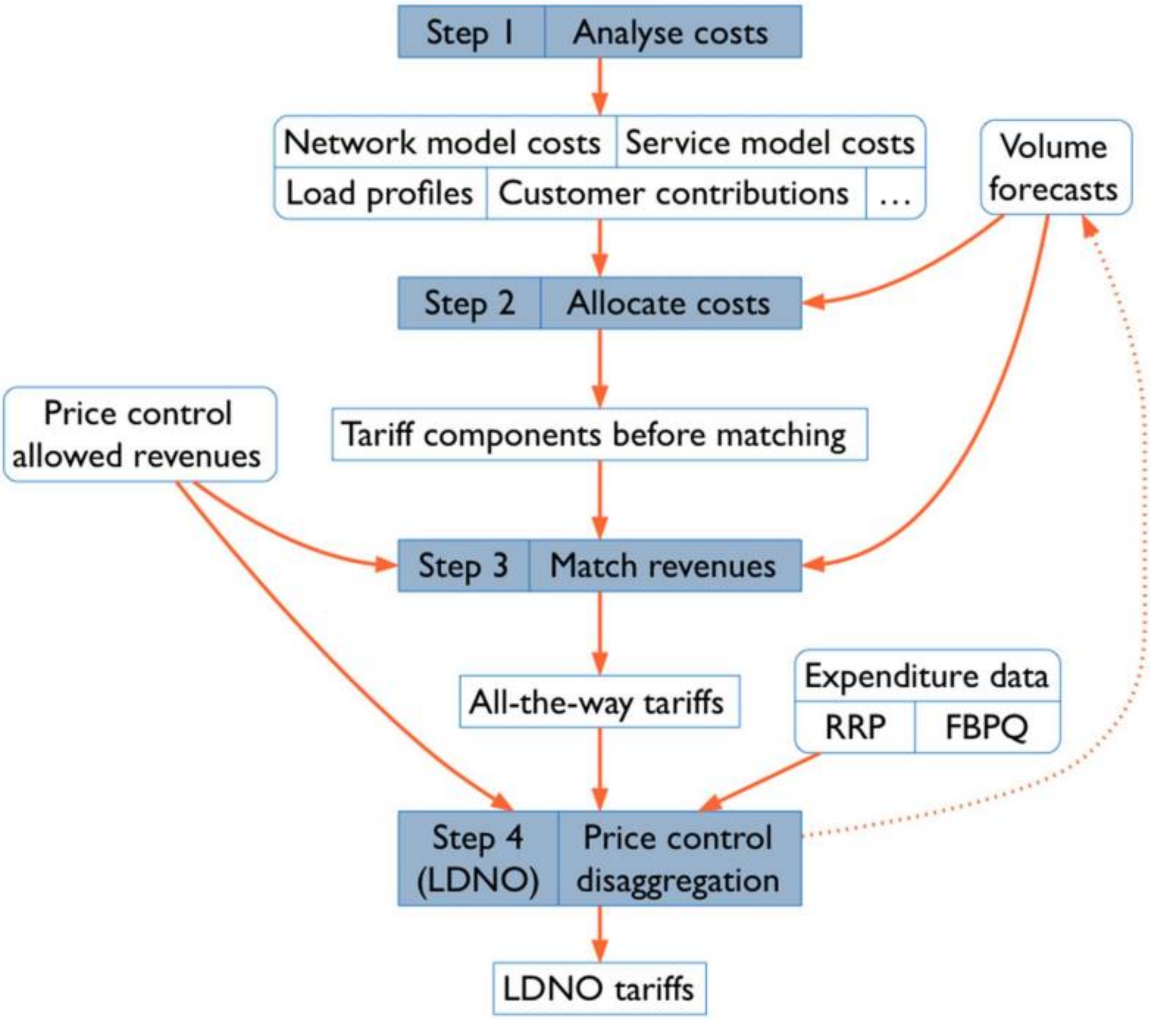
2. Apply the cost allocation rules contained in Schedule 16 of the DCUSA.

3. Adjust the tariff components, calculated in step 2, to match revenue recovered from the CDCM to the amount of revenue allowed under the price control conditions.

4. Use price control condition calculations, actual expenditure data, and forecast expenditure data to determine discount percentages, which are then applied to all-the-way tariffs.

[38] DCUSA Ltd is a company established, owned, and funded by parties to the DCUSA. The main activity of DCUSA Ltd is to administer the governance of the DCUSA.

Figure 2.3 Overview of the main steps in the cost allocation methodology



Source: Distribution Connection and Use of System Agreement.

Part two – Tariff structures and application

The development of the CDCM involved the creation of a common tariff structure for all 14 distributors and their service areas. Part 2 of the CDCM details the common tariff structure and associated tariff elements.

How customers are charged depends on how they are metered. Customers with meters that do not record electricity use by half hour time periods are charged a fixed charge per day, and unit charges per kWh. For customers with meters that record use in half hour periods, charges consist of a fixed, unit, capacity, and reactive power charge.

The reactive power charge has three-unit rate time bands on a time of day basis to reflect the requirements of the cost drivers of the distribution network. These three-time bands are called 'red', 'amber', and 'green' to represent three differing cost signals. The red time band is the peak time period, when demand on the distribution network is at its highest, and is charged at the highest rate per kWh. The amber time band is the time leading into, or out of, the peak demand period, commonly referred to as the shoulder period, and the green time band is when demand is lowest.

As shown in Figure 2.4, distribution time bands are defined separately for Monday-Friday and for Saturday/Sunday. In each case, time bands are defined by reference to United Kingdom clock time only, and always begin and end on the hour or half hour. There is no constraint on either the number of hours that can be covered by each time band, or whether the time band applies to all or only part of a day.

Figure 2.4 Southern Electric Power Distribution time bands for half hourly metered properties

Time Bands for LV and HV Designated Properties			
Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday (Including Bank Holidays) All Year	16:30 - 19:30		
Monday to Friday (Including Bank Holidays) All Year		07:00 - 16:30 19:30 - 22:00	
Monday to Friday (Including Bank Holidays) All Year			00:00 - 07:00 22:00 - 24:00
Saturday and Sunday All Year		09:30 - 21:30	00:00 - 09:30 21:30 - 24:00
Notes	All the above times are in UK Clock time		

Source: Scottish and Southern Electricity Networks.

2.6 North America

We looked at four markets in North America, the Canadian province Ontario and the three US states of New York, Washington, and Texas. While these four markets have slightly differing structures, they all use a public hearing process to set distribution prices.

2.6.1 Ontario

The Government of Ontario, through the Ministry of Energy, sets the overall policy for the energy sector. It does this mainly through laws and regulations. The Ontario Energy Board (OEB) regulates Ontario's energy sector. As an independent government agency, its goal is to promote a sustainable and reliable energy sector that helps consumers to get value from electricity services. The functions of the OEB include licensing distribution companies, also called utilities, making and enforcing rules and customer service standards, and reviewing delivery rates for Ontario's electricity distributors.

Section 57(a) of the Ontario Energy Board Act 1998 (OEB Act) requires that distributors hold a licence to operate an electricity distribution system. Clause 11 of the licence stipulates that the distributor shall not charge for connection to the distribution system, the distribution of electricity, or the retailing of electricity except in accordance with a Rate Order of the OEB.

The OEB's authority to set rates for transmission is set out in section 78 of the OEB Act. The key test is that the rates or payments must be "just and reasonable". In most cases the OEB requires distributors to go through an extensive review, every five years, of their costs of providing service to their customers. This in effect creates a five-year cycle. Each year, distributors apply to the OEB to change their rates. In year one, in the rate setting plan most commonly selected by distributors, there is an intensive and public review of the utility's projected costs, commonly called a cost-of-service review. Following the initial setting of rates in the first year, years two to five will most commonly involve formulaic rate increases.[39]

A comprehensive rate application has three main components: the business plan (along with supporting documentation and reports); historical and forecast information; and rate models that show the derivation of specific proposed rates based on the data. The OEB has developed a set of rate models for electricity distributors which facilitate the review of rate applications and which distributors are required to use.

The OEB reviews each rate application through a public hearing process. Documents are posted on the OEB's website and updated as the OEB reviews the application. Consumer groups and other affected groups may also take part in the process and provide comments. For larger, or more complex cases, the hearing will include an open meeting which anyone can watch in person or listen to via a webcast on the OEB's website.

At the conclusion of the review process the OEB decides whether or not to approve any or all of the application and then sets the rates for the distributor to charge. The onus is on the utility to demonstrate that its rate proposals are just and reasonable. If the OEB determines that the proposals are not just and reasonable, then it may set other rates (or payment amounts) which it determines are just and reasonable.

Principles considered when reviewing rate applications

When making decisions on rate applications the OEB considers its objectives, listed in section 1(1) of the OEB Act, as the main principles of the distribution rate-setting. These objectives are:

- To protect the interests of consumers with respect to prices and the adequacy, reliability, and quality of electricity service.

[39] Ontario Energy Board. Backgrounder: The delivery charges on your electricity bill (2025) https://www.oeb.ca/sites/default/files/backgrounder-2025-distribution-rates.pdf

- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale, and demand management of electricity, and to facilitate the maintenance of a financially viable electricity industry.
- To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
- To facilitate the implementation of a smart grid in Ontario.
- To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission and distribution systems to accommodate the connection of renewable energy generation facilities.[40]

2.6.2 New York

Responsibility for distribution pricing in New York sits with the New York Public Service Commission. The Commission is responsible for overseeing the performance of electric corporations to ensure that they provide safe, adequate, and efficient services at just and reasonable rates, with concern for the environment.[41]

A rate case is the formal process used to determine the amount to charge customers for electricity, and distribution, provided by regulated utilities. The cases proceed in an entirely public and open process and are a primary instrument of government regulation. During rate cases interested persons may intervene and become parties in the case. Typical intervenors include industrial, commercial, and other large-scale users of electricity, public interest groups, representatives of residential, low-income, and elderly customers, local municipal officials, and advocacy groups.

To begin the rate case, the distributor submits a filing to demonstrate the need for a rate increase. The filing is required to have estimates of expenses, including operating expenses (labour, pension costs, materials, and fuel), depreciation costs, taxes, a return on investor-provided capital, and recognition of plant additions and capital expenditures.

The New York Department of Public Service provides staff who are charged with analysing the rate filing and representing the public interest. The team includes lawyers, accountants, engineers, economists, financial analysts, and consumer service specialists, who audit and investigate the distributor's proposals. The Department of Public Service staff typically develop an opposing position and counterproposal to the rate filing. Other interested groups can also file testimony and

[40] Ontario Energy Board. Report of the Board. Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. https://www.oeb.ca/sites/default/files/uploads/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf

[41] New York State Department of Public Service. Electric. https://dps.ny.gov/electric

challenge the distributor's filing. A judge is assigned to preside over the case, hear all the evidence, and provide recommendations to the Commission.

When the testimony filed by staff and/or other interested groups is received, rebuttal testimony from the distributor is allowed and hearings with cross-examination of expert witnesses are conducted. At this stage groups participating in the rate case may negotiate a settlement of the issues and submit it to the judge for review.

Initial and reply briefs are then filed with the judge who may issue a recommended decision. Finally, additional briefs are filed with the Commission, deliberations are held at public meetings, and a written order is issued resolving all outstanding issues and matters necessary to determine the distributor's revenue requirements and the amounts to charge customers.[42] The Commission is required to make a decision within 11 months of a rate case being filed.

2.6.3 Washington

The Washington Utilities and Transportation Commission regulates private, investor-owned electric and natural gas utilities in Washington. The Revised Code of Washington directs the Commission to regulate, in the public interest, the rates, services, facilities, and practices of all persons engaging within this state in the business of supplying any utility service or commodity to the public for compensation.[43]

It is the Commission's responsibility to ensure distributors provide safe, reliable, and equitable service to customers at reasonable rates, while allowing them the opportunity to earn a fair profit.[44] Distributors must receive approval from the Commission to adjust the rates they charge. These formal requests, known as general rate cases, are adjudicated proceedings with a judge, parties, evidence, and hearings.

A distributor is allowed to earn a fair rate of return (profit) on its investments. The rate of return approved by the Commission must be sufficient to attract investors to make investments in the company in order to replace old equipment and install new equipment to meet increasing demand.

Under the Revised Code of Washington, the Commission must establish rates that are fair, just, reasonable, and sufficient. These terms have been identified as "fair to customers and to the Company's owners, just in the sense of being based solely on the record developed in the proceeding following principles of due process of law, reasonable in light of the range of possible

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[42] New York State Department of Public Service. Major Rate Case Process Overview. https://dps.ny.gov/major-rate-case-process-overview#:~:text=A%20rate%20case%20is%20the,government%20regulation%20of%20these%20industries.

[43] Washington State Legislature. Revised Code of Washington. General powers and duties of commission. https://app.leg.wa.gov/rcw/default.aspx?cite=80.01.040#:~:text=(3)%20Regulate%20in%20the%20public,to%20the%20public%20for%20compensation

[44] Washington Utilities and Transportation Commission. Energy. https://www.utc.wa.gov/regulated-industries/utilities/energy

outcomes supported by the evidence, and sufficient to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms."[45]

The setting of rates is accomplished through a formal process, set out in Washington's Administrative Procedure Act, which includes formal evidentiary hearings, discovery, limitations on ex parte contact, and judicial review. Through this process the revenue requirement[46] of the distribution company will be agreed before rates charged for use of the distribution network are set.

The total revenue requirement is then allocated to the different customer classes served by the distributor proportionate to the estimated future electric load for the class. The rate design for each class is established reflecting how much of the revenue requirement will be collected as a per-customer charge, and how much in the volumetric charge. The revenue requirement for each class is then divided by the estimated load to determine a cost per kWh sold.[47]

2.6.4 Texas

As in New Zealand, Texas has a deregulated market for the retail sale of electricity. Also, like New Zealand, distributors in Texas have a monopoly on the delivery of electricity. Distributors in Texas are responsible for maintaining the poles, wires, and meters that deliver and measure the electricity consumed by a home or business. In addition, the distributors read the meters and restore service when there is a power outage.

The Public Utility Commission of Texas regulates the distributors. The Commission sets the rates for transmission and distribution services, establishes reliability and safety standards, and ensures that all customers and retailers are treated the same when it comes to the delivery of electricity to homes or businesses. Like the other states in this report, this is done through a rate case process that typically takes anywhere from six months to a year to reach a final resolution.

Distributors are required to file a petition with the Commission and with the different municipal authorities in the distributor's service territory for approval to change its base rates. The distributor is also required to notify the public, and its customers, that a filing has been made and inform each customer of their ability to participate in the Commission's evaluation of the distributor's petition to change its rates.

After filing the petition an administrative judge is assigned, and interested parties can request to join in the review process. These parties typically include Commission staff, municipal and county governments served by the distributor, large industrial power users, and other parties with an

[45] Washington Utilities And Transportation Commission. v. Puget Sound Energy, Inc., https://earthjustice.org/wp-content/uploads/order-ue-121697-ue-130137.pdf

[46] The sum total of the revenues required to pay all operating and capital costs (includes a return on investment) of a distributor to provide services.

[47] Jones, P.B. (2017). Effective Regulation and Rate of Return 101. https://app.leg.wa.gov/committeeschedules/Home/Document/172347

interest in the filing. A full review of the distributor's petition is then conducted before any decision is made.

Following completion of the review, the distributor and the participating parties may offer additional information and written testimony to clarify issues and resolve differences. The parties may also conduct negotiations through which an agreement can be reached. This agreement would be submitted to the Commission for their review and approval. The Commission has the ultimate authority to approve the distributor's petition to change rates. If no agreement can be reached, the Commission has the authority to issue a decision based on its understanding of the merits of the case.

2.7 Applicability of international approaches to New Zealand

The focus of electricity distribution pricing regulation in the international markets has predominantly been on achieving economic efficiency, and the majority of the approaches reviewed for this report do not consider the impact on consumers facing energy hardship. The policy actions identified have predominantly been based on the premise that electricity distribution is a natural monopoly, and a key desired outcome is efficient and "fair" prices, which is those which allow electricity distributors to make a "fair return" on their network investments, while ensuring that consumers face prices which are "subsidy-free".

2.7.1 Approaches to distribution pricing that could be applied in New Zealand

New Zealand's current approach to distribution pricing is consistent with the reviewed approaches in Australia and Europe. In all the markets we looked at, a revenue cap is initially set, then prices for consumers are determined based on the use of the distribution network by a user group, for example residential and small businesses, and the cost of this use of the network. In all the markets assessed, the price for consumers includes a fixed charge, either daily, weekly, monthly, or quarterly, and a variable change for the volume of electricity consumed. However, there is scope to increase the role of the Electricity Authority before prices are set.

Currently the Electricity Authority has an indirect role in price setting. Distributors are required to follow the 2019 Distribution pricing principles, publish their pricing methodology and discuss their pricing plans and progress with the Electricity Authority each year. Distribution pricing scorecards are the Electricity Authority's main tool to encourage distributors to adopt more efficient pricing, through regular monitoring and discussion of progress, and the publication of the scorecards.[48]

If New Zealand wanted to increase the Electricity Authority's role in pricing distribution it could consider the models in Europe and Great Britain which have greater direct involvement of the regulatory agency in approving the methodology used and/or the prices charged to consumers before they are put in place. In Australia (excluding Western Australia and the Northern Territory)

[48] Electricity Authority (2023). Distribution pricing scorecards 2023 Information paper. https://www.ea.govt.nz/documents/3883/Information_paper_-_2023_Distribution_pricing_scorecards.pdf

and many of the European markets the regulator responsible for electricity distribution is required to review the methodology used and approve proposed prices before they are put in place by the distributor.

An alternative for New Zealand could be to adopt a common distribution pricing methodology similar to Great Britain. This would ensure a common methodology was applied across all of New Zealand's distribution networks. If New Zealand wanted to include principles that address energy hardship the use of a common methodology with a supporting model, provided by the regulator or industry, like the CDCM model, would be an effective alternative.

Although it provides the opportunity for review and public input before prices are set, the time and resources required means it is unlikely New Zealand would adopt the North American hearing model.

2.7.2 Approaches to distribution pricing for those facing energy hardship

During the course of our research, we were unable to identify any specific examples of approaches to distribution pricing that acknowledge:

- Electricity is an essential service
- Many households are not able to easily switch power use to off-peak times
- Raising tariffs will be likely to increase hardship for those consumers who cannot load switch, and/or lack the financial resources required to invest in energy efficient appliances
- Small businesses unable to load shift may also face cost increases as distribution charges rise

If New Zealand were to explicitly pursue an approach that incorporates energy hardship into distribution pricing it would be an outlier amongst markets with retail competition for residential and small business consumers. However, New Zealand could strengthen the principle that "development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives."

For example, Australia's NER pricing principles take the requirement to consider consumer impacts a step further requiring that "a distributor must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the distributor considers reasonably necessary having regard to... (3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services."

3 Potential effects of distributed energy resources

Distributed energy resources (DER), such as electric vehicles (EVs), solar panels, batteries, and smart appliances are changing how New Zealanders consume, generate, and manage energy. The growth and emergence of DER is enabling consumers to generate and/or store their own energy, and either consume it or feed it back into the local grid. DER enables consumers to play a more active role in the use and operation of the electricity network and demand response.

DER includes mostly small-scale power generation or storage technologies that are implemented closer to end-uses of the electricity sector. These resources are generation that is connected indirectly to the grid through a local or secondary network. For example, this includes EV charging, solar panels, battery storage, hot water cylinders, in-home heating, and air-conditioning.

DER, that can be controlled, are often referred to as flexibility services as output or consumption of electricity can be adjusted (up or down) on demand.[49] Through effective demand-side management, flexibility services can reduce consumer, grid, or local or secondary network, and generation peak demand. This can enhance grid, local, or secondary stability. Uncontrolled DER (such as solar panels or batteries without control mechanisms) provide no support to the electricity delivery chain during winter peak demand times. Both controlled and uncontrolled DER can provide value to consumers by lowering electricity bills through generating their own electricity, albeit with an upfront capital cost required.

But specifically, controlled DER (that deliver flexible services) have the potential to deliver the most benefits to consumers, distributors, the distribution network and the electricity market. For consumers that can leverage flexible services, specifically EV charging and water or in-home heating, they will have the ability to reduce electricity bills over the long-term and decrease their reliance on the network. For distributors, DER and flexible services have the potential to defer investment in network infrastructure that would be required to meet the future increases in electrification needs and demand. For the electricity market, DER and flexible services have the potential to reduce demand on generation at peak generation times, by increasing the load factor of the delivery chain.

DER will play a critical role in New Zealand's energy transition

As New Zealand looks to decarbonise the economy and phase out use of fossil fuels, the role of electricity takes priority. To achieve climate change goals set by New Zealand, electricity generation capacity must increase in order to accommodate the widespread electrification of the economy. Climate and weather events also pose a growing risk to electricity distribution and infrastructure. New Zealand's first Emissions Reduction Plan (ERP) stated that "increasing demand flexibility and

[49] Supra n 2.

distributed energy resources will help to manage electricity infrastructure risk".[50] This means that the role of distribution and retailer pricing takes on increased importance. Similarly, the implementation and management of DER grows in importance as another supporting measure, particularly to intermittent generation.

The intermittent generation of solar, for example, will significantly impact the cost of energy, creating shoulder periods that are particularly pronounced in winter, with prices increasing when solar is not available. During these periods, for households in energy poverty, increases in network and electricity prices will make basic necessities, like electric heating, less affordable at the time it is needed the most.

This makes the combination of DER and flexibility services the most effective lever in New Zealand's energy transition. Effective, well-managed, and widespread implementation of DER and flexibility services will provide for significantly improves in overall network efficiency and capacity, while also deferring potential investment required from distributors. Distribution pricing must find a balance between maintaining economic efficiency and incentivising DER investment. Incorporating effective demand-side management is essential in order to ensure the reliability and security of the distribution network, while also improving efficiency. As flexibility services and DER continue to become more prevalent and evolve, how distributors manage this market will be critical for the overall distribution network.

DER and flexibility will reduce the overall cost of the required transition, enhancing network resilience, security, and affordability. An industry reported estimated that a smarter, more flexible electricity system could save approximately $10 billion in costs required for New Zealand's 2050 transition.[51] While this analysis indicated that household energy bills would, on average, decrease the cost relative to the other scenarios proposed, it does not explicitly detail to what degree vulnerable consumers would benefit.

A report from the United Kingdom found that there is limited evidence about how low income and vulnerable consumers could participate in smart energy products and services of the future.[52]

As they serve a critical role in New Zealand's energy transition, the growing investment in and integration of DER and flexibility services raises concerns about the ability for vulnerable consumers

[50] Ministry for the Environment. Te hau mārohi ki anamata. Towards a productive, sustainable and inclusive economy. https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf

[51] Ministry of Business Innovation and Employment. Measures for Transition to an Expanded and Highly Renewable Electricity System. https://www.mbie.govt.nz/dmsdocument/26909-measures-for-transition-to-an-expanded-and-highly-renewable-electricity-system-pdf

[52] Department for Business, Energy & Industrial Strategy. How can innovation deliver a smart energy system that works for low income and vulnerable consumers? https://assets.publishing.service.gov.uk/media/60cc5d47d3bf7f4bd6a9bd29/project-involve-smart-energy-system-low-income-vulnerable-consumers.pdf

to participate in this future. The underlying challenge in this transition is ensuring opportunity for and participation from all consumer groups, specifically vulnerable consumers such as low-income households, households in rental premises, and small businesses. These consumer groups are less likely to be in a position to invest in and leverage the benefits of DER and flexibility services. A cross-subsidy could be generated from those in this position to those who can integrate DER, further disadvantaging vulnerable consumer groups. This remains a critical challenge.

The FlexForum stated that DER and flexibility can be used to build a more equitable power system, to avoid vulnerable households paying more than their fair share for the transition.[53] The opportunity is there but there are serious risks at hand.

To realise the potential benefits for all of New Zealand in the energy transition, without any adverse impact on vulnerable consumer groups, all consumer groups must be involved. This will require innovative solutions and approaches towards providing the opportunity for vulnerable consumers to participate in this future.

3.1 Implications of DER

DER have a wide range of implications on the electricity network for both consumers, the grid, local and secondary networks, and generation. A characteristic of further DER integration is the role of flexible traders and flexibility service markets. As this evolves, coordinated management between industry, consumers, electricity market participants, investors, appliance manufacturers/importers, regulators, and government will be required to realise the benefits of DER and advance New Zealand's energy transition. This will require developing processes and capability to transact and coordinate flexibility, and to improve the cost reflectiveness of price signals and provide greater market access.[54] Failure of this coordination will increase the cost of electricity.

Fundamentally, DER are changing the overall delivery, use, and management of electricity. Further penetration of DER and adoption of flexibility services poses complex challenges for distributors and the distribution network. There are also challenges for generators. An oversupply of intermittent generation has significant implications on wholesale price and investor rates of return.

These challenges are often not independent. Responses and reactions to one challenge have flow-on effects towards others.

An underlying benefit of DER integration and flexibility services is the potential to reduce distribution network capacity investment by improving network efficiency and consumers' reliance and demand on the grid. Specifically, integration of DER can defer some of the required investment in network infrastructure potentially needed to meet expected future electricity demands. On the contrary, however, the current long-life physical systems and infrastructure of the distribution

[53] FlexForum. A Flexibility Plan 1.0: what we need to do and how we can do it? https://www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf

[54] Ibid.

networks were not designed for widespread use of DER by households.[55] Current infrastructure was designed mostly to accommodate only one-way flows. This means that reliability challenges and costs may arise from increased two-way flows on distribution networks if voltage and thermal capacity limitations are not addressed in response to increasing bi-directional flows. Furthermore, DER integration may require distributors to find alternative ways to manage DER and flexible services, and the impact they have on the grid, given the intermittent and unpredictable nature of some technologies.

This is a core example of the complexity involved in the integration of DER and the impact on the electricity sector. Nonetheless, it is a vital opportunity in New Zealand's energy transition that will require careful, coordinated, and effective management. The potential for cost-reducing benefits, for households and small businesses, as well as industry and the government, is significant.

The following section outlines potential implications that DER will have on consumers and distributors (including distribution networks). We present these implications separately, but it is important to emphasise that many of these implications are interlinked and overlap.

3.1.1 Consumers

Enabling consumer choice

The integration and implementation of different DER allows consumers to be more actively involved in the demand side management of electricity, providing more choices about electricity use. For consumers that are in a position to afford and leverage DER, they are empowered to use and generate electricity from alternative sources which can ultimately decrease their reliance on the network. However, those that cannot afford DER, or are in rental premises, will not benefit and may be worse off.

Cost impacts for consumer groups

The installation and adoption of DER can lead to cost reductions for consumers that are able to afford the capital cost, while also potential cost increases for those unable to.

For consumers that are in a position to afford DER, By generating their own electricity (such as solar) or implementing energy efficiency measures (such as smart systems), these consumers are able to reduce their reliance on the local network, which results in lower energy bills. In some instances, consumers can receive financial benefits and incentives through providing electricity back into the grid. These benefits would be best leveraged through consumers embracing flexibility in their energy use, if they are able to do so.

On the contrary, however, consumers that are unable to afford the upfront capital cost required, or are in rental premises, will receive cost increases.

[55] Orion & Wellington Electricity. Resi-Flex Unlocking the value of residential flexibility https://www.oriongroup.co.nz/assets/Company/Innovation/Resi-Flex-Public-Report_Release-1.pdf

Energy independence

Consumers who do not own DER are largely dependent on the local electricity network. Therefore, they are exposed to the risks associated with outages, weather events, or other disruptions. DER, particularly if they are coupled with battery storage or other storage capacities, provide consumers with a level of electricity independence. During such events, consumers with DER, such as solar panels with batteries, with the correct set up can continue to generate and supply electricity to their household.

Given that the upfront capital cost required for DER can be a barrier for many vulnerable households, the risk associated with such events is further pronounced for these already disadvantaged households.

Environmental benefits

The adoption of DER can contribute to improved environmental outcomes with consumers able to reduce their carbon footprint by decreasing their use of fossil fuels.

3.1.2 Distributors

Grid variability

One of the most significant implications of DER penetration is the variability introduced to the electricity network. An underlying characteristic of most DER is their intermittent nature. This variability can have both positive and negative implications for distributors and the network.

On the one hand, DER has the potential to reduce overall electricity demand during peak times through flexibility, with consumers being able to switch demand patterns to periods that match up with solar generation when it is available, use electricity previously stored in those peak times, or adopt efficiency measures. Effective and appropriate management is required to realise these benefits.

On the other hand, the intermittent nature of most DER, and the optionality it provides for consumer behaviour, makes it challenging to predict and manage electricity flows during both off-peak and peak times. This requires distributors to find and implement different strategies or measures for ensuring local and secondary network stability.

Voltage management

Following on from the above, with widespread adoption of DER, the challenge of voltage management becomes more complex and pronounced. DER will create intermittent fluctuations in electricity generation, demand, and consumption. The flexibility that DER can provide can also work to change traditional peak and off-peak load demand. For example, solar panels will cause increased voltages during peak generation times throughout the day and battery storage capabilities might support voltages during peak demand times. In maintaining overall network reliability and security, distributors must carefully manage this implication created by widespread DER penetration.

Introduction of more two-way flows

DER will result in more two-way flows of electricity in the network. That is, consumers who generate their own electricity, and do not consume all of what is generated at the time, can input that electricity back into grid. This will be most common with solar generation but, additionally, some EVs already come equipped with vehicle to grid capabilities that allow them to inject electricity back into the grid. Traditional infrastructure was designed for one-flows which poses a significant challenge for distributors and the network infrastructure, specifically in regard to voltage management and thermal capacity. Continued uptake of DER will require upgrading existing systems and finding ways to measure the widespread increase in two-way flows.

This dynamic also presents a potential change to traditional distributor-consumer relationship. Consumers with DER and the capabilities to inject electricity back into the grid might have different expectations or needs from providers. This changing relationship may require distributors to adapt their engagement strategies.

Adaptation to revenue models

Continued DER penetration, particularly with consumers generating their own electricity and reducing their dependence on the network, will require distributors to adapt or change their traditional revenue models. This may result in increases to network charges, meaning that those consumers who cannot afford DER, or are in rental premises, will need to pay more for their electricity.

Cyber security risks

Further DER penetration across the market opens the potential for cybersecurity threats and attacks. This will require distributors and suppliers/manufacturers to develop advanced measures and practices to protect critical electricity infrastructure and maintain the reliability and security of the network.

3.2 Implementation and integration of DER in New Zealand

In line with overall consumer trends, and various government policies, the investment in and integration of DER and flexibility services in New Zealand is increasing each year. There has been notable growth in the adoption of distributed generation (such as solar panels) and further widespread implementation of appliances providing flexible services (such as smart appliances). But in terms of generation, DER still remains a small proportion of New Zealand's total installed capacity at just below three percent.[56] It has also occurred at a pace that lags behind other International Energy Agency (IEA) countries, including Australia.[57]

There is a lot of uncertainty around the future pace of different DER uptake and adoption of flexibility services in New Zealand, but there is potential for uptake to happen quickly and in localised situations. The absence of DER uptake occurring in a predictable manner will cause difficulties and complexities for distributors and the network.

There is evidence to support that consumer behaviour is changing with more households now interested in ways to reduce home energy use. The Council's 2023 electricity consumer behaviour survey found that four in ten households are more interested in finding ways to reduce their energy use. Although households may want to find ways to change energy consumption patterns, and reduce costs, this is not possible for all. There are particular segments of the market, specifically vulnerable consumers, low-income households, or people in rental premises, who are not able to adjust electricity use. The ability to use electricity during off-peak times does not work with 73 percent of households' schedules. There are also concerns around accessibility of such technology. High income earners were much more likely to own smart devices and be benefitting from the energy savings these devices can provide, compared to low-income households.

MBIE acknowledged that New Zealand's flexibility market is immature and noted a few factors limiting deployment of demand-side participation that were observed by the EA's Market Development Advisory Group (MDAG):

- Consumers' awareness and understanding of the possibilities for demand-side participation, and the various forms that could take.
- The incentives faced by consumers to manage their own consumption, particularly shifting consumption from one time period to another. With the prevalence of retail tariffs which are constant throughout the day, there is no financial incentive to shift consumption.
- The degree to which customers have to – and want to – actively manage demand side flexibility, including the trade-off between the service they require (e.g., heating, cooling, and more recently state of charge of their electric vehicle) and how much flexibility is used to manage their own consumption costs.

As identified by the Electricity Authority, New Zealand "has an opportunity now, to get the settings right to maximise the uptake and the value that DER can provide".

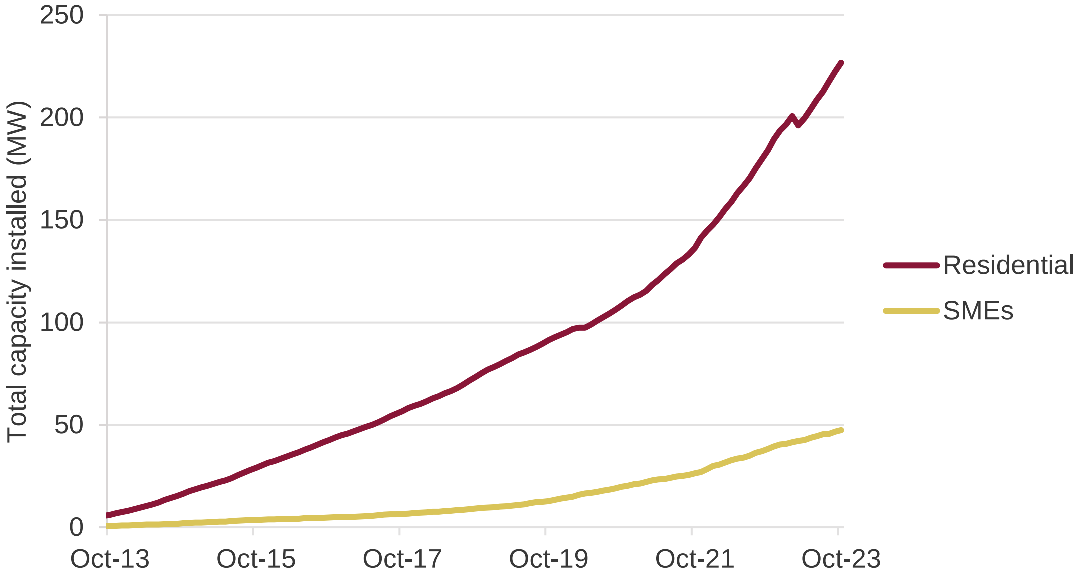
[56] Electricity Authority. Installed distributed generation trends. https://www.emi.ea.govt.nz/Retail/Reports/GUEHMT?DateFrom=20130901&DateTo=20231130&MarketSegment=All&FuelType=All_Total&Show=ICP_Rate&_si=v|3

[57] International Energy Agency. New Zealand 2023. Energy Policy Review https://iea.blob.core.windows.net/assets/124ce0b0-b74e-4156-960b-bba1693ba13f/NewZealand2023.pdf

Solar is New Zealand's fastest growing form of DER

Solar currently contributes one percent to New Zealand electricity supply. However, there are currently proposals for larger scale solar farms In regard to the smaller consumer market (as depicted in Figure 3.1), there was just under 230 MW of solar installed on residential buildings, and 47 MW of solar installed on small-to-medium enterprises (SMEs) in 2023. Although the total capacity of solar installed by residential and business consumers has been increasing steadily over the past decade, the number of new installations annually has stalled somewhat in the last few years, fluctuating between 500-900 installations annually since 2021. This will be in part to rising costs for critical components.

Figure 3.1 Total solar capacity installed (MW), 2013 - 2023



Source: Electricity Authority

It is expected that solar installation, both residential and by businesses, will continue to increase in the future. At a broader level, the majority of all new connection enquiries that are made to Transpower are for solar connections. This indicates a wider market trend, with large scale solar farms becoming more prevalent, as well as wind farms.

Managing this shift will be challenging and complex for distributors and the network. The intermittent nature of solar panels creates a level of uncertainty and unpredictability, particularly if coupled with battery storage capabilities. Generation from solar also varies significantly throughout the year, it is estimated that on winter dark overcast days, solar generation is in the order of 10 percent of rated capacity.

The continued penetration of solar into the market, and further integration of solar by households and businesses, will be critical in New Zealand's wider energy transition. Similarly, it will be a leading factor in reducing costs for consumers that can afford it over the long-term. It is important to recognise that the benefits associated with solar fluctuate significantly.

The upfront cost, however, will still remain a barrier for many consumer groups, including low income, rental, and vulnerable households and small businesses. These consumer groups will not be in a position to reap the benefits that solar (particularly with battery storage) provides through flexibility in electricity demand and use as they will not be able to install generation.

Electric vehicles (EVs) are a growing proportion of the fleet

The penetration of electric vehicles (EVs) in New Zealand is progressively increasing. As of December 2023, EVs represented 27.4 percent of the light vehicle fleet in New Zealand (this includes plug-in hybrid and battery electric).[58] This has steadily increased over the past few years, in part due to increasing market penetration and government policy. It is widely expected that battery EVs will continue to become more prominent in the market and will grow as a share of the wider fleet.[59]

EVs act as a form of DER as they have decentralised electricity storage capacity. When EVs are charging they are often connected to the local grid and are serving as electric batteries. Most of the time spent charging (82 percent) occurs within residential homes and thus connected to local grids.[60] This poses a growing risk for distributors management of the local network. Furthermore, some EVs come equipped with two-way flow capabilities, with the ability to inject electricity back into the grid. This creates an opportunity for EVs to offset households' current power bills but, again, poses an additional challenge for distributors.[61]

It has been identified that clustering or localised adoption of EVs and EV chargers has posed a significant risk to distributors. This dynamic has resulted in unexpected and sudden voltage and capacity management issues. The uncertain geographic uptake of EVs is a complex challenge needing to be navigated and managed.

Flexible services

Outside of the more well-known forms of DER (such as solar and EVs), there are a range of alternative technologies available to consumers that similarly provide flexible services. This includes smart appliances for hot-water heating, in-home heating, lighting systems, smart meters, etc. Integrating smart appliances can contribute to reducing network load for local distributors.

These technologies enable consumers to adjust electricity use in response to a signal or instruction which can be internally or externally prompted. The Council's behaviour survey indicated that just

[58] EVDB. NZ EV Market Share: Light Vehicles. https://evdb.nz/ev-percentage-nz.

[59] Energy Efficiency and Conservation Authority. Improving the performance of electric vehicle chargers https://www.eeca.govt.nz/assets/EECA-Resources/Consultation-Papers/EV-charging-Green-Paper-8-August-2022.pdf

[60] Ibid.

[61] Concept Consulting. Shifting gear How New Zealand can accelerate the uptake of low emission vehicles https://www.concept.co.nz/uploads/1/2/8/3/128396759/ev_study_rept_2_v2.0.pdf

under half of New Zealanders who would want a smart appliance would want to manage it themselves, not having it externally controlled.

Innovation is a driving force behind the growing availability and applicability of these technologies. Although these flexible services offer a lower-cost and easier to implement alternative to technologies such as solar and EVs, they can still be regarded as a premium product. This means that the upfront cost and inability of some households to change electricity usage behaviour to the leverage the flexibility remains a significant barrier. Consequently, these households are still at risk of facing increasing costs. As New Zealand's flexibility market continues to mature, managing the flexibility market and its role in balancing electricity distribution will be critical. There will need to be significant consideration towards finding innovative ways to enable vulnerable consumer groups to engage in this market and receive cost saving benefits.

3.3 DER and flexibility services internationally

The integration of DER, particularly flexibility services, is a globally identified opportunity in countries' energy transitions for a net-zero carbon future. This opportunity is also a significant challenge for actors and participants across the electricity sector, including distributors, generators, and the network.

Many countries are at different stages in navigating the widespread challenges that are associated with their respective energy transitions, and the critical role that DER will play in facilitating this. Uptake of different DER varies considerably between countries as well. It is clear though that many nations, from Australia to Europe, are placing strong emphasis on finding methods and measures for integrating flexible DER in an effective, cost-reducing, and collective manner.

3.3.1 Australia

The uptake of DER, specifically solar, is widespread in Australia, with the country having the highest uptake of solar globally.[62] In 2020, small-scale solar was responsible for 23.5 percent of Australia's clean energy generation, contributing 6.5 percent to the country's total electricity.[63] Solar installations vary significant by state but approximately three million households have rooftop solar in Australia, which equates to more than 30 percent of all households.

There are a number of reasons that have contributed to driving the widespread installation of solar in Australia, including the abundant sunlight across the country, as well as government incentives and policies. Increasing electricity rates have also pushed consumers towards alternative energy use.

[62] Department of Climate Change, Energy, the Environment and Water. Solar PV and batteries https://www.energy.gov.au/households/solar-pv-and-batteries

[63] Clean Energy Council. Solar. https://www.cleanenergycouncil.org.au/resources/technologies/solar-energy

A method that Australia initially used to incentivise investment and adoption of solar was a feed-in tariff (net). A feed-in tariff is a rate that consumers are paid by their energy retailer for electricity that is exported back into the grid. Therefore, consumers who installed solar generation capabilities were able to receive a tariff in return for any electricity that was generated by solar and not consumed by them.

This method, however, resulted in significant consequences. Feed-in tariff prices fell considerably from the initially propped up price which in turn decreased the value that solar delivered did not have a suitable rate of return given the investment cost. This is largely in part due to solar generating electricity during the day when demand is low, and thus excess electricity is not worth as much to distributors. The further adoption of advanced technologies, such as batteries that allow surplus electricity to be stored and used later, will improve this dynamic. The feed-in tariffs also generated a significant cross-subsidy from consumers that were unable to invest in solar, further disadvantaging these consumer groups.

Across Australia, at a federal and state level, there are various rebates or financial incentives that are offered to consumers which encourage solar installation, as well as battery installation. This includes, to name a few:

- New South Wales (NSW) provides the Empower Homes Program that offers interest-free loans for solar battery systems, with loans of up to $14,000 for solar and $9,000 for adding a battery to an existing solar system.
- Victoria provides the Solar Homes Program that offers rebates for solar panels and solar batteries, with rental properties also included in the scheme.
- The Australia Capital Territory (ACT) provides rebates for solar battery installations through the Next Generation Energy Storage Program.[64]

In addition, households can also access and earn the federal government's Small-scale technology certificates (STCs) through the Small-scale Renewable Energy Scheme.[65] STCs can be sold to recoup a portion of the installation costs of solar and their value varies considerably across the country, with it also dependent on the proposed system size.

This widespread and rapid adoption of DER across Australia has pushed forward the issue of needing to address the impact of such technologies on the distribution network. In response, the Clean Energy Council published a report that provided a roadmap to address the challenges that

[64] Solar Emporium. Best Solar Rebate And Incentive Guide for Australia. https://solaremporium.com.au/blog/best-solar-rebate-and-incentive-guide-for-australia/

[65] Clean Energy Council. Government Programs.https://www.cleanenergycouncil.org.au/consumers/buying-solar/government-programs

distributors, regulators, governments, and policy makers will face in this transition to a DER future.[66] This report acknowledged the importance and value of DER adoption for households and the nation's sustainable commitments but recognised the challenges associated with this. These included infrastructure design, uncertainty of DER generation, voltage management, and access and equity.

The Energy Security Board (ESB) in Australia also commissioned research that undertook a rapid evidence review of information related to the barriers and enablers for consumers to be rewarded for access to their flexible DER and energy use.[67] Core findings included understanding and recognising the diversity of consumers, and the factors that influence the motivation, ability, and opportunity of a household or SME to participate. The review also identified the importance of having a tailored approach, which is based on consumer groups, location, and specific DER technology.

The widespread use of solar in Australia has also shown the problems that develop with significant generation connected to low voltage networks. While it seems logical that it is more efficient to locate generation close to consumption, too much generation can cause network congestion issues. In areas of Australia, the number of solar customers on sections of network has caused:

- Significant voltage issues, with the result that many solar systems cannot generate into a low voltage network, and the owners of the system do not receive the full benefit of the investment. This is because networks were not designed for two-way electricity flows.[68]
- Wholesale price distortions at peak solar generation times.[69]

3.3.2 United Kingdom

Across the UK, a total of 1.4 million solar PV systems have been installed (MCS certified), with just under 190,000 installed in 2023.[70] Since late 2022, however, growth in the uptake of solar installations has stagnated between 15,000 to 20,000 per month. This could be partly explained by the increase in the average installation cost per KW, which increased from £1,698 in May 2022 to £2,077 in May 2023. Of the owners of solar systems 69.8 percent were owner-occupied dwellings,

[66] Clean Energy Council. The distributed energy resources revolution a roadmap for Australia's enormous rooftop solar and battery potential. https://assets.cleanenergycouncil.org.au/documents/advocacy-initiatives/the-distributed-energy-resources-revolution-paper.pdf

[67] ACIL Allen. Barriers and enablers for rewarding consumers for access to flexible DER and energy use https://www.datocms-assets.com/32572/1658964119-barriers-and-enablers-final-report-v2-352146-1-3-1.pdf

[68] Energy Networks Australia. Could the solar boom bust the grid? https://www.energynetworks.com.au/news/energy-insider/could-the-solar-boom-bust-the-grid/

[69] Australian Energy Regulator. Wholesale electricity market performance report 2022. https://www.aer.gov.au/system/files/Wholesale%20electricity%20market%20performance%20report%20-%20December%202022_0.pdf

[70] MCS Installation Database (MID). https://datadashboard.mcscertified.com/Welcome

13 percent were privately rented, and 15.6 percent were social rentals. Solar systems were the most prevalent small-scale renewable installations in the UK. What is also evident, and not unusual, is the large variation in the proportion of households with solar between geographical locations, with some areas having upwards of 15 percent of households owning solar, compared to only one percent in other areas.

The Office of Gas and Electricity Markets (Ofgem), Department for Energy Security and Net Zero, and Department for Business, Energy, and Industrial Strategy released the 'Smart Systems and Flexibility Plan 2022'.[71] This plan sets out a vision, analysis, and work programme for delivering a smart and flexible electricity system that will underpin energy security and the transition to net zero. This plan reiterates the opportunity that is provided by flexibility services (through DER), specifically involving demand-side response management.

Throughout the plan, it is emphasised that all consumers must have the opportunity to choose and benefit from flexible products and services (including DER), in order to fully realise the benefits from flexible services and to achieve overarching sustainable commitments. Furthermore, the underlying potential for cost reductions from deferring grid investment will be maximised if all consumer groups are involved. In ensuring this, the government had previously funded a project that identified how innovation might help low income and vulnerable consumers to participate in a smart energy system.[72] The rationale from this research was that "changes to the energy system raise a core concern about whether low income and vulnerable consumers will be able to participate in this future".

Findings from this research will assist the government in ensuring all consumers have access. In particular, the research identified six risks that could emerge as smart energy markets develop:

1. Low income and vulnerable consumers may not be able to afford to purchase smart products and services

2. Low income and vulnerable consumers may not benefit from smart products and services

3. Low income and vulnerable consumers face greater risks if the product or service fails to work as expected

4. Lack of data access reduces how much low income and vulnerable consumers benefit

[71] Department for Business, Energy & Industrial Strategy and Ofgem. Transitioning to a net zero energy system. Smart Systems and Flexibility Plan 2021. https://assets.publishing.service.gov.uk/media/60f575cd8fa8f50c7f08aecd/smart-systems-and-flexibility-plan-2021.pdf

[72] Chard R., Lipson M., Fleck, R. Fleck How can innovation deliver a smart energy system that works for low income and vulnerable consumers? https://assets.publishing.service.gov.uk/media/60cc5d47d3bf7f4bd6a9bd29/project-involve-smart-energy-system-low-income-vulnerable-consumers.pdf

5. Unequal distribution of system costs

6. Low income and vulnerable consumers experience problems that may impede the emergence of a smart energy market.

In order to enable the provision of products and services that low income and vulnerable consumers can use in a smart energy market the report recommends the following initiatives:

- Encourage relevant innovation projects to follow best practice, human-centred innovation processes

- Create a publicly funded innovation ecosystem that supports low income and vulnerable consumers.

Ofgem has made a separate call for input on what is needed to enable a larger proportion of consumers to transition to being flexible energy consumers.[73] In providing information for inputs, the published document details that to realise the benefits of flexibility technology and services customers need to be brought along the journey of demand-side response, which involves consumers adjusting their energy consumption in response to the needs and requirements of the energy system and being rewarded in return. A component of encouraging further adoption of flexibility amongst consumers is ensuring that vulnerable households are not left behind. This call for input acknowledges work undertaken by the Department for Business, Energy, and Industrial Strategy in the Inclusive Smart Solutions Programme.

The UK also released a code of conduct, the Household or Microbusiness Energy flexibility (HOMEflex) Code of Conduct, for facilitating household and business engagement in the flexibility market.[74] This was an important step required in the wider energy transition, establishing standard practices to regulate the growing market, protecting consumers, and managing providers of flexibility. An underlying aim of this code is to encourage consumer participation in the market through improved trust and transparency.

3.3.3 Nordic countries

Across Nordic countries, there is mutual understanding that the sustainable transition to a carbon-neutral future will lead to increased electrification of society and a much larger share of intermittent renewable energy sources (otherwise known as DER).

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[73] Ofgem. Smoothing the Journey: engaging domestic consumers in energy flexibility https://www.ofgem.gov.uk/sites/default/files/2023-08/Smoothing%20the%20Journey%20engaging%20domestic%20consumers%20in%20energy%20flexibility%20CFI%20final%20version.pdf

[74] Osborne Clark. HOMEflex Code of Conduct to revolutionise trust in energy flex market. https://www.osborneclarke.com/news/homeflex-code-conduct-revolutionise-trust-energy-flex-market

A report published by Nordic Energy Research summarises lessons that have been learned for facilitating the use of distributed flexibility across Nordic countries from various pilot-programs.[75] This research explored the role that distributors will play as proactive operators of the network. It noted that "market-based flexibility is one of the key tools that allows distributors to increase both their efficiency and their security of supply".

The five key recommendations on distributed flexibility identified were:

- Different local problems require different solutions for distributed flexibility
- Regulation on cost recovery and tariffs impacts a distributor's incentive to purchase flexibility
- The flexibility provider should be allowed to offer its resources to several bidders
- Priority access for the distributor to distributed flexibility connected in the distribution grid as an acceptable compromise to solve the coordination between the distributors and transmission system operators.
- Do not compromise on the requirements for data quality and automation, especially if local flexibility markets are established.

[75] Nordin Energy Research. Distributed Felxibility. Lessons learned in the Nordics. https://www.nordicenergy.org/wordpress/wp-content/uploads/2022/06/Report-Distributed-Fexibility-Lessons-leared-in-the-Nordics.pdf

Appendix A CEER Guidelines of Good Practice for Distribution Tariffs

In 2017 the Council of European Energy Regulators (CEER), a non-profit organisation in which Europe's national energy regulators, from the 27 EU-Member States plus Iceland, Norway and Great Britain, co-operate to protect consumer interests and to facilitate the creation of a single, competitive, and sustainable internal market for gas and electricity in Europe, released a report on Electricity Distribution Network Tariffs and CEER Guidelines of Good Practice.[76]

In the report the CEER identifies seven principles for the design of distribution network tariffs:

1. **Cost reflectivity:** For efficient use and development of the grid, as far as practicable, tariffs paid by network users should reflect the cost they impose on the system and give appropriate incentives to avoid future costs. To ensure that costs are allocated to those users who impose costs on the network, the right price variables should be chosen, that is, those variables that capture the need for investment or operation. The primary cost drivers of network provision are location, time of use, and power quality.

2. **Non-distortionary:** Costs should be recovered in ways that avoid distorting decisions around access and use of the network. Distribution network tariffs should not be a barrier to innovative market offers that will add value or reduce costs for consumers e.g. related to flexibility and energy efficiency.

3. **Cost recovery:** Distributors should be able to recover efficiently incurred costs. This key principle should also provide efficient long term management conditions to ensure a sustainable development of the electricity network, not only to benefit today's customers of the network but also to safeguard the needs of future customers at reasonable prices. As well as tariffs for use of the distribution system, distributors also recover costs through connection charges and regulated services.

4. **Non-discriminatory:** There should be no undue discrimination among network users. The same use of the network should result in the same network tariff under the same circumstances.

5. **Transparency:** The methodology for calculating tariffs should be transparent and accessible to all stakeholders. Transparency in the cost components included in the distribution tariffs and in the methodology of calculating the tariffs should be ensured to facilitate comprehension and acceptance. The methodologies underlying the calculation of tariffs, should be explained, discussed, and published. Consulting stakeholders on the methodology is good practice and facilitates comprehension. Tariffs should be published prior to their entry into force. Transparency ensures that market participants understand and can respond to the signals network tariffs provide.

[76] Council of European Energy Regulators. Electricity Distribution Network Tariffs CEER Guidelines of Good Practice https://www.ceer.eu/documents/104400/-/-/1bdc6307-7f9a-c6de-6950-f19873959413

6. **Predictability:** It is important that network users can effectively estimate the costs of their use of the distribution system, facilitating efficient long-term investment by network users. However, the changing nature of the energy system mean network tariffs will need to evolve over time.

7. **Simplicity:** As far as possible tariffs should be easy to implement and to understand, particularly at point of use. The simpler they are, the easier they are for consumers to respond to.

The CEER also identified the following central considerations for application of the above principles to tariff design:

1. **Network tariff design should as far as possible be future proof.** Tariffs should not impede management of future challenges in operation and investment in electricity distribution networks as well as the overall system, including due to increasing use of electricity storage, electric vehicles, distribution-connected generation, and demand side flexibility. A key aspect of making tariffs future-proof is having robust change processes that will allow network charging structures to evolve over time.

2. **Tariff structures should be sensitive to the different costs of network provision.** These include the costs of providing capacity at peak, the costs of maintaining the grid, operational expenditure and losses etc. Each should be reflected appropriately through tariff structures. In the shorter term, a proportion of the distributor costs will not be related to load, and can be seen as residual costs that should be recovered in ways that are fair and cause the least possible distortion of network use. In the longer term a greater proportion of the costs can be related to load.

3. **Net metering of self-generation that prevents the fair contribution of self-generation towards network costs should be avoided.** Self-generators that use the energy network should face network tariffs which are fair and cost-reflective in the same manner as consumers that exclusively rely on the network for their energy supply. Net metering implies that system storage capacity is available for free. It reduces consumers' time-value sensitivity to volatile energy prices and hence undermines efforts to enhance flexibility and to develop a wider demand-side response.

4. **Network tariffs are only one of many tools to give price signals to consumers.** Tariffs should recover costs in a way that does not prevent the efficient procurement of flexibility services through competition from alternative service providers (e.g. through market mechanisms). Whilst distribution tariffs can send an incremental price signal which generally reduces peak demand, this may not be sufficient when a 'firm response' is needed, and procurement of flexibility may be necessary through agreements on access to the network and market-based signals.

5. There is a need for a coherent approach across all voltages. Distribution network users' decisions on where to build new assets, how to dispatch plant, and when to consume energy are not made in isolation. The arrangements at transmission level are relevant. Coherence is important and network tariff driven regulatory arbitrage should be avoided.

6. **Any network tariff structure reflects multiple objectives which need to be balanced.** It may be better to reach specific objectives via other means than to try to send all price signals through a network tariff structure. Each country will make different trade-offs regarding tariff principles due to the specificities of their market structure, the pace of change, and the development of their retail market. The costs and benefits of changes to current approaches depend on the starting point and will evolve over time. Tariff design requires careful planning, with effective management of transitions

7. **Regulators should have sufficient expertise and resources.** Expertise and sufficient resources are necessary to assess, choose, and implement appropriate tariff structures, with consultation of stakeholders. The regulatory framework for tariff structures is a core regulatory responsibility.