Blueprint Institute

Untangling the NEM

A policymaker's guide to the National Electricity Market

Contents

This series

This paper is the fourth in our energy initiative series—*Powering the next boom: Priorities for energy reform in the coming decade*, launched on 29 October 2020. The series began with a frank assessment of Australia's lackluster progress on emissions reductions to date, as well as the challenges and opportunities we face in decarbonising our energy sector in the coming decades. Much has changed in a year, but Australia's journey to articulating a national strategy on climate and energy policy is far from complete. This paper continues to push for a national climate and energy policy by enabling better conversations on energy market reform.

About Blueprint Institute

Every great achievement starts with a blueprint.

Blueprint Institute is an independent public policy think tank established in the era of COVID-19, in which Australians have witnessed how tired ideologies have been eclipsed by a sense of urgency, pragmatism, and bipartisanship. The challenges our nation faces go beyond partisan politics. We have a once-in-a-generation opportunity to rethink and recast Australia to be more balanced, prosperous, resilient, and sustainable. We design blueprints for practical action as a nudge in the right direction.

For more information on the institute please visit our website - blueprintinstitute.org.au

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Attribution

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Introduction

The electricity sector is changing rapidly in Australia. To keep up with the changes, the market infrastructure needs to change too. Blueprint Institute's Guide to the National Electricity Market (NEM) is a clear and accessible overview for policy makers, commentators, and anyone wishing to get their head around one of the most important elements of Australia's economy.

No sector is more ripe for decarbonisation than electricity. Demand for renewables is growing, driven by plummeting production costs, as well as global and domestic efforts to reduce emissions and address climate change. Australia's combination of sunshine, wind, and access to financial and human capital uniquely positions us to seize the growth in demand for renewable energy to power our next boom.

Since the last coal-fired generator was commissioned in 2009, wind power has increased four-fold, while solar power has increased by a factor of 49. Indeed, 30% of Australian households have installed solar panels, and renewables have surpassed 30% of electricity generation in the NEM on a rolling annual basis. The pace of renewables' expansion is only going to increase as coal-fired generators bring forward closure dates, state governments create renewable energy zones, and the cost of renewables production and battery storage systems continues to decline.

But as our electricity sources change, the market rules that govern them will need some tweaking too. A multifaceted framework is needed to efficiently power a modern economy over the vast Australian continent—and that goes beyond the question of how we could physically transmit electricity from a wind farm to a home. To be done at lowest cost, the market needs to be designed to consider the incentives of players at each stage of the process: from the generators, to the transmission infrastructure owners and, ultimately, to the companies that send out our energy bills. Changes to electricity generation, from the growth of renewables and decline of coal, will raise new problems for the physical system itself, and all of the associated markets.

Too often, perspectives on energy policy in Australia fail to recognise the opportunities and challenges posed by the physics and market structure of our electricity system. Conjecture abounds on what happens when "the wind doesn't blow and the sun doesn't shine", but these statements are not always consistent with the technical or economic realities of the NEM – the system which powers the eastern half of the country.

The NEM is a complex beast. Without a thorough background in engineering and economics, the jargon used to describe the issues it faces are practically indecipherable. In the physical space, terms such as security, reliability, and system strength are easily confused. The same goes for the economics, such as distinctions between spot and contract prices, wholesale and retail markets, or marginal and average costs.

Understanding these features of our electricity system is a prerequisite to making a reasoned contribution to the debate on NEM reform, and this paper wants to make things clearer.

What follows is the first of two parts in our series on NEM reform—a simple, jargon-free introduction to both the physical and market systems that currently make up the NEM, and the processes which govern its operation. This guide is designed to equip policymakers and commentators with an accessible knowledge base from which to devise or advocate for critical reform.

Our guide begins with an introduction to the NEM and its history. It then outlines two sides of the electricity market all policy makers need to understand: the system's physical constraints and makeup, and the markets which govern it.

On physics—we strip back the textbook complexity to provide a brief crash course on power system basics. With markets, we discuss three further components: the primary wholesale market that ensures reliable supply, the secondary markets that deliver system security services, and the regulated monopoly structure that provides the networks. The paper concludes with a summary of the governing institutional arrangements and further resources for those looking to dig deeper.

The impetus for electricity market reform is only going to grow as the energy transition accelerates. This summary seeks to arm decision-makers with the facts needed to position Australia to thrive in a rapidly changing world. The second part in our NEM reform series will provide specific recommendations on how best to chart the future of the NEM to balance reliability, security and emissions.

What is Australia's National Electricity Market?

The first thing to know about the National Electricity Market is that it's not national and it's not only an electricity market. It is the name given to the interconnected power system that connects the eastern states of Australia and is commonly referred to as 'the NEM'. It is one of the longest interconnected power systems in the world, spanning over 5000 km, from Port Douglas in Far North Queensland down across the Bass Straight to Southern Tasmania and over to Port Lincoln in South Australia (see Figure 1).

The NEM delivers electrical power to over 10 million customers, supplying approximately 80% of Australia's electrical power demand. It comprises over 44,000 km of transmission lines connecting energy consumers with the power plants that generate the electricity. There are approximately 300 large-scale power plants with over 5 MW of capacity connected to the system, in addition to millions of small-scale rooftop solar systems also producing power and now exporting to the national grid.

The NEM at a glance

Number of customers	10.2 Million
Electricity supplied (2020)	190.1 TWh
All time peak demand	35,626 MW
Market turnover (2020)	$10.9 billion
Large-scale generation units	295

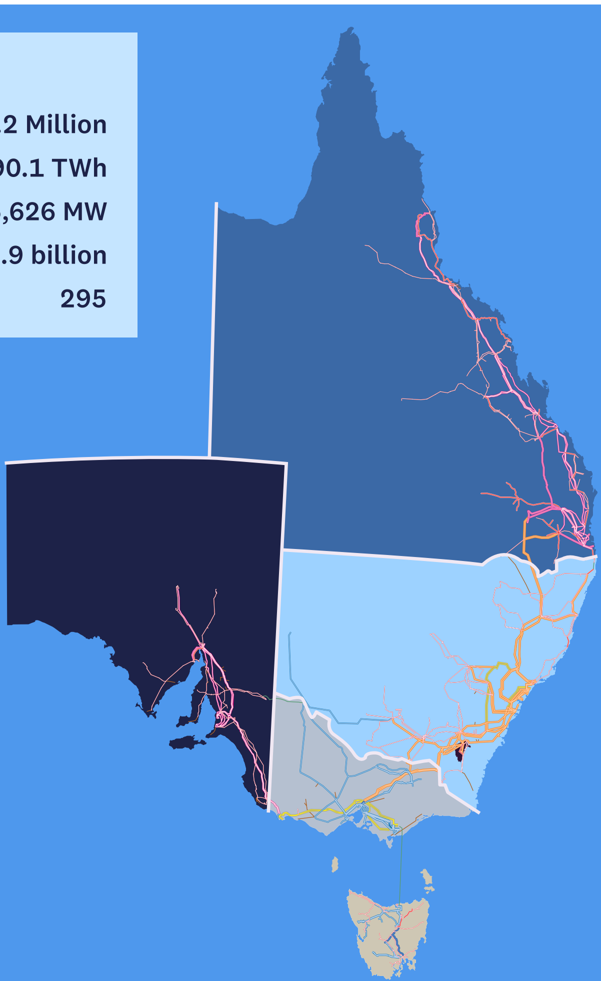


Figure 1 Map of Australia's National Electricity Market
Source AEMO

Why do we have a National Electricity Market?

Prior to the 1990s, the electricity supply chain was owned and operated by vertically integrated, state-based utilities. Each state had its own authority responsible for the generation, distribution, and supply of electricity—such as the State Electricity Commission of Victoria or the Electricity Commission of New South Wales. This was the result of a prior period of consolidation of public and private assets. For the most part, transmission lines did not cross state boundaries and each state supplied its own needs. All public electricity utility commissions were established by Acts of (state) governments, and they were exempt from competition law. Individuals and companies could not choose their supplier, they had to purchase power from their local state provider.

Faced with rising costs, governments eventually shifted away from publicly owned monopolies and towards greater interconnection, inter-regional trade, and ultimately, the formation of the NEM. Concerns over costs were not unique to Australia. Many countries around the world had created state monopolies to supply electricity, and these were increasingly seen as inefficient. By the early 1990s, a number of countries had started to open up their electricity sectors to competition, which promised efficiency gains. Reforms typically involved the introduction of an electricity market, the privatisation of state-owned assets, encouragement of new private entrants, and inter-regional trade where appropriate.

In Australia, state governments agreed in the early 1990s to introduce a competitive, market-based electricity supply system. The agreement set off significant structural change. It ultimately resulted in vertical separation between electricity generators, transmission lines and consumer-facing companies. It also led to corporatisation and privatisation within the sector.

In Australia's new electricity market, generators and retailers were to compete within their own 'layers' of the market to increase efficiency and keep electricity prices down. The 'poles & wires' (transmission and distribution networks) were seen as 'natural monopolies', which would be subject to regulation to ensure efficient outcomes. Figure 2 illustrates the three components of the reformed energy system: the wholesale market, the network, and the retail market.

The introduction of the National Electricity Law in 1996 codified these reforms. It was guided by the principles of competition and enshrined in legislation a suite of bodies to oversee the new, rules-based system. First, there's the Australian Energy Market Commission (AEMC), which acts as a legislature and develops the rules. Second, there's the Australian Energy Regulator (AER), acting as the judiciary and enforcing the rules. Third, the Australian Energy Market Operator (AEMO) was given executive powers to operate the market in accordance with the rules. The law includes the highest point of reference for policy settings for the system, the National Electricity Objective, *"to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy."*

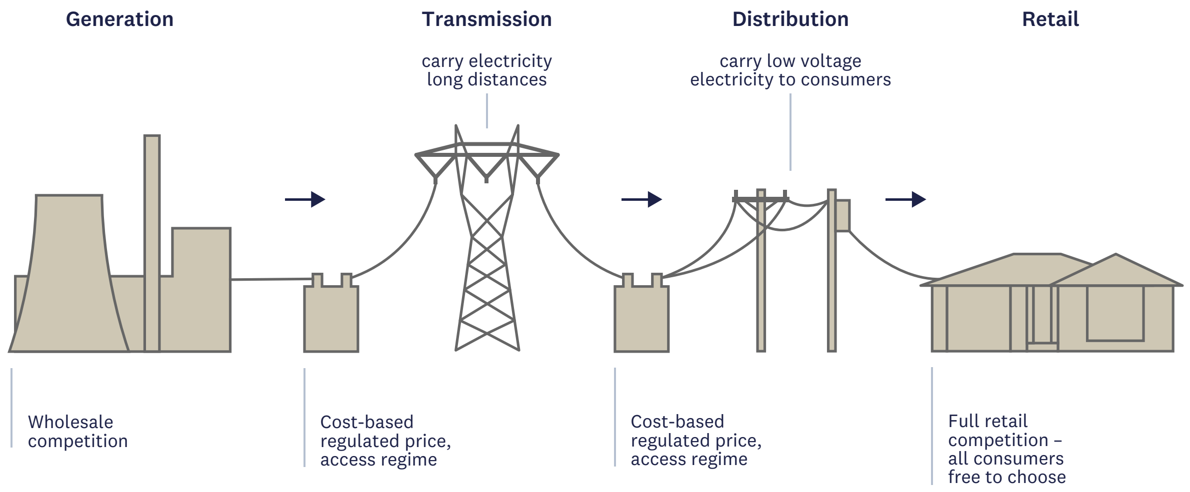


Figure 2 Components of the electricity system
Source Blueprint Institute analysis

The political battle for the NEM

Securing the National Electricity Market wasn't straightforward. Passions ran high. Rumour has it that former NSW Treasurer Michael Egan literally "banged the table" for reform while the then-deputy leader of the Liberal opposition, Ron Phillips, lambasted what he saw as inconsistencies and broken promises in the government's electricity reforms. Phillips even mockingly compared the supposed incompetence and trickery of Egan and NSW Premier Bob Carr to cartoon characters Rocky and Bullwinkle.

Convincing state governments to give up monopoly revenues caused further conflict, with comical repetitions of Paul Keating's famous jab that "you should never stand between a state premier and a bucket of money." Initially it seemed that the only agreement between a variety of different interest groups was to violently disagree. Yet the steady march of incremental progress continued across the 1990s until the NEM Management Company (a precursor to AEMO) was established on behalf of the State governments, to manage the power systems and wholesale markets. On December 13, 1998, the National Electricity Code (a precursor to the current National Electricity Rules) came into force.

Power system basics

Power and energy

Power and *energy* are two distinct but related terms, commonly used to describe different characteristics of the electricity system. Simply put, energy does useful work for us by providing light, heat or moving things. At the household level, *energy* heats our water and runs our appliances. At the industrial scale, it's used for processes such as mineral smelting or moving water with pumps.

The rate at which electrical energy is generated, consumed, and transferred in 'poles and wires' is referred to as *power*. The term power can be used to describe the rate at which energy is produced or consumed. It can also describe the rate at which energy flows through a transmission or distribution network.

Power is typically measured in watts (W), which in turn is a measure of energy per second. In the electricity sector, total energy is typically expressed in watt-hours (Wh). For example, a small load consuming power at 2 watts for two hours will consume 4 Wh of energy. A larger load consuming power at a rate of 4 watts for only one hour would also consume the same amount of energy (4 Wh).

Watts and watt-hours are extremely small and are rarely, if ever, referred to at power system scales. For example, at the household level, a kettle might draw 2.4 kilowatts (kW) of power from the grid when it is switched on. Rooftop solar systems typically produce more than 5 kW of power.

The most commonly used power unit in the context of the National Electricity Market is the megawatt (MW). The MW is 1,000 times larger than the kW, and is typically used to describe:

- The instantaneous demand from the grid at any moment in time or the average demand over a period of time. For example: In NSW, the average demand for power is about 7,700 MW, with peaks above 14,000 MW in times of extreme demand.
- The size of a power plant, also known as capacity. For example: A typical coal plant might have a capacity of 2,000 MW, meaning that it is capable of generating electricity at a rate of 2,000 MW at full power.
- The actual amount of power being produced at a moment in time. A wind farm of 200 MW capacity might only be producing 130 MW of power at any particular moment due to the wind conditions at the time.

Total energy production or demand over a given period of time is typically described in terms of megawatt-hours (MWh), gigawatt-hours (GWh, equivalent to 1,000 MWh) or terawatt-hours (TWh, equivalent to 1 million MWh). Households typically consume 5-10 MWh of energy over the course of a year (depending on a range of factors, including household size and weather conditions). The total energy traded through the NEM on an annual basis is usually measured in TWh. In 2020 approximately 190 TWh passed through the NEM.

Reliability and security

Reliability and *security* are commonly used terms in electricity market discussions. While related, they are distinct concepts.

Reliability, sometimes termed *resource adequacy*, refers to the ability of a power system to provide sufficient power when the system demands it. A reliable system has sufficient capacity or resources available to ensure demand is met, while keeping undelivered energy to an acceptable minimum. The wholesale energy market and spot market is designed to support resource adequacy or reliability (the section on Australia's wholesale electricity market later in this paper has more detail).

In the context of the NEM and power systems more broadly, *security* relates to the ability of the power system to tolerate disturbances. A secure system can handle large faults or incidents—such as the loss of a large generator, a large consumer, or transmission line—without the collapse of the entire system. The market operator is responsible for setting aside enough resources to keep the system secure, through the provision of ancillary services and use of other mechanisms (discussed later in the report).

System security is a necessary but not sufficient condition for a reliable power system. It is possible for a system to be *secure*, in the sense of being able to tolerate disturbances, yet *unreliable* because it lacks sufficient generation capacity.

Voltage, current, and frequency

The terms *voltage* and *current* relate to the means of transferring electrical power. A useful analogy involves a water tank with a tap near its base. The *pressure* of the water at the bottom of the tank is analogous to the voltage, and the instantaneous *flow* of water from the tap is analogous to the current. When the tank is full, the high pressure (voltage) means the water will flow fast if the tap is fully opened. But as the tank level lowers and the water pressure declines, the flow rate also slows downs and may eventually stop altogether. This happens with power too, just think of a battery running down.

The water tank analogy is most useful for direct current (DC) systems, where the current travels in one direction from a high voltage source to a lower voltage destination or 'sink'. It is less directly applicable to alternating power (AC) systems, where the voltage and current periodically reverse direction. Still, the fundamental point remains—you need both voltage (pressure) and current (flow) to transfer power from one place to another.

AC systems, like the NEM, have some advantages over DC systems, including the ability to change voltage. High voltages (more pressure) can be more dangerous. However, transferring power at high voltages results in lower power transport efficiency losses as it travels through the power lines—of particular importance when transmitting over long distances. Therefore, it is common to use high voltage power lines to transfer power over long distances from remote generators to large load centres such as an industrial park and then 'step down' the voltage to safer levels for the shorter local distribution to households. The section on regulated networks in this guide has more detail on regulating this service.

In the NEM, the reversal of current and voltage happens 50 times a second, or at a *frequency* of 50 Hz. This is a somewhat arbitrary choice (some systems have a frequency of 60 Hz), but all equipment that connects to the system operates at this same frequency. This means, for example, that the large spinning generators that connect to the system, such as steam turbines in coal-fired power plants, have to spin in synchronisation with this frequency. The importance of frequency and frequency control will be discussed later in this guide.

The wholesale electricity market

The wholesale market was established to introduce competition in the wholesale electricity sector, decentralise operational and investment decisions and allow private firms to participate. A competitive spot market is central to this design.

The spot market was designed to ensure that electricity is sent out in the most cost-effective way. It's also designed for transparency, so that people and companies would be able to clearly see and understand the price of energy. This price transparency would help investors, too, in their decision-making. Investors also consider other factors such as potential customer demand, location of the energy source, access to water and proximity to the transmission network (how power will be distributed to those who need it).

The National Electricity Market (NEM) is characterised as an *energy-only gross pool* market. This is because all electricity supply is fed into a central market (hence gross pool), operated by the Australian Energy Market Operator (AEMO). While there is a single pool, the market is divided into five interconnected pricing regions or zones: South Australia, Victoria, New South Wales, Queensland, and Tasmania.

Generators receive revenue based *only* on the electrical energy they supply to the market (hence 'energy-only'). This is different from the system found in Western Australia, for example, which runs parallel markets for energy and capacity. In such a capacity market, generators receive additional payments for the *capacity* they provide, irrespective of whether their energy is actually used or not.

How the spot market works

A unique feature of electricity markets is the need to match electricity production and use at exactly the same time. So, one of the most important jobs of the market operator (AEMO in Australia) is to coordinate the dispatch (production) of enough electricity generation capacity to meet demand in real time. The market operator also needs to make sure the power system operates securely, and at the lowest possible cost.

In the NEM, the power generation schedule is managed centrally by the Australian Energy Market Operator via an auction process. This price auction sets a consistent price for all generators. Generation capacity is offered into the market by participants throughout the network.

Conceptually, this capacity is ranked by the price offered by the generators, and is dispatched in 'order of merit' (from cheapest to most expensive) until a target demand has been met. The last generator dispatched to clear the market sets the uniform market price. This means all generators who dispatch energy are paid at the same price—equal to the last generator's bid—no matter which price they had initially offered. Figure 3 shows an illustrative supply curve and the set price for meeting a particular demand. In the graph, all generators receive a price equal to the horizontal blue line.

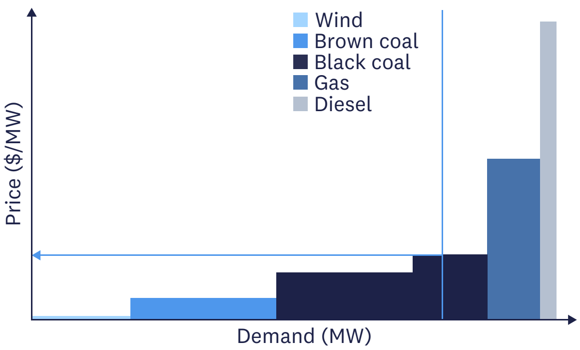


Figure 3 Conceptual electricity supply curve
Source Blueprint Institute analysis

The auction clears on a five-minute 'dispatch interval' basis, with a price determined for each of the five regions. These prices are the settlement prices for all generators and loads within the region. Prior to 1st of October 2021, wholesale or *spot* prices were settled on a half-hourly 'trading interval' based on the average of the six previous five-minute dispatch interval prices. This means that until recently, spot price changes were much less frequent.

The expectation of *energy-only* gross pool markets is that generators will offer much of their capacity at (or close to) the short-run marginal cost of production, which is the cost to produce a single additional unit of electricity. Offering capacity at the marginal cost results in optimal electricity pricing. Generators have their profits maximised and the system's total cost is minimised at the same time.

Marginal loss factors

When power travels from a generator to the consumer, some electricity is lost. To account for those losses, *marginal loss factors* are applied to the capacity. Electrical losses are an unavoidable characteristic of electricity systems. Losses occur as power is transmitted through the power system from generators to customers. They are a function of the load and generation mix (which are constantly changing) and factors relating to the transmission network itself. In practice, the losses on the network change dynamically in real time.

Generators get paid for the electricity they deliver to the central node—essentially their output multiplied by their loss factor. In theory, the marginal loss factors should therefore provide a location price signal. Generators are essentially penalised for generating power in locations with high losses (loss factors below 1.0) and rewarded for generating in areas with low losses (loss factors above 1.0). Marginal loss factors represent a risk to generators because their revenue can suffer when marginal loss factors change year after year (largely outside of a generator's control).

Paying to generate

Some generators will offer a proportion of their capacity to the market at negative prices. This means they are willing to *pay* to feed electricity into the grid. This is commonly the case for large thermal generators like coal-fired power stations due to various physical characteristics of the plant. Physical constraints mean that large thermal plants have a minimum level of generation that they can operate above, typically about 40% of their rated capacity.

Below this minimum level, generators must actually shut down completely, which is both costly and time consuming. To avoid those costs and delays, some generators are willing to pay to generate, by accepting negative prices, and thus avoiding an even more costly shutdown.

Generators dominate the market bidding process. However, consumers of electricity, whether they be large consumers of electricity, or energy storage companies, can agree to purchase a certain amount of electricity at a certain time at an agreed price. Demand reduction can be a cost effective resource to ensure the system is balanced, and can result in lower prices. A new approach to more efficiently managing wholesale demand is also being introduced.

The 'merit order' effect

For every unit of power generated by coal or gas, there is a marginal cost for the fuel. This is not the case for solar or wind, which have marginal costs close to zero. As such, a new renewable entrant can have a big impact on price setting. For example, introducing more wind power to the market has a significant impact on the electricity supply curve because wind power has a low short-run marginal cost (see Figure 4).

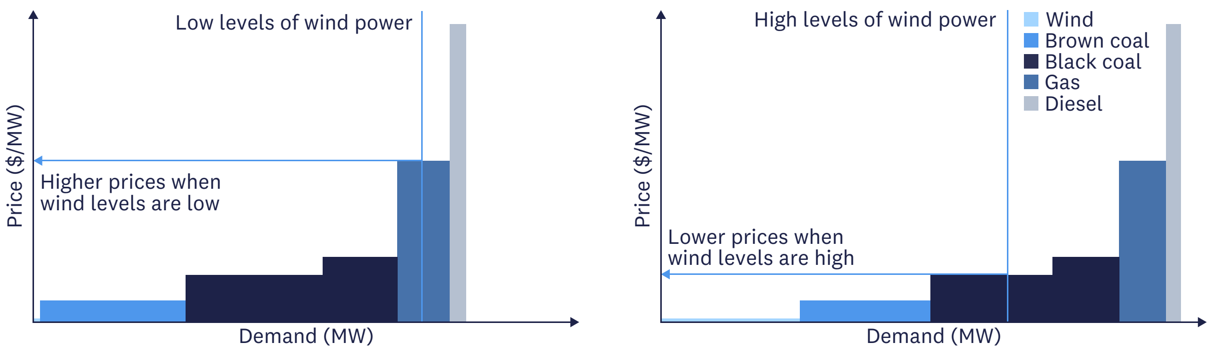


Figure 4 Impact of wind on a hypothetical electricity supply curve
Source Blueprint Institute analysis

This results in prices dropping to zero (or lower) in markets with high proportions of renewable generation. Because some generation is offered to the market below short-run costs, negative prices are becoming increasingly common.

Distributed solar generation such as rooftop solar PV is generally not traded through the central dispatch system, so it shows up as an apparent reduction in demand, rather than additional cheap supply. However, the impact on the wholesale spot price is similar, and the end result is that a generator operating at lower marginal costs sets the dispatch price at a lower point.

The cost of renewable energy is dropping like a stone

As technological innovation marches on, the cost of variable renewable energy sources are continuing to plummet (see Figure 5). Just over a decade ago, solar PV was more than three times as expensive as coal-fired power; now it's almost three times cheaper. While the change in onshore wind costs has been slightly less dramatic, it too has gone from comfortably more expensive than coal-fired power to clearly cheaper in a remarkably short time.

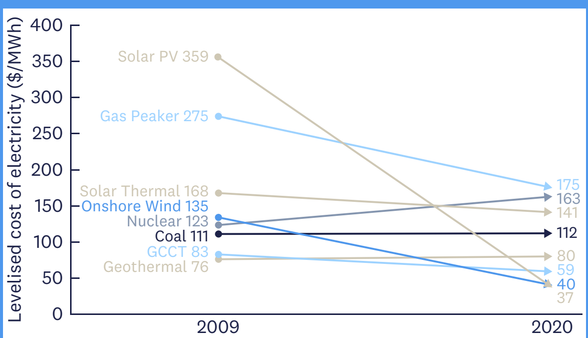


Figure 5 Historical changes in levelised (unsubsidised) average global cost of electricity by generation type, 2009 to 2020

Source Lazard

Figure 5 shows the change in unsubsidised average global costs for each form of energy, levelised to reflect the lifespan and capacity of the assets that produce it. Costs are calculated as total fixed and variable costs divided by an asset's lifespan and production capacity, all discounted into net present terms to account for time. For most renewable energy sources, the vast majority of this figure is driven by upfront capital costs. Once built, renewable assets pay nothing for the wind to blow or for the sun to shine, whereas traditional power sources like coal incur constant fuel costs and other ongoing variable expenses.

These near-zero marginal costs for renewables have produced a dramatic increase in the number of negative price periods in the NEM, particularly during the middle of the day when the sun is shining strongest (see Figure 6). Unsurprisingly, fossil fuel generators are finding it increasingly difficult to compete. Many have begun to lose their commercial viability as a result.

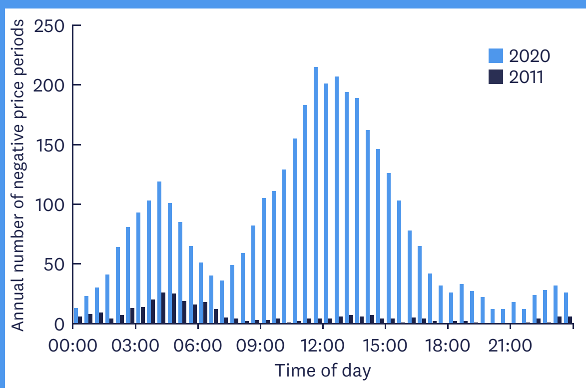


Figure 6 Frequency of negative prices in the NEM across the day, 2011 & 2020

Source AEMO, Blueprint Institute analysis

New renewable capacity flooding the grid

Whether you love it or hate it, the decarbonisation of Australia's energy grid is already underway. And it's happening at a pace AEMO describes as "staggering". We are global leaders in the per-capita deployment of renewable generation (see Figure 7) and have the highest uptake of rooftop solar in the world. In 2020 alone 3 GW of new small-scale solar capacity was added through 362,000 installations on the rooftops of Australian homes. That's a 40% increase from 2019, and the trend is set to continue with a further 3.5 to 4 GW expected to be added this year. Large-scale solar farms have multiplied from 6 to 52 over the last 3 years—an increase of more than 750%. Meanwhile, the number of wind farms has grown from 36 to 58.

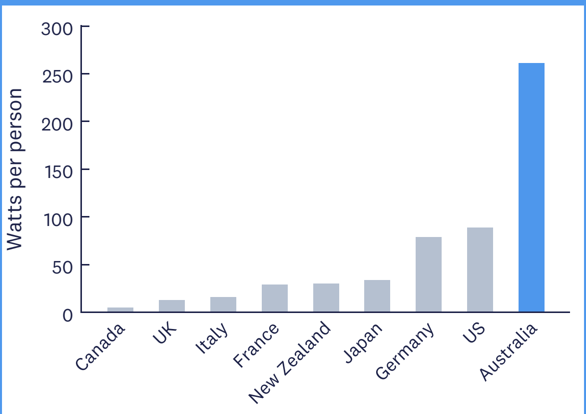


Figure 7 Per capita new renewable energy capacity, 2020

Source World Bank, IRENA

This transformation is being reflected in the changing generation mix, which is favouring renewables over sources fired by fossil fuels. Since the beginning of the millennium, renewables' share of installed capacity in the grid has more than tripled, accounting for over 45% of NEM generation capacity in the 2019/2020 financial year (Figure 8). Residential solar alone makes up 16% of installed capacity. In 2020, for the first time ever, more than a quarter of the nation's electricity supply came from renewable sources.

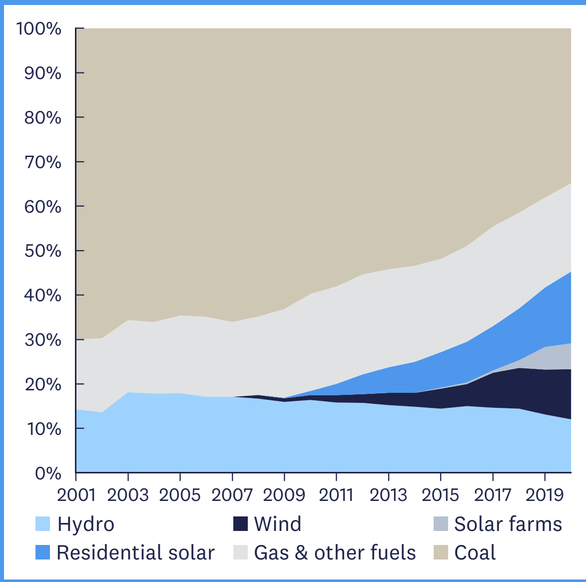


Figure 8 Share of NEM installed capacity by energy type, 2001 to 2020

Source AEMC

The rise of renewables and storage will not end there. With over 1.4 GW of storage and 11.3 GW of new renewable energy capacity currently under construction in 131 projects across Australia, similar trends are set to continue. These new renewable generation projects make up around half as much as all current coal generator capacity. The latest forecast for the registration rate of these kinds of new green energy projects has far exceeded even the market operator's most optimistic expectations—it is 15% higher than anticipated under AEMO's 'step-change' scenario, which predicted that the penetration of renewables in the NEM would reach 94% by 2040. Visibility over the current pipeline of registered and commissioned renewable projects suggests the transition is likely to occur much faster than that—90% of the grid could be driven by renewables as early as the mid-2030s.

The market price cap, reliability, and volatility

Market price cap

Energy-only markets allow prices to rise to extreme highs during periods where reserves are scarce. Such *scarcity pricing* allows generators to recover their substantial fixed capital costs. On the flipside, prices can drop very low—sometimes even turn negative—in times of excess production.

Extreme pricing during *scarcity* events also plays an important role in signalling the need for new investment in *'peaking capacity'* or demand response. Peaking capacity is designed to only run during peak demands and in some cases may only run for several hours a year. Open cycle gas turbines are an example of a technology whose use to meet peak demands can be incentivised by peak scarcity pricing. A similar price response can take place on the demand side, where a *demand response* can also provide a similar function, responding to the price signal by reducing demand, rather than increasing supply.

Energy-only markets are specifically designed with high sensitivity to the supply-demand balance, with prices typically capped at a high value. In theory, the market price cap should be high enough for spot prices to provide a revenue stream that matches the total cost (both fixed and variable) of the optimal fleet of efficient generators.

Most energy-only markets have a price cap at a value many times above the short-run marginal cost of production of even the most expensive generators. Following an increase from $10,000/MWh in 2010 to $15,100/MWh today, the NEM's current *market price cap* is one of the highest in the world. It is approximately 300 times the historical volume-weighted average price. The market also has a floor price of -$1000/MWh.

The price cap is derived from the *reliability standard*.

Reliability Standard

Reliability is a measure of the ability of the grid and its associated electricity generation infrastructure to meet instantaneous demand. In the context of the wholesale market, it indicates whether or not there's enough power being generated and/or shared between regions to meet demand.

The *reliability standard* is the metric used to assess reliability in the NEM. The standard specifies the level of *expected unserved energy* that should not be exceeded. It is reported as a percentage value of total energy demanded in a year. The current reliability standard is 0.002%, meaning that if the expected amount of energy demanded but not delivered is less than 0.002% in a given year, then the system can be said to be *reliable*. In other words, the system should be expected to deliver 99.998% of energy demand in a given year.

Anyone who's ever suffered the frustration of a power cut might ask why the reliability standard isn't 100%. The simple answer is that building an infallible system—to the extent that it is even possible—would be hugely expensive. To do it, we would need enough capacity to supply every conceivable power demand scenario, no matter how outlandish or unlikely.

The Interim Reliability Measure

In March 2020, Australia's energy ministers decided to introduce a new and tighter reliability standard. This new *Interim Reliability Measure* (IRM) was introduced as a temporary measure to support reliability in the system while more fundamental reforms are designed and implemented. As part of the Interim Reliability Measure, *expected unserved energy* in each region is to be kept to no more than 0.0006% (well below the reliability standard of 0.002%). This interim measure commenced in August 2020 and is in place until the end of the 2024 financial year. The market operator (AEMO) can procure additional out-of-market reserves to ensure the standard is met.

The reliability standard is set by the Australian Energy Market Commission's (AEMC) reliability panel, which aims to strike the balance between costs and reliability. The reliability settings are *informed* by the Value of Customer Reliability (VCR)—comparable to the Value of Lost Load used in other jurisdictions.

In theory, the price cap reflects the wholesale price that is necessary for the last power-deploying generator required to meet the reliability standard and still be able to turn a profit/stay in business. As previously mentioned, the price cap should be high enough, so that average spot prices provide a revenue stream to match the total cost (both fixed and variable) of the optimal fleet of efficient generators. In the context of reliability, the 'optimal fleet of efficient generators' is the cheapest mix of generation that ensures the *reliability standard* is met.

Reliability and emergency reserve trader (RERT)

The market is designed to provide incentives to ensure sufficient capacity in generation (or demand-side activities) with the price cap and other market settings. There is, however, an additional tool that the market operator can draw upon as a last resort. If the operator forecasts that the system is likely to serve less than 99.998% of energy demand, it can tender for additional reserves outside of the market. These reserves are typically demand-side response mechanisms, or small generators (like back-up diesel generators) that would otherwise not have participated in the market.

The costs for the reliability and reserve trader mechanism are passed through to consumers as an additional levy. The cost of energy delivered through the RERT is generally very expensive and in many cases much more than the market price cap.

Volatility

The highly variable nature of electricity demand across daily, weekly, and seasonal time-scales, combined with the need to match demand and supply in real time, means prices can be volatile. This can be seen in NEM annual turnover, which has varied between $10 and $19 billion in recent years.

Price volatility is a design feature of energy-only wholesale markets. In normal operating conditions, prices typically reflect the short-run marginal cost of production. However, it is not uncommon for prices to reach the price cap during periods of scarcity. Scarcity conditions arise when all capacity available in the system is needed either in periods of very high demand or when a significant amount of generation capacity is made unavailable—such as in cases of plant failure or maintenance. The expectation that generators can briefly exercise market power in periods of scarcity by exploiting extreme spot prices is a design feature of energy-only markets. As noted earlier, such extreme prices allow generators to recover fixed costs for capacity that is needed to meet rare peak demand events. The price volatility associated with scarcity events also serves as a signal for large consumers to contract demand.

Contracting & hedging

The extreme range in wholesale pricing and the consequent price volatility exposes market participants to significant risk. Persistently low prices in periods of reduced demand may push generator earnings below their long-run marginal cost of production. In contrast, frequent scarcity events can drive energy costs for exposed customers to unsustainable levels.

Consequently, market participants use a variety of strategies to manage wholesale pricing risks. They typically include a combination of vertical integration and hedging on the derivatives markets (Exchange Traded Futures markets or using over-the-counter bilateral contracts).

Vertical integration

The dominant hedging strategy in the NEM is *vertical integration*. Generally, this involves the re-integration of generation and retail business into single entities (so-called 'gentailers'), partly unwinding the structural separation that occurred during the reforms of the late 1990s. This vertical integration allows internal hedging, with the retail component of business the counterparty to the wholesale (supply) component.

Derivative Markets

Exchange traded futures (ETF) and over the counter (OTC) *bilateral contracts* enable suppliers of electricity to hedge against price fluctuations. Suppliers, generators and operators are able to enter into futures contracts, legally binding agreements to buy or sell the underlying commodity (electricity) on a specific date or between two specific dates.

Market participants typically maintain contract portfolios that reflect the uncertainty of future prices. For example, one year out, participants may want to be fully (100%) contracted, two years out 60-70% contracted, three years out 20-30% contracted, and at four years out 5-10% contracted.

Historically, three standard contract types dominated the electricity derivatives markets:

- Base *load futures* covering a full 24-hour period on each day over a specified calendar quarter.
- Peak *load futures* covering the period from 7am to 10pm on working weekdays in a quarter.
- $300 *cap futures* that allow retailers and other consumers to manage the risk of high wholesale prices.

These three standard types are generally either a swap or cap contract.

Swap contracts

Base load and peak futures allow both generators and consumers to manage wholesale price volatility in a similar manner to swap contracts. With swap contracts, the counter-parties effectively 'swap' the payment/receipt of the spot price for the payment/receipt of the contracted strike price. Swaps are also known as *contracts for differences*.

Cap contracts

'Cap contracts' are a common hedging product used in the electricity market. They are effectively a type of option contract and typically involve a large electricity consumer (for example a retailer) that wishes to hedge its exposure to extreme price spikes (for example, when the price rises to the market price cap). The contract counterparty is typically a generator (in particular a peaking generator who is able to respond rapidly to market conditions) seeking a more stable and bankable income stream than that provided by infrequent and inherently unpredictable wholesale spot price spikes.

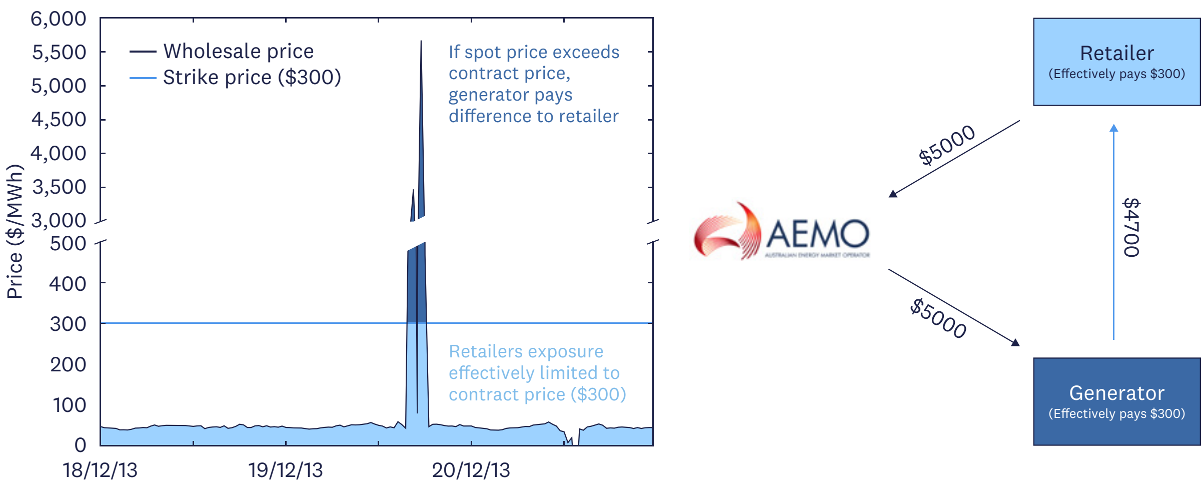


Figure 9 Illustrative cap contract with a strike price of $300
Source Blueprint Institute analysis

In these arrangements, the generators are essentially providing insurance to the consumer that purchases the contract. The generator agrees to reimburse the consumer for any electricity price above $300 dollars (the maximum price the consumer has to pay is effectively $300 dollars). In return, the consumer pays a fixed rate (like an insurance premium) to the generator, thus providing the generator with a steady income stream.

Figure 9 illustrates how cap contracts and their resulting financial transfers work. In this example, the price spikes to $5,000. A generator that is selling into the market will receive $5,000 from AEMO, while a consumer purchasing from AEMO will pay $5,000. If they are contracted to each other with a cap contract, the generator makes payments of $4,700 back to the retailer. In this case, the retailer would only have effectively paid $300, and the generator would have only received $300 dollars. However, the generator would also receive an additional fixed payment (the premium) for providing this insurance to the retailer. In this way, the contract payment limits exposure of the buyer to price spikes exceeding the strike price (the previously agreed electricity price).

Because payments are made to the contracted generator for all trading intervals of the year, even if the generator is not dispatching, such hedging arrangements effectively signal the value of capacity in an energy-only market. They provide a strong incentive to make capacity available during scarcity events. If a contracted generator is unable to respond, it is effectively penalised—payments to the retailer (for example $4,700 in the example above) will not be offset by revenue from the market operator.

The resultant derivative markets produced from these strategies operate in parallel (but are linked to) the spot market. The financial flows occur outside of the market and independently of AEMO. Figure 10 illustrates how these flows, along with those internal to the wholesale spot market, in both financial (and physical) forms, occur between participants.

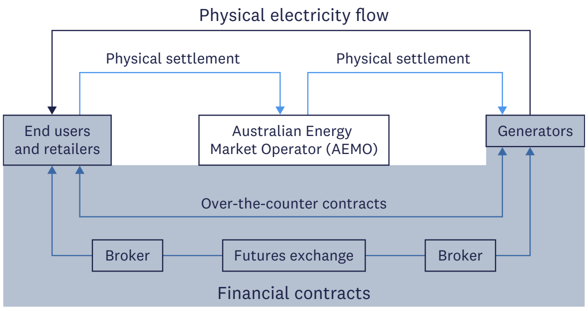


Figure 10 Physical and financial flows between participants in the NEM

Source Energy Reform Implementation Group

Renewable energy support policies

Historically, much of the technology used by fossil fuel companies was developed with government funding. Initially, the electricity transmission networks that now make up the NEM were funded, built, and owned by state governments. Still, Australian governments provide enormous support to the fossil fuel industry to the tune of around $10 billion, with most of this comprising a fuel tax credit that costs more than our nation's army.

Today, renewable energy generation also receives some support and incentives outside of the wholesale electricity market. The main national policy to support renewable generation has been the *Renewable Energy Target* (RET), introduced in 2001. This scheme is broken into two components: a large-scale scheme and a small-scale scheme.

The Large-scale Renewable Energy Target

The Large-scale Renewable Energy Target (LRET) is a scheme that has supported utility-scale renewable energy projects by creating a market for their generation. Under this scheme, eligible generators such as wind and utility solar farms create *renewable energy certificates* for each megawatt hour (MWh) of renewable generation they produce. Retailers and other energy users are required to purchase a certain number of these certificates each year. This sets up both a supply and demand of certificates and thus creates a market.

The certificates provide renewable projects with an additional revenue stream beyond the wholesale market value of power generation. In most cases, the cost of the certificates are passed on to consumers. The number of certificates that need to be generated (and purchased by users) each year is dependent on the target, which is fixed at 33 TWh from 2020 until 2030. The scheme has supported a substantial amount of renewable energy generation installed in the NEM today. However, since this target has now been met and will unlikely be revised upwards, there is limited new demand for the certificates. No new investment projects are being supported.

The Small-scale Renewable Energy Scheme

Small-scale renewable energy systems such as rooftop solar are supported by the Small-scale Renewable Energy Scheme (SRES), which is also part of the national RET, and various state-based schemes. The SRES is similar to the LRET in that retailers are obliged to purchase certificates. However, unlike the LRET, the SRES payments are *deemed* upfront and effectively function as a capital cost subsidy. In addition and unlike the LRET, the SRES continues to support *new* additional rooftop solar installations.

Small-scale generators, like rooftop solar, generally don't directly buy and sell power through the wholesale electricity market. In effect, they reduce the amount of power their retailers have to purchase on their behalf. Rooftop solar owners generate value from reducing their consumption and electricity bill and exporting to the grid. The amount received from exporting to the grid is known as a feed-in tariff. This rate and how it is determined varies by state.

There has been a boom in rooftop solar, driven by rapidly falling installation costs, the potential for savings on electricity bills, and, for some, a desire to reduce greenhouse gas emissions. Rooftop solar is currently the fastest growing source of new capacity in the market. It is the largest power generator in several market regions.

The RET is modelled to have a negligible effect on retail electricity prices in the short-run, with downward pressure on wholesale prices (due to the previously explained merit order effect), offsetting the scheme's cost to retailers. But the benefits of the scheme in incentivising the uptake of renewables is forecast to drive a net reduction in retail prices in the long-term.

The 'capacity cycle'

Wholesale spot prices vary between regions and over time in response to a range of factors. These can be short-term factors related to daily supply and demand patterns or longer-term patterns related to investment decisions. This longer-term investment cycle is sometimes referred to as the *capacity cycle*.

This cycle is driven by the 'reserve margin', which represents the difference between the available capacity and the peak demands. As illustrated in Figure 11, the cycle functions as follows:

1. Investment in new capacity drives up reserve margins
2. Prices fall, investment in new generation capacity stalls
3. Under-investment, together with growing demand, leads to tightening reserve margins
4. Prices rise, and firms invest in new capacity.

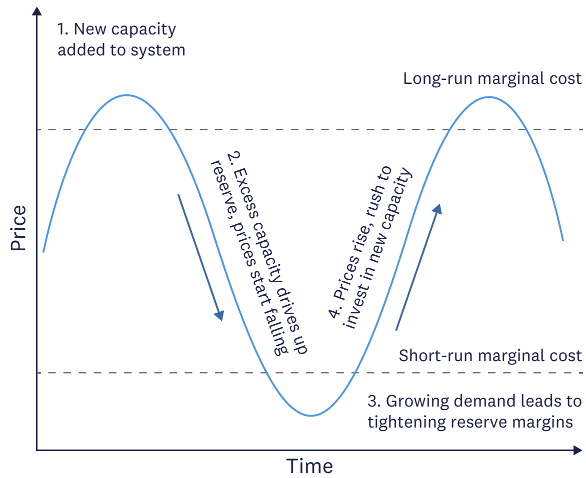


Figure 11 Illustration of the capacity cycle
Source Blueprint Institute analysis

When the amount of power needed (demand) gets close to or exceeds the amount available (supply), prices can spike and consumers pay more for a scarce product. Prices may reach the maximum price cap set by the regulator. If this happens for a while, it's a good signal to a potential investor that there's money to be made. As a result, investors will work to add more power generation capacity. Over time, however, this can create the opposite effect: oversupply. If more power is generated than consumed, prices will fall and discourage new market entrants.

A reserve or capacity margin has historically been used to assess the extent to which the system was balanced. A reserve margin of 15% was generally considered adequate to ensure system security in a balanced system. This means that an electric system has excess capacity 15% above expected peak demand. The required margin varies within individual markets depending on factors such as the shape of the demand curve and the generation mix. In markets with high penetrations of renewable energy, reserve margins much higher than 15% are needed for security.

For many years, reserve margins in the NEM have been consistently higher than 15%, and by 2015 they reached approximately 37%. This increase was driven by a sustained period of demand reduction between 2010 and 2015, as well as new investment in renewable capacity prompted by non-market incentives such as the Renewable Energy Target. By 2015, wholesale prices (when adjusted in real terms) had dropped to some of their lowest levels since the introduction of the NEM.

This price pattern shown in Figure 12 also illustrates the impact of the 'capacity cycle' in the NEM. Peaks in commissioning of new investment in 2000, 2007 and 2008 were followed by falling prices. Since 2016, a significant re-balancing has tightened reserve margins, causing wholesale prices to track well above long-run marginal cost.

This re-balancing is due partly to the closure of several large thermal coal plants and partly to a significant increase in demand that accompanied the development of an LNG export industry in the QLD region.

How did carbon pricing affect the NEM?

From 1 July 2012, Australia implemented a national carbon pricing scheme. While New South Wales had previously operated a Greenhouse Gas Abatement Scheme (GGAS), this was the first model of federal scope. It required 348 emitters, together responsible for over 60% of Australia's emissions, to buy permits for their emissions at a price of $23/tonne in 2012-13, and $24.15/tonne in 2013-14.

Any reader will be familiar with the notorious political campaign that drove the quick demise of carbon pricing in Australia. However, carbon pricing did have real effects on the NEM during its two years of operation. As anticipated, the carbon price flowed through to affect electricity prices in both the wholesale and retail markets. The best estimates suggest the carbon price led to an average 10% increase in nominal retail household electricity prices and a 59% increase in wholesale electricity prices. Importantly, the NEM functioned as theory predicted, generating positive outcomes for both the emissions intensity of the supply mix and overall emissions.

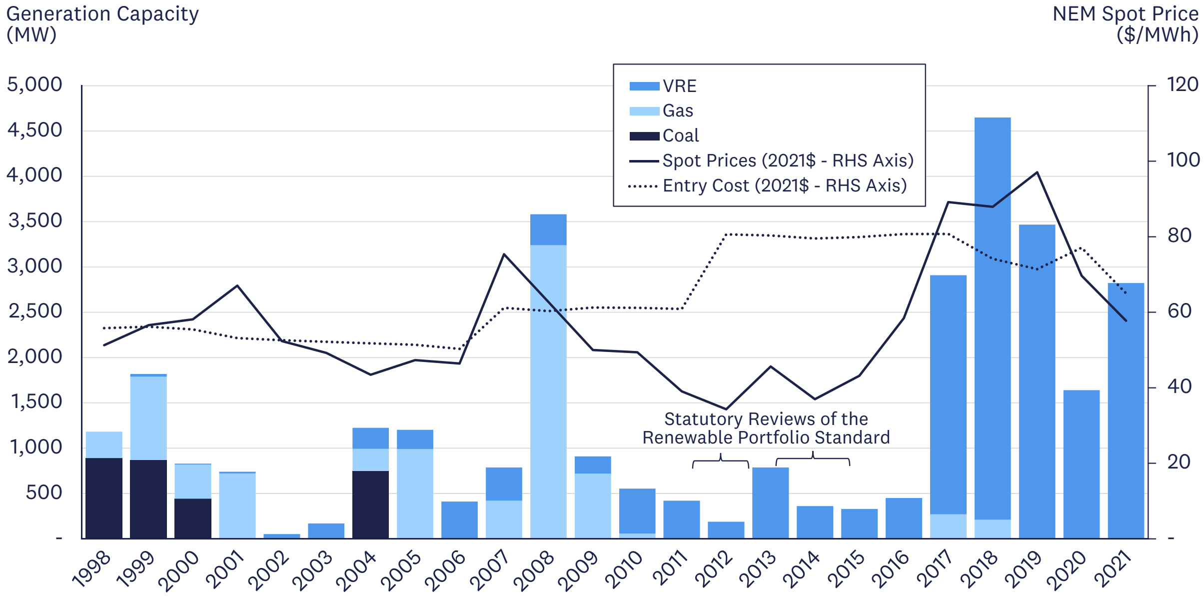


Figure 12 Weighted-average NEM wholesale electricity prices and new investment

Source Simhauser et al, 2021

The demand reduction attributable to the carbon price is estimated between 1.3% and 2.3% of total electricity demand in the NEM (see Figure 13). Perhaps more significantly, emissions-intensive generators fired by brown and black coal lowered their output, resulting in a 1.8-3.3% reduction in the emissions intensity of power supply. Much of the gap was filled by short term and unsustainable increased hydro power generation. The cumulative short term decline in emissions that followed the introduction of the carbon price is estimated between 11 and 17 million tonnes.

The significance of carbon pricing is demonstrated by the immediate rebound in emissions following the scrapping of the scheme in 2014. In the year following, brown and black coal power generation had increased again. Changes to the supply mix caused by the carbon price were short-lived, as expectation of its abolition prevented long-term investment in less emissions-intensive generation.

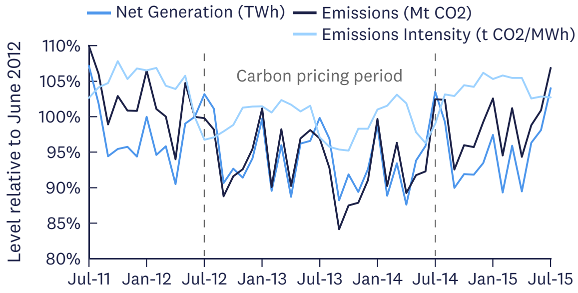


Figure 13 Carbon pricing impacts on the NEM

Source AEMO, Blueprint Institute analysis

Frequency control and system security

Frequency control and system security is an obscure corner of the National Electricity Market (NEM) that historically received little public attention. That has changed following a 'system black' event in South Australia in 2016. Since then, terms like frequency control, system security, inertia, fast frequency response, and system strength have entered the mainstream. This section aims to describe what these terms mean and how they relate to the operation of the power system.

Blackouts and system failures

On Wednesday, September 28, 2016 South Australia experienced an unprecedented 'system black' event. A once-in-50-year violent storm, including at least two tornadoes, paired with winds of up to 260km/h and 80,000 lightning strikes damaged 23 individual pylons and three of the four interconnectors linking the Adelaide area to the state's north and west.

This damage to critical transmission infrastructure produced a cascading failure in the entire network that saw South Australia isolated from the rest of the NEM. As energy supply and demand spun out of sync, the system shut down to protect key assets the same way your house responds to a rogue, faulty toaster. At 4:18pm, most of the state experienced a widespread power outage that left 850,000 customers without electricity. While 80-90% had regained power by midnight, residents in 10,000 homes still awoke in the dark on Friday morning (September 30).

A major hospital in Adelaide's southern suburbs, Flinders Medical Centre, had to rush 17 intensive care unit (ICU) patients into the neighbouring Flinders Private Hospital when its diesel back-up generator failed. Such a close scare highlights the direct human significance of ensuring our technical systems are well-managed. It also shows the potentially devastating consequences when they are not.

Despite some immediate attempts to politicise the crisis by blaming a higher uptake of renewable energy in South Australia, experts have consistently debunked this suggestion. The Australian Energy Regulator (AER) launched a detailed investigation, but none of the recommendations it subsequently published proposed lowering the share of renewables in the South Australian grid. This is because the fundamental issue was with transmission, wholly independent of whichever kind of power generation lay at the end of the line.

In New South Wales and Victoria, the dramatic consequences of wild weather events, such as storms and bushfires have caused similar, albeit smaller, failures over the years. Just earlier this year, Queensland too had its turn, after a fire at Callide Power Station began a domino effect—tripping other network generators to become the state's worst outage in decades, and the 470,000 customers who lost electricity in this case were understandably unimpressed. There's no doubt our modern energy reliance brings massive efficiency to the table, but it also raises the stakes. We need our grid to function well under all scenarios.

Frequency provides the key measure of the balance between supply and demand within the system. If demand exceeds supply, frequency drops—a function of the physical properties of the system. By contrast, if demand unexpectedly drops and supply exceeds demand, frequency rises for the same reason. If the frequency moves too far from the nominal 50 Hz, either loads or generators may be forced to disconnect as a protective or safety measure. This can happen almost instantly (within microseconds), and may lead to cascading failures across the network.

The five-minute operational schedule for matching supply and demand is far too long for managing frequency. Instead, the operator can draw upon a series of additional mechanisms that can respond on shorter timescales to control frequency and system security.

Frequency control in the National Electricity Market

Frequency control is largely coordinated alongside the energy market. The same dispatch engine that schedules enough resources to meet demand also ensures enough capacity is reserved for maintaining system security and frequency control. It does this across eight separate Frequency Control Ancillary Service (FCAS) markets.

Contingency services

Contingency services stabilise the system when a *contingency event* occurs. A contingency event typically involves the failure or sudden and unexpected removal of a generating unit (for example, during an unscheduled outage at a coal-fired generator), a load (such as the trip of an aluminium smelting-line) or a transmission failure (for example, the loss of a transmission line during wild weather).

When such events occur, supply and demand are no longer balanced, and the frequency of the power system can quickly move away from the normal operating range in a very short amount of time. Contingency services ensure that the system is brought back into balance and that the frequency is returned to within normal operating range in less than five minutes.

In the NEM, the frequency is maintained within a *'normal operating frequency band'* between 49.85 and 50.15 Hz (nominally 50 Hz). When the frequency moves outside of this range, enabled capacity responds by automatically increasing or decreasing output as appropriate. *Enabled* capacity (or 'spinning reserve') is capacity that is set aside or reserved, ready to automatically respond to a frequency deviation.

In the NEM these reserves or contingency services need to be delivered within three intervals: six seconds, 60 seconds, and five minutes. Figure 14 illustrates how these services restore the system after a drop in frequency (for example when a power station trips off). As the contingency service may have to increase or decrease the frequency, there are thus a total of six contingency markets (three that raise frequency and three that reduce it over the different intervals).

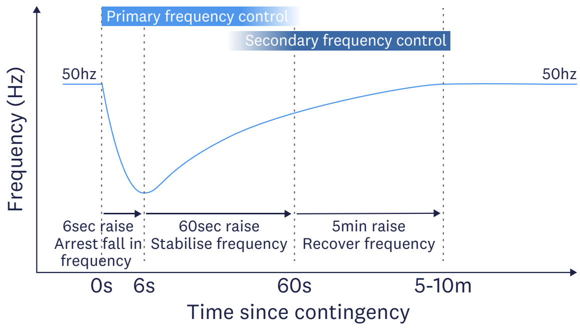


Figure 14 Illustration of the three raise contingency services (x-axis not to scale)

Source Blueprint Institute analysis

Regulation services

Regulation services are used to correct minor deviations in the demand and supply balance *within* the five-minute dispatch interval. Minor imbalances can occur for various reasons, including errors in demand forecasts and generators failing to meet their dispatch target.

Regulation services are governed by signals from the market operator and therefore differ from contingency services, which are signalled by an unexpected local change in frequency. The output of the enabled generators is controlled via the Automatic Generation Control (AGC) system at four-second intervals. The AGC system essentially allows the Australian Energy Market Operator (AEMO) to continually monitor the system frequency and signal generators to alter their output in a manner such that the frequency (and thus supply and demand) is balanced. As with contingency services, there are regulation services to both raise and lower output.

Cost and cost recovery

The pricing of the frequency control markets is linked to the pricing of the wholesale market because of the trade-off between selling capacity for frequency control or using that capacity to sell into the energy market. Consequently, the incentive to make capacity available to the Frequency Control Ancillary Service (FCAS) market is linked to the opportunity cost of using that capacity to sell into the energy market.

Frequency control prices might be expected to correlate with wholesale market prices. However, this has not been the case. Up until 2014-15, the market value of all frequency control services was in the vicinity of $20-40 million per year, or about 0.2-0.4% of the wholesale market. In 2020, the FCAS market was valued at approximately $200 million, representing a 5- to 10-fold increase. Raise services, which raise frequency, are responsible for the majority of the cost increases (see Figure 15).

The cost of these services are borne by market participants. For regulation services, they are recovered on a 'causer pays' basis. This is intended to create incentives for generators to more accurately match their dispatch targets, since failure to hit dispatch targets is a cause of any mismatch between supply and demand within a five-minute dispatch interval. When resources are needed to correct a mismatch, generators that caused this mismatch pay an appropriate contribution. Generators and consumers both pay for the cost of contingency services based on their energy consumption or generation.

Inertia and system strength

The large thermal power stations that traditionally dominate power systems are physically and electrically synchronised with the grid. That is, the generator rotors physically rotate in synchronisation with the grid. By virtue of this connection, they provide other services to the grid and are often referred to as 'synchronous generators'.

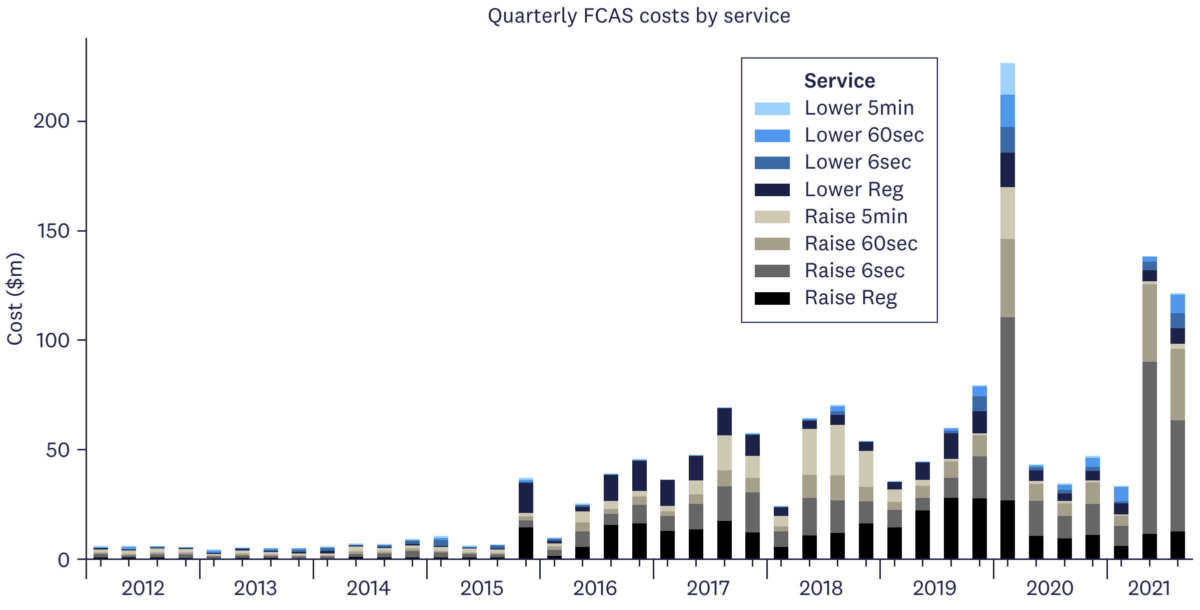


Figure 15 Quarterly FCAS costs by service

Source Australian Energy Regulator

Inertia is one of these services that is important in the context of frequency control. There are additional services such as voltage control, and ability to provide fault current that have been grouped as *system strength*.

Inertia has been provided by default by the thermal generators that have historically provided power to the grid, and as such hasn't traditionally been valued by a market mechanism. In fact, inertia is largely provided at no additional cost. As large synchronous power plants leave the system, there will likely be a need for further consideration of the value of inertia, and the need for a market mechanism to value this service may be required.

The inertia of the system affects the rate of change of frequency (RoCoF) to a disturbance. The rotational inertia from synchronous units provides an inherent and instantaneous response to frequency deviations by slowing the rate of change of frequency. The difference between a high-inertia system and low-inertia system is illustrated below in Figure 16. Impacts are highlighted in grey.

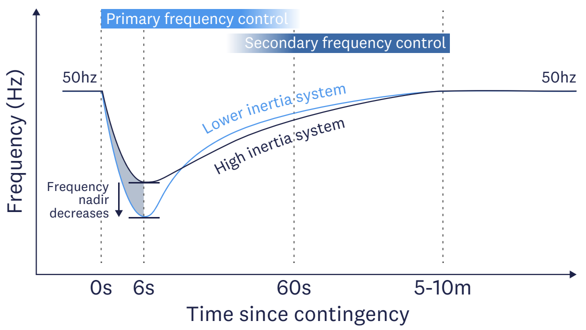


Figure 16 The impact of high and low inertia levels on the three raise contingency services

Source Blueprint Institute analysis

The amount of inertia in a system affects the *frequency nadir*, the point to which the frequency drops in response to a contingency event. The frequency in systems with lower inertia is expected to fall faster for a given event, and thus further before the primary frequency response arrests the decline. This increases the likelihood of cascading failure, when protection systems at other generators are progressively tripped, which in turn would disconnect more generation, which in turn exacerbates the event.

To date, issues to do with inertia and system strength have largely been confined to South Australia and Northern Queensland. AEMO has managed these problems by either intervening directly in the market or by directing certain combinations of synchronous generators to remain online. While such interventions ensure that there is sufficient inertia and system strength, they come at a cost and can prevent the market and the scheduling of resources from functioning efficiently.

Fast Frequency Response

One measure to partly address some of these issues is 'fast frequency response' (FFR). The concept is similar to the contingency services described above. But the response might occur within milliseconds to seconds, not six seconds—as the fastest frequency market response currently achieves.

While FFR does *not* increase inertia (or reduce the RoCoF), it does reduce the magnitude of the frequency nadir, the most extreme point in the contingency event from the nominal 50 Hz. By shortening the time period between the contingency event and the injection of sufficient arresting energy (see Figure 17), FFR can potentially reduce the need for physical inertia.

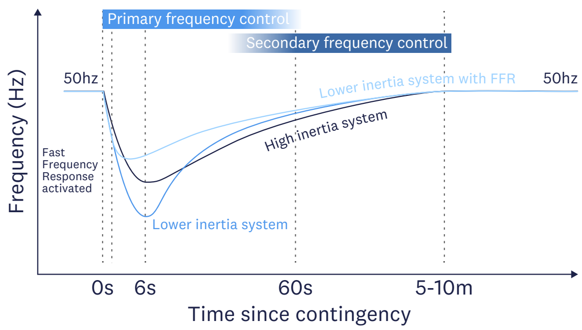


Figure 17 Impact of fast frequency response following a contingency event

Source Blueprint Institute analysis

The Australian Energy Market Commission (AEMC) recently published a decision to introduce two new market ancillary services to help control system frequency and keep the future electricity system secure, namely the "very fast raise service" and the "very fast lower service". Further consultations are exploring a range of questions and characteristics. These include, but aren't limited to the appropriate response time for the new service (for example, 0.5, 1, or 2 seconds).

Regulated networks: 'poles and wires'

The transmission of power from generators to end users is central to the existence and efficient functioning of the National Electricity Market. The network infrastructure consists of transmission and distribution networks.

The *transmission network* transports power in large quantities at high voltages between generators and major load centres. Where power travels from major centres to residents through the *distribution network*, the voltage is lowered for safety. Both networks ensure electricity gets from generators to residential and industrial customers.

The combined value of the network infrastructure in the NEM is valued at over $100 billion. The infrastructure consists of poles and wires, towers, substations, transformers, and switching equipment, along with monitoring and signalling equipment. The sector is colloquially referred to as the 'poles and wires'.

Monopoly regulation

Both transmission and distribution networks are 'natural monopolies'. Natural monopolies tend to occur where it is only possible, or only makes economic sense, for a single entity to provide a service. In the case of networks, it makes little economic sense (nor is it practically feasible) for a multiplicity of suppliers to run parallel power lines down the street to a home and compete for the provision of service.

Consequently, the transmission and distribution networks are broken into geographic monopolies regulated by the Australian Energy Regulator (AER) to mimic competitive pressures where possible. The regulated businesses that operate the transmission and distribution networks are often referred to as Distribution Network Service Providers and Transmission Network Service Providers.

The central process the Australian Energy Regulator uses to encourage efficient service delivery is the determination of a revenue cap. Simply put, the regulator sets the maximum revenue that a network business can earn from its customers for delivering electricity. In this process, it assesses how much revenue a prudent network business would need to cover its efficient costs. The revenues are then capped at this level for the regulatory period, which is typically five years.

Network businesses base their proposed revenue on several components—or 'building blocks'. They include a return on capital, depreciation, operating costs, and taxation. Incentive mechanisms exist to reward the efficient use of capital and operating expenditure. Network business and customers share the benefit of any reduction in costs below the approved cap.

Competition and privatisation

From liberalising the banking sector and floating the exchange rate to extensive domestic deregulation and opening up the economy for greater global trade—the economic reforms of the 1980s and 1990s were all about maximising competition. It's difficult for many modern minds to imagine a time where bureaucrats in Canberra or the state capitals would set the price for daily staples like milk and eggs. Yet, price controls were part of life until they were scrapped at the turn of the century. It's no surprise that a system as big and critical as electricity provision also caught the eye of ambitious reformers.

Changes didn't come without opposition. For example, many people were incredibly anxious about the privatisation of Telstra two decades ago. More recently, electricity privatisation was an enormous issue in both the Queensland and NSW elections in 2015. In each case, the debate was fraught with myths about the impact of privatisation on electricity prices in the NEM. Advocates against the "sell-off" alleged that the privatisation of NSW's poles and wires would cause higher electricity prices and a loss of public profit.

But all transmission and distribution network operators, whether owned by a corporatised government entity or a private company, are constrained by the Australian Energy Regulator's revenue cap. The web of regulation does not distinguish between private and public entities. If anything, the evidence indicates lower charges from private companies may be achievable because of existing incentives to lower costs.

Nor does selling transmission assets necessarily undermine long-run public revenue, so long as the sale is at an appropriate price. A lump-sum payment that enables infrastructure spending will likely do more to grow an economy than the same total amount received in small chunks each year.

While privatisation is no guarantee of efficiency, it certainly has not been the dominant cause of power price woes.

The open-access regime

Transmission is funded by and developed for loads. Transmission businesses are required to make investments to meet the reliability requirements of the jurisdiction in which they operate. These network reliability standards are set by regulators on behalf of the energy consumers in the relevant jurisdiction.

As part of this arrangement, consumers receive a level of implied access 'right' or firm access to the network. Consumers then pay transmission use of system (TUOS) charges. In other words, the customers bear the costs of the assets and operating expenses that are required to provide them with the reliable supply from the shared network they have access to.

This is not the same for generators. Generators have the right to negotiate a connection to the transmission network and pay a 'shallow' connection charge relating to the cost of their immediate connection to the shared transmission network. They have no guarantee that they can export all of their generation to this system, but they also don't pay transmission use of system (TUOS) charges.

As such, transmission businesses focus their investments and operating expenses on creating a reliable supply of energy for consumers. The connection of new generation assets can only develop to the extent that is necessary to ensure consumers receive a reliable supply of electricity.

Congestion

Generators are dispatched based on the price at which they offer their power generation to the market. However, they are also subject to the physical limits of the system, including the capacity of the transmission. If there is not enough network capacity, the dispatch engine will not dispatch a generator, even if it has a lower price. Regardless of price, the energy cannot be delivered to the market. This phenomenon is known as congestion.

Generators earn money by being dispatched. They get paid according to the energy they deliver to the market. Congested networks therefore pose a revenue risk to the generator—a risk generators cannot fully anticipate when they make their investment decisions. For example, there is a risk that just as one generator has cemented its investment, another generator connects to the grid and congests the line. As it currently stands, a generator considering investing in a new plant has no means of managing this congestion risk and the risk of not being dispatched (known as 'constrained off'). As discussed above, generators do not have an inherent right to be dispatched, nor do they pay TUOS charges, meaning they do not have a right to be compensated when not dispatched.

It might be economically beneficial to customers to augment the shared network to alleviate generator constraints. This might ultimately even be financed. Still, a generator has no means of managing the risk that the augmentations are not delivered in a timely manner. Generators can theoretically fund network augmentation, but the nature of the open-access regime implies that generator-funded network augmentations do not bestow any physical or financial rights to the network.

Chronic congestion in the United States

Most Australians can hardly imagine a kind of congestion that is more inconvenient and infuriating than the peak-hour crawl. But recent failures in the American grid have highlighted the potential for similarly frustrating bottlenecks on our electricity transmission lines. Despite some confused claims that windmills were to blame, the primary issue was actually freezing natural gas pipelines and a raft of other transmission issues, rather than generation failures.

While there are a variety of technical problems at play in energy markets throughout the United States, chronic congestion has been pinpointed as a, if not the, "central issue". This inability of current transmission infrastructure to carry the necessary supply to consumers, even if it can be reliably generated, is costing Texas approximately $1.36 billion every single year.

At its worst, a severe winter deep freeze in February 2021 left more than 4.5 million Texas customers (over 10 million people) without power, many for multiple days. Cumulative damages, lost output and electricity price spikes are estimated to have cost the state $177 billion (see Figure 18). That may not be as painful as sitting in traffic for half an hour, but it's certainly close.

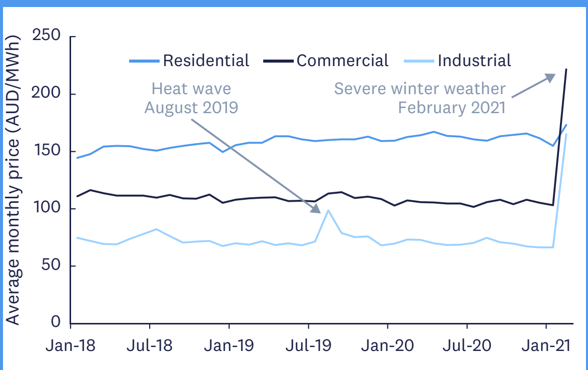


Figure 18 Average monthly electricity price in Texas, by customer sector (Jan 2018-Feb 2021)

Source US Energy Information Administration

On June 8, Governor Greg Abbott heralded new legislative reforms as "everything that needed to be done...to fix the power grid in Texas." And yet it took less than a week for those hopes to begin to melt away, as the Electric Reliability Council of Texas reacted to summer heat waves by appealing for households to limit their air-conditioning usage and endure higher temperatures to conserve power. In a sign of things to come, some Texans even had their smart thermostats raised remotely by utility companies.

Similar blackouts and price spikes have rocked California over the past couple of years. But in California, the reality of present congestion issues may be even harder to swallow. Back in 2001, poorly designed congestion pricing regulations allowed companies like the infamous Enron to engage in 'Death Star' scams. By deliberately overscheduling transmission lines to reserve more capacity than they actually required, market manipulators would create fake congestion and then profit from the illusion by driving up prices and earning 'congestion fees' paid by the state.

If there's anything we can learn from the United States, it's that both congestion, and the way it's regulated, really matters.

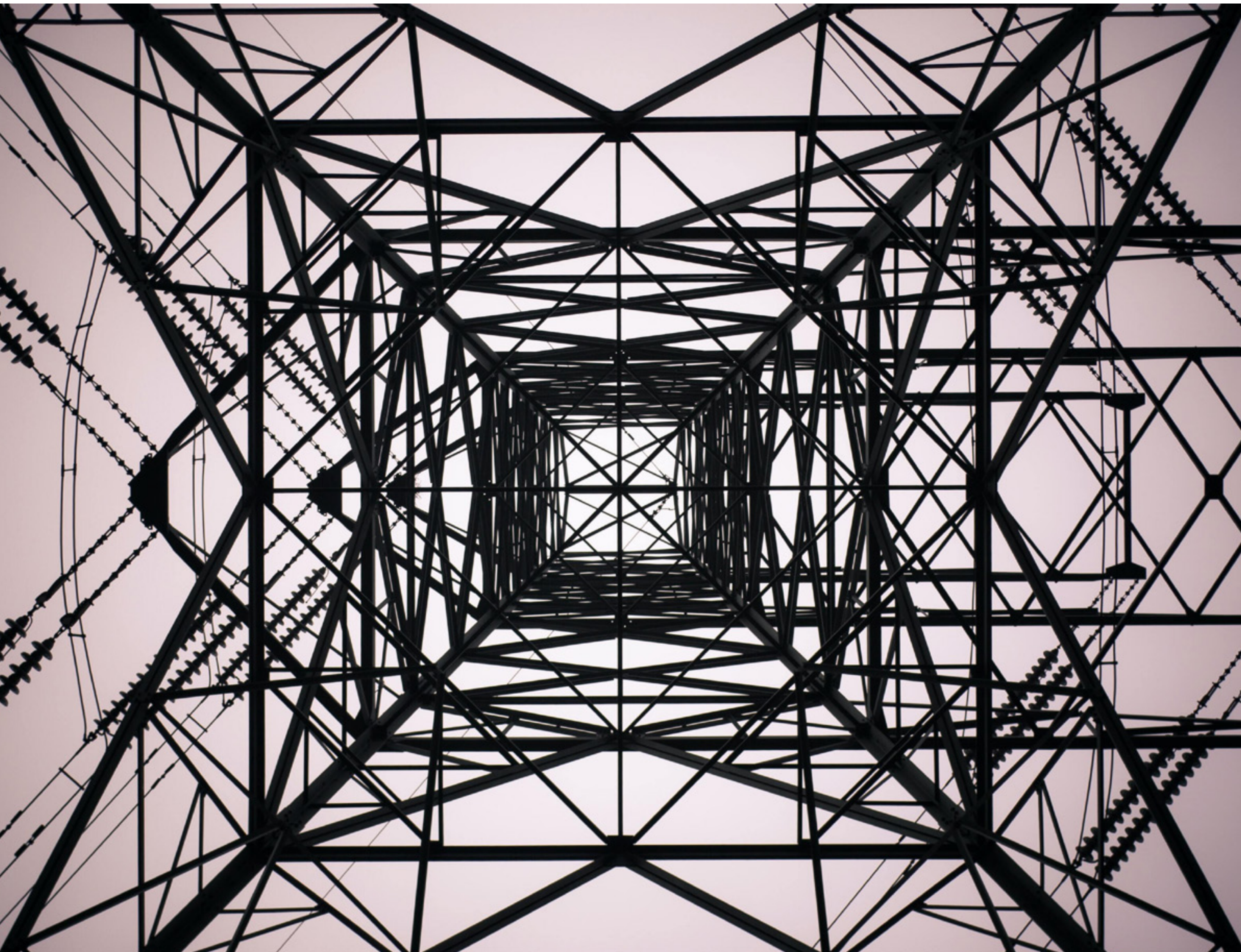
The regulatory investment test for transmission

When a transmission network has reached the limit of how much energy it can transport, this can usually be relieved by augmenting the capacity of the network. Transmission companies are able to invest capital to increase network capacity, when such an augmentation passes a cost-benefit test. This cost-benefit test is known as the regulatory investment test for transmission (RIT-T). It can be applied to transmission projects within a transmission company's own region or between multiple regions.

Under the RIT-T, businesses are required to assess the efficiency of proposed augmentation investment options by estimating their benefit to market participants and consumers, and weighing these against their associated cost.

The purpose of the RIT-T is to identify the transmission investment option that maximises net economic benefits and, where applicable, meets the relevant reliability standards. If a proposed investment passes the criteria governing the RIT-T, the business may proceed with the investment, which will be funded by customers through 'transmission use of system' charges.

This regime is currently being tested by the rapid deployment of renewable energy generation. Generation, rather than load, is increasingly being supplied from geographically dispersed locations. In particular, proposals to develop Renewable Energy Zones (REZ) and other transmission projects are challenging the existing framework, prompting consideration of reform options.



Governance & institutional arrangements

The current regulatory framework was initially codified and outlined in what is known as the Australian Energy Market Agreement, signed by the Commonwealth, States and Territories in 2004. Under this agreement, the current market institutions were proposed, and roles were defined with the aim of improving and streamlining governance arrangements for the nation's energy sector. This final section describes some of the key governance arrangements for the National Electricity Market.

The National Electricity Law

While the current arrangements weren't settled until 2004, the National Electricity Law, the key legislation underpinning the NEM, actually first came into existence in 1996. Perhaps surprisingly, the National Electricity Law is contained within an act of the South Australian parliament. This is due to the fact that within the Australian Constitution, energy is a so-called 'residual power'. This means constitutionally, it is within the state's jurisdiction to make laws about energy (and in this case, electricity). As such, the law is cooperatively adopted and applied as law in each participating jurisdiction of the NEM by application statutes.

This legislation articulates the National Electricity Objective and establishes the National Electricity Rules for regulation of the electricity industry. The law also confers regulatory powers to statutory bodies and other institutions, enabling them to develop and enforce appropriate market rules. The law provides the legal basis for the market and for the National Electricity Rules. It sets out the objectives of the market.

National Electricity Objective

The National Electricity Objective (NEO), as stated in the National Electricity Law, is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

- Price, quality, safety, reliability, and security of supply of electricity; and
- The reliability, safety, and security of the national electricity system.

These objectives are the highest point of reference for policy setting.

The National Electricity Rules

In accordance with the National Electricity Law, National Electricity Rules (NER) are developed for and with respect to regulating the electricity sector. The rules govern the detail of technical and economic regulation of wholesale and retail electricity markets, and electricity network businesses. Specifically, these rules are for regulation of:

- the operation of the national electricity market;
- the operation of the national electricity system for the purposes of the safety, security, and reliability of that system;
- the activities of participants in the national electricity market or those involved in the operation of the national electricity system;
- and any other matter contained within the National Electricity Law.

Key institutions

Australian Energy Market Commission

The Australian Energy Market Commission (AEMC) is the rule maker and developer for the Australian electricity and gas markets. The rules set the operating requirements and obligations for participants and institutions. Key responsibilities include consideration of rule change proposals that govern energy markets and conducting market reviews. The rule making and development process is intended to ensure the rules respond flexibly to the significant changes in market conditions and policy settings.

The National Electricity Law also requires the commission to establish an independent reliability panel. This body essentially monitors, reviews, and reports on the security and reliability of the national electricity system in accordance with the rules. They determine settings related to reliability, including the market price cap.

Australian Energy Regulator

The Australian Energy Regulator (AER) is Australia's national energy market regulator. The AER performs its regulatory functions under the national electricity law, and the national electricity rules.

The key focus is on regulating the natural monopoly transmission and distribution sectors of the NEM, monitoring the wholesale electricity market, and enforcing electricity market rules. The functions are set out in national energy market legislation and rules, and include:

- Setting the prices charged for using energy networks including electricity transmission networks and gas pipelines;
- Monitoring wholesale electricity and gas markets to ensure suppliers comply with the legislation and rules, and taking enforcement action where necessary;
- Publishing information on energy markets, including the annual 'State of the energy market' report and more detailed market and compliance reporting;
- Assisting the Australian Competition and Consumer Commission with energy-related issues arising under the Competition and Consumer Act, including enforcement, mergers, and authorisations.

Australian Energy Market Operator

AEMO's main day-to-day responsibility is the operation of the NEM. This includes operating and maintaining the dispatch system through which electricity prices are set and transactions are carried out. AEMO also acts as the clearing house for transactions in the wholesale electricity market that occur through this process.

Other market operations involve market performance reporting, incident analysis and emergency management, and the provision of market data to participants. A key report published by AEMO is the 'electricity statement of opportunities'. This report is published annually, intended to showcase market investment opportunities to private companies over a ten-year period by highlighting what new capacity may be required.

AEMO is also responsible for the strategic long-term planning of the NEM, including the Integrated System Plan (ISP). The report outlines the long-term, efficient development of the electricity transmission system, its major transmission flow paths and infrastructure projects.

Unlike the other institutions, AEMO is a not-for-profit organisation, registered as a public company limited by guarantee. Its membership is split between government and industry members. A 60/40 weighting between government and industry member voting rights seeks to balance out the public interest and the requirements of electricity market participants.

Energy Security Board

The Energy Security Board (ESB) is a relatively new institution, established after Dr Alan Finkel's 2017 review of the NEM. The intention of the ESB was to oversee the implementation of the 50 recommendations from the Finkel Review, and to last until 2020. The ESB membership was to include the heads of the key Institutions (AEMC, AER and AEMO) and an independent chair and deputy chair. A key aim was to align the market bodies to expedite critical reforms.

However, the ESB has since departed from its initial remit, which includes conducting the 'post-2025 market review'. Final recommendations from the review have been delivered to energy ministers, and now the ESB is set to be reformed itself. A reformed ESB is likely to remain a coordination body headed by the key institutions. But rather than having an independent chair and deputy chair, the AEMC could be chairing the board.

Energy National Cabinet Reform Committee

In the early days of the NEM, state and federal energy ministers established the Ministerial Council on Energy as the overarching national policy and governance body for the NEM.

Since its formation, the Ministerial Council on Energy has gone through several iterations. This includes being the Standing Council on Energy and Resources, and until recently the COAG Energy Council (COAG-EC). The latest iteration is the Energy National Cabinet Reform Committee, established in 2020. While these bodies were not identical, and had different structures and reporting requirements, they all provide a forum for the nation's energy ministers to set policy direction and guide the development of the NEM.

While the current powers and roles of the Energy National Cabinet Reform Committee are less defined with the abolishment of COAG last year, this body fulfils similar functions to its predecessors. This includes the power to issue policy directions to the AEMC with respect to its rule-making function and the power to recommend appointments of commissioners to, and approve funding arrangements for, the AEMC and AER. In line with previous iterations of this council, this body will be expected to be responsible for:

- The national energy policy framework;
- Policy oversight, and future strategic directions for the Australian energy market;
- Governance and institutional arrangements for the Australian energy market;
- The legislative and regulatory framework within which the market operates;
- Longer term systemic and structural energy issues that affect the public interest.

Recommended resources

This list contains some recommended reading for those wanting to dig deeper into the intricacies and details of the NEM. Many of these reports were mentioned or drawn upon in the creation of this guide.

- State of the Energy Market, published by the AER.
- Annual Market Performance Review, published by the AEMC.
- Health of the NEM, published by the ESB.
- Electricity Statement of Opportunities, published by AEMO.
- Integrated System Plan, published by AEMO.
- National Electricity Market Fact Sheet, published by AEMO.
- Guide to Ancillary Services in the National Electricity Market, published by AEMO.

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