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Revisiting Electricity Market Reforms

Lessons for ASEAN and East Asia

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Preface

The United Nations (UN) climate change conference in Glasgow (COP26) where almost 200 countries gathered to discuss all facets of climate change underscored the importance of accelerated global decarbonization. The decarbonization of the electricity sector is central toward meeting this COP26 agenda since the sector offers ample opportunities for the earliest and steepest cuts in global greenhouse gas emissions. Intertwined with the decarbonization agenda are the affordability and sustainability objectives that the electricity sector also has to deliver. Effective electricity sector reforms design and implementation ensures that these interrelated energy policy objectives of affordability, environmental sustainability, and energy security can be achieved.

The Association of Southeast Asian Nations (ASEAN) underwent an electricity market reforms experimentation in the early 1990s for the purpose of achieving the energy policy trilemma of affordability, environmental sustainability, and security of supply. Reforms have both progressed and stalled in the region after more than three decades since the initiation of power sector reforms. Singapore became the first country in Southeast Asia to launch a competitive power market in 2001. Philippines followed suit by establishing a wholesale electricity market in 2006. South Korea introduced competition in the electricity generation segment in 2001. Vietnam is also keen on establishing an efficient and competitive power market since 2012. However, the ASEAN got exposed to the vulnerability of liberalized electricity markets when electricity prices spiked in Singapore in 2021 causing electricity retailers to exit the market. Around 95% of electricity in Singapore is generated from imported natural gas. The rising price of natural gas led to skyrocketing wholesale electricity prices and crippled the market since electricity retailers locked in contracts with consumers but did not sufficiently hedge against a big wholesale price spike. In many ways, the energy crisis in Singapore was a timely reminder of the 2000–2001 Californian electricity crisis.

Several questions are now raised in the ASEAN in the context of electricity market reforms and energy policy objectives. Are the existing electricity markets fit for purpose of delivering the trio goals of energy affordability, sustainability, and supply security? What market designs are necessary in the ASEAN to avert a crisis as experienced by Singapore? What can the ASEAN policymakers learn from the global reform experience including the ASEAN economies? The purpose of this book is to revisit and reflect on the electricity market reforms globally with the objective of providing valuable lessons and guidance for the ASEAN and East Asia as electricity reform deepens in addressing their energy policy objective. The book consists of 12 chapters and is segmented into three distinct but interrelated sections.

The **first section** is based on the ASEAN experience and comprises three chapters that qualitatively and quantitatively captures the reform experiences in the ASEAN region including a country-specific case study on Vietnam. The chapter "From the Market to the State: New Lessons from Regional Experiences with Power Sector Reform" by Sen et al. revisits the status of power sector reforms in non-OECD Asia and Latin America by focusing on the re-emerging role of the state in electricity provision. This chapter highlights how government involvement in the sector continues to meet the financing and investment needs of the electricity sector in liberalized and restructured wholesale electricity markets. Electricity market reforms can involve both private and public sector financing using approaches based on '*competition in the market*' and '*competition for the market*' in meeting environmental objectives.

The chapter "What Have Reforms Delivered So Far?—A Quantitative Analysis of Power Sector Reform Impacts in the ASEAN Economies" by Nepal et al. examines the socio-economic and technical impacts of power sector reforms in the ten ASEAN member countries from 1990 to 2018 relying on econometric techniques. This is one of the limited studies in the reform literature to control for the effects of cross-sectional dependence. The impacts of power sector reforms were found to be mixed and heterogeneous despite reforms being successful in improving technical performance by reducing network losses. The absence of proper regulatory institutions supporting market-based reforms has led to reforms not generating the anticipated impacts across the economic, technical, and welfare dimensions. One of the major messages from this chapter is that the ASEAN economies should not solely rely on power sector reforms to boost electricity consumption in the region but rather accelerate policies to improve electricity access.

The chapter "Electricity Market Development in Viet Nam: Historical Trends and Future Perspectives" by Thai-Ha et al. discusses the process of electricity market development in Vietnam with a focus on key achievements and future perspectives. Security of electricity supply trends is studied for Vietnam and other ASEAN+6 countries for the period 1996–2019 based on principal component analysis (PCA). The study finds that security of electricity supply in Vietnam has been rising over the past 25 years. However, Vietnam should expand the national electricity grid and install a smart power system that integrates different power sources to meet the country's fast-growing electricity demand in the future and not solely rely on electricity market reforms.

The **second section** consists of three chapters that quantitatively and qualitatively captures the electricity market reform experiences in some of the early and advanced reforming countries, namely, Australia, Sweden, and Norway. The chapter "Australia's National Electricity Market: An Analysis of the Reform Experience 1998–2021" by Simshauser studies Australia's National Electricity Market (NEM) reform experience between 1998 and 2021. The highlights of the NEM reforms were the restructuring of vertical monopoly electricity utilities and the creation of an energy-only, gross pool, real-time wholesale market, and associated forward market. The chapter argues that the NEM and associated forward markets could not navigate market failures associated with sudden coal plant divestment and climate change policy discontinuity. A number of market design options are proposed such as a rethink of the ancillary markets FCAS markets, and volumes, in order to deal with rising intermittency as renewables in the wholesale market increase.

Chapter "Analysis of Forecasting Models in Electricity Market Under Volatility: What We Learn from Sweden" by Salah Uddin et al. examines wholesale price volatility which is an inherent feature of a liberalized wholesale electricity market focussing on the case of Sweden. Sweden deregulated its electricity market in 1996. This chapter conducts an extensive empirical analysis based on time-series econometrics to evaluate the short-term price forecasting dynamics of different regions in Swedish electricity market. The chapter showcases that wholesale electricity markets should rely on robust forecasting methods for proper forecasting-process design that will enable effective policy implications for market efficiency and wholesale price predictability.

The chapter "Modelling and Forecasting the Volatility of the Nordic Power Market: An Application of the GARCH-Jump Process" by Datta focuses on modeling and forecasting price volatility in the Nordic power market. The deregulation of the power markets in the Nordic countries occurred in the early 1990s and eventually led to the establishment of Nordpool in 1996 with Finland and Sweden joining the Nordpool in 1998 and 2000 respectively. Nord Pool is Europe's leading and efficient power market owing to its simple market design. The chapter relies on time-series econometrics to describe the volatility process and the jump behavior in Nordic electricity prices. The findings reveal that the Nordic power market is highly volatile with existing time-varying jumps which energy economists, energy policymakers, and market analysts should consider in designing electricity markets.

The **third section** consists of two chapters capturing the reform experience in the South Asian economies of Bangladesh and India. Chapter "An Econometric Assessment of the Effects of Electricity Market Reform on Bangladesh Economy" by Sakib et al. provides the reform perspectives from Bangladesh as the nation undertaking electricity sector restructuring, creating independent regularity bodies, and promoting the private sector firms to enter the electricity market. The effects of electricity market reform on the energy sector development and macroeconomic stability in Bangladesh are studied based on a time-series dataset for the period 1980–2019. Bangladesh government should continue with energy price reform to attract increased private participation.

Chapter "The Role of Electricity Market Reform and Socio-economic Conditions in Electricity Consumption in India" by Parhi study the role of electricity market reform and socio-economic conditions in electricity consumption in India. The Government of India (GoI) started power sector reform initiatives in 1991. This chapter models and estimates the mediating role of intra- and inter-regional electricity consumption patterns to elicit significantly heterogeneous electricity consumption behavior in Indian electricity market. One of the major messages from this study is that the reform itself requires a deeper and strategic interactions with the political will to be successful when implemented.

The **fourth section** consists of four chapters studying varied dimensions of electricity market reform impacts on sustainability and security. Chapter "Have Competitive Electricity Markets Rewarded Flexible Gas-Powered Generation? Australia's Lessons for ASEAN" by Shi et al. investigates the role of the electricity market reforms on flexible gas generation capacity that is needed to mitigate variable renewable energies especially in the context of coal plant closures as in the case of Australia. One of the major contributions of the chapter is undertaking a rare study on the relationship between electricity and natural gas markets in Australian National Electricity Market (NEM). The Australian experience suggests that ASEAN should continuously liberalize its electricity markets and establish a merit-order competitive electricity market while leveraging the flexible role of natural gas.

Chapter "Decarbonizing Emissions in the Electricity Sector of the Mekong Subregion: Policy Implications" by Phoumin focusses on decarbonizing emissions in the electricity sector of the Mekong Subregion and draws policy implications for the electricity market. The challenges of market structure and policy in the power generation sector in moving forwards to embrace electricity market liberalization in the region should not be undermined. The chapter recommends that the ASEAN electricity markets should embrace unbundling of ownerships in the electricity market segments and ensure non-discriminatory third-party access for transmission and distribution networks. The gradual removal of subsidies in fossil fuels based power generation is also necessary are to ensure the pre-conditions for market competition by bringing a level playing field to new technologies and renewables into the energy mix.

In chapter "Sustainable Energy Policy Reform in Malaysia", Ludin et al. study Malaysia's commitment to facilitate sustainable energy policy reforms and the implication to the electricity market. The study recommends that liberalization of the electricity market will be required as part of an energy transition to lower reliance on carbon-based energy sources. Market liberalization will ensure the energy sector's viability by attracting market players who can offer better quality of service and pricing. The establishment of an independent regulator will also protect the interests of both the industry and the consumer.

The chapter "Digitalisation in the Context of Electricity Market Reforms and Liberalisation: Overview of Opportunities and Threats" by Glaa and Uddin discusses digitalization as an enabler of electricity market reforms and thereby promotes competition, security of supply, and sustainability. The chapter argues that digitalization also makes electricity systems more vulnerable to cyber-attacks especially in the context of liberalized electricity markets. One of the important recommendations from the chapter is that international cooperation among liberalized electricity markets can help governments and the electricity industry to build up digital resilience capabilities.

Electricity markets in the ASEAN have transitioned from the vertically integrated state ownership to a single-buyer model in which state-owned utility remains the ‘single buyer’ but the private sectors participate in electricity generation as ‘Independent Power Producers’ (IPPs). Except Singapore and Philippines, wholesale and retail competition is absent in other markets. These markets will have to undergo further restructuring and reforms while being exposed to the supply security risks associated with decarbonization and digitalization of the sector. This book contains important empirical studies providing pragmatic policy recommendations that will enable the ASEAN and other reforming electricity markets around the globe as lessons to carry forward in implementing reforms for provisioning of an affordable, secure and sustainable electricity supply. The book is also an equally valuable resource for researchers and graduates students with a specialized interest in electricity markets and energy policy.

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Contents

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From the Market to the State: New Lessons from Regional Experiences with Power Sector Reform

Rabindra Nepal, Anupama Sen, and Tooraj Jamasb

Abstract Developing economies and emerging markets worldwide are set to experience a significant increase in their electricity system financing needs as their electricity demand expands alongside their ambitions for increased regional electricity trade—all of which is underpinned by an ongoing process of power sector reform. However, in this context, they face the dual challenge of decarbonising their electricity systems and ensuring the security of supply to their economies. This chapter revisits the status of power sector reforms in non-OECD Asia and Latin America. It draws new policy lessons from recent experiences, focusing on the re-emerging role of the state in electricity provision, highlighting how government involvement in the sector continues despite the pursuit of wholesale electricity market restructuring and liberalisation, which has thus far failed to meet the financing and investment needs of the electricity sector. Electricity market reforms can involve private and public sector financing using approaches based on 'competition in the market' and 'competition for the market'. We argue that underdeveloped institutional capacity and a lack of effective governance remain impediments to any reform process, requiring effective regulation and an institutional framework that evolves alongside the pursuit of market-oriented reforms in the era of climate change.

Keywords Power sector · Market reforms · Non-OECD Asia · Government · Private sector · Latin America

JEL Classifications L94 · L98 · L90

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1 Introduction

Governments in most countries owned and operated major infrastructure and network industries, including energy, transport, telecommunications, and water, up until the early 1990s. The state-led model was adopted as the standard approach to economic development following the Second World War. State ownership in the electricity sector was characterised by public sector responsibility towards national industrialisation and rural electrification (Williams and Ghanadan 2006). However, since the 1980s, the growing demand for infrastructure investment and the pressures on limited tax revenues have pushed the public sector to involve private finance (Stern 1997). Estache et al. (2005) found that private corporations had emerged as active actors in electricity provision in 40–50% of countries worldwide.

There is a plethora of economic theories on the relative merits of private and public ownership in infrastructure provision (Laffont and Tirole 1993; Gilbert and Newbery 1994; Hart et al. 1997). Laffont and Tirole (1993) argued that private ownership is beneficial in terms of capital market monitoring and lack of soft budget constraints, while public ownership reduces the typical principal–agent problems in economic regulation and prioritises social welfare. Furthermore, the paradigm shifts towards more private sector involvement in the early 1990s were due to ideological, technological, and financial factors in developing and transition economies (Jamasb et al. 2005). Many state-owned utilities failed to recover their electricity supply costs from highly subsidised electricity prices leading to deteriorating financial conditions.

Further, macroeconomic and fiscal crises in many developing countries during the early 1980s meant that the state-led model failed to improve operation efficiency and attract investments to the sector (Pollitt 2004; 2008). The structural adjustment programmes (conditional financing imposed by multilateral agencies) adopted in many non-OECD Asian and Latin American countries in the 1990s to resolve macroeconomic crises subsequently focused on increased private sector financing to relieve the public sector investment constraint on economic growth as their cornerstone.

Greater competition, alongside privatisation in the infrastructure sectors, in economies such as Chile and Great Britain, was interpreted as blueprints for successful reform across Africa, Asia, and South America irrespective of the differences in the contexts and initial conditions of individual countries. This led to the adoption of the standard menu for reform, also most popularly known as the ‘textbook model of reform’, which had been extensively reviewed in the literature on power sector reforms (Joskow 1998, 2008; Newbery 2002; Besant-Jones 2006; Kessides 2012; Jamasb et al. 2017). The standard reform model brought about a shift in sector structures, state involvement, and independent regulation. The model included the following reform measures (Jamasb et al. 2017): (i) corporatisation of vertically integrated state-owned enterprises; (ii) enactment of reform legislation; (iii) establishment of an independent regulatory body; (iv) vertical separation or ‘unbundling’ of the monopoly segments (transmission and distribution networks) from the competitive segments (generation and retail); (v) incentive regulation of networks, still classed as natural monopolies, based on ‘price cap’ or ‘revenue caps’;

(vi) establishment of wholesale electricity markets; and (vii) divestiture or privatisation of generation (by opening up the generation segment to the independent power producers (IPPs) and retail supply.

Technological advancements and the availability of less costly small-scale electricity generation technologies facilitated the restructuring of the industry through the separation of the competitive segments (generation and retail) from the regulated monopoly segments (networks) (Jamasb 2006).

For example, transition economies, such as those belonging to the Former Soviet Union largely undertook a market-based economic transformation that also included the power sector (Nepal and Jamasb 2012a). While improving efficiency was one of several objectives of power sector reforms, empirical evidence has shown that the link between ownership and efficiency is tenuous at best (Estache et al. 2005).

Nonetheless, the public sector continues to be significantly involved in energy provision in non-OECD countries following nearly 3 decades of the long-running reform trend towards privatisation, competition, and independent regulation (Pollitt 2008; Haney and Pollitt 2013). Almost half of the global installed electricity generation capacity is owned by state-owned entities, with state ownership more pervasive in developing countries (Steggals et al. 2017). Recent assessments also concluded that the impact of private sector participation on utility performance is debatable (Bacon 2018). Many electricity markets possess hybrid facets with various forms of regulatory intervention where the state plays a significant role in electricity sector planning and the auctioning of long-term contracts (Roques and Finon 2017). Public intervention and involvement are apparent in most electricity markets globally, as pure market-based models have failed to deliver adequate security of supply, determine the optimal generation mix, or induce investment towards network expansion (Joskow 2019). In this context, the modus operandi of the power sector currently sits between the 'state' and the 'market', leading to important questions: what are the new drivers of reform that have led to the continued presence of the public sector, and how are these influencing the emergence of different market models in the power sector? The answers are relevant from a policymaking perspective as power sector reforms are still ongoing in many Asian developing countries. However, the pace of the reform process has varied, particularly in non-OECD Asia.

Non-OECD Asian economies comprise about 34% of the world's primary energy demand, 60% of the world's population, and 65% of the world's poor (Sen et al. 2018). The region presents a strong case for studying reforms in the power sector and learning from reforms in other developing regions of the world. Electricity demand is set to increase by 60% from current levels by 2040, with developing countries accounting for 90% of that growth. China and India account for most of that growth (IEA 2018). Increased electricity access, combined with a drive to also electrify the transport and space cooling sectors in major non-OECD Asian countries, implies the need for a major reorganisation and governance of their electricity industries to meet the projected increase in demand.

Recent power sector reform experience in Latin America offers lessons for non-OECD Asia in the context of a revival of public intervention in redesigned wholesale electricity markets. The policy objectives of electricity sector decarbonisation and security of supply have led to reforms in many jurisdictions, such as Latin America, which liberalised their industries (Roques and Finon 2017). Latin America also provides a good frame case from which to draw lessons on electricity reforms since reforms were first adopted in Chile in the 1980s, which experimented with opening the sector to private sector and competition, and later spread throughout the region (Foster and Rana 2019; Pollitt 2004; Millan 2005). The scope of lessons for non-OECD Asia from Latin America originates in the context of wholesale electricity market designs, as some Asian economies such as Viet Nam, Pakistan, and Bangladesh are looking to deepen electricity reforms. Others are considering fostering greater regional electricity cooperation to expand their system balancing capabilities as the demand for electricity increases. Further, the literature on non-OECD reform experience is limited, apart from a few cross-country empirical studies implying limited evidence from within the region to draw lessons (Sen et al. 2018).

This chapter is structured as follows. Section 2 identifies the new drivers of reforms underpinning the continued involvement and even re-emergence of state involvement. Section 3 summarises the reform experience in non-OECD Asia. Section 4 reflects comparative regional experiences with power sector reforms in non-OECD Asia and Latin America. Finally, Sect. 5 offers policy recommendations for non-OECD Asia based on this comparison, and Sect. 6 concludes.

2 New Drivers of Electricity Reforms in the 2010s

The shift towards decarbonisation as a policy priority and the role of electrification in achieving it have led to the emergence of new drivers and new challenges in power sector reform over the last decade. For example, countries that have liberalised their electricity markets must contend with redesigning their markets to include an increasing share of intermittent renewables in the pursuit of climate change mitigation targets, while struggling to attract investments in generation to enable the transition, and embrace new technologies such as distributed energy sources, demand-side response, and storage.

Traditional energy-only electricity markets, designed mainly for fossil fuels, have set prices based on system marginal cost (the cost of the generating plant that meets the last MWh of electricity demanded and includes fuel costs and other marginal costs of generation). In contrast, renewables have low marginal costs as virtually all their costs are up-front in the form of capital costs and incur no fuel costs to produce electricity. Investment signals are built into the price in these energy-only markets, with price spikes indicating the highest demand. At the same time, supply is constrained, hence the need for additional investment in resources (Keay 2016). The high penetration of renewables would imply that prices would be very low as marginal costs set prices in competitive wholesale markets. Likewise, system operators need to more frequently activate ramping resources such as flexible plants that are more costly to operate in managing the intermittency of renewable energy sources. Therefore, the intermittency of renewables impacts the total system costs and leads to more volatile prices.

Developing countries face the additional challenge of security of supply and resource adequacy and funding the investments required to extend and improve access to electricity services and eliminate energy poverty. South Asia, for example, accounts for 25% of the total global population but only 5% of the world's electricity consumption (Sen et al. 2018). One of the fastest-growing economies, India has roughly a third of its population below the poverty line (estimated at 300 million). A significant proportion relies on non-commercial energy sources. Similarly, Pakistan continues to suffer from capacity shortages, leading to frequent blackouts, while little has been done to accelerate access to electricity in rural areas (Bacon 2019a). If these countries continue to follow the textbook model of reform, which does not anticipate the need to accommodate the large-scale penetration of variable renewable energy in wholesale electricity markets, they will unlikely deliver the energy policy goals of affordability, security of supply, and sustainability for their citizens and their economies (Nepal et al. 2018).

A third complication is political intervention in the operation of electricity markets – evidenced, for instance, in Latin America (Hammons et al. 2011; Balza et al. 2013). The original reform advocates arguably did not fully consider the impact of political economy issues. However, the influence of the political economy on power sector reform, evidenced by recurring tensions amongst the different public and private interests during the reform process, has been well documented in South Asia (Victor and Heller 2007; Lee and Usman 2018). Market failures and political economy impediments have led to a revival in public intervention in electricity, particularly when public ownership continues to be significant (Roques and Finon 2017; Haney and Pollitt 2013).[1] The growing involvement of the state in electricity markets is a departure from the 'textbook' reform model that relied on the forces of markets, competition, and privatisation.

Four different but related factors contribute to increasing public involvement and growing public ownership in emerging and developing economies. We describe them below.

2.1 Climate Policy and Renewable Energy Targets

According to REN21 (2017), 176 countries, including many developing countries, have adopted climate change mitigation targets. More recently, the United Nations Framework Convention on Climate Change's Conference of the Parties (COP) has seen record numbers of countries, including large hydrocarbon producers and

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[1] Haney and Pollitt (2013) defined public ownership as encompassing all types of companies that restrict ownership and control rights like traditional state-owned enterprises and municipally owned utilities. Thus, they include both traditional forms of public ownership and new forms of public involvement under public ownership.

exporters, declaring net-zero objectives for the middle of this century, consistent with meeting the 1.5-degree temperature target set out by the Intergovernmental Panel on Climate Change as necessary to avoid dangerous climate change. Meeting these emissions reductions and decarbonisation goals will require significant investments in low-carbon and renewable energy technologies to the tune of billions of United States dollars over the next decade alone to facilitate the energy transition. This implies high up-front costs (i.e. capital costs) that are expected to eventually lead to low variable costs (renewables have low marginal costs). But private investors perceive investments in these technologies in developing-country contexts as risky due to large-scale financing requirements in the face of rising energy policy uncertainty. At the same time, the payback periods are often around 30 years (Haney and Pollitt 2013). Although the recent COP meetings have seen a drive in the private sector towards financing green investments, it is as yet uncertain whether the pace of these investments will be fast enough to meet the scale of financing required for the energy transition. Further, the public-good nature of the large up-front capital investments towards renewable energy in the form of positive spillovers, such as social and environmental benefits, contributes to the case for greater public involvement.

Public ownership is also desirable to mitigate the risks of undersupply and ensure that large-scale investment needs of low-carbon and renewable energy are achieved. For instance, the United Kingdom proposed a new electricity market reform in 2010 signalling greater government intervention to meet its ambitious climate change objectives (DECC 2011). Its energy strategy in 2022[2] was expected to further increase the level of government intervention. Renewable energy technologies also pose technical challenges to the grid in terms of network planning and coordination because of the increasing share of variable loads that the grid is exposed to decentralised generation. Grid balancing and stability become a challenge with the increasing penetration of intermittent energy resources. While decentralisation and the harnessing of distributed energy have been proposed as a method of dealing with intermittency (i.e. matching demand with supply as opposed to matching supply with demand), in developing economies, the absence or slow pace of development of smart network systems has often meant that a centralised publicly owned grid has been easier to manage and coordinate than an unbundled structure that facilitates private sector participation.

2.2 Security of Supply

As discussed earlier, electricity prices in liberalised wholesale markets are set according to the system (short-run) marginal cost, or the short-run marginal cost of the last (and, following the merit order, most expensive) plant brought onto the system to meet demand (Sen 2014). Hence, energy-only electricity markets typically

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[2] At the time of writing, energy security had risen on the agendas of government's energy policies worldwide, due to the war in Ukraine.

suffer from the ‘missing money’ problem, where the recovery of fixed costs, such as investment costs in power plants, is not possible without an outside remuneration scheme and is thus risky. As a result, prices in energy-only markets do not fully reflect the value of the investment in electricity generation.

The lack of a guarantee to recover fixed costs in energy-only markets can lead to capacity shortages in high-demand growth economies, such as in non-OECD Asia. Hence, the ability of these economies to deliver a secure supply of electricity is being challenged while the investment need is more urgent in emerging economies, given the expected growth in demand (Wolfram et al. 2012). Governments can invest in domestic renewable energy and curtail the reliance on imports to improve energy security while also making it possible to subsidise electricity production in the long run for new and cleaner technologies through financial instruments, like tax incentives, loan guarantees, and direct grants. Large-scale investments in renewables are only financeable at a high capital cost, which the private sector may want to avoid, implying that public ownership can de-risk large-scale investments in renewables.

2.3 Inconsistencies in the Design of Market Reforms

The market-based reforms of the early 1990s were implemented within relatively underdeveloped (compared with OECD countries) legal and institutional frameworks in developing economies (Victor and Heller 2007; Lee and Usman 2018). Furthermore, electricity reforms in transition economies mostly occurred within the domain of overall wider economic reforms (Nepal and Jamasb 2012a). Achieving economic efficiency was not a prioritised goal, while poor institutional and regulatory frameworks meant that any efficiency gains, even if achieved, did not necessarily reach end consumers. In non-OECD Asia, for instance, empirical evidence shows that the technical and efficiency gains delivered by reforms have not translated into welfare gain for consumers (Sen et al. 2018), calling for a ‘reform’ of electricity reforms. These inconsistencies may have motivated significant government involvement, as evidenced by the renationalisation of electricity industries in Latin American countries such as Bolivia, Dominican Republic, and Venezuela (Balza et al. 2013). Argentina, a frontrunner in power sector reforms via the textbook model, has also significantly curbed the role of markets in the energy sector (Littlechild 2013).

2.4 Regional Electricity Trade

Several developing economies, such as non-OECD Asia, have increased electricity cooperation in the form of regional trade as a strategy to meet their growing electricity demand. This includes electricity interconnections and trading amongst the Association of Southeast Asian Nations (Thailand–Malaysia, Thailand–Lao PDR, Thailand–Myanmar, Lao PDR–Viet Nam, Viet Nam–Cambodia, Singapore–Indonesia, Thailand–Cambodia, Lao PDR–Cambodia) and the South Asian Association for Regional Cooperation (SAARC) (Halawa et al. 2018).

The operational, economic, environmental, and reliability benefits of power trading are significant, even though these advantages remain largely unexploited in the region. The reforms of the early 1990s did not factor in the possibilities to facilitate power trading in reforming countries. Domestic electricity sector policies have often hindered the scope for regional electricity trade in the SAARC countries (Singh et al. 2018), even when electricity trade can effectively help circumvent the infrastructure investment constraint on economic growth by utilising any spare capacity inherent in the system. The flexibility of the electricity system (in the context of a growing share of intermittent renewables) can be improved through system operators' leverage of larger balancing areas (e.g. in Europe, where system operators utilise regional interconnections as a tool to manage their loads).

However, promoting power trade also exhibits large financing needs in electricity infrastructures, such as generation capacities and transmission networks. This implies that expanding the scope of bilateral electricity cooperation through government-to-government projects and opening trade up to commercial projects are considered effective approaches to building confidence in the process of power trading in Asia in the short and medium terms (Singh et al. 2018). In the long term, an interconnected energy market in the region is only possible by placing appropriate institutional mechanisms (Singh et al. 2018).

3 Electricity Reforms in Non-OECD Asia

We focus on non-OECD Asian economies. These economies (see Table 1) accounted for over a third of the world's primary energy demand and just under half of the global energy-related emissions (IEA 2014). Energy demand for non-OECD Asia is expected to increase to 41% of world demand by 2040 (Sen et al. 2018). Total electricity generation in non-OECD Asia was around 33% of world electricity generation in 2012, while total electricity installed capacity was already 30% of the global installed capacity. The large-scale magnitude of power consumption and generation indicates that electricity sector reforms in non-OECD Asia have direct implications for global energy use and sustainability. Non-OECD Asia also provides a strong case for studying electricity reforms as the public sector plays an active role in the power sectors of many non-OECD Asian economies (Sen et al. 2018).

Table 1 shows the status of reform progress as per the textbook model of reforms in 17 non-OECD Asian economies. India, the Philippines, and Singapore have legislated all the main elements of the electricity market reform. Singapore has also successfully created wholesale electricity markets and introduced competition in retail supply, unlike India and the Philippines. Nepal has a smaller power system with less than 1,000 MW installed capacity. Evidence suggests that the benefits of market-based reforms for a small system are extremely limited (Nepal and Jamasb 2012b). Findings from the Indian reform experience suggest that reform outcomes have tended to be

Table 1 Electricity reforms in non-OECD Asia, 2018

	Independent power producers	Regulator	Unbundling	Corporatisation	Open/Third party access	Distribution privatisation
Bangladesh	x	x	x	x		
Bhutan	x	x	x	x		
Brunei		x				x
China	x	x	x	x		
India	x	x	x	x	x	x
Indonesia	x		x	x	x	
Lao PDR	x					
Malaysia	x	x	x	x		
Maldives	x	x		x		
Myanmar	x	x				
Nepal	x	x	x	x		
Pakistan	x	x	x	x		
Philippines	x	x	x	x	x	x
Singapore	x	x	x	x	x	x
Sri Lanka	x	x				
Thailand	x	x	x	x	x	
Viet Nam	x	x	x	x		

Source Authors

adverse in the initial stages of reform due to political economy factors, as pre-reform distortions (such as underpricing of electricity) become apparent post reform (when prices need to rise in the first instance) (Sen and Jamasb 2012). The next subsections discuss each element of the reforms.

3.1 Independent Power Producers

The most distinct form of private sector ownership is the involvement of the private IPPs in the non-OECD Asian economies. An IPP generally builds, owns, and operates facilities to generate electricity for sale to public utilities owned by the national electricity company and to third-party users. Investments in independent power production steadily increased until the Asian financial crisis in 1997, followed by a period of variability until 2004, after which the flow of investments steadily increased once more. However, the financial crisis of 2010 led to a sharp drop in IPP investments (see Fig. 1).

The involvement of IPPs in Asia has been controversial. For example, Malaysia faces high consumer tariffs even though IPPs have been procured through competitive

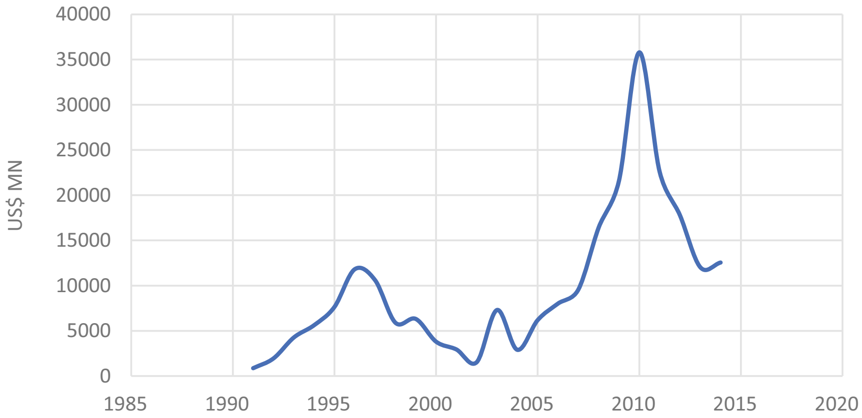

Fig. 1 IPP Investments in Asia, 1990–2014. *Source* World Bank PPI Database, https://ppi.worldbank.org/en/ppi (accessed 6 April 2022)

tendering. Private power contracting in Pakistan was plagued with corruption allegations and renegotiation of tariffs by the government (Fraser 2005), together with the circular debt crisis (Kessides 2012). Indonesia and the Philippines, while relatively successful in the early stages of reform, faced problems with tariff renegotiations after the Asian financial crisis (Wu and Sulistiyanto 2013).

On the other hand, the development of IPPs in hydro-rich economies such as Nepal and Bhutan in South Asia has encountered property rights and sovereignty concerns. Bangladesh opened the sector to IPPs in 1996, with a third of the generation capacity already under private ownership and operation. In Sri Lanka, IPPs have been susceptible to regional fluctuations in demand and supply, adversely affecting private sector investments (Woo 2005). Generally, IPP projects in non-OECD Asia have faced significant hurdles, unlike other developing regions such as Sub-Saharan Africa, where they have been relatively successful in bringing private investments into the power sector (Eberhard et al. 2016).

3.2 Independent Regulation

The primary purpose of introducing separate utility regulation in Asia is to protect investors from unacceptable risks associated with network elements, such as an independent power generator being assured a revenue stream that covers their cost of supply (Stern 1997). The establishment of electricity regulators occurred during the early to mid-2000s within a highly politicised environment for the electricity sector in most non-OECD Asian economies. Regulators struggled to implement reform measures, such as cost-reflective pricing, necessary to attract private investments

(Rufin 2003). Electricity was a politically sensitive issue, leading many governments to hold prices below full economic costs (long-run marginal costs) in Asia (particularly in India).

China's approach to economic regulation has been to consolidate electricity regulation with other energy-related sectors. In contrast, regulation in Bangladesh was established in 2003 with a specific mandate to create an environment conducive to private investments. The energy regulators in the Philippines and Thailand are quasi-government bodies, while Singapore established an industry regulator and a system operator in 2001, aiming to limit the ability of the largest generators to exercise and abuse market power (Chang and Li 2013). 'The independence from government intervention' is a critical feature of independent regulation (Stern 1997) but is not prevalent in Asian economies. For instance, weak governance structures and inefficient regulators have been identified as key determinants of the failure of Pakistan's power sector reforms (Ullah et al. 2017). Bhutan's Electricity Authority was established in 2001 to restructure and regulate the electric supply industry, assuming full autonomy in 2010. Myanmar was amongst the last adopters of electricity regulation, with legislation drafted in 2013.

3.3 Restructuring and Corporatisation

The textbook model of electricity reform involves restructuring in the form of vertical separation (or unbundling) and corporatisation. Vertical separation includes separating the electricity supply industry's natural monopoly segments (transmission and distribution) from the potentially competitive segments (generation and supply). Unbundling prevents cross-subsidisation amongst the competitive and regulated businesses and discriminatory practices such as denial of third-party access to networks (Joskow 2003). The degree of vertical separation varies and takes the forms of functional, accounting, legal, or ownership separation (Jamasb et al. 2017).

Corporatisation is the formal commercialisation of the unbundled entities as commercial businesses under Company Law to prioritise economically rational decisions. The textbook model of reform prescribes unbundling before corporatisation, although the reform experience suggests that China, Singapore, and Viet Nam corporatised before unbundling. Corporatisation followed unbundling in countries like Bangladesh, India, and Pakistan. Empirical evidence shows that establishing an independent regulatory authority and introducing competition before privatisation is correlated with higher investments in generation in developing economies in Asia (Zhang et al. 2005). However, vertically integrated structures are still common in some economies, including Brunei, the Lao PDR, Myanmar, and Sri Lanka. The Maldives has a corporatised, vertically integrated monopoly.

3.4 Open Access

Open or third-party access to the grid is a critical enabling factor of reform, as it facilitates competition (Sen et al. 2018). Open access would require that the natural monopoly electricity networks be made accessible to parties other than their customers on commercial terms comparable to those that would apply in a competitive market. In the case of monopoly electricity networks, open access could be regulated (regulated third-party access or negotiated third party access). Open access facilitates competition in generation and distribution by allowing consumers to switch suppliers (i.e. consumers can opt out of government supply) and by allowing non-discriminatory access to network infrastructures for consumers as well as private sector generation and distribution utilities.

It is evident from Table 1 that open access has not been a popular reform measure in non-OECD Asian countries, with only 5 out of 17 implementing it. India implemented open access to promote captive generation (where electricity is generated for its use) and institutionalised it in the 2003 Electricity Act. Indonesia implemented open access in 2009, even though the state-owned company has priority rights over the network. Thailand practices a form of 'quasi-open access' while the Philippines has had limited success with open access. Singapore successfully implemented open access and retail market liberalisation from 2003 onwards.

3.5 Privatisation

Privatisation of the distribution sector is another direct form of private participation apart from the involvement of IPPs in the electricity industry. Privatisation—a trend characterised by a move away from government ownership, control, or significant participation towards a market-based system and increased private sector participation—can be considered an important reform step in fostering competition. However, only a few countries, such as Brunei, India, the Philippines, and Singapore have implemented distribution privatisation. Singapore has adopted an advanced form of private participation with seven electricity retailers competing for retail customers. In India, distribution privatisation was implemented in Orissa (1996) and Delhi (2002), although this was later reversed in Orissa. The Philippines and Singapore experienced distribution privatisation as part of a sequential electricity market reform package, while Brunei's experience was less structured. Retail prices in the Philippines were higher after reforms due to domestic taxation and inefficiencies that were not yet eliminated by the onset of competition (Bacon 2019b). Overall, utility privatisations in non-OECD Asia have been slow, despite the notable inefficiencies of state-owned enterprises (Estrin and Pelletier 2018).

4 Evidence from Regional Experiences

The electricity reform experience in non-OECD Asia case studies suggests that the IPPs have been the most widely adopted reform step in non-OECD Asian economies as an easy way of introducing some competition in the sector without extensive restructuring. In most non-OECD Asia, economic regulation is not formally independent and accountable to be sufficiently effective, while the major regulatory issue relates to reforming tariffs to reflect the cost of service. Public sector involvement is still persistent in these economies despite implementing unbundling and corporatisation, particularly in the absence of competition in distribution and retail supply. At the same time, accounting separation has not led to healthier financial conditions for distribution companies.

The lack of progress towards implementing open access can deter private sector participation and limit the scope of competition in non-OECD Asian economies. The main opposition to distribution privatisation in developing countries has been over concerns about tariff increases (resulting from the reform of subsidised electricity prices to make them cost reflective), which impacts the socio-economic welfare of poorer consumers. A recent study by Sen et al. (2018) comprehensively reviewed power sector reforms in non-OECD Asia and showed the difficulties of balancing the competing reform objectives of the sector.

Table 2 highlights the timeline and nature of the important institutional changes surrounding the power sectors of non-OECD Asian economies. China enacted the electricity pricing reform rules in 2005. A designated electricity regulatory authority was established after 2000, while Brunei and Indonesia still solely relied on the ministry for electricity regulation. The regulators are also financially independent in the Philippines, Sri Lanka, and Singapore. These countries have pursued deeper reforms by establishing competitive wholesale electricity markets.

The wholesale markets in the Philippines consist of an energy-only bid-based power pool (the wholesale electricity spot market) and bilateral contracts. The market operator's role is to determine the market-clearing spot price considering all power flows in and out of the grid and based on generation offers (Rudnick and Velasquez 2019). Likewise, Singapore runs an energy-only market with a high price cap, where generators bid every half-hourly. This implies that the wholesale price of the electricity can vary every half-hourly, depending on electricity demand and supply and geographic location (locational pricing).

India established a partially centralised bid-based wholesale electricity market in 2003, while the Philippines launched the wholesale electricity market in 2001 (Rudnick and Velasquez 2018). Interestingly, developing economies like Bangladesh, Pakistan, and Viet Nam are transitioning towards a wholesale power market, with the target years 2024 and 2020 for Viet Nam and Pakistan, respectively.

On the other hand, Latin America provides an interesting and contrasting context since the region has substantial experience in electricity market reforms and wholesale electricity market designs, starting in the early 1980s. The region has high electricity demand growth rates (around 5% annually), while the generation mix is

Table 2 Institutional changes in the non-OECD Asian countries

Country	Electricity reform law	Establishment of regulator	Autonomous regulator	Licence fee or government budget regulatory funding
Bangladesh	2003	2004	Yes	Government stipends and operational revenues
Bhutan	2001	2002	Yes	Government budget and operational revenues such as license fees
Brunei	1973 (amended in 2002)	1921	No	Government budget
China	2005	2002	No	Publicly funded through government budget
India	2003	1998	Yes	Central Electricity Regulatory Commission Fund based on fees, government loans and grants
Indonesia	2009	1978	No	Government budget
Malaysia	1990 (amended in 2001)	2002	No	Allocated government funds
Maldives	1996	2006	No	Ministry of Energy, Environment, and Water
Myanmar	2014	1996	No	Ministry of Energy and Electricity
Nepal	1993	1994/2011	Yes	Government budget
Pakistan	1997	1997	Yes	Grants from the federal government and fees and levies accrued
Philippines	2001	2001	Yes	Fees and operation revenues
Singapore	2001	2001	Yes	Fees imposed on licensed operators
Sri Lanka	2002 (repealed in 2009)	2002	Yes	Annual fee levied on licensed entities in the sector
Thailand	2007	2007 (reformed)	No	–

(continued)

Table 2 (continued)

Country	Electricity reform law	Establishment of regulator	Autonomous regulator	Licence fee or government budget regulatory funding
Viet Nam	2005	2005	Yes	State budget and revenues collected for the licensing of electricity service

Source Authors' compilation

dominated by hydropower (about 60%) and has emerged recently as one of the most dynamic regional electricity markets (Hammons et al. 2011). The earliest textbook reform occurred in Chile in 1982, followed by Argentina in 1992, Peru in 1993, and Bolivia in 1994. Reforms also spread to Brazil, Colombia, and other Central American countries by the mid-1990s. Unlike Latin America, electricity reforms in most non-OECD Asian countries were initiated in the late 1990s (Jamasb et al. 2017) and thus provided a precise starting time frame for analysis. Reforms in many Asian economies (e.g. Bangladesh, India, Indonesia, Pakistan, the Philippines, and Thailand) were undertaken as part of structural adjustment programmes linked to multilateral financial lending, as in Latin America, providing a common starting context. Although Latin America successfully implemented the textbook model of reforms and established an electricity market, changes in the drivers of reforms have led to the resurgence of the public sector in the process of reforms.

Table 3 shows that the first wave of electricity reforms in Latin America was initiated in the 1980s. The Dominican Republic was the last country to adopt an electricity reform law in 2001, followed by Venezuela and Nicaragua. Paraguay had established an electricity regulator as early as 1964, followed by Chile in 1978. The timing of establishing regulators has not followed the reform sequence set out under the textbook model, as observed for the Asian economies (Table 2). The regulator is autonomous or non-autonomous from the state irrespective of 'who funds the regulatory body' for non-OECD Asia and Latin America (Stern 1997). The accumulated reform experience has been positive in several aspects, such as inducing greater efficiency of the private utilities and providing clear signals for investors due to greater transparency brought about by regulatory agencies. Latin America was also one of the world's regional leaders in attracting private investments in the 1990s (Hammons et al. 2011).

As in non-OECD Asia, Latin America has prioritised establishing a regional electricity market to create a larger market to enhance efficiency and promote competition and energy security (Oseni and Pollitt 2016). However, unlike non-OECD Asia, Latin American countries have progressed a great deal in regional energy cooperation, primarily due to strong supporting institutions. The Central American Electrical Interconnection System is a cooperation amongst six Central American countries for the reliable, efficient, and affordable delivery of electricity. The supporting institutions for market operation include the regional regulatory commission (Comisión

Table 3 Institutional changes in the Latin American countries

Country	Electricity reform law	Establishment of regulator	Autonomous regulator	Licence fee or government budget regulatory funding
Argentina	1992	1992	Yes	Regulation Tax (1993)
Bolivia	1994	1994	Yes	Regulation Tax (1996)
Brazil	1996	1996	Yes	Regulation Tax (1997)
Chile	1982	1978	No	Government budget (1985)
Colombia	1994	1994	No	Regulation Tax (1994)
Costa Rica	1990	1996	Yes	Regulation Tax (1996)
Dominican Republic	2001	1998	Yes	Regulation Tax (1998)
Ecuador	1996	1998	Yes	Regulation Tax (1999)
El Salvador	1997	1996	Yes	Regulation Tax (1997)
Guatemala	1996	1996	No	Regulation Tax (1996)
Honduras	1994	1994	Yes	Government budget (1995)
Mexico	1992	1995	Yes	Government budget (1995)
Nicaragua	1998	1995	Yes	Regulation Tax (1994)
Panama	1997	1996	Yes	Regulation Tax (1996)
Paraguay	1993	1964	No	Government budget
Peru	1992	1997	Yes	Regulation Tax (1996)
Uruguay	1997	1997	Yes	Regulation Tax (2000)
Venezuela	1999	1999	No	Government budget (2002)

Source Balza et al. (2013)

Regional de Interconexión Eléctrica [CRIE], regional system operator (Ente Operador Regional [EOR]), and the network company owning the grid (Empresa Propietaria de la Red [EPR]). CRIE, established in 2002 and comprising six members, is the regulator of the regional wholesale electricity market. One commissioner is drawn from the electricity regulatory agency of each member state (Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua, and Panama). The selection of representatives from the regulators of various countries was designed to mitigate inconsistency between national and regional regulatory techniques and to harmonise technical and operating procedures (Oseni and Pollitt 2016). CRIE is led by a president rotated amongst its members. The EOR is the regional system operator responsible for coordinating the markets (day-ahead, real-time dispatch, financial settlements) and information transmission through designated national system operators. Planning for regional generation and transmission network expansion is undertaken by the EOR. The EPR owns and operates the regional interconnectors, which are 75% publicly owned by the utilities and transmission companies in the six member-states, with the remaining 25% is owned by private sources.

However, policy discontent with the standard model started to surface in the early 2000s due to dissatisfaction with price regulation, volatile spot prices failing to stimulate timely investments in electricity generation, and inadequate financing for additional generation capacity. These led to problems with the security of supply (power crises and rationing) in many countries in the region, including Brazil (2001), Chile (1999 and 2004), and Peru (2006) (Mastropietro et al. 2014). The price signals provided by the spot market have been very volatile in the energy-only markets, resulting in a failure to incentivise investment in new generation capacity and calling for new wholesale market designs. Generation activity has been affected by the lack of adequate project financing and volatility in economic growth rates.

As a result, the second wave of market restructuring started in the early 2000s with the primary motive of supporting and coordinating investments in new generation capacities (Roques 2017). This led to the (i) introduction of hybrid markets with long-term contracts to coordinate investments through auctions (a competitive process), (ii) decoupling of generation investment from spot market price volatility through long-term power purchase contracts, and (iii) reduction of generation risks for new entrants to allow project financing through long-term contracts.

Table 4 shows the major auction characteristics of four selected Latin American countries, indicating that the market design to attract new generation capacities has moved well beyond energy-only markets and capacity payments. Brazil, Chile, Colombia, and Peru have contracted over 62,000 MW of new generation capacity through auctions between 2005 to 2010, with delivery dates of new capacities from 2008 to 2018 (Moreno et al. 2011).

Table 4 Major auction characteristics per country

	Brazil	Colombia	Chile	Peru
Capacity mix	Hydro 75%, Thermal 25%	Hydro 65%, Thermal 33%	Hydro 40%, Thermal 60%	Hydro 60%, Thermal 40%
Degree of centralisation	Joint auctions by distribution companies organised by the government	Ensure reliability, closing gap between supply and demand arranged by a government agency	Distribution companies organise and manage auctions, possibility of joint auctions	Distribution companies organise and manage their auctions, possibility of joint auctions
Buyers	Regulated users	All consumers	Regulated users	Regulated users but free consumers can be included
Sellers	Separate auctions for existing and new capacity	New energy	All existing and new generation (in the same auction)	All existing and new generation (in the same auction)
Auction process	Two-phase hybrid auction	Descending clock auction	Sealed-bid combinatorial auction with pay-as-bid rule	
Energy policy decisions	Specific auctions for technologies and projects	All technologies compete together	All technologies compete together	Separate auctions for renewables
How often are the auctions organised?	Regular auctions to contract new capacity, government can organise specific (additional) auctions when needed	At planner's discretion, when there is a gap between future demand and supply	Distribution companies decide	Distribution companies decide

Source Moreno et al. (2011)

Using an auction mechanism where potential investors compete to obtain a long-term energy contract is more favourable than relying entirely on an energy-only wholesale market (with or without capacity payments) to provide longer-term investment signals. This is because the wholesale spot price does not give adequate signals for new investments. Determining the optimal size of the regulated capacity payment that stimulates the availability of generation is also difficult. On the other hand, auctions encourage the involvement of many participants, including private participants, foster competition, and allow efficient price discovery due to reliance on the market forces of demand and supply (Klemperer 1999). The government plays an active role in organising and running auctions in Brazil, Colombia, and Peru. This signals a significant shift in the part of the government—from playing a supporting role at the start of reforms when its activity was limited, to undertaking those entrepreneurial activities that the private sector did not pursue, such as rural electrification.[3]

5 Discussion and Policy Implications

One conclusion that can be drawn from the above discussion is that region-specific institutional contexts influence reform measures. The reform experiences in these two regions are contrasting. The Latin American markets underwent a full-fledged transition from the state to the market and now have returned to significant state involvement under new market designs. In contrast, reforms have stalled in most non-OECD Asian markets in the first phase of the transition to markets from the state. However, irrespective of their differential progress in reforms, both regions face the lack of adequate financing in new generation capacities due to rising electricity demand. Economic expansion and a growing middle-class population concentrated in Asia and Latin America will drive energy demand in the coming decades (Wolfram et al. 2012). As a result, the emerging economies in Latin America have become the forerunners and pioneers of innovative electricity market designs, such as electricity markets hybridisation with planning and long-term arrangements. These countries can serve as a useful guide for Asian economies looking to deepen reforms (Roques and Finon 2017).

The experience with market-based reforms amongst the Latin American countries provides valuable lessons and opportunities for policymakers in non-OECD Asia looking to deepen electricity reforms while fostering regional energy cooperation in the context of rising electricity demand. Below, we identify some aspects of reforms that non-OECD Asian economies should consider early in the reform process in the push to a market-based electricity sector.

- Non-OECD Asian economies, such as Bangladesh, Pakistan, and Viet Nam, aim to deepen electricity reforms by establishing competitive wholesale electricity markets. The Latin American case suggests that spot market prices play a crucial role in operational and dispatch incentives. This implies that energy-only markets should be made as competitive as possible by introducing measures to promote ‘competition in the market’. On the other hand, long-term investment decisions and the recovery of fixed costs are increasingly delinked from spot market dynamics and driven by measures, such as auctions, capacity payments, and capacity obligations. Auctioning long-term capacity contracts and energy call options by the government to ensure supply adequacy is a case of promoting ‘competition for the market’. Since the single-buyer model with IPP participation

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[3] See the appendix for some interest cases of increasing involvement of governments in the electricity sectors of Argentina, Brazil, Bolivia, the Dominican Republic, and Venezuela.

is the most dominant wholesale arrangement in non-OECD Asia, other Asian governments such as Malaysia may be able to strike power purchase agreements with the private sector based on competitive auctions as in the Latin American markets to put competitive pressure on capital expenditures.

- Fostering regional electricity trade to facilitate greater regional coordination in capacity investments in non-OECD Asian economies requires creating a level playing field amongst the trading partners, as evident in Latin America's Central American Electrical Interconnection System. Thus, heterogeneity in reforms at the domestic level, such as the lack of cost-reflective energy pricing for consumers in Asian economies, can impede regional energy cooperation due to misaligned investment signals amongst market actors. Inefficient pricing has also been a major contributor to the financial problems of publicly owned electric utilities (Singh et al. 2018). Furthermore, the renationalisation experiences in the electricity sector across Latin America suggest that regional energy cooperation can take a backseat if countries use their natural resources strategically. Therefore, non-OECD Asian economies should translate their reform 'theory' into 'practice' and continue implementing reforms, considering the country-specific political economy context as in Latin America. However, pricing reform is inherently politically sensitive and should be implemented before private sector participation or privatisation, alongside measures to mitigate their impact on vulnerable consumers.
- The Latin American cases also suggest that wholesale power markets remain a viable option for reforming countries—Bangladesh, Pakistan, and Viet Nam—even though the effective functioning of wholesale markets requires a proper design, short-term pricing mechanism, long-term investment signals, and a sound and adaptive governance structure. Deriving greater benefits from regional electricity trade by fostering greater regional electricity cooperation is the other viable option for countries that cannot establish a competitive wholesale electricity market.
- Institutional strengthening through the creation of effective regulatory bodies and economic regulation frameworks is important in non-OECD Asia to implement the benefits of reforms, as demonstrated by the Latin American countries through independent regulation. For instance, it can be argued that some reforms were destined to fail as developing economies implemented the reforms before the regulators were fully competent and in charge of the newly restructured electricity sector. Experience in Latin America suggests that a regional organisation or forum such as CRIE to facilitate cross-country trade coordination is important as regional electricity markets emerge. It is also necessary that Asian governments have the appropriate institutional setup and expertise to run competitive auctions for electricity generation, as many of these governments plan to run capacity auctions for future issuance of power purchase agreements. This is because renewable energy auctions are complex and must be planned and administered with prudence and judiciousness (Hochberg and Poudineh 2018). Institutional leadership and political will to take and implement decisions are hallmarks of a successful procurement programme in Latin America (Moreno et al. 2010). Effective auction design

and implementation should incentivise the active participation of all relevant stakeholders.

- The Latin American experience suggests that adapting the market-based model to varying degrees to suit local contexts is crucial in achieving good outcomes by considering the initial ‘enabling’ conditions of reforms in each country and the political realities.
- The progress with electrification in Latin America and non-OECD Asia indicates that power sector reforms do not automatically improve electricity access. However, in the absence of commercially viable, distributed solutions in developing countries, households need to be connected to the grid to benefit from power sector reforms. As household income is the strongest driver of electrification than any structural reform (Foster and Rana 2019), improving national electricity access needs continued support from the government, such as the allocation of smart market-based capital subsidy schemes.

6 Conclusions

This chapter revisits the status of power sector reforms in non-OECD Asia to draw some policy lessons based on the reform experiences in Latin America, focusing on the changing role of the government in electricity provision. Both regions are experiencing an expansion in financing needs towards adding new capacities in the face of rising electricity demand.

Countries in Latin America are significantly curbing the role of the markets in electricity provision to facilitate the policy objectives of decarbonisation and security of supply. The inability of wholesale electricity markets to finance capital expenditure needs associated with climate change mitigation and decarbonisation objectives and renewable energy targets, and security of supply and regional electricity trade objectives are new drivers of renewed state involvement in the sector.

We show that while non-OECD Asia is experiencing a difficult reform path, there are opportunities to speed up the reform process involving both the state and the market. The Latin American case study suggests that governments can coexist within the market by playing the lead roles in running the long-term contract auctions for power generation and attracting investments in new capacities. As sector regulator, owner, planner, and central procurer, the government can also play an active role in ensuring the energy policy objectives of affordability, security of supply, and sustainability.

The objectives of ‘competition in the market’ and ‘competition for the market’ imply the combined involvement of the state and the private sector rather than prioritising one versus the other.

Appendix: Country Case Summaries

Electricity market trends in Latin America also generally demonstrate the increasing involvement of governments. Some examples are briefly highlighted below (Hammons et al. 2011; Balza et al. 2013):

- Argentina—The electricity sector in Argentina faced a long period of uncertainty over the revision of tariffs and the pricing system, both at the wholesale and retail levels, after the financial crisis of 2002. Private investment in new generation capacity has ceased since 2000. Once at the forefront of reform, the country is now curbing the role of markets in its electricity sector (Littlechild 2013). New rules for the wholesale market have involved increasing subsidies for new forms of power generation and setting new rules for contracts and operations at the regional level.
- Brazil—The rules of the power sector were reviewed in Brazil after the change in government in 2003 in response to investment and operational constraints. The regulator, which is not autonomous from the government, has a reinforced role in the functioning of the market. The new regulations obligated distributors to contract 100% of their forecasted distribution, while the regulatory body led the simultaneous bidding on behalf of all distributors. The electricity market exhibits both private participation and public intervention, given that it includes many state-owned generators, private distributors, and large customers in the auctions.
- Bolivia—The government that entered office in 2006 introduced reforms to re-establish state control in the electricity sector by including the participation of the Empresa Nacional de Electricidad (ENDE) in three subsectors in 2008. The government nationalised assets favouring ENDE to ensure that the Bolivian government's ownership was nearly 72% of the generation sector. The government renationalised most of the transmission and distribution sector in 2012.
- Venezuela—The nationalisation of the main energy company, the Electricidad de Caracas, was announced in 2007. The government created the National Electricity Corporation (CORPOELEC) to reorganise the national electricity sector in 2007. CORPOELEC is responsible for generating, transmitting, distributing, and commercialising electricity. The government created the Ministry of Energy and designated its minister as the president of CORPOELEC in 2009.
- Dominican Republic—The government introduced significant changes to the General Law of Electricity (eventually enacted in 2001) in 2000. These changes led to the creation of the Corporación Dominicana de Empresas Eléctricas Estatales, Empresa de Transmisión Eléctrica Dominicana, and Generación Hidroeléctrica Dominicana. The regulatory body of the state, Superintendency of Electricity, was tasked with regulating the sector, while the Comisión Nacional de Energía was put in charge of establishing overall electricity policies. A fuel subsidy for electricity generation was also authorised in 2000. The government also purchased 50% of the shares in the private company Empresa Distribuidora de Electricidad del Este, SA, also regaining control of the distribution sector in 2009.

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What Have Reforms Delivered So Far?—A Quantitative Analysis of Power Sector Reform Impacts in the ASEAN Economies

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Abstract The importance of the power sector to the ASEAN economies in delivering improved socio-economic prosperity is undeniable. Therefore, reforms in the power sector and their role in guiding the energy policy trilemma of affordability, sustainability, and security of supply should be studied properly. This chapter quantitatively examines the socio-economic and technical impacts of power sector reforms in the 10 ASEAN member countries, relying on the novel data set spanning 1990–2018. We capture the effects of power sector reforms across the economic, technical, and welfare dimensions. Our findings suggest that the impacts of power sector reforms are mixed and heterogeneous even though reforms successfully improved the technical performance of the power sector by minimising network losses. Furthermore, the absence of proper institutions supporting market-based reforms meant that reforms also did not generate the anticipated effects across the economic, technical, and welfare dimensions. We also find that the ASEAN economies should not solely rely on power sector reforms to boost electricity consumption in the region but accelerate policies to improve electricity access. Our results are insightful since we control for the effects of cross-sectional dependence, which many prior empirical studies on power sector reforms failed to do so.

Keywords Electricity · Reforms · Regulation · Competition · ASEAN

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1 Introduction

The Association of Southeast Asian Nations (ASEAN), comprising Brunei, Cambodia, Indonesia, the Lao PDR, Myanmar, Malaysia, the Philippines, Singapore, Thailand, and Viet Nam, is an important economic region in the world, considering key socio-economic indicators. For instance, the ASEAN region hosted 8.5% of the world population and contributed to 3.7% of the global gross domestic product (GDP) in 2019 (ASEAN 2020). Southeast Asia is also one of the fastest-growing regions globally in terms of electricity demand, with electricity demand growing by more than 6% annually over the past 20 years on average (IEA 2020). The four largest electricity consumers of the region's 10 economies—Indonesia (26%), Viet Nam (22%), Thailand (19%), and Malaysia (15%)—are responsible for almost 80% of total regional electricity demand. As electricity is an essential factor input in economic production and consumption, electricity demand in the region is expected to increase with the rising consumption of goods and services. Therefore, the well-being of the ASEAN economies largely hinges on their electricity sector performance, implying that sound design and implementation of energy policies are critically important to the region.

One such common energy policy that these nations embarked on since the early 1990s is the introduction of market-based reforms in their electricity sector, as per the original 'textbook' or 'standard model of electricity reforms'. Introducing competition in the electricity supply industry by separating (or vertical unbundling) the competitive segments of electricity supply (generation and retail) from the monopoly segments (transmission and distribution networks), allowing independent power producers (IPPs) in electricity generation, and incentive regulation of electricity networks were some of the major ingredients of reforms. An earlier study by Sen et al. (2018) overviewed the status and progress of power sector reforms amongst Asian economies. Only the Philippines and Singapore in the ASEAN are considered progressive reformers in electricity. These economies have allowed IPPs; established a regulator; undertaken vertical unbundling; and allowed corporatisation, including the privatisation of electricity distribution and introduction of open third-party access. On the other hand, Brunei, Myanmar, and the Lao PDR are the slow reformers in ASEAN, having just allowed the introduction of the IPPs and the establishment of electricity regulators.

Quantitative studies on the impacts of power sector reforms in the ASEAN region are rare. Also, only a few studies qualitatively evaluate the reform impacts at the regional level, and quantitatively at the country-specific level. Sulisyanto and Xun (2004) argued that the performance of reform efforts in developing economies, including Indonesia, the Philippines, and Thailand, have been mixed even though the case for restructuring from techno-economic perspectives is strong. Sharma (2005), based on a comparative case study approach, showed a significant disparity between the intended and actual outcome of reforms in ASEAN. Wu (2016) and Yao et al. (2021) concluded that domestic institutional and political barriers to power sector reforms impede ASEAN's electricity market integration objectives. A recent quantitative study covering the ASEAN economies include the one by Sen et al. (2018), which applied instrumental variable regression techniques to several models of electricity sector reform outcome to find that the standard reform model has had limited benefits, largely due to sectoral heterogeneity and institutional endowments. In the Philippines, Toba (2007), based on a cost–benefit analysis, showed that reform with private sector participation through the IPPs increased social welfare. The findings by Toba (2007) are important since another study (Abrenica 2009) showed the presence of strategic bidding and capacity withholding by public generations. In the case of Singapore, Chang and Tay (2006) showed that deregulation would lower electricity costs due to the various efficiency gains possible, with cost gains being as much as about 8% of the current production cost. A recent study by Loi and Jindal (2019) empirically showed that deregulation of the electricity market led to reduced wholesale prices, with the Herfindahl–Hirschman Index showing that competition for electricity supply has increased. Foster and Rana (2020), based on a comprehensive review of electricity reforms in developing countries, concluded that although regulation has been widely adopted, the practice often falls short of theory, with cost recovery objectives taking a backseat while restructuring and liberalisation proving too complex for most countries to implement.

Against these backdrops, this chapter undertakes a quantitative approach to examine the impacts of power sector reforms on the economic, technical, and welfare dimensions in ASEAN economies. Therefore, our chapter aims to fill in a significant gap in the empirical literature on the performance evaluation of electricity reforms in the ASEAN region. Furthermore, our study is also timely to revisit since advanced reformers like Singapore have experienced spiking wholesale electricity prices, threatening the electricity supply security in the region as the effect reverberates across Asia (Connors 2021).

The remainder of the chapter is structured as follows. Section 2 examines the ‘standard’ or ‘textbook’ model of electricity reforms in the context of the ASEAN economies. Section 3 discusses the model specification, data, and methodology. Section 4 presents the results. Sect 5 concludes the chapter with relevant policy recommendations.

2 The Standard Model of Electricity Reforms

Since the implementation of the comprehensive market-based reforms in Chile beginning in 1982 (Pollitt 2004), OECD[1] economies like Norway and the United Kingdom adopted electricity reforms in the early 1990s, therefore, giving birth to the ‘textbook’ or ‘standard’ model of reforms. The textbook or standard model of reforms included the following reform components (Gratwick and Eberhard 2008): corporatisation (involves the utility being transformed into a separate legal entity); commercialisation (represents a move towards cost-recovery in pricing); enacting energy legislation (providing a legal mandate for restructuring and the legal framework for

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[1] Organisation for Economic Co-operation and Development.

ownership); establishment of an (independent) regulator (aiming to introduce efficiency, transparency, and fairness in sector management); IPPs (introducing private investment in generation with long-term power purchase agreements); restructuring (involves unbundling the vertically integrated state-owned utility into competitive and monopoly segments); divestiture of generation and distribution assets (divesting state ownership in part or full of generation assets to the private sector); and competition (introduction of wholesale and retail markets). By 1998, about two-fifths of the 115 developing and transition economies had corporatised their state utilities or contracted with IPPs). About one-third had passed new electricity laws, established independent regulators, or restructured their power sectors, and about one-fifth had fully or partially privatised state-owned generation or distribution (ESMAP 1999; Williams and Ghanadan 2006). However, the motives and drivers of implementing reform varied vastly between the developed and developing economies.

In developed economies, improving economic efficiency was the major driver of reforms, while the reforms have also been successful in driving so (Newbery 2005). In developing economies, electricity reforms came as strings attached from the multilateral donor agencies like the International Monetary Fund and the World Bank during the lending. These reforms, therefore, spread across the developing world (Foster and Rana 2020). In ASEAN, the Electric Power Industry Reform Act was passed in 2001, and the comprehensive reform components under the textbook model were implemented by 2013 (Bacon 2019). Political support allowed the Philippine power sector to transform a publicly owned utility into private ownership and introduce competition between generators and distributors. Another advanced reformer in the region, Singapore, has progressively restructured and liberalised its electricity sector since 1995. The Energy Market Company was established in 2001 as the independent operator of the wholesale market through which generation companies bid to sell electricity, while Singapore has always adopted a technology-agnostic approach towards deregulation (Toh and Woodhouse 2020). By May 2019, Singapore had achieved full retail competition as every household became contestable. However, the cost of establishing a wholesale electricity market, even in a small electricity market like that of Singapore, exceeded US$75 million, with annual running costs of US$15 million–US$20 million (Ching 2014; Foster and Rana 2020). Thailand initiated the plan to reform the electricity sector under state-owned enterprises by permitting private participants to introduce small power producers (SPPs) and IPPs in 1980–1998 while the privatisation plan of the electricity sector was adopted in 1999 (Wisuttisak 2019). The Electricity Generating Authority of Thailand (EGAT) is the sole public enterprise that controls electricity supply generation. It is also the owner of the national transmission system. Some IPPs and SPPs generate electricity under the control of EGAT as per the enhanced single buyer model. The Thai government also passed the Energy Industry Act in 2007. In 2019, a further policy was announced to continue liberalising the Thai electricity industry.

Elsewhere in Viet Nam, the power sector has developed rapidly since the 1990s, with the government realising by late 1990s the need to gradually introduce competition to ensure long-term sustainability and foster competition to achieve supply security (Lee and Gerner 2020). The Electricity Law was passed in 2004 and provided the framework to develop a competitive power market, unbundle the state-owned utility Electricity Vietnam, set cost-reflective prices, promote and attract private investment, and establish a regulatory authority. The market is partially competitive today with improved operational and financial efficiency even though state ownership continues to dominate the power sector in Viet Nam. In Malaysia, the liberalisation of the power sector remains ongoing in the quest for a competitive and efficient electricity market system (Kumar et al. 2021). The National Electricity Board was corporatised under the Electricity Supply (Successor Company) Act 1990. This led to the formation of the national electric utility company, Tenaga National Berhad, in 1990, which became a publicly listed company in 1992. The IPPs were introduced in 1993, while the Energy Commission was formed in 2001 as an independent body to regulate the power sector. Cambodia adopted a new Electricity Law in 2001 and created the Electricity Authority of Cambodia (EAC) as the regulatory body. The Electricity Law articulated the separation of responsibilities between the two organisations governing the power sector, the Ministry of Mines and Energy and the EAC, including private sector participation in the electricity sector (ADB 2018). The EAC can still be considered in the early stages of developing a competitive electricity sector in Cambodia.

Indonesia enacted Presidential Degree 37 in 1992, which allowed private entities to be involved in power generation, transmission, and distribution, opening the door for the private sector to participate in the power sector (Wu and Sulisyanto 2013). However, Indonesia's power sector reforms stagnated and were effectively terminated in December 2004, when the constitutional court ruled the Electricity Law of 2002 unconstitutional. The subsequent Electricity Law of 2009 maintained that the state-owned company, Perusahaan Listrik Negara, would remain vertically integrated and control the national transmission network. Brunei, the Lao PDR, and Myanmar remain vertically integrated public sector monopolies. Myanmar liberalised foreign investment legislation in 2012, leading to a spate of power purchase agreements with IPPs (Sen et al. 2016). Myanmar was amongst the last adopters of regulation in ASEAN, considering that Myanmar drafted legislation on the creation of an electricity regulator in 2013. Corporatisation in the Lao power sector started in 1997, with the corporatisation of the state-owned power utility Electricité du Laos (World Bank 2013). Government reforms around the 1980s also enabled the participation of private enterprise in the power sector through the involvement of the IPPs and public–private partnerships. Brunei has implemented distribution privatisation even though no distinctive body operates an electricity regulator. Therefore, electricity reforms in Brunei are less structured than other OECD economies. Table 1 overviews the status of electricity reforms in the ASEAN economies as per the standard or textbook model of electricity reforms.

Table 1 The status of electricity reforms in ASEAN economies as of 2020

	Independent power Producers	Regulator	Unbundling	Corporatisation	Open/Third-party access*	Distribution privatisation
Brunei		√				√
Cambodia	√	√		√	√	√
Indonesia	√		√	√	√	
Lao PDR	√					
Malaysia	√	√	√	√		
Myanmar	√	√				
Philippines	√	√	√	√	√	√
Singapore	√	√	√	√	√	√
Thailand	√	√	√	√	√	
Viet Nam	√	√	√	√		

Source Sen et al. (2016) and authors' compilations

3 Hypotheses, Model Specification, and Data

A recent review of the literature by Jamasb et al. (2017) showed that the impacts of electricity reform in developing economies are both microeconomic and macroeconomic. Therefore, we examine the economic, operational, and welfare impacts of electricity reforms in the ASEAN as summarised by the three key hypotheses below in line with the findings of Jamasb et al. (2017).

> Hypothesis 1 (H1): Electricity reforms led to positive impacts on the economic aspects in the ASEAN economies after nearly 3 decades of reforms.
>
> Hypothesis 2 (H2): Electricity reforms led to positive impacts on the operational and technical aspects in ASEAN economies after nearly 3 decades of reforms.
>
> Hypothesis 3 (H3): Electricity reforms led to positive impacts on the welfare variables in ASEAN economies after nearly 3 decades of reforms.

The estimation specification is based on the following estimation where y_{it} includes the dependent variables, i.e. the economic, technical, and welfare variables, while x_{it} represents the set of independent and control variables. The term β_i represents the coefficient parameters of interest to us that are to be estimated . The term ε_{it} is the error term assumed to have constant variance and zero mean, while i represents the individual cross sections and t represents the year.

$$y_{it} = \alpha_i + \beta_i x_{it} + \varepsilon_{it} \tag{1}$$

We constructed the reform measures by undertaking a thorough country-specific survey of reforms to capture the status and progress of electricity reforms in ASEAN following the approach of earlier studies, such as Nepal et al. (2021) and Sen et al.

(2018). The dependent and independent variables were standardised based on log transformation whenever possible and feasible. We extracted the data from globally recognised sources, such as the World Development Indicators, US Energy Information Administration, Human Development Reports of the United Nations Development Programme, and Corruption Perceptions Index of the Transparency International—and avoided the standardisation problems. Table 2 enumerates the variables' names and their respective units of measurement.

Table 2 Description of variables and data sources

Variable label	Variable name	Units
Dependent variables		
PTDL	Per capita transmission and distribution energy losses	Kilowatt-hour (KWh)
PGDP	Per capita GDP	Purchasing power parity (PPP) (constant 2017 international US$)
PDL	Per capita distribution energy losses	KWh
NI	Net electricity imports	KWh
ETO	Electricity trade openness	Ratio
HDI	Human Development Index	Score
GINI	GINI coefficient	Score 0 to 1
PEPC	Per capita electric power consumption	KWh
Explanatory variables		
Reform variables	–	–
Ipps	IPPs	0/1
Reg	Regulator	0/1
Unb	Unbundling	0/1
Corp	Corporatisation	0/1
OAccess	Open/Third-party access	0/1
DPRV	Distribution privatisation	0/1
Physical variables		
PEG	Per capita electricity generation	KWh
PINSTC	Per capita installed capacity	KW
EA	Electricity access	Percentage
Index variables		
TRPI	Transparency index	Composite index

Source Authors' compilations

4 Methodology

Baltagi and Pesaran (2007) argued that cross-sectional dependence (CSD) could arise when the individual cross sections are related due to common unobservable factors. Therefore, it is impossible to rule out the presence of the CSD in the electricity reform processes of ASEAN because all ASEAN economies started adopting market-based reforms in the early 1990s, owing to these reforms' success in developed economies. In the presence of the CSD, the first-generation panel unit root and cointegration tests are not valid (Baltagi and Pesaran 2007).

4.1 Cross-Sectional Dependence (CSD)

The validity of the analysis outputs is questionable when the relationships existing between countries in the form of CSD are not considered. Therefore, the presence of the CSD should be examined in longitudinal data. So, we apply two types of CSD tests in our analysis. As per Pesaran (2021), the notations in Eq. (1) are as follows: *i* represents the cross section consisting of 1,…N members; *t* represents the time dimensions ranging from 1,..,T; and x_{it} is a (k × 1) matrix of the concerned regressors while α_i is the intermediary and the coefficients of the slope, β_i varies across all panels.

We compute the CSD test as follows given Eq. (1) above:

$$CSD = \sqrt{\frac{2T}{N(N-1)}}\left(\sum_{i=1}^{N-1}\sum_{j=i+1}^{N}\rho_{ij}\right) \rightarrow N(0,1) \tag{2}$$

Please note that ρ_{ij} represents the formed pair's connection of the OLS residuals, ε_{it} as described under Eq. (1).

$$\rho_{ij} = \frac{\sum_{t=1}^{T}\varepsilon_{it}\varepsilon_{ij}}{\left(\sum_{t=1}^{T}\varepsilon_{it}^{2}\right)^{1/2}\left(\sum_{t=1}^{T}\varepsilon_{jt}^{2}\right)^{1/2}} \tag{3}$$

4.2 Panel Unit-Root Test

We apply Pesaran's (2007) cross-section dependency test, the Cointegrated Augmented Dickey Fuller (CADF) test. The CADF test falls under the second-generation panel unit-root test, which demonstrates the results of the entire panel while testing each country in the panel for the CSD. The CADF test is reliable and popular because it can be applied under constraint conditions, such as the length of time series exceeding the number of cross sections (i.e. T>N). The CADF test is computed by comparing CADF critical table values. The hypothesis of the unit-root under the CADF test is constructed as below:

$$y_{it} = (1 - \varnothing_i)\mu_i + \varnothing_i y_{it-1} + \mu_i i = 1, 2 \ldots N\, vet = 1, 2 \ldots T \tag{4}$$

$$\varepsilon_i = \gamma_i f_t + \varepsilon_{it} \tag{5}$$

The unobservable common effects of each cross section (i.e. the countries in our case) in the panel are represented by f_t, while ε_{it} shows the error term of each country. Based on Eq. (5), we established the unit-root hypothesis below:

$$\Delta y_{it} = \alpha_i + \beta_i y_{it-1} + \gamma_i f_t + \varepsilon_{it} i = 1, 2 \ldots N\, and\, t = 1, 2 \ldots T \tag{6}$$

$$H_0 = \beta_i = 0\, for\, all\, i\, (series\ not\ stationary)$$

$$H_0 = \beta_i < 0, i = 1, 2 \ldots N_1, \beta_i = 0i = N_1 + 1, N_2 + 2 .. N.(series\ stationary)$$

We also calculate the mean average of the countries' unit-root test statistics. The mean average allows the computation of the Cross-sectionally Augmented IPS (CIPS) unit-root test statistics for the whole as per Pesaran (2007). The CIPS statistics is computed as below:

$$CIPS = N^{-1} \sum_{i=1}^{N} CADF_i \tag{7}$$

We first employ a first-generation unit-root test using the IPS test in diagnosing the presence of the CSD. The null hypothesis under the IPS test is said not to be stationary for all panels, while the coefficient of the IPS test varies amongst cross-section units. The alternative hypothesis of the IPS test specifies that at least one individual process is stationary. The IPS test process follows separate Augmented Dickey-Fuller (ADF) regressions estimating coefficients from different lag orders across all the cross sections (Eq. 8). Therefore, the mean average of each t-statistics formed from the ADF estimation is presented below:

$$t = \frac{1}{N} \sum_{i=1}^{N} t_{\rho i} \tag{8}$$

Equation (9) can alternatively be rewritten by adjusting the expected test statistic. A z-statistic can be computed following the IPS test, which is based on the mean and variance of the t_ρ series.

$$z(t) = \frac{\sqrt{N}(t - E(t_\rho))}{\sqrt{Var(t_\rho)}} \tag{9}$$

The z-statistic is calculated on an asymptotic theorem of normal distribution. Therefore, we refer to the estimated mean and variance values as Im et al. (2003) presented.

4.3 Two-Stage Least Square

We also applied a two-stage least square through instrumental variable techniques, where Z is the matrix of instruments and y and X, respectively, are the dependent and explanatory variables. Hence, the coefficients calculated in two-stage least squares are as shown in Eq. (10) below:

$$b_{2SLS} = \left(X'Z\left(Z'Z\right)^{-1}Z'X\right)^{-1}X'Z\left(Z'Z\right)^{-1}Zy \tag{10}$$

Following Eqs. (10) and (11) shows the estimated covariance matrix of these coefficients:

$$\widehat{\Sigma}_{2SLS} = s^2(X^{'}Z\left(Z^{'}Z\right)Z^{'}X)^{-1} \tag{11}$$

where $s^2 s^2$ is the estimated residual variance (square of the standard error of the regression).

4.4 Panel Corrected Standard Error (PCSE)

The Time Series Cross-section model using OLS procedures has shortcomings that can be overcome using the PCSE model developed by Beck and Katz (1995). The OLS estimations are criticised for non-spherical errors, which lead to the inability to provide consistent estimates. The PCSE model, on the other hand, provides accurate estimation, considering contemporaneously correlated or heteroskedastic panel errors. Equation (12) captures the PCSE model as below:

$$y_{it} = \theta y_{it-1} + x_{it}\beta + \varepsilon_{it} \tag{12}$$

where the error in Eq. (13) is partially independent while the variance–covariance matrix of the errors takes the following form:

$$\Omega = \Sigma \otimes I_T \tag{13}$$

where Σ shows the N x N matrix of error variances and contemporaneous covariances, ⊗ denotes the Kronecker product, and Σ signifies the T x N matrix of the OLS residuals. E'E/T suggests a consistent estimate of Σ. Therefore, PCSE estimation takes the form of the square root of the diagonal of:

$$(X^{'}X)^{-1}X^{'}\left(\frac{E^{'}E}{T}\otimes I_T\right)X(X^{'}X)^{-1} \tag{14}$$

5 Results and Discussions

Table 3 shows the descriptive statistics of the variables selected. LNNI (ong of net electricity imports) has a mean value of 17.205, suggesting that the ASEAN economies are mostly net importers of electricity. A low mean of 0.245211 for DPRV (distribution privatisation) indicates that electricity distribution privatisation reforms have not progressed in ASEAN. A mean corruption perception index score of 36.56 (TRPI) suggests that the perceived levels of public sector corruption are

Table 3 Descriptive statistics

Variable	Obs	Mean	Std. Dev	Min	Max
LNPGDP	290	15.28966	8.410257	1	30
ETO	290	0.124203	0.299295	0	1.64367
LNNI	290	17.20577	0.199531	14.94239	17.83492
PINSTC	290	0.597097	0.744945	0.005014	2.438308
LNPDL	290	4.423033	1.215632	0.1745	7.0328
LNPEG	290	6.762366	1.62512	2.833732	9.24348
LNPTDL	290	4.059409	1.573257	0.174472	6.857168
LNPEC	290	7.62E-06	1.86E-05	9.80E-08	8.05E-05
LNEA	290	4.176068	0.924057	−4.60517	4.60517
REG	290	0.355172	0.479393	0	1
UNBLDG	290	0.272414	0.445971	0	1
CORP	290	0.551724	0.498177	0	1
OPACCESS	290	0.3	0.45905	0	1
DPRV	290	0.358621	0.480425	0	1
GINI	207	27.12077	15.52042	1	56
TRPI	215	36.56279	26.71229	1	87
HDI	290	0.63949	0.140798	0.342	0.936

Source Authors' calculations

Table 4 CD and CIPS Test

	CD Test		CIPS Test	
	Coefficient	P-value	Level	1st Difference
LNPGDP	4.338***	0.000	−2.152***	1.787 ***
IPPS	3.403***	0.007	−1.554	-2.571***
REG	1.333	0.1824	−1.860	−4.273***
UNBLDG	−0.815	1.5849	−0.939	−2.353***
CORP	0.244	0.8074	−2.092*	−3.650***
OPACCESS	3.695***	0.0002	0.633	−0.712
OPACCESS	−2.039	1.9586	0.788	0.133
PINSTC	−0.264	1.2079	−1.413	−3.767***
LNPEC	−1.704	1.9116	−2.226***	−2.476***
TRPI	34.432***	0.0000	−2.859***	−4.608***
LNNI	−2.979	1.9971	−0.361	−2.885***
ETO	4.173***	0.000	−0.771	−2.777***
LNPEG	3.135**	0.0017	−1.734	−4.211***
LNPDL	4.693***	0.000	−2.391***	−5.211***
LNPTDL	−0.110	1.0880	−2.073*	−5.150***
LNEA	2.119*	0.0341	−1.762	−4.582***
HDI	−0.400	1.3111	−1.924	−3.844***
GINI	−0.774	1.5609	−3.790***	−4.558***

Source Authors' calculations

still high in ASEAN. The region has a medium level of human development (0.64), while income inequality is not high.

Table 4 describes the analysis of the cross-sectional dependence and CIPS test. The results confirm the CSD in some of the reform variables, such as introducing the IPPs and open-access regimes in the electricity sector. Other variables signalling CSD include GDP, corruption perception, electricity trade openness, electricity generation, and distribution losses. We further applied the Pesaran (2007) CIPS test, accounting for the CSD. The results show that all variables reject the null hypothesis of no CSD, except for LNPGDP, COPRS, TRPI, LNPDL, LNPTDL, and GINI.

Table 5 shows the economic impact of electric reforms captured across three dimensions: economic output, net electricity imports, and electricity trade openness. Electricity reform measures, such as regulation in the electricity sector, restructuring in the form of vertical separation or unbundling, and the introduction of open access, positively contributed to GDP. A lower perception of corruption is also associated with higher GDP in ASEAN. However, reform measures, such as corporatisation, distribution privatisation, and investments in electricity generation, led to a decline in GDP. This result can be attributed to the fact that market-based reforms can be unsuccessful without a sound institutional framework (Nepal and Jamasb 2012). In

Table 5 The economic impact

Variable	(1)	(2)	(3)
	LNPGDP	LNNI	ETO
IPPS	−1.377	−0.141***	0.161**
	[1.151]	[0.041]	[0.058]
REG	5.310***	0.068**	−0.04
	[0.726]	[0.026]	[0.037]
UNBLDG	1.448*	−0.029	−0.016
	[0.698]	[0.024]	[0.033]
CORP	−1.862*	0.084**	−0.112*
	[0.869]	[0.031]	[0.044]
OPACCESS	5.423***	0.155***	−0.032
	[1.006]	[0.037]	[0.052]
DPRV	−3.345***	−0.024	−0.187***
	[0.918]	[0.033]	[0.047]
PINSTC	−1.636*	−0.094***	0.133***
	[0.713]	[0.020]	[0.028]
LNPEC	29.703		
	[23.243]		
TRPI	0.065***	2.86e-04	−0.001
	[0.014]	[4.18e-04]	[0.001]
Constant	14.063***	17.245***	0.149**
	[1.000]	[0.034]	[0.048]
Observations	290	290	290
R-squared	[0.362]	0.166	0.723

Standard errors in parentheses
*** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$
Source Authors' calculations

terms of improving electricity security in ASEAN, reform measures, such as the introduction of IPPs and investments in electricity generation, have been successful as expected. On the contrary, regulation, corporatisation, and open access have deteriorated electricity security in the form of increased electricity imports.

To some extent, these results are expected because market-oriented reforms promoted commerce in the ASEAN region. In promoting electricity trade openness, the introduction of IPPs and investments in electricity generation capacities were important policies. However, corporatisation and electricity distribution privatisation decreased electricity trade openness, indicating an earlier observation that market-oriented reforms in the electricity sector require well-supporting institutions to deliver successful outcomes.

Table 6 examines the technical impact of electricity reforms captured across two dimensions: (i) electricity distribution losses and (ii) electricity transmission and

Table 6 Technical impact

Variables	(1)	(2)
	LNPDL	LNPTDL
IPPS	−0.210*	−0.918***
	[0.094]	[0.261]
REG	0.043	1.305***
	[0.065]	[0.180]
UNBLDG	0.032	−0.873***
	[0.061]	[0.168]
CORP	−0.233**	−0.273
	[0.076]	[0.211]
OPACCESS	0.031	−1.293***
	[0.091]	[0.252]
DPRV	0.194*	1.430***
	[0.083]	[0.229]
LNPEG	0.486***	0.209**
	[0.026]	[0.071]
TRPI	0.002*	0.006*
	[0.001]	[0.003]
Constant	1.346***	3.357***
	[0.189]	[0.523]
Observations	290	290
R-squared	0.786	0.235

Standard errors in parentheses
*** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$
Source Authors' calculations

distribution losses. The participation of IPPs in electricity generation and corporatisation decreased electricity losses as the 'soft' budget principles were replaced with more cost-cautious principles and possibly minimising electricity thefts. However, electricity generation expectedly increased electricity losses as more electricity entered the grids. Distribution privatisation increased distribution electricity losses, most likely because of the absence of an appropriate regulatory framework to support the objective of privatisation. Similarly, reform steps such as the participation of IPPs, unbundling, and introduction of open access decreased transmission and distribution losses. However, regulation and electricity distribution privatisation increased transmission and distribution network losses. A higher perceived level of corruption also translates into higher network losses, signalling the prevalence of non-payment of government electricity usage in ASEAN.

Table 7 captures the welfare impacts of reforms across three dimensions: electricity consumption, human development, and income inequality. Electrification policies have successfully improved electricity consumption in the ASEAN region

Table 7 Welfare impact

Variable	**(1)**	**(2)**	**(3)**
	LNPEC	HDI	GINI
IPPS	−2.88***	−20.417	−0.698
	[2.61e-06]	[12.725]	[13.454]
REG	1.05e-05***	−20.934*	−1.347
	[1.88e-06]	[8.209]	[5.512]
UNBLDG	−7.84e-06***	−10.529	−6.167
	[1.69e-06]	[7.505]	[5.020]
CORP	−8.08e-07	38.987***	1.539
	[2.24e-06]	[9.504]	[7.750]
OPACCESS	2.79e-06	48.425***	3.333
	[2.64e-06]	[11.414]	[5.680]
DPRV	−3.62e-07	−2.252	−0.953
	[2.39e-06]	[10.384]	[6.198]
LNEA	2.16***		
	[2.59e-06]		
TRPI	−1.64e-07***	1.222***	0.452***
	[2.68e-08]	[0.106]	[0.084]
LNPEC		1.71e + 06***	3.06E + 05
		[2.03e + 05]	[2.30e + 05]
Constant	−5.58***	108.990***	28.892
	[10.60]	[11.276]	[15.129]
Observations	290	290	290
R-squared	0.41	0.51	0.27

Standard errors in parentheses
*** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$
Source Authors' calculations

than relying on market-based mechanisms, such as IPPs. Regulation in the power sector and vertical unbundling decreased electricity consumption. A higher perceived corruption level is also associated with lower electricity consumption. Reforms did not generate any significant effect on income inequality in ASEAN. Surprisingly, the corruption index is positively related to human development and income equality. This may suggest that the perceived levels of corruption historically have not been a barrier to promoting human development and reducing income inequality in ASEAN. Reform measures like regulation decreased human development while corporatisation and open access improved human development.

6 Conclusions and Policy Implications

This chapter examined the impact of market-oriented electricity reforms on the socioeconomic and technical dimensions in ASEAN economies. As quantitative studies on power sector reforms are limited in the context of the ASEAN economies, this chapter is a valuable attempt in filling such a gap, using accounting for the CSD, which prior empirical studies reforms have not considered. We find that reforms have generated mixed impacts, such that not all reform measures have been successful in generating the desired effects. One of the factors could be a wide-ranging gap between theory and practice when implementing reforms. Reforming countries with stalled electricity reforms in ASEAN, such as Brunei, Cambodia, Indonesia, and the Lao PDR, and should accelerate power sector reforms that will require political support, as demonstrated by the Philippines.

The reform impacts also indicate that market-based reforms require an appropriate institutional set-up to deliver successful outcomes. Therefore, institutional strengthening and robustness are prerequisites before implementing market-based reforms. Reducing the perceived and actual levels of corruption is necessary for ASEAN to generate positive impacts of reforms on power sector outcomes. Specific objectives such as increasing electricity consumption will be best met if pursued independently through targeted policies to improve electricity access rather than relying on power sector reforms. The results also explicitly reveal that power sector reforms led to enhancing the technical and operational efficiency in the sector by minimising network losses.

Nonetheless, electricity distribution privatisation is not recommended in six other ASEAN countries without first installing an appropriate institutional framework. The recent increase in wholesale electricity prices in Singapore also suggests that price volatility will be an inherent feature of liberalised electricity markets as electricity reforms advance in ASEAN. The design and trading of appropriate financial instruments to mitigate such price risks for market participants will be equally important.

Our chapter has also opened up several future research areas for further investigation. As reforms deepen in the ASEAN region, it would be interesting to assess the interaction amongst reforms and the combined effect these will generate. We also do not capture any environmental impacts of reforms that future studies may study by interacting the reform measures with the environmental policies. The availability of more data in the future will also allow the employment of alternative modelling specifications and estimation techniques.

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Electricity Market Development in Viet Nam: Historical Trends and Future Perspectives

Thai-Ha Le, Phoumin Han, and Ha-Chi Le

Abstract This study discusses the process of electricity market development in Viet Nam with a focus on key achievements and future perspectives. The empirical analysis attempts to construct a composite indicator for the security of electricity supply. Specifically, principal component analysis (PCA) is performed based on eight normalised variables representing four aspects of electricity security. The Electricity Supply Security Index (ESSI) trends of Viet Nam and other ASEAN + 6 countries in 1996–2019 are reviewed and compared. This research finds that except for Brunei, the ESSI of ASEAN + 6 (including Viet Nam) has been rising. The findings are robust to different normalisation techniques. Some policy implications are then proposed.

Keywords Electricity market reform · Electricity security index · Principal component analysis · Normalisation · ASEAN + 6

JEL Classifications C38 · P41 · Q48

1 Introduction

Electricity plays a crucial role in life and in production. Thus, it affects the entire development of the national economy, especially in the industrialisation progress. Moreover, on a national level, as electricity is the prerequisite for improving the quality of life and creating opportunities, it helps bridge the gap between urban and rural populations. Universal access to electricity is therefore often regarded as a key driver for inclusive growth.

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This research analyses Viet Nam's electricity sector development and reform experience from the 1990s to 2020. Total power consumption has continued to increase rapidly over the years to serve the country's economic development needs. This growth is in line with the country's industrialisation and integration into the global economy following the *Doi Moi* (reforms) in 1986. Since 1986, its electricity industry has achieved an impressive pace of development, leading the world with an average annual growth rate of 10–12% in electricity production and consumption (based on CEIC[1] data). This rate is on par with South Korea's level during its miraculous development period. As a result, from a very low level of development, Viet Nam quickly surpassed many countries in the region in terms of the electricity sector's production capacity and management efficiency. One particular example is that, according to CEIC data, in 1986, the per capita electricity consumption of the country was only 68 kWh, 4.7 times lower than the Philippines and 6.4 times lower than Thailand. In 2018, Viet Nam's index reached approximately 2,300 kWh, nearly three times higher than that of the Philippines and equal to 85% that of Thailand. Meanwhile, an increase of 10% in Viet Nam's real GDP produced an 18% rise in electricity, much more than any other major economy in Association of Southeast Asian Nations (ASEAN) or China or India (Dapice et al. 2022).

Achievements of the power sector are output growth and management quality. Amongst developing countries, Viet Nam's electricity industry has made remarkable progress in power supply reliability and transmission and distribution loss management (Lee and Gerner 2020). In particular, the country's meaningful effort and remarkable success in bringing electricity to the countryside have been internationally recognised (Gencer et al. 2011; Baum 2019). Its electricity industry has played a critical role in improving the business environment over the past 5 years. In the World Bank's 'Doing Business' ranking in 2020, Viet Nam ranked 27th in the electricity access index, much higher than the country's 70th overall index.

The government currently manages the energy sector through the Ministry of Industry and Trade, while big state-owned enterprises (SOEs) dominate the sector. The integrated state-owned utility Vietnam Electricity (EVN) is the main electricity producer in the country. The EVN controls the power system's transmission, distribution, and operation and occupies a large proportion of the production and generation market. The remaining shares in power generation belong to other big SOEs such as PetroVietnam (gas-fired power plants) or Vinacomin (coal-fired power plants). Most foreign investors use the build-own-transfer model, while domestic investors use the independent power plant (IPP) model. Electricity produced from IPPs is sold to the EVN under long-term contracts. The number of IPPs has increased dramatically in recent years with the remarkable growth of solar and wind power.

Viet Nam plans to develop a competitive electricity market by 2023. A competitive electricity market is one where many different suppliers must sell electricity. It is commonly opined that if a good has only one supplier for some reason, the consumer will have no options. Therefore, there is no motivation for competition, thus translating into a higher cost of the goods. In 2013, a Prime Minister's decision

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[1] https://www.ceicdata.com/en/about-us.

emphasised and confirmed the elimination of monopoly (deregulation) processes since 2005 so that the electricity market would not be monopolised.

This research consists of two parts. The first part analyses the current progress of the power sector development in Viet Nam. It reviews historical trends of some key indicators for the electricity market's development over the past few decades. The future perspectives of the reforms over the next decade are then discussed. The second part of the study develops and constructs a composite Electricity Supply Security Index (ESSI) for Viet Nam by looking at various aspects of the index suggested by the existing literature. The PCA is performed based on eight indicators. Building a composite index like the ESSI aims to quantify electricity supply resilience and enable policymakers to assess the multi-dimensional aspects of resilience (Gasser et al. 2020). This study also compares the ESSI trend for Viet Nam and other ASEAN + 6 countries over 1996–2019.

Specifically, this research aims to address two main questions:

- How has the development of Viet Nam's power sector been in terms of key achievements, challenges, and future perspectives?
- What is the trend of the country's electricity supply security over the past decades?

The rest of this paper is organised as follows. Section 2 comprehensively reviews electricity market developments in Viet Nam. The section presents and discusses some key indicators' historical trends and future perspectives. Key achievements and challenges are critically assessed. Section 3 examines the trend of electricity supply security in Viet Nam and compares it with that of other countries in the ASEAN + 6 region. Finally, Sect. 4 provides concluding remarks with policy recommendations.

2 Review of Electricity Market Development in Viet Nam

2.1 *Historical Trends*

(1) **Review of trends and achievements**

Over the past 65 years, the electricity industry has consistently affirmed its leading role in ensuring electricity supply for Viet Nam's socio-economic development, people's daily life, and national defence and security. From 1954 to the 1990s, power supply was lacking due to warfare and its consequences, and the quality was unstable. In 1990, the total capacity of the whole country was only about 1,800 MW; the electricity output was about 8–10 billion kWh.[2] However, annual electricity output has increased more than 20 times, from 8.6 TWh in 1990 to 240.1 TWh in 2019 (GIZ

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[2] Source: https://www.evn.com.vn/d6/news/Nganh-Dien-Viet-Nam-Hanh-trinh-dong-gop-cho-dat-nuoc-phat-trien-6-12-18031.aspx (in Vietnamese).

2020). During this period, the annual growth rate has been around 12–15%, almost double the GDP growth rate.[3]

By the end of 2020, Viet Nam had a solid power system with a total source capacity of more than 61,000 MW. The national grid had covered the whole country with over 8,500 km of 500 kV transmission lines; 33,000 km of 110–220 kV transmission lines; and hundreds of thousands of kilometres of distribution networks of all kinds. Commercial electricity output in 2020 was 225.4 billion kWh, achieving an annual average growth rate of 9.66% in the 2010–2020 period, about 1.6 times higher than GDP growth. The average commercial electricity output per person by the end of 2020 is approximately 2,200 kWh/person/year, an increase of 2.24 times compared to 2010 (982.7 kWh/person/year).[4]

Thanks to the successful implementation of synchronous solutions to improve economic and technical indicators and production and business efficiency, the electricity loss rate of EVN had decreased from 10.25% (in 2010) to 6.5% by 2020. Thus, during the 2010–2020 period, the average power loss rate of EVN decreased by 0.34% each year and approached the level of power loss in developed economies.[5]

Hydropower, natural gas, and coal are the primary energy sources for electricity production. According to GIZ (2020), in 2019, coal accounted for the highest share (41.6%) of these primary energy sources, followed by hydro (37.7%) and gas (18.8%). Meanwhile, with the exclusion of hydropower, other renewable energy accounted for a tiny portion (0.5%) (GIZ 2020). However, from the beginning of 2019, the share of renewable energy in the system has increased significantly, primarily due to solar energy (solar photovoltaic). Meanwhile, wind power is also rising.

Since 2019, Viet Nam has outpaced most ASEAN countries to be the leader in solar and wind electricity adoption. Tables 1 and 2 show that the country had the second-largest installed wind capacity in ASEAN (behind Thailand) and the largest installed solar capacity in the region in 2020. Viet Nam's total installed capacity reached 600 MW for wind energy and more than 16,500 MW for solar energy by the end of 2020 (International Renewable Energy Agency, 2021). Interestingly, when comparing within ASEAN + 6, the country's total installed capacity for solar energy exceeded Korea and New Zealand (Table 1). More than 100,000 rooftop solar photovoltaic systems were installed in Viet Nam in 2019–2020, an extraordinary achievement (Vietnam Electricity 2020). Most ASEAN countries have yet to experience this rapid progress in solar and wind development witnessed in Viet Nam (Do et al. 2021). The success of its solar and wind development could be attributed to generous feed-in tariffs, considerable income tax and land lease payment exemptions, and a supportive investment environment (Do et al. 2021).

Likewise, Viet Nam's electricity access index also made significant progress as the rural electrification programme, i.e. supplying electricity to remote and border

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[3] CEIC, https://www.ceicdata.com/.

[4] https://zingnews.vn/10-thanh-tuu-noi-bat-cua-nganh-dien-giai-doan-2010-2020-post1165218.html (in Vietnamese).

[5] https://zingnews.vn/10-thanh-tuu-noi-bat-cua-nganh-dien-giai-doan-2010-2020-post1165218.html (in Vietnamese).

Table 1 ASEAN + 6's solar energy (installed capacity) (MW) (2011–2020)

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Brunei	1	1	1	1	1	1	1	1	1	1
Cambodia	4	5	6	9	12	18	29	29	99	208
China	3108	6719	17,759	28,399	43,549	77,809	130,822	175,287	204,996	254,355
India	566	982	1499	3673	5593	9879	18,152	27,353	35,089	39,211
Indonesia	17	26	38	42	79	88	98	69	155	172
Japan	4890	6430	12,107	19,334	28,615	38,438	44,226	55,500	61,526	67,000
Korea	730	1024	1555	2481	3615	4502	5835	7130	10,505	14,575
Lao PDR	0	0	0	3	3	4	22	22	22	22
Malaysia	1	25	97	166	229	279	370	536	882	1493
Myanmar	1	3	4	6	21	32	44	48	88	84
Philippines	2	2	3	28	173	784	908	914	973	1048
Singapore	5	8	12	25	46	97	116	160	272	329
Thailand	79	382	829	1304	1425	2451	2702	2967	2988	2988
Viet Nam	5	5	5	5	5	5	8	105	4,898	16,504
Australia	2473	3799	4568	5287	5946	6689	7354	8627	13,252	17,627
New Zealand	3	4	8	22	37	53	70	90	117	142

Note The data reflects the capacity installed and connected at the end of the calendar year. The data is presented in megawatts (MW) rounded to the nearest 1 megawatt, with figures between 0 and 0.5 MW shown as a 0
Source International Renewable Energy Agency (2021)

areas, was successfully implemented. The World Bank regards Viet Nam as one of the countries with successful and highly effective implementation of rural electricity investment (Baum 2019). Figure 1 shows that the country achieved high access rates to electricity even before embarking on market reforms. Universal access to electricity was reached around 2011. According to the World Banks' Doing Business report, the country's electricity access index in 2019 continues to rank 4th in the ASEAN region while maintaining the 27th position out of 190 countries (up 129 places in 6 years). The percentage of the population with electricity access in Viet Nam is higher than that in some countries in the region with equal or better economic conditions, such as Indonesia, Malaysia, and the Philippines. Similarly, per capita electric power consumption has consistently been rising since 1970, and the growth in electricity demand per capita has accelerated after the 1990s.

Figure 2 plots the growth of direct and indirect participation in the Vietnam Competitive Generation Market (VCGM) over the 2012–2018 period. The VCGM officially launched on 1 July 2012, marking a milestone for the electricity industry, moving from a centralised regulation mechanism to a market mechanism (Khoa 2018). VCGM's goal is to ensure a stable electricity supply, attract investment from all sectors of the economy, and gradually increase competitiveness to improve efficiency in electricity production and trading. The VCGM operates under a cost-based

Table 2 ASEAN + 6's wind energy (installed capacity) (MW) (2011–2020)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Cambodia	0	0	0	0	0	0	0	0	0	0
China	46,355	61,597	76,731	96,819	131,048	148,517	164,374	184,665	209,582	281,993
India	16,179	17,300	18, 420	22,465	25,088	28,700	32,848	35,288	37,505	38,559
Indonesia	1	1	1	1	1	1	1	144	154	154
Japan	2419	2562	2646	2753	2808	3247	3483	3667	3786	4206
Korea	425	464	576	612	847	1067	1215	1420	1512	1636
Myanmar	–	–	–	–	0	0	0	0	0	0
Philippines	33	33	33	337	427	427	427	427	443	443
Singapore	–	–	–	–	–	–	0	0	0	0
Thailand	7	112	223	225	234	507	628	1103	1507	1507
Viet Nam	31	31	53	53	136	160	205	237	375	600
Australia	2127	2561	3221	3797	4234	4327	4816	5679	7133	9457
New Zealand	524	623	623	682	689	689	689	689	689	784

Note The data reflects the capacity installed and connected at the end of the calendar year. The data is presented in megawatts (MW) rounded to the nearest 1 megawatt, with figures between 0 and 0.5 MW shown as a 0

Source International Renewable Energy Agency (2021)

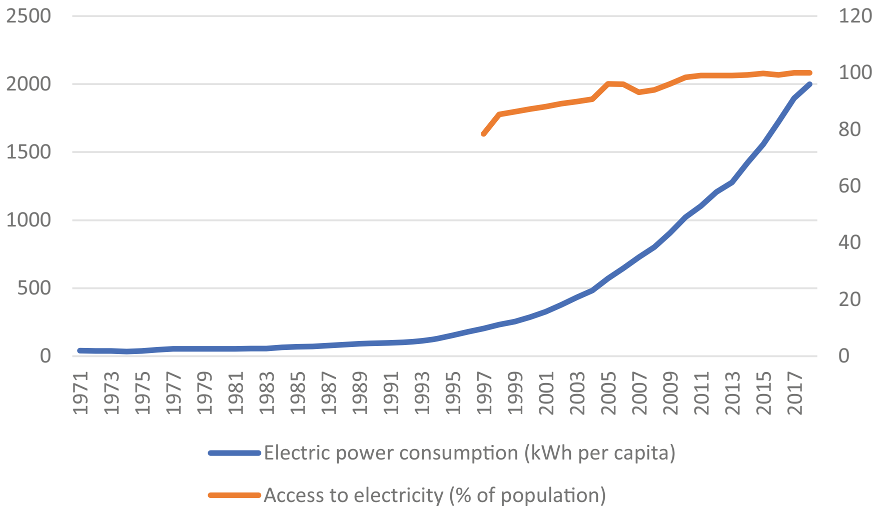

Fig. 1 Viet Nam's electricity access rate and power consumption per person (1971–2018). *Source* Authors' calculations. Statistics are derived from World Development Indicators (2021)

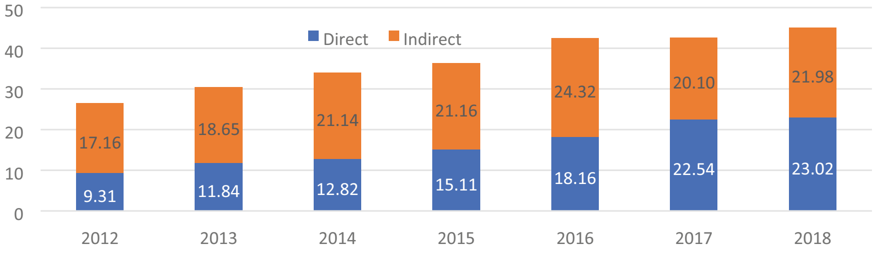

Fig. 2 Capacity traded in the vietnam competitive generation market (GW) (2012–2018). *Source* Author's calculations. Statistics are derived from Vietnam's National Load Dispatch Center (NLDC) (2021)

compulsory pool market model in which all electricity is traded through a day-ahead market, and no generator can exercise market power (Khoa 2018). By 2018, direct participants in the VCGM[6] grew to 23 GW, contributing to more than 50% of the total installed capacity of large power plants in Viet Nam (Fig. 2).

Figure 3 depicts the trend of peak electricity demand and installed generation capacity from 2000 to 2018. During this period, the country's installed electricity capacity has been transitioning from mainly hydropower-based to more fossil-fuel-based sources. Besides hydroelectricity, coal-fired and gas-fired thermal power have become important sources of the domestic electricity supply. Since 2001, supply

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[6] In 2011, the Vietnam Competitive Generation Market (VCGM) was established as a pilot, ahead of the planned privatisation of EVN generation companies, followed by full operation in 2012.

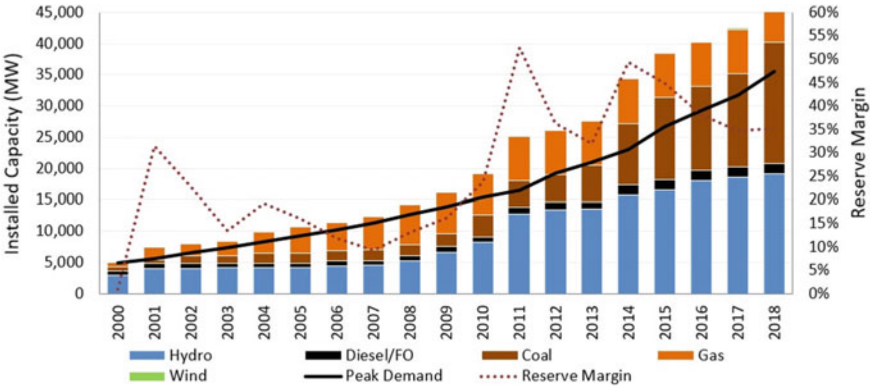

Fig. 3 Installed generation capacity of Viet Nam's electricity (2000–2018). *Source* Lee and Gerner (2020)

has exceeded demand, and this supply–demand gap has been widening. Installed capacity rose to nearly 20 GW by 2010, then increased sharply to more than 45 GW by 2018.

(2) The role of government or state

In the past, the electricity industry across countries operated under the 'natural monopoly' model. With this model, electricity production on an industrial scale is carried out according to the supply chain by 'monopoly' suppliers, with the state's regulation on prices and market entry conditions, investment management, and service quality control. The electricity production and supply process is vertically integrated, focusing on one or several exclusive suppliers under the state's regulation. This model is suitable when the electricity production capacity (generating capacity) is insufficient to meet the demand for electricity consumption. In other words, the priority of the electricity industry in this context is to increase the output and ensure the security of the electrical power supply. Legislation and regulations are crucial instruments for achieving public interest goals (Armstrong and Jan 2000). Given electricity's critical role in socio-economic development, it is the state's role and responsibility to manage the electricity market operation. The government can have multiple roles in the power sector: national energy/power master planning, resource evaluation, market evaluation, least-cost planning, elimination of obstacles to equitable markets, project oversight and evaluation, facilitating access to capital, grid regulation, and market regulation.

When the electricity industry enters the stage of having a higher production capacity to meet the consumption demand of customers, the industry's priority will be having more economical and efficient production, coupled with a more advanced business model and market organisation. At this stage, customers demand electricity services with more reasonable prices and higher quality and reliability, leading to competition in this market.

In line with this trend, over the past decade, Viet Nam's policy has focused on gradually forming a competitive domestic market for electricity, diversifying the ways of doing business, investing in the electricity market, encouraging many economic sectors to participate, and avoiding turning a state monopoly into an enterprise monopoly. For this purpose, the state only holds a monopoly on power transmission as well as the construction and operation of large hydroelectric plants and nuclear power plants. Furthermore, the state should facilitate participation in electricity trading and integration with countries in the region.[7]

Therefore, the state must develop methods and solutions to enhance its role further in regulating and operating the market. The state needs to separate the business function from the social function of the industry. The industry should be put in a competitive environment that operates according to market mechanisms and complies with efficiency standards. The industry must not receive any special incentives beyond the market principle.

2.2 Future Perspectives

The section focuses on the future perspectives of the reforms over the next decade. The development of Viet Nam's electricity sector would face increased encumbrances in satisfying the needs of economic growth and improving people's lives. The major challenges facing the power sector are as follows: (i) electricity demand is projected to continue to grow further, outpacing generation capacity; (ii) the primary energy source is gradually being exhausted, and the ability to supply primary energy is limited, leading to the need to import fuel soon; (iii) many power plants are not built according to plan, and the power plant distribution amongst regions is imbalanced, leading to an increase in inefficient power transmission and high transmission losses; (iv) the rapid development of renewable energy sources, such as wind and solar power, has led to certain difficulties in operating the power system; (v) the increasingly stricter requirements for complying with the regulations on environmental protection in the power operation process.

The prospective reforms of the electricity market should overcome those difficulties and challenges to ensure a stable, affordable, and reliable electricity supply to meet the needs of socio-economic development and national security and defence of the country. In October 2021, Viet Nam released its power sector development plan for the next decade, 2021–2030, with a vision to 2045 (Power Development Master Plan VIII), representing a gradual shift from reliance on inflexible independent coal-fired power projects to renewable energy sources and liquefied natural gas (Fig. 4). Nevertheless, fossil energy will still account for 68–69% of the national electricity production by 2030, making Viet Nam one of the six countries with the world's largest coal power development plan. As such, this Master Plan VIII seems

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[7] See https://www.quanlynhanuoc.vn/2019/06/06/vai-tro-quan-ly-nha-nuoc-ve-thi-truong-dien-o-viet-nam-hien-nay/ (in Vietnamese).

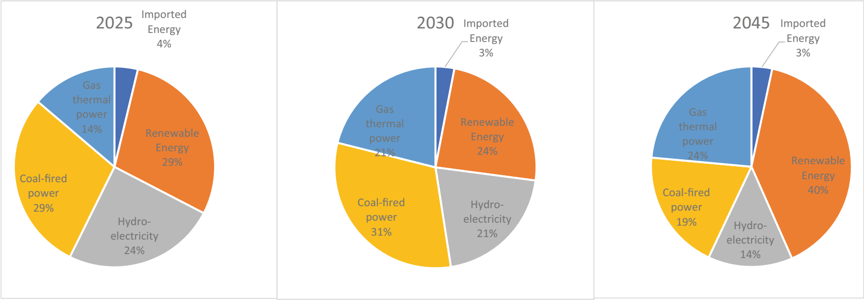

Fig. 4 Viet Nam's energy input structure as proposed by PDP8. *Source* Authors' calculations; Statistics are derived from Vietnam's Power Development Planning VIII (PDP8) (2021)

to go against the global green energy transition, especially given the country's strong commitments at the United Nations Climate Change Summit 2021 (Conference of the Parties 26) to reach its net-zero carbon emission target by 2050.

According to the Institute of Energy,[8] by the end of December 2020, the total capacity of solar power (including rooftop solar power) would be 16,500 MW (accounting for 24.1% of total capacity); the total wind power capacity is 567 MW (accounting for about 0.86% of total capacity). However, solar and wind power contributes very little to electricity output (only about 4% of the total electricity output in 2020). In 2020, the untapped output of solar power was about 364 million kWh. In addition, renewable power sources have many operating characteristics different from traditional power sources, such as high uncertainty, weather-dependent operating modes, no contribution to power system inertia, and primary frequency modulation. Therefore, the sudden increase of renewable power sources leads to many problems in power system operation, such as full load, local overload, decreased system inertia, increased number of starts, and the requirement to adjust the capacity of thermal power plants.

The development of power sources should be synchronised with the transmission grid and smart power systems to integrate different power sources. However, a huge amount of capital (tens of billions of dollars each year) is needed to invest in that system while the country's resources are limited. On the other hand, private investors only invest in areas with great potential and benefits rather than paying attention to social factors. The issue of socialisation of the transmission grid has also been raised but received little attention from investors. In this context, the best option is to reach out to the community of foreign investors, especially development partners such as the European Union, United States, World Bank, and United Nations Development Programme. They are committed to supporting the government of Viet Nam in mobilising resources for the green energy transition.

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[8] https://vietnamnet.vn/vn/kinh-doanh/dau-tu/dien-mat-troi-dien-gio-cang-ve-cuoi-nam-noi-lo-cang-lon-740591.html (in Vietnamese).

Table 3 List of ASEAN + 6 countries in the sample (16 countries)

High-income countries (6)
Australia, Brunei, Japan, New Zealand, South Korea, Singapore
Upper-middle income countries (3)
China, Malaysia, Thailand
Low and lower-middle income countries (7)
Cambodia, India, Indonesia, Lao PDR, Myanmar, Philippines, Viet Nam

3 Empirical Analysis of Viet Nam's Electricity Supply Security

3.1 Brief Review of the Literature

In the empirical part of this study, a composite ESSI is developed and constructed for Viet Nam. Different aspects of the index are considered in accordance with the existing literature. We then perform the PCA to determine the indicators with the greatest individual impacts on this ESSI. The trend of Viet Nam's ESSI over the years is plotted and discussed. The purpose is to help policymakers identify ESSI trends and specific patterns and understand the responsible factors behind this movement. Finally, we compare the ESSI trend for Viet Nam and other countries in the ASEAN + 6 region from 1996 to 2019, subject to data availability. We choose ASEAN + 6 for this comparison because this is a significant economic bloc. Despite substantial differences in socio-economic and technological development levels, ASEAN + 6 countries share common challenges in ensuring the security of their energy supplies, including electricity (IEA 2019). Since these countries share geographical locations, they could help address these challenges by strengthening regional cooperation. Table 3 presents the list of countries in our study sample.

The security of electricity supply has become increasingly important for the national economy and societal development in many countries worldwide (Osorio et al. 2017; Ren and Dong 2018). However, despite the rising literature on providing a conceptual framework and constructing empirical composite indexes for energy security,[9] the number of studies that build a theoretical framework or calculate a composite indicator for electricity security has been much scarcer. To the best of our knowledge, these include Grave et al. (2012), Larsen et al. (2017), Osorio et al. (2017), Dakpogan and Smit (2018), Ren and Dong (2018), Asgari and Behnood (2019), Neelawela et al. (2019), Gasser et al. (2020), and Sarhan et al. (2021).

Notably, Larsen et al. (2017), based on an extensive review of the literature, built a conceptual framework that includes 12 critical dimensions for the security of supply in the electricity sector to provide a management information tool for

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[9] Sovacool and Mukherjee (2011); Winzer (2012); Yao and Chang (2014); Ang et al. (2015); Li et al. (2016); Wang and Zhou (2017); Azzuni and Breyer (2018); Le et al. (2019a, b); Le and Nguyen (2019); Le and Park (2021).

all stakeholders. Another noteworthy empirical study is Gasser et al. (2020), who performed a structured selection process for individual indicators to calculate the comprehensive ESSI for 140 countries worldwide.

The literature seems to indicate that approaches based on a set of indicators are appropriate to evaluate multifaceted problems like energy security or electricity security. Our focus here is on secure and sustainable electricity supply, particularly electricity supply disruption risks. Subject to the theoretical frameworks proposed in existing studies in these fields and the availability of required data, this study adopted the four main pillars ('the four As': availability, accessibility, affordability, and acceptability) that characterise energy and electricity security. We collected data for eight indicators from various sources, including the World Development Indicators, US Energy Information Administration, Worldwide Governance Indicators, World Bank's Commodity Markets, and CEIC data. Table 4 describes our eight selected indicators, their construction, and data sources. The statistical descriptions of the variables are summarised in Table 5.

Table 4 Indicators considered in the study (1996–2019)

Variable	Topic	Indicator	Unit	Source (s)
RACE	Availability	Rate of access to electricity (as a percentage of total population)	%	World development indicators (2021) and CEIC data (2021)
RUB	Availability	The ratio of growth of access to electricity in urban areas (ΔUAE) to growth of urbanisation rate (ΔUR)	%	World development indicators (2021)
ESE	Availability	Rate of electricity supply efficiency, which is defined as the ratio of electricity not lost (ENL) to the total electricity supply (TES)	%	US energy information administration (2021)
ESS	Accessibility	Self-sufficiency rate in terms of domestic electricity supply, which is defined as one minus the ratio of net imports of electricity (NIE) to total supply of electricity (TES)	%	US energy information administration (2021)

(continued)

Table 4 (continued)

Variable	Topic	Indicator	Unit	Source (s)
GQ	Accessibility	Governmental quality, which is defined as the first principal component of the PCA of six governance indicators, including ‘control of corruption’ (COC), ‘rule of law’ (RLA), ‘quality of the regulatory system’ (QAR), ‘government effectiveness’ (GEF), and ‘political stability and absence of violence’ (POS)	Point estimate	Worldwide governance indicators (2018)
RGDPpc	Affordability	Real gross domestic product per capita (constant 2015 US$)	$	World development indicators (2021)
RNEEX	Affordability	Share of real GDP not dedicated to cover the cost of electricity supply, which is defined as one minus the cost of electricity supplied (CES) multiplied by 100. CES is calculated by multiplying the total quantity of electricity supply (TES) converted in barrel of oil equivalent (bbl) by the annual real average crude oil price (COP) (US$/bbl; constant 2010 US$)	%	US energy information administration (2021) World bank’s commodity markets (2021)
REE	Acceptability	Share (RRE) of renewable electricity (RE) in the total domestic production of electricity (ED)	%	US energy information administration (2021)

Note Data is compiled from cited sources and from authors’ calculations
Source Authors’ compilation

3.2 Methodologies

Table 4 indicates that the eight selected indicators have different units and are on different scales. Additionally, Table 5 shows that some variables have a much greater standard deviation (i.e. RGDPpc: $\sigma = 547.637$) than others (i.e. GQ: $\sigma = 0.189$; RUB: $\sigma = 0.424$). Since the derived variables are based on the linear combination of the original indicators to capture maximal variance in the PCA, it will load more heavily

Table 5 Summary of the descriptive statistics

Variables	Obs	Mean	SD	Min	Median	Max
Vietnam	–	–	–	–	–	–
RACE	24	93.12	7.434	70.62402	96.05	100
RGDPpc	24	1523.40	547.637	785.5335	1465.522	2604.224
RRE	24	44.71	11.288	28.03292	42.14128	71.92643
GQ	24	−1.49	0.189	−1.725761	−1.525055	−1.076895
RUB	24	100.18	0.424	99.50642	100.1083	101.5638
ESE	24	88.40	3.585	80.25169	89.49276	92.81135
ESS	24	98.70	1.667	95.13305	99.33987	100
RNEEX	24	97.91	1.296	96.03548	97.69561	99.71371
ASEAN + 6		–	–	–	–	–
RACE	384	86.62	20.794	8.820037	98.49565	100
RGDPpc	384	15,584.23	17,795.601	218.3701	4768.978	61,173.91
RRE	384	37.97	69.857	0	15.53339	417.6643
GQ	384	−0.01	2.270	−4.461329	−0.8166739	3.975289
RUB	384	100.11	2.209	84.83291	100.1211	113.6425
ESE	384	88.87	7.958	59.49618	91.58689	98.88723
ESS	384	112.38	60.231	35.39028	100	520.1736
RNEEX	384	98.86	0.782	96.03548	99.06971	99.92972

Note Data is compiled from cited sources and from authors' calculations

on the large variances (Zou et al. 2006). As such, the individual indicators must be normalised to a common scale before they can be aggregated into a composite score. For this purpose, the empirical analysis of this study employs four transformation methods—z-score, min–max, softmax, and sigmoid normalisation techniques—to have a robustness check.

The z-score normalisation technique is a common standardisation method to normalise variables. The numerical value of the z-score reveals how far a value is from the population mean, and this difference is expressed in terms of the number of standard deviations by which it differs (Kirkwood and Sterne 2010). Cross-country comparison is possible using this method (Le et al. 2019a).

The z-score is computed as follows.

$$zee = \frac{X_i - \overline{X}}{\sigma} \tag{1}$$

where $\overline{X}$ = group average, and σ is the standard deviation.

In the min–max technique, the data are specifically fit in a predefined range with a predefined boundary (Patro and Sahu 2015). A scale is formed using the maximum and minimum values observed. As this scale is built, other data values are positioned with reference to these values. The advantage of this method is that all relationships in the original data could be precisely preserved (Jayalakshmi and Santhakumaran 2011), and the performance would be evaluated based on the top and bottom performance. Nevertheless, similar to the z-score normalisation, this min–max normalisation method suffers from weakness as recalibration is needed when additional data points are added.

Rescaling the min–max normalisation techniques involves a linear interpretation formula, whereas normalised scores are constructed using minimum and maximum observations, as follows:

$$mmx = \frac{X_i - X_{min}}{X_{max} - X_{min}} \tag{2}$$

where X_{min} is the minimum data point and X_{max} is the maximum data point.

The softmax normalisation, also known as normalised exponential function (Bishop 2006), performs a smooth approximation to 'the function whose value is which index has the maximum' (Goodfellow et al. 2016). This technique lessens the impact of extreme values or outliers in the data without taking them out from the data set. Since outliers are an essential part of a data set, we should include them in the data set while still preserving the significance of data within a standard deviation of the mean. The nonlinear transformation of the data is performed using one of the sigmoidal functions.

In the softmax normalisation, normalised scores are computed using an exponential function with mean and standard deviation.

$$softmax = \frac{1}{1 + exp^{-V}} \tag{3}$$

where V = $\frac{X_i - \overline{X}}{\sigma}$ and σ is the standard deviation.

Sigmoid normalisation involves using a mathematical function that has a characteristic S-shaped or sigmoid curve. The normalised score is calculated using exponential function and mean and standard deviation:

$$sigmoid = \frac{1 - exp^{-V}}{1 + exp^{-V}} \tag{4}$$

where V = $\frac{X_i - \overline{X}}{\sigma}$ and σ is the standard deviation.

The normalised data are then processed in the next stage using the PCA to evaluate the effect of variations in the values of the selected indicators on the final outcome. The PCA is a standard technique for simplifying a data set by extracting data for hidden features and relationships while removing data with excessive information (Le et al. 2019b). By doing so, the PCA reduces the dimensionality of data for analysis, increases interpretability, and minimises information loss simultaneously (Jolliffe and Cadima 2016). The new variables (the principal components) are dependent on the data set. Unlike other linear transformation methods, they do not have a fixed set of basis vectors or functions (Jolliffe and Cadima 2016).

PCA is widely used as a descriptive tool for explanatory data analysis. As a projection method, it uncovers the data structure and explains the variations (Jolliffe and Cadima 2016). PCA has rarely been employed to quantify a composite measure for the electricity security index in the literature. Nevertheless, PCA has been widely used in the quantitative measurement or empirical analysis of energy security (see, for instance, Li et al. 2016; Radovanović et al. 2017, 2018; Le et al. 2019a; Abdullah et al. 2020). Li et al. (2016) assessed energy security for four resource-poor yet economically advanced island economies in East Asia using the PCA based on a three-level framework including vulnerability, efficiency, and sustainability, with a total of nine indicators. The study results affirmed the critical roles of all these three dimensions for these economies, but with different weights. More recently, Le et al. (2019a) constructed a comprehensive index for energy insecurity by performing PCA on a group of 12 indicators. The study then examined the trend of this index for 24 Asian countries over the period 1990–2014. The results revealed diverse patterns of energy insecurity trends across countries.

In constructing the index, the principal component is a weighted average of all input variables, determining the outcome variable (Jolliffe and Cadima 2016). As such, the first principal component is considered the best representative of the values of the input variables. Thus, it is defined as the value of the newly created index (Radovanović et al. 2018). The resulting weights reveal the degree of correlation between a specific input variable and the outcome index (Radovanović et al. 2018). This way of construction allows us to determine the variables that have the most significant roles in explaining the outcome index. Due to standardisation, all the principal components have zero means, while the standard deviation for each component is the square root of the eigenvalue (Radovanović et al. 2018).

Prior to PCA, Bartlett's test of sphericity and Kaiser–Meyer–Olkin Measure of Sampling Adequacy (KMO) test were executed to assess the fitness of the data for factor analysis. In Bartlett's test of sphericity, the correlation matrix is tested to be an identity matrix. The null hypothesis indicates that the variables are unrelated and therefore inappropriate for PCA. When the Bartlett's test statistics is statistically significant ($p<0.05$), factor analysis is appropriate for the data (Hair et al. 2006; Tabachnick et al. 2007). For the KMO test, sampling adequacy is measured. It evaluates the proportion of common variance among the variables that are possibly caused by underlying factors (Yoshino and Taghizadeh-Hesary 2015). A KMO test statistic larger than 0.5 typically indicates that factor analysis is appropriate for the data (Hair et al. 2006; Tabachnick et al. 2007). Table 6 reports the results of performing these tests. For the Bartlett test of sphericity, all reported test statistics are statistically significant at the 1% level. The finding implies the rejection of the null hypothesis, indicating that the variables used in PCA are correlated. The calculated values for the KMO test statistic are larger than 0.5 in all cases. Therefore, both tests consentaneously support the employment of PCA in this research.

Table 6 Results of bartlett test of sphericity and Kaiser–Meyer–Olkin measure of sampling adequacy

	Bartlett test of sphericity			Kaiser–Meyer–Olkin measure of sampling adequacy
	Chi-square	Degrees of freedom	p-value	
Electricity supply security index				
z-score normalisation	216.322***	28	0.000	0.693
Min–max normalisation	216.322***	28	0.000	0.693
Softmax normalisation	220.252***	28	0.000	0.726
Sigmoid normalisation	220.252***	28	0.000	0.726

Note Bartlett test of sphericity: H0: variables are not intercorrelated. *** indicates statistical significance at 1% level
Source Authors' calculations

Following this, PCA is utilised as the primary data analysis technique of the study. PCA contains two stages: identifying and interpreting the factors. In the first stage, factors that have the lowest pairwise correlation are detected, and how much they account for the total variance of variables is calculated. Next, the factors that explain most of the total variance of the original variables are identified and extracted. The first component is the factor that explains the largest percentage of the total variation. The second component explains the largest share of the residual unexplained variance uncorrelated to the first factor (Radovanović et al. 2018). The identification and extraction process proceeds until the number of components matches the number of original variables. This procedure extracts components that explain the total variance above a certain threshold based on their contribution to the total variance (or eigenvalues). Existing research typically sets the threshold at one (Mundfrom et al. 2005).

3.3 Empirical Results

In the second stage of the PCA process, the eigenvalues of the estimated factors are reported in Table 7. The table shows that, for all four normalisation methods, more than 92% of the total variance of the ESSI is explained by the first three factors for PCA. As such, the first three components for PCA are retained and employed in this study.

Table 8 reports the estimated principal components for four cases of normalised variables, including z-score standardisation, min–max normalisation, softmax normalisation, and sigmoid normalisation. The first three components capture more

Table 7 Total variance explained: Viet Nam's electricity supply security index

	Component	Eigenvalues	% of Variance	Cumulative variance, %
Normalised variables using standardised Z-score	1	4.962	62.02	62.02
	2	1.534	19.17	81.19
	3	0.907	11.34	92.53
	4	0.302	3.78	96.31
	5	0.171	2.14	98.45
	6	0.062	0.78	99.23
	7	0.047	0.59	99.82
	8	0.014	0.18	100.00
Normalised variables using min–max normalisation	1	4.962	62.02	62.02
	2	1.534	19.17	81.19
	3	0.907	11.34	92.53
	4	0.302	3.78	96.31
	5	0.171	2.14	98.45
	6	0.062	0.78	99.23
	7	0.047	0.59	99.82
	8	0.014	0.18	100
Normalised variables using softmax normalisation	1	4.982	62.28	62.28
	2	1.521	19.01	81.29
	3	0.906	11.32	92.61
	4	0.301	3.76	96.37
	5	0.174	2.18	98.55
	6	0.054	0.68	99.23
	7	0.048	0.6	99.84
	8	0.013	0.16	100.00
Normalised variables using sigmoid normalisation	1	4.982	62.28	62.28
	2	1.521	19.01	81.29
	3	0.906	11.32	92.61
	4	0.301	3.76	96.37
	5	0.174	2.18	98.55
	6	0.054	0.68	99.23
	7	0.048	0.6	99.84
	8	0.013	0.16	100.00

Source Authors' calculations

Table 8 Impact assessment of selected indicators on the principal components of the composite electricity supply security index for Viet Nam (1996–2019)

	Normalised variables using standardised Z-Score			Normalised variables using min–max normalisation			Normalised variables using softmax normalisation			Normalised variables using sigmoid normalisation		
Electricity supply security index												
Variable	Principal component (92.53%)			Principal component (92.53%)			Principal component (89.69%)			Principal component (89.11%)		
	1	2	3	1	2	3	1	2	3	1	2	3
RACE	0.4320	−0.0048	−0.1770	0.4320	−0.0048	−0.1770	0.4351	0.0325	−0.0881	0.4351	0.0325	−0.0881
RGDPpc	0.4027	0.3158	0.1485	0.4027	0.3158	0.1485	0.4127	0.2819	0.0934	0.4127	0.2819	0.0934
RRE	−0.3874	0.2284	−0.0526	−0.3874	0.2284	−0.0526	−0.3785	0.2433	−0.0913	−0.3785	0.2433	−0.0913
GQ	0.1617	0.7082	0.1901	0.1617	0.7082	0.1901	0.1640	0.7078	0.2016	0.1640	0.7078	0.2016
RUB	−0.2720	0.1483	0.7849	−0.2720	0.1483	0.7849	−0.2302	0.1061	0.8735	−0.2302	0.1061	0.8735
ESE	0.4394	0.0781	−0.0525	0.4394	0.0781	−0.0525	0.4381	0.0814	−0.0434	0.4381	0.0814	−0.0434
ESS	−0.2204	0.5618	−0.4803	−0.2204	0.5618	−0.4803	−0.2371	0.5803	−0.3840	−0.2371	0.5803	−0.3840
RNEEX	−0.3993	0.0533	−0.2412	−0.3993	0.0533	−0.2412	−0.4111	0.0684	−0.1490	−0.4111	0.0684	−0.1490

Source Authors' calculations

than 92% of the variation, an adequately reasonable percentage. The coefficients in Table 6 illustrate the contribution of eight variables included in the ESSI construction to the first, second, and third principal components. The values of the coefficients are dependent on the variances of the corresponding variables. From the previous section, a zero correlation between the principal components should be noted. Moreover, due to standardisation, all principal components have zero mean.

The variables with the highest correlation with each component should be identified to interpret the principal components accurately. We need to distinguish the variables whose absolute coefficient value is reasonably large. A correlation of 0.5 and above is substantially important in this study (see Table 6). In the following paragraphs, we will interpret the principal component results in relation to these significant values.

No normalised variables are significantly and strongly correlated with the first principal component in all four standardisation methods. However, there are three normalised variables: (i) rate of access to electricity (RACE), (ii) real GDP per capita (RGDPpc), and (iii) rate of electricity supply efficiency (ESE), whose coefficients are quite close to the cut-off value of 0.5. These variables are positively correlated with the first principal component with a coefficient above 0.4. The results imply that these criteria vary together, which can be explained by the fact that they are affected by common underlying factors. Economic growth and technological advancement are two potential mutual key factors that heavily impact these indicators. For instance, countries with higher economic growth typically have higher real GDP per capita. They are more likely to invest in development programmes to improve electricity supply, materialise access to electricity, and enhance electricity efficiency locally. Technological progress also facilitates the construction of more power stations and the employment of electricity generation from alternative energy sources, along with higher incomes associated with diverse technical professions. The results are per the findings of Sarkodie and Adams (2020), where income level has a substantial impact on electricity access in South Africa, and those of Banerjee et al. (2014) for India. Electricity access is also shown to improve through renewable energy and energy efficiency in Bangladesh (Karim et al. 2017).

The empirical findings indicate that access to electricity, income level, and electricity efficiency tend to move in tandem. Two indicators (RACE and ESE) belong to the accessibility topic, while the other (RGDPpc) belongs to the affordability topic in the construction of the ESSI. While the first principal component is most strongly correlated with the rate of electricity supply efficiency, the correlations of the other two indicators with this principal component are not substantially different. The coefficients for ESE, RACE, and RGDPpc are 0.439, 0.432, and 0.402, respectively. The second principal component increases with governance quality (GQ) and energy self-sufficiency rate in terms of domestic electricity supply. It is most positively and significantly correlated with governance quality, with a coefficient of 0.708. The correlation of the energy self-sufficiency rate with this principal component is also significant at 0.561. These two indicators make up the accessibility topic of the ESSI. Finally, the third principal component increases with the ratio of growth of electricity access in urban areas to the growth of urbanisation (RUB). This normalised variable

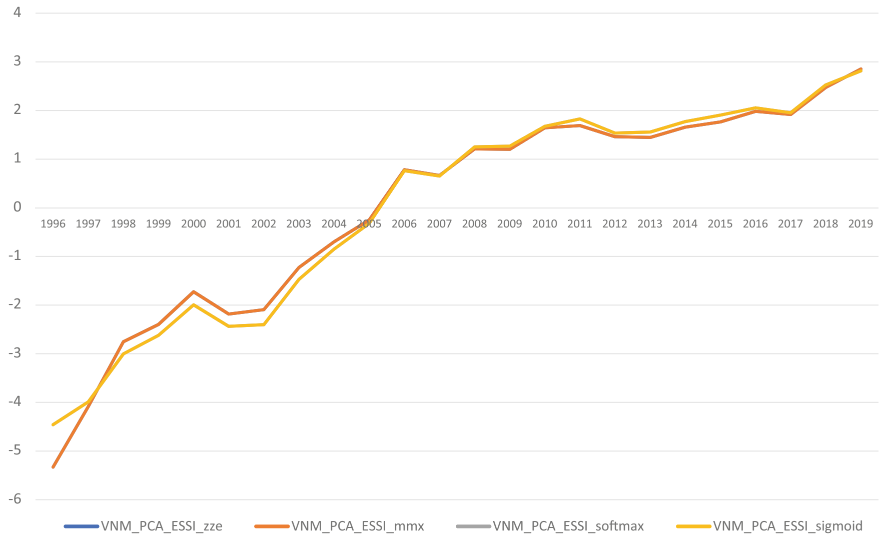


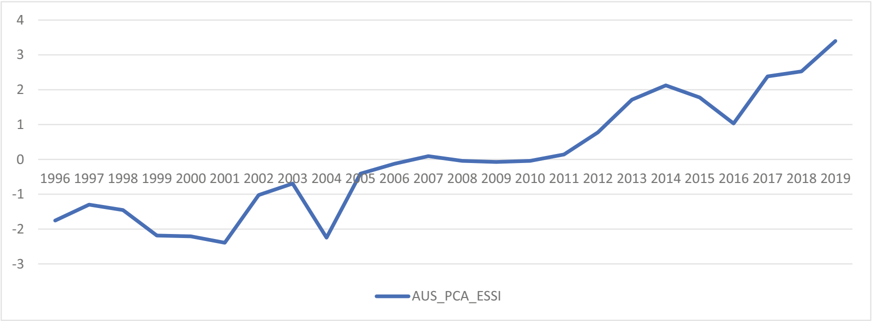
Fig. 5 Trend of Viet Nam's electricity supply security index (1996–2019). *Note* Four normalisation methods (z-score: zze; min–max: mmx; softmax and sigmoid) are used for comparison

has the largest absolute value of the correlation coefficient at 0.784. The results are relatively robust, with similar findings found in all four adopted normalisation techniques.

Figures 5 and 6 illustrate the ESSI as measured by PCA for 16 countries in the sample. In the case of Viet Nam, the principal components are constructed based on normalised variables using four techniques: z-score standardisation, min–max normalisation, softmax normalisation, and sigmoid normalisation. Z-score standardisation is the primary normalisation technique in the study, while the other three techniques are included as robustness check measures for comparison and completeness purposes. The PCA scores based on four types of normalisation are presented on the same graph for Viet Nam. However, due to the nature of the PCA method and the availability of data, only PCA scores based on z-score standardised variables are applicable and presented for the rest of the countries in the sample.

Figure 5 shows that the ESSI was generally increasing in Viet Nam from 1996 to 2019. The findings from different normalisation techniques are relatively similar to each other. Viet Nam witnessed a considerable and persistent increase in electricity supply security from 1996 to 2006. This may be attributable to the local governmental efforts in setting and reaching nationwide electrification targets. By 1995, approximately half of the Vietnamese population had no access to electricity. Only 14% of rural households had electricity connections in 1994 (Gencer et al. 2011). The situation raised the need for national power sector reforms implemented promptly and rigorously. According to a report from the Asian Development Bank (2015), more than 99% of communes and 97% of households in Viet Nam had been connected to the national power grid through stringent organised reformations. In

Australia



Brunei

Cambodia

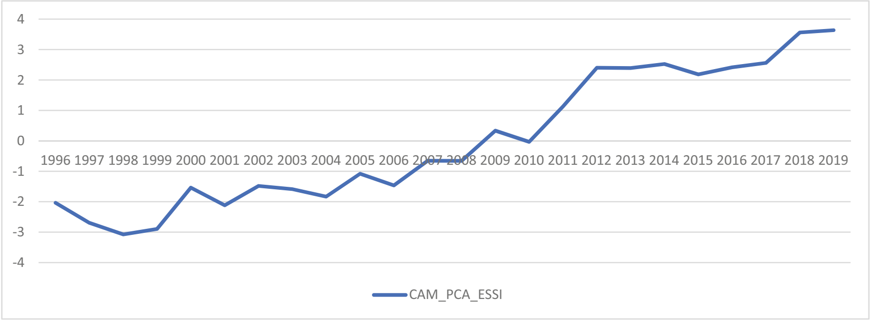


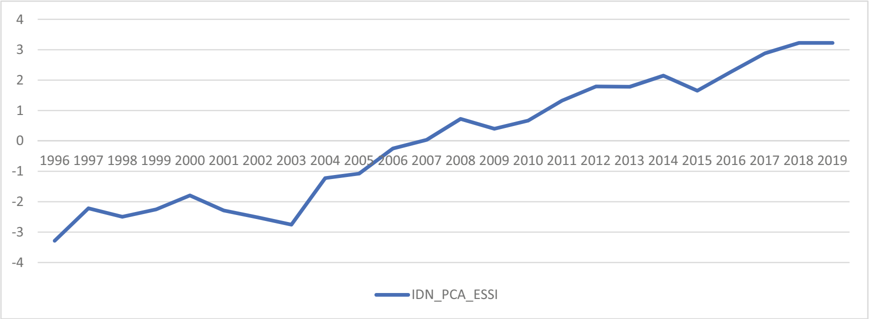
Fig. 6 Trends of ASEAN + 6's electricity supply security Index (1996–2019)

congruence with increased access to electricity, power transmission and distribution system losses were also reduced by 6%, decreasing from 15 to 9% over the same period. However, while Viet Nam experienced improved electricity access and supply, the rapidly increasing power consumption also posed a serious challenge.

To tackle this problem, in 2011, the Prime Minister announced the Seventh National Master Plan for Power Development (PDP-7) with the explicit objective of reducing the electricity elasticity of the country. PDP-7 took place between 2011 and 2020, and it belonged to the National Energy Efficient Programme. The programme's

China

Indonesia



India

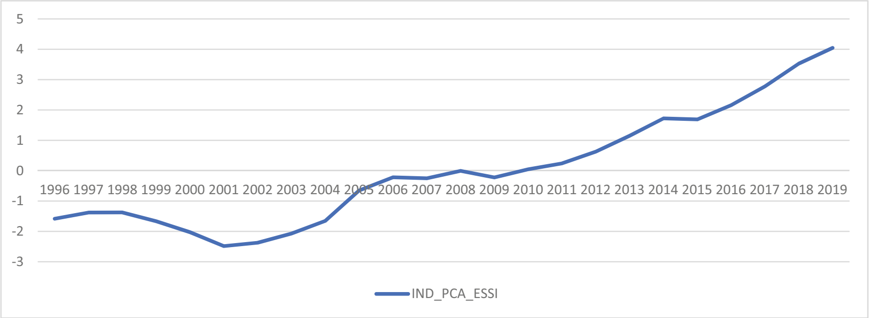
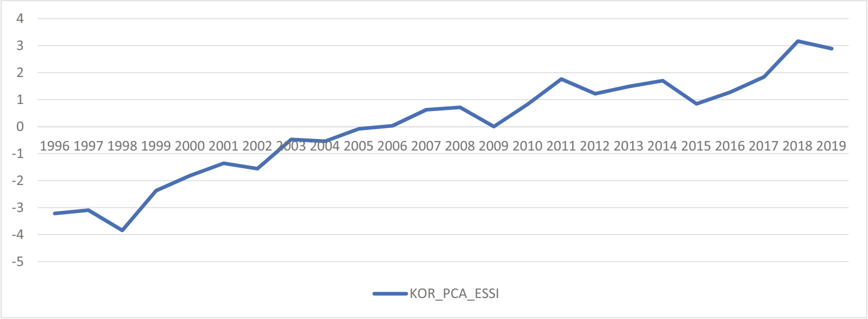


Fig. 6 (continued)

goal is to promote efficient electricity use in particular and energy in general across the country. Viet Nam also utilises renewable energy well in the electricity generation process. Currently, it is exploiting four big sources of renewable energy: hydroelectricity, solar power, wind power, and biomass. The share of renewable energy in the total domestic electricity supply is quite considerable, with hydropower being the largest source and contributing approximately 40% to the national electricity capacity (Vietnam Electricity 2019).

Japan

Korea

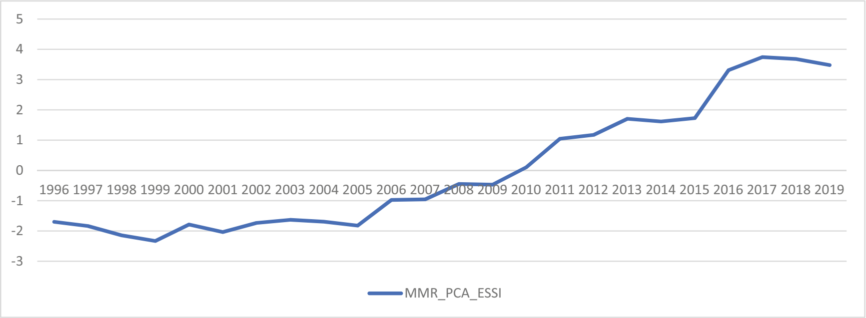


Lao PDR

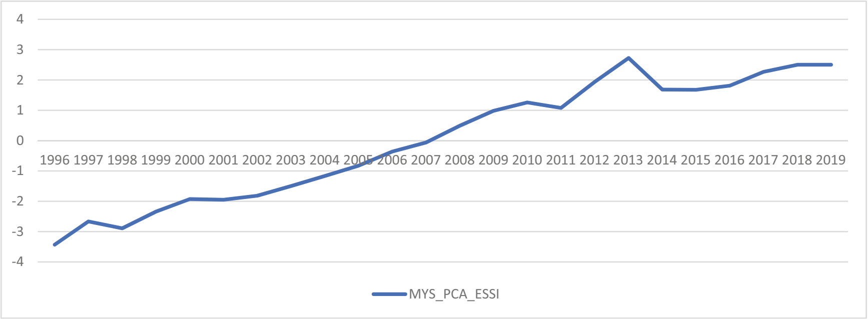
Fig. 6 (continued)

Along with hydropower, Viet Nam is exploiting solar and wind power extensively. The country has the highest installed capacity in Southeast Asia as of 2019 (Do et al. 2020). At the start of 2020, renewable energy sources accounted for more than half of Viet Nam's electrical generation, indicating the future departure from using coal as the primary source (*The* Economist 2020). Evidence suggests that the increasing ESSI of Viet Nam is justified. Despite this, electricity or energy poverty is still an eminent problem, for example, due to temperature shocks (Feeny et al. 2021). In

Myanmar



Malaysia



New Zealand

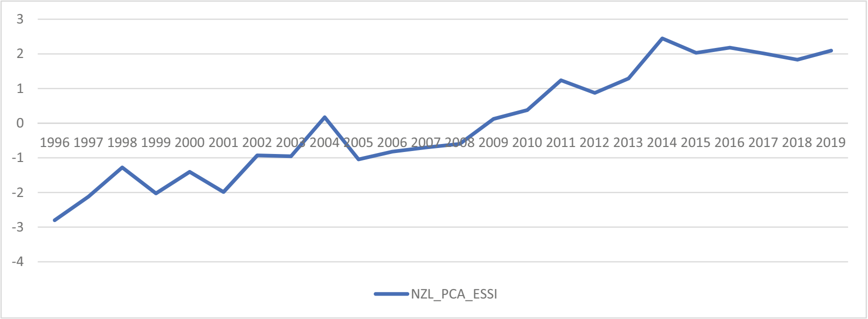
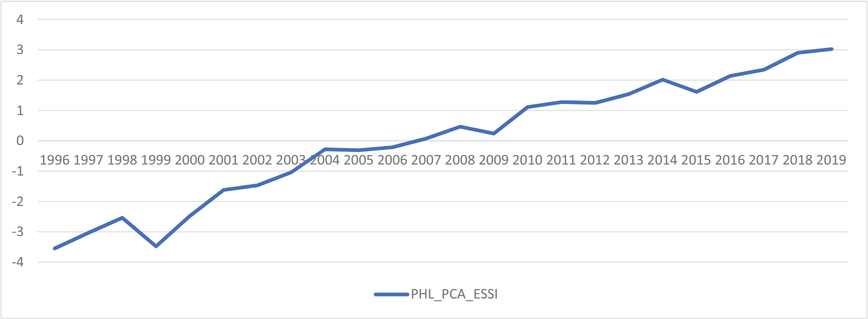


Fig. 6 (continued)

this regard, our findings contrast with those of Hien (2019), who reported excessive electricity intensity in Viet Nam.

Figure 6 shows the ESSI trends for 16 countries in the sample from 1996 to 2019. Generally, except for Brunei, all countries are observed to experience increased energy supply security during the investigation period. For all high-income countries except Brunei, i.e. Australia, Japan, Korea, New Zealand, and Singapore, the pattern is mostly fluctuating with some ups and downs, although the overall trend is increasing. This may be explained by the rate of economic growth in these countries.

Philippines



Singapore

Thailand

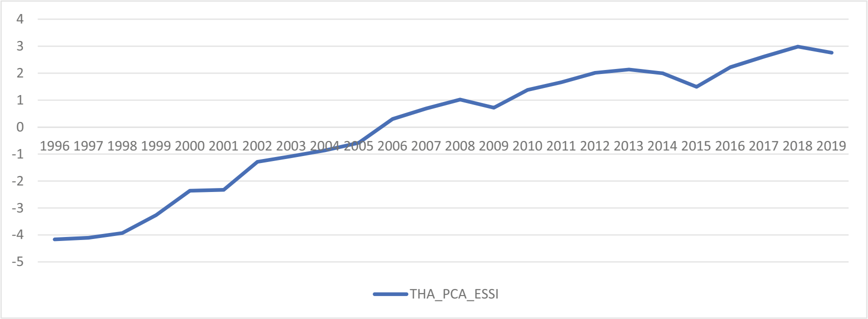


Fig. 6 (continued)

Since a positive bidirectional relationship exists between economic growth and electricity consumption in Asia in general and in ASEAN in particular, the accelerating economic development may cause more strain on the electricity supply of the country than the gain from higher income in advancing electricity generation and efficiency (Yoo 2006; Chen et al. 2007; Taghizadeh-Hesary et al. 2021). Similar fluctuations in trends are observed for Cambodia, Indonesia, and the Lao PDR, although the changes are slightly less noticeable than those of high-income countries. The plots for China and Thailand showed clear, continuously upward trends with minimal decreasing

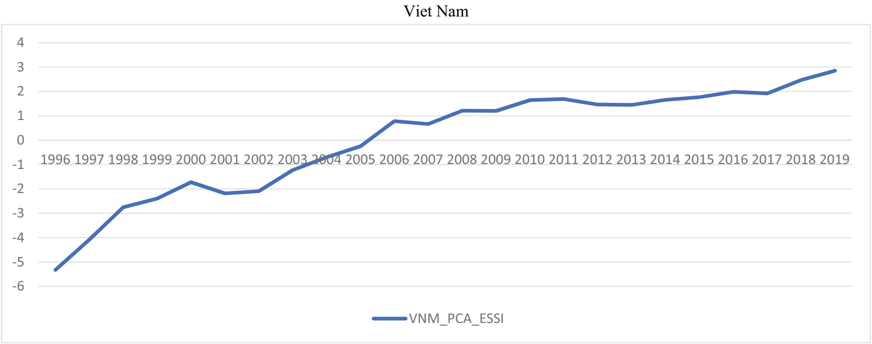


Fig. 6 (continued)

segments. This may be attributable to the early electricity reformations and early adoption of renewable energy sources in both countries (Wattana et al. 2008; Janjai et al. 2011; Shiu and Lam 2004; Cherni and Kentish 2007).

4 Concluding Remarks

This study investigates Viet Nam's electricity sector development from the 1990s to 2020. The country's notable achievements include remarkable growth in electricity production output, power supply reliability, transmission, and distribution loss management; a solid power system; being ASEAN's leader in solar electricity adoption; successful and highly effective implementation of rural electricity investment; and universal access to electricity. A composite index to measure Viet Nam's electricity supply security is developed and constructed in the empirical analysis. The results show that the security of the country's electricity supply has been rising over the past 25 years.

However, challenges remain for the power sector to meet the country's fast-growing electricity demand in the future. The national electricity grid should be expanded, and a smart power system integrating different power sources should be developed to address this. The goal is to build more power transmission lines along with the construction of new power plants to achieve (i) overall investment efficiency, (ii) provincial power supply plans and rural electrification programmes, (iii) power supply reliability, and (iv) efficient use of renewable sources. The most suitable financing option is to reach out to the international community, especially the country's development partners such as the European Union, the United States (US), the World Bank, and the United Nations Development Programme. These countries and entities are dedicated to help the government of emerging economies like Viet Nam in mobilising investment resources for clean energy transition, which is also a global imperative to address the climate emergency.

For future research, the input indicators for PCA could be expanded to include more variables, subject to data availability, such as electricity price and/or its volatility, feed-in tariffs, or other government subsidies. Additionally, one of the tasks of Master Plan VIII for 2021–2030 is to determine correctly and accurately the reasonable electricity demand of the economy in the future. Although power demand forecasting is an indispensable issue in economic development planning, there have not been any studies with reliable models or tools for forecasting Viet Nam's electricity demand. Thus, this can be a direction for future research on this theme.

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Australia's National Electricity Market: An Analysis of the Reform Experience 1998–2021

Paul Simshauser

Abstract Australia's National Electricity Market (NEM) commenced in 1998. The centrepiece of NEM reforms was the restructuring of vertical monopoly electricity utilities and the creation of an energy-only, gross pool wholesale market and associated forward market. For most of the past 20+ years, NEM has displayed consistent economic and technical performance. But missing policies relating to climate change, natural gas and plant exit produced results that tested political tolerance in 2016–2019. However, as with prior episodes of high prices, market participants responded—most recently—with a renewable investment supercycle. Prices have since reverted, but power system security remains challenging as the plant mix changes.

Keywords Microeconomic reform · Electricity markets · Energy-only markets

JEL Classifications D52 · D53 · G12 · L94 · Q40

1 Introduction

For most of the twentieth century, the vertically integrated electricity supply industry was one of the economy's leading sectors vis-à-vis productivity—extracting economies of scale and technological development (Joskow 1987). But by the 1980s, sectoral performance across many countries, including the United States (US), Great Britain, and Australia, was marked by capital misallocation, overcapacity, and rising prices (see, for example, Pierce 1984; Hoecker 1987; Joskow 1987; Kellow 1996; Newbery and Pollitt 1997). Moreover, utility service boundaries were frequently economically meaningless (Fairman and Scott 1977). A global wave of microeconomic reform would follow.

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Industrial reorganisation and restructuring were a critical first step in the reform years. Then followed the creation of competitive markets for generation. Some countries pursued a gross pool model in this design phase; others a net pool model. Some markets were based on an 'energy-only' design, while others were based on a more conservative 'capacity and energy' design. Other variations include 'day ahead' versus 'real-time' spot markets, nodal versus zonal pricing, and central scheduling of generation versus self-commitment. Market variations seem almost endless, and the fact that no common model or design exists tells us this is a complex area.

This chapter reviews the salient features of the Australian reform experience as an energy-only market, a market with one of the highest market price caps in the world, at A$15,500/MWh[1] (US$11,300), and no economic constraints or limitations on generator offers into a real-time gross pool market. This chapter is structured as follows: Sect. 2 reviews industrial organisation; Sect. 3 outlines NEM institutions; Sect. 4 examines critical features of an energy-only market design and briefly reviews associated literature. Section 5 then provides an extensive quantitative assessment of NEM performance from 1998 to 2021. Section 6 analyses the 2016 South Australian black system event. Policy implications and concluding remarks follow.

2 Industrial Organisation and Industry Restructuring

The disaggregation of vertical monopoly electric utilities and the creation of competition within generation and retail segments can be traced as far back as Weiss (1973). As Landon (1983) explained, the basis of restructuring was (i) economic regulation had failed (see Stigler and Friedland 1962; Stigler 1971; Peltzman 1976); (ii) generation-scale economies were increasingly extracted at the plant level; (iii) system coordination could be managed through contracts; (iv) networks could be regulated as common carriers; and (v) a presumption that economies of scope and integration were most likely minimal. The view that prevailed was that electricity would be most efficiently supplied via specialised firms competing in their respective stages of production.

Limits to scale economies in power generation had been empirically documented as early as Christensen and Greene (1976) and Huettner and Landon (1978)—key insights being the average total cost curve for power generation was very flat for a broad range of output. Moreover, technology changes, namely, the combined cycle gas turbine (CCGT), meant scale-efficient entry was contracting after more than 60 years of generation unit size expansion (Joskow 1987; Hunt and Shuttleworth 1996; Meyer 2012a). Consequently, policies promoting restructuring and competition could not be faulted on the grounds of scale economies. In hindsight, the presumption that economies of integration 'were most likely minimal' is surprising. The presence of multistage economies of integration is an empirical question, and

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[1] All financials are expressed in AU$ unless specified otherwise.

remarkably little (if any) evidence existed before the pioneering work of Kaserman and Mayo (1991).

Nonetheless, restructuring plans proceeded. Efficiency gains from competition focused on the generation segment. This was justified given overcapacity and deteriorating economic performance (see Pierce 1984; Hoecker 1987; Joskow 1987; Newbery and Pollitt 1997; Booth 2000; Simshauser 2005). The first practical electricity market experiment based on Weiss's (1973) constructs commenced in Chile in 1978 (Pollitt 2004).[2] Groundbreaking work by Schweppe et al. (1988) on organised spot markets for electricity would lead to the widespread adoption of industry restructuring and competitive markets.

A wave of microeconomic reform swept through Western economies during the 1990s, typically involving the vertical and horizontal restructuring of monopoly utilities and the creation of competitive wholesale power pools, often based on the British model (Newbery 2005, 2006). Any notion that the industry was a natural vertical monopoly was dispelled.

In the case of Australia, the pre-reform era electricity industry structure comprised vertically integrated monopoly utilities—all of which were public assets built up within state boundaries. State electricity commissions were non-taxpaying entities responsible to their state government owners vis-à-vis system planning, investment, system operations, reliability of supply, and tariffs.

Given that Australia's power system was built up around state borders and state governments, the fact that Australia ended up with a competitive national market at all is remarkable (i.e. given the political coordination required). However, as with many vertical utilities worldwide, during the 1980s and early 1990s, the status of the monopoly power generation industry in South-Eastern Australia[3] was critical. New South Wales (NSW) had invested in so much baseload capacity that it would take more than 20 years to clear. Victoria's excess baseload plant investments adversely affected that state's credit rating.[4] Electricity tariffs were above competitive levels and, consequently, the requirement for and objectives of microeconomic reform were clear.

While the idea of competitive generation markets can be traced back to the US in 1973, first pursued in Chile in 1978 and popularised by the British reforms of the late 1980s, the Australian experiment began in 1991 when the Commonwealth government initiated a national inquiry via one of its economics agencies, the Productivity Commission.[5] The recommendation was to restructure and deregulate the electricity supply industry and establish a four-state interconnected grid covering east and

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[2] As Pollitt (2004) notes, vertical and horizontal restructuring was completed by 1981 and enabling legislation enacted in 1982.

[3] The exception to this was the Queensland Electricity Commission, which at that time had the fifth lowest electricity prices in the world. See Booth (2000).

[4] Following a serious downgrading, a Labour Victorian state government was virtually forced to privatise its newest power station as a result.

[5] The Productivity Commission was then known as the Industry Commission.

south-eastern Australia, namely, Queensland, NSW, Victoria, and South Australia.[6] An undersea cable would later interconnect the island-state of Tasmania. Due to geographical distances, Western Australia and the Northern Territory could not be economically connected. This reform would create Australia's NEM. As indicated above, cooperation amongst participating state governments was essential and was successfully achieved.

In electricity markets characterised by generation overcapacity, initial gains from restructuring and competition were predictable and non-trivial. In the case of Australia, by almost any measure, the NEM could only be described as a miracle of microeconomic reform. As noted above, the British electricity market model frequently formed the template for other markets, and Australia was indeed one of these. Four key restructuring steps were undertaken over a 5–10 year window commencing in the early/mid-1990s:

(1) State-owned monopoly electricity commissions were 'corporatised' (i.e. commercialised).
(2) Corporatised monopoly utilities were vertically restructured into three segments: generation, transmission, and distribution and retail supply.
(3) Competitive segments of generation and retail supply were horizontally restructured into several rival entities in each region.
(4) Businesses were privatised and retail price controls removed. However, the timing of this final stage varied considerably across NEM regions due to regional political agendas (and in some regions, large parts of the industry remain in government ownership).

Trial markets were established in Victoria (1994), NSW (1996), and then Queensland (1998). The NEM itself officially commenced in December 1998. When the industrial organisation dust had settled across the four states (i.e. NEM regions), 15 rival portfolio generators,[7] 4 regional transmission networks, and 14 distribution/retail supply[8] entities emerged.[9] The NEM's industrial organisation blueprint had segregated competitive segments from natural monopoly segments (transmission and distribution), and generation had been partitioned from the retail supply.

Looking back, two distinct waves of industrial reorganisation occurred in the NEM experiment. An initial wave of industrial reorganisation (i.e. 1990s) was driven by governments and competition policy across vertical and horizontal dimensions. A

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[6] In 1992, the federal government established a committee to investigate a national competition policy framework. The committee handed down its blueprint for the implementation of a formal competition policy in August 1993, with the report becoming known as 'The Hilmer Report', after the committee chair, Professor Fred Hilmer.

[7] This included four portfolio generators in Queensland, four in New South Wales (NSW) (including Snowy Hydro), five in Victoria, three in South Australia.

[8] This included two in Queensland, six in NSW, one in the Australian Capital Territory, five in Victoria, and one in South Australia.

[9] The NEM's fifth region, Tasmania, is somewhat complicated by the fact that it only joined NEM in 2006, and for a range of reasons including politics and scale, remained a largely monopoly regional market.

second and elongated wave of industrial reorganisation would be driven by capital markets across three dimensions—vertical, horizontal, and geographic—pursuing optimal asset allocation, efficiency gains, and profit maximisation. Within this second wave of reorganisation, three distinct steps occurred.

(1) The first step of reorganisation involved the vertical divestment of competitive retail supply subsidiary businesses from the parent entity—the regulated distribution network. Retail supply ('retailers') were initially stapled to a distribution network monopoly, a model common to Great Britain and Australia and being 'the best that could be done at the time' given complex business interfaces (Helm 2014).[10] While customer interface costs (billing, call centres) are sub-additive, merchant retailers are fundamentally different from regulated distribution networks. Consequently, all distribution networks in the NEM (and in Great Britain) divested their retail businesses. These vertical structural separations were 'value-driven' investor events—capital markets consistently undervalued distributor–retailer businesses.[11] The sum-of-the-parts valuations revealed divestment would yield higher total returns. The corollary to this reorganisation was that retailers would lose the 'credit-wrap' naturally provided by their capital-intensive (investment-grade) distribution network parent company and, as Nillesen and Pollitt (2011, 2019) explained, the start of the loss of competitive intensity.

(2) The second step of industrial reorganisation involved horizontal consolidation across geographies. Most of the NEM's 14 incumbent retailers lacked scale and progressively consolidated to remain competitive. Mergers and acquisitions (M&As) occurred amongst privatised retailers and government-owned retailers.[12] Curiously, state and Commonwealth governments and competition regulators waived all horizontal M&A events through—evidently prioritising proceeds and privatisation over concentration and competition—a decision they would later regret.

(3) The third step of industrial reorganisation was vertical reintegration by retailers.[13] Looking back, an 'electricity market arms race' played out over the

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[10] It also ensured retailers had substantial asset backing.

[11] Networks have stable regulated returns, whereas retailers exhibited increasingly volatile results—a natural outworking of retail contestability and the extreme volatility of wholesale prices in an energy-only market setting, although in New Zealand, forced divestiture seemed to produce very little benefit and a loss on competition (Nillesen and Pollitt 2011, 2019).

[12] Indeed, the states of Queensland and NSW consolidated their own retail supply businesses from nine down to just four before or during privatisation processes in 2007 and 2011, respectively. There were originally three franchise retailers in Queensland and six in NSW. In Queensland, Origin Energy and AGL Energy purchased the retail businesses. In NSW, Origin Energy and Energy Australia purchased the retail businesses.

[13] Forward integration also became the dominant strategy amongst incumbent generators—many of which have formed large vertical businesses.

> period 1995–2015. The NEM's 'Big Three' retailers (or *gentailers*[14] as they are referred to) emerged as winners from a string of horizontal, vertical, and geographic privatisation and M&A events over these 20 years. Vertical reintegration became a visible trend. Not only did the three incumbent retailers pursue vertical integration with merchant generation, but vertical integration also became the dominant strategy amongst incumbent merchant generators, many of which now have large retail businesses in their own right (albeit without a historically 'sticky' retail franchise customer base). A further 15–20 new entrant pure-play retailers form the competitive fringe. Ironically, many policymakers view vertical reintegration, not horizontal consolidation, as an unwelcome development.

Vertical reintegration has been deeply unpopular amongst some regulators and policymakers in Australia and Great Britain.[15] It has been a continual regulatory target and, more recently in Australia, the subject of policy intrusion.[16] Opposition to industrial reorganisation relates to a priori reasoning vis-à-vis vertical market power, withholding capacity, adverse impacts on forward market liquidity, and foreclosure of rival (non-integrated) retailers. By this logic, vertical integration is presumed to be highly anti-competitive and, in turn, adversely impacts 'balances of competition'. However, and to be clear on this, except for bottleneck infrastructure,[17] the weight of theoretical and empirical evidence on vertical integration overwhelmingly concludes the opposite (see Cooper et al. 2005; Lafontaine and Slade 2007; Mansur 2007; Joskow 2010; Simshauser et al. 2015).[18] To the extent that market power issues occasionally arise in the NEM, their common underpinnings are horizontal, not vertical, power—which seems to have bedevilled the Australian Competition and Consumer Commission (see also Simshauser 2019a). As Fig. 1 later illustrates, NEM forward market liquidity is higher now than it has ever been.

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[14] Australia's 'Big Three' are AGL Energy, Origin Energy, EnergyAustralia. Two other large integrated rivals are Alinta Energy and Snowy Hydro (and retail business Red Energy). Godofredo et al. (2017) noted the term *Gentailer* was commonly used in Great Britain, Australia, and New Zealand.

[15] See, for example, the Australian Competition and Consumer Commission's 2018 'Restoring Electricity Affordability and Australia's Competitive Advantage' Report, AER's 2011 State of the Energy Market Report, and, in the case of Great Britain, see Ofgem's 2014 State of the Market Assessment Report.

[16] See the Treasury Laws Amendment (Prohibiting Energy Market Misconduct) Bill 2019), known as the 'Big Stick Bill'.

[17] An electricity transmission line linking generation and retail load is an example of bottleneck infrastructure.

[18] Vertical integration is an organisational form of last resort that occurs in response to non-trivial market frictions and, in most circumstances, is welfare enhancing—even when horizontal issues take on a considerable importance. Once the long list of explicit and implicit assumptions underpinning standard economic models are relaxed, boundary changes are likely when firms face hazards associated with asset specificity, incomplete forward markets, bounded rationality, asymmetric information, and regulatory and policy uncertainty. When non-trivial hazards exist in relation to ex ante investment commitment and the ex post performance of highly specific assets, vertical integration will invariably achieve 'more adaptive, sequential decision-making procedures' than anonymous spot and forward market transactions, especially as market conditions change.

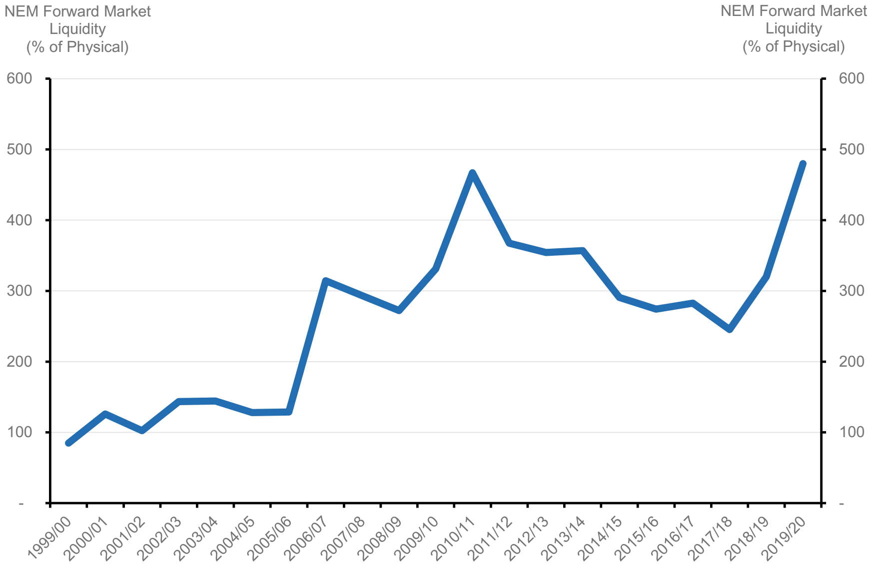

Fig. 1 NEM forward market liquidity (1999–2020), % of physical trade. *Sources* Simshauser (2019a)

Drivers behind the separation of retailers from distribution networks and vertical reintegration between retailers and generation are linked. Electricity supply is amongst the most capital-intensive industries in the world. Understanding how to minimise frictions against the flow of capital is critically important to maintain an adequate plant stock relative to forecast demand given development and construction lags. Investment-grade credit is ultimately the best method to reduce such frictions, and the business combination with the most robust credit metrics in NEM's merchant category is vertically integrated firms (Simshauser et al. 2015; Simshauser 2021).

Some background discussion on the changing role of credit is warranted. To summarise a complex history, credit metrics applied to project financings—a historically dominant source of debt for capital-intensive new power-generating equipment—were tightened by project banks from ca. 2004. This was in direct response to prolonged periods of low prices, generator economic losses, and episodes of 'missing money' in various energy markets around the world, especially Australia, Great Britain, and the USA (see Joskow 2006; Finon 2008; Simshauser 2010; Nelson and Simshauser 2013). As a result, timely investment in the new plant would require the involvement of an investment-grade credit-rated entity, either as a principal investor or as the underwriter of long-dated power purchase agreements.

This represented an entry hurdle that was unlikely to have been envisaged by policymakers or academics during the market design phase. Changes to credit parameters, applied by risk-averse project banks, were not unique to Australia; it was a characteristic of energy markets worldwide. Accordingly, an industrial reorganisation was essential to ensure the smooth flow of capital to underwrite or develop the plant necessary to achieve resource adequacy.

3 NEM Market Bodies

A defining characteristic of the NEM is its governance arrangements. Policy, rule-making, regulation, and system and market operations are segregated, as follows:

- Policy—Energy ministers from each NEM state and the Commonwealth form the members of the Energy Council (although state governments are increasingly reverting to their own policies at the time of writing).
- Rule-making—the Australian Energy Market Commission (AEMC) operates on behalf of the Energy Council as the market rule-making entity and policy advisor and has established an open-source platform for doing so.
- Regulation—the Australian Energy Regulator (AER) enforces wholesale and retail supply rules and is the economic regulator of NEM's regulated networks.
- System and market operations—the Australian Energy Market Operator (AEMO) is the independent system and market operator (i.e. responsible for coordinating dispatch, power system operations, and wholesale market operations, including the spot electricity market and eight frequency control ancillary service markets).
- In 2017, an Energy Security Board (ESB) was inserted above the three market institutions (i.e. AEMC, AER, and AEMO) for a limited period in an attempt to assist policy coordination following a black system event in South Australia in September 2016 (examined subsequently in Sect. 6). The ESB comprises the heads of the AEMC, AER, and AEMO.

An important characteristic of the NEM rule-making process is its 'open source' approach. The AEMC consistently attempts to capture the wisdom of the crowd, that is, from market participants, capital markets, consumer groups, and industry stakeholders. Under Australia's NEM rules, the system operator (AEMO), the regulator (AER), any market participant (i.e. generator, network, retailer), investor, lender, consumer group, interested entity or individual, except for the AEMC itself, can originate a rule change. The AEMC is the institution charged with running a politically independent rule change process in a manner consistent with the National Electricity Objectives.[19] It does so using a conventional policy development cycle incorporating (i) an initial issues paper, (ii) a formal public consultation process, (iii) draft determination subject to a further round of consultation, and (iv) final determination.

Most rule processes are completed within 9–12 months. While there is evidence of urgent NEM rule changes being the subject of delay, causes can usually be traced to the Energy Council process, that is, when the form of a rule change is materially altered in the legal drafting stage (namely, overreach by a jurisdiction trying to achieve some 'additional policy objective'). In such circumstances, all prior consultation

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[19] That 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 and reliability, and security of electricity supply.

processes undertaken by the AEMC is no longer relevant and AEMC commissioners are obliged to reinitiate the policy development cycle once again, given their statutory responsibilities.

4 Energy-Only Market Design and Resource Adequacy

The NEM is classed as a real-time, energy-only gross pool market (i.e. there is no day-ahead market),[20] with 5 min multi-zonal spot prices formed under a conventional uniform first-price auction clearing mechanism. In addition to the spot market for electricity are eight co-optimised Frequency Control Ancillary Service (FCAS) spot markets (MacGill 2010). Locational signals are further amplified by site-specific Marginal Loss Factors—allocated annually by AEMO based on forecast marginal losses.

As an energy-only market, there is no centrally organised capacity mechanism. The NEM's forward contract markets and AEMO projections guide future plant capacity. Derivative contracts are traded both on-exchange and over-the-counter. As Fig. 1 reveals, these have historically exhibited 300+% of physical trade turnover, albeit with considerable variation between seasons and regions.

Generators self-commit units for dispatch through their bids. AEMO centrally coordinates the market to ensure aggregate supply and demand are matched in the electricity and FCAS spot markets, subject to real-time generation and transmission network stability constraints.

From a transmission perspective, the NEM is a zonal market with five imperfectly interconnected regions (recall the NEM commenced with four regions, and Tasmania was subsequently connected by an undersea high voltage direct current link. Transmission operates under an open-access regime whereby generators are free to connect, pay only shallow connection costs, but face the risk of congestion and adverse marginal loss factors if site selection is suboptimal. Transmission planning is undertaken by the (five regional) regulated transmission network service providers.[21] Transmission investment approval[22] is vested with the AER at an aggregate level.

Because the NEM does not have a central capacity mechanism, concerns vis-à-vis resource adequacy are ever-present; that is, an adequate aggregate plant stock relative to forecast maximum demand. There should be no question that investment in energy-only markets will flow under conditions of diminishing supply-side reserves,

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[20] Although, as MacGill (2010) pointed out, the market operator produces a very transparent 40 h pre-dispatch forecast, which is continuously updated.

[21] In Victoria, AEMO undertakes transmission planning. This is unique to Victoria.

[22] The approval of transmission investments is subject to a net-benefits test, known as the RIT-T, the 'Regulatory Investment Test—Transmission'.

provided an energy market's reliability standard has a tight nexus with the administratively set market price cap or value of lost load[23] with no economic constraints on generator bidding. Imbalances induce a growing number and intensity of price spike events which drive investment in new capacity (Simshauser and Gilmore 2020). The central question is whether plant investments occur in time or in response to a crisis, noting practical political limits exist vis-à-vis the severity and duration of wholesale market price shocks (Besser et al. 2002; Hogan 2005; Simshauser 2018; Bublitz et al. 2019).

Although there is no centrally organised capacity mechanism, the system operator (AEMO) can initiate emergency trader provisions if short-term resource adequacy will likely compromise system security. AEMO also benefits from NEM Rule 4.3.1, which states that the system operator should 'initiate action plans to manage abnormal situations or significant deficiencies which could reasonably threaten power system security'. Deficiencies are noted without limitation, viz. (i) power system frequency and/or voltage operating outside the definition of a satisfactory operating state, and (ii) actual or potential power system instability.

Resource adequacy implications of energy-only markets can be traced as far back as Von der Fehr and Harbord (1995). They noted that indivisibility of capacity, construction lead times, lumpy entry, investment tenor, and policy uncertainty make merchant generation, especially peaking plant, unusually risky investments. Early contributions focusing on the investment tractability of peaking plants (or lack thereof) include Doorman (2000). Besser et al. (2002), Stoft (2002), de Vries (2003), Oren (2003), and Peluchon (2003). Bublitz et al. (2019) provide an excellent summary of the rapidly growing literature in the field.

Of central concern to energy-only markets is the stability of earnings and missing money, a concept formally introduced by Cramton and Stoft (2005, 2006). The central idea behind missing money is that net revenues earned in energy-only markets are suboptimal compared with expected returns. Peaking plants are thought to be particularly susceptible, given manifestly random revenues in organised energy-only spot markets (Peluchon 2003; Bajo-Buenestado 2017; Keppler 2017; Milstein and Tishler 2019).

Economic theory and power system modelling have long demonstrated that organised spot markets can clearly demand reliably and provide suitable investment signals for new capacity (Schweppe et al. 1988). But theory and modelling are based on equilibrium analysis with unlimited market price caps, limited political and regulatory interference, and, by deduction, largely equity capital-funded generation plant able

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[23] In theory, from a power system planning perspective, the overall objective function is to minimise $VoLL \times USE + \sum_{i=1}^{n} c(R) \Big| VoLL \times USE + c\left(\hat{R}\right) = 0$, where $VoLL$ is the value of lost load, USE is unserved energy, and where $c(R)$ is the cost generation plant, and $c\left(\hat{R}\right)$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said that there is a direct relationship between reliability and the market price cap. An alternate expression where the reliability criteria are based on loss of load expectation is $LoLE = CONE/VoLL$, where CONE is the cost of new entry. For an excellent discussion on the relationship between a market price cap and reliability criteria, see Zachary et al. (2019).

to withstand elongated 'energy market business cycles' (Simshauser 2010; Arango and Larsen 2011; Cepeda and Finon 2011; Bublitz et al. 2019).

Good economic theory often collides with the harsh realities of applied corporate finance. In practice, energy-only markets are rarely in equilibrium. Persistent pricing at marginal cost does not result in a stable equilibrium, given substantial sunk costs, a problem understood at least as far back as Hotelling (1938), Boiteux (1949), and Turvey (1964). Because merchant generators face rigid debt repayment schedules, theories of organised spot markets suffer from inadequate treatment of how non-trivial sunk capital costs are financed (Joskow 2006; Finon 2008; Caplan 2012).[24]

Generator pricing must deviate from strict marginal cost at some point, but given oligopolistic market settings distinguishing between loss-minimising behaviour and abuse of market power is difficult (Cramton and Stoft 2005, 2008; Roques et al. 2005; Joskow 2008). Further, actions by regulatory authorities and system operators frequently suppress legitimate price signals (Joskow 2008; Hogan 2013; Spees et al. 2013; Leautier 2016). Australia's NEM also suffers from political interference (Simshauser 2019c; Wood et al. 2019).

Risks to timely entry may arise from capital constraints. In the early phases of the global restructuring and deregulation experiment, a vast fleet of merchant plants was project-financed based on forecast spot prices and short-term forward contracts (Joskow 2006; Finon 2008).[25] But recurring damage to merchant generator profit-and-loss statements, a product of structural oversupply, and episodes of missing money eventually led project banks to tighten risk tolerances and credit metrics (see also Simshauser 2010).

Of central importance to the assessment of resource adequacy is 'incomplete markets'—the seeming inability of energy-only markets to deliver the optimal mix of derivative instruments required to facilitate efficient plant entry, specifically, long-dated contracts sought by risk-averse project banks (see Joskow 2006; Chao et al. 2008; Howell et al. 2010; Caplan 2012; Meyer 2012b; Nelson and Simshauser 2013; Newbery 2016, 2017; Grubb and Newbery 2018; Bublitz et al. 2019).

Australia's NEM is noted for favourable forward market liquidity (Fig. 1).[26] But the tenor of activity only spans 3 years, well short of optimal financing comprising 5–12 year semi-permanent project debt facilities set within 18+ year structures. Collectively, these characteristics create risks for the timely investment required to meet power system reliability criteria (Bidwell and Henney 2004; Cramton and

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[24] Fixed and sunk costs in energy-only markets are, in theory, recovered during price spike events. But participants are unable to optimise the frequency and intensity of price spikes (Cramton and Stoft 2005). Moreover, market price caps are frequently set too low (Batlle and Pérez-Arriaga 2008; Joskow 2008; Petitet et al. 2017; Bublitz et al. 2019; Milstein and Tishler 2019) in which case a stable financial equilibrium can only be reached if the power system is operating near the edge of collapse (Bidwell and Henney 2004; Simshauser and Ariyaratnam 2014).

[25] This included 230,000 MW in the US; 13,000 MW in Australia; and more than 6,000 MW of new plants in the United Kingdom. See Joskow (2006), Finon (2008), and Simshauser (2010) for details.

[26] See, for example, Chester (2006), Anderson et al. (2007), Howell et al. (2010), and Simshauser et al. (2015).

Stoft 2006; de Vries and Heijnen 2008; Roques 2008; Hirth et al. 2016). Concerns over resource adequacy are compounded by the fact that large segments of real-time aggregate demand are price inelastic and unable to react to scarcity conditions. Similarly, in the short run, supply is inelastic because storage remains costly (Batlle and Pérez-Arriaga 2008; Cramton and Stoft 2008; Finon and Pignon 2008; Roques 2008; Bublitz et al. 2019).

Yet, as Sect. 5 subsequently reveals, resource adequacy has been delivered in the NEM with few exceptions—and the exceptions were, in most instances, unforecasted events. This means it is not entirely obvious that an organised capacity market would have delivered a different result unless it had engineered deliberate oversupply relative to the desired level of reliability.

In Australia's NEM, the forward markets (which include baseload swaps and $300 caps amongst other instruments) and vertical integration have been an important means by which to deal with the unique characteristics of merchant plants and the complexity of writing long-dated contracts. Complexity includes high asset specificity, bounded rationality, asymmetric information between generators and retailers, long asset lives, and unusually high financial hazards with ex ante capital-intensive investment commitments (Roques et al. 2005; Simshauser 2010; Simshauser et al. 2015).[27]

5 Overview of NEM Performance

The centrepiece of the NEM reforms was the creation of the wholesale market, a five-region energy-only gross pool with a real-time spot market and forward derivatives market—the former coordinating scheduling and dispatch, the latter tying the economics of the physical power system to resource adequacy and new capacity.

Notably, the NEM inherited a high-quality and oversupplied stock of monopoly-built, utility-scale plants at inception. Consequently, gains from exchange via a competitive energy-only gross pool and associated forward market would be material—a characteristic common to many jurisdictions during the 1990s and 2000s.

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[27] Three broad policy remedies are typically suggested to deal with the missing money and risks to timely investment, viz. (i) introducing capacity markets or strategic reserves, (ii) raising the market price cap, or (iii) introducing additional operating reserves. On capacity markets see (Bidwell and Henney 2004; Green and Staffell 2016). On setting higher VoLL and vertical integration, see, for example, Joskow (2006), Finon (2008). and Simshauser et al. (2015). On increasing the requirement for operating reserves and enhancing reliability of supply, see Hogan (2005, 2013). Hogan (2013) noted there is no simple way to observe and measure delivery in capacity markets. Conversely, Cramton and Stoft (2008) observed that even if capacity is overbuilt as a result of capacity mechanisms, the incremental cost to consumers is small because excess 'peaking plant' is the cheapest form of capacity (viz. an extra 10% of peak capacity may increase consumer costs by, say, 2%). Additionally, Spees et al. (2013) observed that on balance capacity markets in the United States have delivered good results in that they met their objective function, mobilised large amounts of low-cost supply including demand response, energy efficiency, transmission interconnection, plant upgrades, deferred retirements, and environmental retrofits.

Table 1 NEM generating plant portfolio balance (1998)

NEM 1997/98	Optimal (MW)	Actual (MW)	Imbalance (MW)	Weighting
Base load plant	20,400	24,500	−4,100	Overweight
Intermediate	2,000	2,100	−100	Overweight
Peak load plant	8,200	6,700	1500	Underweight
Aggregate supply	30,600	33,300	−2,700	Oversupplied

Source Simshauser (2008)

Table 1 contrasts the NEM's opening generation fleet with a modelled 'optimal plant mix'.

As Table 1 highlights, the NEM was initially 'overweight' base plant (~4,100 MW of excess supply), intermediate plant was roughly even, and the peaking plant was 'underweight' (~1,600 MW). The system was oversupplied in aggregate by around 2,600 MW against a then-optimal plant stock of ~30,600 MW and a coincident system maximum demand of about 25,000 MW. The market value of the structural faults was ~$5 billion or 13% of the (then) $44 billion NEM generating portfolio.

The wholesale market operated like *a* marvel of microeconomic reform by virtually any metric. A vast oversupply of generation plants was cleared, unit costs plunged, plant availability rates reached world-class levels, requisite new investment flowed when required, investment risks were borne by capital markets rather than captive franchise consumers, and reliability of supply—despite an energy-only market design—was maintained with few exceptions. One could conclude, with considerable justification, that the reform objectives of enhancing productive, allocative, and dynamic efficiency were achieved.[28]

If there was a caveat to this set of observations, it would be the period 2016–2019 when wholesale prices struggled to remain within politically tolerable limits, and one region (South Australia) experienced a black system event. Yet the NEM market mechanisms remained truthful throughout this period in that prices largely reflected the physical and economic realities of circumstances in which the market found itself. What is more interesting is the underlying causes of what I have previously referred to as the 2016–2021 investment supercycle (Simshauser and Gilmore 2022). Three key issues preceded the 2016–2021 period:

(1) Adverse effects of climate change policy discontinuity, which punctured an otherwise steady flow of investment into new variable renewable energy (VRE) plant, that is, wind and solar photovoltaic (PV);
(2) Sudden and uncoordinated divestment and exit of coal plant;
(3) Turmoil in the adjacent market for natural gas, which would otherwise provide the transitional fuel and shock absorbers required for coal plant exits.

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[28] Performance improvements included average cost, price, plant availability, and reserve margins (see Simshauser 2005). In more recent research, the wholesale market was one of the few areas of the electricity market that was performing well. From mid-2016 however, market performance deteriorated significantly.

Before exploring NEM wholesale prices, plant investment and divestment patterns, it is helpful to first examine items 1 and 3 in Sects. 5.1 and 5.2, respectively.

5.1 Climate Change Policy Discontinuity

Making sense of NEM wholesale market dynamics is difficult without a brief overview of the discontinuity of climate change policy in Australia. In contrast to energy policy, climate change policy (or the lack thereof) is the domain of the Commonwealth government. Unfortunately, the democratic Labour and conservative Liberal parties (i.e. Australia's two main political parties) have been unable to identify a common ground for decarbonising the country's carbon dioxide (CO_2) intensive power system. The Commonwealth has also misaligned climate change policies with Australia's international commitments (e.g. most recently, the Paris Agreement). Industry and consumers have, therefore, been forced to navigate a 2-decades-long climate policy war between the two main political parties (Byrnes et al. 2013; Molyneaux et al. 2013; Nelson et al. 2013; Freebairn 2014; Garnaut 2014; Apergis and Lau 2015; Nelson 2015; Simshauser 2018; Simshauser and Tiernan 2019). Two policy mechanisms have been the subject of discontinuity: (i) Australia's 20% renewable portfolio standard (RPS) and (ii) carbon pricing and an emissions trading scheme (Jones 2010).[29]

Australia introduced the world's first RPS after passing legislation in 2000 (Jones 2010; MacGill 2010). An obligation of '2% by 2010' was placed on electricity retailers and mobilised by tradeable certificates (Jones 2009; Simshauser and Tiernan 2019). The target was comfortably met 4 years ahead of schedule (Buckman and Diesendorf 2010). With Australia's international CO_2 commitments known and the absence of credible matching policy, state governments filled the policy vacuum—as occurred in the US and Canada (Jones 2014; Schelly 2014). From the early 2000s, state governments began to mandate higher targets for their jurisdictions when the Commonwealth's proposed Emissions Trading Scheme (ETS) stalled (Nelson et al. 2013; Cludius et al. 2014; Jones 2014; Simshauser 2018). Work simultaneously commenced on a state-based national ETS (Nelson et al. 2010; Simshauser and Tiernan 2019). A 2007 Commonwealth election thus elicited two commitments from Australia's political parties: the incumbent conservative government's 15% clean energy target and the social democratic opposition's greatly expanded renewable target of 20% by 2020. A united position existed on an ETS (Jones 2010; Apergis and Lau 2015; Simshauser 2018).

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[29] On 20 November 1997, Australian Prime Minister Howard announced that the Commonwealth would work with the state governments to 'set a mandatory target for electricity retailers to source an additional 2% of their electricity from renewable energy sources by 2010' and 'Australia also believes that an international emissions trading regime would help minimise costs of reducing emissions'. (see Parliament of Australia at: http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query%3DId%3A%22chamber%2Fhansardr%2F1997-11-20%2F0016%22 (accessed April 2020).

Australia's 2% by 2010 RPS and associated certificate side-market had trivial impacts on NEM's organised spot market. However, expanding the scheme to 20% (without amendment) revealed certain design flaws, which Buckman and Diesendorf (2010) explain in some detail. The most critical was the initial inclusion of rooftop solar PV, which overwhelmed volumes and de-stabilised the policy, and the use of a fixed volumetric target of 44 TWh rather than a 'percentage of demand' target (Jones 2010; Byrnes et al. 2013; Forrest and MacGill 2013; Bell et al. 2015; Simshauser 2018; Simshauser and Tiernan 2019). Compounding matters, 2-yearly reviews of the RPS produced visible stop-start investment cycles, as Fig. 10 subsequently reveals.

Following the 2013 general election, the newly elected Liberal government initiated an unscheduled review to reduce the fixed volume renewable target after energy demand contracted. Given contracting aggregate demand, the RPS was moving closer to an implied 25–30% target compared with the 20% policy design (noting the policy was, and is, specified in fixed volumetric terms). Forcing renewable capacity into an increasingly oversupplied and unstable wholesale electricity market with certificate costs levied on consumers occurred at a time when residential electricity prices were rising sharply due to network tariffs (Cludius et al. 2014; Garnaut 2014; Nelson et al. 2015; Bell et al. 2017). In the end, the renewable target was scaled back to 33 TWh (Biggs 2016) but not before renewable investment flows were punctured (Simshauser 2018, 2019b; Simshauser and Tiernan 2019).

On emissions trading, formal policies had been developed and discarded in 1999–2001, 2005–2006, and 2007–2010 (Simshauser and Tiernan 2019). In late 2010, a minority Labour government emerged from the 2010 Commonwealth election. It revived an earlier policy that had been discarded only months earlier and legislated a $23/t fixed carbon price from July 2012 as a precursor to an ETS (Garnaut 2014; Wild et al. 2015). The policy was abandoned in 2014 following a change of government. Three further policy attempts at an ETS occurred in 2016, 2017, and 2018 but were discarded by the right faction of the conservative Liberal Party. In all, from 1999 to 2018, seven formal attempts at an ETS were initiated with no tractable policy emerging (Simshauser and Tiernan 2019).

5.2 *Gas Market Dynamics*

Another important building block that helps when analysing the NEM's wholesale market performance relates to gas market dynamics. To summarise a complex story, not only is the NEM trying to decarbonise without a united and synchronised climate change and energy policy architecture, but it is also attempting to transition without the transitional fuel.

Indeed, central to understanding NEM market conditions during the 2016–2021 investment supercycle is the dire state in which the Australian east coast market for natural gas found itself. Following large coal seam gas discoveries in Queensland (viz. 40,000+ PJ, or 6,500+ Mboe of 2P reserves in the mid-2000s), three large liquefied natural gas (LNG) export plants were commissioned in 2014–2016. This

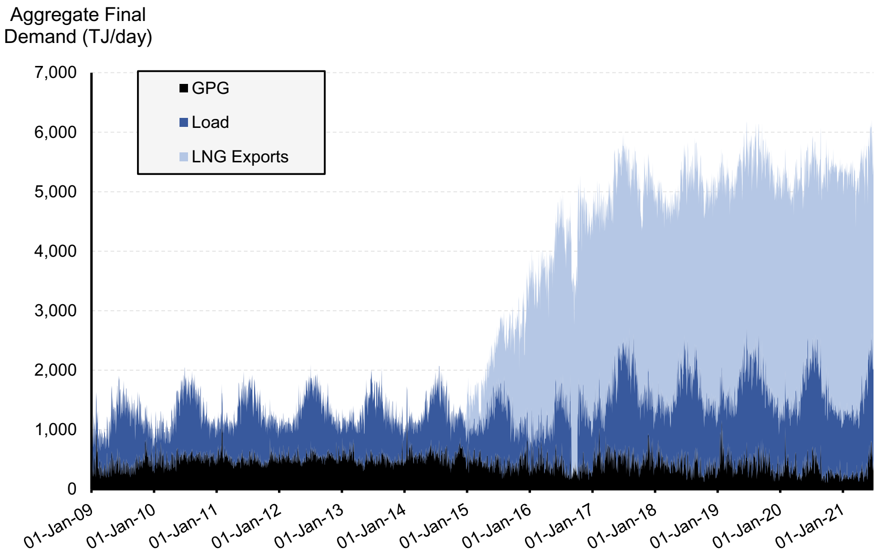


Fig. 2 Aggregate final demand for natural gas (TJ/day, 2009–2021). *Source* Simshauser and Gilmore (2022)

led to a threefold increase in Australian east coast final gas demand, from about 650 to 1,900 PJ/a (Simshauser and Nelson 2015a, 2015b; Billimoria et al. 2018; Ledesma and Drahos 2018; Quentin Grafton et al. 2018). This change in aggregate final demand is illustrated in Fig. 2 (daily resolution, TJ/d) over the period 2009–2021. Note that three market segments are identified: (i) gas-fired power generation; (ii) final (domestic residential, commercial, and industrial) consumer demand; and (iii) LNG exports, which commenced in late 2014.

What Fig. 2 does not capture is the underutilisation of the LNG export plant, and the consequential pressure this has placed on the domestic market for natural gas. Domestic gas prices had historically cleared at A$3–A$4/GJ (i.e. ~US$2.21–US$2.96/MMBtu) under both short and long-dated contracts. But the advent of LNG export terminals linked the $3/GJ domestic market to a highly volatile seaborne market, with an effective netback price of A$8–A$12/GJ (~US$5.91–US$8.87/MMBtu). Because excess LNG capacity had been built, marginal supplies in the domestic consumer market were forced to compete with sunk LNG export capacity. In certain circumstances, domestic prices rose at or above seaborne prices. Figure 3 presents the ramp-up and ongoing LNG plant capacity (from late 2014, daily resolution) and contrasts this with actual production. The visible market shortfall in Fig. 3 (i.e. at least one full LNG train, or about 250–300 PJ/a) is material—noting that aggregate domestic market demand is now c.600 PJ/a.

With gas prices surging, legacy long-dated gas supply agreements held by generators (and struck at the pre-LNG prices of $3–$4/GJ) became more valuable as an LNG feedstock due to very low spot electricity prices over the period 2009–2015 (as Fig. 7

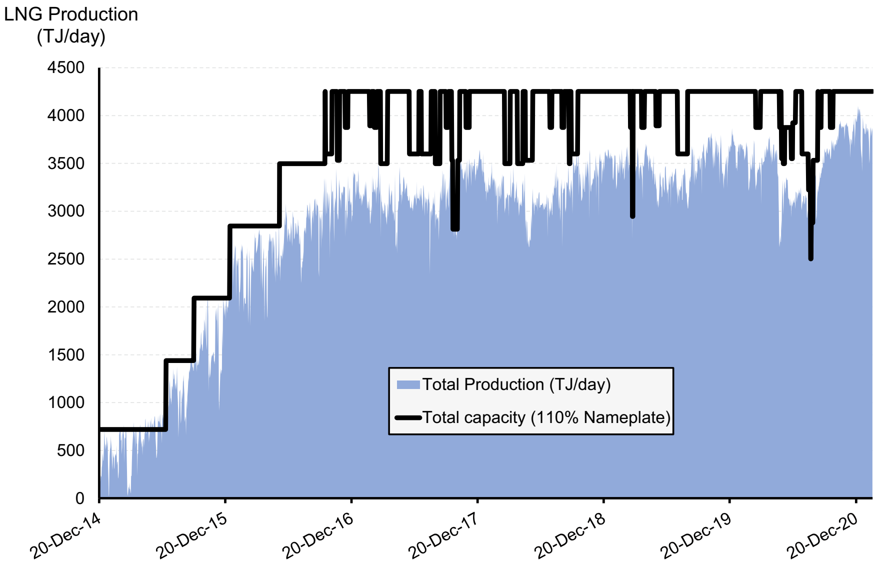


Fig. 3 Australian east coast LNG export capacity versus production (2014–2021). *Source* Simshauser and Gilmore (2022)

later illustrates). Gas turbine 'spark spreads' throughout 2012–2015 were generally negative and well below that which could be sustainably achieved by mothballing a CCGT plant and on-selling the gas fuel to the chronically short LNG exporters under medium-term agreements. Consequently, many gas-fired generators forward-sold their fuel supplies to LNG producers and temporarily mothballed their CCGT plants. These generators were unaware of looming coal plant divestments, which accelerated markedly in 2016–2017.

When the mothballed CCGT plants returned to the market, their marginal running costs were tied to export-linked short-term gas prices (see Fig. 4). This would have crucial implications for spot electricity prices and new plant entry, as Sect. 5.4 later explains. In Fig. 4, a distinct rise in spot gas prices is visible from 2015, driven by a fleet of LNG export facilities commissioned in the Queensland region. As noted above, the LNG terminals linked NEM-region gas prices to international export prices for the first time.

5.3 NEM Plant Stock: Entry and Exit

Over time, the responsiveness of the NEM's aggregate plant stock has been largely as expected. Rising electricity spot prices have induced entry, and sustained low prices have led to plant mothballing or divestment and exit. Figure 5 provides a high-level overview of the NEM's aggregate plant stock from 1998 to 2020. The installed coal

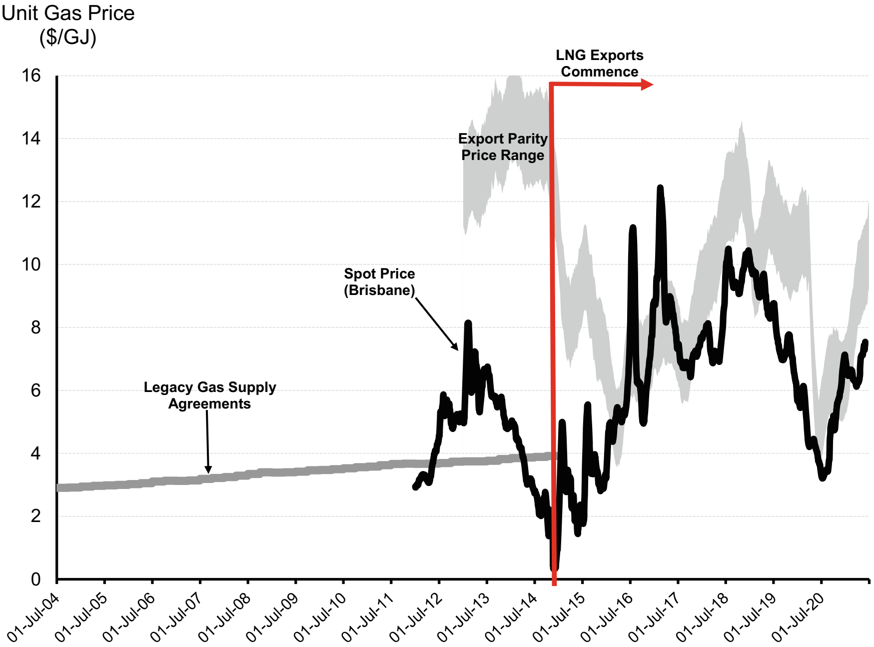


Fig. 4 QLD gas prices (2004/05–2019/20). *Source* Simshauser and Gilmore (2022)

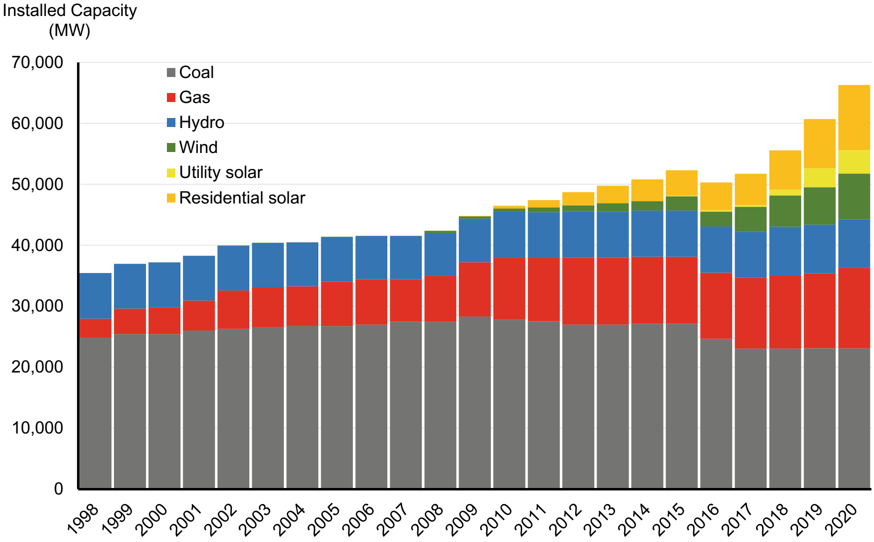
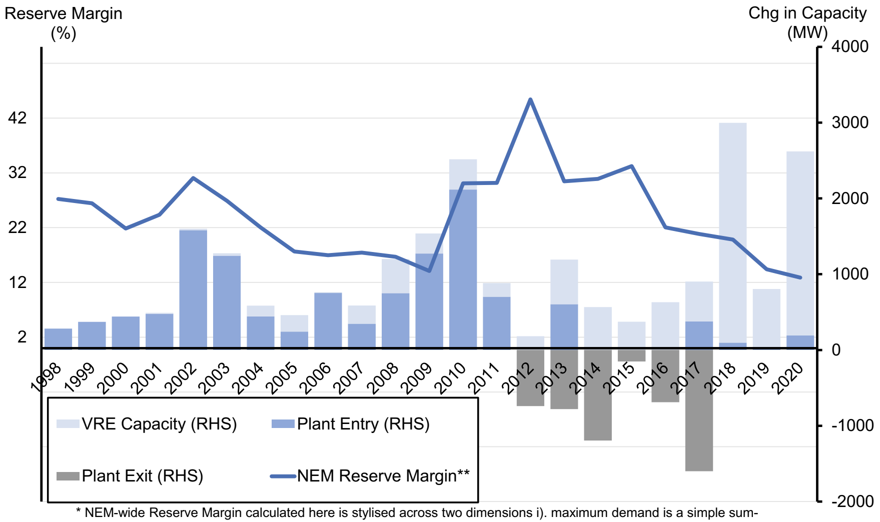


Fig. 5 Aggregate plant stock. *Source* Simshauser and Gilmore (2022)



* NEM-wide Reserve Margin calculated here is stylised across two dimensions i). maximum demand is a simple sum-of-the-regions maximums rather than coincident demand, and ii) generation is aggregated without any adjustment for interconnector constraints. 5.5% of Solar and ~8% of Wind capacity contribute to the Reserve calculation.

Fig. 6 Reserve plant margin (LHS) and plant entry/exit (RHS). *Sources* Simshauser (2019a)

plant effectively reached its peak in 2007 (albeit with a net capacity creep from existing kit occurring through to 2009), after which time the fleet began to contract, particularly during 2016–2017. The other notable feature in Fig. 5 is the run-up in VRE (i.e. solar and wind) and rooftop solar PV, in particular.

Figure 6 provides context around the data in Fig. 5 through a high-level analysis of VRE-adjusted[30] reserve plant margin (line series, LHS axis) and net capacity changes, i.e. investments and divestments (bar series, RHS axis).

The changes to aggregate capacity in 2012–2017 (i.e. coal plant divestment and exit) are central to the analysis that follows. Note in Figs. 5 and 6 that a surge in new plants occurred in 2008–2011, most of which were gas-fired generation in response to the 2007–2008 price cycle (as Fig. 10 subsequently reveals) and state government policies. While not evident from Figs. 5 and 6, overlapping the gas-fired entry phase of 2008–2011 was a period of contracting power system demand. When combined, it led to sharp rises in power system reserve plant margins (i.e. overcapacity). Reserve margins visibly peaked in 2012 (Fig. 6 line series, LHS axis). The extent of oversupply weighed heavily on spot prices. Consequently, many coal-fired generators divested and exited the market (see Fig. 6 series and Table 2). Most critically, notice in Table 2 that the average exit warning period was just 5.2 months.

One of the more intriguing aspects of the 2016–2021 investment supercycle was the relative absence of new entrant gas turbine proposals, let alone entrants. Gas plant entry was subject to critical hold-up for reasons outlined in Sect. 5.2. During previous electricity price cycles (e.g. 2007–2008, driven by east-coast Australia's

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[30] The reserve margin adjusts for the firmness of the VRE but treats the plant stock as if a perfect transmission system exists.

Table 2 NEM coal plant exits 2012–2017

Coal plant	Capacity (MW)	NEM region	Exit (year)	Enter (year)	Age at exit (years)	Warning (Months)	Notice date	Closure date
Swanbank B	500	Qld	2012	1972	40	23.6	26-Mar-10	27-Mar-12
Playford[a,b]	240	SA	2012	1960	52	6.9	7-Oct-15	8-May-16
Collinsville	180	Qld	2013	1972	41	5.9	1-Jun-12	1-Dec-12
Munmorah[c]	600	NSW	2013	1969	44	0.0	3-Jul-12	3-Jul-12
Morwell	195	Vic	2014	1958	56	1.0	29-Jul-14	30-Aug-14
Wallerawang[c]	1000	NSW	2014	1978	36	0.0	1-Nov-14	1-Nov-14
Redbank	151	NSW	2015	2001	14	0.0	31-Oct-14	31-Oct-14
Anglesea	150	Vic	2016	1969	47	3.6	12-May-15	31-Aug-15
Northern[b]	540	SA	2016	1985	31	6.9	7-Oct-15	8-May-16
Hzelwood	1600	Vic	2017	1967	50	4.8	3-Nov-16	1-Apr-17
Total/Average	5156			1972	42.5	5.2		

[a] Mothballed in 2012
[b] Original notice 11 June 2015 with Planned closure date of March 2018
[c] Mothballed, Notice was therefore immediate
Source Simshauser and Tiernan (2019)

millennium drought), more than 5,000 MW of gas-fired generation plants entered the coal-dominated NEM, as Figs. 5 and 6 (and later Fig. 10) illustrate. In the 2016–2021 cycle, there were less than 1,000 MW of new gas plant entrants. As noted earlier, many incumbent gas-fired generators had mothballed their plant, having forward-sold their long-term, low-cost gas supplies to the LNG industry. The mothballed generators had forward-sold their gas over 3–5 year periods and undertook the transactions when power system reserve margins were high and spot prices were low. They were, of course, unaware that the multiple, uncoordinated coal plant divestments and exits outlined in Table 1 were imminent and would drive spot prices to record levels.

5.4 *NEM Spot Prices, 1998–2021*

For most of the NEM's history, annual average spot prices spanned a relatively tight range. As Fig. 7a illustrates, from 1998 to 2015, annual spot prices averaged A$36/MWh (i.e. ~US$28/MWh[31]) with a range of $44/MWh (at the 90th percentile, or P90) to $29/MWh (P10). Figure 7b presents the same data in constant 2021 dollars, with the average being A$52/MWh (~US$39/MWh). Australia's low-cost coal-fired generation fleet underpinned spot prices over this period.

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[31] I use the Australian dollar to US dollars exchange rate of $0.75.

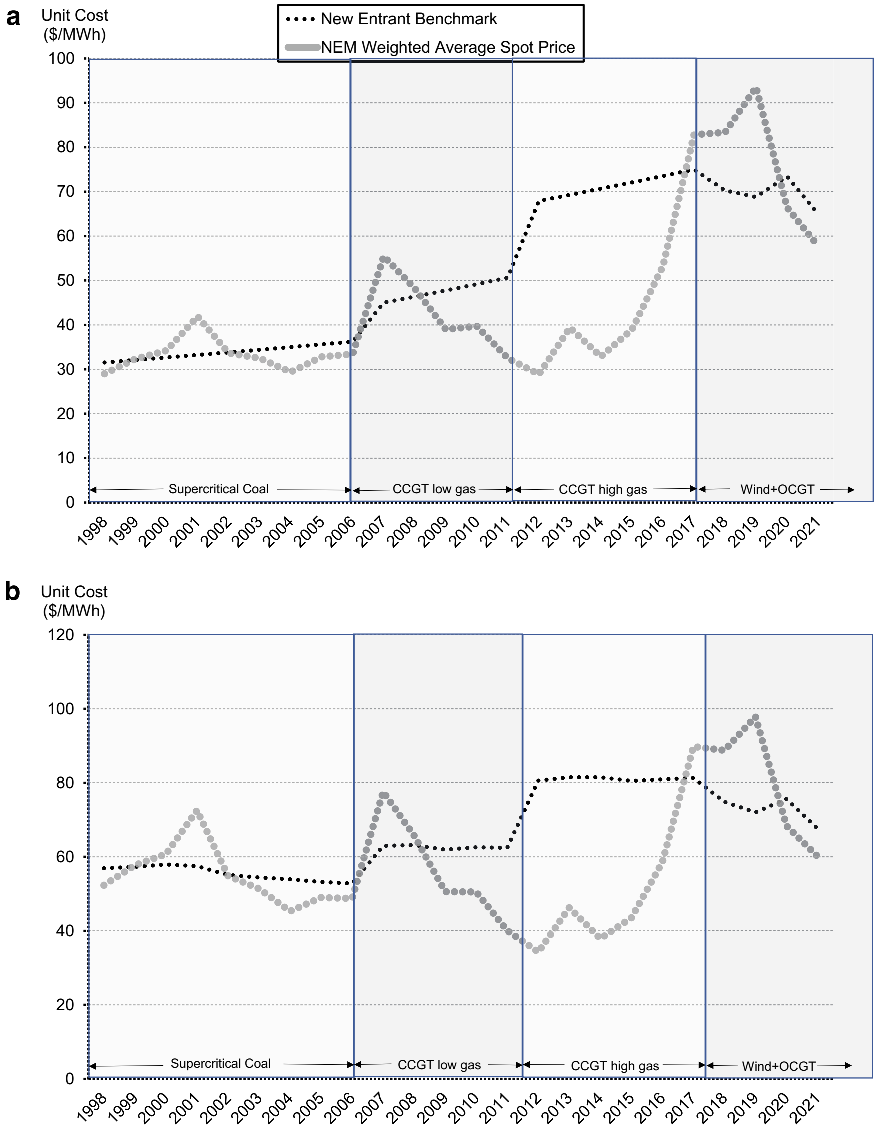

Fig. 7 20 Year NEM spot prices versus new entrant costs: 1999–2021. **a** Nominal dollars. **b** Constant dollars (2021$). *Source* Simshauser and Gilmore (2022)

Over NEM's entire history (1998–2021), average prices in Fig. 7a equate to A$45/MWh (~US$34/MWh) with a range of $78/MWh (P90) to $30/MWh (P10). The average spot price in real terms from Fig. 7b is A$58/MWh or ~US$43/MWh.

Three things in Fig. 7a, b are worth noting:

(1) Spot prices experienced two major excursions. The first (2007–2008) coincided with Australia's east coast millennial drought. Apart from adverse effects on hydro plants, drought conditions were so severe that some coal-fired generators were forced to mothball units due to cooling water shortages (urban drinking water being prioritised from affected dams). And as explained earlier, the second excursion (2016–2019) arose due to turmoil in the adjacent market for natural gas (Sect. 5.2), coal plant divestment and exit (Sect. 5.3), and renewable plant entry lags (examined in Sect. 5.5).

(2) The New Entrant Benchmark plotted in Fig. 7a, b is notionally split into four distinct periods: coal, CCGT low gas, CCGT high gas, wind + open cycle gas turbine (OCGT). The cost of new entry exhibits a steep incline in 2006 and coincides with a shift in the benchmark entrant technology, from coal to gas, and in line with expectations of a carbon constraint. Another step change occurred in 2011 with higher priced gas. Recall from Sect. 5.2 that domestic gas prices rose sharply following the LNG plant commitments, in which domestic gas prices were linked with the seaborne market and rising from a historic A$3/GJ to 9/GJ (~US$2.21–US$6.85/MMBtu). The final change occurred in 2017, at which point the cost of renewables had fallen considerably and, even after accounting for intermittency (by way of an OCGT), became the new benchmark entrant.

(3) While not captured in Fig. 7, the marginal running cost of the NEM's coal-fired fleet has been rising over time. Legacy coal supply agreements at several marginal coal plants across Queensland and NSW had been progressively expiring, with replacement contracts based on the 5,500 kcal coal futures contract (export price ex-Newcastle, north of Sydney).

Figure 7 analyses a weighted average NEM spot price series, whereas Fig. 8 presents spot and forward prices for Queensland, NSW, and South Australia. What each chart has in common is that forward prices have largely followed the pattern of market imbalances and are distinctly mean reverting, with the combined spot and forward prices exhibiting elongated business cycles typical of energy markets generally (see Pindyck 1999; Simshauser 2010; Arango and Larsen 2011; Cepeda and Finon 2011; Bublitz et al. 2019). The forward curves in Fig. 8 are for baseload contracts. An inspection of Fig. 8 shows that the wisdom of the forward markets did not anticipate the rapid coal closures, which caused the surge in spot prices in 2016–2019.

Crucially, note from Figs. 7 and 8 that prices have not been maintained above the cost of entry. Figure 9 contrasts quarterly average gas prices with quarterly average spot electricity prices. To be sure, electricity prices from 2016 to 2019 are high in absolute terms relative to recent history. But these dynamics reflect sudden coal plant closures, falling market imbalances, and rising underlying resource costs rather than market failure to efficiently price supplies. Furthermore, forward prices (Fig. 8) have consistently trended downwards given new investment commitments, suggesting investors make rational (and efficient) decisions.

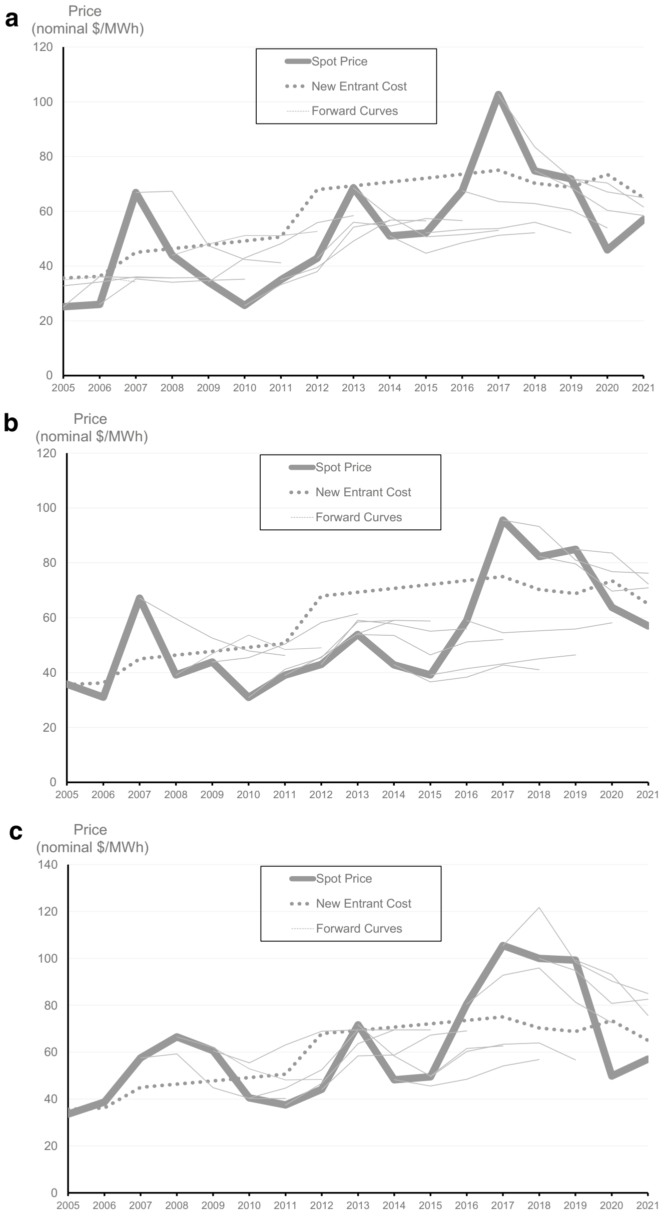

Fig. 8 Spot and forward price curves, 2005–2021 (constant 2021$). **a** Queensland's spot and forward curves. **b** New South Wales's spot and forward curves. **c** South Australia's spot and forward curves. *Note* Price data in these figures are CO_2-inclusive from 2012 to 2014. *Source* Simshauser and Gilmore (2022)

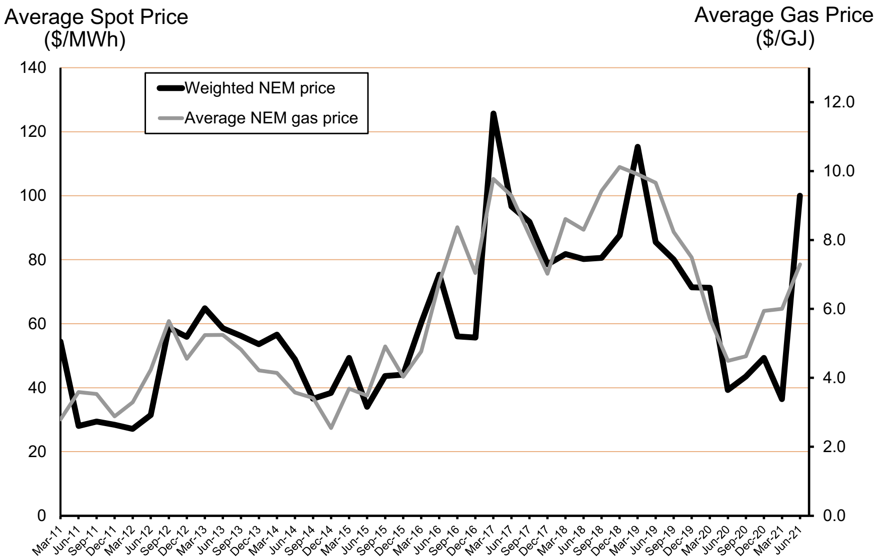

Fig. 9 Quarterly average gas versus electricity prices (2011–2021). *Source* Simshauser and Gilmore (2022)

5.5 Plant Entry Dynamics: Investment Commitments and the Rise of VRE

From 1998 to 2021, ~31,500 MW of new plants was committed across NEMs' five regions, representing a $57.5 billion investment commitment (in 2021$). This is illustrated in Fig. 10a (MW) and Fig. 10b ($ nominal). The data in Fig. 10 were compiled based on when the plant reached 'financial close' (i.e. the point of irreversible financial commitment). Consequently, many of these plant commitments are still under construction or undergoing commissioning at the time of writing.

The data in Fig. 10 illustrate three distinct waves of investment activity. From 1998 to 2004, investment was dominated by coal-fired generation plants (3,000 MW, $6.9 billion). From 2004 to 2010, gas-fired generation dominated (5,350 MW, $3.6 billion). And from 2016 to 2021, the VRE supercycle comprised investment commitments of 15,939 MW or $26.4 billion.

The data in Fig. 10 do not reveal the level and complexity of investment commitment activity. This is best described through the number of projects committed. From 1998 to 2021, the NEM has seen 229 projects reach financial close (Table 3), and within the supercycle, 135 projects (Table 4). Perhaps the most surprising aspect of these data (i.e. Tables 3 versus 4) is the sheer size in 2016–2021. The 135 projects during the 2016–2021 supercycle represent 58% of the total 229 projects since the NEM commenced in 1998. This change in the pace of the number of connecting generators is illustrated in Fig. 11.

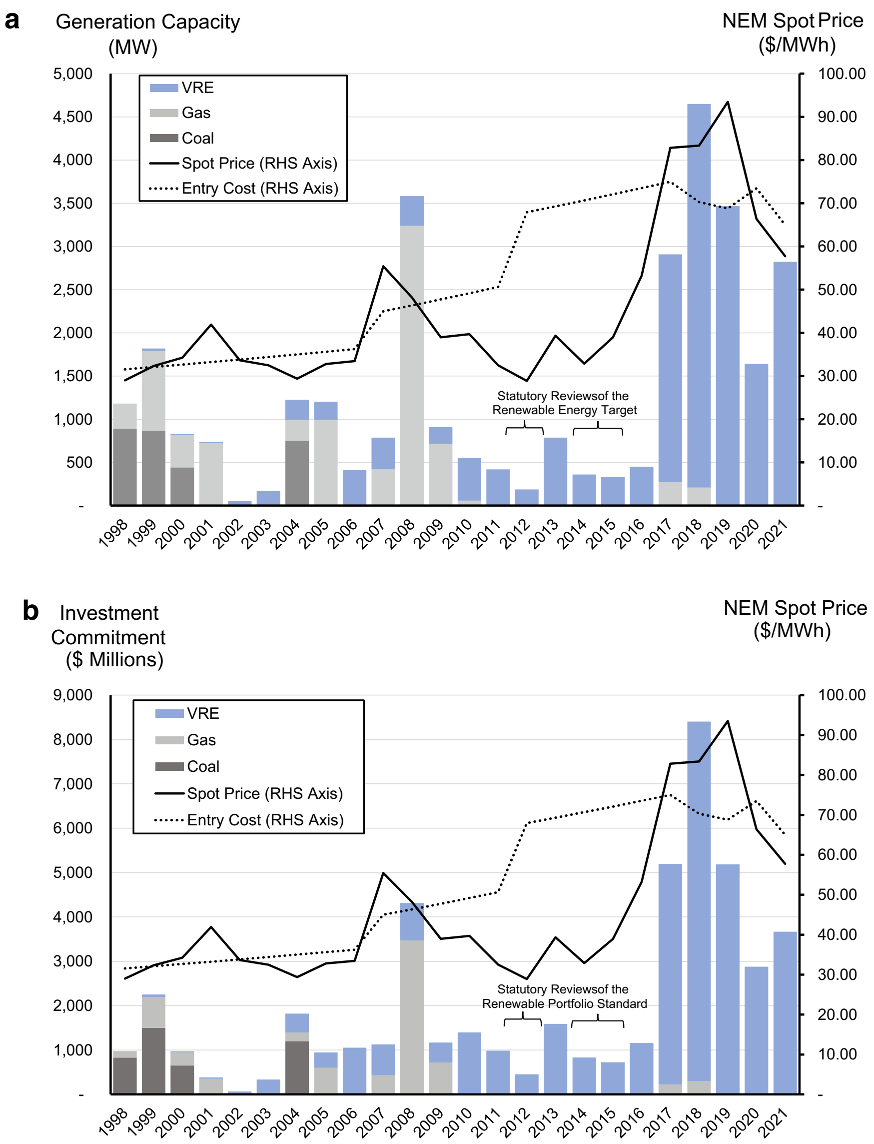

Fig. 10 NEM investment commitments (1998–2021). **a** Investment commitments (generation capacity, MW). **b** Investment commitments ($ million). *Source* Simshauser and Gilmore (2022)

This data underscores what would become a critical 'rate of change' problem. This disruptive supply-side adjustment presented very material challenges to the system operator, transmission networks, and incumbent generators. However, the 'disruptive forces'—i.e. new entrant VRE generators) have also disrupted their businesses through the velocity and pace of entry—manifesting in sharp adverse movements in

Table 3 NEM investment commitments: 1998–2021

	Investment ($ million)	Capacity (MW)	Projects (number)
Solar	14,369	9387	90
Wind	20,857	9984	84
Other	1030	706	18
Gas	7453	8456	32
Coal	4180	2953	5
	47,889	31,846	229

Source Simshauser and Gilmore (2022)

Table 4 NEM investment commitments: supercycle period, 2016–2021

	Investment ($ million)	Capacity (MW)	Projects (number)
Solar	13,686	9111	86
Wind	12,028	6059	39
Other	247	290	8
Gas	522	480	2
Coal	–	–	–
	26,483	15,940	135

Source Simshauser and Gilmore (2022)

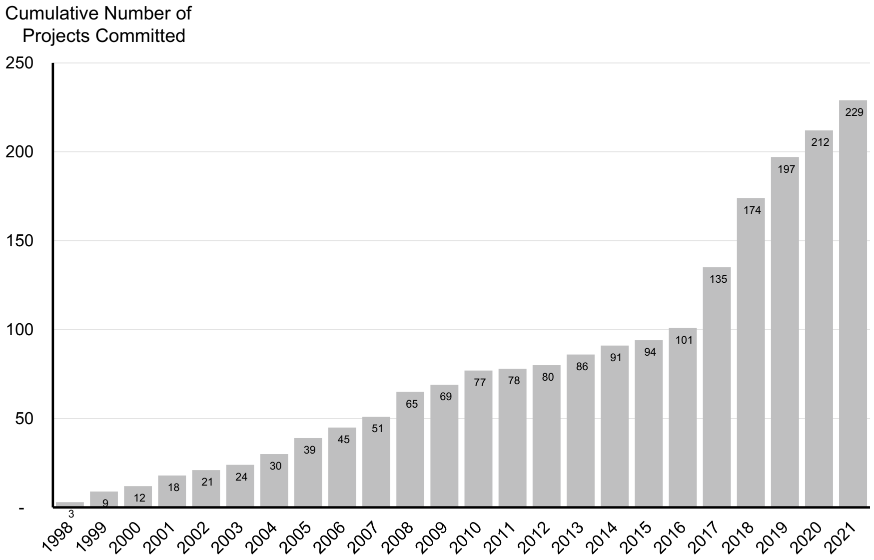

Fig. 11 Investment commitments (NEM), 1998–2021. *Source* Simshauser and Gilmore (2022)

system strength (loosely defined) and visible deterioration in the dispersion of the power system's frequency (i.e. 50 Hz ± 0.15 under normal operating conditions). This is subsequently analysed in Sect. 5.7.

5.6 NEM Resource Adequacy: Reliability Performance

The AEMC's Reliability Panel sets the criteria and reviews overall power system performance from a resource adequacy perspective. As noted earlier, the NEM's reliability criteria (of no more than 1 GWh lost load for every 50,000 GWh served, or <0.002% lost load) has been achieved with few exceptions. Figure 12 displays recorded data over the period 2003–2020. This data includes five regions over 18 years, or '90 region years' of data, and only in 2009 was the reliability criteria breached. The 2009 events were driven by significant (weather-driven) increases in maximum demands in Victoria and South Australia, with coincident network limitations binding within Victoria and Tasmania (Rai and Nunn 2020).

NEM outage analysis covering the period 2009–2019 identified that only 0.1% of system minutes lost related to generation plant shortfalls, the balance arising from a black system event in South Australia[32] (1.6%), transmission plant outages (0.7%), and distribution network outages (97.7%) (see Simshauser and Gilmore 2022).

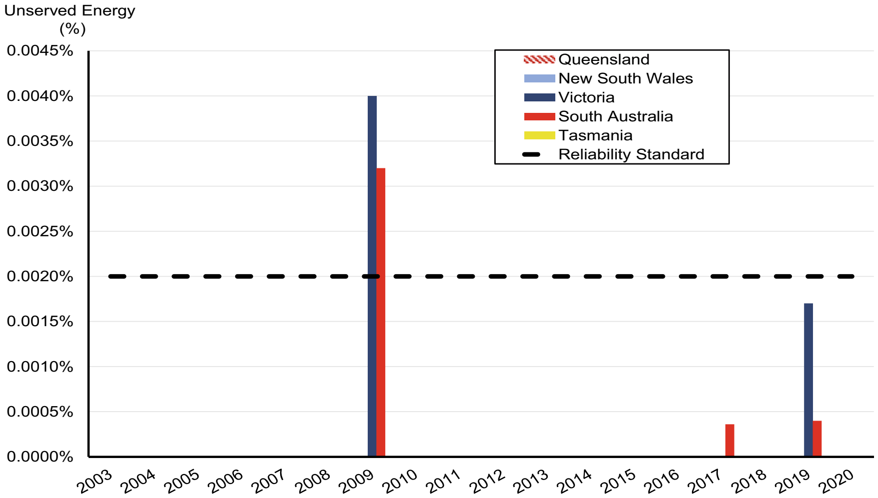

Fig. 12 NEM lost load versus reliability standard (2002/03–2019/20). *Source* Simshauser and Gilmore (2022)

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[32] The South Australia black system event was not a resource adequacy/reliability problem, but a system security issue (i.e. an unstable system in which a voltage collapse led to plant disconnecting, with the rate of change of frequency falling faster than supply and demand resources could respond to.

More recent episodes of lost load (2017, 2019) resulted from the speed of coal plant exit and entry lags identified in the sections above. These were unforecastable events—the system operator (AEMO) did not predict a breach of the standard in the 3 years leading up to coal plant divestments and exits in 2016–2017 (and to be clear, nor did any other marker participant, including forward markets as Fig. 8 reveals). Conversely, closer to real-time emergency trader provisions were activated according to the NEM design.[33] Centralised capacity procurement would not have resulted in different outcomes absent costly and erroneous ex ante over-procurement. The data and analysis from Sects. 5.2, 5.3, 5.4, 5.5 and 5.6 reveal that NEM investment signals appear to have operated exactly as intended.

5.7 On the Security of Supply

In hindsight, the speed of entry (i.e. 135 projects in 2016–2021) was striking. If one set of parameters stood out from all others in terms of a rate of change problem, it is the deteriorating performance of the NEM's supply security (namely, maintaining a frequency 50 Hz and voltages ±10%). Security of supply (i.e. the power system's ability to withstand a sudden shock) is quite different from reliability or adequacy of supply (i.e. an adequate plant stock relative to forecast aggregate demand). That is, a system can be reliable but not secure. To generalise, security of supply events are measured in seconds, whereas reliability of supply events are measured over 'planning timeframes'.

With the rapid entry of VRE projects and gradual reductions in the supply of primary frequency response by coal generators, the system operator is encountering new modes of failure, non-credible contingent events previously considered less impactful, and failing system strength—particularly in renewables-rich South Australia (>50% VRE market share) and in North Queensland (>45% VRE market share).

Figure 13 contrasts the distribution of power system frequency in 2019 and 2012. As coal plants began to close (from 2012 to 2017), the distribution of power system frequency began to deteriorate, with marked acceleration from 2016 onwards. By 2019, the variation in frequency was more than 200% of the 2012 result.

Unsurprisingly, the system operator's number of 'directions' issued has increased sharply (Fig. 14). Again, the rise in system operator directions coincides with the divestment and exit of coal plants in Victoria and South Australia.

The NEMs' normal operating band is 50 ± 0.15 Hz (i.e. 49.85–50.15 Hz), and the frequency operating standard specifies that the power system should be maintained

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[33] An important feature of the NEM is the ability of the market operator to step in and procure additional resources if the reliability standard is forecast to be breached. These emergency powers have been utilised over time, and have served the market well. Under the rules, they are triggered up to 9–12 months in advance if forecast lost load is expected to breach the reliability standard. Sources of supply are typically demand response (closing the gap between the value of lost load and the market price cap) and out-of-market emergency generation packs (e.g. diesel gensets).

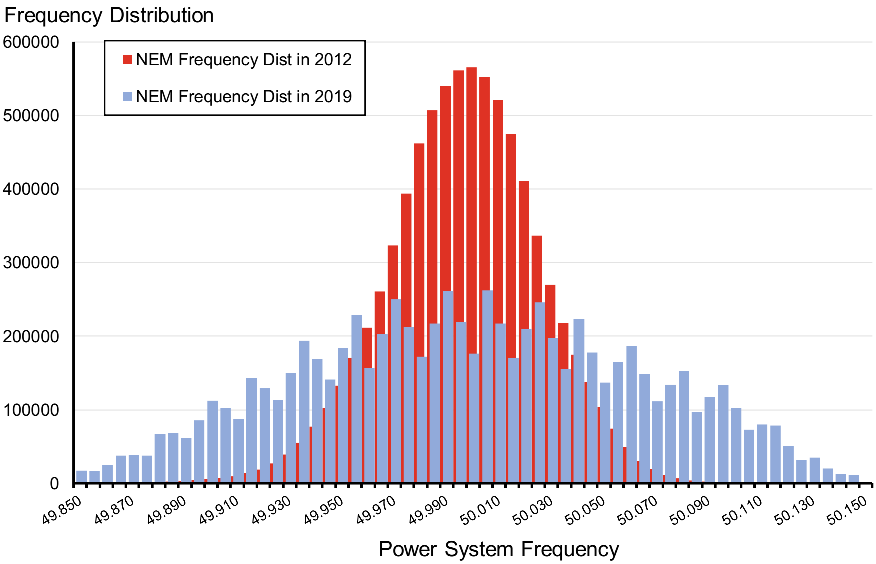

Fig. 13 Distribution of NEM frequency (4 s-data 2012 versus 2019). *Source* Simshauser and Gilmore (2022)

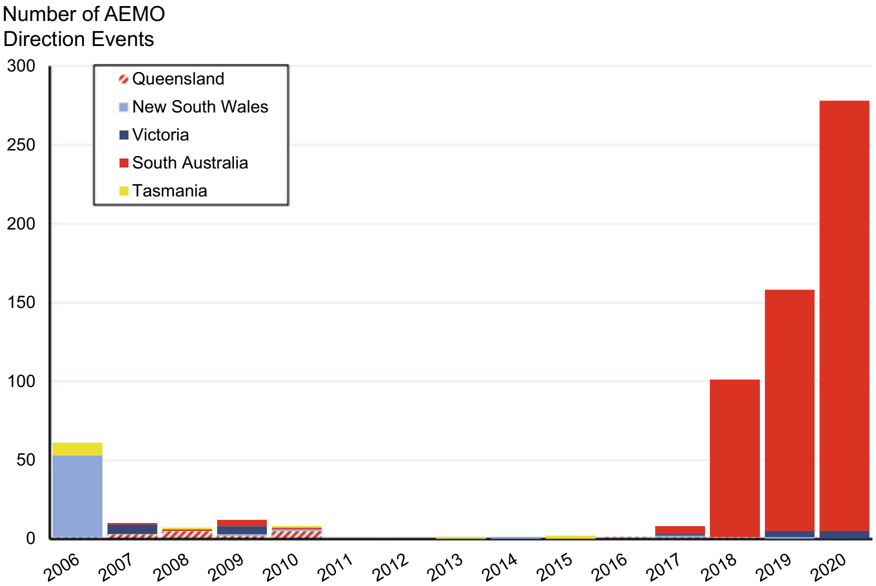

Fig. 14 System operator direction notices to maintain security of supply. *Source* Simshauser and Gilmore (2022)

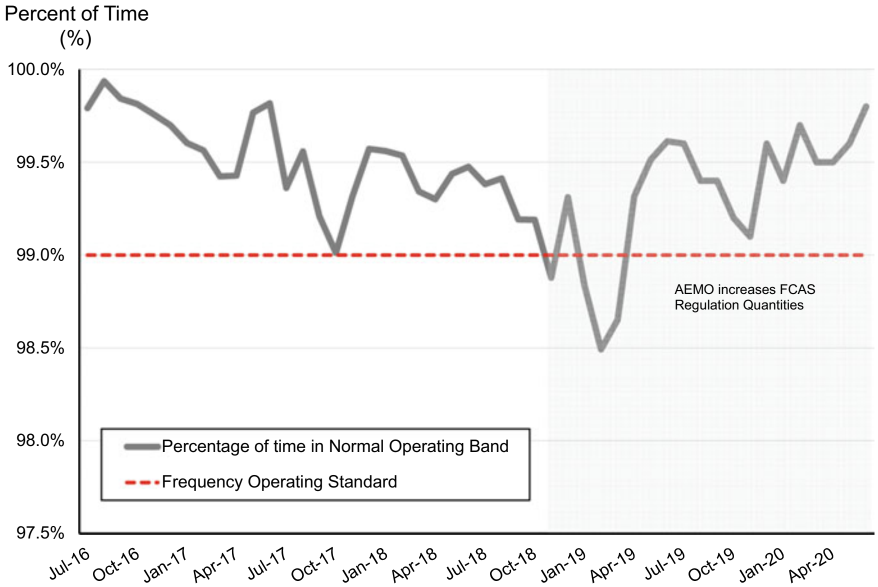

Fig. 15 Frequency versus frequency operating standard. *Source* Simshauser and Gilmore (2022)

within this band >99% of the time. Towards the end of 2018, power system frequency careered outside the standard (Fig. 15).

The deterioration in frequency and transient breach of the frequency operating standard reflect changes in system resources.[34] The administratively determined level of demand for frequency regulation services had historically been set to ~130 MW, with frequency contingency services comprising a further 620 MW under most system conditions (i.e. a total of 750 MW and equivalent to an n − 1 FCAS suite, 750 MW typically being the largest contingency event). The NEM's frequency regulation quantities were set in 2004 when the market had virtually no VRE. Quantities were (finally) reviewed from 3 October 2018 (Simshauser 2019a), and based on the data in Figs. 13, 14 and 15. A non-trivial increase in frequency regulation would follow, rising from 130 to 220 MW (and at times to 350 MW), with regulation FCAS volumes projected by AEMO to be more than 600 MW by 2040.

To be clear, no rule or regulation prevented an earlier revision of necessary quantities.[35] As more VRE enters, we should anticipate rising FCAS quantities and new

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[34] Including some generators that detuned governors in response to conflicting regulatory signals.

[35] NEM's Frequency Operating Standard does not place any specific requirement or limitation on the system operator, AEMO, as to how frequency should be maintained within the normal band, AEMO is in effect free to select the appropriate mix and quantity of services to procure. Currently, this includes frequency regulation and three forms of frequency contingency services (i.e. 6 s, 60 s, 5 min). Apart from increasing the quantity of FCAS Regulation, AEMO has not chosen to augment its services. The author sponsored a rule change to add fast frequency and operating reserves to the FCAS suite.

FCAS services to deal with new risks. By way of example, the n − 1 suite will ultimately be surpassed by forecast uncertainty (in relation to wind and/or solar resource availability) as a more probable mode of failure.

6 The South Australian Black System Event

The special case of the South Australian black system event warrants a section of its own. Recall that in 1997 Australia established the world's first RPS. Commencing at '2% renewables by 2010', the target market share was lifted to '20% renewables by 2020', following a general election in 2007. One direct consequence of this was that the world-class wind resources in South Australia would attract a disproportionate amount of investment because of the certificate side market and further compounded by off-market investments. The off-market investment came via sub-national governments' underwriting entry to acquit their intra-state renewable aspirations. The Australia Capital Territory (ACT) wrote a series of contracts-for-differences in South Australia. Yet, their load is in the NSW region—a region dominated by scheduled plants, thus leaving South Australia with even more VRE plants than the side markets would have otherwise delivered (and also leaving ACT taxpayers and consumers exposed to price divergence between South Australia and NSW). As Fig. 16 illustrates, between 2006 and 2018, the VRE plant market share

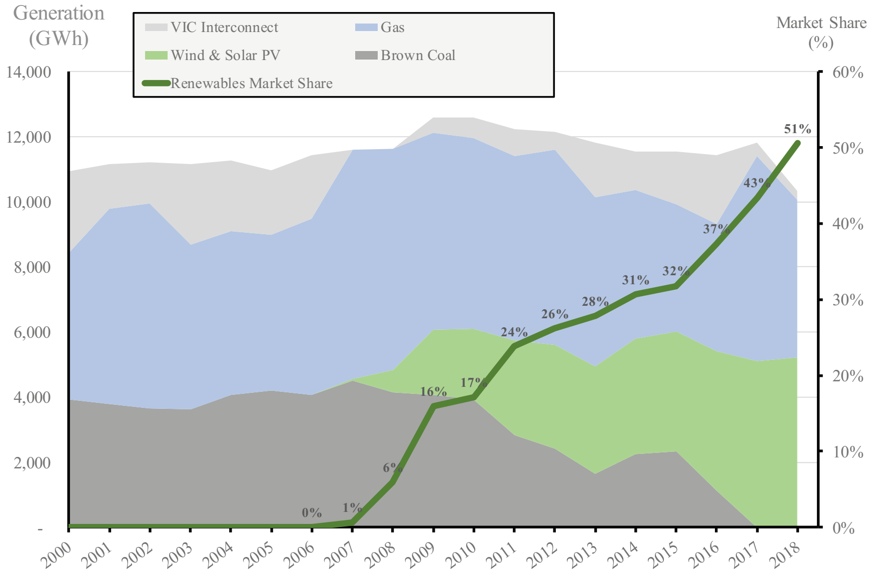

Fig. 16 South Australian generation (GWh) and VRE market share (%), 2000–2018. *Source* Simshauser (2019a)

in the ‘loosely interconnected’ South Australia NEM region rose from 0 to 51% (wind dominating at 42 percentage points). By comparison, the large and more strongly interconnected regions of Queensland, NSW, and Victoria would be greatly ‘under-weight renewables’, each with less than 8% VRE market share as in 2018.

Compounding matters for South Australia is its small system size (3,100 MW peak demand, 12.5 TWh energy demand) and a very poor load factor of 0.45. Indeed, South Australia is, by far, the smallest of NEM’s four main regions, with an underlying baseload of just ~1,100 MW and, as indicated above, limited interconnection to the adjacent region of Victoria.

With an influx of wind generation, South Australia experienced so-called merit order effects as early as 2011 (see Forrest and MacGill 2013; Cludius et al. 2014; Bell et al. 2017). Consistent with literature in the field, merit order effects eventually slow or reverse (see Gelabert et al. 2011; Simshauser 2020), with coal plants forced to withdraw. South Australia lost all of its coal plant generating units over the period 2012–2016 (Fig. 16).

Once VRE annual market share rose above ~25%,[36] coal plant operations became increasingly uneconomic. By the time VRE exceeded ~35% (in 2016), the coal fleet exited and gas-fired generation provided an expensive shock absorber, given the gas price dynamics outlined in Sect. 5.2. The sharp rise in spot prices is illustrated in Fig. 17 (solid black line, RHS axis).

Although South Australia was visibly changing from a synchronous, dispatchable coal and gas resource-based system to one comprising an increasing and dominant level of asynchronous, stochastic VRE wind and solar PV resources, AEMO maintained the same levels of FCAS (i.e. 6 s, 60 s, and 5 min spinning reserves). It had also reduced the levels of frequency regulation and black start services in prior periods.[37] Furthermore, AEMO maintained a global procurement of FCAS across NEM regions whenever the regions were interconnected, rather than localising some minimum level in the VRE-rich South Australia region—noting that the region is imperfectly interconnected to the adjacent Victoria region.[38] These practices, coupled with a

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[36] This occurred in 2012 with an average VRE market share of 26%, maximum VRE for a single day was 68%, and more than 20 days were higher than 50% market share.

[37] In my prior role as Director-General of the Queensland Department of Energy and Senior Official to COAG Energy Council, I had argued for a review of FCAS quantities (viz. an increase in regulated FCAS demand, and a localisation of some component of that demand) from April 2017. In a note to stakeholders on 3 October 2018, AEMO advised that ‘Regulation FCAS’ volumes have not been revised for many years, over which time significant system changes have occurred; less governor-based frequency support and increased penetration of intermittent generation are most notable’. Regulated FCAS quantities were set in 2004 when the NEM had no intermittent renewable resources.

[38] In NEM, the FCAS is determined dynamically in each 5 min interval. The FCAS is also procured ‘globally’ across regions subject to no network congestion. In periods of higher variability, FCAS regulation on procurement automatically rises from the typical set point of 130 MW to as much as 230 MW (in 60 MW increments) to maintain frequency. Threshold quantities of FCAS contingency (6 s–, 60 s–, and 5 min–spinning reserves) are based on the single largest contingency event—the potential loss of the largest generating unit and when combined with FCAS regulation typically adds to about 900–1,000 MW.

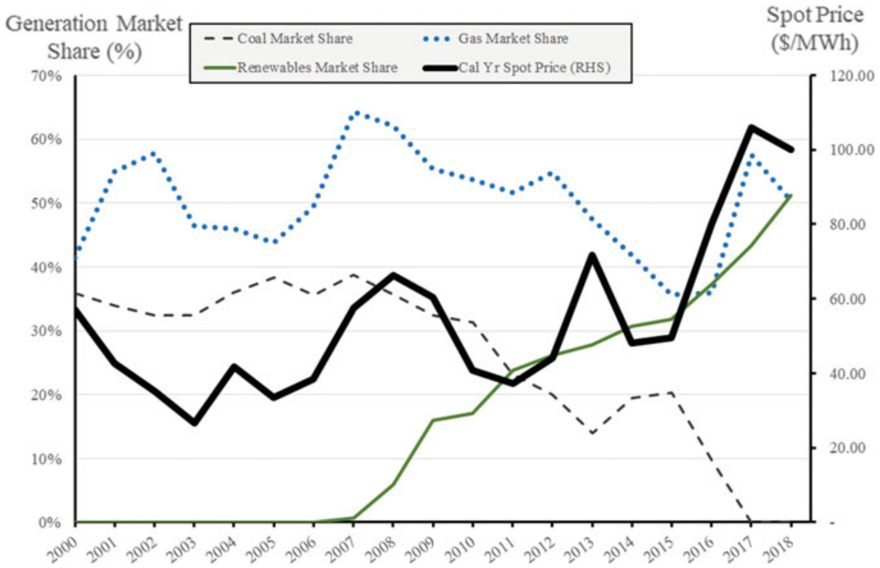

Fig. 17 South Australia's generation market share versus spot price (Spot prices in 2013 and 2014 were adjusted downwards by \$23/t × 0.6t/MWh to remove the effects of the CO_2 tax. The actual spot prices were \$69.75/MWh and \$61.71/MWh, respectively) (calendar years 2000–2018). *Source* Simshauser (2019a)

changing plant mix and how AEMO chooses to define what constitutes a credible contingency, were crucial elements that would exacerbate any supply-side shock.

At 4:18 p.m. on 28 September 2016, South Australia experienced a black system event.[39] A severe storm cell with wind speeds of 190–250 km/h moved through the state and damaged two transmission lines, causing a series of voltage dips over a 2 min window. In real time, South Australia's system demand was 1,826 MW. System dispatch configuration comprised 330 MW of gas-fired generation, 883 MW of wind generation, and 613 MW of imports through the Victoria–South Australia Interconnector. The latter notably operated at close to its rated capacity during the storm event.

As a result of a series of voltage dips, a group of wind turbines operating at ~450 MW disconnected from the grid (n.b. an unknown fault ride-through issue).[40] In response, power imported across the main Victoria–South Australia interconnector, already operating at close to full load, surged from 613 to 890 MW (i.e. >250 MW above the plant's rated capacity). Within 0.6 of a second, protection systems tripped the interconnector offline. At this point, South Australia was 'islanded' from the

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[39] For full details, see https://www.aemo.com.au/Media-Centre/AEMO-publishes-final-report-into-the-South-Australian-state-wide-power-outage.

[40] The fault related to control systems configurations, which triggered disconnection after 2 min of continuous voltage dips (which in hindsight, the wind farms should have been able to ride through).

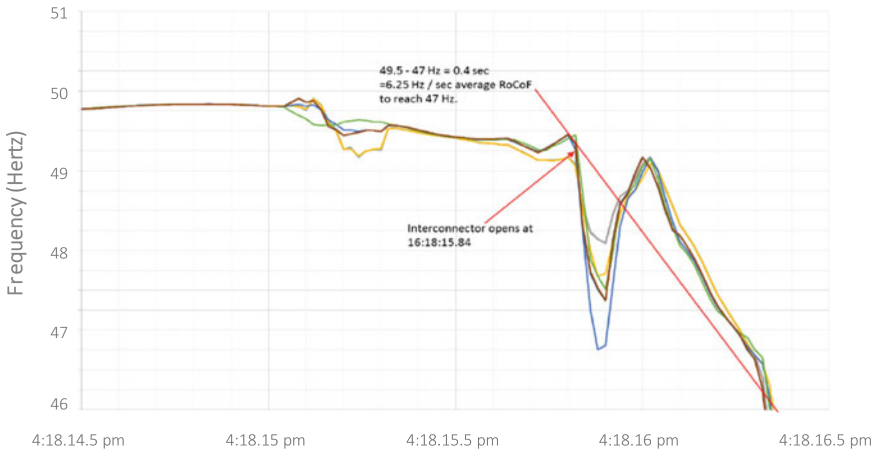

Fig. 18 Frequency and rate of change of frequency (various measurement points). *Source* Simshauser (2019a)

balance of the NEM. Following the combined loss of ~450 MW wind generation and ~600 MW Victoria interconnector flows, contingent capacity from indigenous dispatched plant (330 MW) and under-frequency load-shedding resources were simply inadequate to arrest the decline in frequency, noting that the time-lapse of the events spanned 2 s at 4:18:15 pm (Fig. 18). When combined with the FCAS (frequency regulation and 6 s frequency contingency), under-frequency load shedding can generally arrest a rate of change of frequency (RoCoF) of ~3.5 Hz per second. But notice in Fig. 18, the estimated RoCoF was closer to 6.25 Hz per second.

How AEMO had configured South Australia's power system just before the black system event was intriguing and can only reflect a rapid and unexpected deterioration in weather conditions. Noting the existence of s4.3.1 of the NEM Rules,[41] power system operations immediately before material weather events (viz. cyclones) in the NEM's northern region of Queensland are always configured differently.

Queensland has a long, stringy network spanning several thousands of kilometres. The state's far north will typically experience two to three cyclones per year, some of which can be expected to cross the electricity network. The long-standing coordinating and operating practices of Powerlink (the utility that owns and operates the transmission system) and AEMO (system operator) in periods before cyclones crossing land are to invoke a greater reliance on local dispatchable generation either side of the weather event (i.e. dispatchable generation plant in the north is constrained on out of merit order). This thus reduces reliance on intra-connector flows from the

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[41] NEM Rule 4.3.1 states (amongst other things) that the system operator should 'initiate action plans to manage abnormal situations or significant deficiencies which could reasonably threaten power system security'. Deficiencies are noted without limitation, viz. (i) power system frequency and/or voltage operating outside the definition of a satisfactory operating state, and (ii) actual or potential power system instability.

south in the event of a contingency. Why AEMO did not similarly configure South Australia during this 1-in-50 year storm event (for example, by constraining on local generation, reducing loading of the Victoria–South Australia interconnector, etc.) is unclear. To be sure, the black system was a system security event, not a resource adequacy event. There was more than adequate available generating capacity in the South Australia region, highlighting the subtle, albeit important, distinction between the reliability and security of supply.

7 Policy Reflections

What can be learned from 20+ years of NEM wholesale market history? With the benefit (and luxury) of hindsight, I believe there are three key insights:

(1) The NEM market design has been durable but is now characterised by **missing markets** due to elevated risks to the security of supply. This includes markets for fast frequency, operating reserves, unit commitment for system strength, and in all likelihood, markets for ramping (given solar resources) and inertia. Many of these are currently the subject of rule change proposals (including two originated by the author and colleague, Dr Joel Gilmore, for fast frequency and operating reserves). There is no real evidence that plant entry has been inadequate relative to the reliability criteria on resource adequacy. It is noteworthy that the system operator (and the entire forward markets) had failed to anticipate sudden coal plant divestment and exits. In short, the counterfactual to the NEM design, namely, a centrally organised capacity market, would not have produced a superior outcome—reliability of supply—unless it was purposefully oversubscribed. Even so, it is unclear that it would have produced a superior outcome, namely, security of supply (and highly likely would have produced a suboptimal outcome, viz. costs to consumers).

(2) **Plant exit policy**. When the NEM was designed, considerable thought went into entry. With the benefit of hindsight, it is unclear that much thought went into divestment and exit. Sudden coal plant exits produced surging prices that rightly tested political tolerances. This could have been better managed (vis-à-vis prices) if the east-coast gas market had been functioning properly (i.e. with questions of whether central governments should permit excess LNG development capacity). But regardless of this or perhaps because of it, transparency around exit timing needs to be greatly improved. This has been partially resolved by a rule change requiring continuous disclosure of plant exit timing (referred to as the 3 year closure rule). This is a necessary but insufficient policy adjustment. The closure of the 1,600 MW Hazelwood Power Station (20% Victoria market share) over 6 consecutive trading days with 5 months' notice did not represent an orderly exit. Annual NEM wholesale market turnover rose from \$7.7 billion per annum to \$17.2 billion per annum on either side of the Hazelwood exit. Even if taxpayer-funded, ensuring an orderly exit seems

important given predictable development and construction lags to new entry. Such a policy suggestion should not be interpreted or designed to prevent exit decisions per se and should be used judiciously to facilitate orderly exit and applied in critical circumstances.

(3) **Climate change policy discontinuity**. The general lack of a united climate and energy policy architecture, policy design errors, and the discontinuity of climate-related policies outlined in Sect. 5.1 has amplified plant investment cycles. The most critical of these was the Commonwealth government's decision in 2013 to review the 20% target, with the policy revision occurring in 2015. Consequently, over the period 2013–2015, there was a virtual VRE investment blackout (recall Fig. 10). Once the dust had settled, the industry had only a few short years to meet the 20% renewable target. Renewable certificate prices surged on top of rising spot electricity prices, given coal plant divestment and exits. At the market peak (2017–2018), the bundled spot electricity and spot certificate price exceeded $160/MWh (Simshauser and Gilmore 2022), while the cost of developing wind and solar PV was ~$60 and ~$50/MWh, respectively. Predictably, an investment supercycle ensued, as outlined in Fig. 10. With boom conditions came painful investment errors, i.e. poor site selection and plunging marginal loss factors, severe construction lags, connection lags, system strength remediation costs (for further details, see Simshauser 2021) and market strains, as outlined in Sects. 5.7 and 5.6.

8 Concluding Remarks

This chapter overviews NEM reforms and subsequent performance. The review of industrial organisation in the NEM highlighted the reform blueprint initially designed by governments but altered by capital markets. Capital markets aligned merchant businesses through vertical integration and isolated regulated businesses from merchant businesses. The performance of the wholesale market revealed an institutional design that remained largely true to its objective function of enhancing productive, allocative, and dynamic efficiency. Its high market price cap of $15,000/MWh has ensured resource adequacy with few exceptions. The NEM and its associated forward markets could not navigate market failures related to sudden coal plant divestment and climate change policy discontinuity. Rising levels of VRE presented Australia's NEM with operational challenges. Resolution of this requires a rethink of FCAS markets and volumes to deal with rising intermittency and declining system strength and inertia as further (synchronous) coal plants exit.

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Analysis of Forecasting Models in Electricity Market Under Volatility: What We Learn from Sweden

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Abstract Understanding short-term electricity price forecasting has received considerable attention in recent years. Despite this increased interest, the literature lacks concrete consensus on the best-suited forecasting approach. This study conducts an extensive empirical analysis to evaluate the short-term price forecasting dynamics of different regions in the Swedish electricity market (SEM). We utilise several forecasting approaches ranging from standard conditional volatility models to wavelet-based forecasting. In addition, we perform out-of-sample forecasting and back-testing, and evaluate the performance of these models. Our empirical analysis indicates that the ARMA-GARCH model with the Student's t-distribution significantly outperforms other frameworks. Wavelet-based forecasting is only performed based on the mean absolute percent error (MAPE). Our results of the robust forecasting methods can display the importance of proper forecasting process design, policy implications for market efficiency, and predictability in SEM.

1 Introduction

Many countries are developing new energy policies to secure their energy systems, sustain the development of their economy, and reduce negative environmental impact. Over the past few decades, like many other European countries, Sweden, has been largely promoting renewable energy, such as wind, solar, and biomass, to produce green electricity while reducing the output from nuclear power. This affects the

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electricity price in the long run and increases its volatility in the market since the electricity production profile has been shifted from a relatively reliable mixture of nuclear and hydraulic sources to an intermittent supply using wind and solar (Tang and Rehme 2017). Therefore, understanding the short-term electricity price becomes more important for all players in the market. Furthermore, reliable forecasting is important in developing bidding strategies for electricity-generating firms alongside traders, distributional firms, and large consumers.

On the other hand, the electricity industry is becoming more complicated. Energy conservation programmes and energy efficiency improvements have changed demand. New technologies, such as batteries for electric vehicles, can extensively transform the demand pattern of electricity in the market. Other energy alternatives, such as hydrogen, also alter the demand and shift the timing of electricity demand via storage capability. On the supply side, the electricity-generating profile changes depending on the country's energy policies, which again embeds uncertainty from a long-term perspective. In addition, the electricity price typically has long- and short-term seasonal cycles. Therefore, many factors that could be interrelated could influence electricity.

Forecasting the day-ahead price is fundamental for all market participants in the increasingly competitive electricity market. Accurate forecasting of such prices enables power suppliers to adjust their bidding strategies and allows consumers to derive a plan to protect themselves against high prices. However, unlike the fundamentals of other commodities, the electricity market exhibits a unique characteristic; namely, electricity cannot be stored in significant amounts. The non-storability feature hinders the utilisation of inventories in smoothing the shocks in demand and supply, thereby resulting in increased volatility of electricity prices. Furthermore, such shocks add uncertainty to electricity prices. For instance, during periods of relatively low demand, power generators with lower marginal costs may be sufficient to accommodate demand. However, the increase in demand necessitates the use of additional generators to meet the demand deficit. Accurate forecasting may allow production houses to be better able to utilise their resources to cope with the dynamic demand from various regions.

Previous studies have used different approaches to forecast the prices of underlying assets. These approaches include (i) ordinary least squares (OLS) (Aye et al. 2015; Birkelund et al. 2015; Botterud et al. 2010; Danese and Kalchschmidt 2011; Haugom et al. 2011; Junttila et al. 2018; Mosquera-López and Nursimulu 2019; Van Donselaar et al. 2016; Weron and Zator, 2014); (ii) error correction model and cointegration (Fantazzini and Toktamysova, 2015; Kalantzis and Milonas, 2013; Mjelde and Bessler, 2009; B. Zhu et al. 2019a, b); (iii) vector autoregression (Bunn and Chen 2013; Girish et al. 2018; Junttila et al. 2018; Nakajima and Hamori 2013; Park et al. 2006); (iv) autoregressive integrated moving average (ARIMA) and generalised autoregressive conditional heteroscedasticity (GARCH)-type (Bowden and Payne 2008; Charwand et al. 2017; Ferbar Tratar et al. 2016; Furió and Chuliá 2012; Loi and Jindal 2019; Rostami-Tabar et al. 2015); (v) machine learning approaches (Lolli et al. 2017; Nikolopoulos et al. 2016; Tang and Rehme 2017; Y. Zhu et al. 2019a, b); (vi) optimisation and networks (Hasni et al. 2019; Le et al. 2019; Mirza and Bergland

2012; Tande 2003; Zhu et al. 2011); (vii) quantile smoothing (Bruzda 2019); and (viii) generalised additive models (Serinaldi 2011). Despite significant literature evaluating the forecasting accuracy of various approaches, there is no concrete consensus regarding the framework best suited to encapsulate the dynamics of the electricity markets. Therefore, we extend the previous literature by utilising a wavelet-based forecasting approach. In addition, we determine the robustness of the forecasting performance of our proposed framework by varying the window sizes.

Short-term electricity price forecasting is interesting in many aspects. Understanding the price mechanism will enhance the investment decisions of both energy sector investors and electricity users. Studies on short-term electricity price forecasting received considerable attention recently (Bowden and Payne 2008; Liu and Shi 2013). Nevertheless, the literature lacks concrete consensus on the best-suited forecasting approach to capture the dynamics of electricity markets, possibly due to the challenges mentioned. We, therefore, conduct an extensive empirical analysis to evaluate the short-term price forecasting dynamics using data from four different regions in the Swedish electricity market (SEM). More specifically, we utilise several forecasting approaches ranging from standard conditional volatility models to wavelet-based forecasting to investigate their performance and applicable conditions. In addition, we perform out-of-sample forecasting and back-testing and evaluate the performance of these models by utilising root mean squared error (rMSE) and symmetric mean absolute percent error (sMAPE). Our results could provide guidelines for policymakers, operations managers, and investors related to the electricity market.

The contribution of this study is twofold. First, to the best of our knowledge, this study is the first multi-resolution-wavelet-based decomposed series combined with OLS modelling to forecast electricity prices in the Swedish market. This is essential to capture the hierarchical structure of the original time series and obtain the optimal forecasts at all levels. Second, the expansion of renewable electricity production in Norway and Sweden has led to increased volatility in electricity prices (Serinaldi 2011; Tang and Rehme 2017). The increased employment of renewables in electricity generation further necessitates the examination of forecasting performance due to abrupt adjustments in the electricity markets.

Our empirical analysis suggests that the ARMA-GARCH models significantly outperform the other underlying models based on rMSE and MAPE. Although we utilise the Student's t-distribution to capture the prospective extreme movement, no significant improvement is gained by changing the marginal distributional framework. Furthermore, the wavelet-based forecasting framework only outperforms the MAPE framework.

The remainder of this paper is structured as follows. Section 2 overviews SEM. The methodological frameworks employed are outlined in Sect. 3. Section 4 presents the data and preliminary statistics, while Sect. 5 discusses the empirical findings of this study. Nodal pricing experiences in the ASEAN market are provided in Sect. 6. Finally, Sect. 7 presents the concluding remarks and the implications of the findings.

2 Swedish Electricity Market

The electricity market clearing price is established as the intersection between the supply curve and demand curve, which is set by the sell-bids from generator companies and buy-bids from retailers and buyers (Serinaldi 2011). This settlement price is established for the Swedish market based on Nord Pool Elspot and Elbas (Pool 2018a, b). Nord Pool Elspot is the physical market where short-term contracts are established based on short-term available generation capacity and forecasted demand for the next day. Elspot comprises hourly contracts, 12–36 h in advance every day, and is based on seller-participants' operational generation capacities and buyer-participants' demand. This price relies on several factors, such as hydro, wind, and cloud situations and the level of economic activity and temperature (Barthelmie et al. 2008; Tande 2003). Elbas is an hour-ahead market for hourly contracts where actual capacity and demand are adjusted. The final adjustment balancing is then resolved by continuous contracts and the balancing market, which is the responsibility of the transmission system operator (TSO).

On the supply side, volatility characteristics of new renewable electricity generation, such as wind and solar power, create additional challenges in balancing the electricity grid (Tande 2003; Tang and Rehme 2017). The larger the proportion of new intermittent renewables capacity installed in a power system, the more uncertainty about the electricity supply and the price (Serinaldi 2011). Therefore, a robust forecast model for electricity prices plays an increasingly important role for both sellers and buyers in the electricity market (Barthelmie et al. 2008; Bowden and Payne 2008; Serinaldi 2011).

The electricity markets are, in essence, balancing supply and demand with (i) the day-ahead balance, Elspot market; (ii) the hour-ahead balance if something occurs, Elbas market; and (iii) during operating hours, the TSO is responsible for the final balance to keep the frequency between 49.9 and 50.1 Hz. A better forecast can aid in making this balancing more efficient. Still, it can also be beneficial for other operational aspects, such as planning the maintenance of wind power or when to switch to hydrogen production instead of dispatching to the grid (Barthelmie et al. 2008; Tande 2003). Forecasts are more valuable when the balance markets are part of a competitive electricity trading system and not only treated with long-term bilateral contracts as such market provides more financial incentives to generators and dealers for accurate production forecasts (Barthelmie et al. 2008).

3 Methodology

ARMA-GARCH forecasting models can capture serial correlation both in mean and volatility equations and, therefore, provide a framework to forecast returns. Including time-dependency for returns' first and second moments enables these models to estimate and preserve the effect of positive and negative shocks. Due to autocorrelation, seasonality, and non-stationarity in electricity markets, ARMA-GARCH models are potentially suitable modelling approaches. However, the electricity markets also show non-linearity and complex behaviour that can affect forecast accuracy. Hence, wavelet analysis decomposes the original return series into details and smooths. This provides a forecasting procedure with a well-behaved decomposed series (Uddin et al. 2019; Zhang et al. 2017). We examine a wavelet-based approach for forecasting electricity market returns using multi-resolution analysis and ARMA-GARCH models.

3.1 ARMA-GARCH Forecasting Models

In ARMA-GARCH, expected returns are modelled through an autoregressive moving average process, and derived from a recursive heteroscedastic volatility process. Let $r = \{r_1, r_2, \ldots, r_T\}$ be the discrete return vector obtained from the observed electricity market prices. The mean equation based on ARMA (p, q) is given as

$$r_t = c + \sum_{i=1}^{p} \varphi_i r_{t-i} + \sum_{i=1}^{q} \theta_i \varepsilon_{t-i} + \varepsilon_t \tag{1}$$

where c is a constant term, φ_i is the coefficient of the autoregressive term and represents the effects from past observation, θ_i is the moving average term, and ε_t is the error term.

Assuming that the variance of the error term ε_t is not constant and homoscedastic, we use the standard GARCH (p, q) model, which captures time-varying conditional variance:

$$\varepsilon_t = h_t^{\frac{1}{2}} z_t$$

$$z_t \approx i.i.d.$$

$$h_t = \omega + \sum_{i=1}^{p} \alpha_i {\varepsilon^2}_{t-i} + \sum_{i=1}^{q} \beta_i h_{t-i} \tag{2}$$

where z_t is a vector of standardised residuals, h_t denotes the conditional variance at time $t \in \{1, 2, .., T\}$, with parameter restrictions, $\omega > 0$, $\alpha_i \geq 0$, $\beta_i \geq 0$ and $\sum_{i=1}^{p} \alpha_i + \sum_{i=1}^{q} \beta_i < 1$. As Engle and Bollerslev (1986) suggested, imposing $\sum_{i=1}^{p} \alpha_i + \sum_{i=1}^{q} \beta_i = 1$ results in the persistence of conditional variance forecasts in finite samples and infinite-variance unconditional distribution. This model is known as integrated GARCH (IGARCH), which enables modelling conditional forecasts with persistent shocks. Glosten et al. (1993) introduced the GJR-GARCH model, in which negative and positive shocks are assumed to be asymmetric:

$$h_t = \omega + \sum_{i=1}^{p} (\alpha_i {\varepsilon^2}_{t-i} + \gamma_i I_{t-i} {\varepsilon^2}_{t-i}) + \sum_{i=1}^{q} \beta_i h_{t-i} \tag{3}$$

where γ_i denotes the leverage parameter, and $I_{t-i} = \{0 : \varepsilon_t > 0, 1 : \varepsilon_t \leq 0\}$. Hentschel (1995) demonstrated decomposing the error terms in the variance equation. This decomposition includes different powers for the standardised residuals and conditional variance. This model is known as the family GARCH (FGARCH):

$$h_t = \omega + \sum_{i=1}^{p} \alpha_i {h^\lambda}_{t-i} [|z_{t-i} - \eta_{1i}| - \eta_{1i}(z_{t-i} - \eta_{2i})]^\delta + \sum_{i=1}^{q} \beta_i {h^\lambda}_{t-i} \tag{4}$$

where $\lambda = \delta$ results in the full FGARCH model.

Another GARCH model is the component GARCH (CGARCH) suggested by Engle and Lee (1999), which imposes the conditional variance to be driven by a permanent and transitory component. The CGARCH models short- and long-term volatility by introducing ϑ_t, a parameter that captures the permanent part of the conditional variance:

$$h_t = \vartheta_t + \sum_{i=1}^{p} \alpha_i ({\varepsilon^2}_{t-i} - \vartheta_{t-i}) + \sum_{i=1}^{q} \beta_i (h_{t-i} - \vartheta_{t-i})$$

$$\vartheta_t = \omega + \rho \vartheta_{t-1} + \phi({\varepsilon^2}_{t-i} - h_{t-i}) \tag{5}$$

where ρ is the first-order autoregressive coefficient for the time-varying intercept.

3.2 *Wavelet-Based ARMA-GARCH Forecasting Models*

To construct wavelet-based models, we combine the multi-resolution analysis (MRA) with the ARMA-GARCH models and OLS regression. The MRA is used to decompose the original time series into 'details' and 'smooths'. Utilising the ARMA-GARCH model presented in Sect. 3.1, Eqs. (1)–(4), we obtain 'first-round forecasts', including step-ahead forecasts of the original and decomposed series. Hyndman et al. (2011) and Zhang et al. (2017) suggested that each variable at different scales can be considered a linear combination of the lowest-level variables. To preserve the hierarchical structure of the original time series and obtain the optimal forecasts at all hierarchical levels, we follow Zhang et al. (2017) and regress the first-round forecasts of the series on a 'summing' matrix, which presents the linear relationship in the hierarchical structure.

Using MRA for the training sample r_t, $t \in [1, T]$, we obtain the wavelet details, $D_{j,t}$, and smooths, $S_{j,t}$. We use a maximal overlap discrete wavelet transform (MODWT) to obtain the jth level MODWT wavelet $W_{j,t}$ and scaling V_j coefficients (Durai and Bhaduri 2009) as:

$$W_{j,t} = \sum_{l=0}^{L_1 - l} \tilde{k}_{j,l} r_{t-l \text{ mod } N}$$

$$V_{j,t} = \sum_{l=0}^{L_1 - l} \tilde{g}_{j,l} r_{t-l \text{ mod } N} \tag{6}$$

$$D_{j,t} = \sum_{l=0}^{N-l} \tilde{k}_{j,l} W_{j,t+l \text{ mod } N}$$

$$S_{j,t} = \sum_{l=0}^{N-l} \tilde{g}_{j,l} V_{j,t+l \text{ mod } N} \tag{7}$$

$$r_t = \sum_{j=1}^{J} D_{j,t} + S_{j,t} \tag{8}$$

where $\tilde{k}_{j,l} = k_{j,l}/2^{j/2}$ and $\tilde{g}_{j,l} = g_{j,l}/2^{j/2}$ and denote the wavelet and scaling filters, respectively. $j \in [2, J]$ and J is the level of decomposition. We set $J = 2$ and obtain the two-level MRA-wavelet-based decomposed series, $D_{j,t}$, and $S_{j,t}$. We further use the ARMA-GARCH models presented above and obtain 'first-round forecasts' $\widehat{Y}_{T+h} = [\hat{r}_{T+h}, \widehat{D}_{1,T+h}, \widehat{D}_{2,T+h}, \widehat{S}_{1,T+h}, \widehat{S}_{2,T+h}]'$ for horizon h. Using the algorithm presented by Zhang et al. (2017), we then construct a 'summing' matrix, Z, with 0 and 1 entries, which captures the linear relationship in the hierarchical structure. Considering the base-level variables, $\beta_t = [S_{2,t},\ D_{2,t},\ D_{1,t}]'$, the linear relationship can be expressed as:

$$Y_t \equiv \begin{bmatrix} r_t \\ S_{1,t} \\ D_{1,t} \\ S_{J,t} \\ D_{J,t} \end{bmatrix} = \begin{bmatrix} S_{2,t} + D_{2,t} + D_{1,t} \\ S_{2,t} + D_{2,t} \\ D_{1,t} \\ S_{2,t} \\ D_{2,t} \end{bmatrix} = \begin{bmatrix} 1\ 1\ 1 \\ 1\ 1\ 0 \\ 0\ 0\ 1 \\ 1\ 0\ 0 \\ 0\ 1\ 0 \end{bmatrix} \begin{bmatrix} S_{2,t} \\ D_{2,t} \\ D_{1,t} \end{bmatrix} \equiv Z\beta_t \tag{9}$$

Using OLS, we regress the first-round forecasts $\widehat{Y}_{T+h} = [\hat{r}_{T+h}, \widehat{D}_{1,T+h}, \widehat{D}_{2,T+h}, \widehat{S}_{1,T+h}, \widehat{S}_{2,T+h}]'$ on the summing matrix Z. This provides optimal base-level forecasts $\tilde{\beta}_{T+h} = [\tilde{S}_{2,T+h},\ \tilde{D}_{2,T+h},\ \tilde{D}_{1,T+h}]'$. By utilising the optimal base-level forecasts from the OLS, we estimate the optimal forecasts at all hierarchical levels:

$$\tilde{Y}_{T+h} = Z\overset{\sim}{\beta}_{T+h} = \begin{bmatrix} 1\ 1\ 1 \\ 1\ 1\ 0 \\ 0\ 0\ 1 \\ 1\ 0\ 0 \\ 0\ 1\ 0 \end{bmatrix} \begin{bmatrix} \tilde{S}_{2,t} \\ \tilde{D}_{2,t} \\ \tilde{D}_{1,t} \end{bmatrix} = \begin{bmatrix} \hat{r}_{T+h} \\ \tilde{S}_{1,T+h} \\ \tilde{D}_{1,T+h} \\ \tilde{S}_{2,T+h} \\ \tilde{D}_{2,T+h} \end{bmatrix} \tag{10}$$

4 Data and Summary Statistics

This study analyses SEM data obtained from Nord Pool. The data include daily prices of four Swedish markets from 2 November 2011 to 17 October 2019, resulting in 2,076 daily returns.

The descriptive statistics of electricity market returns are presented in Table 1. The highest average return (0.012%) was reported for NP3SEAV, while the highest volatility was observed for NP4SEAV (21.07%). Both the minimum and maximum returns are reported for NP3SEAV and NP4SEAV. However, the first two markets, NP1SEAV and NP2SEAV, show lower minimum and maximum returns. All series report positive skewness except for NP2SEAV. According to positive kurtosis and the Jarque–Bera normality test results, all of the series follow a non-normal distribution.

Table 1 Descriptive statistics

	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV
Mean	0.002	0.002	0.012	0.003
Std. dev	14.235	13.973	19.278	21.068
Min	−120.91	−120.92	−183.47	−183.47
Max	102.6	102.6	233.43	238.46
Skewness	0.17	−0.07	0.62	0.51
Kurtosis	11.91	12.38	26.47	20.19
J—B	12,306***	13,297***	60,866***	35,429***
ARCH	317***	374***	206***	210***
Q(10)	131***	126***	211***	213***

Notes This table provides descriptive statistics for daily returns of four Swedish electricity markets. The total number of observations for each market is 2,076. The sample period is from 2 November 2011 to 17 October 2019. JB is the result of Jarque–Bera normality test. The test statistic for Ljung–Box Q (with 10 lags) and ARCH (with 1 lag) tests is reported

***, **, *denote significant at the 1%, 5%, and 10% level, respectively

Source Authors' estimation

The significant statistics for Engle's ARCH test with one lag indicates the existence of ARCH effects and volatility clustering for all series. Furthermore, the Ljung–Box test results with 10 lags suggest serial correlation for most of the series. These results indicate the possibility of using ARMA-GARCH models, which take advantage of existing serial correlation and ARCH effects for forecasting electricity market returns.

5 Empirical Analysis

To evaluate the performance of the forecasting models, we predict the one-step-ahead electricity market returns using rolling window estimation. We set the training sample size to 15, 30, and 50 days and forecast the market returns over the out-of-sample period. We then analyse the forecasting models using rMSE and sMAPE measures. The rMSE assumes a normal distribution for forecast errors and penalises error variance by assigning more weights to larger errors. sMAPE is a common accuracy measure when the relative error is of interest, particularly when forecasting returns, as these are relative values. Furthermore, we used paired t-tests and the Diebold–Mariano test (Diebold and Mariano 1995). The latter is used to compare wavelet-based or simple forecasting models to understand better which models are more suitable for SEM.

Since the goal of this study is to evaluate and compare wavelet-based forecasting for SEM, we consider improvements obtained from the ARMA-GARCH models based on MRA compared to benchmarks, which are simple ARMA-GARCH models. To show improvements, we obtain forecast accuracy measures (rMSE and sMAPE) for each wavelet-based and simple forecasting model and compute the corresponding percentage change. We also use autoregressive (AR) and ARMA models with lag models. For other models, we use lag 1 for GARCH and ARCH terms.

Improvements in the forecast accuracy measures are reported in Table 2. As we can see, there are gains from utilising wavelet-based decomposition in forecasting electricity markets when the rolling window size is small (e.g. 15 days). According to panel (A), all the MRA-based models outperformed the benchmarks in reducing rMSE and sMAPE. For instance, considering NP1SEAV, there is an 8.18% (6.05%) improvement (decrease) in rMSE (sMAPE). However, there are limited improvements from wavelet-based models when using longer horizon training sample sizes (30 and 50 days). In panels (B) and (C), there are improvements from MRA when using AR and ARMA models. In general, when using larger rolling window sizes and modelling the dynamics of conditional volatility with GARCH models, there are no gains from wavelet-based decomposition in forecasting SEM.

Table 3 reports the results of statistical significance in forecast accuracy improvements using the two-tailed paired t-test.

Tables 4 and 5 provide the Diebold–Mariano test results for improvements in forecasting accuracies for wavelet-based and simple models, respectively. All forecasting models significantly outperform MRA-AR(1), which indicates the benefits

Table 2 Improvements in forecast accuracy

Forecasting model	rMSE				sMAPE			
	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV
Panel (A) Window size = 15 days								
MRA-AR	2.68	2.72	3.54	2.66	1.57	1.09	1.28	1.02
MRA-ARMA	8.18	7.67	10.91	6.05	1.94	1.46	1.00	1.45
MRA-ARMA-GARCH	2.88	2.86	2.38	2.52	0.77	0.55	1.01	1.40
MRA-ARMA-IGARCH	3.02	3.19	3.28	3.15	0.20	0.06	0.87	0.39
MRA-ARMA-GJRGARCH	2.36	2.62	2.42	2.99	1.09	1.14	0.69	0.71
MRA-ARMA-FGARCH	2.89	2.90	2.26	2.00	0.79	0.51	1.17	1.61
MRA-ARMA-CSGARCH	4.87	5.78	2.25	2.92	1.04	0.82	1.32	1.00
Panel (B) Window size = 30 days								
MRA-AR	−0.97	−0.57	15.14	16.19	1.77	1.40	1.22	0.33
MRA-ARMA	1.79	2.39	22.17	21.74	0.87	0.77	1.43	0.80
MRA-ARMA-GARCH	−0.89	−0.36	15.07	9.43	−0.12	−0.02	−0.51	−0.75
MRA-ARMA-IGARCH	−0.97	−0.49	14.28	15.72	−0.68	−0.77	−0.80	−0.91
MRA-ARMA-GJRGARCH	−1.76	−1.92	−2.93	−2.65	−0.05	−0.18	−1.29	−0.37
MRA-ARMA-FGARCH	−1.65	−1.84	−1.99	−1.75	0.30	0.35	−0.71	0.17
MRA-ARMA-CSGARCH	−0.62	−0.71	−2.08	−0.18	0.21	−0.01	0.40	0.00
Panel (C) Window size = 50 days								
MRA-AR	−2.63	−3.31	−0.62	−0.79	3.97	2.78	2.86	2.70
MRA-ARMA	−1.24	−2.24	0.63	0.33	0.95	0.22	1.18	−0.26
MRA-ARMA-GARCH	−3.40	−5.24	−2.63	−2.61	−0.13	0.15	−0.47	−1.65

(continued)

Table 2 (continued)

Forecasting model	rMSE				sMAPE			
	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV
MRA-ARMA-IGARCH	−2.31	−3.92	−2.53	−2.05	−0.35	0.03	−0.04	−2.10
MRA-ARMA-GJRGARCH	−2.73	−3.77	−2.07	−2.37	−1.24	−0.34	−0.37	−2.06
MRA-ARMA-FGARCH	−3.21	−4.99	−2.44	−2.56	−0.08	0.21	−0.44	−1.69
MRA-ARMA-CSGARCH	0.49	−0.27	−1.63	−1.84	0.43	0.32	−0.27	−1.49

Note This table provides improvements in root mean squared error (rMSE) and symmetric mean absolute percentage error (sMAPE) calculated for the Sweden Electricity Market data, including daily returns. Each value represents a percentage change (reduction) in forecast accuracy from the wavelet-based forecasting model compared to its simple counterpart model. Panels A–C report the results based on 15, 30, and 50 days as training sample sizes

Source Authors' estimation/

Table 3 Paired t-test for forecast accuracy

Forecasting model	rMSE				sMAPE			
	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV
Panel (A) Window size = 15 days								
MRA-AR	1.17	1.13	1.53	1.32	2.21**	1.55	1.80*	1.46
MRA-ARMA	2.35**	2.12**	2.73***	2.71***	2.34**	1.75*	1.17	1.69*
MRA-ARMA-GARCH	2.16**	2.05**	1.51	1.65*	0.91	0.64	1.19	1.65*
MRA-ARMA-IGARCH	2.10**	2.10**	1.74*	1.79*	0.25	0.07	1.07	0.47
MRA-ARMA-GJRGARCH	1.99**	1.99**	1.06	1.42	1.27	1.29	0.81	0.82
MRA-ARMA-FGARCH	2.16**	2.08**	1.43	1.35	0.93	0.59	1.38	1.87*
MRA-ARMA-CSGARCH	2.20**	2.51**	1.37	1.779*	1.23	0.96	1.57	1.18
Panel (B) Window size = 30 days								
MRA-AR	−1.01	−0.58	0.90	0.91	2.39**	1.85*	1.66*	0.46
MRA-ARMA	1.53	1.97**	1.19	1.09	0.96	0.83	1.58	0.86
MRA-ARMA-GARCH	−0.91	−0.37	1.45	1.17	−0.13	−0.02	−0.56	−0.81
MRA-ARMA-IGARCH	−1.02	−0.53	0.99	1.02	−0.74	−0.85	−0.89	−1.00
MRA-ARMA-GJRGARCH	−1.62	−1.67*	−1.01	−1.00	−0.05	−0.19	−1.39	−0.39
MRA-ARMA-FGARCH	−1.36	−1.48	−1.47	−1.35	0.33	0.37	−0.77	0.18
MRA-ARMA-CSGARCH	−0.54	−0.68	−1.41	−0.16	0.22	-0.01	0.43	0.00
Panel (C) Window size = 50 days								
MRA-AR	−4.41***	−5.38***	−0.32	−0.49	5.10***	3.47***	3.52***	3.39***
MRA-ARMA	−1.18	−2.15**	0.28	0.17	0.98	0.23	1.24	−0.27
MRA-ARMA-GARCH	−2.22**	−3.24***	−1.93*	−2.07**	−0.14	0.16	−0.52	−1.83*

(continued)

Table 3 (continued)

Forecasting model	rMSE				sMAPE			
	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV	NP1SEAV	NP2SEAV	NP3SEAV	NP4SEAV
MRA-ARMA-IGARCH	−1.88*	−3.02***	−1.84*	−1.42	−0.38	0.03	−0.05	−2.34**
MRA-ARMA-GJRGARCH	−1.90*	−2.50**	−1.88*	−2.15**	−1.32	−0.36	−0.40	−2.27**
MRA-ARMA-FGARCH	−2.25**	−3.32***	−1.83*	−1.99**	−0.09	0.22	−0.50	−1.87*
MRA-ARMA-CSGARCH	0.50	−0.26	−1.18	−1.48	0.47	0.34	−0.30	−1.66*

Note This table provides test statistics for the difference in mean of forecast accuracy measures between simple forecasting models and wavelet-based models. For rMSE (sMAPE), the null hypothesis is the difference in mean of squared errors (absolute percentage errors) is not greater than zero

*, **, *** denote statistical significance at 10%, 5%, and 1%, respectively

Source Authors' estimation

Table 4 Diebold-Mariano test for wavelet-based models

Forecasting model	MRA-AR	MRA-ARMA	MRA-ARMA-GARCH	MRA-ARMA-IGARCH	MRA-ARMA-GJRGARCH	MRA-ARMA-FGARCH	MRA-ARMA-CSGARCH
MRA-AR	0	−1.53	−2.20	−1.41	−2.22	−2.20	−2.34
MRA-ARMA	1.53*	0	−1.06	−0.02	−1.03	− 1.05	−1.12
MRA-ARMA-GARCH	2.20**	1.06	0	1.47*	−0.72	0.04	−0.70
MRA-ARMA-IGARCH	1.41*	0.02	−1.47	0	−1.43	−1.46	−1.42
MRA-ARMA-GJRGARCH	2.22**	1.03	0.72	1.43*	0	0.72	0.07
MRA-ARMA-FGARCH	2.20**	1.05	−0.04	1.46*	−0.72	0	−0.70
MRA-ARMA-CSGARCH	2.34***	1.12	0.7	1.42*	−0.07	0.7	0

Note This table provides Diebold–Mariano test statistics for improvements of forecast errors between the forecasting model in each row and the forecasting model in each column. Results are obtained using daily returns of NP1SEAV and an estimation window of 15 days

*, **, *** denote statistical significance at 10%, 5%, and 1%, respectively

Source Authors' estimation

Table 5 Diebold-Mariano test for simple models

Forecasting model	AR	ARMA	ARMA-GARCH	ARMA-IGARCH	ARMA-GJRGARCH	ARMA-FGARCH	ARMA-CSGARCH
AR	0	−0.55	−1.94	−2.19	−2.01	−1.96	−1.78
ARMA	0.55	0	−1.68	−1.80	−1.56	−1.68	−1.51
ARMA-GARCH	1.94**	1.68**	0	0.71	0.28	−0.81	0.88
ARMA-IGARCH	2.19**	1.80**	−0.71	0	−0.37	−0.79	−0.07
ARMA-GJRGARCH	2.01**	1.56*	−0.28	0.37	0	− 0.38	0.38
ARMA-FGARCH	1.96**	1.68**	0.81	0.79	0.38	0	0.98
ARMA-CSGARCH	1.78**	1.50*	−0.88	0.07	−0.38	−0.98	0

Note This table provides Diebold-Mariano test statistics for improvements of forecast errors between the forecasting model in each row and the forecasting model in each column. Results are obtained using daily returns of NP3SEAV and an estimation window of 50 days

*, **, *** denote statistical significance at 10%, 5%, and 1%, respectively

Source Authors' estimation

of including the moving average term in the mean equation. In particular, the MRA-ARMA-CGARCH model achieves higher test statistics (2.341) and shows better outperformance of the MRA-AR than other models. This indicates the existence of permanent and transitory effects in the conditional volatility process. The results in Table 5 indicate gains from modelling the dynamics of conditional volatility using GARCH models. All simple ARMA-GARCH models perform better than the AR and ARMA models. This shows the presence of heteroscedasticity in error terms. In addition, from both Tables 4 and 5, there is not much improvement from different GARCH models. In general, these results for electricity markets indicate that the choice of variance equation does not result in a better point forecast for both wavelet-based and simple models.

To summarise, our empirical analysis reveals four aspects of forecasting SEM. First, MRA and wavelet decomposition lead to more accurate forecasts with smaller estimation windows. This result is applicable when fewer observations are available for forecasting. Second, in almost all cases, better forecasts are obtained when the dynamics of conditional volatility are included. Third, there is not much improvement in changing the GARCH models. Finally, there are differences between the four Swedish districts in forecasting 1-day-ahead electricity prices.

6 Nodal Pricing Experiences in the ASEAN Region

The ASEAN-5 context in terms of social and economic factors has changed over the past years. These socio-economic indicators, which have remarkable implications for changes in the electricity industries, mainly include rapid population growth, urbanisation, increasing per capita income, improvement of the Human Development Index, and significant growth in foreign direct investment in the industry (Vithayasrichareon et al. 2012). ASEAN countries are amongst those with a rapidly expanding electricity market. The electricity demand for household and service consumption has increased by 6% yearly over the past 20 years. Amongst 10 countries within the region, the highest electricity consumption was estimated at 26% in Indonesia, 22% in Viet Nam, 19% in Thailand, and 15% in Malaysia. To respond to this demand, the ASEAN community has developed a regional project (ASEAN Power Grid) to achieve the goals of growth and integration of renewable energy by 23% by 2025. The goal is expected to be achieved by interconnection and trade at regional and cross-border levels (International Energy Agency 2020).

There is a need for a multilateral cross-border mode in trading electricity in the ASEAN region as the current state is mostly bilateral. Compared to the European Union electricity market, the ASEAN electricity market might need to take steps towards a liberalised and more integrated electricity market. The fundamental elements to achieving an integrated market include the following (Li et al. 2020):

(1) Open access to transmission grids: As a key step to an integrated electricity market, open access to both transmission and distribution grids necessitates enforcing legal rights for suppliers and buyers.
(2) Estimation, allocation, and compensation: Coordination in estimating available cross-border capacity is a component of achieving a liberalised electricity market. A compensation mechanism, including hosting cross-border electricity flows and electricity loss costs, is another step in the electricity trade.
(3) Market coupling, splitting, and auction: A system price through which a network of various regions and nations works following a common algorithm for market transactions. This network can explore the grid constraints. In the case of price differences, the tradable transmission capacity in the markets can be estimated at the prices according to the coupled markets.
(4) Nodal pricing method: Nodal pricing is one approach to congestion management. This method provides production and energy transmission costs based on locational analysis (known as nodes). As this pricing method offers information on marginal costs, it is a stronger incentive for investors and the electricity trade (Borowski 2020; Li et al. 2020).

Although the ASEAN electricity market has its characteristics, some challenges in estimating available transmission capacity, market coupling, market compensation mechanism, and nodal pricing can be applied in the ASEAN context. More institutional support and coordination, e.g. planner and regulator groups and TSO groups, and a fundamental infrastructure plan at the ASEAN regional level with a financial fund in the electricity market are needed (Li et al. 2020).

7 Conclusion and Implications

Forecasting electricity prices is complex. Predicting the day-ahead price is essential for all market participants in the increasingly competitive electricity market. Accurate forecasting of such prices facilitates the power suppliers to modify their bidding strategies. In the meantime, it enables consumers to devise a plan to hedge themselves against high prices. The non-storability characteristic of electricity hinders the exploitation of inventories to smoothen supply and demand shocks, thereby causing increased uncertainty in electricity prices. Therefore, accurate price forecasting may enable electricity generators to optimally allocate their resources to manage the dynamic demand from various regions.

Using data from four regions in SEM, this study investigates and compares several short-term forecasting models. Our empirical analysis shows that the ARMA-GARCH models significantly outperform other frameworks when rMSE and sMAPE are used as performance measures. In addition, the wavelet-based forecasting outperforms sMAPE. The MRA-based models outperformed the benchmarks in reducing the rMSE and sMAPE in forecasting electricity prices when the rolling window size is small (e.g. 15 days). However, wavelet-based models have limited improvements with longer horizon training sample sizes (30 and 50 days).

The empirical findings are important for policymakers, power suppliers, electricity generators, and general consumers. In particular, accurate forecasting may enable power generators to offset the uncertain demand and supply from different regions, eventually leading to reduced variability of electricity prices. In addition, these findings are important regarding the stability of grids and the economic profitability of market participants. Specifically, with a better understanding of variations in electricity prices, grid operators can avoid the grid disparities exemplified by large variations in electricity prices. Improved understanding of accurate forecasting significantly contributes to the economic benefits of market agents. In addition, these findings are of significant interest to policymakers, given the increased diversion of resources towards clean energy production. An accurate forecasting framework may enable policymakers to devise a road map to integrate better grid systems and electricity prices across different regions. This may lead to reduced supply and demand disparity and eventually decrease the uncertainty in electricity prices.

As understanding and capturing the price dynamics are essential in the electricity market, our numerical results of the robust forecasting methods can display the importance of a proper forecasting process design, policy implications for market efficiency, and predictability in SEM. Nevertheless, this study only focuses on the data statistics of the electricity market. In contrast, important operational factors, such as the profile of electricity production sources and seasonal influence, are not included. A combined method will be interesting for exploring the principal factors influencing electricity prices (compare Barthelmie et al. 2008; Tande 2003). This will also be one direction for future research.

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Appendix

Table 6.

Table 6 Literature review

Authors	Data	Methods	Results
(Mosquera-López and Nursimulu 2019)	Spot and futures data of German electricity markets (Daily data from 2010 to 2017)	Linear, Non-linear, and Threshold regression	Different time-varying short- and long-run price drivers Spot market is influenced by electricity demand while the futures are impacted by gas, coal, and carbon prices
(Zhu et al. 2019a, b)	European data on carbon price, oil, coal, gas, electricity, STOXX, and GSCI (Daily data from 2009 to 2016)	Multiscale decomposition, cointegration, and Error correction model	Long-term equilibrium relationship amongst carbon, coal, electricity, and stock index At short-run, electricity and stock market significantly impact carbon market
(Kalantzis and Milonas 2013)	Electricity futures and spot prices of French and German electricity markets (Daily data between 2002 and 2011)	Bivariate VECM-GARCH model	Introduction of futures lowers the spot price volatility in France German market dominates and leads the long-run relationship
(Birkelund et al. 2015)	Implied and realised volatility Indexes in Nordic power forward market (Daily data between 2005 and 2011)	Ordinary least squares (OLS)	Positive volatility risk premium in options prices
(Nakajima and Hamori 2013)	Electricity, gas, and crude oil prices (Daily data from 2005 to 2009)	Lag-augmented VAR, Granger-causality, cross-correlation	Gas price Granger-cause electricity prices in mean
(Bunn and Chen 2013)	Electricity spot and futures (Daily data from 2007 to 2010)	MSVAR model	Undertaking various regimes is important for forecasting
(Botterud et al. 2010)	Nord pool electricity market spot and futures prices (Daily data from 1996 to 2006)	Regression analysis	Differences between supply and demand explain the short-term price variation

(continued)

Table 6 (continued)

Authors	Data	Methods	Results
(Mjelde and Bessler 2009)	US spot prices, natural gas, uranium, coal, and crude oil (Weekly data from 2001 to 2008)	Cointegration analysis	Contemporaneous peak electricity prices move natural gas prices Fuel sources market are weakly exogenous in the long-run
(Charwand et al. 2017)	Electricity retailers	SARIMA	SARIMA helps the retailer to identify procurement strategy and evaluate its policy against risk
(Van Donselaar et al. 2016)	Perishable items data from retailers	Regression analysis, moving average forecast	Modelling threshold and saturation effects lead to worse forecasting performance
(Eksoz et al. 2014)	Seasonal, perishable, promotional, and newly launched products	Conceptual framework	Forecasting strategies of manufacturers and retailers are fundamental to consensus forecasts Forecast horizon and frequency should not be neglected
(Ferbar Tratar et al. 2016)	M3-competition (quarterly and monthly)	Four-parameter exponential smoothing	Their proposed methods produces more accurate short-term out-of-sample forecast
(Loi and Jindal 2019)	Wholesale and retail electricity prices in Singapore (Daily data from 2012 to 2017)	ARIMA-GARCH	Supply competition and retail liberalisation led to a decrease in electricity prices
(Aye et al. 2015)	Aggregate retail sales (Monthly data from 1970 to 2012)	Linear and non-linear models, time recursion estimation schemes	Combination forecast models provide better forecast and is unaffected by business cycles and time horizons
(Fantazzini and Toktamysova 2015)	German car sales (Monthly data from 2001 to 2014)	Multivariate cointegration tests, VECMX, VAR, AR	Multivariate models outperformed the competing models in terms of forecast horizons

(continued)

Table 6 (continued)

Authors	Data	Methods	Results
(Ferbar Tratar 2015)	Noisy demand data	Multiplicative HW method, seasonal ARIMA	HW methods (additive and multiplicative) are appropriate for demand with trend and seasonality
(Zhu et al. 2019a, b)	SMEs' credit risk in supply chain finance (46 SMEs' and 7 enterprises data from 2014 to 2015)	Machine learning approaches	Random subspace MultiBoosting has good performance in dealing with small samples
(Nikolopoulos et al. 2016)	Supply chain sporadic demand data	Nearest neighbour approaches	Nearest neighbour approach pickup patterns in short series
(Le et al. 2019)	Case study	Optimisation model and network constraints	Model can be utilised to evaluate current and future integration
(Rostami-Tabar et al. 2015)	Demand data set of European grocery store (Weekly data of 103 observations)	IMA and SES	Increased benefit resulting from cross-sectional forecasting in a non-stationary environment
(Hasni et al. 2019)	Demand information data of 9,000 stock-keeping units (monthly data with 84 observations)	Two bootstrapping methods	Proposed adjusted methods result in a higher service-cost efficiency
(Mirza and Bergland 2012)	Wholesale electricity in the Norwegian electricity market (Weekly data from 2000 to 2010)	Partial adjustment model	Dominant retailers may be exercising power in retail electricity market
(Furió and Chuliá 2012)	Spanish electricity, crude oil, natural gas forward market	VECM-MGARCH	Crude oil and natural gas forward prices play a prominent role in Spanish electricity price Causation flow from crude oil and natural gas forward markets to the Spanish electricity forward market

(continued)

Table 6 (continued)

Authors	Data	Methods	Results
(Park et al. 2006)	11 US spot market electricity prices (Daily data between 1998 and 2002)	VAR	Time-varying relationship amongst assets The separations amongst markets disappear in longer time-frames
(Junttila et al. 2018)	Finnish electricity futures (Monthly data from 2006 to 2016)	OLS, VAR, Granger-causality	Significant positive excess futures premium in the Finnish market Speculative and hedging-based strategy is increasing in the Nordic markets
(Bruzda 2019)	Monthly, quarterly, and annual sales data from M3 forecast competition	Quantile smoothing	Suggested procedure leads to better quantile forecast of logistic data Conditional median and mean modelling able to provide best forecasting in time series data
(Haugom et al. 2011)	Daily data of Nord pool electricity forward market	OLS	Strong degree of persistence in realised volatility and significant impact of market measure in predicting
(Weron and Zator 2014)	Spot and futures prices in the Nord Pool electricity market (Weekly data from 1998 to 2010)	Regression models with GARCH residuals	Impact of water reservoir level on the risk premium is positive
(Zhu et al. 2011)	Single selling season manufacturers	Different forecast scenarios	Forecast accuracy is costly
(Lolli et al. 2017)	Intermittent demand forecasting	Single-layer neural network	Employed framework provides superior performance in terms of back-propagation Forecast accuracy of models doubled with augmentation of increased frequency horizons

(continued)

Table 6 (continued)

Authors	Data	Methods	Results
(Girish et al. 2018)	Spot electricity prices in Indian electricity sector (Hourly price data from 2014 to 2015)	Granger causality and VAR model	No causality exists amongst the electricity markets Short- and long-run causality between peak and off-peak price
(Serinaldi 2011)	Electricity markets (CalPX and IPEX)	GAMLSS	GAMLSS framework is a flexible alternative to various linear and nonlinear stochastic models
(Tang and Rehme 2017)	Swedish electricity industry	System dynamic approach	Complex and nonlinear interaction of various factors in electricity sector Energy policy should incorporate incentives of renewables with other decisions
(Bowden and Payne 2008)	MISO hubs	ARIMA-EGARCH	Model demonstrates the presence of an inverse leverage effect in electricity prices ARIMA-EGARCH-M outperforms in terms of out-of-sample forecasting performance
(Tande 2003)	Wind farms	Grid integration	Use of reactive compensation may relax the short-term voltage and allow integration of wind power
(Danese and Kalchschmidt 2011)	343 manufacturing firms from 6 different regions	Hierarchical regression	Structured forecasting process can improve operational performance

Notes Generalized Autoregressive Conditional Heteroscedasticity (GARCH), Vector Error Correction Model (VECM), Markov Switching Vector Autoregressive (MSVAR), Seasonal Autoregressive Integrated Moving Average (SARIMA), Non-stationary Integrated Moving Average (IMA), Single Exponential Smoothing (SES), Generalized Additive Models for Location, Shape, and Scale (GAMLSS), California Power Exchange (CalPX), Italian Power Exchange (IPEX), Midwest Independent System Operator (MISO)

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Modelling and Forecasting the Volatility of the Nordic Power Market: An Application of the GARCH-Jump Process

Anupam Dutta

Abstract Although extreme jumps in electricity prices are a common phenomenon, investigating the jump behaviour in the power market does not receive significant attention in earlier studies. The present study aims to conceal this void in the existing literature. To do so, we employ the autoregressive conditional jump intensity (ARJI) model, combined with the generalised autoregressive conditional heteroskedasticity (GRACH) method, to describe the volatility process and the jump behaviour in Nordic electricity prices. The empirical findings reveal that the Nordic power market is highly volatile, and time-varying jumps exist in the electricity prices. In addition, the GARCH-jump models produce more accurate out-of-sample volatility forecasts than the GARCH and EGARCH models. In summary, the results demonstrate that energy economists, energy policymakers, and market analysts should consider the existence of time-varying jumps in the Nordic power market because the GARCH-jump model provides the best forecasts for electricity prices.

Keywords Nordic power market · GARCH-jump model · Time-varying jumps · Outliers · Volatility forecasts

JEL Classifications C5 · Q4

1 Introduction

Over the last few decades, electricity price forecasting has received much attention in the literature. This is because accurate price forecasting is crucial for bidding strategies, making proper investment decisions, and hedging against risks (Zhang and Tan 2013). Besides, consumers can also use price forecasting to develop appropriate power purchasing schemes for utility maximisation (Pindoriya et al. 2008). Therefore, many studies have employed several alternative approaches to forecasting electricity prices more precisely.

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Notably, modelling the volatility of electricity prices has recently received particular attention amongst academics, given that understanding the volatility of the power market plays a crucial role in policymaking. Kostrzewski and Kostrzewska (2019) adopted a Bayesian process to model the volatility of Pennsylvania-Jersey-Maryland (PJM) electricity markets. The study shows that the employed approach is a promising tool for modelling and forecasting electricity prices. Ciarreta et al. (2020) conducted an empirical analysis of Spanish electricity price volatility. The authors detected two important structural breaks linked to key measures related to renewable electricity: (i) the abolishment of the feed-in tariff scheme and (ii) the establishment of a more market-oriented regulation based on investment and operating costs. Do et al. (2020) explored the volatility linkage between the Irish and Great Britain electricity markets and how it is driven by changes in energy policy, institutional structures, and political ideologies. The study concludes that the magnitude of the good volatility connectedness is marginally larger than that of the bad volatility connectedness. In addition, Han et al. (2020) investigated the volatility connectedness across different regions in the Australian national electricity market to shed light on the transmission of risks in a multi-regional context. The authors documented that volatility spillovers are typically more pronounced between physically interconnected markets.

It is worth mentioning that recent studies on electricity price volatility have been dominated by time series models and artificial neural networks (Shrivastava and Panigrahi 2014). Although these models provide accurate predictions for short-term electricity price forecasting, they cannot capture extreme jumps that frequently occur in electricity prices (Cifter 2013).

Due to the large price jumps detected in electricity markets, several researchers considered jump components in electricity price models. Notable contributions include Kaminski (1997), Clewlow and Strickland (2000), Deng (2000), Huisman and Mahieu (2003), Knittel et al. (2005), Seifert and Uhrig-Homburg (2007), Chan et al. (2008), Ullrich (2012), and Cifter (2013). These studies, in general, recommended the application of jump approaches while modelling and forecasting the volatility of electricity markets. For example, Huisman and Mahieu (2003) claimed that employing such models characterises the frequent extreme jumps in electricity prices and outperforms the standard time series or artificial neural network models. Moreover, while analysing and predicting the German electricity price index, Seifert and Uhrig-Homburg (2007) discussed why jumps are observed in the power market. The authors argued that power plant or supply line outages could lead to short or long price impacts, depending on the severity and length of the outage. In addition, unexpected strong changes in weather could cause price spikes, while extreme weather situations could result in volatile and jumpy price periods due to a high load level. Therefore, it is crucial to use a model that can capture both volatility dynamics and jump behaviour of electricity prices to measure future volatility more closely.

Note that several recent studies (Daskalakis and Markellos 2009; Wimschulte 2010; Nomikos and Soldatos 2010a, b; Cifter 2013; Dong et al. 2019) focused on the price and volatility dynamics of the Nordic power market. This market has received ample attention over the past decades as Nord Pool is one of the world's most successful deregulated power markets. It has a very liquid derivatives market as well. Studies including Nomikos and Soldatos (2010a) and Vaissalo (2021) claimed that the Nordic electricity market is amongst the most efficient regional electricity markets in the world. Since the establishment of the Nord Pool market in the early 1990s, security of supply has been at a very high level, and electricity prices in the Nordic wholesale market have been historically amongst the lowest in Europe. In terms of power generation capacity, there is no lack of electricity supply in the Nordic market.[1] We thus study this market as one of the leading electrical power suppliers in Europe.

Notably, many recent papers shed light on the importance of detecting jumps in power markets. Nomikos and Soldatos (2010b), for instance, argued that electricity prices exhibit very high volatility, and large jumps represent the main feature of power markets. Such jumps and spikes are extreme short-lived price movements in the spot market due to load fluctuations and generating outages or transmission failures. Therefore, it is essential to use a volatility model to also capture jumps. Cifter (2013) also showed that the Markov-switching GARCH (generalised autoregressive conditional heteroskedasticity) model, which also considers jumps, performs better than the traditional GARCH models. More recently, Dong et al. (2019) employed a non-parametric model to study the volatility and jump dynamics of electricity prices in Denmark and Sweden. The findings indicate that electricity prices are more stable in Swedish price areas as hydropower is a more stable energy source.

It is also noteworthy that Nordic countries usually have longer winters and relatively colder summers, which leads to different demand-side patterns (Dong et al. 2019). Besides, the substantial use of renewable energy in the electricity generation process tends to significantly impact the variation of electricity prices. These characteristics of price movements may introduce large jumps in Nordic power prices, which need to be captured for managing risk more precisely so that future electricity prices can be predicted correctly.

In this study, unlike the earlier researchers, we employ the autoregressive conditional jump intensity (ARJI) model, combined with the GARCH method, to simultaneously capture the volatility process and the jump behaviour in Nordic electric power market prices. The GARCH-jump approach, proposed by Chan and Maheu (2002), is considered advantageous. Contrasting the traditional GARCH models can capture the impact of extreme news or abnormal information emerging from crashes, terrorist attacks, and similar other events (Fowowe 2013). Moreover, in addition to accounting for smooth persistent changes in volatility, the model also captures the discrete jumps in the underlying price series. Since modelling jumps in electricity prices are crucial to understanding future price risks, our study contributes to the scarce literature by further unfolding the jump behaviour in the power market.

The rest of the study will proceed as follows. The next section briefly overviews the Nordic electricity markets. Section 3 describes the data considered in our empirical analysis. Section 4 outlines the GARCH-jump models. Results are discussed in Sect. 5. Finally, Sect. 6 concludes the paper.

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[1] The information is sourced from Fortum Energy Review, November (2016).

2 Nordic Electricity Markets

Nordic power markets have one dominating exchange for energy, called Nord Pool. Nord Pool is one of the oldest marketplaces for electricity in the world. The market covers most of Europe as market operators from 20 different countries participate in it.

The Nordic power system appears to be a mixture of generation sources. Electricity is mainly produced from hydro, nuclear, and wind power in this market. The Nordic region has several energy-intensive industries and a large share of electric-heated houses. Accordingly, the electricity consumption in this part of the world is higher than in the rest of the European Union (EU). Growth in electricity consumption greatly depends on weather conditions. For instance, lower electricity demand is observed during the summer, while demand grows significantly in wintertime. The Nordic countries have a higher share of clean energy production than the rest of the EU. Hydropower accounts for more than 50% of the electricity production in this region. The Nordic power industry contains several markets that are 'time windows' for physical trading in electricity: the day-ahead, intraday, and balancing markets. In this zone, trading is performed mainly on the day-ahead market (spot market). The 'system price', the common Nordic price for all hours of the next 24-h period, is crucial for price formation within the other time windows (the intraday and balancing markets and the financial market for long-term contracts). The intraday market is primarily a correction market, where actors have the opportunity to trade into balance, including adjusting any earlier trading if the forecasts turn out to be wrong. The intraday market closes 1 h before the delivery hour. The balancing market is trading in automatic and manual reserves used by the Nordic transmission system operators (TSOs) to maintain power balance during the hour of operation. Nord Pool Spot is responsible for the day-ahead and intraday markets, while the TSOs are responsible for the balancing market.[2]

The Nordic countries deregulated their power markets in the early 1990s and brought their markets together into a common Nordic market.[3] Estonia, Latvia, and Lithuania deregulated their power markets and joined the Nord Pool market in 2010–2013. Since the deregulation, the Nordic electricity market has continued to inflate; today, it is the main electricity marketplace in 13 countries. Moreover, Nord Pool also provides electricity for Belgium, Germany, the Netherlands, Luxemburg, France, and the United Kingdom. Altogether, trading in the Nord Pool region includes 360 companies in 20 countries. The overall volume of electricity traded in the exchange was 494 TWh in 2019 (Nord Pool 2021). Integration of the Nordic market to other European markets continues via new grid investments and improved congestion

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[2] The information is sourced from www.nordicenergyregulators.org.

[3] The term 'deregulation' means that the state is no longer running the power market; instead, free competition is introduced. Deregulation is undertaken to create a more efficient market, with exchange of power between countries and increased security of supply. Available power capacity can be used more efficiently in a large region than in a small one, and integrated markets enhance productivity and improve efficiency (for more details, see www.nordpoolgroup.com).

management. The emissions trading system also contributes to such integration. European-level market liberalisation and integration continue.

Nordic countries, including Finland, Sweden, Norway, and Denmark, accounted for 401 TWh generation out of the total 494 TWh traded in the Nord Pool power exchange during 2019. Figure 1 illustrates how the power production mixes in these countries are constructed in the corresponding year. In this region, hydropower appears to be the dominant method of energy production. In Norway, for instance, hydro generation accounts for 93% of all electricity. Wind power, the other popular production method, contributes to 35% of power production in Finland and 40% in Sweden. The volume of wind power has grown substantially over recent years; currently, it is used to generate a significant proportion to match the energy demand in the Nordic region. As evident from Fig. 1, countries in Nord Pool already rely on production methods capable of generating electricity without or with only low-carbon emissions (Vaissalo 2021).

It is noteworthy that the Nordic power industry uses financial contracts for price hedging and risk management. These contracts have a time horizon of up to 10 years and cover daily, weekly, monthly, quarterly, and annual contracts. The system price calculated by Nord Pool is considered the reference price for the financial market in the Nordic region. There is no physical delivery for financial power market contracts. Instead, cash settlement takes place throughout trading and/or the delivery period, starting from the due date of each contract, depending on whether the product is a future.

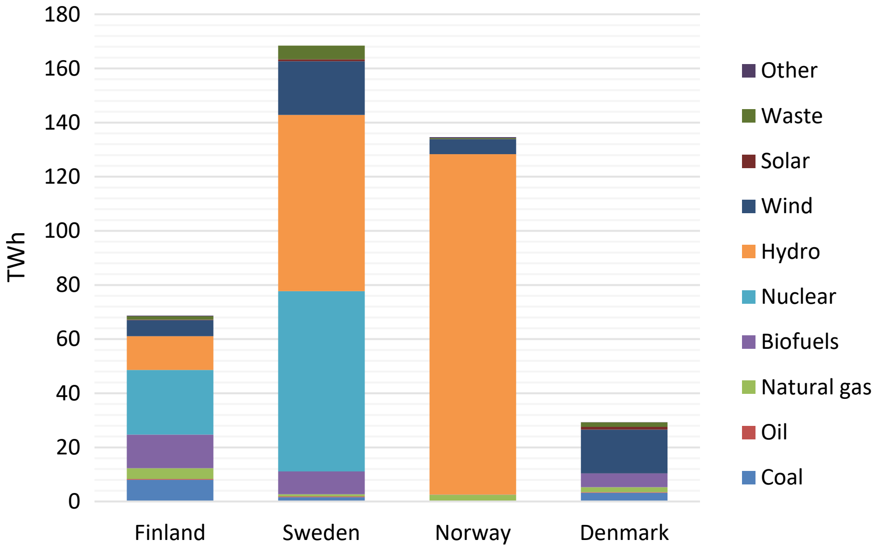

Fig. 1 Electricity production mix in Nordic countries. *Source* Vaissalo (2021)

Table 1 Descriptive statistics and unit root test results

	Logarithmic difference ($R_t = \ln(P_t / P_{t-1})$)
Mean	0.000051
Standard deviation	0.051467
Skewness	0.655886
Kurtosis	11.890430
Jarque–Bera test	4912.931***
ADF test	−10.60210***
PP test	−54.17813***

Notes *** indicates statistical significance at 1% level
Source Author's own calculations

3 Data

The data used in this study have been sourced from the website of the Nordic power market.[4] This database reports intraday, daily, quarterly, and annual power prices. We consider daily spot prices since the GARCH-type models are mainly appropriate for daily frequency (Cifter 2013). Our sample period started on 1 January 2013 and ended on 31 December 2020. The beginning of our sample period depends on the availability of the data.

Table 1 displays the descriptive statistics and unit root test results for the return series. The findings show that the data are positively skewed and leptokurtic. The Jarque–Bera test further confirms that the electricity prices do not follow the normal distribution; hence, the volatility models should be estimated with non-normal distributions (e.g. t-distribution). While assessing the stationary property of the data used, the augmented Dickey–Fuller and the Philips–Perron tests suggest that the return series does not contain a unit root.

4 Methodology

The GARCH-jump model has recently received ample attention from academics across the globe. Some fresh evidence includes Dutta et al. (2017), Xiao and Zhou (2018), Zhang et al. (2018), Zhou et al. (2019), Chiang et al. (2019), Gronwald (2019), and Dutta et al. (2020). While all these studies mainly investigated the occurrence of jumps in stock and commodity prices, this paper examines such events in electricity prices. This process takes the following form[5]:

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[4] The data are retrieved from https://www.nordpoolgroup.com/.

[5] Selection of the mean and variance equations is based on the Akaike Information criterion (AIC) and Bayesian Information criterion (BIC). We first estimate the AR(1)-GARCH(1,1) model. In

$$R_t = \pi + \mu_1 R_{t-1} + \mu_2 R_{t-2} + \epsilon_t \tag{1}$$

where R_t is the log return of electricity prices at time t and ϵ_t refers to the error term at time t, which has two components as follows:

$$\epsilon_t = \epsilon_{1t} + \epsilon_{2t} \tag{2}$$

The first component ϵ_{1t} is a mean-zero innovation with a normal stochastic process assuming the following form:

$$\epsilon_{1t} = \sqrt{h_t} z_t,\ z_t \sim NID(0, 1)$$

$$h_t = \omega + \alpha\epsilon_{1t-1}^2 + \beta h_{t-1} \tag{3}$$

The second component ϵ_{2t} is a jump innovation consisting of abnormal price movements with $E(\epsilon_{2t}|I_{t-1}) = 0$, where I_{t-1} designates the information set. Now ϵ_{2t} is defined as the discrepancy between the jump component and the expected total jump size between t-1 and t:

$$\epsilon_{2t} = \sum_{l=1}^{n_t} U_{tl} - \theta\lambda_t \tag{4}$$

where U_{tl} denotes the jump size and is assumed to be normally distributed with mean θ and variance d^2, $\sum_{l=1}^{n_t} U_{tl}$ is the jump component, and n_t defines the number of jumps. It is assumed that n_t is distributed as a Poisson variable with an ARJI given by

$$\lambda_t = \lambda_0 + \rho\lambda_{t-1} + \gamma\xi_{t-1} \tag{5}$$

where λ_t is the time-varying conditional jump intensity parameter and $\lambda_t > 0$, $\lambda_0 > 0$, $\rho > 0$ and $\gamma > 0$.

Now the log-likelihood function can be expressed as:

$$L(\Omega) = \sum_{t=1}^{T} \log f(R_t|I_{t-1}; \Omega)$$

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addition, several alternative models are also considered. These include AR(2)-GARCH(1,1), AR(3)-GARCH(1,1), AR(2)-GARCH(2,1), AR(2)-GARCH(2,2), amongst others. But based on AIC and BIC statistics, we finally choose the AR(2)-GARCH(1,1) model as it produces the lowest values for AIC and BIC. Once the appropriate lags have been identified, we test for the autocorrelation amongst the residuals to verify whether the selected model is correctly fitted.

where $\Omega = (\pi, \mu_1, \mu_2, \delta, \omega, \alpha, \beta, \theta, d, \lambda_0, \rho, \gamma)$.

Moreover, for robustness checking, the constant jump intensity model (Jorion 1988) is also estimated in addition to the ARJI approach. The constant jump intensity model simply assumes that $\lambda_t = \lambda_0$.

5 Empirical Results

5.1 *Results of the GARCH-Jump Models*

Table 2 exhibits the results of constant jump process and the ARJI model These findings indicate that the GARCH parameters are statistically significant at a 1% level, suggesting the existence of strong ARCH and GARCH effects. The sum of α and β also reveals a high degree of persistence in the price fluctuations.

Table 2 Results of GARCH-jump models

Variable	Constant jump intensity model	ARJI
π	−0.0007 (0.47)	−0.0014** (0.03)
μ_1	0.0235 (0.38)	0.0276 (0.17)
μ_2	−0.2714*** (0.00)	−0.2669*** (0.00)
ω	1.4×10^{-8} (0.99)	0.00001 (0.42)
α	0.1613*** (0.00)	0.1659*** (0.00)
β	0.7922*** (0.00)	0.7931*** (0.00)
θ	0.0041 (0.15)	0.0058*** (0.00)
d^2	−0.0360*** (0.00)	−0.0338*** (0.00)
λ_0	0.3401** (0.02)	0.1008*** (0.00)
ρ		0.7154*** (0.00)
γ		0.1448*** (0.00)
Log likelihood	2746.1506	2749.4637

Notes The values in the parentheses indicate the *p*-values. *** and ** imply significance at 1% and 5% levels, respectively

Source Author's own calculations

It is also evident from Table 2 that the jump parameters are all significant, implying that jumps do exist in the Nordic electricity market returns, and they are time-varying. The positive coefficient of the jump mean indicates that the jump behaviour driven by abnormal information has a positive impact on returns. In contrast, the negative coefficient of the jump variance infers that volatility driven by abnormal information negatively affects the volatility of returns (Fowowe 2013; Dutta et al. 2017). The results further document that all the jump intensity parameters (λ_0, ρ, γ) are also statistically significant, suggesting that the jump intensity varies over time. For instance, the ρ parameter, which provides a measure of persistence in the conditional jump intensity, is estimated to be 0.7154, implying that a high probability of many (few) jumps today tends to be followed by a high probability of many (few) jumps tomorrow, as documented by Chan and Maheu (2002). In addition, the γ parameter, which measures the sensitivity of λ_t to the past shock, ξ_{t-1}, appears to be 0.1448, indicating a unit increase in ξ_{t-1} results in a dampened effect (0.14) on the next period's jump intensity (Chan and Maheu 2002).

Additionally, these parameters satisfy the constraints that $\lambda_0 > 0$, $\rho > 0$ and $\gamma > 0$; hence. we can infer that the GARCH-ARJI model is a proper choice for describing the jump behaviour in the electricity market returns. Furthermore, the positive ρ and γ indicate that the current jump intensity (λ_t) is affected by the most recent jump intensity (λ_{t-1}) and intensity residuals (ξ_{t-1}). We also report that the high values of ρ and γ suggest a high degree of persistence in the jump intensity.

Moreover, the supremacy of the jump models is also evidenced by both the standard information criteria and the likelihood ratio test (see Table 3). The findings confirm that each jump model outperforms the traditional GARCH models

Table 3 Model performance

Model selection criteria				
Criterion	GARCH	EGARCH	Constant jump intensity (CJI)	ARJI
Log likelihood	2719.08	2722.30	2746.15	2749.46
AIC	−3.7202	−3.7233	−3.7321	−3.7483
BIC	−3.6949	−3.6943	−3.7009	−3.7113
HQ	−3.7108	−3.7124	−3.7200	−3.7216
Likelihood ratio test				
CJI versus GARCH			54.14***	
CJI versus EGARCH			47.70***	
CJI versus ARJI				6.62***
ARJI versus GARCH				60.76***
ARJI versus EGARCH				54.32***

Notes *** indicates statistical significance at 1% level
Source Author's own calculations

as benchmarks.[6] Further, the ARJI model surpasses the constant intensity jump model, which, in turn, implies that the jump intensity is time dependent. To sum up, the GARCH-ARJI model provides the best fit for the electricity price series under investigation.

5.2 Out-of-Sample Forecast Results

We now evaluate the forecast performance of various models considered in our empirical analysis. We choose the in-sample estimation period from 1 January 2013 to 31 December 2019 and the out-of-sample forecast period from 1 January 2020 to 31 December 2020. The following loss functions are used in our investigation:

$$\text{Mean Square Error: } MSE = \frac{1}{n}\sum_{i=1}^{n}\left(\sigma_{a,t}^{2} - \sigma_{f,t}^{2}\right)^{2}$$

$$\text{Mean Absolute Error: } MAE = \frac{1}{n}\sum_{i=1}^{n}\left|\sigma_{a,t}^{2} - \sigma_{f,t}^{2}\right|$$

where n indicates the number of forecast data points, $\sigma_{a,t}^{2}$ signifies the actual volatility on day t, and $\sigma_{f,t}^{2}$ denotes the volatility forecast for day t. The actual volatility is defined as the squared daily returns.

Table 4 exhibits the 1-day ahead forecasting performance of different models. These outcomes support that in each case, the GARCH-ARJI model evidences a superior volatility forecasting ability by producing the lowest values for both mean squared error (MSE) and mean absolute error (MAE) statistics. It is also noteworthy

Table 4 Out-of-sample forecasts

	MSE	DM tests	MAE	DM tests
GARCH	0.000063	2.85**	0.003074	4.67**
EGARCH	0.000065	3.09**	0.002983	3.59**
CJI	0.000061	1.79*	0.002768	2.41**
ARJI	0.000059		0.002711	

Notes ** and * imply significance at 5 and 10% levels, respectively. DM indicates the Diebold and Mariano test

Source Author's own calculations

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[6] We consider the GARCH (1,1) and EGARCH (1,1) approaches in our analysis as the benchmark models. These models are defined as follows:

GARCH (1,1): $h_t = \omega + \alpha\varepsilon_{t-1}^{2} + \beta h_{t-1}$, where $\omega > 0$, $\alpha \geq 0$, $\beta \geq 0$ and $\gamma \geq 0$ to guarantee the positivity of h_t.

EGARCH (1,1): $\ln(h_t) = c + \frac{a|\varepsilon_{t-1}| + v\varepsilon_{t-1}}{\sqrt{h_{t-1}}} + b\ln(h_{t-1})$.

that the constant jump model has emerged as the second-best model, confirming that while predicting the Nordic power market price series, all the employed jump approaches outperform the standard GARCH models. The Diebold and Mariano test (1995) further confirms that the ARJI model performs better than others.

5.3 *Additional Tests*

In this section, we conduct additional tests to examine further if the ARJI model produces better volatility forecasts than other approaches. In particular, we estimate the Mincer and Zarnowitz (MZ) (1969) regression model to serve our purpose. The MZ regression is specified as

$$Vol_t = \varphi_0 + \varphi_1 \widehat{Vol_t} + \epsilon_t \tag{6}$$

where Vol_t and $\widehat{Vol_t}$ indicate the true volatility and volatility forecast for day t, respectively. Our objective is to compute the coefficient of determination (i.e. R^2) to find the best forecast model.

We present these R^2 (%) values in Table 5. We find that the ARJI model (26%) generates the highest R^2 values, with the constant jump intensity (CJI) process (22%) being the second-best model. Moreover, of the traditional GARCH models, the asymmetric GARCH or EGARCH process excels its symmetric counterpart. In sum, we document that the ARJI model appears to be the best forecast model followed by the CJI process. We, therefore, conclude that the information content of time-varying jumps is important for forecasting the volatility of Nordic power markets.

5.4 *Jumps and Outliers*

It is important to note that several studies had investigated the volatility dynamics of the Nordic electricity market using GARCH-type models without correcting for potential outliers. However, several researchers argue that outliers can affect the identification and estimation of the GARCH-type models. Such outliers can wrongly suggest conditional heteroscedasticity or hide true heteroscedasticity (Charles and Darné 2005; Carnero et al. 2007, 2012; Catalán and Trívez 2007; Charles 2008).

Table 5 The Mincer and Zarnowitz (MZ) regression results

Models →	GARCH	EGARCH	CJI	ARJI
R^2(%)	16.53%	18.91%	22.38%	26.84%

Notes The R^2 values are obtained from the Mincer and Zarnowitz (MZ) regression
Source Author's own calculations

Therefore, it is of paramount importance for practitioners to use outlier-free data to estimate the volatility of financial markets (Dutta 2018a). In addition, it is also stimulating to examine if time-dependent jumps exist even after correcting for outliers. Given that the significance of outliers and time-varying jumps in the Nordic power market does not receive considerable attention in earlier studies, this empirical research adds a new dimension to the standing literature.

In this study, we follow Ané et al. (2008) in detecting the presence of outliers. Let R_t be the log return on the electricity price index on day t, which follows an AR(2)-GARCH(1,1) model:

$$R_t = b_0 + b_1 R_{t-1} + b_1 R_{t-2} + \varepsilon_t \tag{7}$$

$$\sigma_t^2 = a_0 + a_1 \varepsilon_{t-1}^2 + a_2 \sigma_{t-1}^2 \tag{8}$$

where $\varepsilon_t = \sigma_t z_t$ with z_t being an i.i.d. process such as $z_t / I_{t-1} \sim IIN(0, 1)$; I_{t-1} refers to the filtration of information at time $t - 1$.

R_{t+1} is considered an outlier if it does not belong to the following interval:

$$R_{t+1} \in [R_{t,t+1} \pm F(1 - \frac{\alpha}{2})\sigma_{t,t+1}]$$

where $R_{t,t+1}$ is the one-step ahead return forecast given by:

$$R_{t,t+1} = E(R_{t+1}/I_t) = b_0 + b_1 R_t + b_2 R_{t-1}$$

and $\sigma_{t,t+1}^2$ denotes the one-step ahead variance forecast defined as:

$$\sigma_{t,t+1}^2 = \mathrm{var}(R_{t+1}/I_t) = a_0 + (a_1 + a_2)\sigma_t^2$$

Furthermore, $F\left(1 - \frac{\alpha}{2}\right) = P(z_t \leq 1 - \alpha/2)$ is a fractile of the assumed conditional distribution.

The above detection procedure is rolled over until the end of the sample period. Notably, the detection procedure is robust to any model misspecifications (Ané et al., 2008). Several recent studies have employed this process to identify outliers in different financial markets. Dutta (2018a), for example, documented that outliers play a crucial role in modelling the volatility of the European Union emission market. Another study by Dutta (2018b) obtained similar results for various precious and industrial metal markets. Other important studies included Chen et al. (2010), Dai et al. (2012), Behmiri and Manera (2015), Chatzikonstanti (2017), and Chatzikonstanti and Karoglou (2020). All these papers find this approach, developed by Ané et al. (2008), suitable while identifying possible outliers or extreme observations in stock and commodity markets.

Table 6 Results of GARCH-jump models after correcting for outliers

Variable	Constant jump intensity model	ARJI
π	−0.0012 (0.35)	−0.0006* (0.07)
μ_1	0.0469 (0.13)	0.0099 (0.24)
μ_2	−0.2551*** (0.00)	−0.2988*** (0.00)
ω	0.0002 (0.82)	0.0007 (0.31)
α	0.1476*** (0.00)	0.1200*** (0.00)
β	0.7522*** (0.00)	0.7765*** (0.00)
θ	0.0025 (0.12)	0.0021 (0.11)
d^2	−0.0431*** (0.00)	−0.0402*** (0.00)
λ_0	0.3253** (0.03)	0.0962*** (0.00)
ρ		0.7256*** (0.00)
γ		0.1843*** (0.00)
Log likelihood	2721.2801	2700.7234

Notes This table presents the results of GARCH-jump models after correcting for outliers. Both the CJI and ARJI models were considered in this analysis. The values in the parentheses indicate the *p*-values

*** and ** imply significance at 1% and 5% levels, respectively

Source Author's own calculations

The findings from the outlier detection process suggest that extreme observations occur in the Nordic electricity prices. Overall, we have found 11 outliers during the sample period. We also document that these outliers are mainly present after the soar.

Next, Table 6 presents the results of GARCH-jump models after correcting for outliers. We consider both the constant jump intensity and ARJI models in our analysis. The findings show that most of these jump parameters appear significant even after utilising the outlier-free data. These findings clearly evidence that outliers and time-varying jumps play a key role in modelling the volatility or risk of the Nordic electricity price index. Nevertheless, assessing the significance of outliers and time-varying jumps in this power market has received little or no attention in prior research. Our empirical analysis aims to fill this void in the existing literature.

6 Conclusion

Although the extreme jumps in electricity prices are a common phenomenon, investigating the jump behaviour in the power market does not receive significant attention in earlier studies. This study aims to conceal this void in the existing literature. To serve our purpose, we consider using the ARJI model, combined with the GARCH method, to describe the volatility process and jump behaviour in Nordic electricity prices.

The key findings of our research are the following. First, the GARCH parameters are found to be statistically significant at a 1% level, indicating that the Nordic power market is highly volatile. Second, jumps do exist in the electricity prices, and they are time-varying. Third, the standard information criteria and the likelihood ratio test confirm that the jump models outperform the traditional GARCH models. Finally, the GARCH-jump models generate more accurate out-of-sample volatility forecasts than the GARCH and EGARCH models. It is also important to note that we find outliers in electricity prices, and more importantly, the jumps occur even after correcting for such outliers. Thus, these findings suggest that the Nordic power market is characterised by time-varying volatility and extreme price movements, which exceed the current market volatility. Such jump behaviour points towards an unstable condition in the market; hence, the information on electricity prices could mislead investment decisions. On the whole, our findings suggest that energy economists, energy policymakers, and market analysts should consider the presence of time-varying jumps in the Nordic power market, given that the GARCH-jump approach provides the best forecasts for electricity prices.

Note that the stable price of electricity in the Nordic region could be attributed to the fact that these markets make significant use of renewable energies for producing electricity. The high percentage of wind power generation, for example, can cover most of the total demand for electricity in this region (Dong et al. 2019). However, as wind power production may vary second by second depending on the meteorological conditions, electricity prices tend to experience hourly jumps. It is thus important to use the appropriate econometric models for capturing such jumps in the Nordic electricity markets. Besides, a proper choice of econometric models will also allow policymakers to comprehend the dynamics of the risk premium. Such knowledge is essential, given that understanding the frequent changes in the risk premium behaviour plays a major role in designing the optimal hedging strategies for investors and policymakers since the cost of hedging is substantially affected by the time the hedge is created (Gudkov and Ignatieva 2021). Depending on the complexity of the contracts and the adopted hedging strategy, the precise use of derivatives would also help market participants hedge the potential risk significantly.

Moreover, few earlier works (Schlueter 2010; Cifter 2013) documented that electricity prices exhibit asymmetric characteristics. Further research may include the application of asymmetric GARCH-jump models to forecast the electricity price volatility more accurately. In addition, future studies could also examine whether key relevant factors such as crude oil prices, emission allowances, or prices of renewables can predict these time-varying jumps.

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An Econometric Assessment of the Effects of Electricity Market Reform on Bangladesh Economy

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Abstract The supply of reliable and affordable electricity has become imperative in most production and household activities in modern society. No country has progressed after subsistence extent without guaranteeing the least electricity level. Many developing and emerging countries have started implementing reform initiatives around the electricity market since the 1990s. The major developments in reforming countries are structural changes and privatisation of electricity and energy utilities. Bangladesh is also no exception to this trend. Realising the significance of the electricity sector as the lifeblood of industrial and economic development, the country also took multiple strides towards developing the sector by restructuring key power companies, creating independent regulatory bodies, and promoting private sector firms to enter the electricity market. However, to our knowledge, no literature focuses on the impact of the electricity market reform (EMR) in Bangladesh through the lens of privatisation, competition, and regulation. Addressing the research gap and discussing the reform initiatives critically, this chapter aims to empirically analyse the effects of the EMR on the energy sector development and macroeconomic stability of Bangladesh with the help of a time-series data set covering 1980–2019. We use standard and robust unit root and cointegration tests for empirical analysis. For the long-run estimation purpose, we use the dynamic OLS method. The results of our study can help policymakers adopt effective policies for sustainable development in Bangladesh.

Keywords Electricity · Reform · Bangladesh · Dynamic OLS · Market · Cointegration

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1 Introduction

Modern society is heavily dependent on affordable and reliable electricity in most household and production activities. Amin et al. (2020) argued that the least electricity level is mandatory for accomplishing progress after a subsistent amount. In his seminal work, Stern (2011) further discussed the importance of electricity as a precondition for meeting basic social needs. The necessity of electricity as a development instrument is unquestionable. Moreover, in developing and emerging economies, electricity greatly influences economic activities, the productivity of workers, and the overall improvement of living standards (Rehman et al. 2019). Therefore, a proper strategic plan for the electricity market is required for the long-run sustainable development of any nation.

Having realised the significance of the electricity sector as the economy's lifeblood, several developing and emerging countries across the world started initiating market-oriented reforms in the early 1990s (Jamasb 2002, 2006; Jamasb and Nepal 2011; Jamasb et al. 2016). The major reforms in these countries are restructuring and privatisation of electricity utilities. Zhang et al. (2008) also argued that electricity market reform (EMR) occurs through the combination of privatisation, regulation, and product market competition. The success of developed countries' EMR has been thoroughly documented (Pollitt 2008). Parker and Kirkpatrick (2005) examined the effect of EMR on the economic performance of developing countries at the sector and firm-level. They revealed that privatisation in the electricity market would be most effective in developing economies if it is accompanied by strategies that stimulate competitive behaviours and regulate the market effectively while simultaneously being integrated with the broader structural reform process.

The key reasons behind EMR programmes can be seen between 'push' and 'pull' factors. The 'push factors' are twofold. The first push factor implies the necessity of adopting a structural adjustment programme in the electricity sector as demanded by the donor agencies, such as the World Bank, the Asian Development Bank, and the International Monetary Fund. The second 'push factor' is linked to prevalent problems in the electricity sectors of different countries and a legitimate necessity for market reform (Sen 2014). These push factors include the weak performance of state-owned electric utilities, growth in power demand, the inadequate volume of investment, etc. The' 'pull' factors include a demonstration outcome following practices in Chile, England and Wales, and Norway in the 1980s and early 1990s (Zhang et al. 2008).[1]

Bangladesh, located in the north-eastern region of South Asia, is also no exception to this trend. Bangladesh has taken multiple strides towards developing the electricity sector since its independence. The reform programmes were initiated by restructuring the vertically integrated monopoly utility into different distribution and

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[1] 'Power' and 'electricity' are used interchangeably in this chapter.

Table 1 An overview of socio-economic indicators in Bangladesh

Criteria	1972	1980	1990	2000	2009	2019
GDP growth (%)	−13.97	0.81	5.62	5.29	5.04	8.15
Foreign reserves (Current US$ billion)	0.20	0.33	0.65	1.52	10.34	32.70
Extreme poverty rate (%)	90.00	75.00	43.00	34.30	17.60	10.50
Literacy rate (%)	17.60	29.20	35.32	47.49	58.77	74.68
Life expectancy (Years)	46.51	52.90	58.21	65.45	69.49	72.32

Source World Bank (2020)

transmission utilities. Amin et al. (2021d) highlighted that the core reform initiatives in Bangladesh tend to include (i) unbundling the key power institutions, (ii) establishing independent regulatory bodies, (iii) promoting private firms to enter the electricity market, (iv) diversifying the fuel mix in electricity generation, and (v) ensuring large-scale investments in the power generation sector. These reform initiatives in the electricity market led the country to achieve landmark success over the last 5 decades.

Table 1 shows that the average gross domestic product (GDP) growth increased to around 7% in the 2010s compared to 3% in the 1970s. The country has maintained a GDP growth of 8% in pre-pandemic conditions. The Bangladesh Bureau of Statistics shows that extreme poverty decreased from around 90% in the early 1970s to around 10.50% in 2019.

However, to our knowledge, no literature focuses on the impact of EMR in Bangladesh through the lens of privatisation, competition, and regulation. Addressing the research gap, we aim to empirically analyse the assessment of EMR on the energy sector development and macroeconomic stability in Bangladesh with the help of a time-series data set covering 1980–2019. We use standard and robust unit root and cointegration tests for empirical analysis. We apply the dynamic ordinary least squares (DOLS) technique for the long-run estimation purpose. Additionally, model stability tests are used to examine the stability of the results.

The novelty of the chapter is threefold. First, no existing studies looked into the in-depth policy analysis of the Bangladesh electricity sector. Second, the chapter applies robust time-series econometric techniques based on data covering 1980–2019 to assess the long-run impacts of electricity sector reforms on the aggregate economy. Third, this chapter contributes to the literature with strategic policy options for Bangladesh to articulate its electricity policies to achieve its vision for 2041 of becoming a high-income country after having cleared the interim goal of becoming a middle-income country at its 50th anniversary of independence.[2]

The rest of the chapter is organised as follows. Section 2 highlights the relevant literature on EMR. Section 3 discusses stylised facts of the Bangladesh electricity market over the last 50 years, followed by a brief discussion on market reforms in the

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[2] For more details, see http://oldweb.lged.gov.bd/UploadedDocument/UnitPublication/1/1049/vision%202021-2041.pdf.

electricity sector in Sect. 4. Section 5 presents and discusses the empirical modelling approach and results. Finally, Sect. 6 concludes the chapter with a robust policy discussion in line with Vision 2041.

2 Literature Review

This section summarises the existing literature surrounding the EMR. For better understanding, we divide the section into two subsections—theoretical and empirical discussions.

2.1 Theoretical Discussion

Fenglong (2011) applied a computable general equilibrium (CGE) analysis to understand the effect of competition policies on the electricity market in Singapore by stimulating a hypothetical regulatory condition. Compared to the regulated electricity market, simulation results show that deregulation greatly increases GDP and exchange rate and leaves the choice of higher national income and worse consumer welfare to implement government policies. If regulation is essential for political motives, a formal legal framework must ensure that the economy is free of regulatory constraints.

Yin et al. (2019) analysed the electricity market in China using a CGE analysis to understand the influence of liberalisation on the market by considering three sub-sectors of electricity: generation, transmission, and distribution. The current state is compared to a market reform of decreasing entry barriers on generation, increasing competition for distribution, and regulating the transmission sub-sector. The results show an increased efficiency in the market and a reduction in electricity prices.

Akkemik and Oğuz (2011), using an applied CGE model and a counterfactual simulation, investigated the potential effects of full liberalisation on efficiency and competition in the Turkish electricity market. According to simulation results, the electric sector will be more efficient, home electricity prices will be lower, and output and welfare will increase by 0.5%–1.1% of GDP. They also discussed the various causes of discrepancies between estimated and real effects. Political considerations tend to dominate efficiency benefits when the institutional context and legal framework change.

Timilsina et al. (2019) employed The Integrated MARKAL-EFOM System (TIMES) model for the energy sector and a CGE model that examines the macroeconomic implications of a component of China's power sector reform initiative, which began in 2015. They revealed that if China uses the market principle to govern its power system, electricity prices will be roughly 20% cheaper than expected in 2020. As a result, electricity price reductions would have a ripple effect throughout the economy, leading to a 1% boost in GDP in 2020. It would also increase household income, economic opportunities, and international trade.

By developing a novel dynamic stochastic general equilibrium model, Amin et al. (2021a) examined the effect of captive power plants (CPPs) on the national grid. The model is calibrated and estimated by the Bayesian estimation technique. It is revealed that when the CPPs are connected, GDP, household consumption, and industrial output decline because of the prevailing distortions in the energy price. The result is closely associated with the notion of second-best theory. Finally, it is concluded that the CPPs should not be included in the national grid without reforms that can clear existing price distortions. In another theoretical analysis, Amin et al. (2021b) revealed that Bangladesh would be more exposed to the oil price shocks due to the sudden shutdown of the CPPs. Furthermore, industrial output and GDP would reduce by 1.5% and 1.2%, respectively, in the long run when the CPPs are completely shut down as a reform strategy. Therefore, as policy suggestions, alternative reforms, such as creating a pathway for advanced and efficient technologies and renewable-based CPPs, would be effective.

2.2 Empirical Discussion

Du et al. (2010) showed how regulatory reforms affect the productiveness of fossil-fired power generation plants based on the plant-level national survey data from 1995 and 2004. The impacts of the reforms on demand for fuel, non-fuel energy, labour, and other inputs are estimated by utilising a differences-in-differences econometric method. The findings reveal that the net efficiency improvement in labour input and non-fuel materials associated with the regulatory reforms is roughly 29% and 35%, respectively. On the other hand, these reforms showed no improvement in productivity in fuel input.

Zhang et al. (2008) examined an econometric analysis of the impact of competition, privatisation, and regulation on the electricity generation industry, conducting a panel study for 36 developing and transitional countries between 1985 to 2003. The study is depicted from a database developed from various international sources, measuring the effects of competition, privatisation, and regulation on electricity generation performance in emerging countries. They show that regulation and privatisation do not lead to significant economic performance benefits. Furthermore, competition among producers in the electricity market is more influential than privatisation or setting up independent regulations to increase generation and performance. The findings parallel those of Pollitt (1997), who ascertained that effective regulation is a vital component of the success of privatisation, especially when the market lacks competition.

Nakano and Managi (2008) assessed the performance of Japan's steam power–generation sector and analysed the productivity measures due to reforms from 1978 to 2003. Using a data envelopment analysis approach, they employed a Luenberger productivity indicator, a generalised version of the widely used Malmquist Productivity Index. The dynamic generalised method of moments estimation is used to investigate the factors associated with product performance changes. The results reveal that the regulatory reforms are instrumental for productivity growth in Japan's steam power–generation sector.

Kessides (2012) conducted an empirical survey of case studies across countries, mostly Latin American, for their respective electricity sector reforms. He revealed that when extensively planned and carefully applied, the synergy of adequate regulations, institutional reform privatisation, and unbundling results in a notable upgrade in levels of operational effectiveness around different scenarios and country settings. However, he pointed out that investment in transmission and generation capacity in the liberalised electricity market is yet a concerning aspect.

Khandker et al. (2012) examined the impact on the welfare of household grid connectivity by implementing a cross-sectional survey on 20,000 households in rural Bangladesh in 2005. They used rigorous econometric estimation techniques, such as Maximum Likelihood Probit Model IV Estimation and propensity score matching, and estimated that grid electrification has positively affected household income, expenditure, and educational outcomes. For instance, rural electrification has impacted total income to increase as much as 30% and as low as 9%. Other benefits also experience a steady improvement since household exposure to grid electrification increases and gradually reaches a plateau. They further discover that richer households gain more from electrification than poor households. The estimates also unveil that electrification generates income benefits that exceed cost by a wide margin on average.

Nepal and Jamasb (2012) used a panel data set covering 1990–2008 to investigate links between energy sector reforms and broader institutional criteria in 27 transitional economies. Applied bias–corrected fixed effect estimation and dynamic generalised method of moments estimation techniques are used for the empirical analysis. Their estimation results showed that energy sector reforms do not influence the selected countries' economic, operational, and environmental aspects. They also show that failure to synchronise inter-sector reforms ultimately leads to ineffective energy sector reforms implementation. As policy suggestions, they argued that successful energy sector reforms should depend on how they are synchronised with intra-sector reforms.

By analysing panel data (2002–2013) of 47 Sub-Saharan African countries, Imam et al. (2019) found that institutional deficiency, such as corruption, reduces the impact of electricity sector reforms for increasing access to energy and national income by increasing the loss of technical efficiency. However, they found that such an effect diminishes as the regulatory body can work without any externalities. On the other hand, Amin et al. (2021c), using the panel dynamic autoregressive distributed lag (ARDL) model, highlighted that power sector reforms such as privatisation and independent regulatory body – combined with political indicators – significantly influence the key components that predict energy demand in the South Asian context.

3 Electricity Market Scenario in Bangladesh

This chapter underlines some significant, stylised facts about the Bangladesh electricity sector connected to the reform activities undertaken by the government over the last 50 years to assure a steady base for sustainable development.

3.1 Electricity Generation Capacity

The electricity generation capacity was the lowest in Bangladesh around the 1970s, with the average generation capacity at 684.88 megawatts. This gloomy tendency continued to prevail until 2009. Mujeri et al. (2013) and Tamim et al. (2013) discussed that the primary reason behind the poor performance in the electricity market is the under-maintained condition of generation equipment; very few power plants; technical constraints; and insufficient operational, organisational, and maintenance regimes. Nevertheless, Bangladesh has effectively addressed the disequilibrium between supply and demand of electricity by profusely expanding its power generation capacity since 2009 (Fig. 1).

3.2 Per Capita Electricity Consumption (PCEC)

Previous literature suggests that sustained economic growth leads to increased use of technology and energy-intensive innovative appliances by households, higher industrialisation, and urbanisation, resulting in higher PCEC (Amin and Khan 2020;

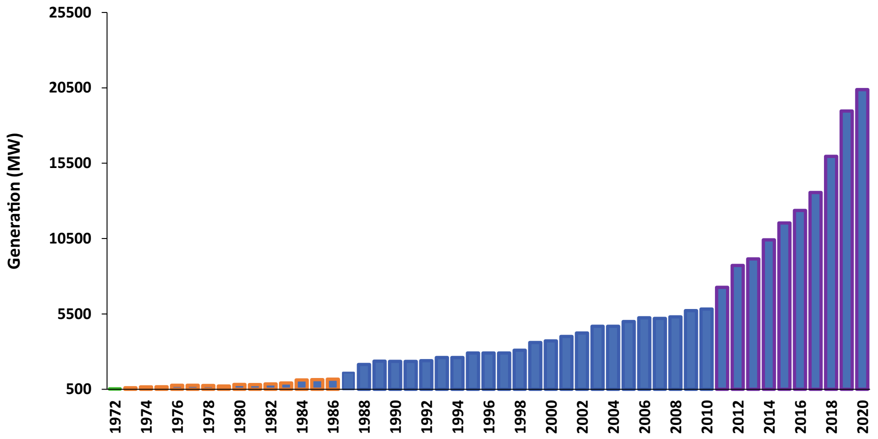

Fig. 1 Generation Capacity between 1972 and 2020. *Source* Various BPDB annual reports

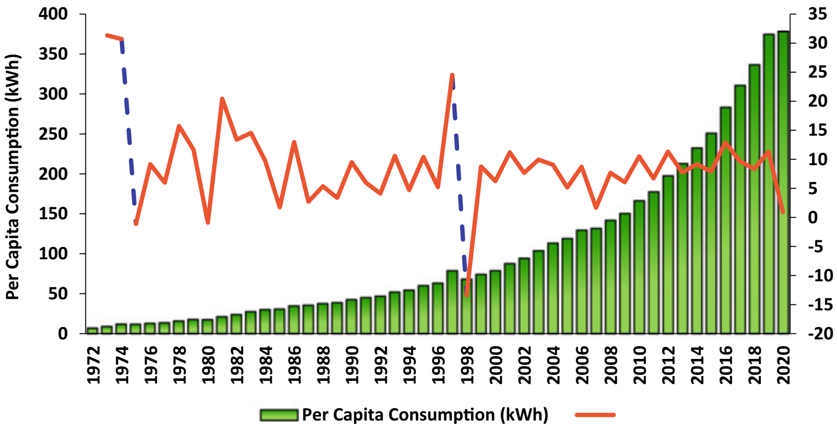

Fig. 2 Per capita electricity consumption between 1972 and 2020. *Source* Various BPDB annual reports

Pachauri 2012). Murshid (2020) also concluded that the escalated urbanisation and industrialisation rates promote rural non-agricultural activities, particularly in places networked to major urban hubs, thus increasing the PCEC. Figure 2 shows that the PCEC has gradually risen from 1972 to 2020 with an 8.9% growth rate. The average PCEC in 1970, 1980, and 2020 was 12.60 kWh, 30 kWh, and 378.16 kWh, respectively. The PCEC started rising dramatically in the 1990s as the Bangladeshi economy moved from an agrarian to an intensive industry sector.

3.3 Access to Electricity and System Loss

Bangladesh has experienced remarkable advancement in securing access to electricity across all groups among the entire population. However, the average electrification rate was less than 15% before the 1990s,[3] and only 20% of the nation had sourced electricity during the 1990s. The average share of the grid-connected population was 45% from 2000 to 2010, more than double since the 1990s. Presently, 100% electrification rate across the grid-covered regions has been realised because of the time-variant strategies initiated by the current government since 2009. Besides, Bangladesh has installed up to 6 million solar home systems to provide clean electricity in off-grid areas.

Moreover, the country successfully lowered the distribution system loss over a substantial volume. Due to heavy distribution system loss, the economy hurt from

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[3] Only 3% of the population had access to electricity in 1971.

extensive load shedding between the 1990s and early 2000s. Nevertheless, the condition has developed steadily because of technical progress and prompt policy implementation since 2009. The 2020 annual report of the Bangladesh Power Development Board (BPDB) indicates that the distribution system loss exceeded 35% in 1992, which decreased to 8.99% in 2020.

3.4 Fuel Mix Options in Electricity Generation

Due to domestic availability, fuel mix options for electricity generation in Bangladesh have been governed historically by natural gas. Figure 3 shows the fuel mix from 1972 to 2020 for a grid-based generation. It is evident from the figure that the average share of natural gas in power generation increased in 2000–2006, and declined slowly onwards (2007–2013 and 2014–2020). In the 2000–2006 period, the average share was 86.69%. Besides, in 2007–2013 and 2014–2020, the average natural gas shares were 76.50% and 60.59%, respectively. However, due to the introduction of oil-based power plants to meet the increasing electricity demand, the shares of different oils such as furnace oil (FO) and high-speed diesel (HSD) increased rapidly after 2009. For instance, the share of FO in the 2007–2013 and 2014–2020 periods were 10.71% and 22.18%, respectively. On the other hand, the share of HSD in the same periods was 5.28% and 8.18%, respectively. However, the renewable energy share trend has been declining for the past 50 years, standing only at 1.65% in the electricity generation mix of the 2014–2020 period.

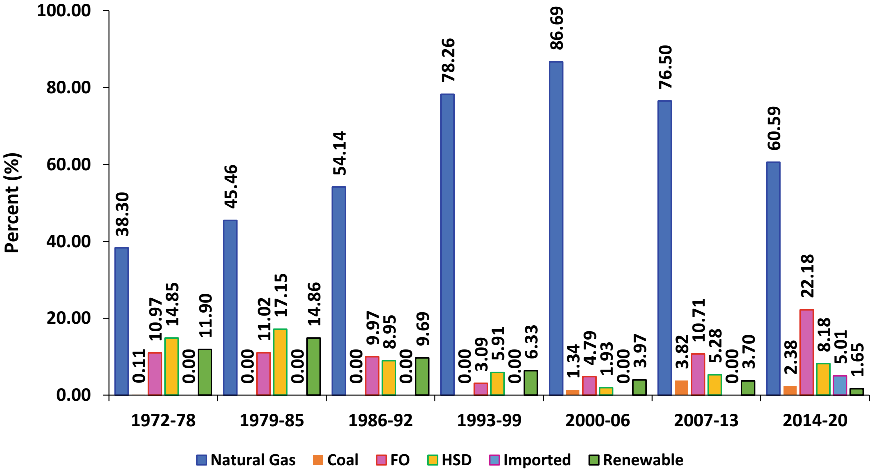

Fig. 3 Fuel mix in electricity generation in Bangladesh. *Source* Various BPDB annual reports

3.5 Move Towards Competitive Market Environment and Investment Trend

Despite the remarkable progress in the electricity generation capacity, Bangladesh has yet to go a considerable distance to make a competitive market environment since many power utilities are still controlled by the government and have little operational or financial independence. On many occasions, the state controls the regulatory commission to determine energy prices, which do not abide by the standard economic principles; however, they are based on political interests. Because of the imperfect or politically influenced pricing in the absence of economic costs, and operational inefficiencies in the lack of competition, government power utilities experience losses, obstructing investment in the energy sector. For example, the Bangladesh Petroleum Corporation's net loss due to the fuel subsidies was US$208.57 million in 2020.[4]

Besides, since the per-unit cost of electricity generation rose after 2009 due to the backing out from highly subsidised natural gas and using imported liquid fuels, the Bangladesh Energy Regulatory Commission (BERC) has made numerous adjustments to balance the wholesale and retail electricity markets.[5] Recently, BERC has implemented a benchmark pricing system to encourage private participation in electricity generation.[6] Moreover, since the administered prices of nationally sourced natural gas are set at levels considerably below world prices—and remain very low considering the opportunity cost in respect of imported fuel equivalence—the natural gas prices have also multiplied five times between 2009 and 2020, proceeding towards the competitive market environment.

Furthermore, it is argued that the government's attempts to ensure competition can be seen in the overall performance of the electricity sector in terms of generation availability, system losses, accessibility of service, non-technical losses, price levels and structures, investment, and service quality. The 6th, 7th, and 8th Five Year Plans of Bangladesh report an increasing trend in private investment in the generation sector because of the power and energy price adjustments in the past 10 years.

Given the current scenario, it is about the right time to access the transmission and distribution sectors for private investment.[7] Jamasb (2002) inferred that privatisation at the distribution and transmission utilities might be applied later in the reform initiatives, promoting further efficiency improvement for any country that has already significantly ensured private participation in the electricity generation sector. Since substantial progress has been made in private electricity generation over the last

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[4] For more details, see http://www.bpc.gov.bd/sites/default/files/files/bpc.portal.gov.bd/annual_reports/7c8c15d9_8aae_4168_89b5_8a2d5a862c28/2022-01-26-05-07-e2df1142db3df1a9ab702b4dd2ff5487.pdf.

[5] For more details, see http://plancomm.gov.bd/sites/default/files/files/plancomm.portal.gov.bd/files/68e32f08_13b8_4192_ab9b_abd5a0a62a33/2021-02-03-17-04-ec95e78e452a813808a483b3b22e14a1.pdf.

[6] Bangladesh becomes the first South Asian country to introduce benchmark pricing system.

[7] Amin et al. (2021c) report that private investment is better than government investment in increasing energy consumption in South Asia. = .

decade, it is now crucial for establishing effective competition through private sector participation in the distribution and transmission sector. Approximately US$216 billion will be required for the generation, transmission, and distribution sector by 2041[8] Given that the Power Grid Company of Bangladesh remains stand-alone for confronting all emerging challenges in the transmission sector, the Bangladesh government also plans to open up private investment.[9]

4 Electricity Reform Initiatives in Bangladesh

The socio-economic development of any economy is linked with electricity as a strategic input due to its impacts on economic stability and environmental sustainability. Therefore, powering up the nation remains a major policy agenda of the Bangladesh government since independence. The Father of the Nation, Bangabandhu Sheikh Mujibur Rahman, took several steps to develop the power sector, including restoring transmission and distribution lines, harnessing the country's mineral resources, and repairing power stations and bridges. He also included electricity in Article 16 of the constitution to ensure that all citizens have access to electricity.[10] Moreover, he also established Petro Bangla, nationalised the country's energy resources, acquired low-cost natural gas fields, and assured Bangladesh's long-term energy security. Due to the visionary and dynamic leadership of the Father of the Nation and his worthy daughter Prime Minister Sheikh Hasina, Bangladesh has achieved remarkable development in terms of access to electricity in the last 50 years.

Since 1990, most developing and emerging economies have begun considering the EMR as part of the broader strategies to create a more liberalised market (Erdogdu 2011; Jamasb 2006). In the past 50 years, Bangladesh has also introduced institutional reforms in the electricity sector by restructuring the electricity market. It unbundled the sector to create various government-owned utilities for generation, transmission, and distribution. The large-scale restructuring occurred through various policy measures, including inviting independent power producers, privatising the core power utility, implementing an independent regulatory authority, and establishing large-scale power generation plants.

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[8] For more details about investment potentials in the Bangladesh power sector (as of 13th June 2019), see http://www.powercell.gov.bd/site/page/8bf3f2bf-cdc8-4235-b2ca-1e8e39e3e7df/-.

[9] For more details, see https://ep-bd.com/view/details/article/NjAyMA%3D%3D/title?q=open+up+power+transmission+to+private+investment.

[10] Article 16 states: 'The State shall adopt effective measures to bring about a radical transformation in the rural areas through the promotion of an agricultural revolution, the provision of rural electrification, the development of cottage and other industries, and the improvement of education, communications and public health, in those areas, so as progressively to remove the disparity in the standards of living between the urban and the rural areas'. See http://bdlaws.minlaw.gov.bd/act-367/part-199.html.

4.1 Reform Policies

Since independence, EMR programmes have been experiencing a remarkable institutional shift and are claimed to be extremely successful. With the formation of the power sector reform in Bangladesh in 1993, the government outlined a reform process primarily focused on institutional issues. The National Energy Policy, adopted in 1996 and revised in 2004, was the first formal energy policy in Bangladesh to develop the infrastructure for the better achievement of this sector.

In 1996, the Private Sector Power Generation Policy[11] was implemented, which invited national and foreign private investment in electricity generation. Following this policy after 1996, the independent power producers entered the electricity market; in 1998, the policy guidelines for small power plants[12] were considered to mobilise private resources further. Besides, the Private Sector Infrastructure Guidelines[13] were adopted in 2004 to implement private infrastructure projects through institutional arrangements. Bangladesh also adopted policies for purchasing electricity from the CPPs in 2007.[14] The guidelines for remote area power supply systems were adopted in 2007.

Bangladesh undertook three major PSMP in 2005, 2010, and 2016 to meet the electricity demand goals and sustenance. The PSMPs were primarily adapted to shift to more mid to long term and comprehensive planning for meeting future electricity generation by augmenting the challenges in the interim period (Tamim et al. 2013). Initially, PSMP 2005 mainly focused on utilising domestically produced natural gas to increase the generation capacity. However, since natural gas stock was depleting at an unprecedented rate, PSMP 2010 tried to shift the focus towards the fuel diversification process for electricity generation by tapping all the possible fossil and non-fossil fuel sources. The plan called for the urgent commissioning of several oil-fired quick rental power plants (QRPPs) to meet demand in the short term. It emphasised solar home systems to boost the share of renewable energy in power generation and take cross-border electricity trading initiatives. Therefore, the government welcomed the QRPPs in 2010 under the Power and Energy Fast Supply Enhancement (Special Provision) Act 2010[15] as a quick solution to resolve the power crisis issue and provide 100% electrification by 2021. Finally, PSMP 2016 was articulated with a primary focus on infrastructure development for energy import, human capital development, and increasing renewable energy share in the electricity generation mix for a stable

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[11] For more details, see https://www.bpdb.gov.bd/bpdb_new/d3pbs_uploads/files/11%20March%2019/1.%20PSEPGPB.pdf.

[12] For more details, see https://berc.portal.gov.bd/sites/default/files/files/berc.portal.gov.bd/policies/9ddbabab_e084_464d_9511_46c0364d0ac4/Policy%20Guidelines%20for%20SPP.pdf.

[13] For more details, see https://berc.portal.gov.bd/sites/default/files/files/berc.portal.gov.bd/policies/bf23784c_4f48_4520_ace0_59667f00838f/Private%20Sector%20Infrastructure%20Guidelines.pdf.

[14] For more details, see: https://www.adb.org/sites/default/files/publication/692451/adbi-wp1238.pdf.

[15] https://www.dpp.gov.bd/upload_file/gazettes/18893_67482.pdf.

energy supply. Paltsev (2020) postulated that relevant stakeholders such as governments, industrial firms, and think tanks must prioritise research and development goals to achieve economic growth jointly with affordable and reliable energy.

The National Renewable Energy Policy[16] was formulated in 2008 to (i) recognise the significance of renewable energy and eliminate the discrepancy in electricity distribution between rural and urban areas, (ii) increase the contribution of renewable energy in the energy mix by setting targets, and (iii) develop a local authority to look after the dissemination of renewables. In 2008, a 3-year road map, the Power and Energy Sector Road Map,[17] was adopted and outlined new strategies for reconstructing the power and energy sector.[18] In 2013, Bangladesh and India also signed a memorandum of understanding on importing 500 MW of power from India. More recent policies included the Energy Efficiency and Conservation Master Plan up to 2030 in 2015,[19] the Electricity Act[20] in 2018, and the 8th Five Year Plan in 2020 for the next 5 years' energy sector development targets. Guidelines to further improve the power and energy sector and ensure energy security are also discussed in the 2nd Perspective Plan of Bangladesh 2021–2041 (GED 2020)[21] and Bangladesh Delta Plan 2021 (GED, 2018).

4.2 Energy Sector Reforms in Bangladesh

The primary reform initiatives in Bangladesh's electricity sector include privatisation, restructuring the core utilities, undergoing institutional reform, and establishing independent regulatory bodies (Fig. 4).

4.2.1 Institutional Reforms

The Power Cell was formed in 1995 to support the Power Division of the Ministry of Power, Energy, and Mineral Resources (MPEMR) in monitoring and implementing reform projects, helping different stakeholders for future sectoral activities, and attracting private investment. In 1998, to improve the efficiency of institutions, the MPEMR was divided into two divisions: the Energy and Mineral Resources Division

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[16] For more details, see http://policy.thinkbluedata.com/sites/default/files/REP_English.pdf.

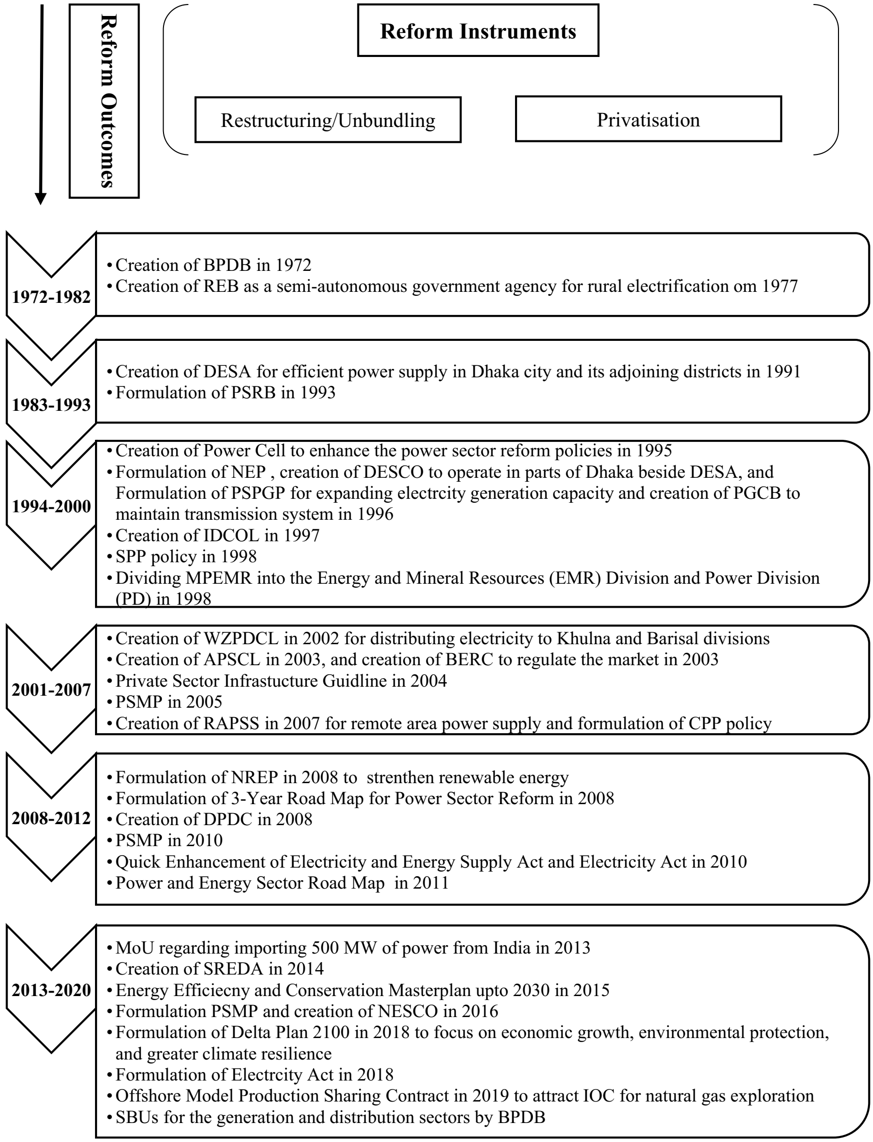
[17] For more details, see https://policy.asiapacificenergy.org/sites/default/files/Roadmap_power_energy_2010.pdf.

[18] This power sector road map was further revised in 2011.

[19] For more details, see https://policy.asiapacificenergy.org/sites/default/files/EEC_Master_Plan_SREDA_2.pdf.

[20] For more details, see https://powerdivision.portal.gov.bd/sites/default/files/files/powerdivision.portal.gov.bd/page/18d2690b_f02f_4c35_8f90_79b70d333242/ELECTRICITY%20ACT,%202018.pdf.

[21] More details can be found at http://oldweb.lged.gov.bd/UploadedDocument/UnitPublication/1/1049/vision%202021-2041.pdf.



1972-1982

- Creation of BPDB in 1972
- Creation of REB as a semi-autonomous government agency for rural electrification om 1977

1983-1993

- Creation of DESA for efficient power supply in Dhaka city and its adjoining districts in 1991
- Formulation of PSRB in 1993

1994-2000

- Creation of Power Cell to enhance the power sector reform policies in 1995
- Formulation of NEP , creation of DESCO to operate in parts of Dhaka beside DESA, and Formulation of PSPGP for expanding electrcity generation capacity and creation of PGCB to maintain transmission system in 1996
- Creation of IDCOL in 1997
- SPP policy in 1998
- Dividing MPEMR into the Energy and Mineral Resources (EMR) Division and Power Division (PD) in 1998

2001-2007

- Creation of WZPDCL in 2002 for distributing electricity to Khulna and Barisal divisions
- Creation of APSCL in 2003, and creation of BERC to regulate the market in 2003
- Private Sector Infrastucture Guidline in 2004
- PSMP in 2005
- Creation of RAPSS in 2007 for remote area power supply and formulation of CPP policy

2008-2012

- Formulation of NREP in 2008 to strenthen renewable energy
- Formulation of 3-Year Road Map for Power Sector Reform in 2008
- Creation of DPDC in 2008
- PSMP in 2010
- Quick Enhancement of Electricity and Energy Supply Act and Electricity Act in 2010
- Power and Energy Sector Road Map in 2011

2013-2020

- MoU regarding importing 500 MW of power from India in 2013
- Creation of SREDA in 2014
- Energy Efficiecny and Conservation Masterplan upto 2030 in 2015
- Formulation PSMP and creation of NESCO in 2016
- Formulation of Delta Plan 2100 in 2018 to focus on economic growth, environmental protection, and greater climate resilience
- Formulation of Electrcity Act in 2018
- Offshore Model Production Sharing Contract in 2019 to attract IOC for natural gas exploration
- SBUs for the generation and distribution sectors by BPDB

Fig. 4 Reform outcomes in Bangladesh. *Source* Amin (2015)

and the Power Division. The government also created the Sustainable and Renewable Energy Development Authority in 2014 as a nodal agency facilitating renewable energy development in Bangladesh.

4.2.2 Restructuring Core Utilities

Restructuring the core power and energy utilities has played a crucial role in Bangladesh's energy sector, briefly discussed below.

Generation Utilities

Bangabandhu Sheikh Mujibur Rahman, the Father of the Nation, emphasised the development of essential institutions and qualified human resources for a sustained and reliable energy sector. With Presidential Order 59 of 1972 (The Bangladesh Power Development Boards Order, 1972),[22] the Father of the Nation began a new era in the power sector by splitting the Water and Power Development Authority and establishing the Bangladesh Power Development Board (BPDB) and Bangladesh Water Development Board. As a result, the BPDB became the single entity in charge of electricity generation, transmission, and distribution. Moreover, the guidelines provided by Bangabandhu Sheikh Mujibur Rahman in 1977 also formed the Rural Electrification Board to share responsibility with the BPDB in promoting electricity in rural areas. In 1995, the importance of private companies in electricity generation was acknowledged, and some of the burden of electricity generation was shifted from the public utilities under the BPDB to private stakeholders. According to the 2020 BPDB annual report, the private sector generated 44.47% of the total electricity in 2019. The BPDB has been unbundling its utilities throughout the last 50 years to maintain adequate electricity generation while upholding administrative efficiency. For example, the Ashuganj Power Station Company Limited, North-West Power Generation Company Limited, BR Powergen Limited, and Rural Power Company Limited work as subsidiaries of the BPDB in power generation.[23]

Distribution Utilities

The Rural Electrification Board is responsible for distributing'electricity in the rural area as the first restructuring initiative in the distribution sector of Bangladesh. Until then, almost 80 collaborative organisations, commonly known as Palli Bidyut Samity, have contributed to creating additional connections and developing distribution channels for enhancing rural electrification and services. The BPDB was restructured further in 1991, leading to the creation of the Dhaka Electric Supply Authority (DESA), a public company facilitating power supply and services in Dhaka and its surroundings. After 5 years, a new company called the Dhaka Electric Supply Company emerged in 1996 to distribute electricity parallel with DESA, enhancing consumer satisfaction and achieving better management of resources. In 2002, the

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[22] http://bdlaws.minlaw.gov.bd/act-392.html.

[23] For more details, please see https://www.bpdb.gov.bd/bpdb_new/index.php/site/page/13e9-2cc0-ce41-9c09-088d-94d5-f546-04a6-b4fa-1d18.

West Zone Power Distribution Company Limited was opened to distribute electricity in the Khulna and Barisal divisions. And in 2016, the Northern Electricity Supply Company Limited was established to distribute electricity in Rangpur and Rajshahi. Furthermore, in 2008, DESA was redefined as the Dhaka Power Distribution Company, with new directives of attaining and increasing the city's energy demand.

Transmission Utilities

Through the unbundling of the BPDB in 1996 under the Companies Act 1994, the Power Grid Company of Bangladesh was formed to act as a separate transmission utility in the energy sector. This was primarily done to increase efficiency in operational activities and maintenance while simultaneously improving the transmission infrastructure all over the country.

4.2.3 Independent Regulatory Body

A major reform initiative taken by Bangladesh was establishing an independent regulatory authority in 2003 known as the Bangladesh Energy Regulatory Commission (BERC) through a legislative act of the Government of Bangladesh. Currently, BERC is responsible for regulating the tariff rate for electricity and other natural resources like coal and natural gas. Moreover, the commission guides policy formulation and implementation by other entities in the energy industry and promotes a competitive market environment while also protecting consumer rights.

5 Econometric Estimation

This section aims to empirically analyse the effect of major reform initiatives on the Bangladesh electricity market. The econometric analysis is mainly designed to reveal reform effects on three major blocks: the electricity market, welfare, and the environment. The electricity market block captures the direct effect of reforms on electricity consumption and generation. On the other hand, the welfare and the environment blocks capture the possible influence of EMR on aggregate welfare and environmental aspects. Following Amin et al. (20162021c), Amin and Khan (2020), Imam et al. (2019), and Sen et al. (), the general expression of the models from each block is expressed by the following Eqs. (1–7).

Electricity Market Block

$$lnE_t = \alpha_1 + \beta_1 lnY_t + \beta_2 lnP_t + \beta_3 PRI_{t-2} + \beta_4 REG_{t-1} + \varepsilon_t \tag{1}$$

$$lnG_t = \alpha_2 + \mu_1 lnY_t + \mu_2 lnP_t + \mu_3 PRI_{t-2} + \mu_4 REG_{t-1} + \varepsilon_t \tag{2}$$

Welfare Block

$$lnHDI_t = \alpha_3 + \vartheta_1 lnY_t + \vartheta_2 PRI_{t-2} + \vartheta_3 REG_{t-1} + \vartheta_4 POL_t + \varepsilon_t \tag{3}$$

$$lnGINI_t = \alpha_4 + \lambda_1 lnY_t + \lambda_2 lnY_t^2 + \lambda_3 PRI_{t-2} + \lambda_4 REG_{t-1} + \lambda_5 POL_t + \varepsilon_t \tag{4}$$

$$\begin{aligned} lnGINI_t =& \alpha_5 + \pi_1 lnY_t + \pi_2 lnY_t^2 + \pi_3 PRI_{t-2} + \pi_4 REG_{t-1} \\ &+ \pi_5 PRI * POL_{t-2} + \varepsilon_t \end{aligned} \tag{5}$$

Environment Block

$$lnCO_{2,t} = \alpha_6 + \psi_1 lnY_t + \psi_2 lnY_t^2 + \psi_3 PRI_{t-2} + \psi_4 REG_{t-1} + \varepsilon_t \tag{6}$$

$$lnCO_{2,t} = \alpha_7 + \phi_1 lnY_t + \phi_2 lnY_t^2 + \phi_3 PRI_{t-2} + \phi_4 REG_{t-1} + \phi_5 RE_t + \varepsilon_t \tag{7}$$

In the above equations, E_t = electricity consumption per capita (kWh),Y_t = real GDP per capita (US$), Y_t^2 = squared real GDP per capita (US$), P_t = electricity price (proxy by an aggregate price index),PRI_{t-2} = privatisation dummy with two-period lag, REG_{t-1} = introduction of regulatory body with one period lag, HDI_t = human development index (proxy of welfare), POL_t = political stability index, $GINI_t$ = Gini coefficient (proxy of welfare), $PRI * POL_{t-2}$ = interaction of privatisation and political stability with two-period lag, $CO_{2,t}$ = CO_2 emissions (tonne), RE_t = renewable energy consumption (tonnes of oil equivalent), α_i = constants, and ε_t = error terms. Data of the variables are obtained from the World Bank (2020), BPDB (2020), Standardised World Income Inequality Database (2020), and Amin et al. (2021c). The data set covers data from 1980 to 2019. It is worth noting that reform variables are entered into the models with the lagged time period. One main reason for such design is that these reform initiatives are subject to a time lag to be observed (i.e. delayed effect). It implies that the effects of the planned reform initiatives are not observed in the market as soon as the government adopts them. Rather, the effects become visible after some time. Numerous reasons can cause this delay. For emerging countries like Bangladesh, some reasons are the fragmented nature of the institutional set-up, bureaucracy, market rigidity arising from supply and demand, political economy aspects, etc. Additionally, the time needed for observing the privatisation effect is expected to be higher than that of the regulatory effect due to underlying structure and implementation strategies. Accordingly, lag 2 is considered in the equations.

Before performing any dynamic long-run estimations, it is standard to run some pre-testing techniques such as stationarity and cointegration tests to confirm robust results. We perform the Augmented Dickey-Fuller and the Dickey-Fuller-GLS (DF-GLS) stationary tests. For the stationary properties, Table 2 shows that all the concerned variables are stationary at the first difference form.

Then, we examine the existence of a long-run relationship among the variables through the ARDL bound test. Table 3 illustrates that the F-statistics exceed the upper bound critical values, confirming the long-run cointegrating relationship among the model variables.

Since the sample size is relatively small (1980–2019) in the models, we use the DOLS method to estimate the coefficient values (Stock and Watson, 1993). Table 4 shows the results of the DOLS estimation of the variables of interest from the proposed blocks. According to the electricity market block results, it is evident that

Table 2 Stationary properties of the variables

ADF				
Variable	Level		First difference	
	Intercept	Intercept and trend	Intercept	Intercept and trend
Y	1.90	−0.43	-3.69^{***}	-6.12^{***}
Y^2	2.15	−0.33	-3.74^{***}	-3.51^{***}
E	0.85	−3.07	-4.38^{***}	-4.35^{***}
G	−0.70	−2.04	-4.50^{***}	-4.40^{***}
P	0.19	−2.75	-2.96^{**}	-3.47^{**}
RE	−0.09	−1.61	-3.12^{***}	3.52^{*}
CO_2	2.53	0.06	-4.19^{***}	-6.49^{***}
GINI	−2.53	−2.27	−2.49	1.55
HDI	−1.22	-5.21^{***}	-5.38^{***}	-5.18^{***}
POL	−1.44	-3.33^{*}	-4.09^{***}	-4.13^{**}
DF-GLS				
Y	1.32	−2.12	-2.70^{***}	-4.23^{***}
Y^2	1.29	−2.06	-2.63^{**}	-4.22^{**}
E	2.49	−2.88	-2.10^{**}	-4.26^{***}
G	1.10	−1.41	-2.60^{**}	-2.94^{*}
CO_2	0.33	−1.81	-1.95^{**}	-4.18^{***}
P	2.56	−2.04	-4.65^{***}	-5.25^{***}
RE	−0.88	−1.49	-2.97^{***}	3.74^{**}
GINI	−1.41	−1.89	-1.95^{**}	−2.43
HDI	−1.53	-3.13^{**}	-3.10^{***}	-3.83^{***}
POL	−1.86	-4.22^{***}	−1.17	-4.34^{***}

Note ***, **, and * denote significance level at 1, 5, and 10%, respectively
Source Authors' own calculation

Table 3 ARDL Bounds Cointegration Test with Surface Regression Results

Model	Value	10%		5%		1%		P-Value	
		I(0)	I(1)	I(0)	I(1)	I(0)	I(1)	I(0)	I(1)
Model 1	5.42	2.63	4.03	3.24	4.85	4.73	6.87	0.005	0.031
Model 2	5.22	2.63	4.11	3.25	4.98	4.83	7.16	0.007	0.042
Model 3	4.14	2.64	4.03	3.24	4.85	4.74	6.87	0.019	0.091
Model 4	5.48	2.47	3.89	3.02	4.66	4.37	6.53	0.003	0.024
Model 5	5.18	2.66	3.94	3.25	4.65	4.65	6.55	0.006	0.033
Model 6	4.00	2.68	4.00	3.29	4.87	4.83	6.91	0.026	0.100
Model 7	3.99	2.48	3.98	3.05	4.80	4.51	6.84	0.017	0.099

Note The test is run for both no trend and intercept configuration
Source Authors' own calculation

Table 4 DOLS long-run estimation results

Model	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6	Model 7
VAR	E	G	HDI	GINI	GINI	CO_2	CO_2
Y	0.75^a (0.12)	1.47^a (0.18)	0.16^a (0.02)	11.18^a (0.91)	9.43^a (0.62)	60.40^a (11.51)	58.04^a (9.39)
Y^2				−0.54^a (0.04)	−0.47^a (0.03)	−2.83^a (0.56)	−2.17^a (0.45)
P	−0.26^a (0.12)	−0.02 (0.13)					
PRI_{t-2}	0.20^a (0.03)	0.18 ^{b} (0.06)	0.02^b (0.10)	0.004 (0.01)		−0.10 (0.07)	−0.07 (0.27)
REG_{t-1}	0.17^a (0.04)	0.33^b (0.08)	0.05^b (0.02)	−0.08^a (0.12)	−0.09^a (0.004)	−0.35^a (0.08)	−0.30^a (0.07)
POL			0.03^b (0.01)	0.001 (0.01)			
PRI^*POL_{t-2}					−0.02^a (0.005)		
RE							−0.27 (0.17)
N	34	32	35	34	34	34	34
Adj-R^2	0.99	0.99	0.99	0.99	0.99	0.99	0.99
J-B	3.56	5.35^c	1.12	2.73	1.83	2.46	0.70
Q-Stat (AC)	2.45	3.96	0.59	4.30	1.15	0.21	2.72

Note Standard errors are in parenthesis. a, b, and c show significance at 1%, 5%, and 10%, respectively. J-B and AC refer Jarque–Bera and Autocorrelation tests. Both tests are done in the residuals of the regressions. Model 1 uses a time trend. The F-statistics show that the time trend is significant at a 1% confidence level ($F = 14.76$ and $Prob = 0.0023$)
Source Authors' own calculation

electricity consumption depicts the characteristics of an inelastic normal good in the long run (model 1). A 1% increase in income increases electricity consumption by 0.75%. Besides, electricity consumption is also negatively related to price. Moreover, our results indicate that electricity consumption reduces by 0.26% due to an increase in price by 1%. Such a level of inelasticity shows the degree of consumer reluctance since, without access to electricity, it is nearly impossible to complete any activity in the current context. The overall result is consistent with Amin and Khan (2020). On the other hand, results suggest that generation capacity is positively associated with income but not price (model 2).

We also find that reform initiatives significantly impact electricity consumption and generation capacity (models 1 and 2). It is evident from the results that privatisation positively impacts electricity consumption and generation by 20% and 18% in the long run, respectively, compared to a situation of no privatisation. Similarly, introducing a regulatory body increases electricity consumption and generation capacity by 17% and 33%, respectively, in the long run. These findings are expected as privatisation initiates, more private firms enter the market competitively, and, as a result, generation capacity increases and meets the growing demand from consumers. The growing demand is well explainable through the transformation of Bangladesh as the country that entered into an industrialised regime from the mid-1980s (Amin et al. 2020).

One key aspect to notice from the results is that the effects of regulatory reform on electricity consumption and generation are significantly different, even though the variation in effects is expected to be minimal. This finding reflects the issue of power theft[24] as evident in Bangladesh, like any other emerging country. Finally, both models show no autocorrelation problem per the model diagnostic tests. Although the electricity consumption model (model 1) residual term is normally distributed, the residual term of the electricity generation model has trivial irregularity (model 2).

From the welfare block, it is evident that the HDI has a positive association with the reform initiatives (model 3). According to the estimation, privatisation and regulatory bodies increase the HDI by 2% and 5%, respectively. We also find that political stability is another determinant of the HDI in Bangladesh. Inequality (i.e. Gini coefficient) reduces with the introduction of a regulatory body (model 4: 8% and model 5: 9%). These results are consistent with the earlier literature. From the theoretical perspective, induction of electricity sector reforms can improve the efficiency of the electricity sector and alleviates poverty, reduces inequality, increases healthcare, facilitates education services, and improves environmental aspects, leading to overall economic development (Newbery 2002; Jamasb 2006; Sen and Jamasb 2012; Jamasb et al. 2014). However, there is also evidence that the reform initiatives sometimes alone may not lead to such developments (Nepal and Jamasb 2012; Amin et al. 2021c). Our analysis also finds a similar indication since privatisation influences inequality negatively when interacting with institutional variables such as political stability (model 5: −2%). Therefore, following Jamasb et al. (2014) and

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[24] This can be simply referred to as unregistered consumption of electricity.

Sen et al. (2016), we argue that the EMR could reduce income inequality through several channels when implemented and maintained through good governance, given political stability. Examples of these channels are access to quality infrastructure, job creation, and increased generation capacity that leads to the desired level of electricity to improve the standard of living, etc. We also observe that income has a long-run non-linear effect on the Gini coefficient of Bangladesh, and it is an inverted U-shape. In other words, in the beginning, as income increases, Gini rises but falls after a certain threshold. On the contrary, HDI has a linear relationship with income in the long run. Also, model diagnostic tests do not show autocorrelation and residual irregularity problems.

Following Nepal and Jamasb (2012), we analyse the impact of reforms on environmental aspects. As highlighted in the previous studies, we also find that CO_2 emissions have a non-linear relationship with income per capita in the long run (models 6 and 7). The relationship is more widely known as the environmental Kuznets curve (Kacprzyk and Kuchta 2020). Also, an increase in renewable energy consumption may not significantly reduce long-run CO_2 emissions (model 7). This outcome of the low share of renewable energy in electricity generations in Bangladesh is immensely poor compared to the fossil fuel counterpart. According to the recent statistics of SREDA (2020), the share of renewable energy in electricity generation is only about 3% (considering off-grid and on-grid). So, a change in the consumption pattern of renewable energy may not bring any progressive alteration in the CO_2 emissions path unless its share in electricity generation reaches an adequate level.

On the other hand, no significant relationship is found between privatisation and CO_2 emissions. A key reason behind such a result is that private companies mostly invest in Bangladeshi generators that use fossil fuels like natural gas and imported oil to generate electricity. It also implies that the country is slowly transitioning to renewable energy and energy efficiency programmes. The regulatory reform also shows the expected sign on CO_2 emissions. It is because the presence of a regulatory body influences behavioural patterns of the stakeholders with regulative and monitoring authority. Regulatory reform can reduce CO_2 emissions by 35% and 30%, respectively, in the long run (models 6 and 7). Finally, post-estimation diagnostics tests reveal no residual irregularity and autocorrelation in both models.

Lastly, we check the stability of the variables used in the model by using the novel CUSUM test in Fig. 5. All the variables are stable considering exogenous effects (systematic and sudden movements).

6 Conclusion and Policy Recommendations

Bangladesh was approved for graduation from the least developed country status list by the United Nations General Assembly in 2021. The country has satisfied

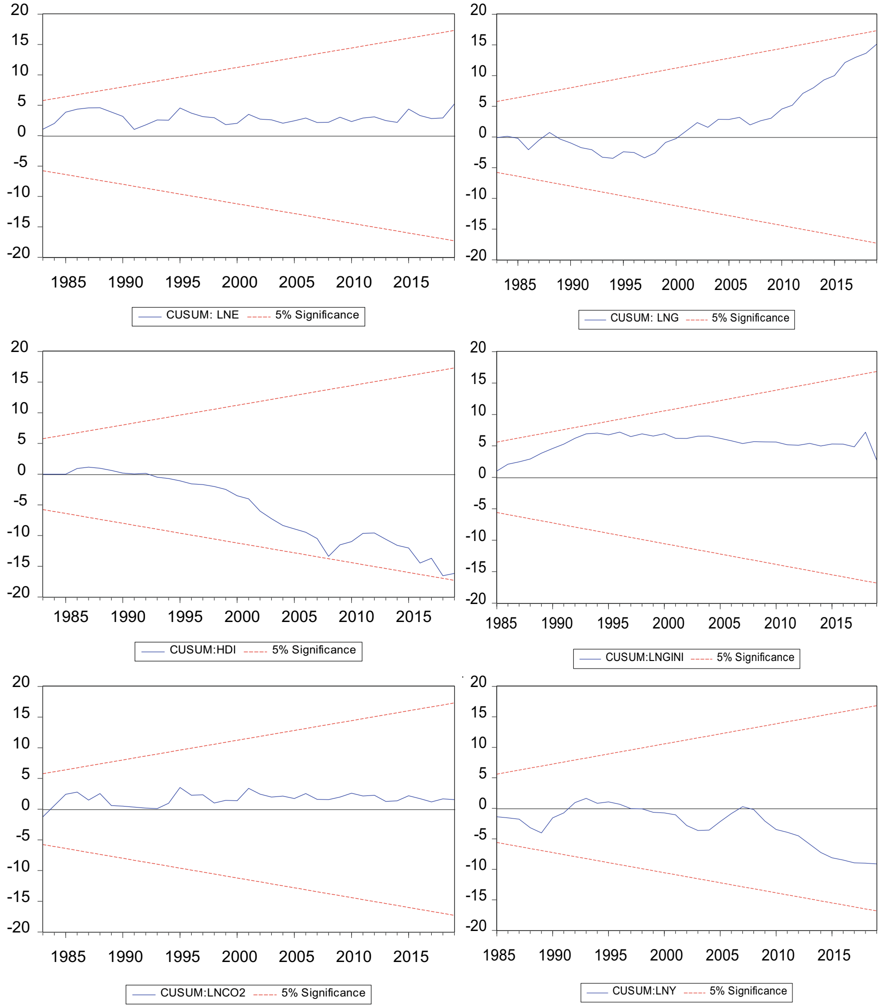

Fig. 5 The CUSUM tests. *Source* Authors' own calculation

the necessary criteria of per capita income, economic and environmental vulnerability, and human resources for the second consecutive time since 2018.[25] With the aspiration of a futuristic Bangladesh as a high-income country by 2041 with reduced extreme poverty by 2030, the focus of the present Awami League government is sustaining economic growth by employing more people, enhancing structural growth by promoting health and education standards, accelerating the growth

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[25] For more details, see https://www.thedailystar.net/business/news/bangladesh-gets-un-recommendation-graduating-ldc-status-2051857.

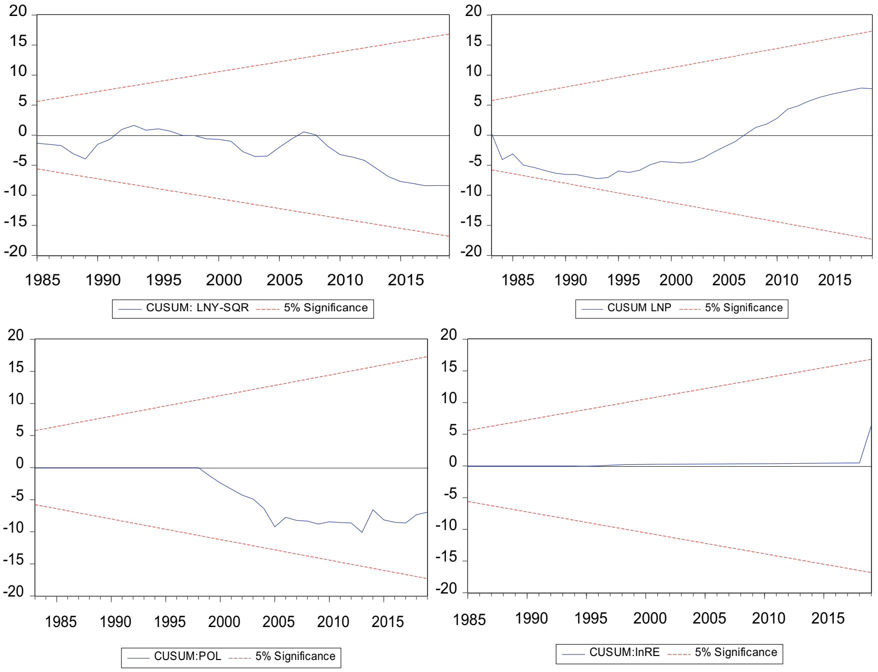

Fig. 5 (continued)

of energy and transport infrastructure, and maintaining good governance while reinforcing anti-corruption policies and regulations (GED 2020). Hence, the electricity sector has been recognised as imperative for sustainable future growth. It is also vital to critically and empirically review the overall assessment of the electricity reform initiatives in Bangladesh. This chapter, therefore, thoroughly discusses electricity reform initiatives in Bangladesh.

Moreover, highlighting the literature review, we also conduct an empirical exercise to assess the policy's effectiveness. The empirical results indicate that reform initiatives, such as privatisation and regulation, significantly impact electricity consumption and generation capacity in Bangladesh. Electricity sector reform initiatives can also affect the economic indicators significantly.

We recommend that the government continue with energy price reform. It will enable the country to progress to a competitive and environmentally sustainable least-cost power generation, transmission, and distribution system, with increased private participation and own-resource mobilisation, reducing reliance on limited financial resources and meeting Bangladesh's environmental goals, including its commitment to the Paris Accord on Carbon Emission Reduction.

Bangladesh could also build large-scale power transmission and distribution systems to secure network voltage fluctuations and frequency issues, establish uninterrupted quality power distribution, and develop more high-power transmission lines to cater to the rising demand from new power generation hubs. Attracting large-scale private investment on a global and domestic scale and bringing new newer innovative solutions could be given top priority in the coming years to develop the transmission and distribution sectors. To meet the energy efficiency targets, the government may look into implementing well-articulated demand-side management to help ensure cost-effective ways to reduce peak demand and curb load shedding while simultaneously encouraging consumers to use energy-efficient appliances and equipment and introducing better energy-efficient technologies and new building insulation standards.[26]

Institutional reforms are crucial, as decentralised institutions' lack of organisational power within a centralised system hinders policy implementation and private investments (Vijay et al. 2015; Ghafoor et al. 2016; Cai and Aoyama 2018). Furthermore, several administrative issues delay the speed of ongoing power and energy projects in emerging countries. As a result, the policy may be strengthened to implement synchronised institutional reforms in natural gas exploration for power generation, increase investment opportunities, ensure demand-side management, and negotiate cross-border electricity trade and power dissemination projects (Jamasb et al. 2016). Finally, the government could reckon with implementing plans to improve the skills of the current labour force in the power sector to minimise managerial bottlenecks and redistribute existing subsidies to develop renewable energy energies.

Since electricity consumption keeps increasing, energy efficiency programmes must be enhanced to promote the sale of high-efficiency household appliances awareness campaigns to evoke behavioural changes in individuals to save electricity. Furthermore, welcoming research and development initiatives can focus on the development of energy storage systems.

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The Role of Electricity Market Reform and Socio-economic Conditions in Electricity Consumption in India

Mamata Parhi

Abstract Does a reform in the electricity market enhance energy consumption? To what extent do the complex layers of socio-economic and demographic fabric moderate the positive externalities of reform on consumption behaviour? To answer these questions, the current study models and estimates the mediating role of the socio-economic-demographic fabric of intra- and interregional consumption patterns to elicit significantly heterogeneous electricity consumption behaviour in India's energy market. The study also aims to offer predictive insights into the speed at which a fully reformed energy market would produce equivalent Pareto optimal welfare consequences in terms of electricity consumption. Policy implications are drawn given our empirical findings.

Keywords Energy market reform · Consumption pattern · Socio-economic development · India

JEL Classifications E20 · K32 · O12 · P21 · Q43

1 Introduction

The fact that reform in a socio-economic-political milieu brings changes to the lives of the common people is an uncontested view that is theoretically driven and empirically proven. Amongst others, a reform in the energy sector in a developing economy brings more to life than just minimising the extent of inequality concerning the elevation of consumption status. It empowers people with the necessary comfort, improving people's social status and putting labour hours to the most productive use, thus enhancing the overall productivity level in the economy.

Amongst developing economies, the need and persistence of reform in the energy market in India hold immediate implications for safeguarding a sustainable energy future. Over the years, India has swiftly deployed renewable energy technologies with astounding growth prospects in the coming decades. The government's actions have

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been exemplary, and the outreach of this reform has been felt steadily across states recently. Yet, the expected welfare consequences of the reforms have to translate into sustainability-enhanced electricity consumption within a fully efficient electricity market hypothesis.

Figure 1a presents an analytical framework indicating how a transition from a relatively restrictive to a fully reformed energy market translates into differential consumption patterns influenced by socio-economic and demographic parameters. Indeed, no consumption basket—whether it is energy or any other form of commodity—is complete without a tangential analysis of society's social, economic, and demographic fabric. Reforms in the commodity market, such as the energy market, can break free of certain limiting implications of social norms and poor economic conditions to boost energy consumption and accelerate the energy market towards a sustainable energy future. However, despite many studies showing how reforms in the energy market can impact energy consumption, there is a sparse understanding of the differential effects across and within states determined by heterogeneous social and economic orders. This study is a rigorous attempt in this direction.

In particular, this study examines unique survey data to understand electricity consumption behaviour amongst households and tries to differentiate effects across social strata and geography. The question one may try to answer is how and to what extent (an incremental or sudden electricity market) reform can produce a better welfare-embedded consumption basket of electricity? Victor (2005), in a recent work, analysed the impact of power sector reforms on energy services for the poor. Comparing the effects across several countries, he found that power sector reforms often coincide with many changes in the organisation of industry and government. While it is difficult to disentangle the true effects, extant evidence suggests that power sector reforms, on average, improve energy services and household welfare.

Underlying the hypothesis that reforms can enhance welfare, progressive relaxations of electricity reforms are often better matched and adapted well to various regions' complex social and economic fabric. In our work, we argue and demonstrate that the success of the energy market depends on the economic status of a particular region, its geographic location, and social status amongst other regions. Our study also shows that despite subsidisation and many other controls the government has put in place to float an affordable pricing strategy, more structural reforms are needed to generate growth synergies from this reform. To elicit our hypotheses and support them with empirical evidence, we provide in Sect. 2 a brief overview of the energy policy in India with various data gathered from secondary data sources. Section 3 describes our data and empirical strategy. Finally, Sect. 4 presents and discusses the findings, and Sect. 5 concludes with policy implications.

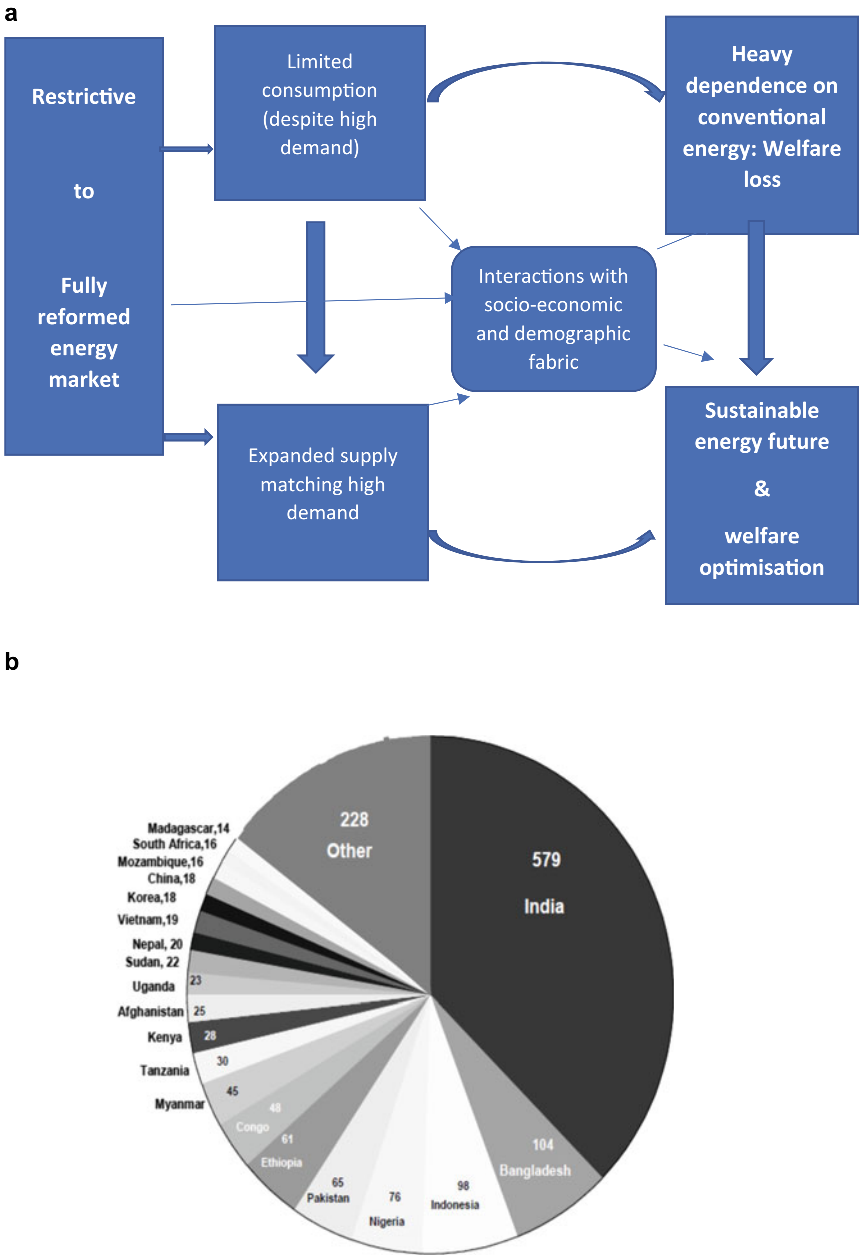

Fig. 1 **a** From progressive market reform to sustainable energy future. *Source* Author's construction. **b** Population without access to electricity over time (top) (in millions) 'Access' is measured at the household level. *Source* IEA (2002)

2 Overview of Energy Policy in India and Predictive Patterns

2.1 Energy Reform in India

This section provides a synoptic overview of the dynamics of energy policy in India over the past 2 decades. It compares the country's standing in terms of policy reforms vis-à-vis other developing countries. Although there are varied reasons why a country focuses on energy reforms, India is driven by its growing energy deficit and focus on developing alternative energy sources. The latter, of course, is motivated by the country's ambition to have net-zero emissions by around 2030.

Beginning in 1879, when the first historic electricity generation began in India under British rule, the spatial diffusion of electricity consumption has been slow. Approximately 150 years since its early establishment, electricity consumption has been limited mainly to the rich (a status-quo symbol inculcated during British rule to the modern-day). Mumbai (then Bombay) was the second city in India to electrify (after West Bengal), although many private companies built urban power supply systems soon after. These were under franchises that allowed for reasonable rates of return and included regulatory oversight to prevent monopolistic abuse.

In the early 1970s, Prime Minister Indira Gandhi created a tariff structure that provided free electricity to farmers. Since then, the low-cost electricity provision has become a systematic expectation during elections and various political regimes. But this was also combined with certain inefficient technology use, such as the provision or installation of inefficient pump sets and thirsty crops (such as cotton), making it politically difficult to roll back free power to farmers. The latter was used as an effective instrument to safeguard electoral vote banks. Tongia (2006) noted that rural farmers in other countries, such as China, are less well organised as a political force. Planning in the power sector is controlled by a central planning apparatus that has valued industrial output. This is one reason electricity prices in rural agricultural areas in China are much higher than in India.

When India sought to attract private greenfield, the projects often grappled with the significant difference between incumbent and new power. This is where the reform in the electricity sector needs fine-tuning to bridge a strong moderating link between the incumbent and the new. If we compare the same with China, those differences have been less severe. Some greenfield independent power producers were seen to deliver new power at lower prices than the incumbents. Overall, this reflects that large industrial power consumers in China were usually state firms that did not respond to normal price signals. This partly reflects the particularly active form of Indian democracy (Tongia 2006; Zhang and Heller 2007).

Lately, the current Prime Minister, Narendra Modi, has been using the political opportunity created by the pandemic to push through several stalled reforms in the energy sector. These reforms indicate a desire to ensure that energy consumption shifts are driven largely by market forces and regulatory action rather than state outlays of imposing varied restriction levels (such as tariff-embedded transfer of excess electricity to other states). The complex interactions with the socio-economic fabric have meant an incremental but somewhat fragmented response to curtail greenhouse gas emissions. Of course, the government's overriding reform priority is to end the chronic financial problems of the electricity system. Its draft electricity bill proposes an end to cross-subsidies and depoliticised distribution companies; it will face considerable political opposition. From the sectoral perspective, the drop in solar prices has revived investor interest. The coming together of a natural gas market continues to be encouraged.

One complication is adopting protectionist measures to inhibit Chinese imports and boost domestic industry. This has already meant stiff tariffs on solar modules and cells. It has also led to moves to encourage private coal mining to reduce imports. In the past few weeks, possibly because India assumes the chair of the G-20 in 2022, the Modi government has begun to paint a bigger picture with talks of a regional solar grid and a global solar bank. Figure 2a–c describe India's economy–energy growth nexus with a detailed distributional contribution, namely, service, industry,

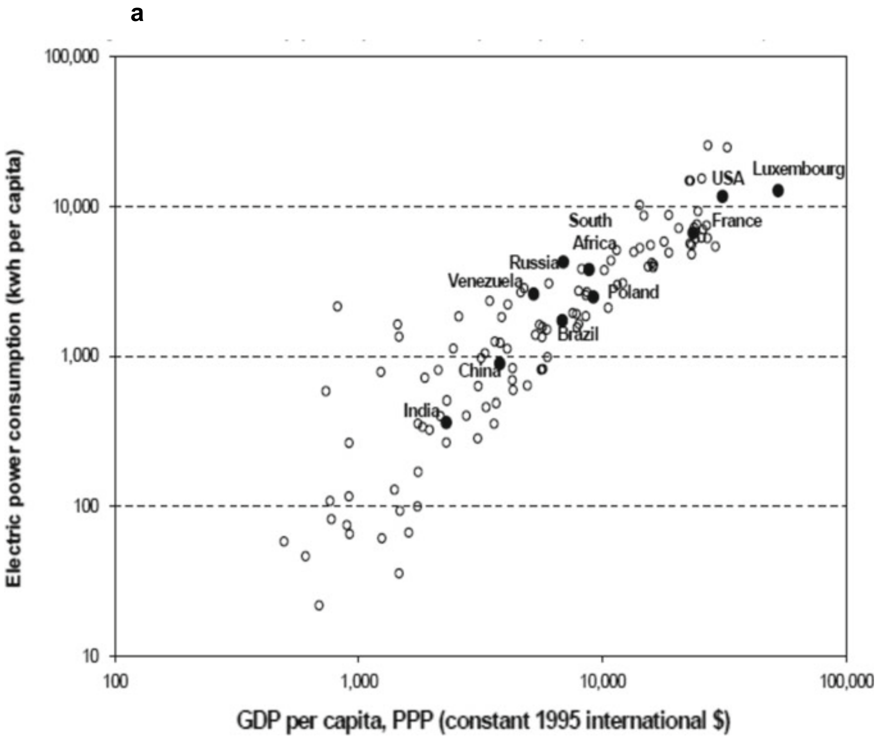

Fig. 2 **a** Electricity per capita versus GDP per capita (selected countries). *Source* World Bank (2004). **b** Energy demand growth in India, by scenario, 2019–2040. *Source* IEA (2021). **c** Economy–energy growth nexus in India. *Note* Y-axis and X-axis in each plot indicate annual growth rates in electricity consumption and value added, respectively. *Source* Reproduced from CEA General Reviews, RBI Database from Indian Economy

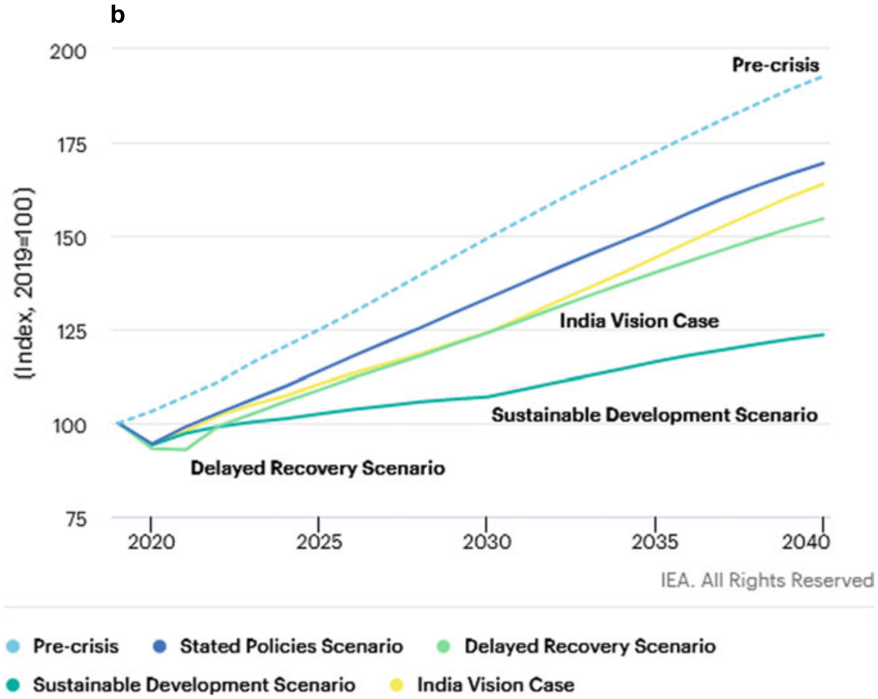

Fig. 2 (continued)

and domestic. What is sparsely investigated is quantifying the transitional aspects of electricity consumption from domestic to urban, governed by complex layers of social status and economic classes of the masses.

Electricity is a status commodity for most of rural India, and its growth in consumption is an indicator of economic strength and social identity. Yet, its discontinuous supply in the rural areas is often determined by the purpose of usage—for agriculture and domestic use. There has been some ambiguity on the exact use of energy across sectors. Methodological issues drive ambiguity. As such, the lack of clarity over their usage can complicate the generalisation of the extent sectoral use of energy has benefited from energy market reforms. A recent study by Tong et al. (2021) adopted a bottom-up plus top-down approach to assemble all India databases for 2011, representing energy use across 640 urban districts in India across multiple sectors. The authors championed the relevance of machine learning models to leverage individual-level energy usage dynamics in urban areas while also aligning total energy use by fuel types across state, city, and national totals. Survey data, such as the one used in this study, is also a very good source of primary information of micro-level information on energy consumption.

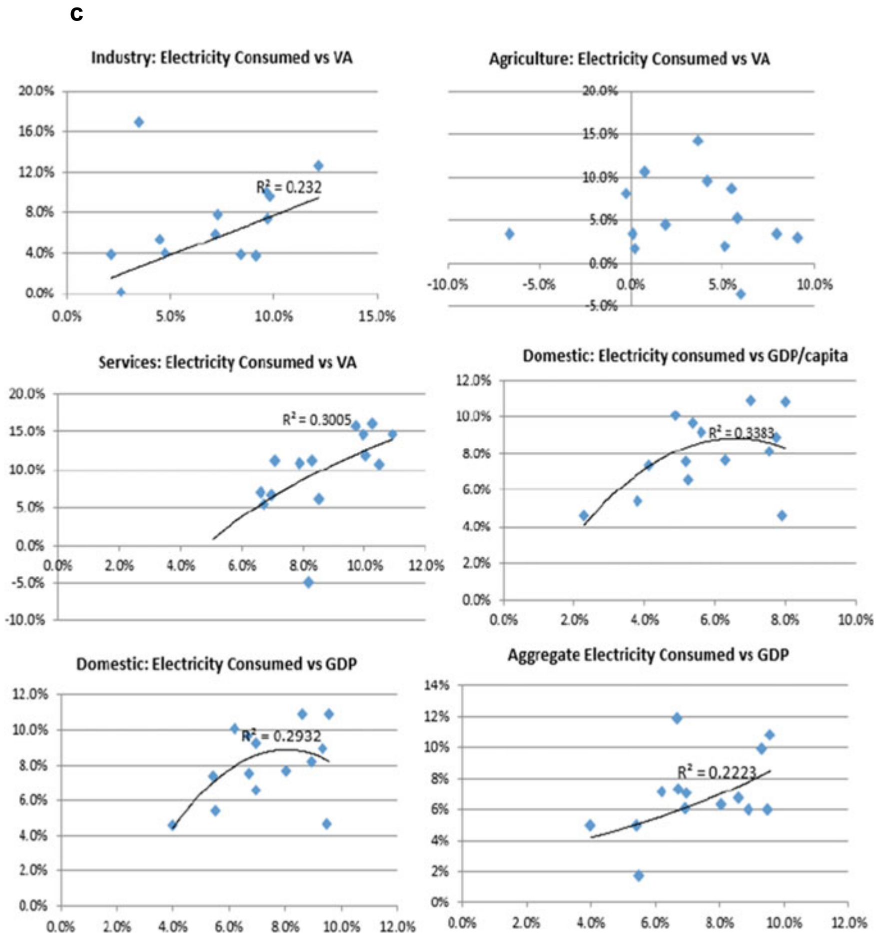

Fig. 2 (continued)

2.2 Consumption Patterns of Electricity Through the Lens of Time

Figure 1b presents cross-country households (in millions) without access to electricity over time in 2001. It is evident that India, partly due to its sheer population size, stands at the top: about 579 million households do not have access to electricity. By 2050, it is estimated that a further 416 million urban population will not have access to electricity; thus, rapid urbanisation can drive an accelerated demand for energy use. Of course, while urbanisation growth will drive energy consumption, it is possible to innovate on machinery that can promote low-carbon city planning. There is an inherent need to characterise the socio-economic drivers of energy use.

While the Indian government has conducted district-level surveys on various socio-economic-infrastructural attributes, no baseline study models key local energy–use features determined by socio-economic classes.

The type of reform in the energy sector is often governed by the nature of regulation of electricity consumption, which depends on the capital-intensive and public-good nature of electricity consumption. In India, energy policies are primarily focused on increasing supply capacity and reserves to generate and sell power. Over the years, the country has been moving slowly but steadily from coal dependence to variable renewable energy—maximising the use of solar and wind power or, at the least, being part of the development of new technologies that can generate carbon-free electricity. Since 2000, India's energy use has doubled, although about 80% of this demand is met by biomass, oil, and coal. As the country adjusts to the pandemic-induced slump in 2020 and strategises growth on the new surge of COVID-19 variants, it is also re-entering a dynamic period in energy development. The ballooning urban population and the growth surge mean that the country needs an effective power system the size of the European Union.

However, the large size of the power system alone cannot ensure a nation's fair energy distribution for consumption-driven welfare metrics. Its socio-economic and geographic attributes can drive the extent a certain energy market reform may unleash greater positive effects than others. What is required goes beyond the pure supply-side dynamics of energy distribution. It has to align with the demand-side attributes that differ across India's cultural and social fabric.

Figure 2a reports electricity per capita versus gross domestic product per capita for nearly all countries (2001) on a logarithmic scale (data source from The World Bank 2004). India appears to be amongst the lower quartile (PPP adjusted figures that consider world prices for many goods and services and exchange rate fluctuations). Figure 2b presents the energy demand growth scenario between 2019 and 2040. Data from the World Bank and the International Energy Agency show that in the pre-pandemic period, India's energy demand was forecast to rise by almost 50% between 2019 and 2030. The pandemic has led to emission suppression to some extent, yet coal and oil appear to suffer the most from the laggard demand during the pandemic.

The comparison with the pre-pandemic level of various scenarios, such as sustainable development and delayed recovery, presents important dynamics of the growth prospects of energy demand. These scenarios can guide the futuristic policy planning for the energy sector. Figure 2c reports annual growth rates in electricity consumption and value added for different sectors: industry, agriculture services, and domestic. The overall trend shows growth of over 20% over time versus the value added. This indicates that the reform should have its construct based on variations of growth contributions across sectors.

3 Data and Empirical Strategy

Our empirical analysis is based on a two-point survey of panel data of households in India. In particular, the India Residential Energy Survey data, on which our empirical examination is based, is the first of a pan-India survey on the state of energy access and consumption amongst Indian homes. The data is collected at granular levels (ward and village levels, for instance) across states and over two periods, 2019 and 2020 (see Agrawal et al. 2021). The data covers nearly 15,000 households in 1,200 villages and 614 wards in 152 districts across 21 states. This data will help us assess the quality of power supply, its distribution, and determinants of consumption depending on various socio-economic and demographic statuses. This study aims to quantify the differential effects of energy reform policy on electricity consumption. Thus, the empirical verification based on the 2 year (2019 and 2020) household surveys will shed much-needed insights into the determinants of electricity consumption in the recent periods following several policy measures undertaken to reform the energy market (Some of the reflections on reforms are presented in Sects. 1 and 2).

If we compare macro-level data in the preceding years of the 2019–2020 survey, we know that the energy and peak deficits have seen a secular decline, reducing to as low as 0.3% in the last quarter of 2016–2017 (Central Electricity Authority 2012–2018). Thermal power plants have been operating at low plant-load factors due to suppressed consumption growth, utility offtake, and coal linkage issues. On the other hand, renewable energy capacity additions have picked up pace as new solar tariffs fall under reverse bidding. In addition, the central and state governments' policies on 24/7 Power for All, electricity market reforms, domestic manufacturing via Make in India, electric mobility, and energy efficiency will be instrumental in influencing the level and pattern of future consumption dynamics.

The empirical foundation of our work rests on two important pillars. First, we study the conditional distribution of energy consumption and make an informed assessment of differential patterns regulated by various stages of energy market reforms and social and demographic layers. We can exploit the large cross-sectional data to reveal distributional patterns of intra- and inter-regional energy consumption differentiated carefully by social, economic, and demographic fabric. An adaptive Kernel density and other non-parametric distributional approaches can identify pockets of clusters with similar consumption dynamics for electricity and its usage, further differentiated by households' socio-economic status. For instance, a schedule caste (SC)/schedule tribe (ST) may prefer to consume lesser than the other backward class or general category. Depending on the historical antecedents of the caste and their prevalence in regions (more in some and less in others), we can substantiate whether some states overlap others in terms of distributional changes. Thus, the approach can also enlighten us on whether a specific distribution (classified by caste, gender, and economic status) converges or diverges over time, allowing us to assess predictive power. The relative rate of conditional convergence or divergence can tell us whether by 2050, India would need, say, X amount of energy and whether x% of the Indian population would be urbanised.

Finally, we undertake a median-based quantile regression to elicit the quantitative effects of various determinants on electricity consumption. This regression approach helps us identify heterogeneous effects of main predictors of energy usage, differentiated geographically across states. Because quantile regression has become a robust regression study on which there has been substantive research, we do not present its properties in detail in this section. However, we mention here to gauge the effect of a predictor, X, on electricity consumption, Y. We regress X on Y at each quantile θ (that lies between 0 and 1) so that the effect magnitudes are differentiated between, for instance, the lower, median, and upper quantiles of the distribution of consumption. This median-based regression approach is known to hold robust power for policy prescription.

4 Results and Discussions

4.1 Distributive Analysis and Trends

This section discusses various results, beginning with the distributional characteristics of electricity consumption per household. Table 1 and Appendix Tables 3, 4, 5 and 6 present descriptive statistics of electricity consumption, measured by average monthly bills. The results are presented for the all-India and disaggregate levels, viz., segregation by caste (Table 1), and state and caste category (Appendix Tables 3, 4, 5 and 6). To what extent is the electricity consumption clustered, depicting high concentration at some levels and low concentration at others? A density plot can reveal such hidden dynamics signifying, in our case, the classes of 'equilibrium consumption' amongst households segregated by caste and geographic location.

Table 1 Descriptive statistics (across caste categories): average monthly bills

Caste types	Mean	sd	Min	Max	p25	p50	p75	iqr
Scheduled caste	756.958	748.910	0.000	8000.000	225.000	533.333	1066.667	841.667
Scheduled tribe	638.080	694.264	0.000	6666.667	200.000	400.000	803.333	603.333
Other backward castes	700.580	662.768	0.000	7000.000	233.333	470.000	1000.000	766.667
General	749.557	812.002	0.000	12333.330	233.333	500.000	966.667	733.333
None/don't want	510.209	512.581	50.000	2933.333	166.667	350.000	700.000	533.333
Don't know	674.585	552.592	73.333	2533.333	266.667	500.000	966.667	700.000

Source Author's calculations from data

Figure 3a presents a Kernel density plot of the average monthly bill by caste types. First, looking at the Kernel density plot, it is evident that the distribution of average monthly expenditure (or equivalently, consumption) is highly skewed, peaking near very small expenditure. In other words, despite significant reforms in the energy market, the survey data show that across caste categories, a large pool of poor households spends marginally, partly due to energy subsidies to agriculture and poor households and the economic status of the households across states. Figure 3b shows a trend in household electricity consumption per capita between 2000 and 2016 (when significant plans of restructuring energy market reforms were taking place). The average consumption has nearly tripled between 2000 (from 74.6) and 2016 (206.7) in 16 years In terms of kilowatt-hours. Although this average shows

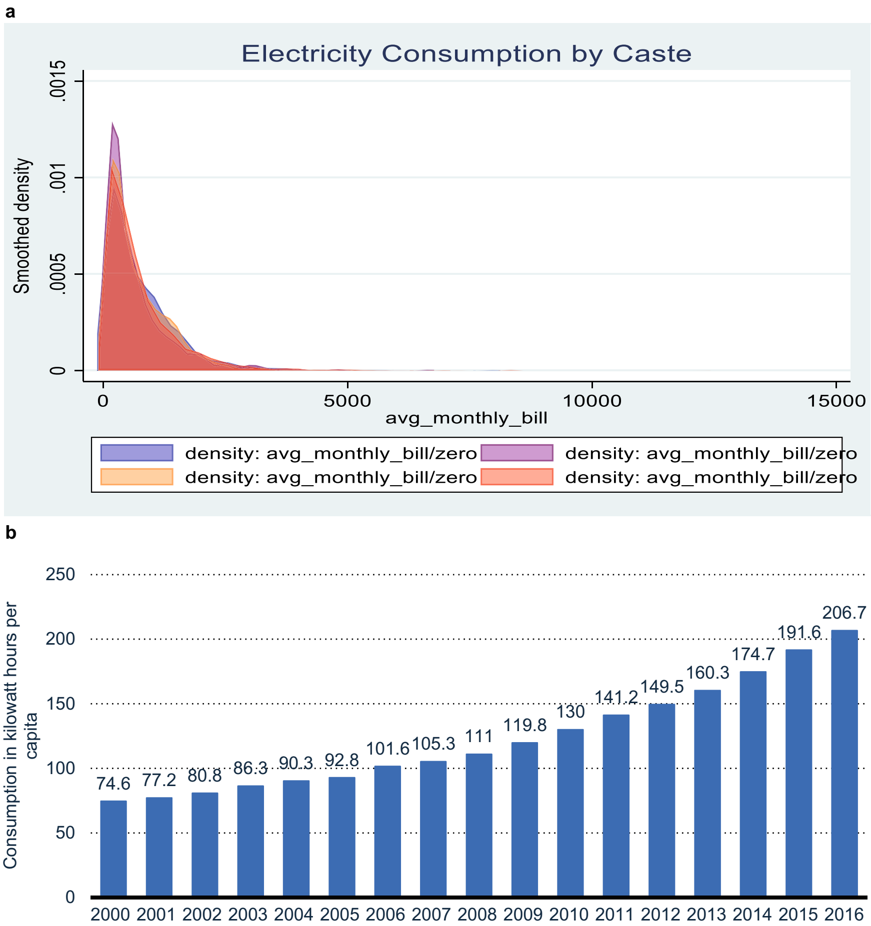

Fig. 3 **a** Kernel density (by caste): average monthly bill. **b** Household electricity consumption per capita in India, 2000–2016 (in kWh). *Source* Author's calculations from data

significant improvement in consumption pattern, Fig. 3a, which clearly shows the ongoing or post-reform period since 2016, illustrates a highly skewed distribution of consumption.

The descriptive statistics in Table 1 also complement our findings of distributional bias. We find, for instance, that amongst caste categories, the general caste category depicts far smaller variations across distributions (from 25th to 75th percentiles) than schedule caste (for this category, the 75th quantile average of energy consumption is approximately four times larger than it is for the 25th percentile). However, even across other caste categories, such characteristic growths are visible, implying that the average expenditure on electricity is still skewed irrespective of social strata. In other words, the reform appears to have done very little to flatten the skewness and cluster concentration.

Appendix Table 3 presents the state-wise distribution of electricity consumption for scheduled caste. In contrast, Appendix Tables 4, 5 and 6 present the same distribution for the scheduled tribe, other backward castes, and the general category. Although there are substantive differences in spending patterns across states, some depict greater equality. For instance, in Appendix Table 3 (for scheduled caste), Chandigarh (CH) has a mean expenditure of 295.185, and the median is 350 (the 50th percentile), where the standard deviation is 147 (the other state having smaller dispersion is Tamil Nadu [TN], 103.52). Figure 4a plots the mean and dispersion (standard deviation) of the average monthly bill across states for the scheduled caste. This figure is based on the estimates presented in Appendix Table 3. For some states, such as Uttara Khand (UK), Uttar Pradesh (UP), and West Bengal (WB), the dispersion appears to get bigger than the mean.

As such, the higher dispersion (significantly exceeding the mean) across all states depicts inherent instability and inequality in the consumption patterns. In summary, while some states display greater stability and distributive equality in average monthly bills, the majority of the states show more significant variability. The latter is also reflected by the estimates of the interquartile range (*iqr*) in the table. Considering other caste categories and state-wise variations, we present below the mean and standard deviation plots corresponding to Appendix Tables 4, 5 and 6. Similar to Fig. 4a, all other caste categories depict a similar pattern: Orissa (OR), Jharkhand (JK), Chandigarh (CH), and Tamil Nadu (TN) have the least variations in monthly bill spending, given the very close gap between the mean and the standard deviation.

4.2 Understanding Heterogeneous Effects: Quantile Regression Results

Having discussed the distributional differences in average monthly bills on electricity, both across states and caste categories or social strata, we present results based on quantile regression. Table 2 shows those results. The quantile estimation

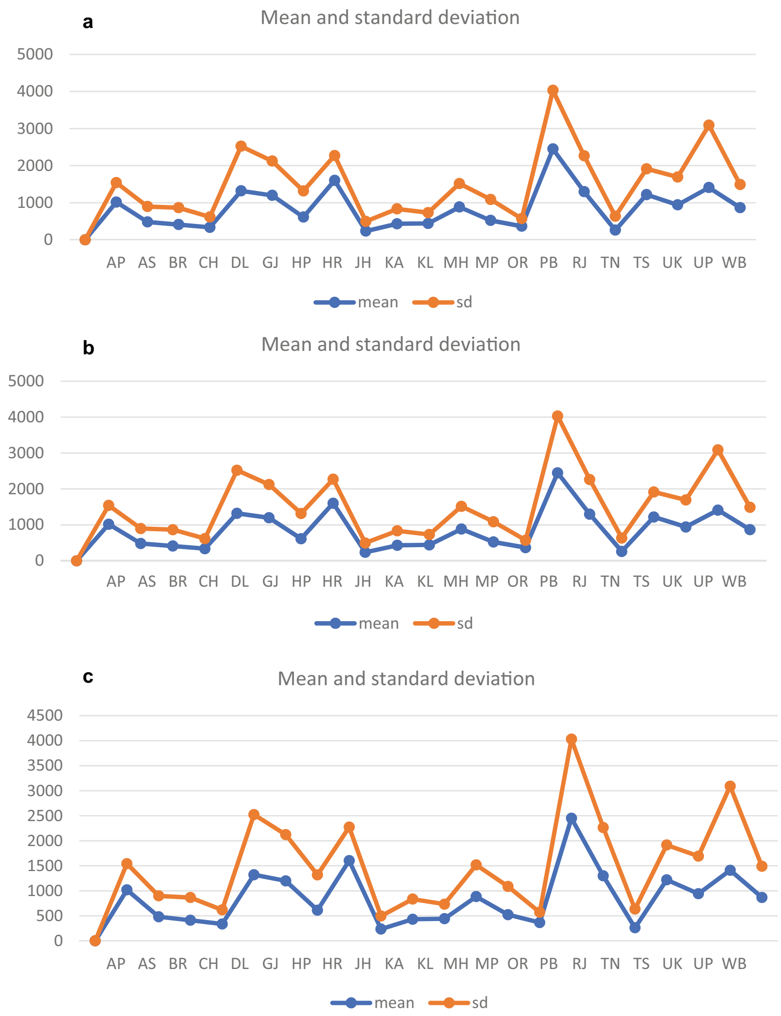

Fig. 4 **a** Cross-state variations of average monthly bills and dispersion: scheduled caste. **b** Cross-state variations of average monthly bills and dispersion: scheduled tribe. **c** Cross-state variations of average monthly bills and dispersion: other backward castes. **d** Cross-state variations of average monthly bills and dispersion: general category. *Source* Author's calculations from data

we performed is based on the unconditional quantile of Powell (2015, 2016) and Chernozhukov and Hansen (2008). This quantile regression approach addresses an important problem posed by traditional quantile estimators concerning the inclusion of additional covariates. Further, Powell (2015, 2016) also argued that the unconditional quantile approach is a powerful tool for a policy as for a policymaker, unconditional effects of a covariate, rather than the conditional effects, which are more meaningful and policy-relevant than the former.

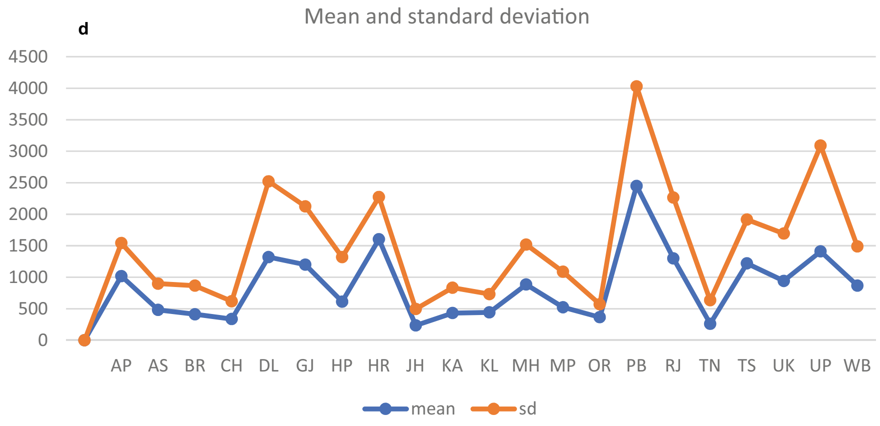

Fig. 4 (continued)

Table 2 summarises results by first considering data for both survey years (2019 and 2020) and, second, by separately presenting estimates for 2019 and 2020. The latter strategy is meant to distinguish the effects of covariates—such as the age of the household, their caste (or social status), and whether they are primary earners—on the changes in average expenditure on electricity consumption. We have reported results for three quantiles: $\theta = 0.25, 0.50, 0.75$ (the 25th, the median, and the 75th quantile of the expenditure, respectively). Our predictors of average bills are the age of households, whether they are primary earners; caste categories, whether they have ration cards (indicating economic status); and two different asset sizes (further showing the households' relative economic positions).

We find that for both years pooled together and for 2019 and 2020 separately, the impact of age on average monthly expenditure (our dependent variable) is positive across all quantiles. However, the impact differentials vary over the distribution. For instance, for the pooled data, the impact of age rises from the 25th quantile (0.688) to the 75th quantile (3.201). The estimates are statistically significant at the 5% level. For 2019, being a year older (the age effect) at the 25th quantile is 0.739, while the same for 2020 is 0.707. There is a very weak quantitative difference in the effects of this distribution level between the 2 survey years. However, the impact magnitude is larger at the 75th quantile for 2020 (2.502) than 2019 (0.663). At the median, the effects are quantitatively similar for 2019 and 2020 (1.342 and 1.251), and an F-test shows no significant difference between the two estimates.

Considering the impact of social status on average monthly expenditure, we find an interesting implication. The negative effects of caste across various levels of quantiles (except for the 25th quantile for the pooled data and 50th quantile for 2019) show that social positioning (especially moving the status down) negatively affects expenditure. This result may not be taken into confidence because the coefficients are not statistically significant. Yet, when we combine the results of caste and economic positioning (the ration card) jointly and perform an F-test, the results are statistically

Table 2 Quantile regression results (all years)

	Pooled data			2019			2020		
	25th quantile	50th quantile	75th quantile	25th quantile	50th quantile	75th quantile	25th quantile	50th quantile	75th quantile
Age	0.688***	1.971***	3.201***	0.739**	1.342**	0.663	0.707***	1.251***	2.520***
Primary earner	−24.772***	−44.851***	−67.807***	−50.308***	−82.250***	−84.800***	−10.520***	−17.115***	−17.557**
Caste	0.068	−0.717	−0.666	−0.382	0.729	−0.442	−0.173	−0.202	−0.769
Ration card	1.003***	0.991***	0.760	1.417***	0.707	1.243	0.992***	0.586***	−0.502
Asset index 1	112.043***	161.744***	256.371***	182.287***	235.169***	279.317***	45.567***	56.289***	−33.360
Asset index 2	−51.366***	−46.785***	−57.023	−98.598***	−76.151*	−69.961	−14.706	19.373	160.798***
Constant	263.736***	484.888***	923.462***	361.636***	710.031***	1217.976***	185.101***	354.402***	587.220***

*, **, and ***: Significance at 10%, 5% and 1%, respectively
Source Author’s calculations from data

significant, implying that both social and economic strata combined impact how households spend on electricity consumption. As such, we find that holding a ration card positively affects expenditure mainly because of the subsidised rates enjoyed. Also, as expected, the asset size holding has positive effects: the higher the asset size (measured by the Asset index), the higher the average expenditure. This conforms to economic theory: a higher income triggers higher spending on essential goods and services.

Finally, to elicit differences across states, we present in Fig. 5a–c the unconditional quantile effects (the vertical axis: percentage effects) for 21 states (the horizontal axis: 1–21 denotes states). The graphs are presented based on the estimates at the 50th quantile or the median. Except for Chandigarh, Karnataka, and Orissa, the effects of primary earners in the household on monthly expenditure are positive for all states (see Fig. 5a). Varied patterns are also observed for the impact of caste (Fig. 5b) and

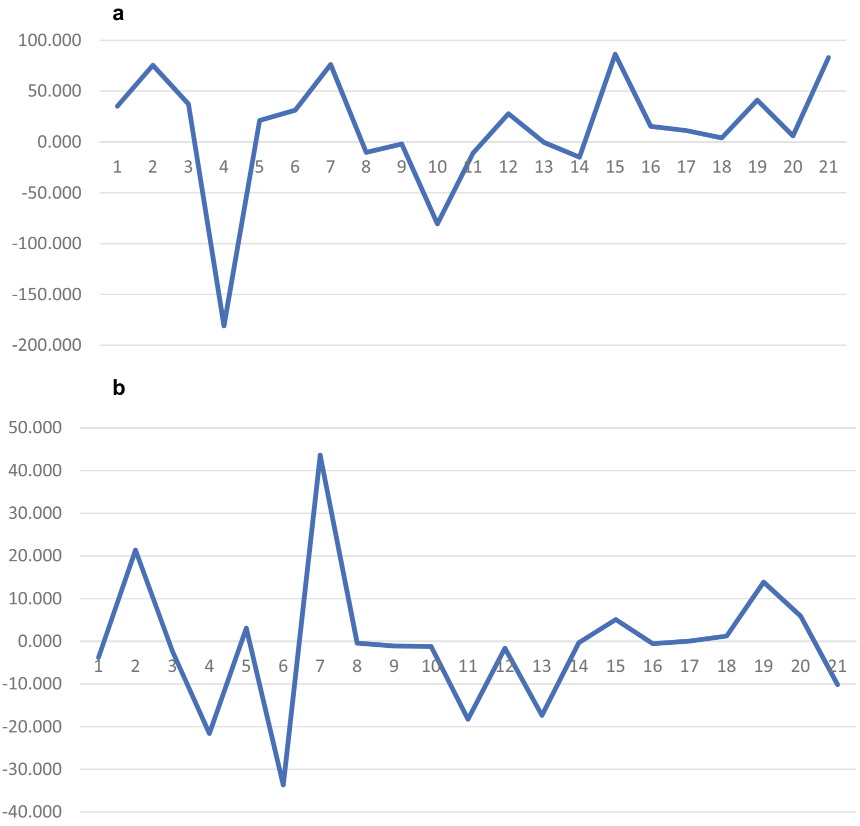

Fig. 5 **a** Impact of primary earners on average monthly expenditure at median quantile (state-wise differences). **b** Impact of caste on average monthly expenditure at median quantile (state-wise differences). **c** Impact of age on average monthly expenditure at median quantile (state-wise differences). *Source* Author's calculations from data

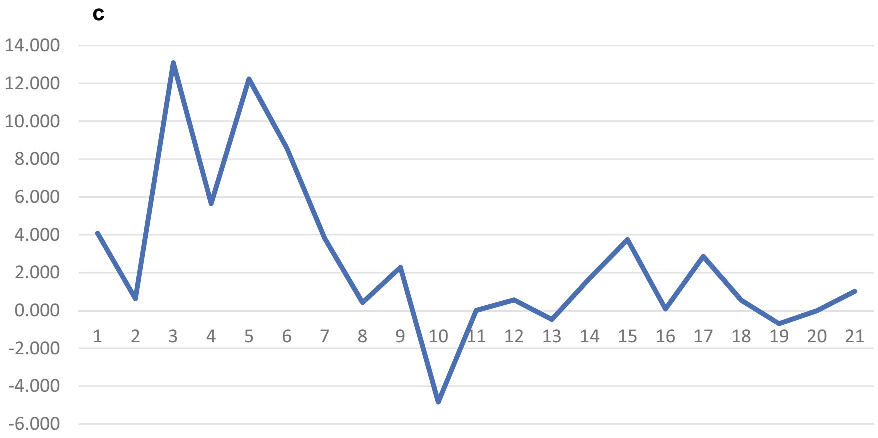

Fig. 5 (continued)

age (Fig. 5c). While we find that an increase in age, on average, positively affects expenditure, which is expected, combined with primary earners and caste categories, the state-wise differences in effects show the relative ineffectiveness of the existing policy.

5 Conclusion and Policy Implications

5.1 Key Takeaways From the Study

Power sector reform has improved energy services for the poor. Later, more significant reforms are envisaged to bring greater efficiency of distribution within the economy, improve the welfare of all households (by considering consumption patterns and quality), and enhance production efficiency (considering industrial resource cost management). In this research, we exploited unique survey data of households in India spread over 2 years (2019 and 2020) to study the distributional patterns of average monthly expenditure of households on electricity consumption. We focused on demographic and social strata profiles to perceive any significant differences in the expenditure or consumption pattern within and across sub-strata (viz., states). Finally, we also performed quantile regression to understand the nature of the effects of various determinants of electricity consumption (or expenditure). Amongst important findings, we found significant volatility in mean expenditure levels across states, partly due to geographic location and urbanisation propensity. Therefore, our results clearly show that pro-urban and pro-poor states enjoyed better access to electricity. On the other hand, the expenditure patterns were far more balanced across households, with a smaller gap between the mean expenditure and its dispersion.

The distributions (density plots) showed that the average monthly expenditure is highly skewed at the all-India level. This implies the role of cluster dynamics: a large group of socio-strata or economically affine groups appear to spend a small amount, and a very small, economically diverse, and high-income group appears to spend a large proportion on monthly bills for electricity consumption. The purpose of the reform is to eventually ‘smooth out’ humps of concentration, and that is what the ongoing or future reforms should do. Amongst various determinants, we have found that while age has some role in the expenditure pattern, belonging to a specific lower rung of social strata and the household’s asset classes are important. The future policy direction of reforms needs to consider the economic viability and the innate hidden noise in terms of classifying the poor and their income streams. The quantile regression results revealed hidden patterns of heterogeneity of effects of socio-economic and demographic parameters on consumption behaviour. Policy interventions designed to improve the aggregate welfare of households in terms of energy consumption need to accommodate the instrumental effects of social barriers and electoral politics. We present some insights on policy implications in the following section.

5.2 Policy Implications

While reform in the electricity market is vital to ensure convergence in electricity consumption across economic strata and social classes, the reform itself requires deeper and strategic interactions with the political will. What constitutes ‘poor’ cannot be solely determined by owning ration cards. Corruption practices at the local level appear to have included more higher-income groups (without a proper accounting of agricultural income) in the ration-seeking classes than the actual figures suggest. In urban areas, however, incomes are accounted for by taxation. The good synergies of reforms are not enjoyed so much by the lower-level income group than by a similar rung of the population in rural areas. Therefore, electricity market reform needs to have a two-pronged strategy. First, it needs a national-level strategy with an internal design to include all under the umbrella of reform. Second, it needs to be differentiated and strategic in terms of the inclusivity and accountability of economically dominant and suppressed households, irrespective of the conventional assignment of social classes and strata. India has moved admirably towards the inclusivity of all strata of people in the development process.

While aligning energy reforms to international standards—minimising to a great extent the monopoly power of energy suppliers domestically—strategically adapting energy market reforms to the demand of households classified as poor or rich in their economic status should have greater emphasis.

Appendix

(Tables 3, 4, 5 and 6).

Table 3 Descriptive statistics—scheduled caste (all states): average monthly bills

State	Mean	sd	Min	Max	p25	p50	p75	iqr
AP	946.719	1140.727	50	8000	250	866.6667	1166.667	916.6666
AS	618.7879	617.0921	70	2433.333	250	383.3333	850	600
BR	323.0621	322.7063	0	2500	137.5	200	433.3333	295.8333
CH	295.1852	147.9312	0	533.3333	230	300	383.3333	153.3333
DL	1154.007	1083.988	250	5666.667	500	738.3333	1333.333	833.3334
GJ	1168.583	840.8662	200	5566.667	673.5	1089.667	1433.333	759.8334
HP	474.2276	245.954	140	1200	316.6667	450	566.6667	250
HR	1223.611	638.8738	0	2400	700	1466.667	1633.333	933.3334
JH	104.5238	174.1102	0	645	0	0	145	145
KA	416.25	461.639	76.66666	2733.333	133.3333	275	550	416.6667
KL	537.619	507.4435	180	1533.333	250	300	933.3333	683.3333
MH	778.1765	577.1897	70	4666.667	420	583.3333	940	520
MP	455.0057	523.8825	0	3500	150	200	533.3333	383.3333
OR	274.3089	183.7735	0	966.6667	136.6667	233.3333	350	213.3333
PB	1309.579	934.8961	0	4500	666.6667	1400	1833.333	1166.667
RJ	1141.107	784.3493	0	4333.333	616.6667	866.6667	1466.667	849.9999
TN	119.1011	103.5241	0	583.3333	58.33333	88.33334	143.3333	85
TS	1037.344	590.4278	96.66666	3000	638.3333	950	1266.667	628.3333
UK	748.8889	356.7638	166.6667	1500	466.6667	833.3333	1000	533.3333
UP	999.9089	866.0353	0	6000	383.3333	816.6667	1266.667	883.3333
WB	920.9836	637.6338	76.66666	3333.333	350	879.5	1258.167	908.1666

Source Author's calculations from data

Table 4 Descriptive statistics—scheduled tribe category: average monthly bills

State	Mean	sd	Min	Max	p25	p50	p75	iqr
AP	1099.333	452.0374	433.3333	1916.667	783.3333	963.3333	1500	716.6667
AS	384.246	300.6871	0	1166.667	150	260	583.3333	433.3333
BR	355.5952	349.6042	0	1700	150	216.6667	440	290
CH	316.2171	272.2052	0	1833.333	200	250	333.3333	133.3333
DL	944.4444	467.0633	466.6667	1400	466.6667	966.6667	1400	933.3333
GJ	1195.694	1104.298	89.33334	6666.667	416.6667	833.3333	1500	1083.333
HP	421.2994	389.6127	133.3333	2900	220	333.3333	500	280
HR	2816.667	1673.486	1633.333	4000	1633.333	2816.667	4000	2366.667
JH	436.7361	619.7238	0	2466.667	0	216.6667	436.6667	436.6667
KA	351.5238	387.031	83.33334	1900	126.6667	183.3333	466.6667	340
KL	431.6667	285.1997	230	633.3333	230	431.6667	633.3333	403.3333
MH	700.3205	407.7585	146	2000	350	633.3333	903.3333	553.3333
MP	332.6633	454.2953	0	3450	135	200	366.6667	231.6667
OR	293.6923	234.2794	0	1166.667	133.3333	233.3333	400	266.6667
PB	1713.333	795.6396	400	3166.667	1183.333	1950	2063.333	880
RJ	939.4852	623.1181	0	2833.333	533.3333	766.6667	1166.667	633.3333
TN	210.2222	280.1317	0	1166.667	90	150	216.6667	126.6667
TS	1056.667	724.9652	300	3400	441.6667	800	1500	1058.333
UK	633.3333	185.5921	433.3333	800	433.3333	666.6667	800	366.6667
UP	752.1042	689.3898	0	2466.667	200.1667	591.6667	1200	999.8333
WB	685.4028	797.5798	66.66666	2363.333	150	234.8333	1083.333	933.3333

Source Author's calculations from data

Table 5 Descriptive statistics—other backward category: average monthly bills

State	Mean	sd	Min	Max	p25	p50	p75	iqr
AP	1198.138	602.573	93.333	5333.333	826.667	1133.333	1433.333	606.667
AS	455.969	434.133	0.000	1866.667	182.000	286.667	660.667	478.667
BR	342.790	308.630	0.000	2233.333	163.333	250.000	406.667	243.333
CH	332.500	256.028	0.000	1066.667	200.000	236.667	433.333	233.333
DL	1107.297	1083.951	200.000	5666.667	400.000	800.000	1333.333	933.333
GJ	921.130	739.104	133.333	4213.000	400.000	716.667	1266.667	866.667
HP	642.222	789.943	150.000	5333.333	266.667	466.667	700.000	433.333

(continued)

Table 5 (continued)

State	Mean	sd	Min	Max	p25	p50	p75	iqr
HR	1356.207	507.462	133.333	2933.333	966.667	1466.667	1666.667	700.000
JH	318.222	502.038	0.000	2866.667	0.000	200.000	350.000	350.000
KA	419.296	512.564	0.000	3233.333	121.667	230.000	500.000	378.333
KL	432.378	360.638	100.000	2166.667	266.667	300.000	466.667	200.000
MH	831.495	608.468	0.000	4666.667	416.667	650.000	1166.667	750.000
MP	491.622	451.097	0.000	2333.333	180.000	366.667	666.667	486.667
OR	332.636	295.040	0.000	1866.667	150.000	250.000	408.333	258.333
PB	1490.909	667.712	466.667	3000.000	1066.667	1366.667	1833.333	766.667
RJ	1120.601	671.787	233.333	3333.333	633.333	900.000	1500.000	866.667
TN	150.524	149.860	0.000	870.000	50.000	113.333	203.333	153.333
TS	997.923	562.332	96.667	4333.333	600.000	933.333	1333.333	733.333
UK	924.775	681.274	133.333	4000.000	533.333	725.000	1066.667	533.333
UP	900.901	806.531	0.000	7000.000	300.000	733.333	1233.333	933.333
WB	585.494	615.172	60.000	2600.000	150.000	266.667	900.000	750.000

Source Author's calculations from data

Table 6 Descriptive statistics—general category: average monthly bills

State	Mean	sd	Min	Max	p25	p50	p75	iqr
AP	1018.47	524.00	226.67	3000.00	633.33	866.67	1266.67	633.33
AS	481.19	417.27	0.00	2433.33	216.67	350.00	566.67	350.00
BR	411.57	454.53	0.00	3000.00	183.33	258.33	416.67	233.33
CH	336.83	281.68	86.67	866.67	150.00	227.50	350.00	200.00
DL	1320.69	1202.03	0.00	7333.33	600.00	1000.00	1500.00	900.00
GJ	1198.73	925.11	0.00	6333.33	616.67	949.33	1433.33	816.67
HP	612.98	705.81	93.33	5000.00	300.00	466.67	666.67	366.67
HR	1603.33	669.32	213.33	3166.67	1200.00	1516.67	2100.00	900.00
JH	235.35	260.61	0.00	866.67	0.00	226.33	316.67	316.67
KA	431.72	402.71	33.33	3666.67	163.33	283.33	566.67	403.33
KL	442.21	290.17	116.67	1866.67	300.00	375.00	500.00	200.00
MH	884.39	632.94	0.00	4666.67	466.67	666.67	1133.33	666.67
MP	523.72	564.06	0.00	2516.67	183.33	333.33	733.33	550.00
OR	365.77	205.58	0.00	900.00	191.67	350.00	500.00	308.33
PB	2450.00	1580.33	0.00	6833.33	1600.00	2100.00	3333.33	1733.33
RJ	1298.74	965.87	183.33	5833.33	583.33	966.67	1800.00	1216.67

(continued)

Table 6 (continued)

State	Mean	sd	Min	Max	p25	p50	p75	iqr
TN	261.26	373.30	0.00	3233.33	83.33	146.67	276.67	193.33
TS	1220.00	694.56	233.33	2633.33	750.00	1050.00	1466.67	716.67
UK	942.01	751.14	100.00	4066.67	533.33	700.00	1033.33	500.00
UP	1410.57	1680.12	0.00	12333.33	493.33	900.00	1600.00	1106.67
WB	866.71	622.59	50.00	3600.00	333.33	766.67	1235.33	902.00

Source Author's calculations from data

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Have Competitive Electricity Markets Rewarded Flexible Gas-Powered Generation? Australia's Lessons for ASEAN

Xunpeng Shi, Lequan Zhang, Keying Wang, Wen Chen, and Han Phoumin

Abstract The presence of a competitive electricity market, which allows high prices to reflect generation shortage, is often assumed to be a beneficiary factor for gas-powered generation, but the actual impact of a competitive electricity market on gas generation is yet to be examined. Using Australian daily gas and electricity data, this paper investigates whether Australia's competitive electricity markets have promoted the development of gas power generation (GPG). Considering the significant renewable energy penetration and increasing GPG in Australia and Australia's highly transparent competitive electricity market, the Australian case offers future scenarios that developing countries may face. The empirical tests fully support the hypothesis, namely GPG is negatively related to generation from VREs and positively related to electricity demand gap and electricity price. The findings suggest that ASEAN should boost gas use, continue electricity market liberalisation and regional electricity market integration.

Keywords Electricity market · Renewable · Gas power · Australia

JEL Classifications Q41 · C32

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1 Introduction

A competitive electricity market, which allows high prices to reflect generation shortage, is often assumed to be a beneficiary factor for gas-powered generation (GPG) (Devlin et al. 2017). However, the actual impact of a competitive electricity market on gas generation is yet to be examined. Natural gas is widely considered a transitional fuel during the energy transition process due to its flexibility in power generation that can mitigate volatility from variable renewable energies (VREs). Due to the relatively high costs of gas to coal, GPG is not competitive with coal-fired generation in a competitive market, except in the United States, where gas prices are low due to the shale gas revolution. However, GPG could be a cost-competitive solution to avoid the high system integration costs of a large share of VREs (Atwa and El-Saadany 2010). In the case of higher-than-usual demand for electricity or low generation from VREs, GPG will step in to fill the gap, which earns its reputation as a peak demand generator. For this flexible role, when gird scale storage is not available, the availability of GPG capacity will determine the penetration of VREs. However, due to its intermittent use induced by low generation from VREs, gas power generator needs high prices to be economically feasible. A competitive electricity market based on merit-order in dispatch could accelerate the development of VREs in theory. However, the role of the electricity market in facilitating VREs is certain as real-world evidence is mixed. For example, GPG was crowded out of the German generation mix (Hörnlein 2019).

Understanding the relationship between GPG and VREs is important as the rising VREs share worldwide prompts the question of who will provide the backup to offset the variability of VREs. While the development of storage technologies is the ultimate solution, GPG is considered an immediate and transitional solution. Much of the literature considers a functional gas market will provide the price signals for GPG. However, the relationship between GPG and VREs is complicated in that VREs could reduce the gas generation.

The Australian case provides an interesting example to investigate the role of the electricity market on the development of flexible generation capacity needed to mitigate VREs. The Australian national electricity market (NEM), which commenced operation as a wholesale spot market for electricity in December 1998, is one of the most successful electricity markets in the world. However, while VREs increased dramatically in capacity and generation, GPG is stable, and the capacity even declined between 2014 and 2020. Furthermore, two more GPG plants were being closed before 2022, and the future of the rest of the GPG plants is uncertain (Australian Energy Regulator 2021). The Morrison government proposed a gas-fired recovery to boost economic growth during the COVID-19 pandemic (Australian Government 2020). The policy assumes that Australia has abundant gas reserves, so GPG is affordable and can function as a critical enabler of the economy. However, the first project under this plan has invited many objections to the government investing in new gas (Guardian 2020). The Australian pioneer experience can inform latecomers in electricity market development, including Southeast Asian nations.

Considering the significant renewable energy penetration and increasing GPG in Australia and its highly transparent competitive electricity market in terms of historical prices and generating plant dispatch, with Australian daily gas and electricity data, this paper investigates: (i) whether GPG is negatively related to the generation from VREs, (ii) whether GPG and gas prices are positively related to electricity demand gap and electricity prices, and (iii) whether gas prices have mixed relationships with GPG.

The main contribution of this paper is threefold. Firstly, this chapter presents empirical studies on the relationship between electricity and natural gas markets in Australian NEM with daily data. Secondly, it presents an econometric analysis of the impact of renewable energy generation on GPG through actual generation instead of generation capacity. Thirdly, this chapter statistically tests the interplay between the gas and the electricity markets from multiple perspectives by using various time-series models and available daily data in different locations of Australia, considering the season effect, region effect, and endogenous effect, which provides convincing evidence to support this chapter's conclusion.

The paper proceeds as follows. After the introduction, Sect. 2 discusses the Australian NEM and the development of VREs and GPG. There researchers' hypotheses are proposed based on NEM and literature review. Section 3 reports the data and methodology. The empirical results are presented in Sect. 4 followed by implications for ASEAN and other latecomers in the electricity market. The last section concludes the paper.

2 Background and Research Hypotheses

2.1 The Australian National Electricity Market (NEM) in Transition

NEM started operation in December 1998 and spans Australia's eastern and south-eastern coasts, including six interconnected states and territories and five price regions: New South Wales (NSW) (including the Australian Capital Territory), Queensland, Victoria, South Australia, and Tasmania.[1] NEM is one of the world's largest interconnected electricity systems, having around 40,000 km of transmission lines and cables, delivering around 80% of Australia's electricity consumption, and supplying 10.2 million customers (DISER 2021). Around 30 retailers and over 100 generation companies are in the NEM wholesale market. There are also eight frequency control ancillary services spot market prices, with electricity production and frequency control services co-optimised across five imperfectly interconnected states or regions (Table 1).

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[1] Due to the distance between networks, Western Australia and the Northern Territory are not connected to NEM. They have their own electricity systems and separate regulatory arrangements.

Table 1 National electricity market, January 2021

Participating jurisdictions	OLD, NSW, VIC, SA, TAS, ACT
NEM regions	OLD, NSW, VIC, SA, TAS,
NEM installed capacity (including rooftop solar)	67,046 MW
Number of large generating units	295
Number of customers	10.2 million
NEM turnover 2020	$10.9 billion
Total electricity consumption 2020	190.1 TWh
National maximum demand 2020	35,043 MW

Source Australian Energy Regulator (2021)

NEM is a wholesale market where exchange between electricity producers and electricity consumers is facilitated through an electricity pool, a set of procedures that the Australian Energy Market Operator (AEMO) manages according to laws, regulations, and rules rather than a physical location. NEM is made possible by sophisticated information technology systems that balance supply with demand, maintain reserve requirements, determine dispatch and the spot price, and facilitate the financial settlement of the physical market (AEMO 2010).

NEM has a transparent and balanced regulatory framework, including various key institutions (DISER 2021). The Australian Energy Market Commission (AEMC) develops market operation rules, and the Australian Energy Regulator (AER) enforces the rules and judgments on the regulatory proposals of monopoly network operators. AEMO handles day-to-day operations of the electricity and gas markets. The Energy Security Board (ESB) was established to monitor NEM's system performance, risks, improvement opportunities, and affordability to safeguard NEM's health. The ESB also coordinates the implementation of the reform blueprint produced by Australia's chief scientist. The Australian Competition and Consumer Commission informs the Australian government on long-term energy policies that may be changed due to changes in electricity generation, emerging technologies, such as solar batteries, and shifting consumer preferences. The policies will further promote NEM's modernisation.

2.2 *Energy Transition in Australia's Electricity Generation*

Energy transition has progressed well in Australia's electricity market, summarised from two aspects: capacity and electricity generation by fuel type. Figure 1 shows that the generation capacity for black and brown coal has declined in the past 2

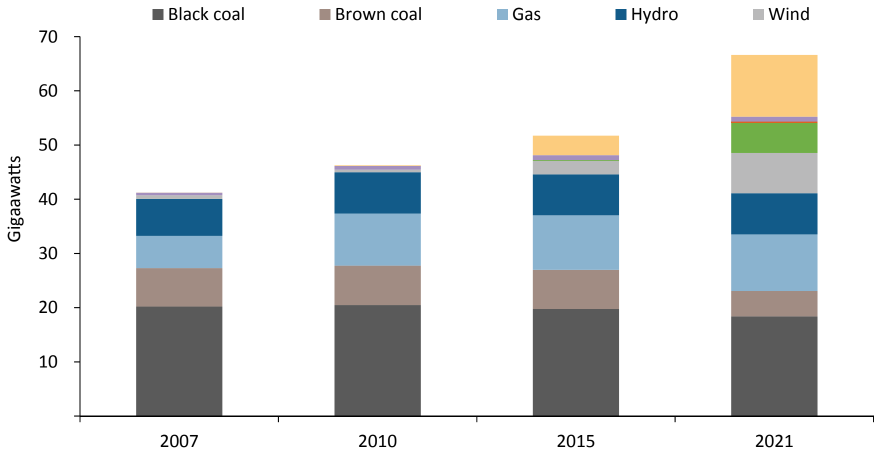

Fig. 1 Generation capacity, by generation technology. *Source* Australian Energy Regulator (2021)

decades, accounting for 66.2% in 2007 and 34.6% in 2021. Meanwhile, wind and solar generation capacity has dramatically increased after 2015. Notably, solar PV (including solar farms and rooftop solar) was the second-largest generation technology in Australia in 2021. The total VREs generation capacity is the largest amongst all fuels, 36.9%.

Moreover, a close examination of the change in generation capacity can better demonstrate the transition in the power generation sector. According to Fig. 2, there has been no new investment in coal-fired generation in Australia since 2012, and almost 4 gigawatts (GW) of coal-fired generation has left the market since 2012. On the contrary, around 12.5 GW of large-scale wind and solar capacity and 8.5 GW of

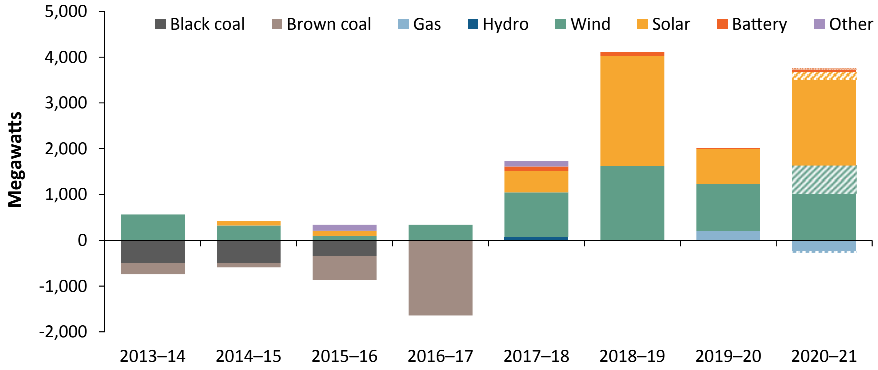

Fig. 2 Entry and exit of generation capacity in NEM by generation technology. *Note* Capacity includes scheduled and semi-scheduled generation but not non-scheduled or rooftop PV capacity. 2020–2021 data are on 31 March 2021. Investment and closures expected between 1 April and 30 June 2021 are shown as shaded components. *Source* Australian Energy Regulator (2021)

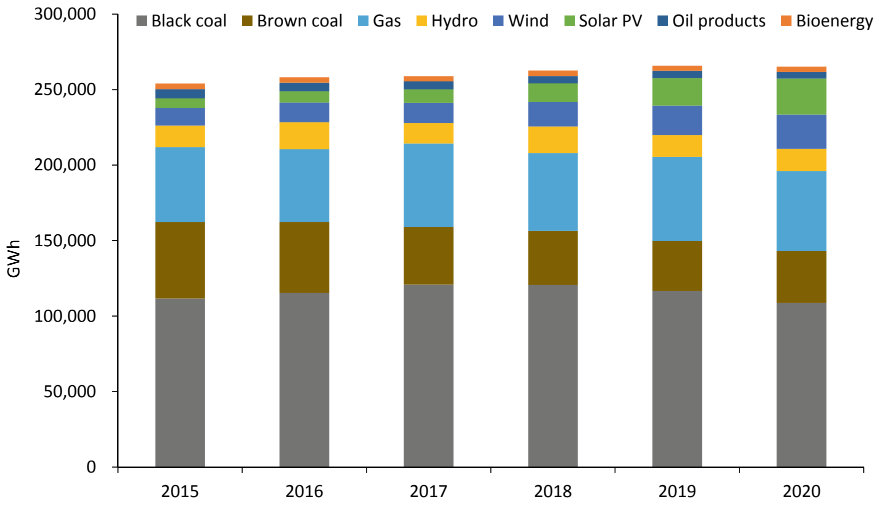

Fig. 3 Australian electricity generation by fuel type. *Source* Department of Industry Innovation and Science (2021)

rooftop solar PV began operating over this same period and significantly increased dramatically from 2017.

Regarding electricity generation by fuel type in Australia, the proportion of generation from coal declined from 63.9% in 2015 to 53.9% in 2020. Meanwhile, the proportion of generation from VREs increased from 14.1 to 24.4%. Notably, solar power grew by 30.3% in 2020 and overtook wind to be the largest contributor to VREs, with a 36.9% share of renewable generation and 9.5% of total electricity generation in Australia (Fig. 3).

As for the generation output by fuel source in NEM, the proportion of generation output from VREs has reached 27.3%, of which the proportion of wind generation output is 13.9% (Table 2).

2.3 Development of GPG and VREs

GPGs typically operate as ‘flexible’ or ‘peaking’ plants in Australia because gas is a relatively expensive fuel for electricity generation. Gas generation will be operated when electricity demand and prices are highest; it also tends to be seasonal. Furthermore, it is strongly affected by the increasing renewable generation and withdrawal of coal-fired generators.

GPG plays an increasingly crucial role in managing the variability of output of weather-dependent renewable generations. However, GPG capacity has not been developed along with the VREs. While VRE generation capacity increased from 674 MW in 2007 to 24,614 MW in 2021, GPG capacity only increased from

Table 2 Generation in NEM by fuel source (as of 30 September 2021)

Fuel	NEM capacity (% of total generation)	NEM output (% of total generation)
Black coal	32.0	49.2
Brown coal	8.4	16.7
Gas	17.1	6.4
Hydro	14.6	9.3
Wind	14.7	13.9
Liquid	1.3	0.1
Grid solar	9.9	3.9
Battery	0.6	0.1
Other	1.4	0.4

Source Australian Energy Regulator (2021)

5,946 MW to 10,436 MW at the same time. Moreover, GPG capacity declined between 2014 and 2021 (Fig. 4), despite a small new investment in gas generation in 2019. Two GPG plants were also scheduled to retire in 2020–2022. The future of other plants is speculated to be in danger, too.

The gas power generation is also not in parallel with VRE development. For example, while VRE generation increased 126-fold from 260 GWh in 2000–2001 to 32,778.8 GWh in 2018–2019, the GPG only increased threefold from 17,271 to 52,387 GWh in the same period. Particularly, when VRE generation increased 430% in 2010–2019, the GPG only increased 7% (Fig. 5).

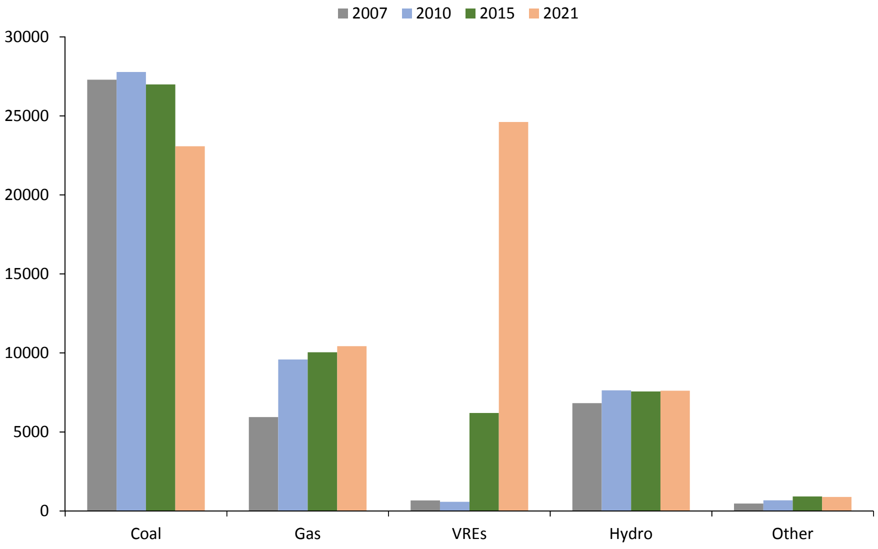

Fig. 4 Generation capacity by technology (MW). *Source* Australian Energy Regulator (2021)

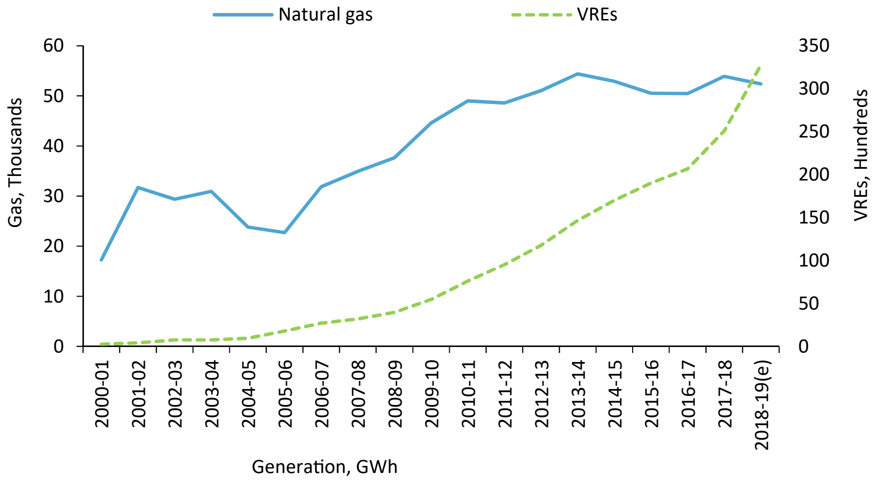

Fig. 5 Generation in the Australian national electricity market. *Sources* Department of Industry Innovation and Science (2021)

The lack of parallel development between GPG and VREs could be due to a low frequency of high electricity prices and a high frequency of high gas prices. Due to the large share of renewables in the generation mix, the capability of coal and gas plants to set high dispatch prices declines (AER 2020). The number of intervals when the spot electricity price is above $300 per MWh in NEM (Fig. 6) may impair the profitability of gas plants that often rely on selling cap contracts to customers that wish to insure against high prices. This low frequency of high electricity prices is in contrast with the significantly increased gas prices from 2015 to 2018 when Queensland's liquefied natural gas (LNG) plants purchased gas supplies from the domestic market to meet export obligations (Grafton et al. 2018). Gas prices were volatile in 2017 due to the

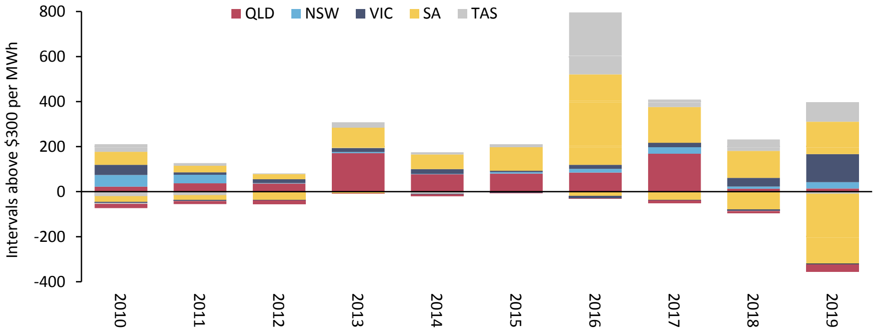

Fig. 6 Prices above $300 per MWh and below—$100 per MWh (number of intervals). NSW = New South Wales, QLD = Queensland, SA = South Africa, TAS = Tasmania, VIC = Victoria. *Source* Australian Energy Regulator (2021)

LNG export and large brown coal plant closures (Hazelwood and Northern). These events resulted in high electricity prices across NEM despite electricity demand remaining flat. Higher fuel costs further worsened the economic viability of the GPG during this period. Recent dramatic falls in NEM electricity prices followed the domestic gas market, which has followed the world LNG markets. Given that the NEM market structure and demand have not changed much since 2017, it is hard to see how it could be suggested that the level of generation competition has had any material impact on electricity price outcomes—either high or low.

2.4 Regional Generation Mix

The generation mix has significant heterogeneity across the states or territories in NEM. From the regional distribution of the generation capacity, coal is the dominant generation source in NSW and Queensland, while gas and VREs dominate South Australia, and hydroelectricity dominates Tasmania (Fig. 7). Moreover, wind generation capacity in Australia's NEM is located mainly in Victoria, South Australia, and NSW. Solar generation capacity is situated primarily in NSW and Queensland. Meanwhile, GPG capacity is located mainly in Queensland, South Australia, Victoria, and NSW. Each of these regions also has short-term gas trading hubs. Australian domestic wholesale gas price market hubs are found in Adelaide, Sydney, Brisbane, and Victoria's Declared Wholesale Gas Market (DWGM) (Grafton et al. 2018).

As for the electricity generation in 2020, coal was still the dominant generation source in NSW, Victoria, and Queensland, while VREs and hydrogen dominate South Australia and Tasmania (Fig. 8). In terms of emissions, South Australia and Tasmania have done well.

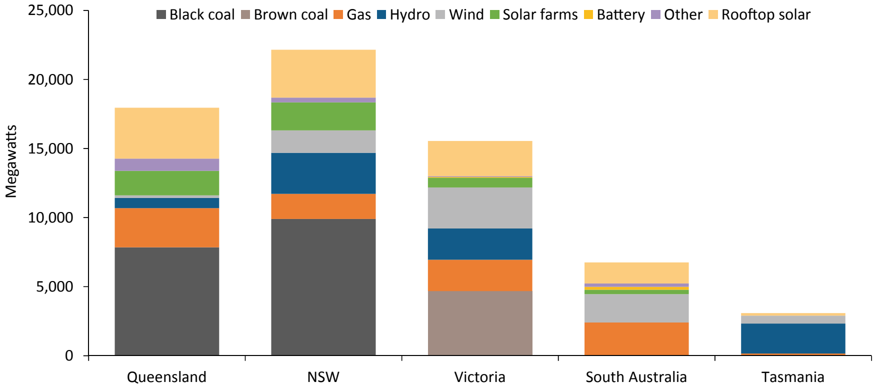

Fig. 7 Generation capacity in the national electricity market by region and fuel course in 2020. *Note* Generation capacity on 1 January 2021. Other dispatch includes biomass, waste gas, and liquid fuels. *Source* Australian Energy Regulator (2021)

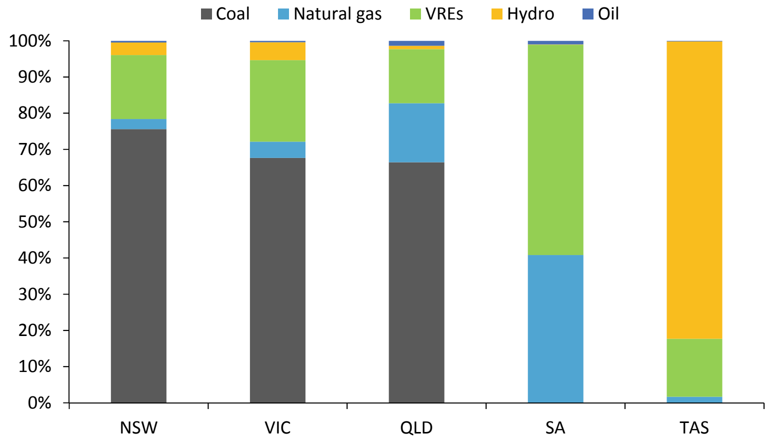

Fig. 8 Australian electricity generation mix by state, 2020. *Source* Department of Industry Innovation and Science (2021)

The proportion of GPG in South Australia is still the largest, at 56.6% and 55.0% in 2007 and 2017, respectively. That declined to 40.9% in 2020, causing VRE generation to increase sharply (Figs. 9 and 10). On the other hand, the proportion of GPG in Queensland climbed to 22.4% in 2014, then decreased to 9.6% in 2020. The proportion is not high in other regions, but it has been decreasing in recent years.

Moreover, each state in Australia will further increase VRE investment (Fig. 11). For example, Queensland and NSW will invest more in solar generation. NSW, Victoria, and South Australia will invest more in wind generation, while the GPG investments of states are very small.

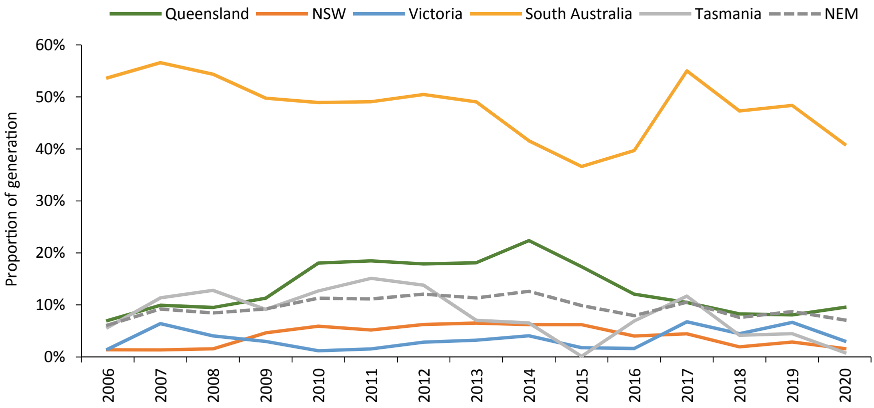

Fig. 9 The proportion of gas-powered generation. *Source* Australian Energy Regulator (2021)

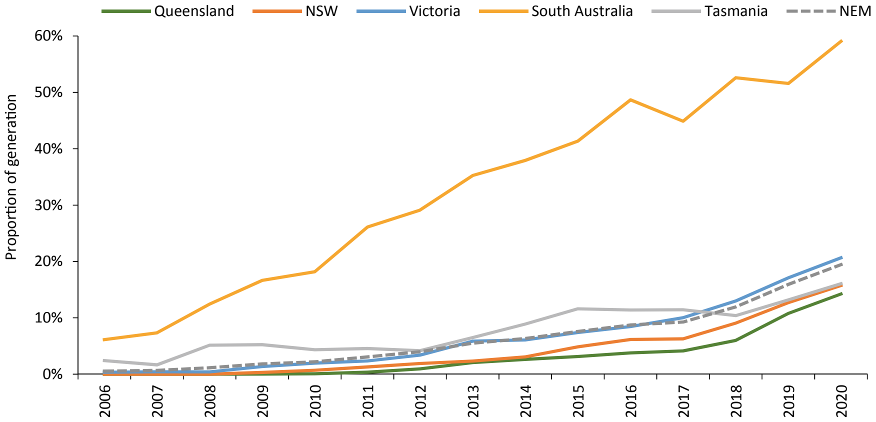

Fig. 10 The proportion of VRE generation. *Source* Australian Energy Regulator (2021) AER; AEMO (data)

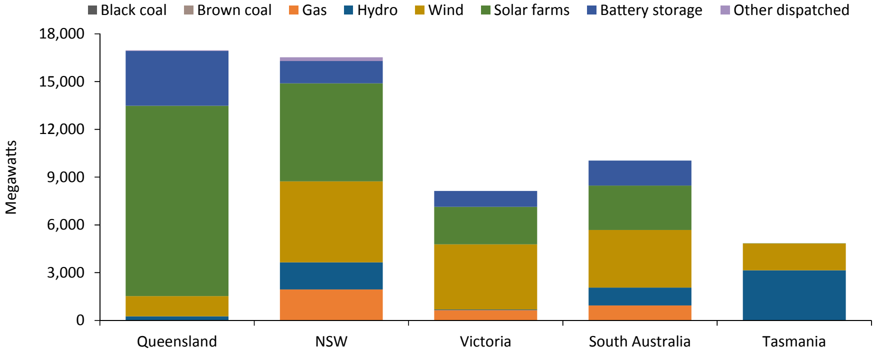

Fig. 11 Announced generation proposals, January 2021. *Source* Australian Energy Regulator (2021)

2.5 Gas Demand

The gas demand for GPG was above 220 petajoules (PJ) before 2014 and then declined to 116 PJ in 2020 with the increase of VERs (Fig. 12).

As for each region, the gas demand for GPG shows obvious seasonal fluctuations. For example, there was a significant decline from 2014 in Queensland and from 2017 in other regions (Fig. 13).

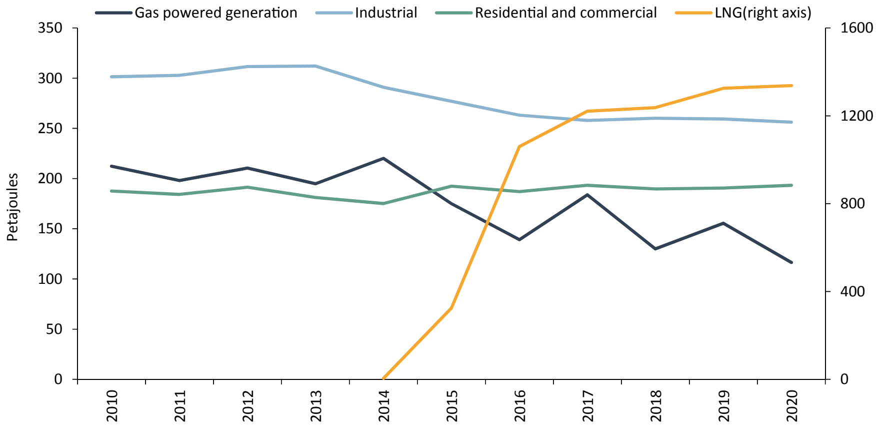

Fig. 12 Eastern Australian gas demand. *Source* (AEMO 2021)

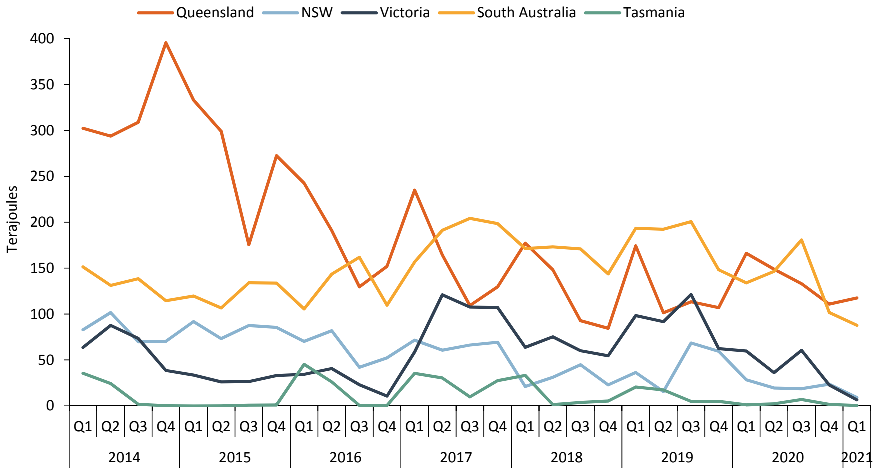

Fig. 13 Quarterly gas demand for gas-powered generation (average Tj/day). *Source* Australian Energy Regulator (2021)

2.6 The Electricity and Gas Price

The trend of electricity prices in various regions is very similar, showing obvious fluctuations and an upward trend (Fig. 14). The peaks appear in 2002, 2005, 2007 (2008 in Victoria), 2014, and 2017. The electricity prices of Victoria and South Australia reached the highest in 2019 in this period, but the electricity prices in each region dropped sharply in 2020.

The trend of gas prices in various regions is more similar, showing an inverted 'U' (Fig. 15). Moreover, the trend of gas prices is like that of electricity prices in the

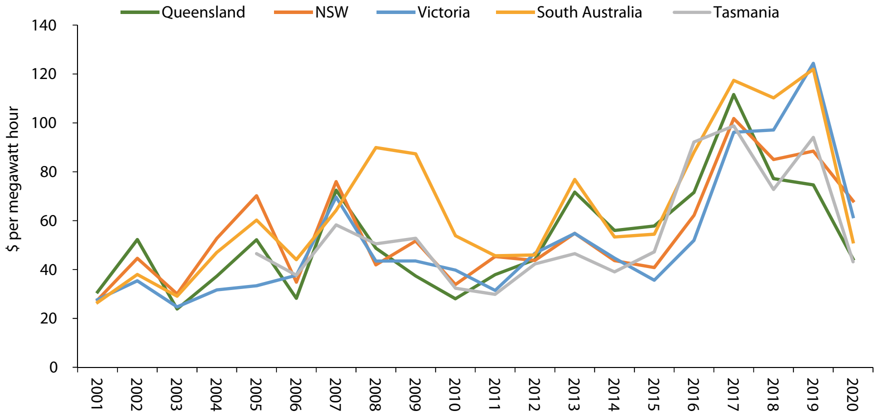

Fig. 14 Wholesale electricity prices. *Note* Volume weighted annual averages. *Source* Australian Energy Regulator (2021)

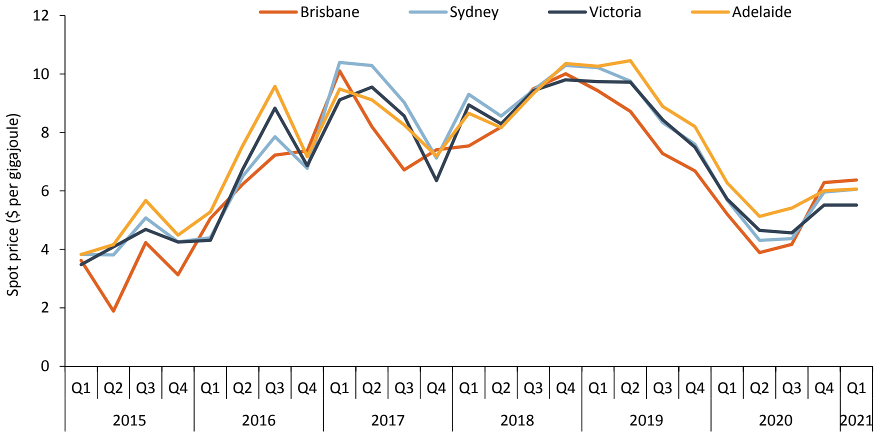

Fig. 15 Eastern Australia gas market prices. *Note* Adelaide, Brisbane, and Sydney prices are ex ante. The Victorian price is the 6 a.m. schedule price. *Source* Australian Energy Regulator (2021)

period after 2015. The peaks appear in Q1 of 2017 and Q1 of 2019, respectively, and there is a clear trough in Q2 of 2020 (Fig. 15).

2.7 Research Hypothesis

A functional electricity market will shape the relationship between the power market with high penetration of renewable energy and gas generation. Due to its capabilities of high ramp rates, quick start-ups, and relatively low emissions, the GPG provides a lower, although not zero, emission solution to the intermittence of VREs (Heinen et al. 2017). However, whether the power market with high penetrations of renewable energy can facilitate the GPG will depend on market design, which needs to adequately reward the flexibility that, in most cases, is provided by the GPG (Devlin et al. 2017). In the Australian context, gas has been found to have a competitive role against coal, while facilitating the development of renewables (Guidolin and Alpcan 2019).

Nevertheless, the GPG is likely to be affected by VRE generation in the electricity generation partly because the GPG is functional as a backup for the VREs (Qadrdan et al. 2010). Therefore, we have the first hypothesis:

Hypothesis 1: The GPG is negatively related to VRE generation.

An increasing share of GPG results in a stronger interconnection between gas and electricity networks. The GPG is related to the electricity demand, especially the peak demand (Chen et al. 2018). Moreover, high demand tends to be associated with higher wholesale energy prices. Thus, a positive correlation exists between the wholesale spot electricity price and GPG dispatch. That leads to our second hypothesis.

Hypothesis 2: The GPG is positively related to the electricity demand gap and electricity prices.

Higher spot gas prices usually imply higher electricity prices, and this effect is amplified at higher prices due to the convexity of the bid-supply curve (Poyrazoglu and Poyrazoglu 2019). Therefore, we have the third hypothesis.

Hypothesis 3: Spot gas prices are positively related to the electricity demand gap and electricity prices.

Gas price could affect the adequacy of natural gas supply and the long-term expansion planning of electricity generation. But, on the contrary, the gas spot prices are reflected as the costs for GPG, so that gas prices will be passed through by the marginal GPG generator to the electricity price (Bolinger et al. 2006; Csereklyei et al. 2019). Therefore, we have the fourth hypothesis.

Hypothesis 4: Spot gas prices have mixed relationships with the GPG.

3 Data and Methodology

3.1 Data and Sources

Data used in this paper include electricity generation by fuel type, daily spot electricity prices, electricity demand, and daily gas prices in four regions (NSW, Victoria, Queensland, and South Australia).[2] All data are sourced from AEMO.

(1) The electricity generation dispatch data includes all units AEMO captures, namely, scheduled, semi-scheduled, and non-scheduled units in NEM, which are a 5 min dispatch interval by unit (DUID). We match the electricity generation data with the region and fuel source information for each DUID and then aggregate the data by the level of date*region *fuel source,[3] and the data spans from 1 January 2011 to 28 April 2021. The Declared Wholesale Gas Market (DWGM) also provides the daily data of GPG demand in Victoria.

(2) The electricity price data and electricity demand data date back to the start of NEM, 13 December 1998 to 28 April 2021.

(3) The spot gas prices of NSW, Queensland, and South Australia are from the short-term trading market (STTM), which includes the date, region, ex ante market price, and provisional market price, and the period is from 1 September 2010, when the STTMs started operation, to 28 April 2021. The spot gas prices data of Victoria are from the DWGM. The data period is from 1 February 2007 to 28 April 2021. Unlike the STTM, the DWGM has multiple trading prices per day. Thus, we average those prices to produce the daily prices.

3.2 Methodology

In this chapter, we use different methods to test the four hypotheses considering the relationship of variables.

To test hypotheses 1 and 2, we set up the OLS regression model for each region and the panel model for all regions as Eqs. (1) and (2).

$$\begin{aligned}\ln gpg_t &= \beta_0 + \beta_1 \ln Wind_t + \beta_2 \ln Solar_t + \beta_3 \ln ed_t + \beta_4 \ln pe_t \\ &+ \beta_5 \ln gasp_t + Year_{dummy} + Season_{dummy} + \varepsilon_t\end{aligned} \tag{1}$$

$$\begin{aligned}\ln gpg_{it} &= \beta_0 + \beta_1 \ln Wind_{it} + \beta_2 \ln Solar_{it} + \beta_3 \ln ed_{it} + \beta_4 \ln pe_{it} \\ &+ \beta_5 \ln gasp_{it} + Year_{dummy} + Season_{dummy} + \mu_i + v_t + \varepsilon_{it}\end{aligned} \tag{2}$$

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[2] The other two jurisdictions were not included because the Australian Capital Territory is a part of the NSW electricity market while the proportion of the GPG in Tasmania is very small.

[3] The fuel sources include black coal, brown coal, gas, wind, hydro, solar, biomass, battery, and liquid fuel.

where t is the time and i is the region. gpg is the daily GPG;$Wind$ and $Solar$ are the daily power generation from wind and solar, respectively; ed is the daily electricity demand gap[4]; pe is the daily spot electricity price; and$gasp$ is the daily gas price. All data in the models in this paper is in logarithmic form. $Year_{dummy}$ and $Season_{dummy}$ are the dummy variables of year and season, μ_i is the region fixed effect, and v_t is the time fixed effect. β_1 and β_2 are expected to be negative, while β_3 and β_4 are positive.

In hypothesis 3, for testing the relationship between daily gas price and electricity demand gap, we set the OLS regression model for each region and panel model for all regions, as Eqs. (3) and (4).

$$\ln gasp_t = \beta_0 + \beta_1 \ln ed_t + Year_{dummy} + Season_{dummy} + \varepsilon_t \tag{3}$$

$$\ln gasp_{it} = \beta_0 + \beta_1 \ln ed_{it} + Year_{dummy} + Season_{dummy} + \mu_i + v_t + \varepsilon_{it} \tag{4}$$

β_1 is expected to be positive.

Furthermore, considering the endogenous and possible causal relationship between the daily gas and electricity prices, we firstly set up VAR models for each region as Eqs. (5) and (6) and then conducted the Granger causality test.

$$\ln gpsp_t = \beta_{10} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{11k} \ln gpsp_{t-k} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{12k} \ln pe_{t-k} + \varepsilon_{1t} \tag{5}$$

$$\ln pe_t = \beta_{20} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{21k} \ln pe_{t-k} + \sum_{\mathrm{i}}^{\mathrm{p}} \beta_{22k} \ln gpsp_{t-k} + \varepsilon_{2t} \tag{6}$$

where $\ln gpsp_{t-k}$ is the lag of daily gas generation price, and $\ln pe_{t-k}$ is the lag of spot electricity price. β_{11}, β_{12}, β_{21}, and β_{22} are expected to be positive.

To test hypothesis 4 on the mixed relationships between gas prices and the GPG, we set up VAR models as Eqs. (7) and (8) for each region and then conducted the Granger causality test.

$$\ln gasp_t = \beta_{20} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{21k} \ln gasp_{t-k} + \sum_{\mathrm{i}}^{\mathrm{p}} \beta_{22k} \ln gpg_{t-k} + \varepsilon_{2t} \tag{7}$$

$$\ln gpg_t = \beta_{10} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{11k} \ln gpg_{t-k} \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{12k} \ln gasp_{t-k} + \varepsilon_{1t} \tag{8}$$

where $\ln gasp_{t-k}$ is the lag of spot gas price, and $\ln gpg_{t-k}$ is the lag of daily GPG.

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[4] The daily electricity demand gap is the difference between the potential electricity demand and the real electricity demand, which can be estimated by the HP filter method.

In addition, as AEMO provides the data of GPG demand for Victoria, which is regarded as a proxy variable of GPG, we set a robustness test for hypotheses 1 and 2 with GPG demand data in Victoria to strengthen the conclusions of this paper.

4 Empirical Results

4.1 Unit Root Test for Time Series

Firstly, we conduct the unit root tests for time series, and the results are shown in Table 3. The *p* value of each time series is less than 0.01, which means each series is stationary and can set up regression models directly with them.

4.2 Natural gas's Flexibility Role in the Power System

The first empirical question is whether the GPG has been functioning as a flexible and dispatchable power source in the national market. This flexibility role can be tested through two relationships: (i) GPG and the wind or solar power dispatch for GPG's backup role to VREs (hypothesis 1), and (ii) GPG and the total electricity demand for GPG's peak generator role (hypothesis 2). In each case, the dependent variable is GPG dispatch, and the core explanatory variable is wind generation and

Table 3 Unit root test results

Variables	NSW	OLD	SA	VIC	Panel
Ln (GPG dispatch)	−22.845 (0.000)	−13.748 (0.000)	−24.124 (0.000)	−28.678 (0.000)	−56.213 (0.000)
Ln (GPG demand)				−34.575 (0.000)	
Ln (wind generation)	−24.841 (0.000)	−10.068 (0.000)	−37.749 (0.000)	−31.602 (0.000)	−65.547 (0.000)
Ln (solar generation)	−9.185 (0.000)	−10.726 (0.000)	−10.745 (0.000)	−9.943 (0.000)	−34.714 (0.000)
Ln (gas price)	−13.727 (0.000)	−14.181 (0.000)	−8.214 (0.000)	−12.416 (0.000)	−24.614 (0.000)
Ln (electricity price)	−20.780 (0.000)	−27.023 (0.000)	−32.592 (0.000)	−22.121 (0.000)	−69.594 (0.000)
HP_Ln (electricity demand gap)	−22.988 (0.000)	−19.933 (0.000)	−26.299 (0.000)	−28.323 (0.000)	−51.112 (0.000)

Note In parentheses is the *p* value corresponding to the statistical value
Source Authors' calculations

Table 4 Testing natural gas's flexibility role in power system (for panel data)

Dependent variable	GPG dispatch						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Wind generation	-0.330^{***}				-0.295^{***}	-0.221^{***}	-0.079^{**}
	(0.016)				(0.031)	(0.030)	-0.031
Solar generation		0.019			-0.225^{***}	-0.089^{**}	-0.113^{***}
		(0.028)			(0.044)	(0. 043)	-0.044
Electricity demand gap			3.872^{***}			4.507^{***}	3.184^{***}
			(0.100)			(0.205)	(0.237)
Electricity price				1.088^{***}			1.085^{***}
				(0.030)			(0.068)
Gas price							-0.317^{***}
							(0.116)
Constant	11.049^{***}	9.337^{***}	8.726^{***}	5.199^{***}	14.154^{***}	12.672^{***}	8.227^{***}
	(0.137)	(0.210)	(0.039)	(0.107)	(0.392)	(0.382)	(0.485)
Year_dummy	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Season_dummy	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Adj R^2	0.059	0.109	0.119	0.124	0.068	0.09	0.085
N	12,217	7,264	15,008	14,612	5,300	5,300	5,112

Note ***, **, * are statistically significant at the 1%, 5%, 10% level
Source Authors' calculations

solar generation, electricity demand gap, respectively. Table 4 shows the empirical results for panel data, and Table 5 shows the results for the regions.

Firstly, the coefficient of wind generation is negative and significant at the 1% level for the panel data, as shown in columns (1), (5)–(7) of Table 4. And as shown in Table 5, the coefficient of wind generation is also significantly negative in NSW, South Australia, and Victoria, but not significant in Queensland. Four states rely on GPG differently. In NSW, South Australia, and Victoria, GPG was squeezed due to lower grid demand and higher wind and solar output. However, the main reason for the slumping GPG in Queensland is the increasing gas fuel cost due to the start of Queensland's LNG industry rather than the wind generation.

Moreover, the wind generation proportion in Queensland is the lowest in NEM. Thus, the negative effect of wind on GPG is not significant in Queensland. In addition, the coefficient of the solar generation is negative and significant at the 1% level for panel data in columns (5)–(7) of Table 4. And the coefficient of solar generation is also significantly negative in NSW, Queensland, and Victoria when the dependent variable is GPG dispatch but not significant in Victoria when the dependent variable is GPG demand. More particularly, the coefficient is positive and significant at the 1% level in South Australia. The inconsistent coefficients of solar generation may be related to its scale. Compared to the GPG, the scale of solar generation is still small in some regions and does not have enough substitution effect on the GPG.

Table 5 Testing natural gas's flexibility role in power system (for regional data)

Dependent variable	GPG dispatch				GPG demand
	NSW	QLD	SA	VIC	VIC
	(1)	(2)	(3)	(4)	(5)
Wind generation	-0.136^{***}	-0.019	-0.240^{***}	-0.221^{***}	-0.235^{**}
	(0.065)	(0.014)	(0.013)	(0.060)	(0.116)
Solar generation	-0.362^{***}	-0.129^{***}	0.024^{**}	-0.146^{**}	-0.106
	(0.123)	(0.032)	(0.011)	(0.068)	(0.134)
Electricity demand gap	5.848^{***}	2.880^{***}	1.172^{***}	3.367^{***}	2.033^{**}
	(0.565)	(0.169)	(0.054)	(0.478)	(0.924)
Electricity price	3.348^{***}	0.193^{***}	0.152^{***}	1.522^{***}	2.491^{***}
	(0.202)	(0.033)	(0.016)	(0.132)	(0.220)
Gas price	-1.361^{***}	-0.584^{***}	0.364^{***}	0.186	0.52
	(0.198)	(0.053)	(0.053)	(0.300)	(0.574)
Constant	1.806	10.899^{***}	10.224^{***}	3.622^{***}	-10.012^{***}
	(1.198)	(0.337)	(0.201)	(1.101)	(2.102)
Year_dummy	Yes	Yes	Yes	Yes	Yes
Season_dummy	Yes	Yes	Yes	Yes	Yes
Adj R^2	0.433	0.566	0.748	0.443	0.366
N	2,157	974	971	1010	1,046

Note ***, **, * are statistically significant at the 1%, 5%, 10% level
Source Authors' calculations

Especially in South Australia, the proportion of GPG is the highest, and the scale of solar generation is the lowest.

On the average effect of VREs on the GPG, when the wind and solar generation increases by 1%, the GPG will decrease by an average of 0.079% and 0.113%, as in column (7) of Table 4. The negative effect of wind generation on the GPG is the largest in South Australia and is the smallest in Queensland. The negative effect of solar generation on the GPG is the largest in NSW and is the smallest in Queensland. But in South Australia, the relationship is positive. The GPG increases in South Australia may mainly link to the demand gaps due to the closure of coal power stations. Also, South Australia relies on the GPG more than other states. Thus, even though the solar generation is growing, the GPG also increases to meet the demand gaps.

The significantly negative coefficients of wind and solar generation in most models provide sufficient support for hypothesis 1, namely, the GPG is negatively related to the generation from VREs.

Secondly, the coefficients of electricity demand gap are positive and significant at the 1% level for the panel data and all regions (Tables 4 and 5). And when the electricity demand gap increases by 1%, the GPG will increase by an average of 3.184%. The positive effect is the largest in NSW and is the smallest in South Australia. The significantly positive coefficients support hypothesis 2, namely, the GPG is positively related to the electricity demand gap.

4.3 GPG's Response to Market Price Signals

In a market setting, price signals reflect the gaps between supply and demand. Therefore, this empirical test will check how much GPG will respond to electricity prices. As in the previous case, there are estimations in panel data models (Table 4) and a separate estimation for each regional electricity market (Table 5).

Columns (4) and (7) of Tables 4 and 5 show that the coefficients of electricity prices are positive and significant at the 1% level for the panel data and all regions. And when the electricity price increases by 1%, the GPG increases by an average of 1.085%. The positive effect is the largest in NSW and is the smallest in South Australia, which is the same as the effect of electricity demand gap. In 2020, the GPG fell in NSW mainly due to low electricity prices. However, in South Australia, the reduced generation coincided with the closure of two units at gas-powered plants, which may have resulted in the smallest positive effect of electricity price on the GPG. The significantly positive effect of electricity prices on the GPG also supports hypothesis 2, namely, the GPG is positively related to electricity prices.

4.4 Interrelationship Between Gas and Electricity Prices

The active role of the GPG in the power market will form a close relationship between the natural gas market and the electricity markets. These will have two sub-hypotheses.

4.4.1 Spot Gas Prices Will Positively Respond to Electricity Prices

We construct a VAR model and Granger causality test to explore the relationship between gas prices and electricity prices for the hypothesis. The results are shown in Tables 6 and 7.

It can be seen that electricity prices of a day lag period have a positive impact on the gas prices, and gas prices of a day and 2 days lag period also positively impact on the electricity prices. In addition, the gas price does Granger-cause electricity price, and electricity price also does Granger-cause gas price in all four regions.

Table 6 The relationship between gas and electricity prices

	NSW	QLD	SA	VIC	Panel (FE)
	(1)	(2)	(3)	(4)	(5)
Dependent variable: Gas price					
L1. Gas price	0.622*** (0.016)	0.660*** (0.017)	0.753*** (0.016)	0.712*** (0.016)	0.671*** (0.008)
L2. Gas price	0.241*** (0.016)	0.214*** (0.017)	0.208*** (0.016)	0.208*** (0.016)	0.227*** (0.008)
L1. Electricity price	0.096*** (0.015)	0.113*** (0.017)	0.021*** (0.003)	0.027*** (0.009)	0.055*** (0.005)
L2. Electricity price	0.011 (0.014)	−0.018 (0.016)	−0.009*** (0.003)	0.004 (0.009)	0.000*** (0.005)
Constant	−0.194*** (0.033)	−0.173*** (0.048)	0.015 (0.010)	0.009 (0.019)	−0.050*** (0.014)
Dependent variable: Electricity price					
L1. Electricity price	0.607*** (0.014)	0.507*** (0.016)	0.378*** (0.016)	0.628*** (0.016)	0.511*** (0.008)
L2. Electricity price	0.145*** (0.014)	0.136*** (0.015)	0.089*** (0.016)	0.065*** (0.015)	0.129*** (0.008)
L1. Gas price	0.103*** (0.015)	0.091*** (0.015)	0.454*** (0.081)	0.182*** (0.028)	0.145*** (0.013)
L2. Gas price	0.042*** (0.015)	0.049*** (0.015)	−0.016 (0.080)	0.054* (0.028)	0.064*** (0.012)
Constant	0.729*** (0.031)	1.174*** (0.044)	1.334*** (0.050)	0.796*** (0.034)	1.055*** (0.021)
N	3,713	3,352	3,452	3,665	14,182

Note ***, **, * are statistically significant at the 1%, 5%, 10% level
Source Authors' calculations

4.4.2 Spot Gas Prices Are Positively Related to Electricity Demand

We construct the OLS model and panel fixed model to test the relationship between gas prices and electricity demand, and the results are shown in Table 8. It can be seen that the coefficients of electricity demand are positive and significant at the 1% level for all models. This means that the electricity demand is positively related to gas prices; when electricity demand increases by 1%, gas prices increase by an average of 0.463%. The positive impact of electricity demand on gas prices is the largest in Queensland and the smallest in South Australia.

Hence, the results of Tables 6, 7, 8 support hypothesis 3 that spot gas prices are positively related to electricity prices and electricity demand.

Table 7 Granger causality Wald tests for gas and electricity prices

		H0: Electricity price does not granger-cause gas price	H0: Gas price does not granger-cause electricity price
NSW	chi2	103.560	245.860
	P	0.000	0.000
QLD	chi2	59.661	239.080
	P	0.000	0.000
SA	chi2	41.200	316.690
	P	0.000	0.000
VIC	chi2	21.602	274.390
	P	0.000	0.000

NSW = New South Wales, QLD = Queensland, SA = South Australia, VIC = Victoria
Note In parentheses is the p value corresponding to the statistical value
Source Authors' calculations

Table 8 The relationship between gas prices and electricity demand

Dependent variable	Gas Price				
	NSW	QLD	SA	VIC	Panel (FE)
	(1)	(2)	(3)	(4)	(5)
Electricity demand	0.733^{***} (0.056)	0.781^{***} (0.134)	0.288^{***} (0.019)	0.475^{***} (0.038)	0.463^{***} (0.025)
Constant	0.983^{***} (0.017)	1.190^{***} (0.087)	1.231^{***} (0.010)	0.991^{***} (0.014)	1.072^{***} (0.011)
Year_dummy	Yes	Yes	Yes	Yes	Yes
Season_dummy	Yes	Yes	Yes	Yes	Yes
Adj R^2	0.681	0.523	0.810	0.747	0.594
N	3,764	3,426	37,548	3,761	14,705

Note ***, **, * are statistically significant at the 1%, 5%, 10% level
Source Authors' calculations

4.5 Interrelation Between the GPG and Gas Prices

We construct a VAR model and Granger causality test to test the relationship between the GPG and gas prices. Tables 9 and 10 show that the GPG of a day's lag period has a significant positive impact on gas prices in South Australia and Victoria but has no significant impact in NSW and Queensland and the panel data. The GPG of 2 days lag period has a significant negative impact on gas prices in all regions and the panel data. The gas prices of a day lag period have a significant positive impact on the GPG in South Australia and Victoria. Still, they have no significant impact in NSW, Queensland, and panel data. But the GPG of 2 days lag period has a significant

Table 9 The relationship between gas-powered generation (GPG) and gas prices

	NSW	QLD	SA	VIC	Panel (FE)
	(1)	(2)	(3)	(4)	(5)
Dependent variable: Gas price					
L1. Gas price	0.660^{***} (0.016)	0.668^{***} (0.017)	0.750^{***} (0.016)	0.685^{***} (0.016)	0.687^{***} (0.008)
L2. Gas price	0.268^{***} (0.016)	0.212^{***} (0.017)	0.226^{***} (0.016)	0.258^{***} (0.016)	0.246^{***} (0.008)
L1. GPG	−0.001 (0.002)	−0.028 (0.026)	0.044^{***} (0.005)	0.006^{***} (0.002)	0.002 (0.002)
L2. GPG	-0.005^{**} (0.002)	-0.064^{**} (0.026)	-0.046^{***} (0.005)	-0.006^{***} (0.002)	-0.007^{***} (0.002)
Constant	0.167^{***} (0.019)	1.114^{***} (0.137)	0.070^{**} (0.034)	0.095^{***} (0.015)	0.151^{***} (0.013)
Dependent variable: GPG					
L1. GPG	0.641^{***} (0.016)	0.933^{***} (0.017)	0.809^{***} (0.016)	0.603^{***} (0.017)	0.650^{***} (0.008)
L2. GPG	0.129^{***} (0.016)	-0.078^{***} (0.017)	-0.117^{***} (0.016)	0.015 (0.017)	0.089^{***} (0.008)
L1. Gas price	0.041 (0.117)	−0.014 (0.011)	0.112^{**} (0.053)	0.348^{***} (0.127)	0.060 (0.040)
L2. Gas price	-0.344^{***} (0.015)	-0.044^{***} (0.011)	−0.077 (0.053)	−0.033 (0.126)	-0.137^{***} (0.040)
Constant	2.403^{***} (0.144)	1.529^{***} (0.091)	2.900^{***} (0.114)	2.412^{***} (0.118)	2.429^{***} (0.064)
N	**3,723**	**3,422**	**3,750**	**3,669**	**14,564**

Note ***, **, * are statistically significant at the 1%, 5%, 10% level
Source Authors' calculations

Table 10 Granger causality wald tests for gas-powered generation and gas prices

		H0: Gas-powered generation does not granger-cause gas price	H0: Gas price does not granger-cause gas-powered generation
NSW	chi2	13.757	40.351
	P	0.001	0.000
QLD	chi2	51.611	91.476
	P	0.000	0.000
SA	chi2	97.484	10.909
	P	0.000	0.004
VIC	chi2	10.453	43.193
	P	0.005	0.000

Source Authors' calculations

negative impact on gas prices in NSW, Queensland, and panel data, consistent with the results in Table 5.

Although the effect of independent variables 1 day lag period on dependent variables varies in different regions, the coefficients 2 days lag period are negative. So, the relationship between the GPG and gas price is roughly negatively correlated.

The results of the Granger causality Wald test show that the GPG does Granger-cause gas prices in all four regions, and gas prices also do Granger-cause GPG in all regions.

5 Policy Implications for ASEAN and Latecomers

With a total GDP of US $3.1 trillion in 2017, ASEAN is the fifth-largest economy in the world, only after the United States, China, Japan, and Germany. The ASEAN economy is expected to grow to US $12.25 trillion in 2050. Under the business-as-usual scenario (BAU), ASEAN's total final energy demand is expected to grow from 480 Mtoe in 2017 to 1,355 Mtoe in 2050, and its emissions will increase from 375 Mt CO_2 (Mt-C) equivalent to 1,216 Mt-C (Han and Kimura 2021). Although the share of electricity in ASEAN's total final energy consumption (TFEC) will increase modestly from 16.5% in 2017 to 20.65% in 2050 in BAU, the total electricity output will increase threefold from 1,041 to 3,439 TWh in BAU and 2,895 TWh in the alternative policy scenario (APS) during the same period.

Unfortunately, fossil fuels will still count for 72% of the generation mix even in the APS, while VREs will account for only 12.3% in 2050. Due to the low electricity share in the TFEC and the generation mix, emissions in ASEAN are expected to increase from 375 to 876 Mt-C in 2050 (Han and Kimura 2021). In the context of global consensus on fighting climate change, the ASEAN region needs to take immediate actions to reduce future carbon emissions through measures such as more gas use and renewable energies.

Given the high share of fossil fuels (78% share of oil, coal, and natural gas) in ASEAN's energy mix, ASEAN must advance the decarbonising process, which requires policy commitments and significant efforts. However, although Singapore has announced its plan to achieve net-zero emissions beyond 2050, many ASEAN countries have yet to set any net-zero emissions target.

Natural development in decarbonising energy mix is possible. Since VREs such as solar and wind have so far contributed negligible amounts (2.4% in 2020) to the power mix (Han et al. 2021), the future growth potential is there. Due to its low starting level, renewables such as biomass, wind, and solar are expected to increase largely by 93% due to upscaling renewable policy in ASEAN. Such rapid growth requires grid-stabilising techniques to accommodate the increasing penetration of VREs.

ASEAN's rich natural gas reserves provide a much-needed technical option to manage the challenges from large shares of VREs, but there is not a market to reward gas's role. Due to its flexibility in generation, natural gas generation can reduce emissions (compared with coal power generation), provide power system flexibility, and maintain national security (compared with imported electricity). Natural gas accounts for 40% of the ASEAN generation mix, an asset for advancing VREs. Given the urgent and critical need for transitioning to low-carbon energies, especially to decarbonise the grid electricity sector, many ASEAN governments will need to implement deeper electricity market reforms to accommodate clean and renewable electricity.

ASEAN is stepping behind Australia's electricity sector from three perspectives: the linearisation of the electricity sector, development of electricity markets, and increasing penetration of renewable energy. Many ASEAN countries embarked on electricity reform from the centrally or vertically integrated stated ownership to the hybrid market-based system in which state-owned utility remains the 'single buyer' and the private sector joins in the supply of electricity as 'independent power producers'. However, the ASEAN electricity markets are not competitive in most countries except the Philippines and Singapore. Given the current electricity market in ASEAN, attracting new investment in this sector is very hard. It is especially difficult to introduce the high share of renewables and innovative technologies such as smart grids, which will allow more renewable energy penetration technically.

Therefore, the Australian experience can inform ASEAN on electricity sector development and renewable energy. In the absence of competitive markets, natural gas generation, despite being flexible, would not deliver the flexibility as contractual and other institutional constraints prevent them from being a mate of VREs.

Our estimation results of Australia's NEM indeed suggest that a well-functioning electricity market can reward the flexible role of natural gas, and a competitive market is certainly conducive to the development of renewable energies. Therefore, we could generate the following implications from our study.

First, ASEAN should leverage the flexible role of natural gas. Such significant role in the ASEAN generation mix is an asset. Thus, efforts should be made to generate gas pricing signals to timely react to power market needs.

Second, ASEAN should continuously liberalise its electricity markets and establish a merit-order competitive electricity market. Confirmed significant roles of the electricity market in promoting the GPG can shed light on ASEAN's future policies on the electricity markets.

Third, ASEAN needs to continuously promote regional integration as another cost-effective policy to handle the increasing penetration of VREs. ASEAN countries have complementary energy resources, and the abundance of hydropower resources in the Greater Mekong Subregion is an asset to offset the volatilities from VREs. Therefore, the penetration of solar PV and wind in ASEAN could be advanced by power connectivity and trade within ASEAN (IRENA 2018; Shi 2016).

A framework that can combine the gas and electricity markets should be established. Due to the increasing penetration of VREs, power systems are relying more on the flexibility roles of the GPG, which will gradually link the currently separated gas and electricity markets (Chen et al. 2018; Heinen et al. 2017). However, the existing market framework is not conducive: neither reliable nor efficient and also economically unfriendly to GPG investors (Heinen et al. 2017). A framework that combines the two markets and properly prices the scarce resources, e.g. gas transmission capacity, is required to efficiently allocate resources while satisfying the demand (Heinen et al. 2017).

6 Conclusion

Natural gas is considered a natural partner for VREs due to its flexibility in generation at affordable prices. However, whether the GPG can play such a flexible role in the generation mix depends on such flexibility being rewarded. A competitive electricity market rewards peak prices to GPG and is expected to be a reason to liberalise the electricity markets. Empirical evidence of a competitive market's role in GPG development can inform future electricity market reform, mainly in developing countries.

This chapter theoretically analyses the relationship between the competitive electricity market and the GPG and hopes to take Australia's energy transformation as an example to give ASEAN some constructive suggestions. First, based on the literature review, this chapter puts forward several assumptions on the relationship between the electricity market and Australia's GPG. Then it verifies the hypotheses by constructing OLS, panel, and VAR models, and the Granger causality test with the daily data from AEMO.

The empirical tests fully support the hypotheses: (i) that the GPG is negatively related to generation from VREs and positively related to electricity demand gap and electricity prices, (ii) spot gas prices are positively related to electricity prices and electricity demand, and (iii) spot gas prices have mixed relationships with the GPG. Therefore, the findings suggest that ASEAN should boost gas use and continue electricity market liberalisation and regional electricity market integration.

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Decarbonizing Emissions in the Electricity Sector of the Mekong Subregion: Policy Implications

Han Phoumin

Abstract The Mekong subregion faces tremendous challenges regarding the future energy landscape and how the energy transition will embrace a new architecture. This includes sound policies and technologies to ensure energy access, affordability, energy security, and energy sustainability. Fossil fuels (oil, coal, and natural gas) comprise almost 80% of the region's current energy mix. Moreover, the region will continue to rely on fossil fuels for economic growth in the foreseeable future. Thus, decarbonising emissions in the Mekong subregion is critically important to redirect the energy trajectory of fossil fuel–based energy system to low-carbon and green energy systems. This chapter discusses the energy landscape, including the rising electricity demand in the region, explores the potential of renewables in replacing fossil fuels in the electricity sector, and examines the possibility of carbon capture, utilisation, and storage for remaining emissions from coal and natural gas power generation. It also examines the power generation sector's market structure and policy challenges to embrace electricity market liberalisation in the region. Finally, the chapter will provide policy recommendations to stakeholders, such as electricity authorities and business players in this market.

Keywords Decarbonisation · Power mix · Renewables · And clean energy and technologies

JEL Codes Q59 · Q49 and Q29

1 Introduction

Common energy challenges link the Mekong subregion.[1] There are challenges in maintaining economic growth and ensuring energy security while curbing climate

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[1] The Mekong subregion here refers to the Lower Mekong subregion consisted of Cambodia, Lao PDR, Myanmar, Thailand,, and Viet Nam.

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change and reducing air pollution. At the intersection of these challenges is the corresponding need to rapidly develop and deploy energy efficiency, low-emissions coal technology, and double the share of renewables in the energy mix towards more inclusive and sustainable growth. This is because the region's energy demand is expected to rise significantly over the next 30 years (Kimura and Han 2020). Such an increase brings both opportunities and challenges, including climate change which is a result of fossil fuels. Despite significant progress in recent decades in terms of energy poverty alleviation, countries such as Cambodia and Myanmar are still struggling to provide energy access to their rural populations.

The coronavirus disease (COVID-19) pandemic caused a global economic downturn. Countries in the Mekong subregion and the Association of Southeast Asia Nations (ASEAN) were no exception. Since the outbreak of the COVID-19 pandemic in early 2020, the travel restrictions imposed by countries have impacted the service sectors, such as tourism, and industries, especially the supply chain. In addition, the pandemic brought the world economy into recession: global growth contracted by −4.9% in 2020, and all ASEAN countries experienced negative growth, except Viet Nam (Table 1) (WEO 2020). As the result, global carbon dioxide (CO_2) emissions were estimated to fall by 8% in 2020 compared to 2019 levels (Han 2020).

However, as governments begin lifting restrictions and business activities resume, so will the demand for energy. Economic recovery could see carbon dioxide (CO_2) emission levels bounce back very quickly (2 Institute 2020). The post-COVID-19 economic recovery will drive increased energy demand, which emphasises the need to find appropriate energy policy and strategy to permanently lower emissions as part of efforts to contribute to the Paris Agreement on climate change to limit the rising global temperature to lower than 1.5 °C by 2050.

Given the high share of fossil fuels (almost 80% share of oil, coal, and natural gas) in the Mekong subregion's energy mix in 2017, decarbonising the energy system will require efforts and commitment, such as policy reform and energy infrastructure

Table 1 Economic growth rate of Mekong Subregion and ASEAN countries

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Brunei	−2.9	1.4	2.4	2.7	−1.4	5.6	4.4	2.8	2.4	2.2
Cambodia	7.0	7.2	7.5	6.7	−3.9	5.6	6.2	6.2	6.2	5.7
Indonesia	5.7	4.5	−1.1	5.7	−4.8	5.5	4.7	4.0	3.8	3.8
Lao PDR	7.5	5.3	4.3	3.0	−9.2	−2.5	3.7	4.1	4.1	4.3
Malaysia	−1.7	2.1	11.7	1.6	−7.0	10.3	6.7	6.4	5.3	4.9
Myanmar	−5.1	−3.2	3.2	−3.2	−2.9	1.7	2.5	2.7	2.7	2.8
Philippines	2.7	0.8	1.8	7.8	−4.6	5.3	5.6	6.1	6.0	6.1
Singapore	2.7	4.4	5.9	−0.4	−7.5	7.2	3.4	3.1	3.0	2.9
Thailand	0.4	8.2	9.4	6.5	−5.8	4.5	5.8	5.3	5.0	4.2
Viet Nam	4.6	5.3	5.7	6.1	0.8	4.9	5.8	5.4	5.1	4.8

Source Data taken from database of WEO (2020) investment towards clean technologies, energy efficiencies, and renewable energy. Renewables such as solar and wind have contributed negligent amounts (2.4% in 2020) to the power mix (Han et al. 2021). Of course, reforms in the energy sector are needed, especially in the electricity market, to have more open competition in all sections of the electricity market, such as generation, transmission, and distribution. Further reform in rules and procedures will be needed to allow more advanced and competitive technologies to enter the market share of the energy mix rather than using old rules and procedures to favour traditional fuel. The future electricity market needs to move from the hybrid model 'single buyer' to full market competition, with an independent power regulator and regional institutional system operator to facilitate the electricity market in the wholesale and retail markets and encourage more market players to join. This way, electricity reform will attract foreign investment to modernise the electricity infrastructure, including more efficient power systems, and gradually allow inefficient power generation and technologies to phase out. The quality energy infrastructure needs to be promoted and adopted in the region to ensure inclusive growth to bring harmony amongst people, development, and environmental sustainability.

The pursuit of net-zero emission is starting. It is particularly challenging for many countries highly dependent on fossil fuels, especially for many developing countries worldwide. In ASEAN and East Asia, Japan and South Korea have joined the pledge for net-zero emissions by 2050, while China aims to achieve net-zero emissions by 2060. Singapore has also announced its ambitious plan to go net-zero emissions beyond 2050. Although many ASEAN countries have yet to set any specific target for net-zero emissions, countries are working hard to redesign their policy to a more sustainable and cleaner energy system (Nishimura 2021).

Going for a green and clean energy system will rely on clean technologies, such as carbon capture, utilisation, and storage (CCUS) and the deployment of renewable energy resources. We know that ASEAN is rich in solar photovoltaic (PV) resources. However, only a few countries, such as Philippines, Indonesia, and Viet Nam have offshore wind resources. On the other hand, Continental Southeast Asia, known as the Mekong subregion, is rich in hydropower resources. Thus, the high penetration of solar photovoltaic (PV) and wind in ASEAN could be facilitated by the future power connectivity and trade within the whole ASEAN. If the ASEAN electricity market gradually moves up to multilateral/electricity market, the hydropower resources from the Mekong subregion could play a significant role as the baseload power. It complements the high penetration of solar and wind energy very well (Han 2021).

However, the high penetration of variable renewable energy such as wind and solar will require a large capacity of electrical discharge 'battery storage' to back up the power shortage during the worse and extreme days of less sunshine and less wind. Since the large capacity of battery storage calls for huge investment costs, it is pragmatic to use thermal power plants for backup. In this case, CCUS is indispensable in the quest for decarbonised energy system (Han et al. 2020). While hydrogen is another crucial technology for decarbonisation, when it is produced from fossil fuels, CCUS is also needed to neutralise CO_2 emissions. Towards carbon neutrality, the International Energy Agency (IEA) estimated that almost half of the emission reduction must come from carbon sink technologies such as CCUS (IEA 2020). Thus, CCUS commercialisation will be central to the success of deep decarbonisation. This is particularly the case for the ASEAN region, including the Mekong subregion with strong presence of fossil fuels now and in the future.

The paper discusses the energy landscape of the Mekong subregion, including the rising electricity demand and the potential of renewables to replace fossil fuels in the electricity sector. The paper also examines the possibility of CCUS deployment for the remaining emissions from coal and natural gas power generation. The chapter also examines the challenges of market structure and policy in the power generation sector in moving forward to embrace electricity market liberalisation in the region. Finally, it provides policy recommendations to stakeholders, such as electricity authorities and business players in this market.

2 Energy Landscape and the Rising Electricity Demand in the Mekong Subregion

At the outset, this section employed the energy outlook and saving potential database of the Economic Research Institute for ASEAN and East Asia (ERIA). Experts from ASEAN and East Asia provided regular data inputs to produce regular energy outlook reports. The author of this paper is also the co-editor of the *Energy Outlook and Saving Potential for East Asia*. Thus, he accessed the database and extracted data for the energy landscape of the Mekong subregion. This section provides a view of the energy landscape, such as the energy supply and demand situation, including the power generation of the Mekong subregion.

The total primary energy supply (TPES) in the Mekong subregion (Cambodia, the Lao PDR, Myanmar, Thailand, and Viet Nam) is projected to increase by 189% in the business-as-usual scenario (BAU),[2] and by 121% in the alternative policy scenario (APS)[3] from 2017 to 2050. It will increase from 234 million tonnes of oil equivalent (Mtoe) in 2017 to 675 Mtoe in BAU, and 516 Mtoe in the APS by 2050. The Mekong subregion is heavily dependent on fossil fuels (oil, coal, and gas). Based on the baseline data in 2017, the fossil fuel share in the energy supply is around 75% of the total in the region. The region will see a growing dependence on fossil fuels in the future. In this regard, the study results showed that by 2050, the share of fossil fuels in the energy supply will be about 88% in BAU and 81% in the APS. In actual amounts, the combined coal, oil, and gas in the energy supply are expected to increase from 175 Mtoe in 2017 to 595 Mtoe in BAU and 420 Mtoe in the APS in 2050. Oil

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[2] The business-as-usual scenario (BAU) was developed for each East Asia Summit country, outlining future sectoral and economy-wide energy consumption, assuming no significant changes to government policies.

[3] The alternative policy scenario (APS) was set to examine the potential impacts if additional energy efficiency goals, action plans, or policies being or likely to be considered were developed.

is the dominant energy source in the energy supply, followed by natural gas and coal (Fig. 1). Oil is expected to increase from 74 Mtoe in 2017 to 255 Mtoe for BAU and 197 Mtoe for the APS in 2050. Natural gas is expected to increase from 49.3 Mtoe in 2017 to 184.3 Mtoe for BAU and 133.6 Mtoe for the APS in 2050. Coal will increase from 51.6 Mtoe to 155.8 Mtoe for BAU and 89.3 Mtoe for the APS in 2050. Other sectors, including biomass, wind, solar, and electricity, will increase from 58.8 Mtoe in 2017 to 80.0 Mtoe for BAU and 96.5 Mtoe for the APS in 2050.

The difference between BAU and the APS is the energy-saving potential in the TPES. Coal will see the largest energy savings, with a potential of 42.7%, followed by 27.5% for natural gas and 22.7% for oil. These large energy savings are expected from implementing energy efficiencies, with improved efficiency in thermal power plants and energy efficiency in end-use sectors such as transportation, industry, commercial, and residential. The Mekong subregion is expected to see an increase in renewables of about 20.6% in the energy supply mix by 2050 (Fig. 1).

Industry accounts for the largest share of the total final energy consumption (TFEC), followed by transportation and other commercial and residential sectors (Fig. 2). Energy consumption in the industry sector is expected to increase from 68 Mtoe in 2017 to 217 Mtoe for BAU and 184 Mtoe for the APS by 2050. Energy consumption in the transport sector is predicted to increase from 48 Mtoe in 2017 to 160 Mtoe for BAU and 104 Mtoe for the APS by 2050. For other sectors, including commercial and residential, energy consumption is expected to increase from 46 Mtoe in 2017 to 105 Mtoe for BAU and 89 Mtoe for the APS by 2050. Non-energy (naphtha) is also used in the TFEC, especially for the refinery and petrochemical industries. Its use will remain the same for BAU and the APS in 2050.

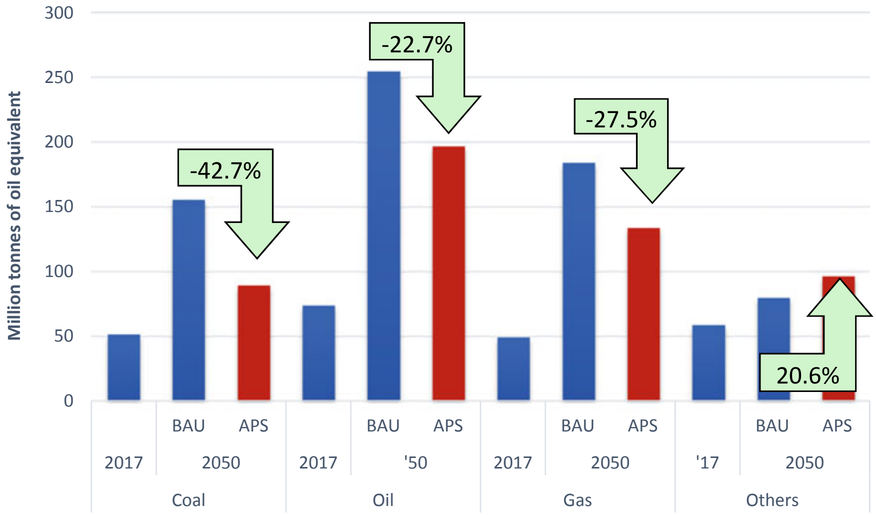

Fig. 1 TPES, by Energy Source, BAU versus APS. APS = alternative policy scenario, BAU = business-as-usual scenario, TPES = total primary energy supply. *Source* Author's calculations

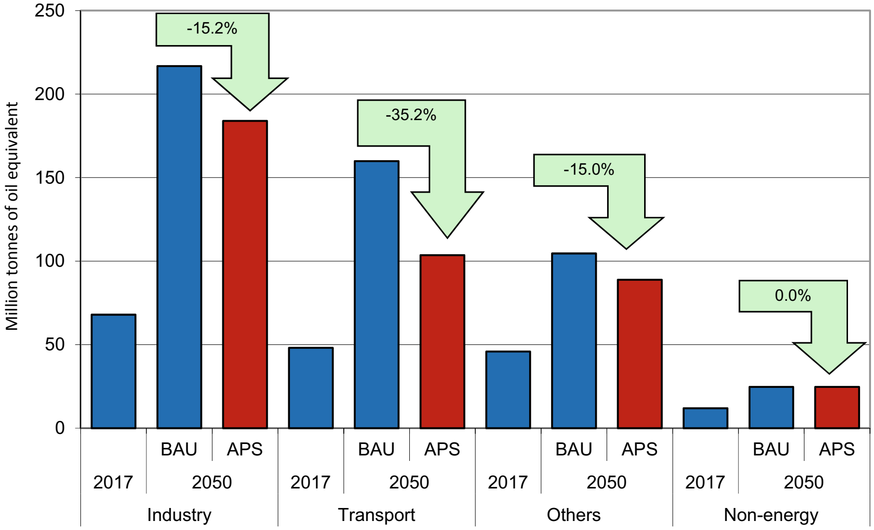

Fig. 2 TFEC, by Sector, BAU vs APS. APS = alternative policy scenario, BAU = business-as-usual scenario, TFEC = total final energy consumption. *Source* Author's calculations

Energy saving is expected to be highest for the transportation sector at 35.2%, 15.2% for the industry sector, and 15.0% for the commercial and residential sectors (Fig. 2). The reduction in energy consumption in the final energy sector will derive from fuel efficiencies in the transportation, industry, commercial, and residential sectors (e.g., the introduction of more efficient heat and power, a shift to electric vehicles, hybrid and fuel cell vehicles, more efficient electric appliances, and energy-saving buildings).

The natural gas is the dominant fuel source in power generation, followed by coal and hydropower (Fig. 3). Natural gas is expected to increase from 170.4 megawatt-hours (MWh) in 2017 to 798.7 MWh in 2050 in BAU and 690.3 MWh in the APS by 2050. Electricity from coal-fired power generation will increase from 116 MWh in 2017 to 374 MWh in BAU and 150 MWh in the APS by 2050. Electricity from hydropower is expected to increase from 133 MWh in 2017 to 252 MWh in BAU and 245 MWh in the APS by 2050.

Electricity from 'others' (including biomass, wind, and solar) will increase from 6.2 MWh in 2017 to 87.2 MWh in BAU and 172.4 MWh in the APS by 2050. Significant energy savings are expected in coal-fired power generation (59.7% savings, a reduction from BAU to the APS), followed by the gas combined cycle (13.6%). Energy savings in power generation are expected due to the introduction of high thermal efficiency. Electricity from renewables such as biomass, wind, and solar is expected to increase sharply by 97.7% due to upscaling of renewables in the power mix in the APS scenario than with BAU.

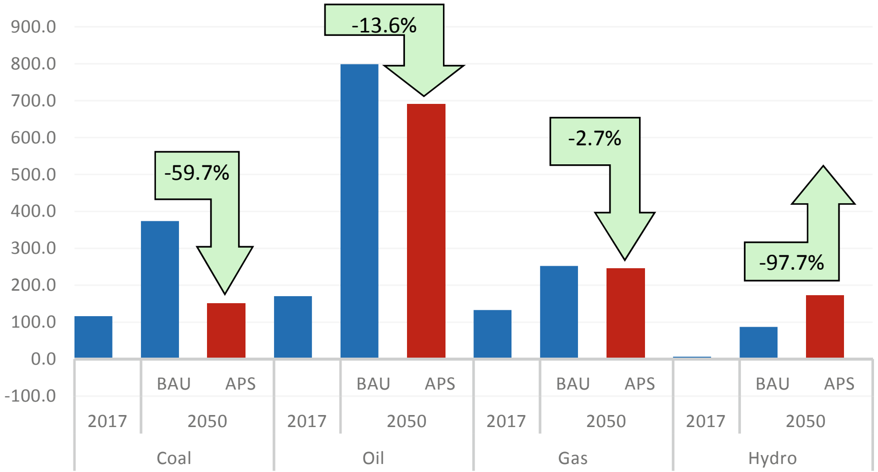

Fig. 3 Total Power Generation (TFEC), by Energy Source, BAU vs APS. APS = alternative policy scenario, BAU = business-as-usual scenario, TFEC = total final energy consumption. *Source* Author's calculations

3 Decarbonising the Electricity Sector in the Mekong Subregion

The region will continue to rely on fossil fuel in the foreseeable future. This is mainly because of the high combined share of fossil fuels in the power generation mix of the Mekong subregion, at 67% in 2017 and 78% in BAU by 2050 (Fig. 4). The decarbonisation scenario ($DeCO_2$) assumes a 30% reduction of coal, oil, and gas

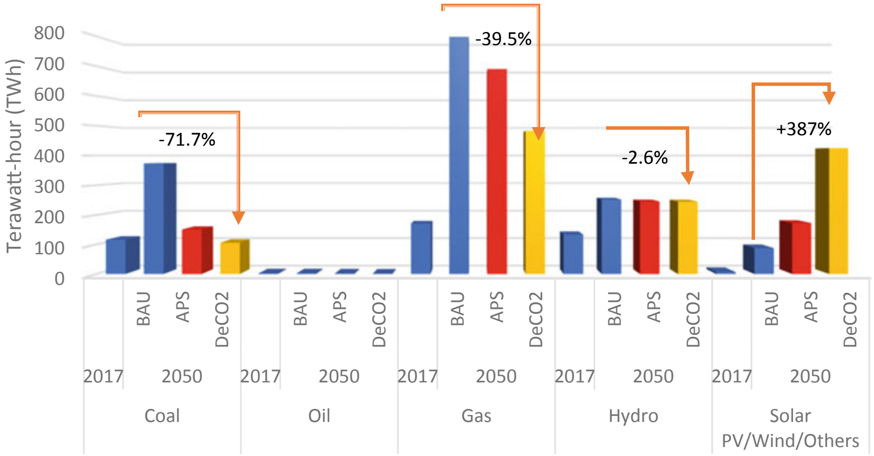

Fig. 4 Decarbonisation scenarios ($DeCO_2$) in the electricity sector. *Source* Author's calculations

further from the APS by 2050. At the same time, the reduction of power generation from fossil fuels is replaced by increasing renewables such as solar PV, wind, and biomass. Large fossil fuel power generation is expected to reduce substantially from BAU to $DeCO_2$. In this case, coal-fired power generation output will be reduced by almost 72% from BAU to $DeCO_2$; gas-fired power generation will be reduced by almost 40% from BAU to $DeCO_2$. In comparison, renewables are expected to increase by 387% from BAU to $DeCO_2$ (Fig. 4).

CO_2 emissions rose from 42 million tonnes of carbon equivalent (Mt-C) in 1990 to 127 Mt-C in 2017. CO_2 emissions are expected to rise to 457 Mt-C in BAU and 318 Mt-C in the APS by 2050. However, emissions will drop to 140 Mt-C in $DeCO_2$. It is a large reduction In percentage, about 69.2% emission reduction from BAU to $DeCO_2$ (Fig. 5). However, such a large emission reduction can only happen when renewables' acceleration can be realised by 2050.

Thus, $DeCO_2$ is considered in the high share of renewables, particularly solar PV and wind energy in the power generation mix. All Mekong subregion countries are rich in solar PV, while wind energy potential is scarce in the region, except for Viet Nam and some parts of Thailand (Global Solar Atlas 2021). Thus, decarbonising the electricity sector in the Mekong Subregion will greatly rely on the increasing share of solar PV and wind. Hydropower does not seem to be an option as the resources will reach their potential limitation. Furthermore, some of the Mekong mainstream hydropower may not be suitable from the viewpoint of sustainability. Thus, solar PV and wind are the resources that can be utilised, especially abundant solar resources, in

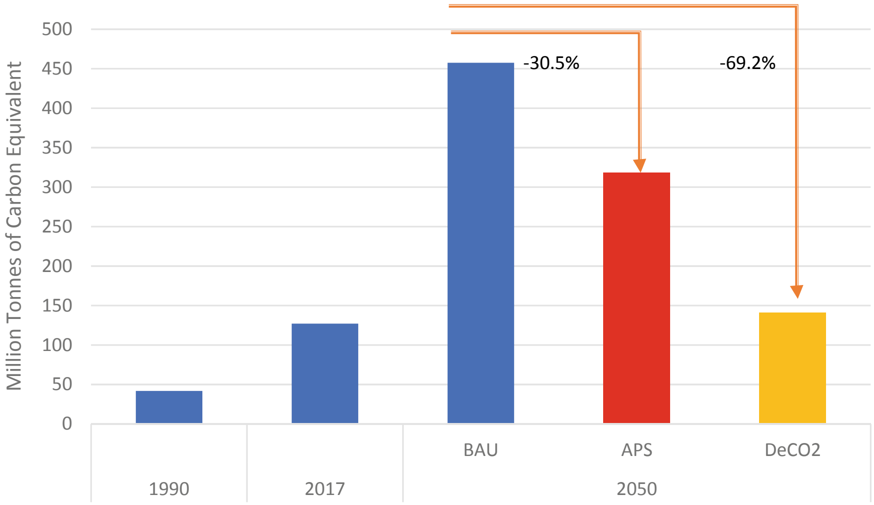

Fig. 5 CO_2 Emissions in the Mekong Subregion, BAU versus APS versus $DeCO_2$. APS = alternative policy scenario, BAU = business-as-usual scenario, CO_2 = carbon dioxide, Mt-C = million tonnes of carbon equivalent. *Note* The CO_2 emission reduction calculation method is the Greenhouse Gas Equivalencies, using an emission factor of 7.03×10^{-4} metric tonnes CO_2/kWh (EPA, US Environmental Protection Agency 2019). *Source* Author's calculations

the Mekong region. The remaining energy sources will come from fossil fuels, but the clean use of fossil fuels through clean technology deployment must be considered. In this regard, CCUS must deal with the remaining emissions from fossil fuels.

According to the solar PV potential, these resources are not constrained or limited in replacing fossil fuels. The main reason is the cost of doing so and how practically the grid can absorb such high penetration of variable renewable energy (VRE) such as solar and wind. Technically, VRE power production output varies within a few seconds depending on wind or sunshine. However, the risk of variable energy output can be minimised if the power system is largely integrated within the country and the region. Aggregating output from different locations from solar and wind energy has a smoothing effect on net variability (NREL 2020).

The Mekong subregion grid is progressing slowly. The integrated Mekong subregion power market might be far off for several reasons, such as regulatory and technical harmonisation issues within the region's power grids and utilities. Thanks to advanced research and technologies for battery storage (lithium-ion batteries) for surplus electricity produced from wind and solar energy. However, advanced battery storage remains costly. Further, the renewable hydrogen produced from electrolysis using surplus electricity from wind and solar has many advantages. It can be stored as liquid gas, suitable for numerous uses such as backup power generation, or as a liquid fuel that is easy to transport for other uses. Countries in the Mekong region could produce wind, solar, hydropower, or geothermal electricity and use surplus electricity to produce green hydrogen or store it as battery storage.

3.1 Low-Cost Renewables with Hydrogen Are the Game Changer

The fast drop in the cost of renewables can make DeCO_2 a reality. The levelized cost of electricity (LCOE) is expected to fall below US$4 cents/KWh in 2021 for solar PV and onshore wind (Fig. 6) (IRENA 2020). This low cost can be an enabler to producing hydrogen or largely deploying solar PV and wind.

Hydrogen is a potential game changer for decarbonising emissions, especially in sectors where they are hard to abate, such as cement and steel. Scalable resources from wind and solar energy and other renewables can be fully developed by widely adopting the hydrogen solution. The more electricity produced from wind and solar energy, the higher the penetration by grid renewables. At the same time, surplus electricity during low demand hours can be used to produce hydrogen. The more power generated from wind and solar energy and other renewables, the greater the possibility of increasing the efficiency of electrolysis to produce hydrogen. On-site hydrogen production from wind and solar farms will solve the issue of curtailed wind and solar electricity. To increase electrolysis efficiency and allow further penetration by renewables of grids, a hybrid energy system including hydropower, geothermal, or nuclear plants, for example, would be the perfect energy choice. Hydrogen is a

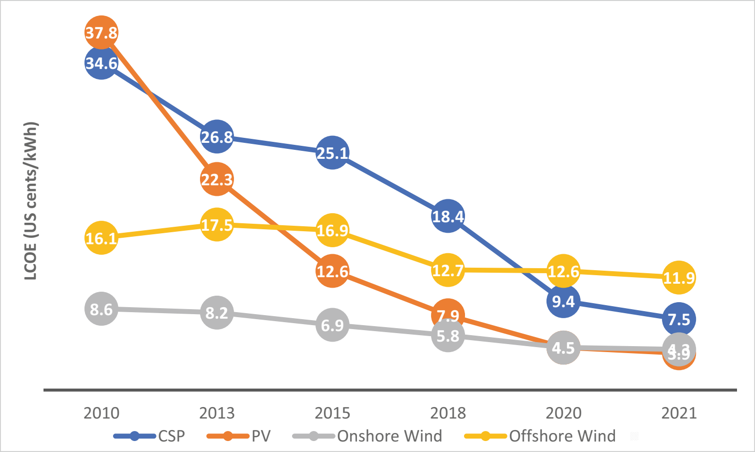

Fig. 6 Falling costs of renewables. CSP = concentrated solar power, kWh = kilowatt-hour, LCOE = levelized cost of electricity, PV = photovoltaic. *Source* IRENA (2020)

clean energy carrier that can be stored and transported for use in hydrogen vehicles, synthetic fuels, upgrading of oil and/or biomass, ammonia and/or fertiliser production, metal refining, heating, and other end uses. Thus, hydrogen development is an ideal pathway to a sustainable clean energy system and enables scalable VRE, such as solar and wind energy.

3.2 *The Need to Strengthen Environmental Standards for Power Generation in the Mekong Subregion*

Mitsuru et al. (2017) reported Mekong subregion countries have relatively high allowable emissions in terms of sulphur oxides (SOx), nitrogen oxides (NOx), and particulate matter (PM) (Fig. 7). This means that countries in the subregion have lower emissions standards than advanced countries such as Germany, the Republic of Korea, and Japan, where clean coal technology is mandatory.

Major harmful air pollutants, such as SOx, NOx, and PM, come from fossil fuel and biomass power plants, which must be carefully regulated. Short-term exposure to sulphur dioxide can harm the human respiratory system and make breathing difficult.

Thus, the region's leaders may need to consider promoting and effectively enforcing clean technologies, higher standards, or stringent environmental regulations for coal-fired power plants. This may push investors to select more advanced and clean technologies.

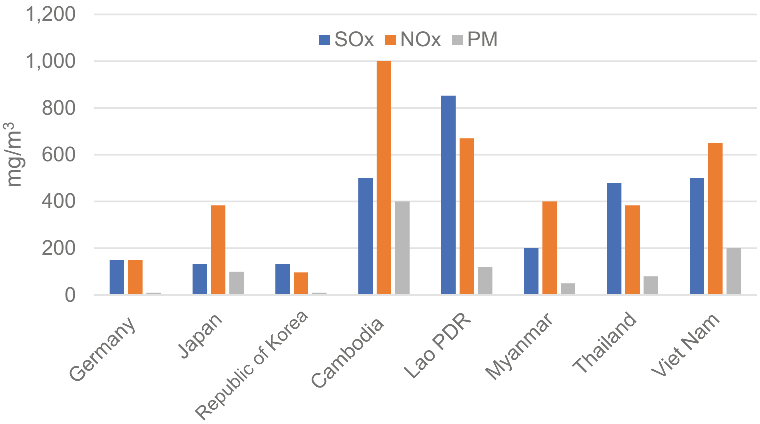

Fig. 7 Emissions standards for newly constructed CPPs in selected countries. (SOx, NOx, and PM). CPP = coal-fired power plant, Lao PDR = Lao People's Democratic Republic, mg/m^3 = milligram per cubic metre, SOx = sulphur oxides, NOx = nitrogen oxides, PM = particulate matter. *Source* Mitsuru et al. (2017)

3.3 Moving Towards ASEAN Power Connectivity

The Heads of ASEAN Power Utilities/Authorities (HAPUA) plays a significant role in pursuing the future integration of the ASEAN Power Grid (APG) (HAPUA 2019). HAPUA's mission is to support the ASEAN Economic Community through ASEAN energy market integration by succeeding in implementing the APG. Amongst the cross-border interconnections in ASEAN member states (AMSs), the Mekong subregion's interconnection has already existed. These interconnections mainly consist of medium/low voltage (115 kV or less) transmission lines and a few high-voltage transmission lines (500 kV, 230/220 kV). An electricity power trade has been carried out amongst Greater Mekong Subregion countries. However, it is bilateral or based on a power purchase agreement (PPA) that independent power producers sell electricity via dedicated transmission lines to power utilities. The cross-border interconnection of a 500 kV transmission line is only installed to dedicated transmission lines for the PPA. Therefore, electricity power trade in ASEAN has been limited.

The AMSs have long recognised the potential benefits of the APG; however, this benefit can only be realised when they establish the multilateral power trade in the ASEAN region. Generally, utilising the value of the difference is one of the key reasons for regional integration and cooperation, positively affecting the security of supply and, hence, grid stability. In addition, the economic benefits of having complementary production are one of the main drivers and reasons for building interconnections. The ASEAN Plan of Action for Energy Cooperation 2016–2025 explains that an interconnected APG brings multiple benefits. (ERIA 2015). Multilateral power trade aims to optimise resources on a regional, instead of a national, basis to meet the electricity demand in the region as a whole at the least possible cost. Multilateral power trade results in the following key potential benefits, amongst others:

(1) It enables more efficient use of the region's energy resources, leading to lower overall production costs in the APG since optimal investments can be made on the regional scale instead of suboptimal solutions separately in each country.
(2) It helps the utilities in the region balance their excess supply and demand, improves access to energy services, and reduces the costs of developing energy infrastructure.
(3) It accelerates the development and integration of renewable power generation capacity into the regional grid.
(4) It reduces the need for investment in power reserves to meet peak demand, lowering operational costs while achieving a more reliable supply and reducing system losses.
(5) It attracts additional investment in the region's interconnection by providing a price signal as a key catalyst for investors' financial returns.

To trigger the multilateral power trade in ASEAN, the AMSs have completed a pilot project of 100 MW phase I called the Lao PDR–Thailand–Malaysia –Singapore Power Integration Project (LTM-PIP) as the first multilateral power trade in ASEAN. Now phase II of the project aims to increase multilateral energy trade from 100 to 300 MW and commence work to include Singapore in the Lao PDR–Thailand–Malaysia–Singapore Power Integration Project (LTMS-PIP) in 2020 (HAPAU 2019).

Developing a common wheeling methodology will be necessary to establish multilateral power trading in the region. The LTMS-PIP wheeling methodology could be an appropriate start. The LTMS-PIP wheeling charge is based on the following elements: (i) the distance of the trade (megawatts per mile); (ii) a loss charge (charged per megawatt-hour); (iii) a balancing charge (per megawatt-hour); and (iv) a fixed administrative charge. The LTMS partner countries will need to share additional details on how each component is calculated to generalise this methodology for ASEAN. However, it should be emphasised that this can be done without sharing the actual wheeling charge applied to the LTMS-PIP trade, should this information be considered too sensitive to share publicly.

The underlying process used to develop this project is also very relevant to the ASEAN-wide discussion. In particular, work on the project was divided across four working groups, which looked at (i) tax and tariff structure, (ii) commercial arrangement, (iii) technical viability study, and (iv) regulatory and legal arrangements, each of which was led by a different country. There are two key lessons from this arrangement. First, dividing work across the participating countries is a good way of giving everyone a stake in, and a sense of ownership over, the underlying process and, therefore, the overall project. Second, a particular AMS may be actively involved in the development process even if it does not participate in the trading arrangement itself. This is an important lesson for ASEAN as a whole, as it is sure to be the case that some AMSs will participate in multilateral power trade early on (IEA 2020).

Moving forward to the multilateral power market within ASEAN or the Mekong subregion is still a long way. One reason for the slow progress is the many types of power sector structures and markets throughout ASEAN, creating problems and barriers on all levels of collaboration. These challenges remain in setting up the following: (i) a regional regulators group/regional regulatory body to harmonise regulations and standards relevant to grid interconnection, (ii) a regional operators group or regional system operator to synchronise actions in balancing the grid and the cross-border power exchange systems, and (iii) a regional system planners' group to coordinate and optimise the future investment plan of power stations and the grid.

HAPUA, the ASEAN Centre for Energy, ERIA, and the Asian Development Bank conducted several studies to solve these issues. The findings suggest harmonising the legal and regulatory frameworks and creating technical standards and codes relating to planning, design, system operation, and maintenance. In addition, ERIA conducted two studies to support ASEAN's future power market. The first was the 'Study on the Formation of the ASEAN Power Grid Transmission System Operators (ATSO) Institution'. Its two layers of objectives were (i) to establish the roles, structures, operational guidelines, and processes of the ATSO institution; and (ii) to provide a detailed implementation plan for the creation and operation of ATSO. This study overviewed the international case examples used to create ATSO, the ASEAN Power Pool (APP) guidelines, and the APP Implementation Plan and Roadmap (ERIA 2018a). The second was the 'Study on the Formation of the ASEAN Power Grid Generation and Transmission System Planning (AGTP) Institution'. It aimed to propose applicable procedures, structures, roles, and mechanisms to establish and maintain the AGTP. ATSO and the AGTP institutions, once achieved, would symbolise regulatory connectivity in ASEAN. This study provided case examples in this field in Japan, Europe, and the Southern African region to refer to and learn AGTP guidelines and the AGTP implementation plan (ERIA 2018b).

These two studies aimed to help the AMSs achieve consensus on the principles, building blocks, and framework of an integrated regional electricity market. The output from the two studies concluded that the functions of the AGTP and ATSO should be placed in the same organisation to secure a close relationship between planning and power system operations. After discussions during the AGTP and ATSO studies workshops, the ASEAN Power Grid Consultative Committee (APGCC) and the AMSs agreed to merge the functions of the AGTP and ATSO into one organisation, named the ASEAN Power Pool (APP). APP's primary role will be to act as a coordinating body with the AMS transmission system operator, focusing on harmonising operational standards across ASEAN to achieve a more efficient operation of the future APG. More efficient operations are anticipated to come from better coordination and alignment of the system operation and generation within the region. The APP is expected to be a key institution to enable multilateral trading of electricity amongst the AMSs while maintaining the balance, stability, and reliability of the interconnected power grids across borders. In addition, coordinating APG system planning, and grid developments will be greatly important in making the APG more efficient and better coordinated.

The APP will resemble a forum where operational, technical, and multilateral trading topics can be discussed and agreed. It will also have an essential information-sharing role for the region. The suggested responsibilities of the APP will be to lead and coordinate the development of the regional market, establish, and own the APG network codes and guidelines, and produce a regional system planning and development plan that will be continuously revised going forward. Code development by the APP and overall activity shall focus on interconnections, and how these will be utilised best. The APP shall not have an operational role within the different AMS national transmission grids. Instead, it is proposed to be responsible for the APG system operational coordination. This responsibility will be achieved through the 'Control Block Coordination Centre'. The point is that there should be only one coordination centre in ASEAN.

4 Conclusion

The Mekong subregion faces mounting challenges matching its increasing electricity demand with a sustainable energy supply. This is because the regional reliance on fossil fuel consumption is projected to last until 2050. The transition to a lower-carbon electricity sector will require the region to develop and deploy renewables, greener energy sources, and clean use of fossil fuels through innovative technology such as high-efficiency, low emissions technologies, and the deployment of CCUS. Coal- and natural gas–fired power generation patterns in the region reflect the rising demand for electricity to power and steer economic growth. Hence, building low-efficiency coal-fired power plants is an obvious choice for power-hungry emerging Mekong subregion due to lower capital costs. However, such plants cause more environmental harm and health issues due to air pollution, CO_2, and other GHG emissions. Widespread coal power plant construction could also point to the low environmental standards for coal-fired power generation in the Mekong subregion. The role of natural gas in the energy transition cannot be overlooked. This is because it can be used as a bridging fuel between high emissions fuels, such as coal and oil, to cleaner energy systems in which renewables and clean fuels take the major share in the energy supply mix.

In the current situation, hydropower accounts for quite a large share of the energy mix in the Mekong subregion. However, as energy demand is expected to increase further, hydropower sources will be fully utilised. Thus, the share of renewables, such as wind, solar, and biomass, will play a critical role in $DeCO_2$ for the future clean electricity system in the region. The lower cost of these renewables will make it possible for a higher share of wind and solar in the energy mix. Since electricity from wind and solar sources is variable and intermittent, there is a need to invest in grid infrastructure with smart grids, using the internet of things and other technology to predict electricity production. This will ensure proper system integration in which battery storage and hydrogen fuels play a critical role in the backup system. The Mekong subregion may benefit greatly from developing the full potential of renewables and hydrogen production because of its large solar, wind, and hydropower potential. Thus, electricity from wind and solar, plus other unused electricity during low-demand hours, should be converted to be stored in a large battery or to hydrogen as stored energy. Thus, decarbonisation electricity in the Mekong subregion will rely on the high share of renewables, especially solar PV, wind, hydropower, and biomass.

The future institution of the APP and the Mekong subregion needs to be established and operated. The power pool, once up for running with the proper institutions guided by regional electricity market rules and procedures, can hugely benefit the region in terms of (i) avoided cost of building new generations, (ii) creation of more efficient use of the region's energy resources, (iii) helping the utilities in the region balance their excess supply and demand, (iv) improving access to energy services, (v) reducing the costs of developing energy infrastructure, (vi) accelerating the development and integration of renewable power generation capacity into the regional grid, (vii) reducing the need for investment in power reserves to meet peak demand, and (viii) attracting additional investment in the region's interconnection by providing a price signal as a key catalyst to investors for their financial returns.

However, reforms will be needed in the electricity sector, especially the deregulation of national and own rules and procedures to join the regional power pool's rules and procedures. Further, the unbundling of ownerships in the electricity market segments and the non-discriminatory third-party access for transmission and distribution networks, and the gradual removal of subsidies in fossil fuel–based power generation are to ensure the preconditions for market competition by bringing a level playing field to new technologies and renewables into the energy mix. Other necessary policies to attract foreign investment into renewables and clean technologies included fiscal policy incentives of tax holidays, reducing market barriers and regulatory burden, other policies to reduce upfront cost investments, such as rebated payment system through government subsidies and government guarantee to make the investment become feasible and low risk.

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Sustainable Energy Policy Reform in Malaysia

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Abstract The global energy system must be reformed. Energy supply systems largely based on fossil fuels must be replaced with those based on renewable energy (RE) to achieve at least 66% in limiting global temperature increase to below 2° C in the present century. The world remains below the 2° C climate objective and is even farther from attaining the aspirational target of limiting global warming to 1.5° C. Energy efficiency (EE) and RE are the pillars of the energy transition. They can provide more than 90% of the required energy-related CO_2 emission reduction by using safe, reliable, affordable, and widely available technologies. Similarly, Malaysia is also transforming fossil-based energy into sustainable energy, such as RE. Malaysia is endowed with abundant resources. Solar, hydropower, and biomass are amongst the most popular sustainable energy forms available in Malaysia. Therefore, beginning sustainable energy growth for the current and future generations without policy intervention is critical for the country. This chapter aims to provide the readers with an overview of Malaysia's commitment to facilitate sustainable energy policy reforms. It discusses RE development, including the key focus areas, policies, achievements, targets, existing initiatives that the government and the private sector are undertaking, and upcoming initiatives wherein relevant government entities are committed to fulfilling their roles. A study on policy performance and transition is also conducted using data envelopment analysis. The study identifies the effects of policy implementation on RE growth and the policy landscape in Malaysia. This chapter also highlights the roles of energy policy reform players and existing

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barriers. Finally, it concludes that some lessons learned from Malaysia's experience in driving sustainable energy policy reforms may be critical if the projected development is realised without incurring substantial economic, social, and environmental consequences.

Keywords Energy policy · Energy reform · Energy transition · Renewable energy · Data envelopment analysis · Sustainable energy

1 Introduction

Energy is necessary to drive a country's industrial and commercial development; it also serves as a basic utility that provides social necessities for maintaining a good standard of living. Malaysia's energy sector has undergone reforms to ensure a sustainable energy supply while simultaneously encouraging efficient use, diversification of supply, and waste minimisation. Future energy supply and demand have prompted proposals for energy policy reform to sustain Malaysia's energy supply. This chapter focuses on Malaysia's sustainable energy policy reform by considering the policy landscape, sustainable energy potential, and challenges to ensure that the reform of Malaysia's sustainable energy policy is successful. A study on renewable energy (RE) policy performance and transition is also conducted to assess the overall effect of the policy on RE development in the country. This study is expected to provide a reference for other countries of the Association of Southeast Asian Nations (ASEAN).

2 Country Background

2.1 Geography

Malaysia is a Southeast Asian country that lies immediately north of the equator. It is divided into two noncontiguous regions, namely, Peninsular Malaysia and East Malaysia, which is located on the island of Borneo. Peninsular Malaysia, Sabah, and Sarawak comprise Malaysia's territory of 330,621 square kilometres (sq km). Peninsular Malaysia, which lies north of the equator in central Southeast Asia, is above Singapore and south of Thailand. It is separated from Sabah and Sarawak, which share the island of Borneo with Indonesia and Brunei Darussalam, by approximately 540 km of the South China Sea. Malaysia is entirely located in the equatorial zone, with typical daily temperatures ranging from 21° to 32° C.

Malaysia is composed of 13 states (Johor, Kedah, Kelantan, Melaka, Negeri Sembilan, Pahang, Pulau Pinang, Perak, Perlis, Selangor, Terengganu, Sabah, and Sarawak) and three federal territories (Kuala Lumpur, Labuan, and Putrajaya).

Malaysia's capital, Kuala Lumpur, is located on the peninsula's western side, approximately 40 km from the coast. Meanwhile, the administrative capital, Putrajaya, is about 25 km south of the capital. Malaysia's population was expected to reach 32.7 million in 2021, increasing from 32.6 million in 2020, with an annual growth rate of 0.2%. The three states with the highest population composition in 2021 were Selangor (20.1%), Sabah (11.7%), and Johor (11.6%) (EPU 2020).

2.2 Recent Industries

Malaysia, a middle-income country, has transformed from a predominantly agricultural raw material provider to a thriving multi-sector economy since the 1970s. It is predicted to transition to a high-income economy between 2024 and 2028 based on the country's economic transformation trajectory over the past decades (Mottain 2021). Malaysia is seeking to move up the value-added production chain by attracting investments in Islamic banking, high-technology sectors, biotechnology, and services. Electronics, oil and gas, palm oil, and rubber exports are major economic drivers.

2.3 Recent Politics

Nine of Malaysia's states are ruled by traditional Malay rulers of royal descent called sultans. Malaysia's executive power is vested in a cabinet led by the prime minister, also the country's leader. The country's principal administrative divisions are the 13 federal states and 3 federal territories. Malaysia is a parliamentary democracy with a constitutional monarchy inherited from the British Empire after it gained independence in 1957. The king is the chief of state, while the prime minister is the head of government. The prime minister has executive authority and oversees legislation. Every 5 years, the public votes for 222 members of Parliament in a general election. The country has undergone 14 general elections and 9 premierships since a pre-independence general election in 1955. The Honourable Dato' Sri Ismail Sabri bin Yaakob was elected as prime minister of Malaysia on 20 August 2021.

2.4 Economics

Malaysia is a market economy that is generally open, state-oriented, and newly industrialised. The government plays a substantial role in guiding economic activities through macroeconomic policies. Although Malaysia has long been a middle-income country, becoming a high-income country will necessitate collaborative, strategic efforts from all parties involved. From a competitive standpoint, Malaysia's key hurdle in becoming a high-income country is its slow productivity development. This is mostly attributed to several concerns, such as the reallocation of economic resources, restricted technology creation, skills gap, low female labour force participation rate, and structural labour market challenges. Malaysia has a mixed economic system, with a combination of private liberty and centralised economic planning and government regulation. The country is a member of the Asia–Pacific Economic Cooperation, ASEAN, and the Trans-Pacific Partnership. The Malaysian economy recorded a slower growth rate of 4.8% in 2018 compared with 5.8% in the previous year due to global trade tensions and the uncertainty of the economy (EPU 2020). Although a shift in policy focus was necessary for long-term sustainability, it implied unavoidable short-term economic growth trade-offs in the form of reduced government spending.

3 Malaysia's Energy Sector

3.1 Sources of Energy

Malaysia is an energy-independent country because of its abundant energy sources (oil, natural gas, and coal) and renewable energy sources (biomass, solar energy, and hydropower). Malaysia is still considered one of the world's leading energy exporters. Per the *Oil and Gas Journal,* the country had oil reserves of 3.6 billion barrels as of January 2020, the fourth-largest reserves in Asia–Pacific after China, India, and Viet Nam (USEIA 2021). Malaysia's oil comes almost entirely from offshore fields. The country is also one of the world's top producers and exporters of natural gas. Petroliam Nasional Berhad (Petronas) dominates the natural gas industry. Petronas historically monopolised all upstream natural gas developments due to its function as the national oil firm and a regulator of upstream operations. It is also a major player in midstream and downstream industries and liquefied natural gas (LNG) trade. Sarawak's state-owned oil and natural gas corporation, Petroleum Sarawak Berhad (Petros), was created in March 2018 and given equal status as Petronas by Sarawak's chief minister. Petros and Petronas signed a domestic natural gas agreement in February 2020, giving Petros responsibility for natural gas sales, distribution, and supply in Sarawak. However, reports indicate that Petros and Petronas remain at odds over their regulatory roles in Sarawak's oil and gas sectors.

Coal has become considerably more economically competitive with natural gas in terms of power generation, accounting for 43% of the total generation in 2018. In Peninsular Malaysia, the move from natural gas to coal has gained speed in recent years, with leading utility and power firms increasing their coal-fired capacity. In 2018, Malaysia produced over 3 million tonnes of coal, accounting for approximately 8% of total coal consumption. In 2017, the country's domestic coal reserves were estimated at 200 million tonnes. Sarawak holds nearly all of Malaysia's domestic coal reserves; hence, the country highly relies on imports. Malaysia imports most of its coal from Indonesia and Australia, with over 38 million tonnes imported in 2019 (USEIA 2021).

3.2 Electricity Supply

Malaysia has an abundant electricity supply. Gas is the most common fuel, accounting for more than half of the country's energy requirements. Energy demand will naturally increase along with the country's continued population growth; however, the increase can be easily met by the country's local supply. Hydropower, thermal, and self-generation plants are Malaysia's three types of power stations. In 2018, total energy generation reached 163,415 gigawatt-hours (GWh), excluding self-generation, an increase of 5.1% from the previous year's figure of 155,456 GWh (Suruhanjaya Tenaga 2020). In Malaysia, fossil fuels continue to dominate the fuel input for energy generation. Coal remains the most commonly used fuel for generating energy, accounting for 47.3% of the generation mix. Natural gas ranks second with 35.7%, followed by hydropower (16.1%), renewable sources (0.6%), and oil (0.3%). As of 31 December 2018, Malaysia had a total installed capacity of 33,991 megawatts (MW) (Fig. 1).

Peninsular Malaysia accounted for 79.4% of the total installed capacity, with Sarawak accounting for 15.0% and Sabah accounting for 5.6%. Peninsular Malaysia's peak demand was 18,338 MW on 15 August 2018, an increase of 3.1% from 17,790 MW in 2017. The peak demand in Sabah rose by 1.8% (938 MW to 955 MW), while that in Sarawak increased by 0.4% (3489–3504 MW). Peak demand refers to the time of day when power usage is at its maximum. In 2018, overall electricity consumption was 152,866 GWh, an increase of 4.3% from the previous year (Fig. 2) (Energy Commission 2020).

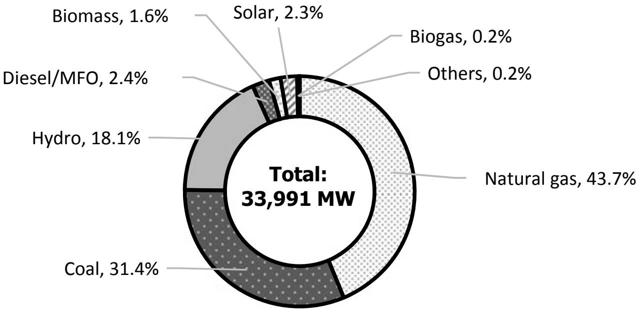


Fig. 1 Malaysia's installed capacity in electricity, as of 31 December 2018. *Source* Energy Commission (2020)

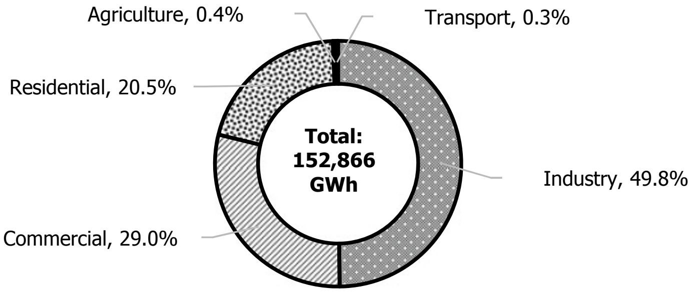


Fig. 2 Electricity consumption by sector 2018. *Source* Energy Commission (2020)

3.3 Government Energy Institutions

3.3.1 Government Institutions

The Economic Planning Unit (EPU) is the government department responsible for formulating Malaysia's national development plans. EPU's Energy Division is a dedicated office that develops national energy policies, including policies for the oil and gas sector, and plans and initiatives for the energy sector's long-term development in the Five-Year Development Plan. This agency also contributes to development expenditures for implementing energy-related projects and programmes in the country, such as the oil and gas industries, RE, and energy efficiency (EE).

The Ministry of Energy and Natural Resources (KeTSA) oversees Malaysia's energy, natural resources, lands, mines, minerals, geoscience, biodiversity, wildlife, national parks, forestry, surveying, mapping, and geospatial data portfolio. KeTSA is committed to pursuing its agenda to ensure that the country's natural resources are protected and maintained sustainably and responsibly for future generations. In keeping with the country's climate change policy, KeTSA has committed to increasing electricity generation from RE sources through the Electricity Supply Generation Development Plan 2021–2039.

The Ministry of Environment and Water (MEWa) is responsible for the country's climate change obligations and commitments under the United Nations Framework Convention on Climate Change (UNFCCC). MEWa is currently investigating potential methods for applying mitigation measures to new sectors, such as RE, electric transportation, and waste management. Furthermore, MEWa intends to draft the legal framework of the National Climate Change Law, formulate the basic structure of the national greenhouse gas (GHG) inventory centre, and develop a framework for a domestic environmental carbon trading scheme. In addition, MEWa will launch the Green Jobs Portal to create job possibilities in Malaysia's green economic growth sector.

The Sustainable Energy Development Authority (SEDA) Malaysia is a statutory agency established under the Sustainable Energy Development Authority Act of 2011 (Act 726). SEDA Malaysia was established on 1 September 2011, with the primary responsibility of administering and monitoring the feed-in tariff (FiT) system specified by the Renewable Energy Act of 2011 (Act 725). The key tasks of SEDA Malaysia include promoting the use of RE and EE technologies and measures to minimise energy consumption.

The Malaysian Green Technology and Climate Change Centre (MGTC) is an organisation of MEWa tasked to lead the country in green growth, climate change mitigation, and green lifestyle. The MGTC governs three government policies: the National Green Technology Policy, the National Climate Change Policy, and the Green Technology Master Plan (GTMP). The MGTC implements initiatives and programmes that provide specific details for achieving the long-term effect of the nationally determined contribution to reduce the intensity of GHG emissions by 45% based on the gross domestic product (GDP) in 2030, increasing the GDP rate from green technology by USD 22.81 billion, and creating 230,000 green jobs, compared with the emission intensity in 2005.

3.3.2 Regulators

The Energy Commission of Malaysia was established as a regulator for the energy industry in Peninsular Malaysia and Sabah under the Energy Commission Act of 2001. The commission was founded to ensure the efficient development of Malaysia's energy industry, enabling the country to handle the new challenges of globalisation and liberalisation, particularly in the energy supply industry. Within the framework of applicable legislation, it controls and promotes all aspects of the electricity and gas supply industries, including the Electricity Supply Act of 1990, License Supply Regulation of 1990, Gas Supply Act of 1993, Electricity Regulation of 1994, and Gas Supply Regulation of 1997. The commission regulates the electric industry in Peninsular Malaysia and Sabah. Sarawak's electricity business is regulated by the state government.

3.4 Private Sector, National Operators, and Independent Power Producers (IPPs)

3.4.1 Private Sector

Petronas is a Malaysian multinational corporation specialising in hydrocarbon-based energy, primarily oil and gas explorations. Under the Petroleum Development Act, Petronas, a wholly owned government organisation, was established with exclusive rights to all of Malaysia's oil and gas resources. A Petronas licence is required to process, refine, market, or distribute petroleum or petrochemical products. Petronas maintains its position as one of the world's largest and most forward-thinking LNG producers. Sarawak, a Malaysian state in the east, has recently gained a regulatory role in gas distribution within the state through Petros.

3.4.2 National Operators

Tenaga Nasional Berhad (TNB) is a Malaysian multinational electric company and Peninsular Malaysia's primary electric utility company. TNB's primary business is electricity generation, transmission, and distribution. The TNB not only generates electricity for the country but also transmits and distributes it throughout Peninsular Malaysia, Sabah, and the Federal Territory of Labuan. The TNB supplied power to approximately 9 million users as of 30 June 2018. Sarawak Energy Berhad (SEB) is a Malaysian energy development company whose primary business activities include electricity generation, transmission, distribution, and retail. SEB generates electricity by utilising Sarawak's substantial indigenous resources, such as hydropower, coal, and gas, and distributes it to clients across Sarawak and beyond through an extensive network. SEB uses Sarawak's vast indigenous natural resources to create mostly renewable hydropower with gas and coal thermal plants for energy security and variety. Meanwhile, SEB is a power business in Sabah that generates, transmits, and distributes electricity primarily in Sabah and the Federal Territory of Labuan.

3.4.3 Independent Power Producers (IPPs)

The TNB, Malaysia's national electric utility company, remains the country's largest power generator. Meanwhile, YTL Power, Genting Sanyen, Malakoff, and Edra Global are other IPPs in the country. An IPP is a company that owns and runs power generation facilities to sell electricity to utility companies. Since the early 1990s, 14 IPPs have been licensed to generate power and sell it to the TNB, including first-, second-, and third-generation IPPs.

4 Potential for Sustainable Energy in Malaysia

To date, Malaysia's energy mix, which includes petroleum, natural gas, coal, hydroelectric power, and RE, has been demonstrated to be reliable in supplying the country's energy requirements. Coal, hydropower, and renewable energy will become more important in electricity generation as the prices of oil and gas increase owing to their finite supplies. However, unless new energy sources of indigenous origin are discovered and effectively developed, Malaysia is expected to become a net energy importer by the end of the 2030s. Between 1998 and 2018, fossil fuels provided more than 90% of Peninsular Malaysia's electricity. In 2018, fossil fuels, such as natural gas, coal, and crude oil, accounted for up to 93% of Malaysia's TPES, while RE

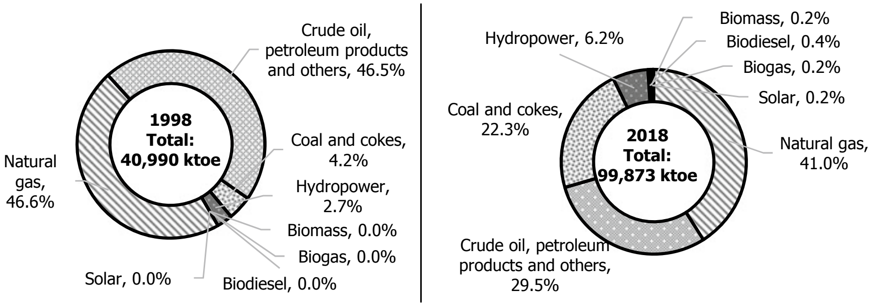


Fig. 3 TPES by fuel type. *Source* Energy Commission (2020)

accounted for only 7% (Fig. 3) (Energy Commission 2020). This current situation, combined with dwindling local fossil fuel reserves, will force Malaysia to import fossil fuels at a slightly higher market price, putting it at risk of purchasing energy resources from a foreign fuel market with volatile prices. As domestic fossil fuel depletion threatens the country's development, dealing with the country's overreliance on fossil fuels is more important than ever. Given this problem, Malaysia has announced its current energy transition plan until 2040, with two highlights: an increased RE target of 31% by 2025 and 40% by 2035 (up from the previous target of 20% by 2025 set in 2020) and a statement that Malaysia will not build new coal power plants.

Electricity demand in Malaysia is increasing in conjunction with the country's economic growth. Demand has increased at 2.5% each year from 2015 to 2019, ranging from 16,822 MW to 18,566 MW. Demand is expected to grow at 1.8% per year from 2020 to 2030. More RE sources will be used in distribution networks in the succeeding years, directly meeting the demand. The net RE demand is expected to increase by 0.7% per year in the next 11 years after deducting the planned RE sources in distribution networks. Gas demand in the electricity production sector and oil demand in the transportation sector are also driving the growth. The oil and gas industries have long been important contributors to Malaysia's GDP and energy security. However, this situation is expected to change as domestic demand grows and fuel reserves are depleted. To address this challenge, Malaysia will increase downstream growth and leverage its strategic location to become a regional hub for oil field services by rejuvenating existing fields and intensifying exploration activities. Following this forecast, the country will require even more electric energy as it attempts to achieve the status of a high-income economy. With depleting local gas and petroleum sources and the need to conform to stricter environmental rules while meeting the demand for increasing electricity consumption, new possibilities for future fuel mix must be explored. Such a fuel mix is critical for ensuring supply security by maintaining the sustainability, adequacy, diversity, and reasonable prices of fuel supplies.

Several sustainable energy generation techniques have been explored. The most optimum ones have been proposed to meet Malaysia's estimated energy requirements until 2030, in line with the country's objective of adopting low-carbon systems and technologies. During the 21st Conference of the Parties in 2015, Malaysia pledged to reduce its carbon emission intensity per GDP by 35% by 2030, compared with its value in 2005, or 45%, with cooperation from developed countries. This nationally determined contribution was formalised in the Paris Agreement and unanimously adopted by United Nations member states to address the harmful effects of climate change. The use of RE is currently one of the country's top priorities to reduce reliance on fossil fuels, conserving the environment in the face of climate change. The current RE mix, which includes a large proportion of hydropower, is 22.9%. It is expected to increase further because of government-led efforts, such as FiT, net energy metering (NEM), and large-scale solar (LSS). The government and the business sector must back Malaysia's existing RE policies. A primary issue in this area is establishing an appealing and user-friendly system for financing RE projects. EE is also important in the fight against climate change, given that Malaysia has several potential energy-saving techniques. The Malaysian government is currently drafting the Energy Efficiency and Conservation Act. This legislation will be critical in mandating the deployment of EE measures, resulting in a long-term reduction in energy intensity.

5 Policy Landscape for Sustainable Energy

5.1 Sustainable Energy Policy Evolvement in Malaysia

5.1.1 National Energy Development Policy

Malaysia's first energy policy, known as the National Energy Policy of 1979, was formulated in 1979 with extensive recommendations on long-term energy objectives and strategies to ensure an efficient, secure, and environmentally sustainable energy supply. This major policy governs Malaysia's energy sector. The country's energy policies have prioritised sustainability, resource efficiency, environmental protection, and high-quality services to its stakeholders. The National Energy Policy of 1979 was established with three objectives, as follows:

(1) To supply adequate energy cost effectively from indigenous, non-renewable, and renewable resources, yet securely by diversifying sources;
(2) To utilise energy efficiently and productively; and
(3) To minimise negative environmental effects on the energy supply chain.

The National Depletion Policy was established in 1980 to prevent the over-exploitation of the country's finite and non-renewable petroleum resources. The Four-Fuel Diversification Policy of 1981, which aimed to reduce overdependence on oil as the primary energy source, complements the National Depletion Policy. The Four-Fuel Policy calls for a four-fuel supply mix (oil, gas, hydroelectric power, and coal) for electricity generation. This objective resulted in the National Mineral Policy of 1998, which established standards for the efficient use of domestically sourced coal through enhanced underground mining technologies, larger equipment in surface mining operations, and the computerisation of mine maintenance and administrative functions.

The Five-Fuel Diversification Policy of 2000, implemented under the Eighth Malaysia Plan (MP 2001–2005) and the Third Outline Perspective Plan (2001–2010), marked the first time RE was incorporated into the country's energy mix for grid-connected power generation. This policy recognises the importance of RE by classifying it as the fifth fuel for grid-connected electricity generation, alongside oil, gas, hydropower, and coal. The Small Renewable Energy Power (SREP) programme, launched in 2001 to further develop renewable energy resources for power generation, is in line with the previous effort. SREP developers signed renewable energy power purchase agreements (REPPAs) with power utility companies that buy renewable energy–generated electricity from them, primarily the TNB, Malaysia's national utility company. Biomass and biogas from palm oil mill waste, solar photovoltaic (PV), biogas from municipal landfills, mini hydroelectric, wind, and biofuels from municipal trash are all permitted under SREP. However, the results of the SREP programme were disappointing, with less than 14 MW achieved compared with the 9th Malaysia Plan target of 350 MW of renewable energy. The primary barriers identified include the high subsidies for fossil fuels, whereas incentives for RE initiatives are minimal. Therefore, financial institutions and investors are wary of RE projects because of their high capital costs, extended payback periods, and low tariffs. Moreover, REPPA entails lengthy discussions with strict conditions while the price and availability of biomass as a long-term fuel are uncertain for RE generation. Notwithstanding its poor acceptance, SREP has underlined the government's commitment to developing RE as the fifth fuel for the country.

In 2009, the National Green Technology Policy was formulated to boost the country's economy and promote long-term development (KeTTHA 2010). RE, the environment, the economy, and social perspectives are four of the policy's five core strategic thrusts for stimulating implementation and expansion of green technology in most sectors. This policy also established a road map for the transition to a low-carbon economy. The National Policy on Climate Change was developed in 2009 to build specific national policies for climate change initiatives in Malaysia and respond to UNFCCC (NRE 2009). The Malaysian government prioritises sustainable development and environmental and natural resource conservation in this strategy, ensuring that climate-resilient development meets national sustainability goals.

The New Energy Policy of 2010, part of 10MP (2011–2015), broadens the energy vision to encompass economic efficiency and environmental and social concerns while strengthening security through alternative resources (EPU 2010, 2011). The policy stressed energy efficiency and conservation and the use of RE in power generation. In addition, the Renewable Energy Act of 2011, which established and implemented the FiT system for RE-generated power, was recently enacted (Government of Malaysia 2011). The Renewable Energy Act went into effect in 2011, and a FiT system was implemented, favouring RE developers and accelerating the expansion of the RE sector.

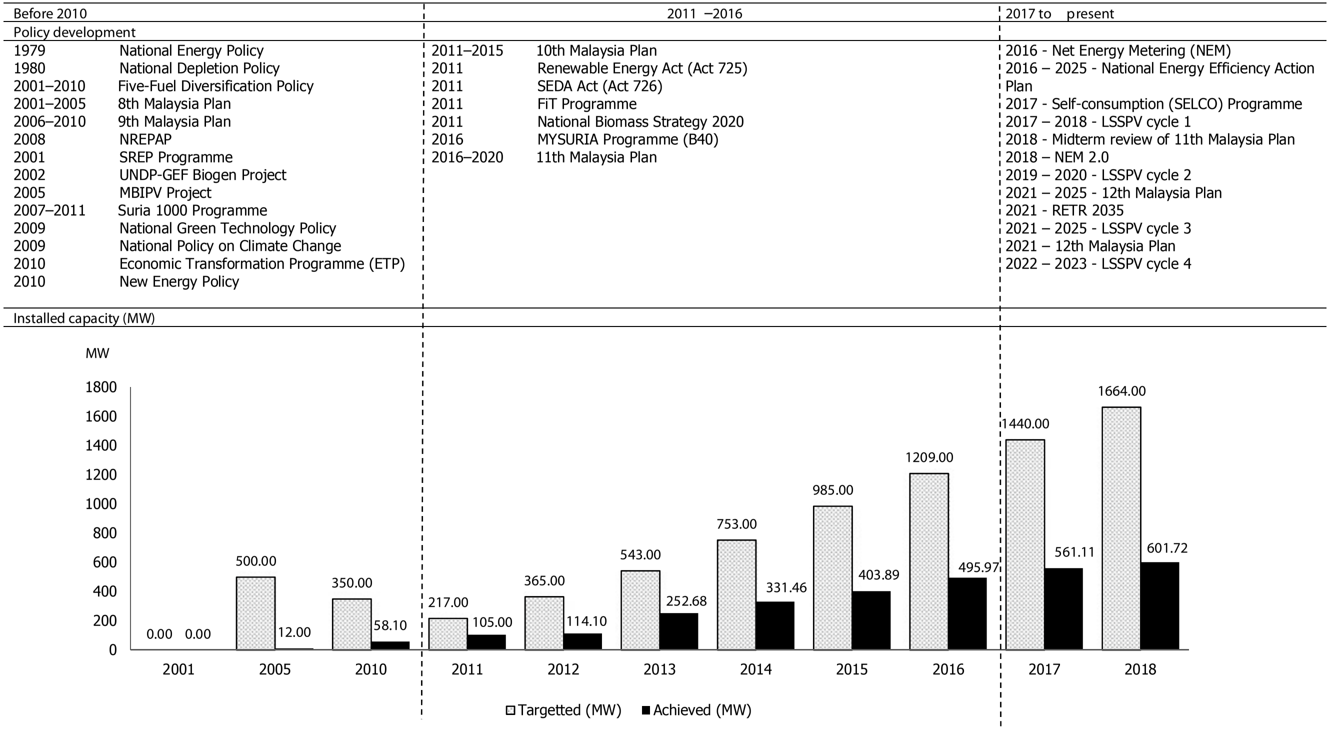
Green growth was also identified as one of the key thrusts in 11MP (2016–2020), allowing Malaysia to remain ahead of environmental concerns and construct a sustainable economy (EPU 2015). The recently developed National Energy Efficiency Action Plan 2016–2025 contains the key actions for increasing energy efficiency in the economy (KeTTHA 2015). This plan is aligned with 11MP, which governs policy across the economy.

The government has launched many renewable energy–related programmes, including FiT, NEM, the LSS, and self-consumption for solar installations, to increase the proportion of renewable energy in the capacity mix to 20% by 2025 (SEDA 2021). As a result, the country has advanced to the LSS, and is increasingly focusing on solar energy as a renewable energy source. Solar energy appears to be the most promising RE source because it is the easiest to implement compared with biogas, biomass, and other RE sources. Although Malaysia has considerable potential for small hydropower development, this resource is largely available in rural areas, and connecting to the main grid is expensive.

Malaysia's pledge to become a carbon–neutral country by 2050 at the earliest is declared in 12MP, along with other steps to drive green growth (EPU 2021). Although Malaysia accounts for only 0.7% of GHG emissions, the government intends to keep its promise to cut its GHG emission intensity of GDP by 45% by 2030. This value is based on the GDP emission intensity in 2005 under the 2015 Paris Agreement. The government will shortly release the National Energy Policy, which will serve as a road map for developing Malaysia's energy sector, particularly as it transitions to a low-carbon future. The overall policy reform towards RE development in Malaysia is presented in Fig. 4.

5.1.2 Energy Master Plan

The current energy master plan will be based on 12MP (EPU 2021). During the 12MP period, the energy sector's sustainability will be further strengthened through the liberalisation of the gas market. Energy sustainability will continue to contribute to sustainable economic development and the well-being of the people. Two key initiatives will be implemented to strengthen the energy sector: formulating a comprehensive energy policy and establishing a systematic communication plan. Existing energy-related policies will be streamlined under the new policy. A more coordinated communication plan will enable better governance engagement and effective energy sector reform. The selected targets related to sustainable energy under 12MP is shown in Fig. 5.



Before 2010		2011 –2016		2017 to present
Policy development				
1979	National Energy Policy	2011–2015	10th Malaysia Plan	2016 - Net Energy Metering (NEM)
1980	National Depletion Policy	2011	Renewable Energy Act (Act 725)	2016 – 2025 - National Energy Efficiency Action Plan
2001–2010	Five-Fuel Diversification Policy	2011	SEDA Act (Act 726)	2017 - Self-consumption (SELCO) Programme
2001–2005	8th Malaysia Plan	2011	FiT Programme	2017 – 2018 - LSSPV cycle 1
2006–2010	9th Malaysia Plan	2011	National Biomass Strategy 2020	2018 - Midterm review of 11th Malaysia Plan
2008	NREPAP	2016	MYSURIA Programme (B40)	2018 – NEM 2.0
2001	SREP Programme	2016–2020	11th Malaysia Plan	2019 – 2020 - LSSPV cycle 2
2002	UNDP-GEF Biogen Project			2021 – 2025 - 12th Malaysia Plan
2005	MBIPV Project			2021 - RETR 2035
2007–2011	Suria 1000 Programme			2021 – 2025 - LSSPV cycle 3
2009	National Green Technology Policy			2021 – 12th Malaysia Plan
2009	National Policy on Climate Change			2022 – 2023 - LSSPV cycle 4
2010	Economic Transformation Programme (ETP)			
2010	New Energy Policy			

Fig. 4 Policy reformation towards RE development in Malaysia. *Source* Mohd Chachuli et al. (2021)

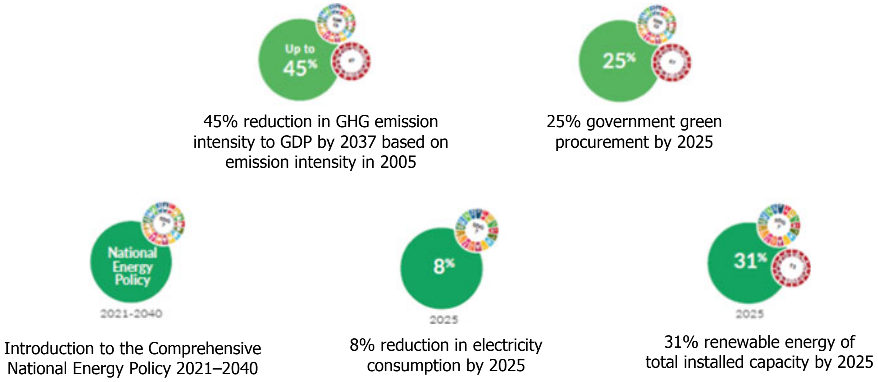


Fig. 5 Selected targets related to sustainable energy under 12MP. *Source* EPU (2021)

5.1.3 Electricity Law

The Electricity Supply Act of 1990 governs the electricity supply industry, including the regulation of the industry, the supply of electricity at reasonable prices, and the licensing and control of any electrical installation, plant, and equipment about matters that concern people's safety and the efficient use of electricity, amongst others. (Government of Malaysia 2013)

5.1.4 Green Technology Master Plan (GTMP)

GTMP 2017–2030 is the result of 11MP (2016–2020), which identified green growth as one of the six goals for changing the country's growth trajectory (EPU 2015; KeTTHA 2017). The GTMP establishes a framework for mainstreaming green technology into Malaysia's planned initiatives, considering the four pillars outlined in the National Green Technology Policy: energy, environment, economy, and social sectors (KeTTHA 2010). The plan lays out strategic plans for developing green technology to achieve a low-carbon, resource-efficient economy. The GTMP lays out the country's urgent strategy for achieving green growth. It creates the groundwork for changing people's ideas and behaviour to instil a green lifestyle in the nation. In the future, the GTMP will serve as a fundamental reference document describing Malaysia's green technology development priorities.

5.1.5 National Renewable Energy and Action Plan (NREPAP)

The Ministry of Energy, Green Technology, and Water created NREPAP to overcome key impediments to RE deployment in Malaysia (KeTTHA 2008). The policy vision aims to increase the use of indigenous RE sources achieving 20% RE capacity mix by 2025, which will help ensure the security of electricity and fuel supplies. NREPAP identifies the necessity and justification for the convergence of energy, industrial growth, environmental and information dissemination policies, and a new and forward-looking RE policy. This policy is critical for the development and growth of Malaysia's RE industry. It is also one of the most important mitigation initiatives in the fight against global warming caused by the continuous use of fossil fuels in electricity generation. The conventional methods of doing things are no longer valid, and the country must evolve into a modern path. NREPAP demonstrates that policy objectives can be met if the RE law and the RE fund–supported FiT are implemented.

The RE action plan must include provisions for implementing a FiT system to (i) reduce financing transaction costs, (ii) create a conducive business environment for RE businesses to grow, (iii) build local competencies and capacities, (iv) attract skilled workers to the sector, and (v) initiate a long-term research and development programme. The Renewable Energy Action Plan defined generating targets until 2050, when RE should account for 24% of the total energy mix, an increase of 1% in 2011 and 9% in 2020, enabling the avoidance of more than 30 million tonnes of CO_2 emissions in line with the national target.

5.2 Empirical Analysis of Policy Performance and Transition Towards RE Development in Malaysia

5.2.1 Background of the Study

Malaysia is shifting its energy production and consumption system away from fossil fuels and towards low-carbon energy sources, particularly sustainable energy. The Malaysian government has developed and implemented several policy instruments to encourage the use of RE in electricity generation. The comparison of four major operating policies for RE in Malaysia is presented in Table 1. RE policy must become more methodical and sophisticated to demonstrate the revolutionary changes generated by the energy transition in the energy sector, the society, and the economy. Decision-makers have gained experience and developed abilities in scheme execution per their objectives and energy demand conditions at lower costs due to their political awareness. However, the successful application of this policy instrument is contingent on the attainment of the goal, which is the country's capability to expand the use of RE further. To illustrate the transformative changes triggered by energy transition in the energy sector, the society, and the economy, the introduction of RE policies must become more systematic and nuanced. Political awareness has guided decision-makers to develop expertise and skills in scheme execution according to their preferences and energy demand conditions at lower costs.

A study on the effect of Malaysia's energy transition process was conducted to evaluate the effectiveness of these policies. The effectiveness of current policy instruments must be evaluated to improve their implementation. The effect of the transition

Table 1 Comparison of RE operational policies in Malaysia

	SREP	FiT	LSSPV	NEM
Concept	Small-scale RE with a production capacity of below 10 MW	Requires renewable electricity generated up to 30 MW to be sold to a utility company at a set premium price for a specific time	Competitive bidding process for RE producers in large solar PV plants with a capacity of up to 30 MW	Energy generated by the solar PV system will be used firstly, and any surplus will be sold to a national utility company at the current displacement cost
Period	2000–2010	End of 2011 until the present	LSSPV cycle 1 (2017–2018) LSSPV cycle 2 (2019–2020) LSSPV cycle 3 (2021) LSSPV cycle 4 (2022–2023)	NEM (2016) NEM 2.0 (2018–2020) NEM 3.0 (2021–current)
Advantages	Kick-start of RE programme development in Malaysia to tap palm oil waste energy potential and promote innovation and technological learning	Guarantees investment security through a long-term contract for RE investors and producers	Great return on investments for 21 years	Cost savings are only beneficial for large and medium consumers
Disadvantages	Financial burden to RE producers, including upfront cost and grid interconnections	Long-term financial burden to the government	High initial cost for the balance of system and a large area for installation	Both NEM schemes do not provide any savings to small consumers due to the low electricity tariff charged, high capital, and the PV system's maintenance cost

FiT = feed-in tariff, LSSPV = large scale solar photovoltaic plant, NEM = net energy metering, SREP = small renewable energy power
Source Mohd Chachuli et al. (2021)

phase of sustainable energy operational policies in Malaysia from 2010 to 2017 is investigated using data envelopment analysis (DEA) and the Malmquist Index (MI) or Malmquist Productivity Index. It also assesses the performance of four regions in Malaysia in implementing small renewable energy power (SREP), feed-in tariff (FiT), large scale solar photovoltaic plant (LSSPV), and net energy metering (NEM). Three input elements (employment, electricity generation, and licensed RE capacity) and two output elements (gross domestic product (GDP) and RE generation) are used in this analysis. Based on the panel data set, MI is adopted to calculate changes in efficiency, technology, and total productivity in Malaysia's four regions from 2010 to 2017. The study's findings are critical in informing policymakers and the government about the necessity of policy incentives for RE development.

5.2.2 Methodology

This study applies DEA to determine the performance efficiency of a decision-making unit (DMU) with their peers by using multiple input and output factors in a static analysis (Zhou et al. 2018). DEA is based on the linear programming concept, using a mathematical strategy to optimise the distribution of limited resources to meet a decision-making objective (Avkiran 2006; Charnes and Cooper 1962; Cooper et al. 1999; Zhou et al. 2018). According to Charnes et al. (1978), the weighted total of output to the weighted sum of input for each DMU evaluation cannot exceed 1. DEA also specifies a linear mathematical programming technique for maximising the weighted sum output ratio provided that the weights of each input and output elements are greater than 0. The output-oriented Banker–Charnes–Cooper–DEA model is presented through Eq. (1).

$$Min\Phi$$

Subject to

$$\sum_{i=1}^{n} z_i x_i + s^- = x_0, i = 1, \ldots, n;$$

$$\sum_{j=1}^{n} z_j x_j + s^- = x_0, j = 1, \ldots, n;$$

$$z_0 \geq 0, j = 1, \ldots, n.$$

If the variable returns to scale, then add

$$\sum_{j=1}^{n} z_j = 1. \tag{1}$$

In the dynamic analysis, MI is used to assess the effect of Malaysia's RE policy during the transition phase. The implementation programme of Malaysia's RE policy is divided into three periods: (i) the SREP programme (2010–2011), (ii) the FiT programme (2012–2016), and (iii) the integrated programme (2017–2018). Consequently, the transition of the RE policy is divided into two phases: (i) transition phase

I from the SREP programme to the FiT programme in 2012 and (ii) transition phase II from the FiT programme to the integrated programme in 2016.

The MI study examines the efficiency changes that occurred throughout the transition phase (Avkiran 2006; Woo et al. 2015). To determine their productivity, the index indicates the ratio of two distance functions: t and t + 1 (Menegaki 2013). Färe and Grosskopf (1994) extended the DEA-based MI by adopting the geometric mean of two indices. Equation (2) depicts the DEA-based MI, which is divided into two parts: the technical efficiency change (EC) and technological changes (TC) (Woo et al. 2015).

$$M_t^{(t+1)} = \left[\frac{D_0^t\left(x_0^{(t+1)}, y_0^{(t=1)}\right)}{D_0^t\left(x_0^t, y_0^t\right)} \frac{D_0^{(t+1)}\left(x_0^{(t+1)}, y_0^{(t+1)}\right)}{D_0^{(t+1)}\left(x_0^t, y_0^t\right)} \right]^{(1/2)}, \tag{2}$$

$$EC = \frac{D_0^t\left(x_0^{(t+1)}, y_0^{(t+1)}\right)}{D_0^t\left(x_0^t, y_0^t\right)}, \tag{3}$$

$$TC = \left[\frac{D_0^t\left(x_0^{(t+1)}, y_0^{(t+1)}\right)}{D_0^{(t+1)}\left(x_0^{(t+1)}, y_0^{(t+1)}\right)} \frac{D_0^t\left(x_0^t, y_0^t\right)}{D_0^{(t+1)}\left(x_0^t, y_0^t\right)} \right]^{(1/2)}, \tag{4}$$

where M_t^{t+1} refers to the index between periods t and $t + 1$, $D_0^t\left(x_0^t, y_0^t\right)$ refers to the distance functions of the input and output between t, and $D_0^{t+1}\left(x_0^t, y_0^t\right)$ refers to the distance functions of the input and output between $t + 1$.

The results of Eq. (2) can be interpreted as follows: $M_t^{t+1} > 1$ indicates that efficiency improves, $M_t^{t+1} = 1$ indicates that efficiency remains the same, and $M_t^{t+1} < 1$ indicates that efficiency decreases between the periods t and $t + 1$. Between periods t and $t + 1$, technical EC estimates the catch-up effect of a certain DMU position, which is either closer or farther away from the production frontier. TC reflects the frontier shift effect in Eq. (4), which estimates technological progress or regression in each DMU between periods t and $t + 1$. The MI may be calculated by multiplying EC with TC. EC denotes the time transition from the production frontier; TC denotes how changing technology influences productivity through time. Assume that the EC and TC concepts can be applied to a government policy. In such a situation, EC depicts how effectively policy instruments are applied to achieve the policy's goal. Meanwhile, TC depicts the changes outside the policy, such as deploying a new initiative or a new organisational policy.

5.2.3 Research Framework

DEA and MI methods are used to evaluate the effectiveness of RE policy initiatives in Malaysia between 2010 and 2017. The study's research framework is depicted in Fig. 6. Three input and two output elements are used to analyse the efficiency of each region in implementing RE throughout the policy transition in Malaysia. The data collection process for this study is performed based on 13 Malaysian states (divided into four regions) to ensure that panel data from 2010 to 2017 are collected. As indicated in Table 2, the DMUs in this study are the southern region (SOR), the

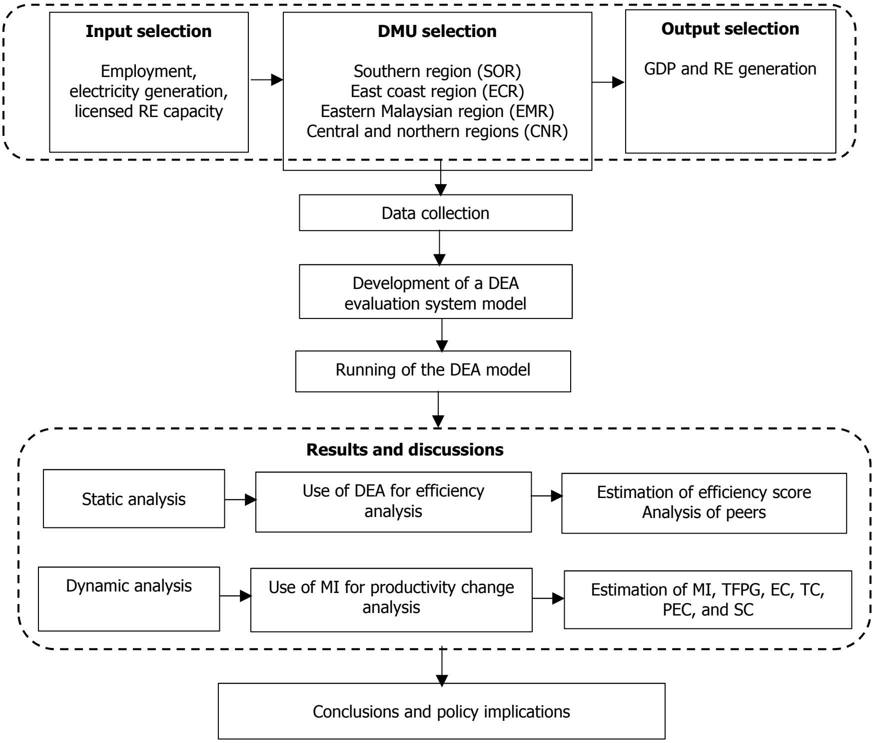


Fig. 6 Proposed DEA research framework. EC = efficiency change, MI = Malmquist Index, PEC = pure efficiency changes, SC = scale changes, TC = technological changes. *Source* Mohd Chachuli et al. (2021)

Table 2 Categorisation of the regions used in the DEA–MI analysis

DMU	Region	State
SOR	Southern region	Negeri Sembilan, Melaka, Johor
ECR	East coast region	Kelantan, Terengganu, Pahang
EMR	Eastern Malaysian region	Sabah and Federal Territory of Labuan
CNR	Central and northern regions	Selangor, Kuala Lumpur and Federal Territory of Putrajaya, Perlis, Kedah, Penang, Perak

Source Mohd Chachuli et al. (2021)

east coast region (ECR), the eastern Malaysian region (EMR), and the central and northern regions (CNR).

The first input component (number of employees) is obtained from the Department of Statistics Malaysia (DOSM) based on the Malaysia Standard Industrial Classification 2000 for total employment in the electricity, water, and gas sectors in various states (DOSM 2018). The Energy Commission of Malaysia provides the other input factor (electricity consumption), which refers to the amount of power consumed in gigawatt-hours (Energy Commission 2018a, b). RE supply refers to RE's installed capacity in megawatts. It considers four types of renewable energy sources: mini-hydropower, solar PV, biomass, and biogas. In this analysis, two output variables are considered: GDP and RE generation. GDP is calculated using DOSM's 2010 purchasing power parity in millions of Malaysian ringgit (DOSM 2017). RE generation is taken from four renewable resources in gigawatt-hours per the Malaysian Energy Commission's annual report titled 'Performance and Statistical Information on Electricity Supply Industry in Malaysia' (Energy Comission 2011, 2012, 2013, 2014a, b, 2015, 2018a, b).

5.2.4 Results and Discussion

Figure 7 depicts the EC, TC, and MI patterns in Malaysia during the implementation of the operational RE policy from 2010 to 2017. In 2012, a significant downward trend was reported in EC and TC, contributing to a decrease in MI. However, an increase in TC in 2013 helped compensate for the deficit. This conclusion can be considered the first policy change in 2012, as evidenced by the DEA findings. Adopting a new policy invariably necessitates a period of adjustment for the entire framework, in this case, RE producers and industry, and those responsible for enforcing the policy transition,

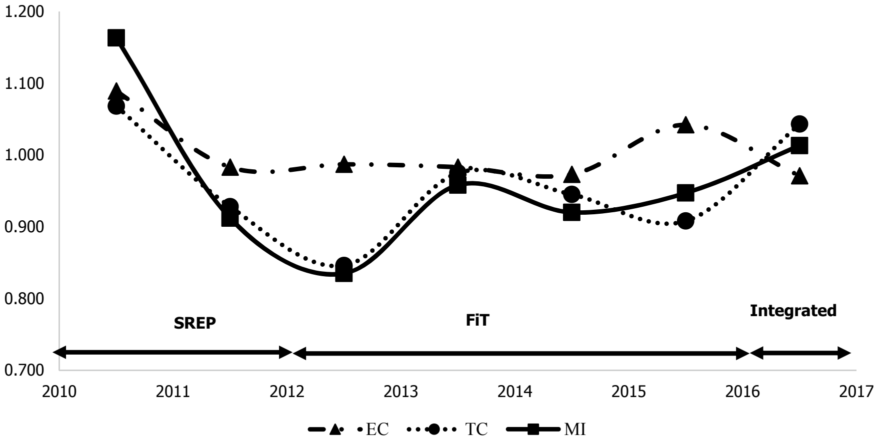


Fig. 7 Productivity growth of Malaysia's RE policy. *Source* Mohd Chachuli et al. (2021)

particularly government agencies, including decision-makers, policymakers, and the authorities. Therefore, obtaining the same productivity level even with the same amount of input may be difficult during the operational policy transition phase. After the transition period, however, the FiT scheme compels RE producers to achieve the generation objective far more efficiently than the SREP programme, with government financial incentives supplied during the permitted term.

Consequently, the efficiency of RE increased after 2013 as projected. From 2013 to 2016, however, an inconsistent efficiency trend was observed due to a lack of expertise in producing RE amongst states in the regions as a result of various events in each region affecting efficiency during this period. Although Malaysia's total RE generation has increased yearly, RE generation in each region has not remained consistent. Furthermore, the annual rise in power consumption, an input component in DEA analysis, can be highlighted as one of the reasons the regions' efficiency scores do not remain consistent over time.

The second operational policy transition in 2017, which involved the transition from the FiT programme to the execution of an integrated operational policy that included FiT, LSSPV, and NEM, saw a considerable increase in efficiency across Malaysia's regions. The successful implementation of integrated operational policies in Malaysia and the witnessed advantages from many stakeholders in Malaysia's RE industry may be increased in efficiency in 2017. The government's implementation of the LSSPV programme, achieved through an open bidding process, can be classified as a targeted approach for increasing the volume of RE generation in Malaysia because resources are abundant, and technology cost is expected to decrease in the near future.

5.2.5 Summary

Before 2016, the policy transition from SREP to FiT, and then from FiT to the integrated programme, switched the major driver of RE policy efficiency from EC to TC. The perception that under the SREP and FiT programmes the government focuses on maintaining technological productivity and subsidies under a clear policy for each operating policy introduction, resulting in fewer opportunities to establish new management strategies, can be interpreted as changes that occurred. Most RE producers rely on government subsidies and financial incentives to maintain the RE generation during both operational policy programmes.

The introduction and implementation of an integrated programme consisting of FiT, LSSPV, and NEM to accelerate RE generation in Malaysia in 2016 are not as direct as they appear. The introduction of new technologies or processes affects the implementation of these programmes. The government's support, particularly from policymakers and authorities, and the dedication of RE providers, whether small businesses or large corporations, are critical for the effective implementation of these programmes. This effect has the following possible explanations. First, in contrast with the SREP and FiT programmes, an integrated programme allows the government to manage better and achieve RE generation targets. Second, the competition between small-scale and large-scale RE producers has improved the efficiency and productivity of the country's integrated programme to encourage RE generation and socioeconomic growth. Third, the LSSPV programme implemented as part of the integrated programme increased the competitiveness of RE producers by requiring them to meet the standards of the bidding process to meet the desired amount of generation and maintain their profit.

This study offers a quantitative contribution to the transition of RE operational policy and how the introduction of such policies affects the growth of RE development. The contribution of this study is to drive the Malaysian government's effort to increase the share of RE in the country with strong policy support to fulfil its commitment to the Paris Agreement.

5.3 Effects of RE Policy Transition

Energy transition to low-carbon energy will result in a wealthier and more inclusive society. RE technology implementation has increased dramatically in recent decades owing to enabling legislation and significant cost reductions. RE has social, economic, and environmental effects, including climate-safe solutions, while simultaneously supporting many social advantages, such as job development, productivity growth, and increased social inclusion.

5.3.1 Social Effects

RE development is frequently regarded as having enormous potential social effects for broadening a country's human skills, enhancing industrial development, and assisting communities in achieving their developmental goals. Malaysia has risen to become the world's third-largest solar PV manufacturer due to the government's effort to promote RE, offering job opportunities in the industry's engineering and technical sectors and service providers. Malaysia is also a major supplier of solar PV modules, with planning facilities for half a dozen large companies with a total module production capacity of approximately 5.4 gigawatts (GW) (IEA 2020). According to the International Renewable Energy Agency, Malaysia is the sixth-largest solar PV employer globally and the largest in the ASEAN region. The number of Malaysians employed in the solar PV business increased from 7300 in 2012 to 54,900 in 2019 (IRENA 2013, 2019).

In 2008, Malaysia's NREPAP emphasised the significance of expanding human capital development activities in the RE sector. Consequently, the country generated 1205 qualified employees in the solar PV and biogas sectors between 2012 and 2018 (SEDA 2020). In addition, SEDA Malaysia trained 1939 individuals in RE-related courses, including seminars, roadshows, and training sessions, between 2011 and 2018 (SEDA 2020). More jobs in solar PV are projected to be created because of the government's implementation of integrated renewable programmes that incorporate FiT, NEM, and LSS. Efforts will be exerted to increase collaboration between public and private training institutes to generate 28,000 trained and semi-skilled professionals by the end of 2020 (Kementerian Hal Ehwal Ekonomi 2018). The government will also continue to teach over 1000 people in the biomass, biogas, mini-hydropower, and solar PV fields, resulting in expertise in these domains. Representatives from various industries, including RE project developers, financial institutions, and potential service providers, will attend these events.

5.3.2 Economic Effects

RE development is considered a green technology in Malaysia; it is one of the game changers mentioned in 11MP (2016–2020). It also supports the government's commitment to the UN's 2030 Agenda for Sustainable Development and the Paris Agreement of the United Nations Framework Convention on Climate Change (UNFCCC) signed and confirmed in 2016, which aims to cut GHG emission intensity to GDP by 45% by 2030 compared with that in 2005 (Energy Commission 2018a, b). According to the Mid-term Review of the Eleventh Malaysia Plan 2016–2020 report published by Malaysia's Ministry of Economic Affairs, the government has effectively achieved major milestones for its green growth sustainable finance mechanism (MEA 2018). The government successfully launched 102 green technology projects, including solar, biomass, recycling, and integrated waste management projects, with a total investment of USD 537.88 million in 2016–2017 (MEA 2018). In addition, the government issued the first green *sukuk* in 2017, with an initial value of USD 57.03 million and a subsequent issue worth USD 228.10 million (MEA 2018). A sukuk is an Islamic financial certificate, similar to a bond in Western finance, that complies with Islamic religious law commonly known as Sharia.

The government has also created the Green Technology Financing Scheme (GTFS), a specific funding programme worth USD 342.15 million that will aid in the development of green technology in Malaysia (MGTC 2021a, b). Between 2010 and 2015, the GTFS offered financing to 94 projects worth USD 342.15 million and 225 projects worth USD 570.26 million (MEA 2018). The government relaunched the current GTFS programme as GTFS 2.0 on 6 March 2019, adding new funds of up to USD 456.20 456.20 million to the prior scheme. Between January 2019 and December 2020, GTFS 2.0 was introduced to assist six important sectors: energy, waste, water, construction, transportation, and manufacturing. As part of an effort to stimulate the acquisition and sale of green technologies in Malaysia, the government grants an investment tax allowance for purchasing green technology equipment or assets and an income tax exemption for offering green technology services. Under the Green Technology Tax Incentive are the Green Investment Tax Allowance (GITA) for assets and projects and the Green Income Tax Exemption (GITE) for service providers (MGTC 2021a, b, 2019). However, solar projects accepted by SEDA under the FiT programme are not eligible for GITA. In 2018, the GITA incentive financed

175 RE projects and 55 EE projects with a total expenditure of USD 32.41 million. GITE included 14 green service projects totalling USD 34.40 million in domestic and international investors (MGTC 2021a, b).

5.3.3 Environmental Effects

RE generation is one of the most promising strategies for reducing GHG emissions while meeting increasing energy demand. RE exhibits the potential to substantially reduce negative environmental and public health consequences if properly deployed. In 2018, Malaysia generated 4301.67 GWh, with solar PV accounting for 40.15% and biomass contributing 34.07% of the total power (SEDA 2020). The amount of energy generated by solar PV is enormous due to many solar PV projects that have begun commercial operations. Over the same period, solar PV projects reduced CO_2 emissions by 1178617.69 tonnes, or 42.55%. Meanwhile, biomass, biogas, and small hydropower reduced CO_2 emissions by 30.61%, 16.72%, and 10.12%, respectively (SEDA 2020). Consequently, generating electricity from renewable resources positively affects Malaysia's environmental situation.

6 Energy Policy Reform Players in Malaysia

6.1 Financial institutions

The Asian Development Bank (ADB), providing technical assistance to numerous governments to aid in the development of green cities and the energy industry, is engaged in Malaysia. ADB has supported Malaysia's energy sector, particularly in hydropower development, transmission lines, and RE (CBI 2020). ADB also assisted in developing and implementing Malaysia's Green City Action Plan for integrated urban management by providing a technical assistance grant and implementation assistance. The ASEAN Catalytic Green Finance Facility is a new initiative that aims to boost green infrastructure investments in Southeast Asia by more than USD 1 billion (CBI 2020). RE, EE, sustainable transportation systems, green communities, and sustainable water supply and sanitation are only a few initiatives being considered. The new facility is co-funded by ADB, ASEAN Infrastructure Fund, Agence Française de Développement, European Investment Bank, the European Union, and the Republic of Korea. This initiative will be a great source of funding for Malaysia's future green projects.

6.2 Private Interest

In 2018, Malaysia declared using 20% RE in its power mix by 2025. Its RE sector is expected to require USD 7.53 billion in investments to meet its 2025 target. The planned investments will come from various sources, including the government, public–private partnerships, and private financing. The government will undoubtedly need to incentivise private financing to promote private participation. Apart from continuing government incentives, such as GTFS, GITA, and GITE, institutional reforms should also be prioritised. The Malaysia Energy Supply Industry 2.0 strategy may help the government meet its goal. With a series of initiatives implemented by the government to enhance public–private partnerships and private financing, the country can receive more private sector investments in the RE industry, propelling the sector's growth and allowing the country to meet its 2025 target.

6.3 Government

The government first introduced the GTFS in 2010, with a total target financing approval of USD 798.36 million to encourage the development of green technology. The Ministry of Finance approved extending the GTFS, called GTFS 2.0, in March 2019, with a budget of USD 456.20 million until 2020 (MGTC 2021a, b). The initiative aims to encourage green investments in qualified industries, such as energy, water, building and townships, transportation, waste, and manufacturing, by making finance more accessible and at reduced rates. The GTFS has benefited from several green projects since its inception. Only 13 projects received soft loans totaling USD 37.48 million in 2010. By 2017, the number of projects with major social and environmental implications increased to 319, with USD 829.84 million to be allocated. Nearly 5000 green jobs are created yearly, and 3784 million tonnes of CO_2 are saved. GTFS 2.0 has approved 336 new green technology manufacturers and users for soft loans totaling USD 0.23 million. GTFS 3.0, the most recent version, has a fund size USD 500 million for 2 years until 2022 to stimulate the issuance of sustainable and responsible investment *sukuk* (CBI 2020). Green investments are estimated to provide USD 912.41 million in income and 2500 job opportunities to Malaysia. As of July 2018, 28 banks and financial institutions had signed up for the GTFS, with a total loan volume of USD 875 million. Conventional financing accounted for approximately 53% of all projects funded, with the remaining coming from Islamic sources. The GTFS is a one-of-a-kind example of how governments can use tools, such as guarantees and incentives, to help green projects develop in a country.

6.4 Conclusion

Malaysia has a bright future in sustainable energy adoption, supported by a generally favourable investment environment. In this changing green energy scenario, maximising existing businesses, extending the value pool, and exploring new frontiers are valuable areas that require success. New RE sources will add value along the value chain, resulting in widespread advantages for the country. RE deployment will result in creating new jobs and new commercial opportunities to improve the current network infrastructure. Sustainable energy opens up new economic possibilities for Malaysia in the future. Solar PV production in Malaysia and the capability to extend its thriving automobile sector through battery manufacturing are amongst the possibilities in the industrial prospects.

7 Barriers to Sustainable Energy Policy Reforms

In the current world, the development of sustainable energy technology is accelerating. RE, which is derived from natural resources, aids in providing long-term electricity to users. As consumers, using natural resources, such as solar, biomass, biogas, and hydropower, to generate electricity is a realistic option for energy demand. In 2018, RE, including hydropower, produced approximately 7% of Malaysia's electricity. This accomplishment is regarded as a success for these technologies, which have overcome several barriers to becoming more competitive. Here are eight barriers to the development of RE technology in Malaysia.

7.1 Technology Stigma

A significant obstacle to a country's growth in its sustainable energy industry is the perception that implementing sustainable energy initiatives is costly. Therefore, collaboration amongst stakeholders, scientists, and industry players is necessary to publicise the benefits and appropriate the costs of implementing sustainable energy programmes to dispel this stigma. To solve these issues, Malaysia must implement various long- and short-term policies and awareness campaigns and assist in developing sustainable energy to attain energy security and autonomy.

7.2 Capital Cost

Another barrier to RE technology is the high capital expenditures of solar farm construction. Nevertheless, solar and other renewables are inexpensive as they require no maintenance and do not use fuel. Consequently, most of the costs will be incurred during solar farm construction. The deployment of RE technology necessitates significant upfront investments that must be financed. Capital expenses account for a large portion of the life cycle costs of RE projects. Beyond regular operating expenses, capital costs include the upfront costs of constructing the plant and substantial maintenance work that must be performed during the unit's lifetime. Solar technology installation will be more expensive, causing the government and financial institutions to view renewables as risky. As a result, they can lend money at higher rates, making it difficult for developers and utilities to maintain their investments. However, investors should be aware that utility-scale solar farms can become the least expensive renewables when the construction costs are factored in. Furthermore, renewable energy capital costs may continue to decline in the following years.

7.3 Siting and Transmission

Most renewable technologies, such as solar panels, are decentralised RE sources. They are small production systems dispersed across a vast region and work together to generate electricity. Grid resilience is one of the benefits of decentralisation. However, the grid resilience can still pose two major obstacles to renewables: siting and transmission. The site is the area where renewable plants, such as solar farms, must be located. Siting approvals are required to construct and operate electric transmission lines physically. Finding an appropriate location may be difficult, which is one of the barriers to RE use. Years and millions of dollars can be spent on this procedure. It also necessitates permits, contracts, community interactions, and negotiations, all of which add to the project's expenditures.

7.4 Market Entry

One major barrier to RE technology is market access. RE sources must compete with other fossil fuel energy sources, such as natural gas and coal. Low-cost solar technologies must also demonstrate to investors and consumers their capability to generate huge amounts of energy because nuclear, coal, and natural gas provide most of the energy for baseload demand in enormous quantities. These energy sources demonstrate that they can wield massive market power over renewable technologies, such as solar. Consequently, compared with many fossil fuel–based sectors, penetrating the market is more difficult for renewable technologies.

7.5 Unequal Playing Field

One of the challenges to renewables is the unequal playing field created by other energy industries. Subsidies and other government incentives will assist taxpayers in funding fuel imports, electricity generation, resource exploration, and industry research and development, all of which will help expand domestic production. Moreover, solar power will also receive fewer subsidies and favourable political treatment. The divergence between policy and science implies that the customers' price for energy options, such as fossil fuels, may not reflect their true cost. It also indicates that renewables will be on an unequal playing field. They will be competing against subsidised industries but will be powerless to punish polluters indirectly. Therefore, RE technologies should receive the same subsidies as fossil fuel technologies to ensure that both technologies will compete on an equal playing field.

7.6 Reliability Misconceptions

One of the barriers to solar power adoption may be misconceptions about RE's reliability. Solar power generation will always require government support to build electrical grids, to ensure the reliability misconceptions. They can also emphasise that RE generators will require fossil fuels as a backup when the sun is not shining. However, solar energy is a clean source of energy. When solar panels are spread across a vast region and linked with compatible energy sources, solar energy becomes highly reliable. Smart appliances, real-time pricing, sophisticated batteries, storage systems, and other modern grid technologies will improve solar efficiency performance. These technologies can assist countries in operating grids reliably and safely while generating energy with a high proportion of renewables.

7.7 Lack of Data

A data-driven decision-making process will be critical in the future planning of sustainable energy policies. It will allow governments to develop new policies and plans, create opportunities, increase revenue, forecast future trends, improve present operational efforts, and generate actionable insights into sustainable energy planning. However, various obstacles have been reported in the data-driven decision-making process in most sectors, including sustainable energy. One issue is the lack of an open data policy, which restricts the use of the acquired and access to government data, resulting in excessive fees and the lack of complete access to data gathered by respective agencies. Malaysians researching on the same subject may have different results and crucial conclusions because of the limited access to data sets. This situation negatively affects capacity development and the government's policymaking.

7.8 High Hope

One of the country's major barriers to establishing an RE industry is high hope. To support the implementation of the Paris Agreement, the Malaysian government recently raised its RE target to 31% by 2025 and 40% by 2035. The objective of 40% RE by 2035 is ambitious. The installed RE capacity is expected to be approximately 18,000 MW by 2035, more than quadruple the current installed capacity. Industry players should not urge Malaysia to adopt an unrealistically high RE target without considering the electricity cost to consumers because the government's strategy for planning the country's electricity supply is to balance the three parts of the energy trilemma, i.e., to assure energy supply, affordability, and sustainability to end consumers.

8 Conclusions

Malaysia's economic growth as a developing country is heavily reliant on energy. The availability of adequate, reliable, and affordable energy is crucial for driving the country's development. It also acts as an essential utility that provides social necessities to maintain a desirable quality of life for the citizens. Consequently, Malaysia's sustainable energy sector reform should focus on ensuring a secure, reliable, and cost-effective energy supply while encouraging efficient use, advocating supply diversity, and reducing waste. As the government attempts to balance energy security, sustainability, and equality, i.e., the energy trilemma, RE and EE have become increasingly important in sustainable energy reform initiatives. It has already taken steps towards sustainable energy policy reforms, such as those related to RE and EE. However, challenges will arise in the future; thus, Malaysia must maximise its capability to overcome shocks or any unfavourable scenarios. In nearly all of these circumstances, all stakeholders must play an active role in supporting these initiatives. Governments should also implement policies and regulations that are enabling, sustainable, and encouraging to industries, requiring them to adapt their daily operations.

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Digitalisation in the Context of Electricity Market Reforms and Liberalisation: Overview of Opportunities and Threats

Besma Glaa

Abstract Digitalisation enabled by advances in technology has an enormous potential to create value for electricity market reforms by helping promote competition, security of supply, and sustainability. It contributes to the growth of the electricity sector and changes the electricity market and the way consumers can engage in it. However, besides the opportunities emerging with digitalisation, the threats of emerging digital technologies are increasing. While digitalisation can bring many positive benefits, it can also make electricity systems more vulnerable to cyber-attacks. This chapter investigates digitalisation in electricity market reforms and liberalisation worldwide, specifically in ASEAN. It also discusses the potential opportunities and threats of digitalisation for electricity market reforms.

1 Introduction

Restructuring the electricity sector is one of the most important changes that occurred around the world. It has helped the electricity sector evolve from a natural monopoly with strict government prices, entry regulation, and state ownership to a more liberalised and competitive electricity market. These restructuring initiatives aimed to promote competition, shrink the scope of electricity sector output, and introduce new regulatory mechanisms to provide better incentives for cost reduction and efficient pricing (Joskow 2002).

In particular, Southeast Asia, considered the fastest-growing region globally in terms of electricity demand, has experienced a demand growth of more than 6% annually over the past 20 years. Of the region's 10 countries, the 4 largest by electricity consumption—Indonesia (26%), Viet Nam (22%), Thailand (19%), and Malaysia (15%)—make up more than 80% of total demand in the region (Knive 2011). These countries are part of the Association of Southeast Asian Nations (ASEAN), comprising 10 members: Brunei, Cambodia, Indonesia, the Lao PDR, Malaysia, Myanmar, the Philippines, Singapore, Thailand, and Viet Nam. These 10 countries

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have been undergoing continuous change to find the most suitable reform model for their electricity market capable of promoting competition, security of supply, and sustainability while at the same time being compatible with their countries' context and government objectives. These economies have gone through different stages of the liberalisation process to do so. Liberalised or deregulated electricity markets aim to maximise social welfare via competition (Aliabadi et al. 2021).

In most cases, liberalisation is associated with the unbundling of the electricity sector into generation, transmission, distribution, and retail activities. The aim was to make electricity supply more efficient by allowing more competition while integrating necessary regulations. However, this unbundling did not happen overnight and it is not completely finished today.

In this context, numerous new industry megatrends emerged in the electricity sector. The first megatrend is decentralisation, which includes customer participation and integration of distributed resources. The second megatrend is electrification, increasing electricity demand due to electric vehicles and other new solutions. The third and most critical megatrends is digitalisation, which includes smart energy networks using digital technologies. These megatrends mentioned lead to further reform initiatives to make the power sector more efficient, reliable, and sustainable (Kumar et al. 2021).

Worldwide, the speed of digitalisation in the electricity sector is increasing. The global investments in digital electricity infrastructure and software have, according to the International Energy Agency (IEA), increased by more than 20% per year since 2014, reaching US$47 billion in 2016. This is almost 40% higher than the global investment in gas-fired electricity generation (US$34 billion) and almost as much as the total investment in India's electricity sector (US$55 billion) (IEA 2017). In particular, the electricity sector has experienced rapid digitalisation with the emergence of smart grids and smart devices. Besides, the adoption of intelligent, sophisticated technology, including artificial intelligence (AI) for control and monitoring systems, is enabling new business models and more efficient asset management. The energy sector's investment in big data and AI expanded by a factor of 10 in 2018, according to a new report by accountancy firm BDO (Innoenergy 2019). Indeed, digital technologies have enormous potential to contribute to growth in the electricity sector and help deliver exceptional value to shareholders, customers, and the environment. Hence, digitally advanced firms are taking more risks to achieve new levels of competitive advantage (Kane et al. 2015). As a result, both the benefits and risks of emerging digital transformation technologies are increasing (Christensen et al. 2013).

Despite the numerous advantages gained from digitalisation and modernising the grid, this increased the risks for cyberattacks and the number of routes hackers can exploit to enter utility systems. The emergence of smart grids triggered the embeddedness of information and communication technologies with devices and increased the linkage between the networks. Therefore, the system became complex, and the number of access points increased. Furthermore, the rise in the use of software and information technologies in the utilities' operations and the automation of functions played a central role in increasing the vulnerability and the impact of attacks on the energy sector (Livingston et al. 2019). Likewise, as they become renewable energy sources, utilities are quickly enlarging the number of connections and sensors along with their networks, expanding the risk for cyberattacks (Stringer and Lee 2021). Cybersecurity plays an important role in the electricity sector. A reliable electricity supply is indispensable for everyday life. Attackers have been targeting electricity utilities for years, potentially causing blackouts that can result in catastrophic consequences. Especially today, when digitalisation is omnipresent in all areas of our lives, we must be careful with the implementation of digitalisation in a critical area, such as the electricity sector.

This chapter aims to enhance understanding of how digitisation has impacted the electricity sector, particularly the electricity market reforms and liberalisation worldwide and in ASEAN. It also aims to uncover the opportunities of digitalisation for the electricity market reforms in ASEAN and the consequent threats that could trouble the electricity sector and the electricity market reforms.

2 Electricity Market Reforms and Liberalisation Worldwide and in ASEAN

Historically, a single firm, primarily a government entity, was mandated to manage all three functions: electric power generation, transmission, and distribution. Nevertheless, this entity created under the monopoly market gave consumers limited options to select suppliers. Besides, the price of electric power, the quality of service, and competitiveness have been negatively affected (Coricelli et al. 2006). Thus, 'traditional structures within the electricity sector are no longer those best able to meet the sector's growing appetite for capital. Regulatory reform, restructuring, and privatisation are becoming the norm' (Caruso and Chen 1996, p. 1).

The electricity sector of various countries has been transitioning and restructuring by moving away from vertically integrated monopolies and towards more competitive market models (Singh 2011). This process is also known as the liberalisation of electricity markets. Figure 1 shows the electricity market before and after market liberalisation.

Liberalised electricity markets aim to improve economic efficiency and maximise social welfare via competition (Aliabadi et al. 2021; Renn and Marchall 2020). The perceived benefits of a liberalised market include economies of scale, better management of peak demand and improved efficiency in power supply, and potentially lower electricity prices (Wu 2013). Markets that have liberalised successfully also show a clear trend of falling electricity prices for industrial consumers in nominal and real terms (IEA 2005). The transition from a natural monopoly to a competitive market will not necessarily result in lower consumer tariffs. However, the transition ensures that the electricity price reflects the cost of power generation, which is essential to secure a sustainable energy supply within a market (Knive 2011). Furthermore, liberalisation has helped the electricity sector improve efficiency in the operation of generation plants, networks, and distribution services.

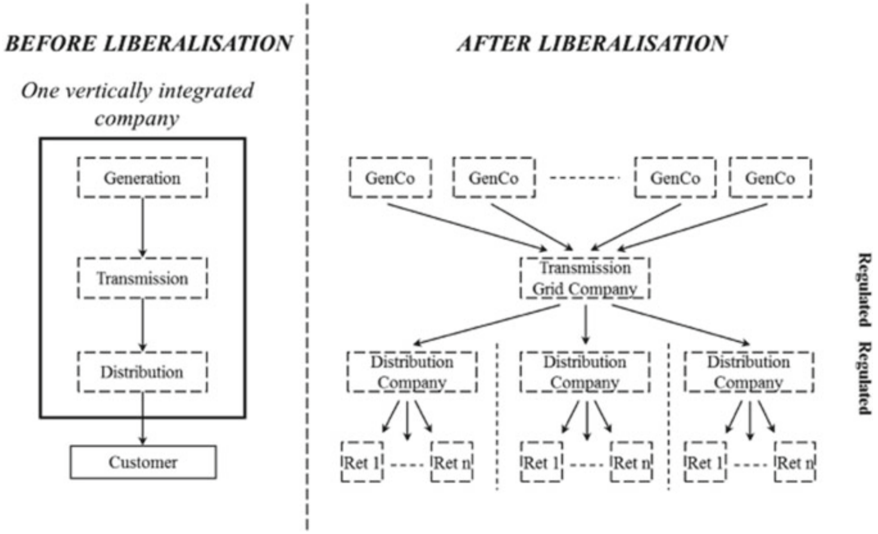

Fig. 1 Liberalising the electricity market. *Source* Pepermans (2019)

In the early 1990s, the successful liberalisation of electricity markets in Europe formed the basis of a wider trend towards the deregulation of power markets around the world. For instance, the electricity market reforms in the Nordic countries were more far-reaching and well-functioning than in the European Union by achieving efficiency and transparency. A dilution of market power amongst incumbents has been achieved by integrating the national markets (Knive 2011). In the mid-to-late 1990s, several ASEAN countries initiated wide-ranging programmes to reform their electricity industry, improve its productivity, and attract much-needed private investment (Sharma 2005). The main drivers for market liberalisation in ASEAN are (i) the loan conditions of the International Monetary Fund, (ii) lower government debt burden, (iii) lower electricity prices, and (iv) increasing electrification rate (Jaeger et al. 2017). Singapore was the first country in ASEAN that launched a competitive power market in 2001, followed by the Philippines in 2006 with the commencement of the wholesale electricity spot market.

Furthermore, ASEAN countries have initiated an ambitious project of regional development to support economic growth and the integration of higher shares of renewable energy. The ASEAN region aims to integrate 23% renewable energy by 2025. One way of reaching that target is through regional interconnection and trade (Knive 2011). Therefore, the development and growth of renewable energies enhanced the cross-border electricity market integration intended to help countries deal better with peak demand and intermittency in production and use abundant renewable energy resources more efficiently. In addition, the ASEAN Power Grid (APG) construction aimed to ensure regional energy security, enhance cross-border electricity trade, promote efficient utilisation of resources, and share surplus reserve generation capacity amongst member states (Ibrahim 2014).

Since then, ASEAN countries have moved a long way and made a lot of progress. However, they are still facing some critical challenges to achieving and benefiting from market liberalisation in all ASEAN countries, specifically those where market liberalisation has been slow and faces many barriers.

3 Liberalised Electricity Markets Challenges in ASEAN

Although there is a lot of progress in liberalising electricity markets, ASEAN countries face scepticism towards market liberalisation such as (i) resistance of labour unions (Indonesia, Thailand, and Viet Nam); (ii) a low rate of electrification (Cambodia, Myanmar); (iii) political environment (Lao PDR, Thailand); and (iv) size of the country (Brunei Darussalam) (Jaeger et al. 2017). ASEAN economies must overcome several institutional and political obstacles to develop an integrated electricity market (Wu 2016) though designing a perfectly competitive liberalised market is extremely difficult (Aliabadi et al., 2021). ASEAN countries face many barriers that are slowing down the liberalisation of the electricity market process. First, governments in some ASEAN countries are reluctant to support the ASEAN Power Grid (APG) due to the need to protect their own energy sectors (Kumar 2015). Second, without the participation of the private sector and achieving interconnection in ASEAN, electricity market integration cannot be developed. Indeed, this depends on how ASEAN member states and involved companies cooperate and deepen their relationships (IEA 2015). Third, many ASEAN countries are underdeveloped in terms of transmission grids and other electricity infrastructure. For example, the electrification rate in some ASEAN member countries is still very low. The construction of APG needs substantial investment in capacity building (Kutani and Li 2014; Li and Chang 2015). Therefore, the role of international organisations, especially regional organisations such as the Asian Development Bank and the Asian Infrastructure Investment Bank, is important (Wu 2016). Fourth, relying on polluting electricity sources such as hydropower in cross-border trade (e.g. the Lao PDR government relies on hydroelectricity in cross-border trade) is another barrier that is allowing down the liberalisation of the electricity market process. Even though the ASEAN region aims to integrate 23% renewable energy by 2025, there is still more work to minimise negative externalities and expand the production of wind and solar power.

4 The Impact of Digitalisation on the Electricity Sector

Digital technologies such as artificial intelligence, machine learning, and predictive analytics are becoming an integral part of everyday life in organisations. This development can completely transform businesses (Jesuthasan et al. 2016). Initially, digitalisation aimed to increase efficiency (Andersson et al. 2018). However, the current effects of the digital transformation have had far-reaching impacts on society, politics, organisations, and individuals. For instance, according to Matt et al. (2015, p. 339), ‘potential benefits of digitisation are manifold and include increases in sales or productivity, innovations in value creation, as well as novel forms of interaction with customers, among others’.

In particular, the electricity sector can capture enormous value from rapid digital transformation. According to the World Economic Forum (2022), $1.3 trillion of value can be captured globally, from 2016 to 2025. By leveraging digital technologies, such as digital service platforms, smart devices, the ‘cloud’, advanced analytics, and big data, companies in the electricity industry can (i) optimise electricity network flows, (ii) increase the asset life cycle of electricity infrastructure, (iii) innovate, and (iv) create customer-centric products.

Digital transformation blurs the difference between generation and consumption and enables four intertwined opportunities. For instance, digital transformation could allow the integration of variable renewable energy sources, smart demand response, the emergence of small-scale distributed electricity resources such as household solar PV panels and storage, and the implementation of smart charging for electric vehicles. First, variable renewables are integrated by enabling grids to match better energy demand (e.g. when the sun is shining and the wind is blowing). In the European Union alone, increased storage and digitally enabled demand response could reduce solar photovoltaics (PV) and wind power from 7% to 1.6% in 2040, avoiding 30 million tonnes of carbon dioxide emissions in 2040. Second, smart demand response could provide 185 GW of system flexibility. This could save US$270 billion of investment in new electricity infrastructure (IEA 2017). Third, the emergence of small-scale distributed electricity resources such as household solar PV panels and storage is achieved by creating better incentives and making it easier for producers to store and sell surplus electricity to the grid. Fourth, new digital technologies, such as blockchain, could make payments smooth and help facilitate peer-to-peer electricity trade within local energy communities. Fourth, implementing smart charging technologies for electric vehicles could help shift charging to periods when electricity demand is low, and supply is overflowing. This would provide additional flexibility to the grid, and save between US$100 billion and US$280 billion between 2016 and 2040 (IEA 2017).

Besides, digitalisation helps electrical grids maintain their stability and reliability by balancing reserves from sources like wind and solar. This means digitalisation will also help cut costs by improving efficiency in homes and businesses with more connected sensors in place. These sensors will improve maintenance and keep components running better for longer by monitoring the grid and identifying points of failure and faults. Through predictive maintenance, data exploitation can reduce operating and maintenance costs in production and distribution and, eventually, the price of electricity. This reduces costs, increases the resilience and reliability of supply, and diminishes the costly network failures for the utility and the economy. Furthermore, consumers will be more encouraged to generate their electricity at home and move it to the grid as needed (BloombergNEF 2017).

According to Bryan Friehauf, global head of Enterprise Software for Hitachi ABB Power Grids, digital technologies will make electricity systems more efficient and cost effective. Likewise, he emphasised the importance of ‘communicating the benefits of digitalisation and how it can enable them to work better, smarter, and faster’. However, he also argued that the biggest challenge to more extensive deployment of digital technologies besides regulatory approval and costs is ‘a demonstrated return on investment’ (Friehouf 2020).

5 Digitalisation Opportunities for the Electricity Market Reforms

By helping electrical grids maintain their stability and reliability and balancing reserves from sources like wind and solar, digitalisation will help cut costs by improving efficiency in homes and businesses. Digitalisation can then facilitate and accelerate the liberalisation of the electricity market process. Moreover, digitalisation is changing how consumers can engage in the electricity market. This means that consumers—instead of actively monitoring the electricity market and decide how or when to participate—can now set batteries, pool pumps, smart air conditioners, and any other number of devices to consume electricity at the cheapest times and export at the most expensive times (i.e. when the power system needs it most). By taking advantage of new technological developments, consumers can capture the benefits of participation that require minimal action. One more benefit of digitalisation is helping reduce barriers to a two-sided market where both demand and supply sides are actively engaged in scheduling and dispatching in the wholesale market (Australian Energy Market Commission 2019). Additionally, digitalisation is helping reduce the cost of participation in the electricity market.

In general, technology is a significant aspect of deregulation measures. It has played a substantial role in enhancing deregulation efforts. New technologies have impacted the economy, reducing operational and utility costs. For example, to improve customer satisfaction, entities in the electricity industry have adopted flexible, change-oriented computer systems (Necoechea-Porras et al. 2021). Some companies have adopted utility translation systems software to obtain consumption data from massive power customers. For instance, the firms have also developed real-time pricing of electric power and enhanced tailored billing systems (Schuelke-Leech et al. 2015).

All drivers of electricity market reforms that contribute to an open and liberalised market, such as cost reductions, competitiveness, lower electricity prices, and increasing electrification rate, can be facilitated by adopting digital technologies. As mentioned earlier, by leveraging digital technologies—such as digital service platforms, smart devices, the ‘cloud’, advanced analytics, and big data—companies in the electricity industry can optimise electricity network flows, increase the asset life cycle of electricity infrastructure, innovate, and create customer-centric products. In addition, new digital technologies such as blockchain could make payments smooth and help facilitate peer-to-peer electricity trade within local energy communities. Furthermore, implementing smart charging technologies for electric vehicles could help shift charging to periods when electricity demand is low and supply is overflowing. This would provide additional flexibility to the grid and create savings. Moreover, digital technologies could integrate variable renewable energy sources, smart demand response, and the emergence of small-scale distributed electricity resources relevant for achieving perfect market liberalisation (IEA 2017).

Despite the numerous opportunities gained from digitalising the electricity market and due to the increased interconnectivity of electricity systems throughout the world, the electricity sector has grown to be an attractive target for cybercriminals and the electricity system has become vulnerable to cyberattacks.

6 The Threats of Digitalisation in the Electricity Sector

Considered the most critical to a functioning society, the electricity infrastructure is one of the most frequent targets of cyberthreats worldwide. The world's power grids and the electric power sector have become even more vulnerable to hackers. Over the past 4 decades, the shift from manual to automatic control of the power plants and substations, on the one hand, and the growth of the connection to public and private networks for remote access, on the other hand, have increased the exposition of the power grids to attacks (Stringer and Lee 2021). Today, cyber risk is evolving to reach into industrial control systems and supply chains. One factor that accelerated and facilitated the growing cyber risk is the modernisation that allows internet connectivity, the digitalisation of the electric power sector, and more smart applications (Livingston et al. 2019). Attackers have been targeting power utilities for years. They can cause blackouts resulting in catastrophic consequences. Therefore, cybersecurity plays an important role in the electricity sector and ensures a reliable electricity supply indispensable for everyday life. Especially today, when digitalisation is omnipresent in all areas of our lives, we must be careful in implementing it in a critical area, such as the electricity sector.

The increased interconnectivity of energy systems worldwide has made the sector an attractive target for cybercriminals. And the electricity system becomes vulnerable to cyberattacks. According to the German Federal Office for Security, the number of cyberattacks on critical infrastructure tripled in 2018 compared to the previous year (Innoenergy 2019). Therefore, data protection and data security became some of the greatest weak points of artificial intelligence. In its latest World Energy Congress report, the World Energy Council argued that the number of successful cyberattacks has enormously risen. The energy industry may be unready to deal with new and emerging risks (World Energy Council 2019). These risks are not specific to one country, but the electricity sector has been targeted in, for example, the United States, the United Kingdom, Asian countries, Europe, Japan, Australia, and many other countries (Livingston et al. 2019).

Many firms are increasingly working systematically to manage cybersecurity risks and have either started or planned to start with cybersecurity as part of internal compliance. In particular, the electricity sector requires specific cybersecurity and data protection considerations. Therefore, a high level of digitalisation can only happen if it will not threaten the electrical power system. Thus, the new geopolitics of technology, including data protection and cybersecurity, raises questions about the role of digitalisation in the electricity sector in the long term. Furthermore, the geographic demarcations between geographic boundaries are rapidly diminishing, and an outage in one country might easily trigger blackouts in other sectors and countries.

Indeed, there has been a lot of global nervousness around electricity market security recently. For example, a key player in the United Kingdom electricity market fell victim to a cyberattack in May 2020. The victim of the said attack is Elexon. This company plays a vital role in monitoring electricity generation, matching it to the national grid demand and ensuring that correct payments are made to those generating the electricity. Being at the heart of the balancing and settlement system, Elexon worked with Great Britain's national grid electricity system operator to keep the lights on nationwide. The electricity market business amounts to some US$2.07 billion (£1.7 billion) of transactions every year. These high-value transactions, combined with an essential part of the electricity supply market, make Elexon and similar companies a primary target for cyberattacks (Winder 2020).

As Livingston et al. (2019) stressed, energy and electrical power are amongst the top three sectors targeted for attack in the United States (US). In 2016 alone, 59 incidents were reported in the electricity sector, 20% of the 290 total attacks reported.[1] US Energy Secretary Rick Perry reported a growing cyber risk in the power sector and an extreme increase of cyberattacks in early 2018 targeting the electric grid in North America. Cybersecurity expert Rich Heidorn Jr., whose firm discovered the massive cyberattack that targeted electric grids and caused blackouts in Ukraine in 2016 and left a quarter of a million Ukrainians without electricity, told state regulators that not only are the attacks are rising. But the number of hackers targeting the US electric industry is also growing, and the hackers' capabilities are expanding.[2]

The Asian electricity sector has also been a target for cyberattacks. For instance, in India, a blackout in Mumbai caused by a cyberattack impacted stock markets, trains, and thousands of households in the nation's financial hub. Another example is the malware that infected a computer network used for administrative functions in India Ltd.'s Nuclear Power Corp. in 2019. Reji Kumar Pillai, president of India Smart Grid Forum, a think tank backed by the federal power ministry that advises governments, regulators, and utilities, has urged for proper cybersecurity systems to support India's power system (Stringer and Lee 2021).

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[1] https://us-cert.cisa.gov/sites/default/files/Annual_Reports/Year_in_Review_FY2016_IR_Pie_Chart_S508C.pdf (accessed 10 November 2019).

[2] https://www.rtoinsider.com/articles/20526-expert-sees-extreme-uptick-in-cyber-attacks-on-utilities (accessed 10 November 2019).

Total prevention of cyberattacks is impossible, but their impact can be limited if countries and companies are well prepared. This raises the question of the best practices for succeeding with digitalisation and the associated risk mitigation measures that help prevent failures in the electricity sector.

7 Digital Resilience in Electricity Market Liberalisation

While digitalisation can bring many opportunities to electricity market liberalisation, it can also make electricity systems vulnerable to cyberattacks. The digitalisation of the electricity sector and the growth of the internet of things are increasing the cyberattacks and risks in the electricity sector. Furthermore, today cyberattacks in the electricity sector are becoming easier and cheaper to organise.

Although complete prevention of cyberattacks is impossible, limiting their impact by building system-wide resilience is needed (IEA 2017). However, ‘even with modern electricity infrastructure, the disruptive events are still occurring, and resilience is a big question’ (Kumar et al. 2020). Resilience, defined by Linkov et al. (2018, p. 1) as ‘the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions’, accepts the possibility of system failure and focuses on its recovery and adaptation. If experts wish to adopt a resilience-based approach, they should focus on system recovery and adaptation to the after-effects of threats (Linkov et al. 2018). The International Energy Agency (IEA 2017) highlighted the importance of cyber hygiene and security by design as key concepts besides resilience. Cyber hygiene is the basic precautions and monitoring that all information and communication technology users should undertake. Security by design means incorporating security objectives and standards as a core part of the technology research and design process. Furthermore, Bryan Friehauf, global head of Enterprise Software for Hitachi ABB Power Grids, highlighted the relevance of ‘both the domain and software expertise to intelligently guide a utility’s digitalisation journey’ and the ‘commitment from the workforce’ (Friehouf 2020).

International efforts can also help governments, companies, and others build digital resilience capabilities. Various organisations are already involved, each contributing its comparative strength, including sharing best practices and policies and helping mainstream digital resilience in energy policymaking. However, this depends on all actors and stakeholders first being aware of the risks. Besides, a common understanding of the potential of digitalisation and a coordinated effort between policymakers and industry is critical for reaching the electrical grid’s efficiency, reliability, and security. Digital resilience must also be included in technology research and development efforts and built into policy and market frameworks. Indeed, policy and market design are vital to guide digitally enhanced electricity systems in an efficient, secure, accessible, and sustainable way (IEA 2017).

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